Coiled Tubing Manual

NOV CTES
3770 Pollok Drive
Conroe, TX 77303
+1 936 777 6200
CTESSales@nov.com
www.nov.com/ctes

Contents

Chapter 12

Mechanical Operations

Chapter 17

Minimizing Risk For CT Operations

1

INTRODUCTION

OBJECTIVE OF THIS MANUAL

The objective of this manual is to prepare personnel for planning and executing CT workover, completion, and drilling operations in a safe and cost-effective manner. Pursuant to this objective, the manual provides a detailed discussion of CT technology and its applications, and provides general guidelines for planning and executing CT operations. A significant portion of this manual is devoted to minimizing the risks of CT operations while maximizing their benefits.

NOTE: NOV CTES will use its best efforts in gathering information and its best judgment in interpreting and providing engineering calculations and analysis of any information; however, NOV CTES does not guarantee the accuracy of any interpretation, research analysis, job recommendation, engineering calculations, or other data furnished by NOV CTES. Accordingly, NOV CTES shall not be liable for any damages arising from the use of such information. NOV CTES also does not warrant the accuracy of engineering calculations or data transmitted by electronic process and NOV CTES will not be responsible for accidental or intentional interpretation or interception of such data by others. In no event shall NOV CTES be liable for special, incidental, indirect, consequential or punitive damages.

NOV CTES

This manual was developed over the course of several years by NOV CTES.

An engineering company supporting the well intervention and drilling industries, NOV CTES is the leading worldwide provider of advanced coiled tubing monitoring devices, data acquisition systems, and modeling software, with offices in Conroe, Texas, U.S.A.; Aberdeen, U.S.; and Dubai, U.A.E.

For more information about the contents of this manual, please contact:

NOV CTES
Phone: 936-777-6200
FAX: 936-777-6312
E-mail: ctesinfo@nov.com

Edition September 2013

2 CT HISTORY

CT, as a well service tool, was originally developed in the early 1960's and has become a key component of many well service and workover operations. Well service or workover applications still account for over three-quarters of CT work. However, the recent and more advanced use of CT technology for completion and drilling applications is rapidly gaining popularity.

The major driving force behind the original use of CT was a desire to perform remedial work on a live well. To do this, three developments were required:

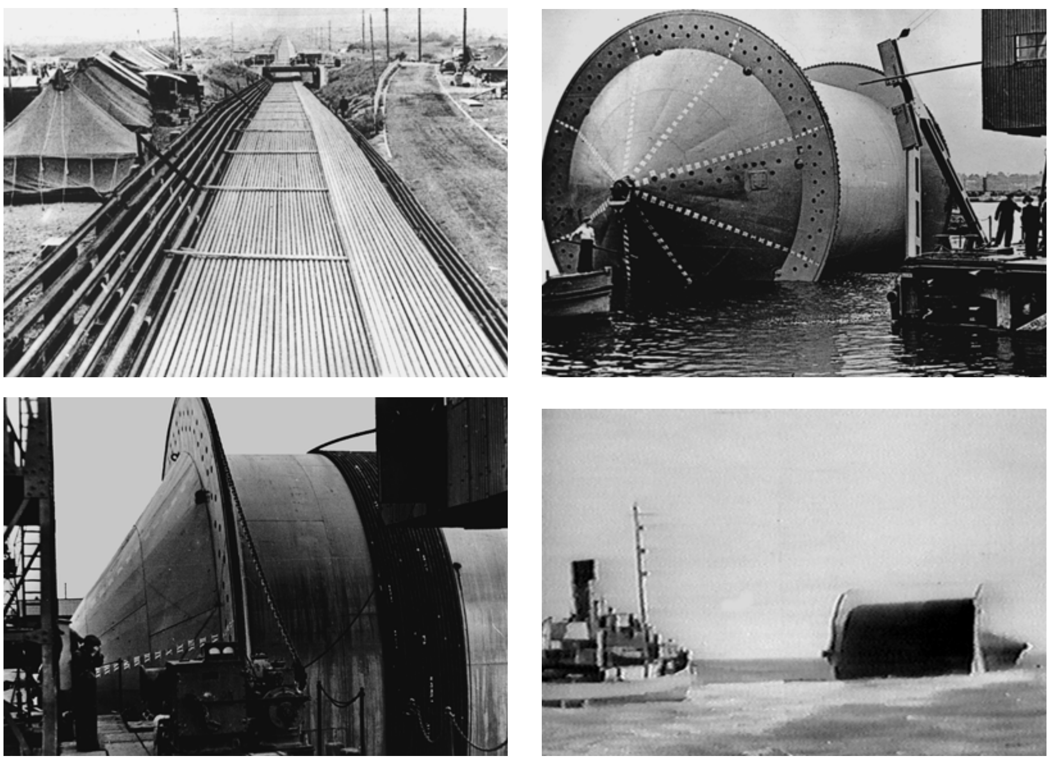
- A continuous conduit capable of being inserted into the wellbore (CT string).
- A means of running and retrieving the string into or out of the wellbore while under pressure (injector head).
- A device capable of providing a dynamic seal around the tubing string (stripper or packoff device).

The following chapter summarizes the history of these developments.

THE ORIGIN OF CT

Prior to the Allied invasion of Europe in 1944, engineers developed and produced very long, continuous pipelines for transporting fuel from England to the European Continent to supply the Allied armies. The project was named operation PLUTO, an acronym for “Pipe Lines Under The Ocean”, and involved the fabrication and laying of several pipelines across the English Channel.

FIGURE 2.1 *Operation PLUTO*



The successful fabrication and spooling of continuous flexible pipeline laid the foundation for further developments that eventually led to the tubing strings used in modern CT.

Steps leading to the first CT unit included:

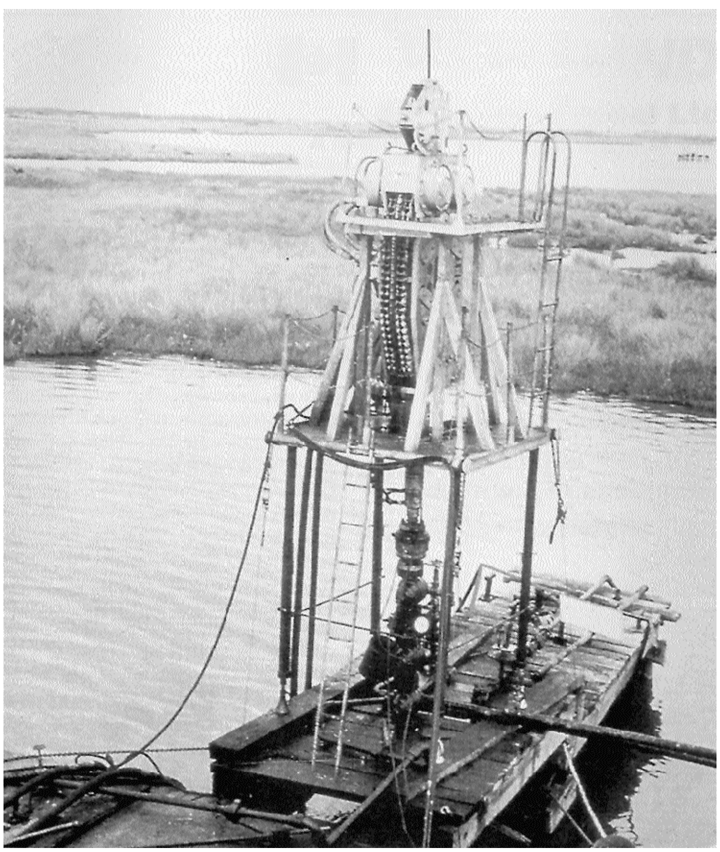
- In the late 1940’s, several concepts relating to the injection of continuous tubing or cable into a live wellbore were patented.
- In the early 1950’s, several concepts relating to drilling with continuous, flexible strings were patented.

- In the early 1960's, a device was developed by Bowen Tools to deploy antennas aboard submerged submarines. The antenna, a 0.625 in. brass tube, was spooled onto a reel for storage and was capable of reaching the surface from a submerged depth of 600 ft. This system used the same principle of the contra-rotating chain drive that would be later adopted for CT injectors.
- In 1962, Bowen adapted the injector design used on the antenna deployment for the prototype that was developed with the California Oil Company.

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

The first injector heads (Figure 2.2) operated on the principle of two vertical, contra-rotating chains, a design still used in the majority of CT units today. The stripper was a simple, annular-type sealing device that could be hydraulically activated to seal around the tubing at relatively low wellhead pressures.

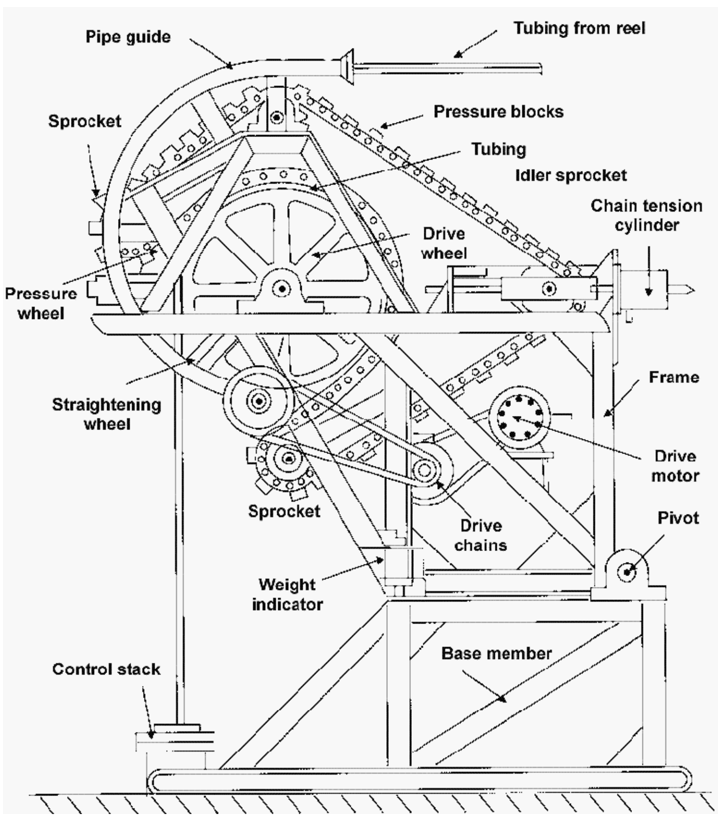
FIGURE 2.2 *Bowen Injector Head (circa 1962)*



The tubing string used for the initial trials was fabricated by butt-welding 50 ft sections of 1.375 in. OD pipe into a 15,000 ft string and spooling onto a reel with a 9 ft diameter core.

Following the success of the Bowen Tool / California Oil Company efforts, in 1964, Brown Oil Tools and Esso collaborated to develop a system that utilized a slightly different principle for the injector design. Instead of a set of contra-rotating chains to grip and drive the tubing, the tubing was squeezed between a single chain and a grooved drive wheel. The entire unit was mounted in a mast type assembly that suspended the CT injector head above the well-head. Figure 2.3 shows a schematic of this design.

FIGURE 2.3 *Brown Oil Tools Injector Head (circa 1964)*



The success of the early prototypes generated a commercial interest in CT as a well service option.

THE EVOLUTION OF CT EQUIPMENT

Throughout the remainder of the 1960's and into the 1970's, both Bowen Tools and Brown Oil Tools continued to improve their designs to accommodate CT up to 1 in. OD. By the mid-1970's, over 200 of the original-design CT units were in service.

In the late 1970's, injector design was influenced by several new equipment manufacturing companies (Uni-Flex Inc., Otis Engineering, and Hydra Rig Inc.).

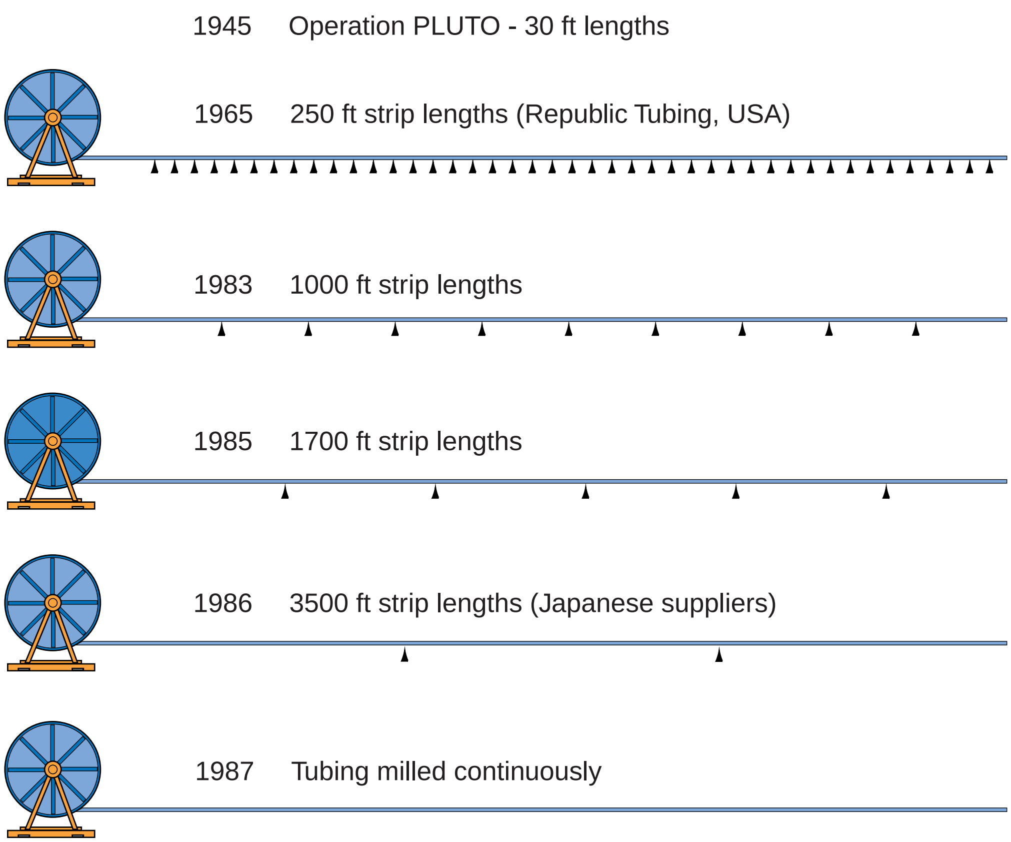
While injector heads were being improved, the CT strings were also undergoing some significant development.

The early commercial period of CT services (the late 1960's and early 1970's) was dominated by tubing sizes up to 1 in. and relatively short string lengths. The tubing diameter and length were limited by the mechanical properties of the tubing material and manufacturing processes available at the time.

Early CT operations suffered many failures due to the inconsistent quality of the tubing strings. A major portion of the problem related to the numerous butt welds present in the assembled tubing string.

By the late 1960's, tubing strings were being milled in much longer lengths with fewer butt welds per string. At the same time, steel properties improved. The resulting improvement in string reliability significantly benefited CT services (Figure 2.4).

FIGURE 2.4 *CT String Construction*



In 1969, Southwestern Pipe Inc. began manufacturing CT using improved material and techniques. Another company, Quality Tubing Inc., started manufacturing tubing in 1976 using a process similar to Southwestern Pipe.

During the 1980's, CT materials and strings improved significantly, and the maximum practical CT size increased to 1.75 in. By 1990, the first 2 in. tubing was being produced, followed shortly by 2.375 in., 2.875 in., and 3.50 in.

CT SERVICES

Speed and economy are key advantages of applying CT technology. Also, the relatively small unit size and short rig-up time compare favorably with other well drilling and workover options. Beneficial features of CT technology include the following:

- Safe and efficient live well intervention
- Capability for rapid mobilization, rig-up, and well site preparation
- Ability to circulate while RIH/POOH
- Reduced trip time, hence less production downtime
- Lower environmental impact and risk
- Reduced crew/personnel requirements
- Relatively low cost

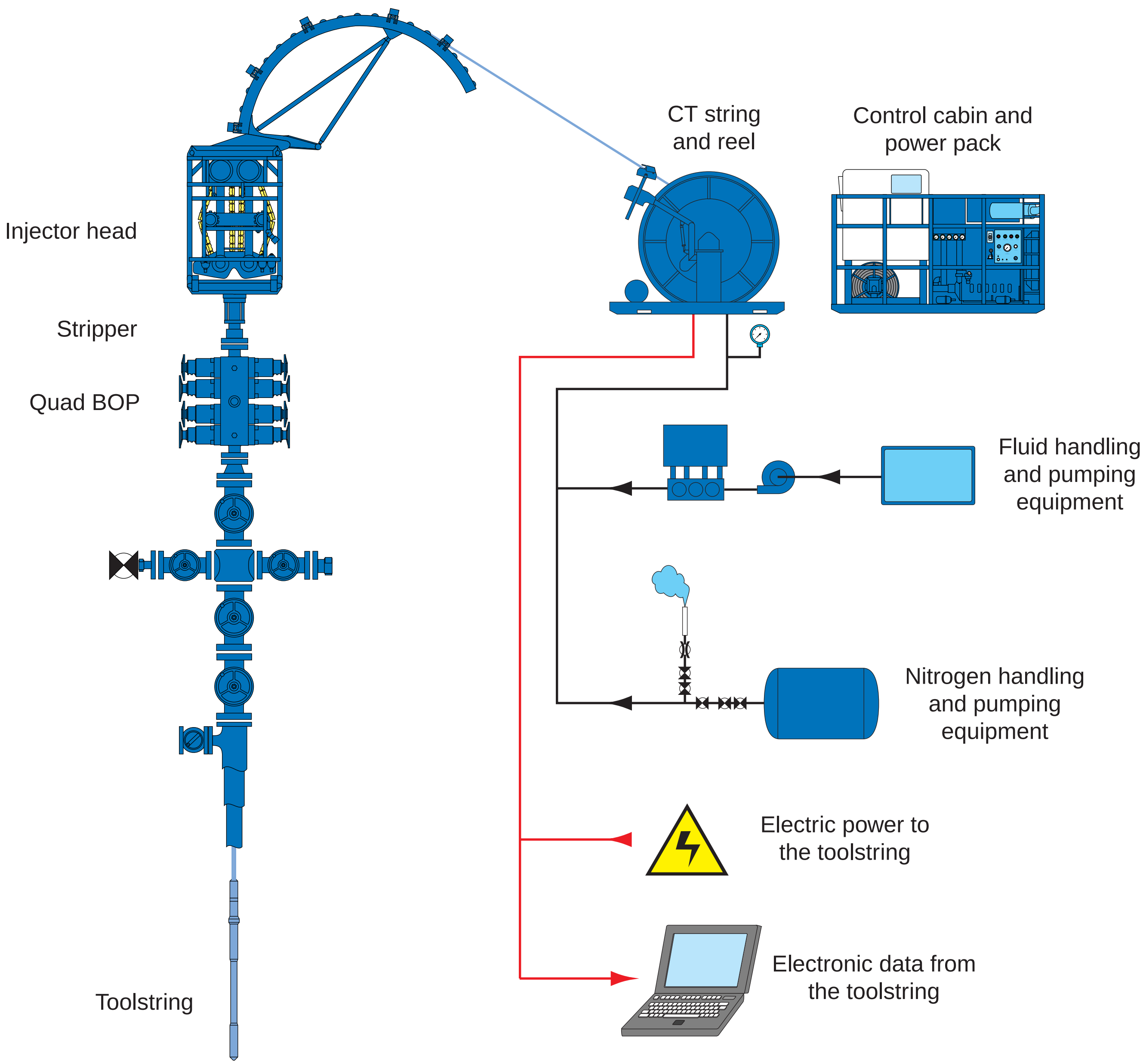
Early applications were designed around the fluid circulating/placement capabilities of the CT string, while more recent applications can rely on several unique features of the CT string and associated equipment.

Most current CT applications make use of one or more of the following features:

- Live well operations—pressure control equipment enables CT to be safely applied under live well conditions.
- High pressure conduit—CT string provides a high pressure conduit for fluid circulation into, or out of the wellbore. In addition, hydraulically operated tools may be operated or powered by fluid pumped through the string.
- Continuous circulation—fluids may be pumped continuously while the CT string is run and retrieved.
- Rigidity and strength—the rigidity and strength of the CT string enables tools and devices (and the string itself) to be pushed/pulled through highly deviated and horizontal wellbore sections.
- Installed conductors and conduits—electrical conductors or hydraulic conduits may be installed in the CT string, and terminated at the CT reel. This enables additional control and power functions to be established between the BHA and surface facilities.

Modern CT equipment is now commonly used to perform a variety of applications on well-sites or locations of widely varying conditions. As a result, no standard equipment configuration applies to all conditions. However, Figure 2.5 shows principal CT equipment used for most operations. The following sections of this manual describe these components in detail and explain their use for selected CT operations.

FIGURE 2.5 *CT Operations - Principal Equipment Components*



CT Industry Status

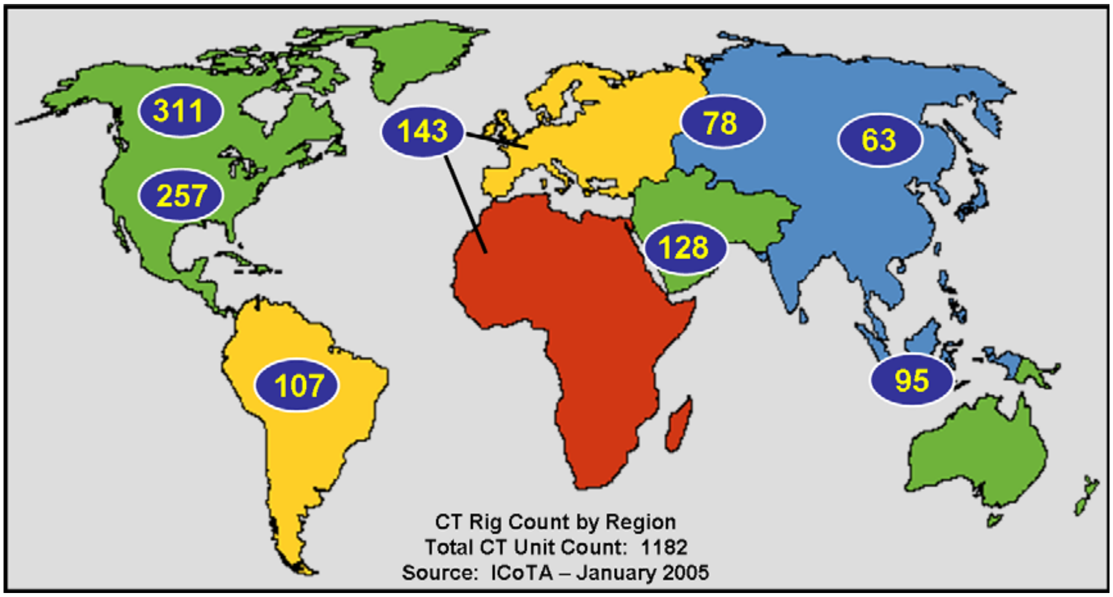
The following points summarize the status of the CT industry at the time of this writing in late 2004. Note that these contain estimates from various sources, not verified by CTES:

- The total number of CT units in the world is about 1,000
- Half of these units are operating in North America
- Total CT service revenue is estimated to be about US $ 1 billion per year.
- The growth rate of the industry is estimated to be 8% per year.

Through the last 15 years of the 20th century the CT service industry grew at a very rapid rate of about 20% per year. Many attribute this growth to the improvements in the pipe manufacturing process developed in the 1980's. These developments significantly improved the reliability of CT services, allowing them to gain wider acceptance. A "wave" of excitement developed in the industry, and many new CT applications were developed.

As we enter the 21st century, the CT industry is more mature and the number of new CT applications being developed has decreased. The development emphasis in the industry has shifted to "expanding the envelope". CT services are being performed on deeper, longer reach, more tortuous wells with higher pressures, more corrosive and erosive fluids using larger pipe sizes, longer lubricators, moving platforms, etc. Also the geographic envelop is being expanded. The newer services are typically developed and proven in a small geographical area. Once proven they gradually become accepted and utilized in other geographic areas.

FIGURE 2.6 *CT Unit Distribution*



3 THE TUBING

RAW MATERIAL FOR CT

Virtually all CT in use today begins as large coils of low-alloy carbon-steel sheet. The coils can be up to 55 in. wide and weigh over 24 tons. The length of sheet in each coil depends upon the sheet thickness and ranges from 3500 ft for 0.087 in. gauge to 1000 ft for 0.250 in. gauge. The first step in tube making is to slice flat strips from the coil of sheet using a slitting machine Figure 3.1. A specialist company usually performs this operation and ships the coils of strip to the CT mill for further processing Figure 3.2. The sheet's thickness sets the CT wall thickness and the strip's width determines the OD of the finished CT.

In some cases the gauge of the sheet material is tapered over a portion of its length, as is shown in Figure 3.3. This variation in thickness is used by Quality Tubing to produce CT with a wall thickness that varies along its length, known as "True-Taper™".

The CT manufacturer splices strips with similar properties together using bias welds to form a single continuous strip the length of the desired CT string. This strip is stored on an accumulator called a "Big Wheel", Figure 3.4. Joining strips of different thickness or using strips with a continually changing thickness yields a tapered string. The CT mill forms the flat strip into a continuous tube and welds the edges together with a continuous longitudinal seam.

FIGURE 3.1 *Slitting Steel Sheet for Strips*

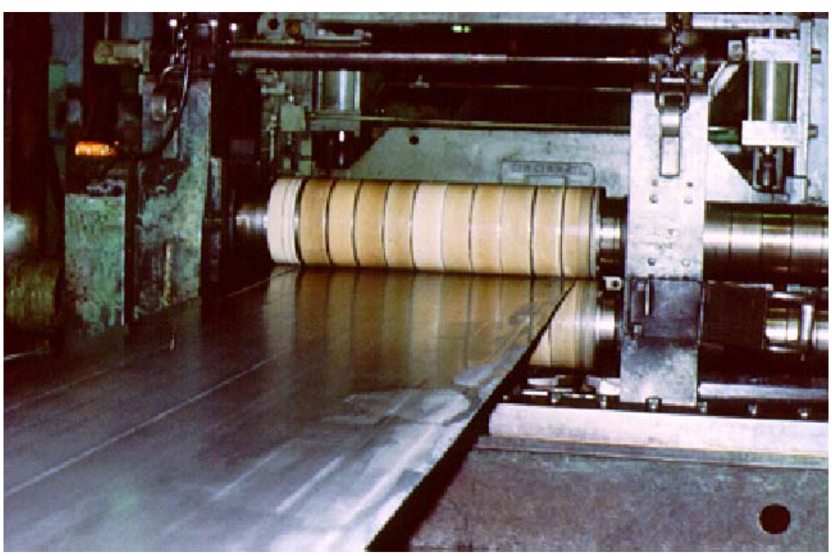


FIGURE 3.2 *Rolls of Steel Strips*

FIGURE 3.3 *True-Taper™*

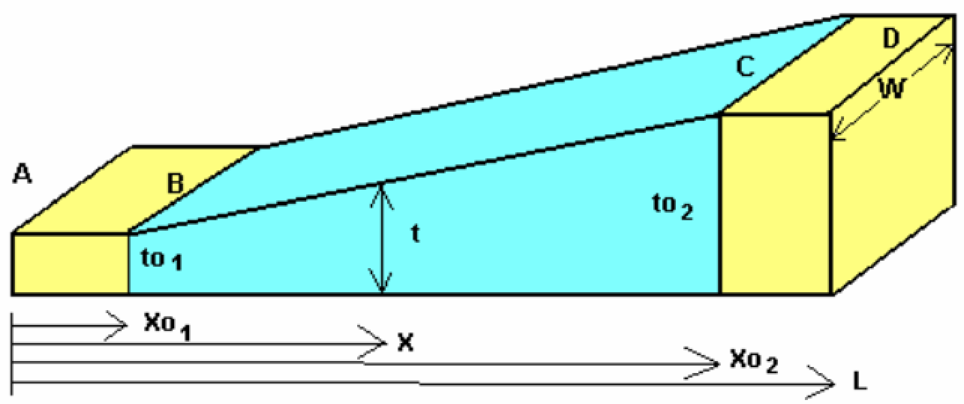


FIGURE 3.4 *"Big Wheel" of Flat Strip*

The most common low-alloy carbon steels used for CT are thermo-mechanically controlled rolled ASTM A606 Type 4 modified and modified ASTM A607. The mills can adjust the yield strength of these steels over the range of 55-90 Kpsi with proper heat treatment. However, they attempt to keep the surface micro-hardness of the finished CT below HRC 22 to decrease its susceptibility to sulfide stress cracking (NACE MR-01-75). CT products are commercially available with OD from 1.0 in to 4.5 in, although larger diameters up to 6.625 in have been produced in short lengths for testing.

At the end of 2004, two companies supplied all of the steel CT used by the petroleum industry from two CT mills near Houston, Texas. These companies are Quality Tubing, a National Oilwell Varco company, and Precision Tube Technology, part of Maverick Tube Corporation. Both companies have service centers at strategic locations around the world capable of inspecting and repairing CT, installing E-line in reels, spooling CT from reel to reel, and routine maintenance on CT strings.

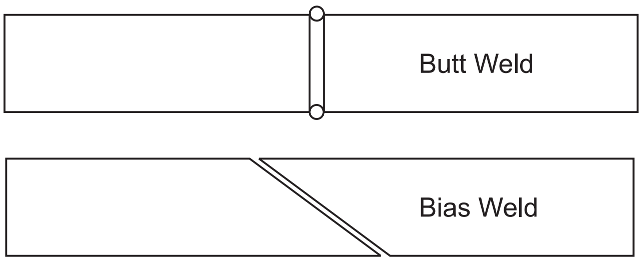
The advent of CTD in 1991 spurred numerous advances in the technology for manufacturing CT, including larger sizes and exotic materials. The range of yield strengths of the CT material also increased during this time. Today CT can be purchased with yield strengths ranging from 55 Kpsi to 120 Kpsi.

CT MANUFACTURING

Prior to 1987, the mills used butt welds to join together sections of tubing for a string of CT. Unfortunately, a butt weld was generally the location where the CT string failed due to fatigue. The butt weld had inferior mechanical properties to the parent tube, particularly in the heat effected zone (HAZ), and the weld profile concentrated into a narrow band the stresses caused by plastic deformation of the CT in the surface equipment. Butt welds were sometimes used to join together flat strips during the milling process, but these welds were low quality and were only inserted to allow successive strips to be fed into the tube mill. These flat strip butt welds were always removed from the CT string after milling.

After 1987, the tube mills began using bias welds (Figure 3.5) to join the flat strips together prior to milling, and this resulted in a dramatic increase in the working life of CT strings. The mechanical properties of the bias strip welds almost match the parent strip in the as-welded condition, and the profile of the weld evenly distributes stresses over a greater length of the CT.

FIGURE 3.5 *Types of CT Welds*



In the CT mill, a series of rollers (usually seven) gradually form the flat strip into a round tube. The final rollers in the series force the two edges of the strip together inside a high frequency induction welding machine that fuses the edges of the strip together into a longitudinal seam. This welding process does not use any filler material, but it creates a small bead of steel (weld flash) on both sides of the strip. The mill removes the external bead with a scarfing tool to provide a smooth OD. For CT sizes larger than 1.25 in, the mill can remove the internal weld flash with a special tool inserted into the nearly-formed tube just ahead of the induction welding machine. After the CT has been wound on to the shipping reel, the manufacturer flushes the loose material from the finished CT string.

After the scarfing process downstream of the welding station, the weld seam is annealed using highly localized induction heating. After annealing, the weld seam is allowed to air cool prior to water quenching. The cooled weld seam is then subjected to eddy current inspection to ensure a satisfactory weld quality. Full tube body eddy current inspection may also be performed depending upon mill set up. Both systems use automatic paint marking systems to identify any flaws for subsequent manual inspection by the mill's quality control staff. The tubing passes from the inspection station through sizing rollers that reduce the tube OD slightly to maintain the specified manufacturing diameter tolerances. A full body stress relief treatment that imparts the desired mechanical properties to the steel follows the sizing station.

After full body heat treatment the tubing air-cools prior to water cooling to reduce the tubing temperature to that of the ambient surroundings. A spooling unit at the end of the mill wraps the tubing onto a suitable wood or metal spool. Figure 3.6 through Figure 3.14 show selected portions of the CT manufacturing process

FIGURE 3.6 *Bias Welding Steel Strips*

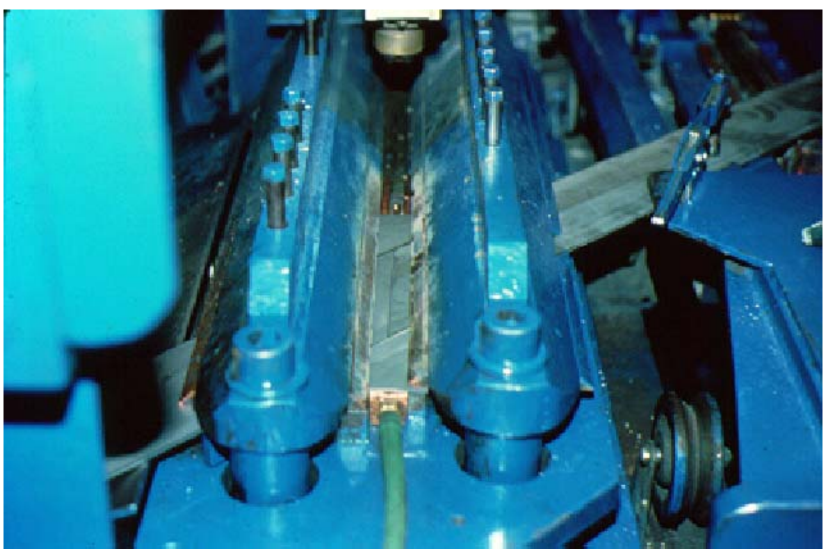


FIGURE 3.7 *Initial Forming Rollers*

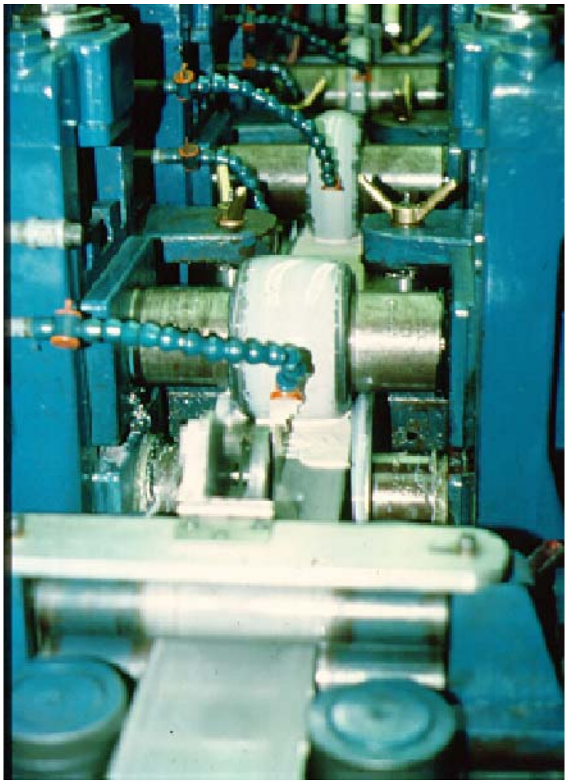


FIGURE 3.8 *Induction Welding the Longitudinal Seam*

FIGURE 3.9 *External Weld Flash Removal*

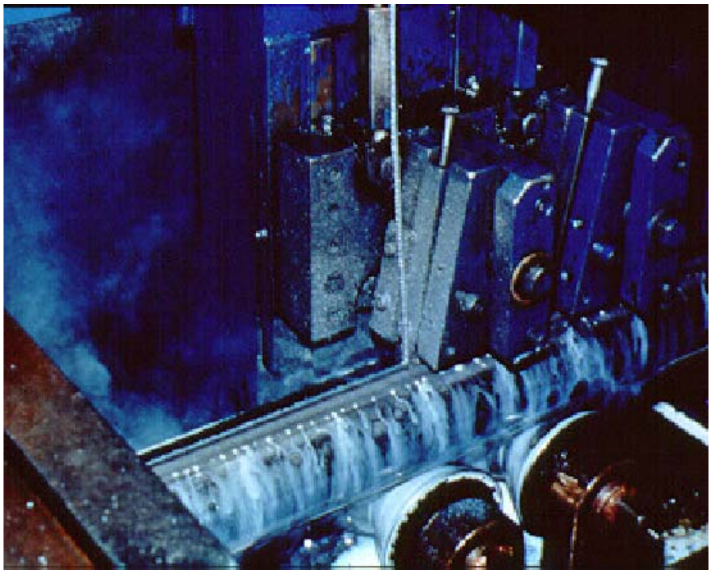


FIGURE 3.10 *Weld Seam Annealing*

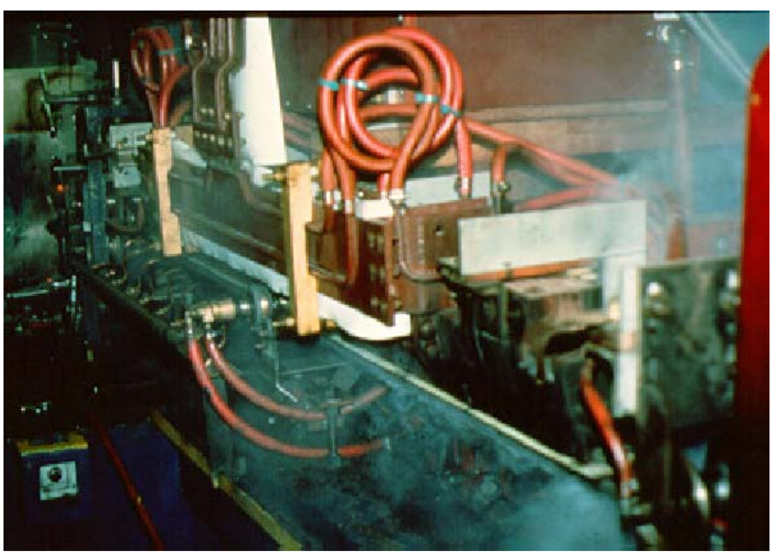


FIGURE 3.11 *Water Cool After Seam Anneal*

FIGURE 3.12 *Final Sizing Rollers*

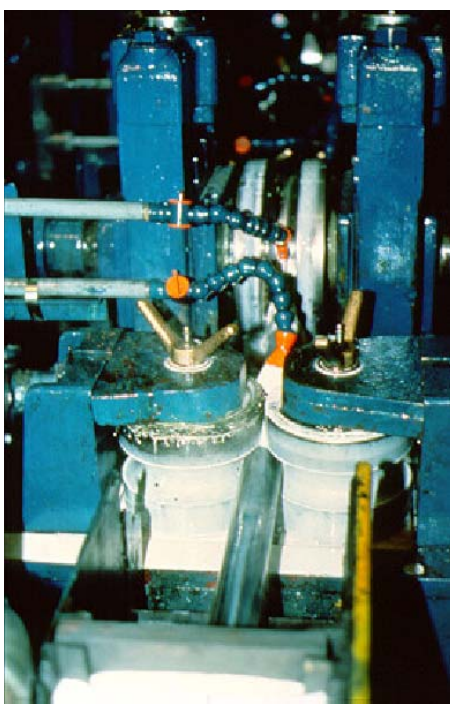


FIGURE 3.13 *CT Leaving the Mill*

FIGURE 3.14 *CT Wound Onto a Shipping Reel*

CT MECHANICAL PERFORMANCE

Plastic deformation in a metallic object is a permanent change in its geometry (strain) caused by forces (loads) exceeding the material's strength. The mechanical performance of CT is fundamentally different from all other tubular products used in the petroleum industry because it plastically deforms with normal use. CT begins its working life plastically deformed on a reel and is repeatedly subjected to additional plastic deformations in normal use. This section describes the terms, properties, and relationships necessary to define the mechanical performance of CT.

Stress and Strain Fundamentals

Figure 3.15 shows the fundamental relationship between force, stress, and strain in a CT segment. "A" is the cross-sectional area of the steel in the CT wall. The applied force, "F", can be tensile (pull) or compressive (push). The original length of the segment, "L", will change by an amount "ΔL" when subjected to a force. Elastic deformation means ΔL is zero (0) upon removal of the force; otherwise the deformation is plastic. For the purposes of this manual, stress (σ) is force per unit area, F/A, and strain (ε) is a relative length, ΔL/L.

FIGURE 3.15 *CT Stress and Strain Definitions*

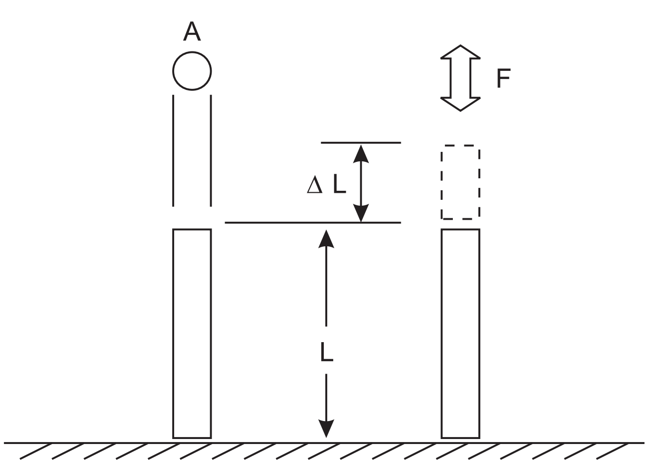
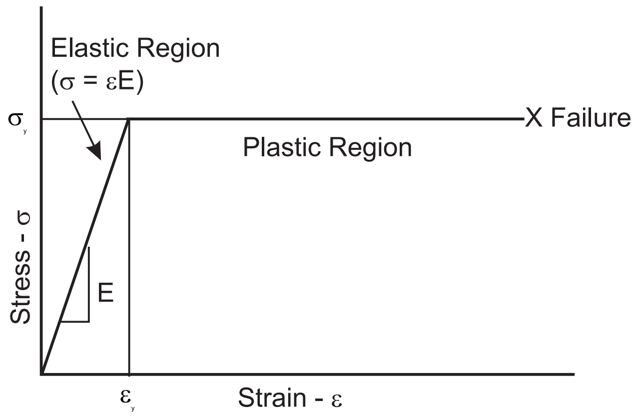


Figure 3.16 illustrates elastic perfectly plastic behavior in a material. It is an idealized representation of the stress/strain relationship for steel. In actual practice, this relationship is nonlinear and more complex. However, the figure illustrates the fundamental behavior of a CT segment subjected to tensile forces. In the elastic region, the constant of proportionality "E"

(modulus of elasticity or Young's modulus) is 26-30 x 10^6 psi for CT steels. The upper limit of the elastic region, the boundary between elastic and plastic deformation, is the yield strength of the material, σ_y. The corresponding strain at this limit is the yield strain ε_y. Therefore, any strain greater than ε_y causes plastic deformation in the CT material.

FIGURE 3.16 *Elastic Perfectly Plastic Material Behavior*

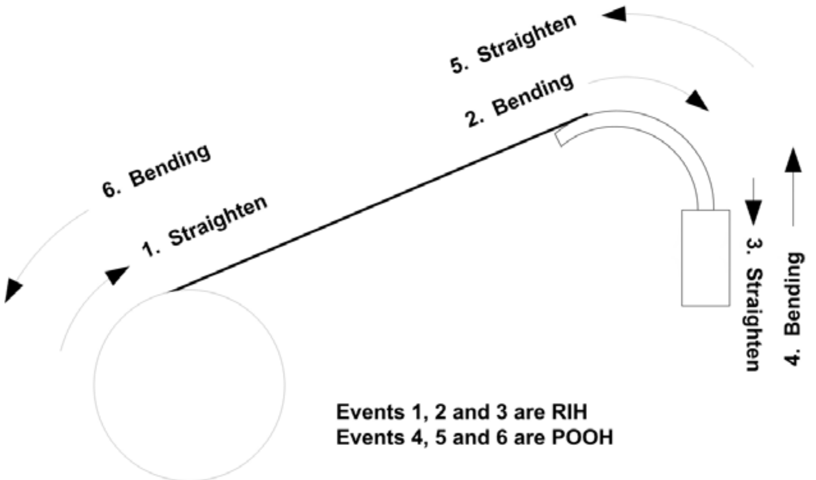


EXAMPLE 0.1 *Calculation of Yield Strain for Typical CT*	
Given that • Young's modulus, E = 27 x 10^6 psi • Yield stress, σ_y = 80,000 psi • Yield Strain $\varepsilon_y = \sigma_y / E$ = 0.003 in/in	Therefore, 80 Kpsi material will yield whenever $\varepsilon > 0.003$ in/in. This number can also be expressed as 3000 x 10^{-6} in/in or 3000 microstrain.

Bending Strain

Users of jointed tubular products (drill pipe, casing, and production tubing) carefully control or select a combination of product dimensions, properties, and operating conditions to avoid yielding in the material. That is, they take extraordinary care to avoid plastically deforming jointed pipe. However, this result is not possible for typical CT operations. Figure 3.17 shows the locations of bends in the CT caused by common CT surface equipment.

FIGURE 3.17 *Location of Bends in CT Cause by Surface Equipment*



Equation 3.1 defines the strain caused by bending a segment of CT with r = OD/2 around a curve with radius R.

EQUATION 3.1 *Bending Strain*

$$\varepsilon_B = r / R$$

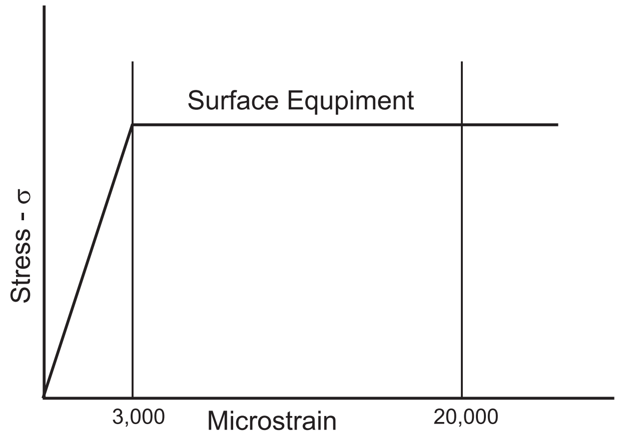
Table 3.1 shows the bending strain for CT sizes commonly used in workover operations assuming R = 50 in.

TABLE 3.1 *Typical CT Bending Strains*

CT Bending Strain, R = 50 in	
CT OD (in)	**Strain (microstrain)**
1.25	12,500
1.50	15,000
2.00	20,000

Figure 3.18 shows the relationship of these bending strains to the yield strain of 3000 microstrain for 80 Kpsi material calculated in the preceding example. This figure provides ample proof that typical CT surface equipment plastically deforms steel CT during normal use.

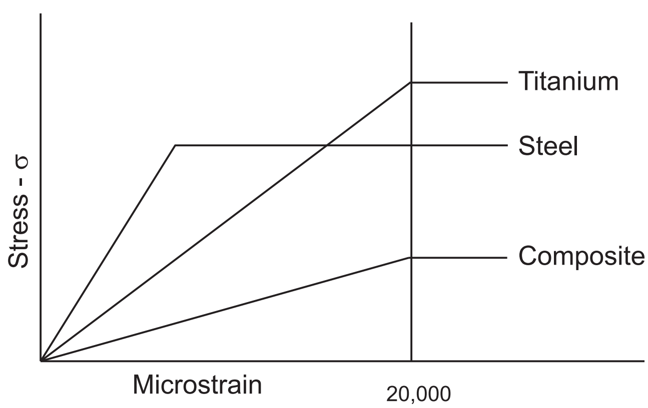
FIGURE 3.18 *Range of CT Bending Strains Caused by Typical Surface Equipment*



If plastically deforming the CT is unacceptable, the only alternative with the CT surface equipment commonly available today (see Chapter 4 "CT Surface Equipment") is to use a different CT material. Figure 3.19 illustrates this solution. One can select a material such as titanium with higher yield strength and lower modulus of elasticity than steel or a material like composite with a low modulus of elasticity.

Note that reducing the modulus of elasticity reduces the stiffness of the CT. There is a basic dichotomy between having the CT flexible enough to be bent around a reel on surface and yet having it stiff enough to perform the desired work downhole. Composite CT is very flexible and thus can be spooled with little or no damage. However, it has a very low stiffness and thus buckles quickly when put in compression.

FIGURE 3.19 *Elastic vs. Plastic Bending*



Effects of Cyclic Loading

If a metallic specimen is loaded beyond the yield point, subsequently unloaded, then loaded in the opposite direction, the material yield point in the opposite direction is reduced. This phenomenon is known as the Bauschinger effect. Since CT is routinely subjected to cyclic loading and unloading (bending and straightening) in the surface equipment, the Bauschinger effect is an important consideration when describing CT mechanical performance.

Figure 3.20 depicts an apparatus designed to hold a 3 in. test specimen of CT in an INSTRON universal testing machine. This machine applies cyclic axial strains on the specimen. The specimen has pressure ports for applying internal pressure while the sample is subjected to cyclic loading. An extensometer measures axial strain in the sample, and a load cell measures the axial force. The amount of strain applied to the specimen controls the experiment.

FIGURE 3.20 *Cyclic Loading Test Apparatus*

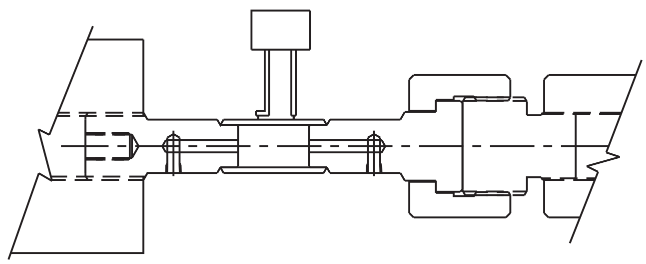
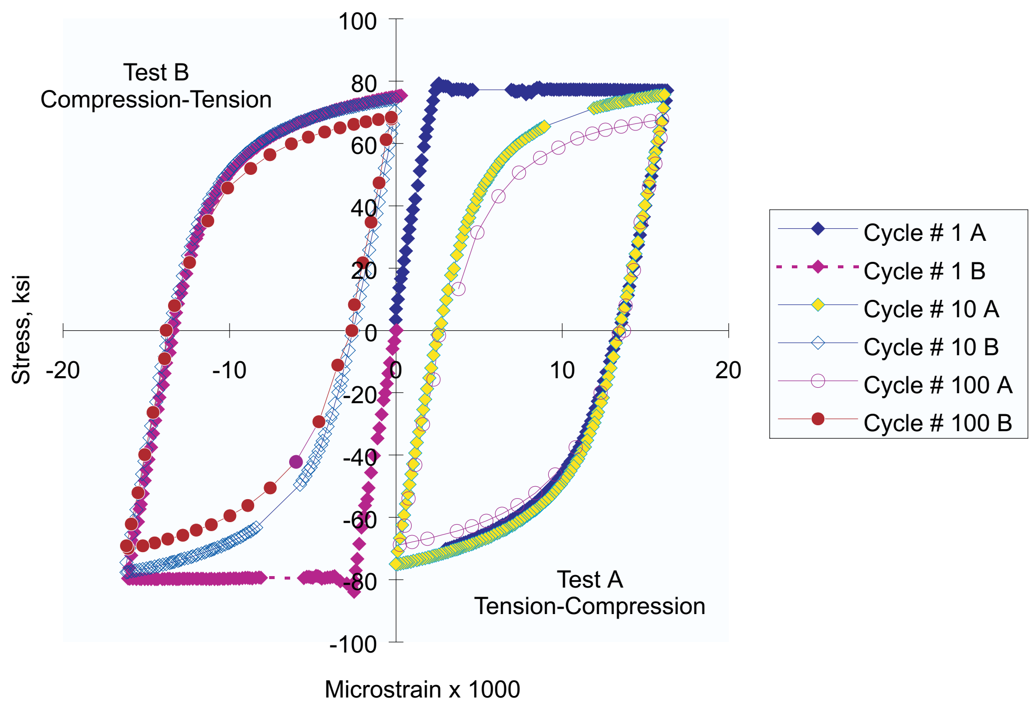


Figure 3.21 shows the results from two of these cyclic loading tests conducted with zero (0) internal pressure. In Test A (right half of the plot), a sample of 1.5 in OD x 0.109 in wall CT was

1. pulled to seven times the yield strain
2. unloaded
3. compressed to zero strain
4. pulled again to seven times the initial yield strain
5. Subjected to steps 1 through 4 for 100 cycles.

In Test B (left half of the plot), the loading sequence was the reverse of Test A. The sample was first compressed to seven times the yield strain, unloaded, pulled to zero strain, and compressed to seven times the initial yield strain for 100 cycles.

FIGURE 3.21 *Cyclic Loading Test Data (Bauschinger Effect)*



The test data in Figure 3.21 indicate that the CT exhibits elastic perfectly plastic behavior only in its virgin state. Reversal of loading changes the character of the stress-strain diagram, causes strain softening, and eliminates the sharply defined yield point. After 100 axial loading cycles, the force required to achieve the initial yield strain dropped by approximately 20%. Assuming the CT wall cross sectional area did not change significantly, this result means that the material “yield stress” decreased approximately 20% after 100 tension/compression cycles.

A segment of CT experiences plastic bending and partial straightening three times per round trip through typical surface equipment. The CT wall on the outside (convex) side of each bend experiences a loading sequence similar to Test A described above. The CT wall on the inside (concave) side of each bend experiences a loading sequence similar to Test B described above. The neutral plane is the locus of points in the wall that does not experience any strain during bending. Figure 3.21 implies that the CT yield stress could decrease as much as 20% after only 30 round trips through the surface equipment. However, the reduction in yield stress due to bending/straightening cycles would be less than predicted by cyclic axial loading tests because the strain varies across the wall during bending. None-the-less, the ability of CT to support loads (yield strength) gradually decreases with normal use.

Permanent Elongation of CT

For many years, CT field personnel have claimed that the CT elongates with every round trip into and out of a well. Previously the inaccuracy of the depth measurement systems was the prime suspect for discrepancies in depth measurements. However, in some cases CT service companies have run a CT string to a known depth using a downhole reference and then marked the CT at surface. After POOH and then RIH to the depth reference, the mark had moved up, indicating that the CT was longer. CT service companies have reported such results from a wide variety of CT operations in scattered locations around the world. Typically, the apparent elongation of the CT string for each round trip was on the order of 10 ft. These results indicated the depth measurement system could not be responsible for the observed elongation.

CT undergoes plastic bending and straightening followed by axial loading throughout its life. A significant portion of the CT cross section yields plastically due to this bending. Rotation of the CT about its longitudinal axis also occurs during the life of the CT, causing the neutral bending axis to rotate. Thus, during its life, the entire cross-section of the CT experiences plastic yielding. Axial loading occurs on the reel and the guide arch, due to reel back tension, and in the well, due to string weight and drag. Intuitively, applying an axial load to CT that has been plastically yielded could cause axial elongation.

Such experiences and observations led to the formation of a joint industry project (JIP) in 1996 to evaluate the depth measurement accuracy and determine how to predict the permanent elongation of the CT. The project attempted to quantify this elongation with:

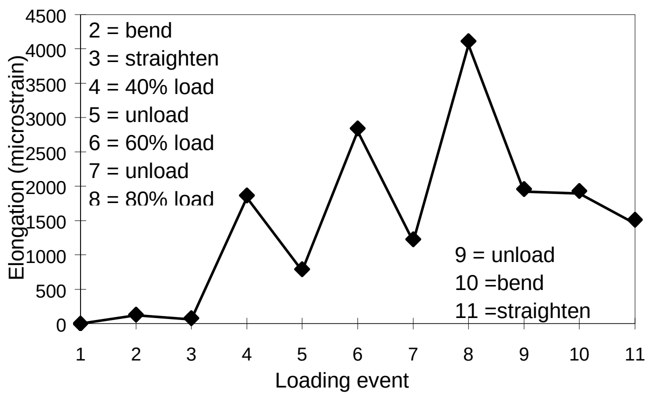
- Finite element analysis
- Numerical modeling
- Analytical modeling
- Experimental testing

The results from all four of these methods agreed quite well. The following sections summarize key findings from the study.

Finite Element Analysis

The first modeling used a general-purpose finite element analysis program which modeled a half section of CT using 108 solid brick elements with isotropic elastic-plastic material properties. The initial model had no internal residual stresses (loading event 1 in Figure 3.22).

FIGURE 3.22 *Finite Element and Numerical Results*



The model was used to simulate bending the CT around a typical guide arch radius of 48 in. and then straightening it (events 2 and 3). This straightening was done by forcing the CT into a straight position as would be done by the chains of an injector head. Axial loads were then applied to the CT and released, simulating the axial load applied to the CT in the well and released when the CT is pulled back up into the chains. An axial load of 40% of the yield stress was then added and released (events 4 and 5). An axial load of 60% of the yield stress was then added and released (events 6 and 7). An axial load of 80% of the yield stress was then added and released (events 8 and 9). Finally the CT was bent and straightened again (events 10 and 11) to simulate bending over the guide arch upon exiting the injector. The line in Figure 3.22 shows the elongation of the CT for each of these events.

Note that the total elongation of 1500 microstrain is equivalent to 15 ft of elongation in 10,000 ft of CT. Also notice that the final bending and straightening (simulating the bending and straightening which happens at the guide arch after coming up through the chains) actually removes some of the elongation. After event 3, when the CT had simply been bent and straightened, but before any axial load is applied, the CT had some elongation (about 70 microstrain).

Numerical Modeling

CTES, L.P. developed a numerical computer model, *Plastic*, which divided the cross section of a CT sample into an array of 200 elements around the circumference by 8 elements through the wall thickness. *Plastic* uses a simple numerical scheme to calculate the elastic-plastic response of each element as the CT sample is subjected to various bending and load events. Again isotropic elastic-plastic material properties were assumed for the CT material.

Plastic was used to perform the same simulation as with the finite element model. The results from *Plastic* are shown as diamonds in Figure 3.22. The results from this simple numerical model (which took only a few seconds to run) agreed very well with the finite element results. *Plastic* also predicted that there would be slight elongation of the CT the first time it was simply bent and straightened. However, this was only true for the first bend cycle. Subsequent cycles showed no additional elongation if nothing else was done to the CT between cycles.

Elongation experiments were run with *Plastic* in which the CT sample underwent the following sequence:

1. Bend to radius of curvature R_b

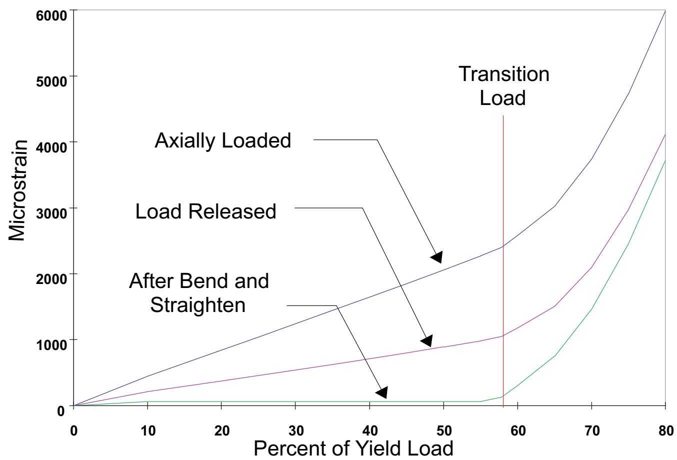
2. Straighten

3. Axially load

4. Release axial load

At this point there was some residual strain that appeared to be the sought after “permanent” elongation. However, when the axial load applied was less than a certain value, and the CT sample was bent and straightened again after the above sequence, this “permanent” elongation disappeared. When the axial load applied was above a certain value, bending and straightening decreased the “permanent” elongation but did not eliminate it. Defining the transition load became an important objective for the JIP. Figure 3.23 shows the results of these experiments.

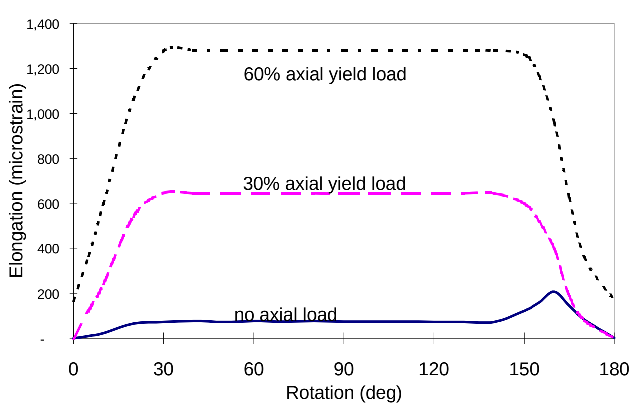
FIGURE 3.23 Plastic *Results, Elongation Due to Axial Loading Only*



After the CT sample is bent and straightened it is loaded to some axial load. The upper curve in Figure 3.23 shows the total elongation that *Plastic* predicts when the sample is loaded. The middle curve shows the elongation when the load is released. For clarity these points are shown at the same axial load as the upper curve, though the actual axial load is zero. The lower curve shows the elongation after the sample is bent and straightened again. This lower curve is the most interesting, because it shows the permanent elongation once the CT has been retrieved from a well. Permanent elongation caused solely by axial loading in the well is only significant for CT samples loaded above the transition load.

Plastic was used for experiments in which the CT sample was rotated between bending events. Figure 3.24 shows the results of these experiments.

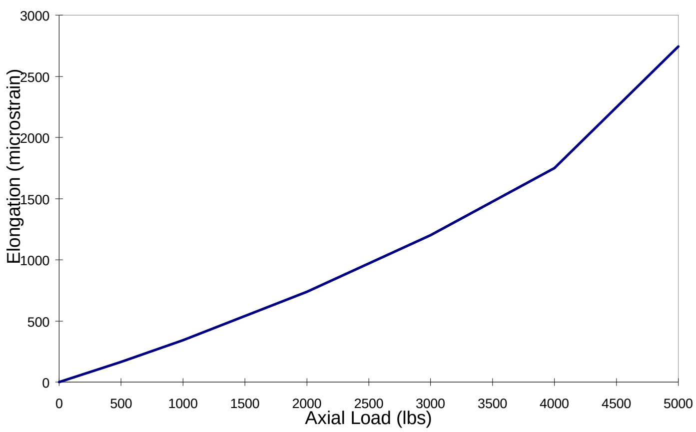
FIGURE 3.24 Plastic *results, Elongation Due to Rotation and Axial Loading*



This figure only shows the permanent elongation after the second bend and straightening event. The CT sample was rotated by the amount shown on the X-axis after it had been axially loaded but prior to subsequent bending. The rotation of the CT in the well significantly increases the permanent elongation. This increase occurs for axial loads below the transition load, as well as for axial loads above the transition load.

The CT is under tension during bending on the reel and over the guide arch due to reel back tension. *Plastic* was used to study the permanent elongation caused by axially loading the CT while bending. Figure 3.25 shows the results of this study.

FIGURE 3.25 Plastic *Results, Elongation Due to Axial Load while Bending*



In this case an axial load equal to the value on the X-axis was applied and the CT was bent and straightened. The axial load was then released to determine the permanent elongation. Note that even a small axial load of 1000 lbs causes significant permanent elongation. Thus, the elongation that happens on surface due to reel back tension may be greater than the elongation which occurs in the well.

Analytical Modeling

Analysis of the mechanics of plastic deformation showed that the transition load is the load at which the neutral axis of the CT begins to yield plastically. The following equation calculates the transition load, F_t:

EQUATION 3.2

$$F_t = 0.5A\sigma_y + 3\frac{\sigma_y^{\ 2}}{E}R_b t$$

where t is the CT wall thickness, and R_b is the bending radius.

Experimental Testing

The JIP performed a series of tests to validate the numerical and analytical analysis. The fatigue test machine (see Chapter 9 "CT Fatigue", page 9-5) was used to bend and straighten the CT samples. An axial load fixture (ALF) was used to apply an axial load to the samples while they were in the straight position. Strain gauges were mounted on the neutral axis to measure the strain. The data from these tests are confidential to the sponsors of the JIP. However, the experimental results compare well with those from *Plastic*. The experimental tests confirmed the existence of the transition load.

Conclusions About Permanent Elongation

1. Three types of modeling and experimental testing showed that significant permanent elongation of CT can occur.

2. For a given tensile load, elongation of plastically deformed CT is roughly twice the elastic elongation at that load.

3. After releasing the tensile load, the permanent elongation of the CT is approximately equal to the elastic elongation at that load.

4. Elongation due to tensile loads after plastic deformation of the CT is “permanent” only for tensile loads exceeding a transition load. In other words, elongation due to tensile loads less than the transition load can be erased by subsequent bending.

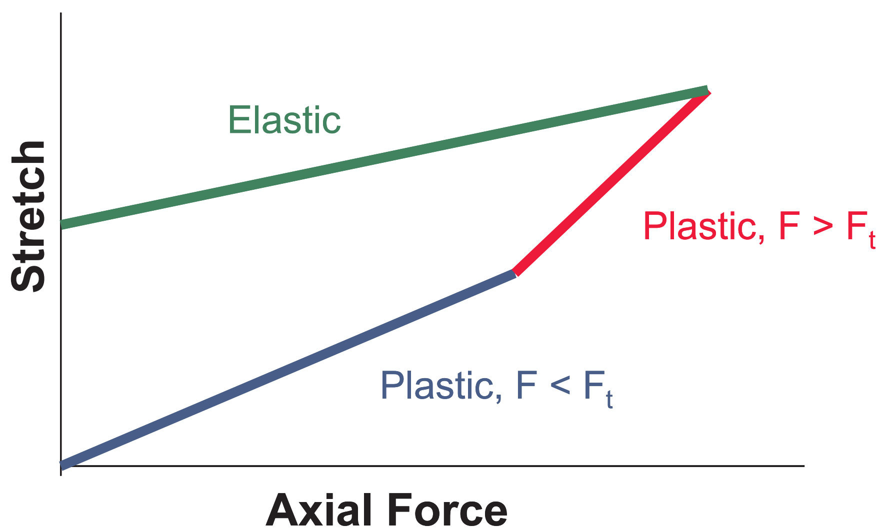
5. Rotation of the CT between RIH and POOH significantly increases the permanent elongation.

6. Axial loading of the CT while bending (usually caused by reel back tension) causes permanent elongation. The elongation between the reel and the guide arch may be greater than the elongation caused by the axial loading in the well.

Mechanisms for CT Length Change

CT changes length during every CT operation due to axial forces, temperature, pressure differential across the CT wall, and helical buckling. Each of these can cause error between the depth measured at the surface and the actual depth of the BHA downhole. The length change can be elastic (the deformation is fully reversible) or plastic. Plastic length change can be recoverable by subsequent plastic deformation in the surface equipment if the axial force is less than the transition force (F_t, see Equation 3.2) or only partially recoverable if the axial force exceeds F_t. The length change (depth error) can be positive (+) or negative (-). However, most of the length change is elongation due to tension in the CT during RIH and POOH. Figure 3.26 illustrates this concept for a length of CT subjected to an axial force that exceeds the transition force.

FIGURE 3.26 *CT Stretch Due to Axial Load*



The amount of elastic stretch, ΔL, for a segment of CT with length "L" is Lε or Lσ/E. However, strain and stress measurements are not available during a CT operation; force measurements are. So in terms of force and properties of the CT, elastic stretch can be calculated from the following equation:

EQUATION 3.3

$$\Delta L = \frac{L \times F}{A \times E}$$

revised 6/27/14

Plastic stretch calculations are more complex because they depend on the severity of the deformation and the volume of material in the CT wall affected by the deformation. When the axial force is less than the transition force, use to calculate the plastic stretch.

EQUATION 3.4

$$\Delta L_{F<F_t} = \frac{L \times F}{\left(\frac{A}{2} + \Phi\right) \times E}$$

where $$\Phi = r_o^2\theta_o - r_i^2\theta_i + r_o r_i \sin(\theta_i - \theta_o)$$

r_o = the CT external radius (OD/2)
r_i = the CT internal radius (ID/2)

$$\theta_o = \arcsin\left(\frac{3r_y}{2r_o}\right) \qquad \theta_i = \arcsin\left(\frac{3r_y}{2r_i}\right)$$

Equation 3.5 shows the radius at which yielding begins for a CT material with yield strength of σ_y bent around a radius R_b.

EQUATION 3.5

$$r_y = \frac{R_b \sigma_y}{E}$$

When the axial force is greater than the transition force, use Equation 3.6 to calculate the plastic stretch.

EQUATION 3.6

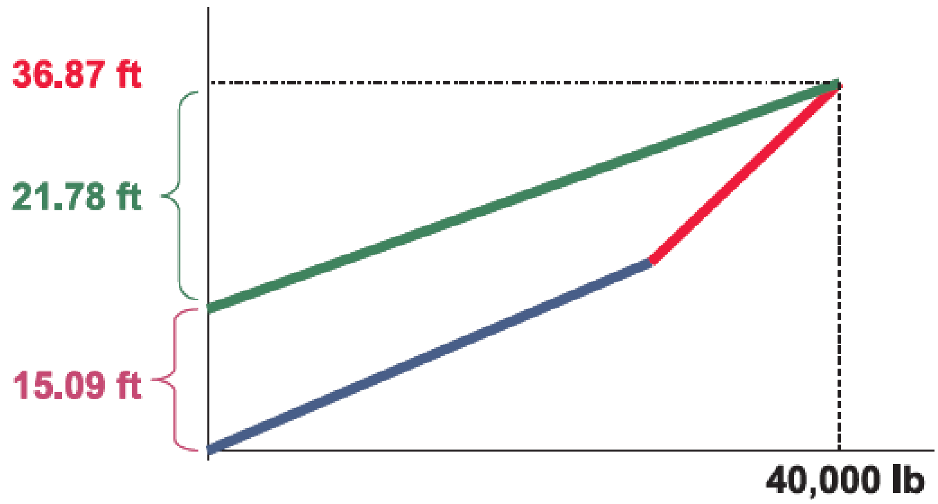
$$\Delta L_{F>F_t} = L \times \left[\frac{F_t}{\left(\frac{A}{2} + \Phi\right) \times E} + \frac{(F - F_t)}{\left(\frac{A}{2} - \Phi\right) \times E} \right]$$

EXAMPLE 0.2 *Calculation of Stretch for 1.75 in OD x 0.134 in wall CT*

Problem: Calculate the plastic and permanent stretch in the CT with given conditions:

Given that • σ_y = 80,000 psi • E = 27 x 10^6 psi • L = 10,000 ft • R_b = 84 in • F = 40,000 lbf	From Equation 3.2, F_t = 35,204 lbf From Equation 3.5, r_y = 0.249 in Therefore, θ_o = 0.4408 rad, θ_i = 0.5280 rad, and Φ = 0.1040 in^2 From, Equation 3.6, the plastic stretch is 36.90 ft. Upon release of the axial force, the CT relaxes elastically. So, from Equation 3.3, the elastic stretch is 21.78 ft. The permanent (residual) stretch in the CT is therefore 15.11 ft

FIGURE 3.27 *Residual Stretch in 10,000 ft of CT*



Use Equation 3.7 to calculate CT length change due to thermal effects.

EQUATION 3.7

$$\Delta L_L = L \times \beta \times T_{Avg}$$

where β is the thermal expansion coefficient for CT steel and T_{Avg} is the average temperature across the length of CT.

EXAMPLE 0.3 *CT Elongation Due to Temperature*

Problem: Find the CT elongation due to the temperature:

Given that:

- Surface temperature = 100°F
- Downhole temperature = 350°F
- L = 10,000 ft
- $\beta = 6.5 \times 10^{-6}$ 1/°F

$$T_{Avg} = \frac{350°F + 100°F}{2} = 225°F$$

From Equation 3.7,

$$\Delta L_T = (10{,}000\ ft)(6.5 \times 10^{-6°} F^{-1})(225°F) = 14.63\ ft$$

CT length change due to differential pressure across the wall is normally quite small. The primary mechanism for this length change is the Poisson effect as shown in Equation 3.8.

EQUATION 3.8 *CT Length Change Due to the Poisson Effect*

$$\Delta L_P = -\frac{2L\mu}{E}\left(\frac{r_i^2 P_i - r_o^2 P_o}{r_o^2 - r_i^2}\right)$$

where P_i and P_o are the pressure inside and outside the CT respectively, and μ is Poisson's ratio for CT steel (0.33).

EXAMPLE 0.4 *CT Length Change Due to the Poisson Effect*

Problem: Calculate the change in length due to the pressure change:

Given that:	From Equation 3.8,
• OD = 1.75 in • Wall thickness = 0.134 in • L = 10,000 ft • P_i = 3,000 psi • P_o = 1,700 psi	$\Delta L_P = \frac{-2(10,000)(0.33)}{27\times10^6}\left(\frac{(0.741)^2(3,000)-(0.875)^2(1,700)}{(0.875)^2-(0.741)^2}\right) = -0.39\,ft$

Helical buckling always reduces the apparent length (depth) of CT in the well because the axial force is compressive. However, the reduction in length is typically small. See Chapter 7 "Buckling and Lock-up", for a complete discussion of helical buckling and its effect on CT length.

CT STRING DESIGN

A CT string for any operation must have the following attributes:

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

Optimizing the design of a CT string to simultaneously meet these criteria for a given CT operation requires a sophisticated CT simulator (see Chapter 17 "CT Simulators", page 17-11) and numerous iterations with proposed string designs. CT strings designed in this manner usually have multiple sections with each section having a different wall thickness. Often called tapered strings, the wall thickness does not necessarily taper smoothly from thick to thin (top to bottom). Instead, the wall thickness along the string varies according to the local requirements. [Note: Virtually all CT strings have uniform OD; only the wall thickness changes with position along the string. Likewise, CT strings are made of the same material from end to end.] The basic procedure consists of “running” the CT operation on the computer for a given CT string and then modifying the string design by changing the length and wall thickness of the sections to achieve the desired result. Even though this technique can provide the best CT string for a given job, the string may not be suitable for CT operations in other wells or even other applications in the original well. Usually a more generic CT string design is desirable.

The simplest method of designing a CT string considers only the wall thickness necessary at a given location for the required mechanical strength and the total weight of the string. This method assumes the open-ended CT string is hanging vertically in a fluid with the buoyed weight of the tubing the only force acting on the string. Starting at the bottom of the string and working up, the designer selects the wall thickness at the top of each section that gives a certain stress for the corresponding tensile force at that location. String A in Table 3.2 is an example of this approach where the designer limited the stress at the top of each wall section to 30% of the material yield strength. String B in Table 3.2 shows a string design based on each wall section having the same length.

TABLE 3.2 *CT String Design Examples (1.50-in OD, 80 Kpsi Material)*

	String A - Uniform Stress			**String B - Uniform Length**		
Wall (in.)	**Length (ft)**	**Air Wt (lbs)**	σ_a/σ_y **(%)**	**Length (ft)**	**Air Wt (lbs)**	σ_a/σ_y **(%)**
0.109	7058	11,430	30	2000	3239	8.5
0.125	833	1528	30	2000	3672	16.0
0.134	431	843	30	2000	3910	23.5
0.156	896	2007	30	2000	4479	29.0
0.175	782	1937	30	2000	4954	34.8
Totals =	10,000	17,745		10,000	20,254	

CT INSPECTION TOOLS

There are three basic types of CT inspection technologies currently available in the industry:

a. Electro-magnetic proximity sensor - This technology uses proximity sensors to measure the diameter and ovality of the CT. Two diametrically opposed proximity sensors each measure the distance from the probe to the surface of the CT. The distance between the probes is known, and thus the diameter of the CT can be calculated. Multiple sets of probes measure multiple diameters around the CT. Orthogonal diameter measurements are used to calculate the ovality. The CT DOG developed by CTES (Figure 3.28), and the UTIM developed by Schlumberger are two examples of this technology. Note that this technology cannot be used for non-magnetic materials such as the CRA (corrosion resistant alloy) materials currently being commercialized.

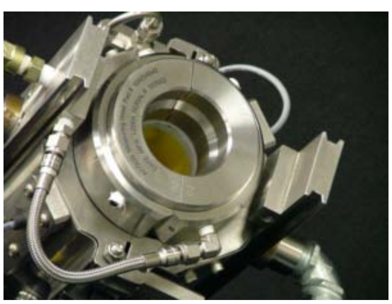
FIGURE 3.28 *CT DOG*

b. Electro-magnetic flux leakage - This technology uses magnets to induce a magnetic field into the pipe wall. Hall effect sensors around the pipe sense leakage of the magnetic flux from the wall. This flux leakage gives an indication of cracks and pits both inside and outside the pipe. It can also give an indication of how much steel is in a given portion of the pipe, from which an average wall thickness can be calculated. This technology is well known for inspecting oilfield tubular goods by such companies as Tuboscope. It is used in the CT manufacturing facilities to inspect new pipe. Several field worthy CT inspection devices have been developed which use this technology, including the CT Scope from Tuboscope (Figure 3.29), and the ACIM from Rosen. Acceptance of this technology by the CT service industry has been limited due to the expertise required by an operator of the equipment and the associated costs.

FIGURE 3.29 *CT Scope (Tuboscope)*

c. Ultrasonic - UT technology is commonly used in pipe manufacturing facilities to inspect new pipe. It is able to accurately measure wall thickness, and to give indications of cracks, inclusions and pits. Quality Tubing have implemented phased array UT inspection techniques for examining welds in their manufacturing facility. The only field worthy device which uses UT technology for CT inspection was developed by CTES as seen in Figure 3.30[1]. This device, known as the Argus, measures a localized wall thickness at 12 locations around the circumference of the pipe with an accuracy of ±0.005". 1200 wall thickness measurements are made per second (100 at each location) which provides a thorough coverage of the pipe as it is moving in and out of a well. It also performs 6 diameter and 3 ovality measurements, based upon the same UT readings used for wall thickness. This has been the most successful CT inspection system to date, with 22 systems built at the end of 2004.

FIGURE 3.30 *Argus*



1. Newman, K.R., Stein, D., and Ackers, M., "Rotation of Coiled Tubing", SPE 60737, SPE/ICoTA Coiled Tubing Roundtable held in Houston, TX, 5-6 April 2000.

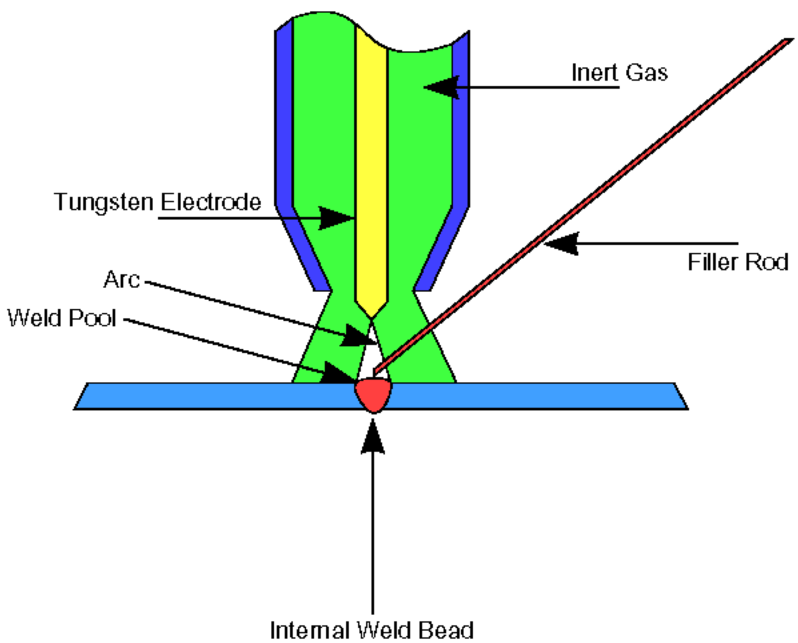
REPAIRS AND SPLICING

The only acceptable method of repairing mechanical or corrosion damage to a CT string is to cut out the bad section of tubing and rejoin the ends with a temporary or permanent splice. The temporary splice is a mechanical connection formed with a tube-tube connector. These are not suitable for prolonged use during a CT job, only as an emergency repair to allow POOH safely or until a permanent splice can be made with Tungsten Inert Gas (TIG) welding. Only butt welds are possible for repairing CT strings; bias welds are for joining flat strips in the CT mill.

The industry has two choices for temporary tube-tube connectors, internally flush and externally flush. Both of these are essentially double-ended slip type connectors (see Chapter 5 "CT Connectors", page 5-3). Neither has the flexibility of CT and both can be difficult to run through an injector or spool onto a reel. Internally flush connectors have the same ID as the CT and use internal slips to lock onto the OD of the tubing. They don’t have any internal upset, but their large OD can cause clearance problems in the wellbore. Externally flush connectors have the same OD as the CT and use external slips to lock onto the ID of the tubing. They don’t have any external upset, but their small ID can interfere with the flow of fluids and passage of balls through the CT.

TIG welding is the best method for permanently repairing CT work strings. TIG welding uses the heat generated by an arc formed between a tungsten electrode and the work-piece (Figure 3.31). During the welding process, an inert gas floods the weld location to exclude contaminants from the weld site. The joint may be formed either by melting the edges without adding filler (autogenous weld) or, more commonly, by feeding a filler rod into the molten pool. The TIG welding technique is generally restricted to materials less than 0.280 in. (7.1 mm) thick. The low heat input and the slow deposition rate of this technique make it ideal for use with CT. Due to the inert atmosphere surrounding the weld site, the finished welds are clean and of high quality. CT with wall thickness up to 0.125 in. can be repaired with a single welding pass. Thicker-walled CT requires multiple welding passes.

FIGURE 3.31 *TIG Welding Process*



The CT industry has three different ways of applying the TIG welding technique:

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

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

> *CAUTION:* Derate the fatigue life of the corresponding section of the CT string by at least 50%. CT fatigue simulators (see Chapter 9 "CT Fatigue", page 9-5) must account for the effect of a weld on the working life of a string.

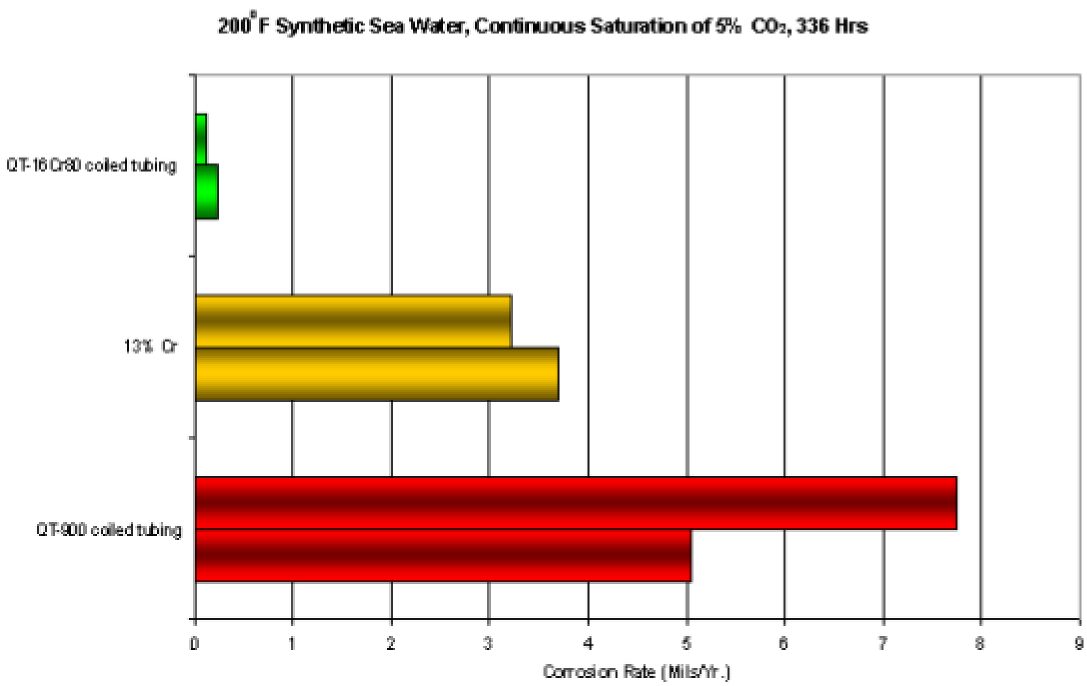
The advantage of the manual welding method is its versatility and adaptability to changing conditions. However, a human welder generally has trouble maintaining consistency from weld to weld. Compared to the manual welding method, the fully automatic (robotic) method can consistently deliver high quality welds, as long as the tubing or environmental conditions do not change much. The fully automatic method essentially employs a welding “factory” to prepare the ends of the tubing, align the ends properly for the weld, and then make the TIG weld with an orbital welding machine. The disadvantages of this method are its high cost and lack of versatility. The semi-automatic approach is a compromise between the other two extremes. A technician prepares the ends of the tubing, aligns the ends in a welding fixture, and then makes the weld with an orbital welding head.

ALTERNATIVES TO CARBON STEEL CT

Corrosion Resistant

The CT manufacturing companies are working on corrosion resistant alloy (CRA) CT materials. Precision Tube Technology are making a CRA material for umbilical conduits used between offshore platforms. Quality Tubing is making a downhole grade CTA material out of a 16 chrome (16Cr) stainless steel. Figure 3.32 shows the corrosion resistance to wet carbon dioxide (CO2) of this 16Cr alloy compared to 13% Chrome and to conventional carbon steel (QT 900). The corrosion rate of the 16Cr material is very small compared to these other two materials.

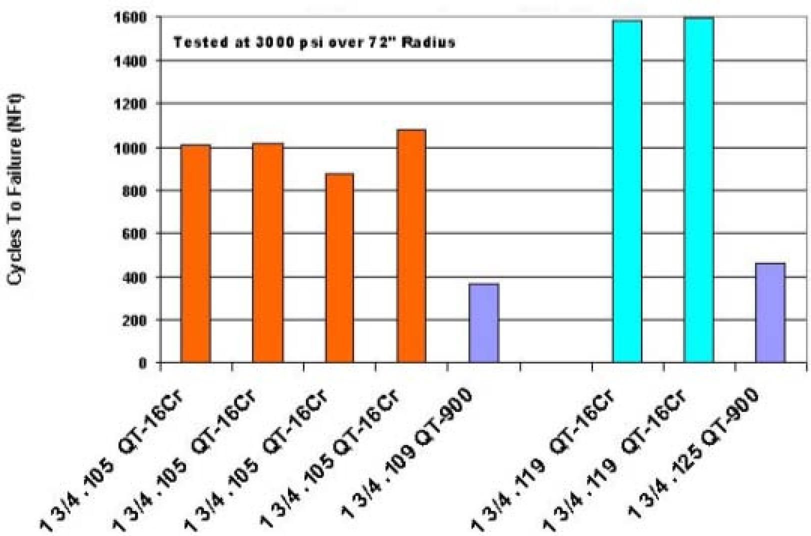
FIGURE 3.32 *Wet Co_2 Susceptibility Corrosion Tests*[*]



*. Figures by Quality Tubing

The fatigue life of a CRA material has been a major concern in this development process. Figure 3.33 shows the fatigue life of CT made with the 16Cr alloy compared to CT made with conventional steel CT. The fatigue life of the CRA material is approximately triple the life of conventional steel CT.

FIGURE 3.33 *Fatigue Life of a CRA Material*



Testing of the 16Cr material in H_2S indicates that this material will require a special inhibition when used in a sour environment.

Titanium

The CT mills have produced small quantities of CT made of titanium or stainless steel for highly corrosive environments, but the high cost of these materials has severely limited their use. Titanium is the preferred material for such an application, but it is difficult to weld and costs approximately 10 times as much as carbon steel. At the close of 2000, the mills had produced only three strings of titanium CT, and all were for permanent installations.

- 1.0 in. OD x 0.083 in. wall x 5000 ft string for a power company in California—not installed
- 1.0 in. OD x 1000 ft string for O_2 injection for downhole heating—shut in
- 1.75 in. OD x 500 ft string for Unocal Thailand for tubing patch in sour well—not installed

Composites

Another alternative to steel for manufacturing CT is a composite made of fibers embedded in a resin matrix. The fibers, usually glass and carbon, are wound around an extruded thermoplastic tube (pressure barrier) and saturated with a resin such as epoxy, in a continuous process. Heat or UV radiation cures the resin as the tube moves along the assembly line. Figure 3.34 shows examples of three different composite CT products from Fiberspar, the only company producing composite CT at the end of 2000. The white or tan surface on the inside of a tube is the thermoplastic liner. For a given OD and wall thickness, Fiberspar can provide a wide range of performance characteristics by changing the mix of fibers, the orientation of their windings, and the properties of the resin matrix. The first commercial application for composite CT was three velocity strings deployed by Halliburton in The Netherlands in mid-1998. In March 1999, Halliburton deployed a 1.50 in. OD x 0.25 in. wall string for cleaning out CO_2 injector wells in West Texas. By mid-2000, Fiberspar had installed over 100 miles of composite LinePipe™.

FIGURE 3.34 *Composite CT (Fiberspar)*

Benefits of composite CT compared to carbon steel include:

- high resistance to fatigue damage, at least 10 times greater than steel
- impervious to corrosion
- significantly lighter than steel CT with comparable ID—fewer logistical problems
- electrical conductors or optical fibers can be included in the wall

Moreover, extensive testing has shown that existing CT surface equipment (Chapter 4 "CT Surface Equipment") is suitable for handling composite CT. However, composite CT has several disadvantages compared to carbon steel CT, including:

- 3-5 times the cost (at the end of 2000)
- maximum operating temperature of 250 ºF
- significantly lower stiffness – critical buckling force is much less (see Chapter 7 "Buckling and Lock-up")
- limited availability – (at the end of 1998, Halliburton had exclusive rights to all of Fiberspar's production of composite CT for downhole applications)

4

CT SURFACE EQUIPMENT

The following section describes the CT surface equipment commonly used for most CT operations, starting at the BOP and working upwards. Almost all CT units in active service today are hydraulically powered. This section does not address any other mode of power. Also, this section does not discuss the crane used for most CT operations to rig up and down the injector head and BOP.

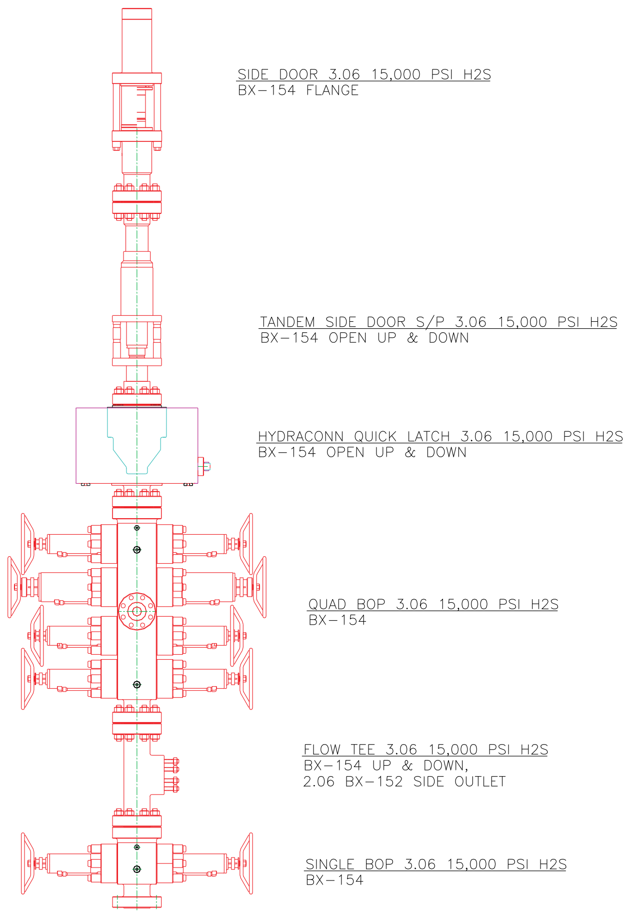
WELL CONTROL EQUIPMENT

Figure 4.1 shows typical well control equipment for CT operations, consisting of a BOP topped with a stripper (high pressure CT units have two strippers and additional BOP components). Both components must be rated for the maximum wellhead pressure (WHP) and temperature possible for the given operation. Also, each component must be compatible with any corrosive fluids that might be produced from the well or introduced as part of the CT operation.

FIGURE 4.1 *Quad CT BOP with Side Door Stripper (Texas Oil Tools)*

Figure 4.2 shows a complete stackup of well control equipment for CT operations at WHP up to 15,000 psi.

FIGURE 4.2 *Example Well Control Stack for CT Operations (TOT 3.06 in., 15 Kpsi)*



Blowout Preventer (BOP)

A blowout preventer (BOP) contains wellbore pressure. It's main function is to prevent well fluids from escaping into the atmosphere. A CT BOP is designed specifically for CT operations.

A CT BOP consists of several pairs of rams. Each type of ram performs a specific function.

The number and type of ram pairs in a BOP are determined by the configuration of the BOP: single, double, triple, quad, or quint. The standard CT BOP preventer is a quad.

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

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

Blind Ram Assembly

Blind rams are sealing rams. They isolate well bore fluids and contain pressure when there is no CT in the BOP. Unlike pipe rams, blind rams will not seal on any wireline, cable or tubing. If closed on wireline the seals will damage the wireline. Blind rams consist of identical ram bodies positioned opposite each other in a ram bore. Each ram assembly contains a ram body, front seal, rear seal and a retainer bar. The front seal closes on an open hole and the rear seal contains the well pressure from behind the ram body. Hydraulic pressure acts on a piston connected to a piston rod. The force moves the rams to the center of the through bore. As the force is increased, the rubber deforms and forms a seal.

Shear Ram Assembly

Shear rams have cutter blades to cut through CT, wireline, and cable. Shear rams have right and left hand ram bodies. The ram assembly consists of ram bodies, shear blades and socket head cap screws. The blades on both ram bodies are identical. The socket head cap screws hold the blades in their proper place. The blades are made out of a material that is hardened after machining. The base material used for the blades is a NACE approved material, and therefore the core of the blades remains relatively soft. The material gives the blades the ductility required to prevent their cracking while shearing the CT. A single set of shear blades can cut multiple times. More than 30 cuts have been made with one set of blades without damage. Shear blades for H_2S service have special requirements, as noted in the NACE specifications MR-01-75. Since the blades may be exposed to H_2S during CT operations, the shear blades are made with a soft core and hard case. The hard outer case will be subject to cracking; however, the softer core will not be as likely to crack in an H_2S environment.

Slip Ram Assembly

Slip rams grip the CT to prevent it from being pushed out of the well or from falling down the well. Slip rams consist of identical rams and slip inserts positioned opposite each other in a ram bore. Each ram assembly contains a ram body, slip insert and a retainer pin. The slip insert slides into the ram and is held in place with the retainer pin. The retainer pin does not take any loading; it merely prevents the insert from falling into the well. The slips should hold the yield load of the CT. The slip inserts have a special tooth design to minimize the stresses on the CT. The slip insert is machined out of a NACE material and then hardened for gripping and holding the CT. This process makes the slips highly susceptible to sulfide stress cracking. Since the slips may be exposed to H_2S during CT operations, the slip inserts are made with a soft core and hard case. The hard outer case will be subject to cracking; however, the softer core will not be as likely to crack in an H_2S environment. The wedge slip insert is a bi-directional slip designed to maximize the gripping area and bite into the tubing as weight is applied. This design has tapers that force the slips into the CT.

Pipe Ram Assembly

Pipe rams, also called tubing rams, are sealing rams. They seal around CT to isolate well bore fluids and contain pressure. Pipe rams consist of identical ram bodies positioned opposite each other in a ram bore. Each ram assembly contains a ram body, front seal, rear seal and a retainer bar. The front seal closes around the CT and the rear seal contains the well pressure from behind the ram body. Hydraulic pressure acts on a piston connected to a piston rod. The force moves the rams to the center of the through bore. Guides, machined on the rams, guide the CT into the center of the rams to the front seal. As the force is increased, the rubber deforms around the CT and forms a seal.

Standard CT BOPs

The standard CT BOP has two equalizing ports, one on each of the sealing rams. It also has a side outlet between the slip and shear rams. This side outlet can be used as a safety kill line.

BOPs are available in several sizes. These sizes normally follow the API flange sizes. They start with the 2.56 in. and can be as large as 7.06 in. Currently the most commonly used size is the 3.06 in. quad. The following table is a rule of thumb for what size CT can be used in each BOP.

TABLE 4.1 *BOP and CT Sizes*

BOP Size	Coiled Tubing Range
2.56 in.	0.75 in. through 2.00 in.
3.06 in.	
4.06 in.	1.00 in. through 2.875 in.

TABLE 4.1 *BOP and CT Sizes*

BOP Size	Coiled Tubing Range
5.12 in.	1.25 in. through 3.50 in.
6.375 in.	
7.06 in.	

Pressure ratings of the blowout preventers correspond with API 6A and 16A information. Currently, CT BOPs have been built for 5,000 psi, 10,000 psi, and 15,000 psi working pressure.

FIGURE 4.3 *Typical CT BOP Configurations*

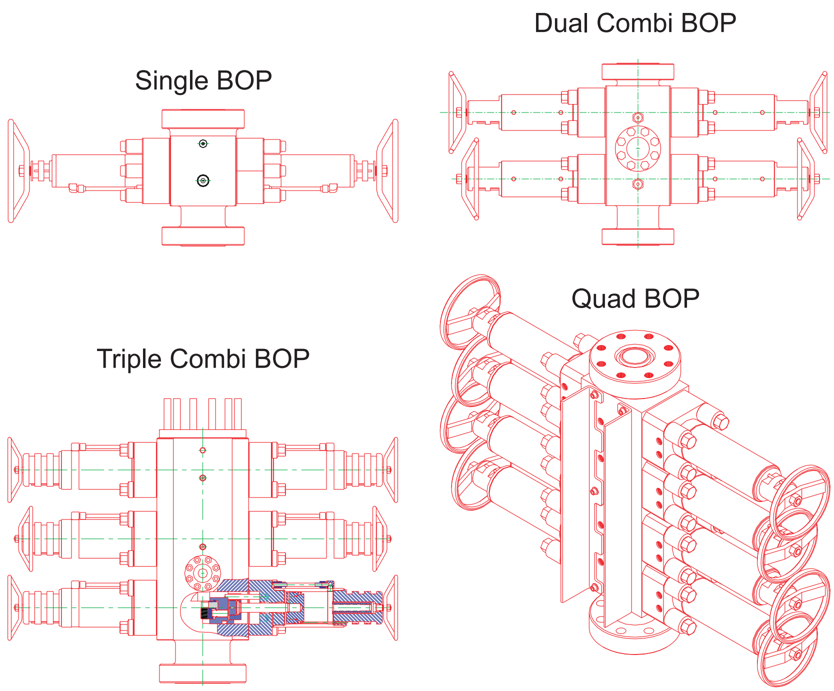
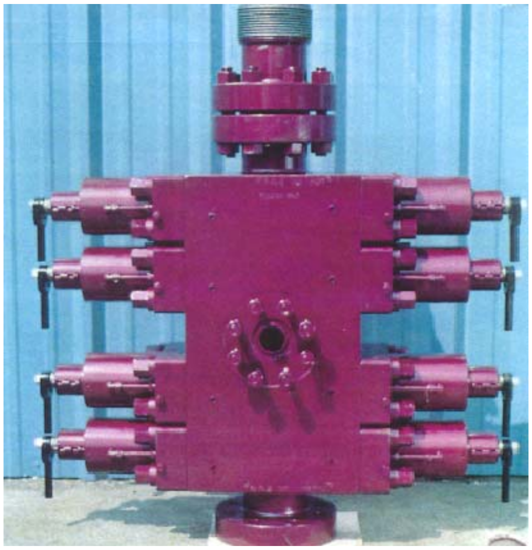


Figure 4.4 shows another style of quad BOP. The stripper connects to the threaded coupling on top. The port facing out of the picture is a circulating port for the kill line.

FIGURE 4.4 *Stewart and Stevenson Quad BOP*



Some BOPs combine the blind ram and shear/seal ram in one ram and the pipe ram and slip ram in a second ram. Figure 4.5 shows a typical combi-BOP.

FIGURE 4.5 *Combi-BOP (Texas Oil Tools)*

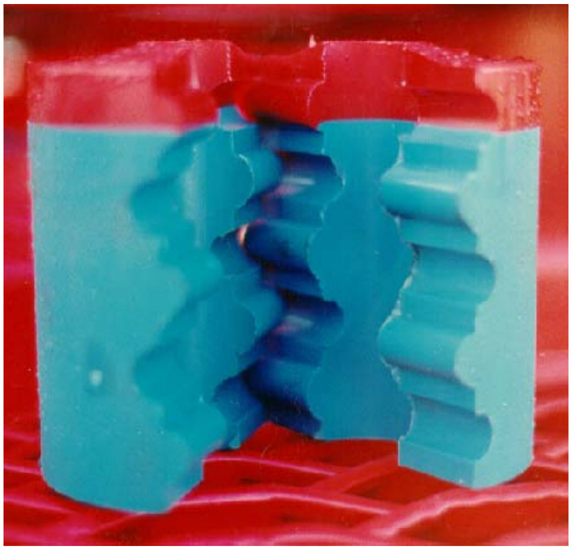
Stripper (Stuffing Box)

The stripper (stuffing box) between the BOP and the injector head provides the primary operational seal between pressurized wellbore fluids and the surface environment. The stripper forms a dynamic seal around the CT during tripping and a static seal around the CT when it is stationary. The early model inline stripper did not provide access to the sealing elements with the CT in place. This style was replaced by the side door stripper design shown in Figure 4.6 that permits easy access and removal of the sealing elements with the CT in place.

FIGURE 4.6 *CT Side Door Stripper (Texas Oil Tools)*

The sealing elements are similar in both stripper designs and consist of thick-walled elastomer cylinders split length-wise as in Figure 4.7. Stripper elements are composed of layers of different elastomers selected for their unique properties.

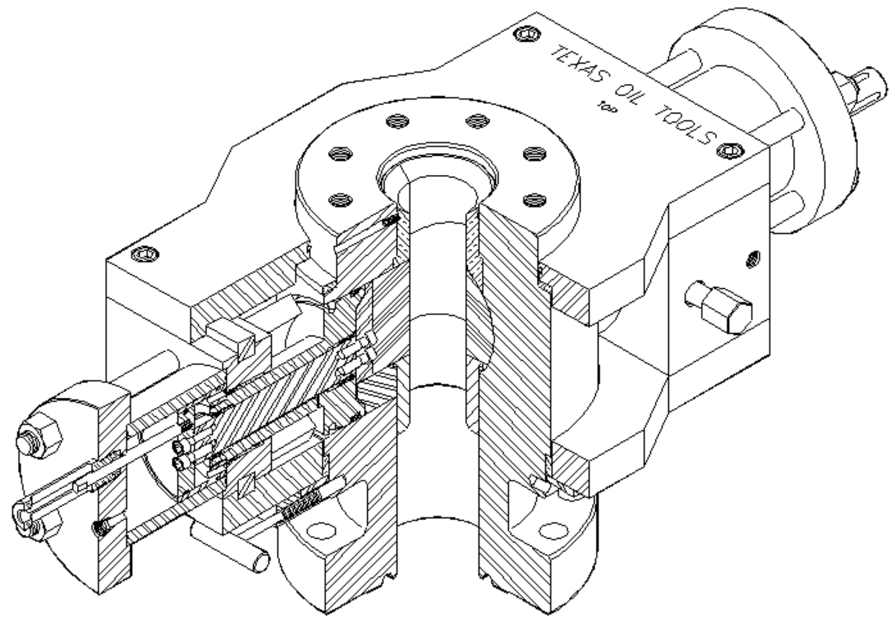
FIGURE 4.7 *Stripper Elastomer (BJ Services)*



Usually, the WHP energizes the stripper seal by forcing a piston against one end of the elastomer cylinder. This axial force creates a pressure seal around the CT by compressing the stripper element between the CT and the surrounding pressure housing. The CT operator increases the axial force on the piston with hydraulic pressure from the power pack to increase the sealing force around the CT. The resulting frictional drag when the CT is moving through the stripper can significantly affect the CT weight indicator reading. (see Chapter 6 "General Force Balance", page 6-3.) Consequently, elastomers used for stripper elements must have low coefficient of friction (Cf) and good chemical and abrasion resistance. Injecting a lubricant into the stripper cavity around the CT can reduce stripper friction.

Figure 4.8 illustrates a third stripper design that applies a radial force directly to the stripper element. In a radial stripper, hydraulic fluid forces opposing pistons together with the stripper elements between them. This squeezes the elastomer between the pistons and CT to create a pressure seal.

FIGURE 4.8 *CT Radial Stripper (Texas Oil Tools)*



Wellhead Connections

Rigging up pressure control equipment is a time consuming task. Working with the cranes and slings to lift the equipment and install it on the well can be dangerous. The hydraulic quick latch is a pressure control tool that makes the rigging process quicker and safer.

The quick latch is normally the last connection made during the CT rig up.

1. Install the BOP and flow lines on the well head and mount the stripper to the injector.

2. Stab the CT into the stripper packer and make up the tools.

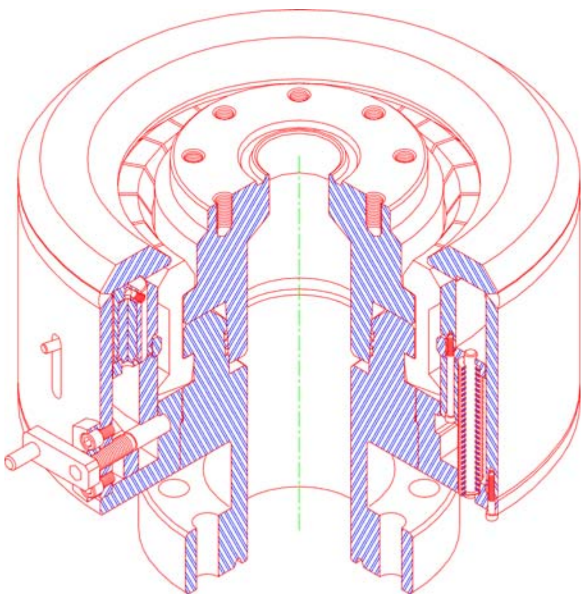
3. Pick up the injector, and use the quick latch to stab it onto the BOP stack.

Hydraconns

The hydraconn is designed to facilitate a secure connection between the CT BOP and stripper packer while providing an elevated level of personnel safety by minimizing the need for operator assistance during rig-up of the pressure control stack. The hydraconn incorporates a tapered seal bore that facilitates stabbing the connection with the injector. A safety latch, with a manual override and an indicator are included to prevent an unintentional release while operating with well pressure in the stack.

Hydraulic pressure is required to open or unlatch the tool. To close or latch the tool, release the hydraulic pressure and allow the fluid to drain back into the handpump. The tool has a spring return that will provide enough force to close and lock the locking dogs into position.

FIGURE 4.9 *Hydraconn (Texas Oil Tools)*

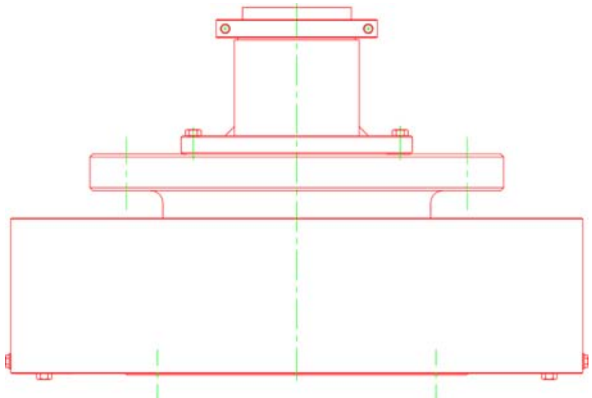


Quick Latch between the Stripper Packer and the Injector Head

The injector connector is used as a tool to connect the pressure control equipment to the injector head. It is mounted above the stripper packer and is therefore a non-pressure containing device.

Hydraulic pressure is required to open or unlatch this tool. To close or latch the tool, release the hydraulic pressure and let the fluid flow back into the handpump. Hydraulic working pressure is 3,000 psi maximum.

FIGURE 4.10 *Injector Connector*



Hydraulic Releasing Connector

The hydraulic releasing connector (HRC) is designed to facilitate the connection of the BOP and/or lift frame to the wellhead or drill pipe, making this procedure quick with increased operator safety.

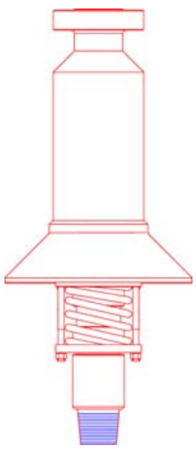
The HRC has two mating sections. The skirt section is installed in the lower spreader bar of the lift frame or the BOP, and the stinger section is connected to the wellhead or drill pipe. These two sections are latched together by a collet mechanism as part of the stinger section. The collet mechanism is attached to the stinger section and retracted by an integral hydraulic cylinder during the latching and unlatching sequence.

When latching, the collet is retracted and the skirt is lowered over the stinger. The weight of the skirt and spreader bar will collapse the collet fingers until the lugs of the collet spring into position in the recess machined into the skirt section. This allows the stinger to fully engage the skirt. The release of hydraulic pressure will then allow the spring to return the collet to the extended and locked position.

The connector can be unlatched by hydraulically retracting the cylinder and collet, allowing the skirt to be removed from the center section. In the event of a hydraulic failure, a manual override mechanism is attached to retract the collet by using the three tension bolts that are provided on the manual override.

The seal between the stinger and skirt is formed by three independent seals each of which is capable of sealing against the working pressure. The multiple redundancy is to accommodate the heavy, sometimes brutal latching experienced when handling the large lift/frame on a semi-submersible vessel in heavy seas.

FIGURE 4.11 *Hydraulic Releasing Connector*



Unions

Unions are a quick and easy method to attach pressure control equipment. Also known as quick unions, the unions have an elastomer seal for the well bore pressure. The seal is either on the box or pin connection depending on the type of union. The quick union is comprised of four components, which consist of the box end, pin end, union nut, and seal. The pin end is stabbed into the box end and the union nut holds everything in place. Quick unions offer a quick method of assembling pressure control equipment as opposed to bolting up flanges.

There are several types of quick unions on the market being used for pressure control equipment. The three most common are Bowen type, Otis type and TOT type unions.

The unions do not interchange with each other.

INJECTOR HEAD AND GUIDE ARCH

The CT injector head is the prime mover for a CT unit. Modern injector heads, like the Hydra Rig 5100 (Figure 4.12), come in a range of sizes, weights, and performance capabilities. The largest, the Hydra Rig 5200, can handle CT up to 7-in diameter and pull up to 200,000 lbs. Many can move the CT up to 200 ft/min. This section describes the features and performance capabilities of most of the injector heads commonly available.

FIGURE 4.12 *Hydra Rig 5100 Injector Head*

Introduction

Figure 4.13 shows a typical CT injector head and a guide arch. The injector provides the following functions:

- Apply dynamic axial force to the CT to control movement into or out of a well
- Supply enough traction to avoid slipping on the CT
- Apply static force to hold the CT when stopped
- Platform for weight and depth measurement sensors

The guide arch is a static device that provides the following functions:

- Support the CT above the injector head

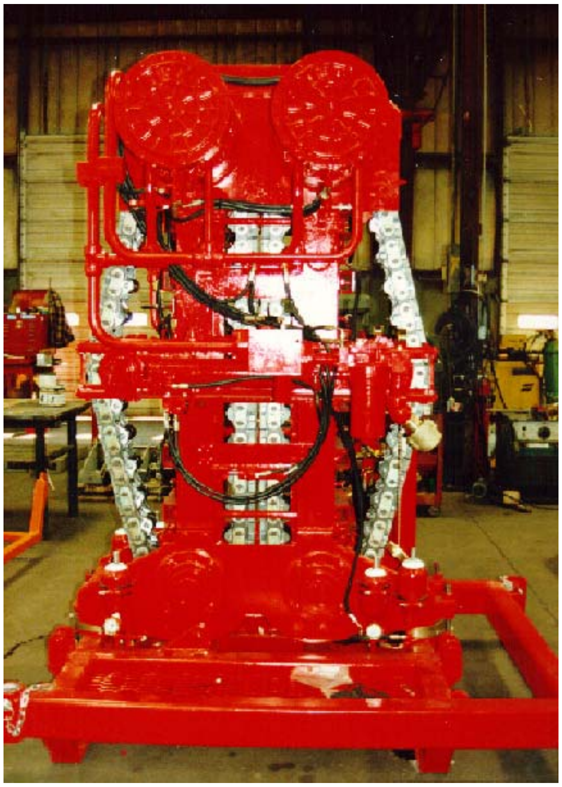
- Provide a controlled radius of bending into/from the top of the injector head
- Withstand the reel back tension
- Accommodate the fleet angle due to spooling on/off the reel

FIGURE 4.13 *Typical CT Injector Head and Guide Arch*

Two continuous and opposing chains are the primary feature of this type of injector head. Short gripper blocks contoured to match the OD of the CT or shaped like a ”V” cover each chain. Hydraulic cylinders force the chains, hence the gripper blocks, together around the CT. Variable-speed hydraulic motors drive the gripper chains. As the chains move linearly in the direction of the CT axis, friction between the gripper blocks and the CT causes it to move at the same rate as the chains. The process resembles climbing a rope hand-over-hand. Friction is the only force supporting the CT in the injector head.

Figure 4.14 shows a typical high performance CT injector head with the external lifting frame removed. The two opposing chains are clearly visible. The injector drive assembly pivots on the base frame and rests on two load cells, one on each side of the pivot.

FIGURE 4.14 *Hydra Rig 480 Injector Head*



Chains and Gripper Blocks

Figure 4.15 is another view of the Hydra Rig 480 injector head showing the cylindrical gripper blocks on one of the chains and one of the hydraulic load cells.

FIGURE 4.15 *Hydra Rig 480 Injector Head*

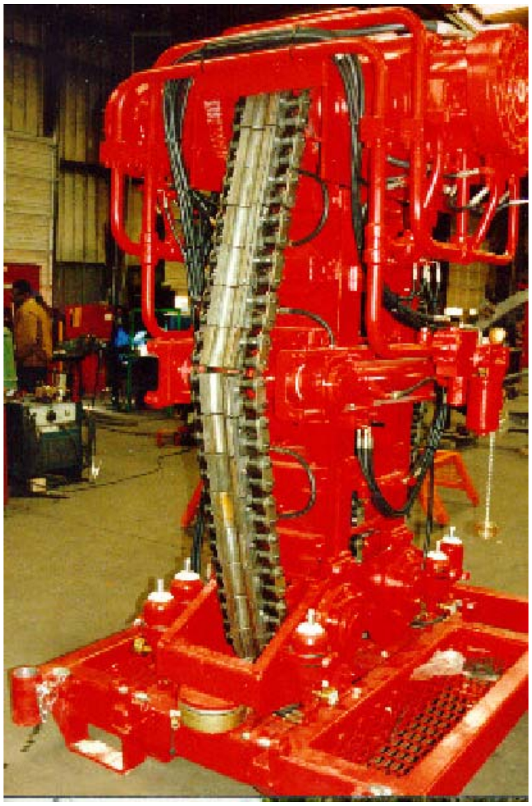
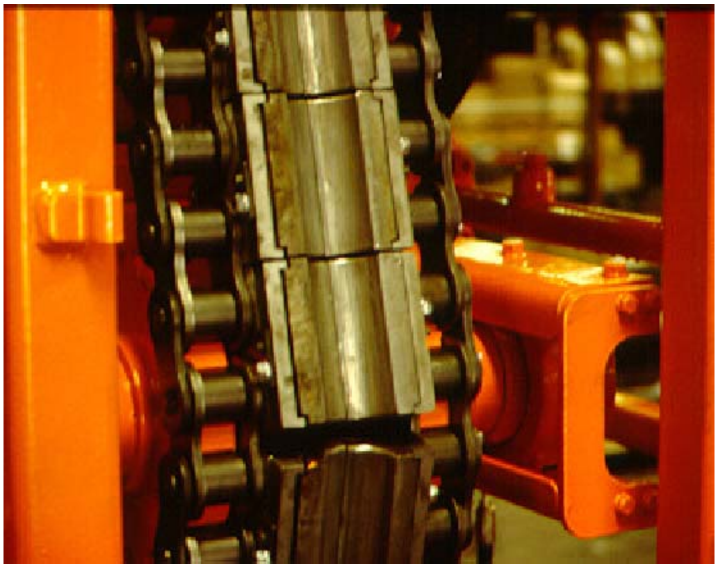


Figure 4.16 shows a close-up view of cylindrical gripper blocks like those used by Hydra Rig and several other manufacturers of injector heads. This design requires a different gripper block for each CT size. However, the blocks spread the gripping force evenly over the entire surface of the CT. This minimizes the risk of scarring or mashing the CT.

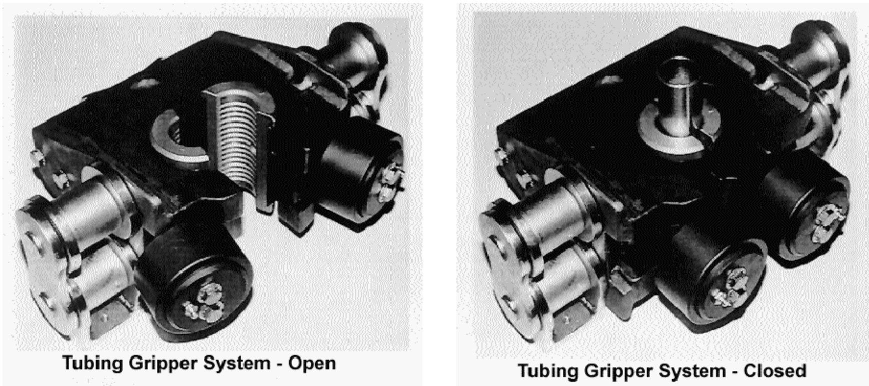
FIGURE 4.16 *Cylindrical CT Gripper Blocks*



Halliburton supplies V-shaped gripper blocks with their injector heads. This design makes line contact with the CT at four locations around the circumference of the CT. The advantage of this block design over a cylindrical contour block is that one size block can grip a range of CT diameters. This provides more flexibility for the user. However, the potential downside of the “V” design is the higher contact pressure between the block and the CT for a given gripping force.

Dreco developed a third type of chain and gripper block design. Figure 4.17 shows the cylindrically contoured gripper blocks hinged together inside the chains. The roller on the front of each half-block rides against a rail which forces the half-block towards its mate when RIH and separates the two halves when POOH. Figure 4.18 shows the complete injector head that uses this gripper block system.

FIGURE 4.17 *Dreco Gripper Block System*



Tubing Gripper System - Open

Tubing Gripper System - Closed

FIGURE 4.18 *Dreco Injector Head*

CT Weight Sensors

CT Injector head load cells can be either hydraulic or electronic. A hydraulic load cell is an elastomer bladder filled with hydraulic fluid or a piston within a cylinder full of hydraulic fluid as shown in Figure 4.15. A small-diameter hydraulic line connects the load cell to a pressure gage in the CT unit control cabin. The analog gage is calibrated to display the force on the load cell corresponding to the hydraulic pressure. Some CT units add an electronic pressure sensor to the hydraulic line from the load cell so that CT weight can be displayed and/or recorded digitally. Electronic load cells are usually strain gage sensors.

Many CT injectors have only one load cell mounted on the opposite side of the CT from the pivot. This arrangement works like a door hinge with the load cell between the two sides. If the load cell is bi-directional (compression/tension), this arrangement can accurately measure the forces during snubbing operations

The dual load cell arrangement shown in Figure 4.14 and Figure 4.19 ensures that one load cell is always in compression and permits greater measurement accuracy. Each load cell measures a portion of the axial force applied to the CT.

FIGURE 4.19 *Hydra Rig 5100 Injector with Dual Load Cells*

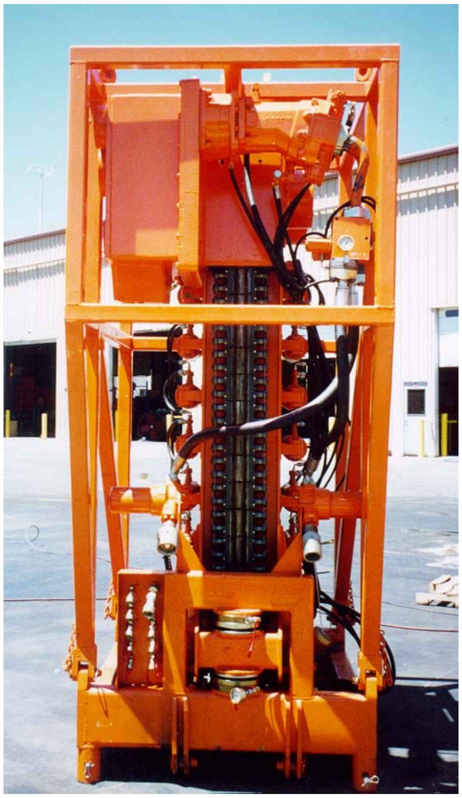


FIGURE 4.20 *NOI RT60 Injector with Load Pins*

A third method of measuring the CT axial forces uses instrumented load pins (strain gage type) to attach the injector head to the support frame, shown in Figure 4.20.

Weight Indicator Calibration System (WICS)

The WICS by CTES, L. P. consists of a bi-directional electronic load cell that attaches to both the CT threaded connector and the bottom connection on the stripper. A small electronic box connected to the load cell with a shielded signal cable contains a digital display for reading the axial force applied to the load cell by the injector. The load cell capacity is 100,000 lbs in tension and compression, and WICS is accurate to ±0.5% of reading.

Figure 4.21 is a sectional view of the individual WICS components. The CT threaded connector (grapple) screws into the top bolt of the weight calibrator. The bottom bolt captures the load cell in the housing. The assembled weight calibrator attaches to the threaded connector on the bottom of the stripper. Pulling or pushing on the CT with the injector transmits force directly to the load cell through the top bolt.

FIGURE 4.21 *WICS Components*

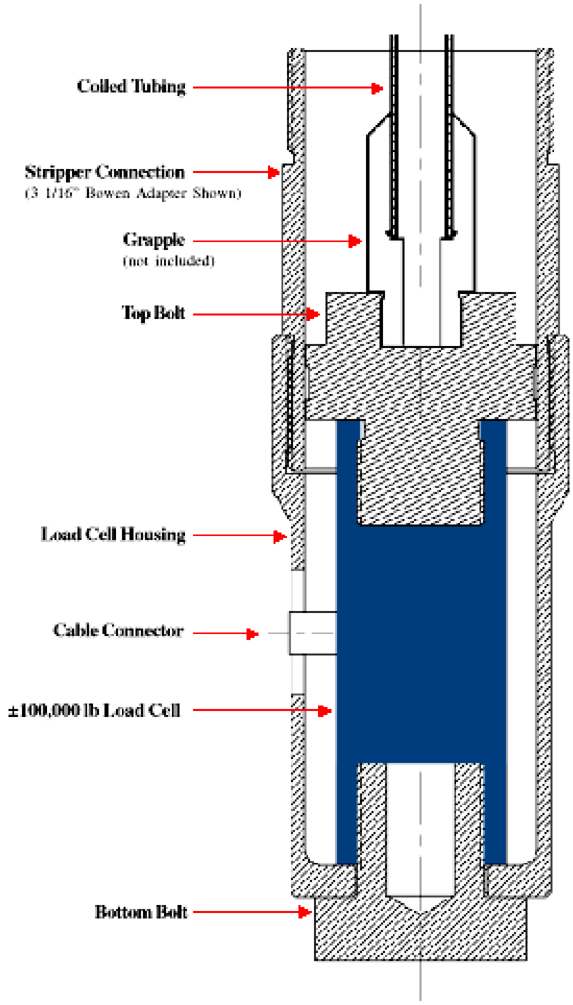


FIGURE 4.22 *WICS in Operation*

Depth Measurement

Some CT injectors incorporate a depth counter for measuring the length of CT traveling through the injector. Figure 4.23 shows a typical installation for the depth counter. A small wheel contacts the CT immediately below the chains. The counter connected to the wheel mechanically converts the revolutions of the wheel into a linear measurement, much like an automobile odometer. If necessary, an electronic encoder attached to the wheel axle can send an electronic depth measurement to the control console and data acquisition system.

FIGURE 4.23 *Mechanical Depth Counter at Injector*

The location of depth monitoring can be in several places on the unit. The most common place is mounted below the injector head chains, but other location such as the sprocket shafts on the injector head or the levelwind at the reel are a few alternative locations. Measuring depth at the reel will be discussed in the following section. Table 4.2 shows the various locations for monitoring depth with the benefits and drawback of each:

TABLE 4.2 *Mechanical Depth Counter at the Injector Head*

Mounting Location	Benefit	Drawback
• Below the injector head	• Measure the pipe movement even when the chains slip • Measure the stretch in the pipe • Directly measure the pipe movement • Accurately measures depth and speed when used on floating or tender assisted vessel	• Close to the wellhead, which requires zoning considerations • Wellbore debris builds up in this area, which can induce errors in the depth • Sensor must be retracted when stabbing pipe
• On the Motor or Sprocket Shaft	• Rugged system • Unaffected by wellbore debris or dirty pipe • No additional steps when stabbing pipe • Accurately measures depth and speed when used on floating or tender assisted vessel	• Close to the wellhead, which requires zoning considerations • Will not accurately measure pipe when slippage occurs • Does not measure stretch in the pipe
• Levelwind	• Usually close to the control cab for easy visibility • Measures the pipe when slippage occurs	• Does not accurately measure the pipe movement or speed • Depth and speed are dependant on the relative motion of the floating or tender assisted vessel • Does not measure tubing stretch

Guide Arch

During most CT operations, injectors have a curved structure mounted on top of them to support and guide the CT in/out of the injector. This guide arch (or gooseneck) has a number of rollers along its length to support the CT. The guide arch serves two purposes:

- provide a controlled radius of bending for the CT to enter/leave the top of the chains
- accommodate the fleet angle between the injector and the reel due to spooling on/off the reel

The first purpose is extremely important to the fatigue life of the CT (see Chapter 9 "CT Fatigue", page 9-5). The CT fatigue life increases as the radius of curvature of the guide arch increases. Typical guide arch radii are 48 in. to 100 in. Most guide arches are removable for easier transport of the equipment. Historically, the large radius arches were vulnerable to high reel back tension and sometimes collapsed, especially with larger diameter CT. However, current guide arch designs generally can withstand the maximum reel back tension.

The following figures show common guide arch configurations.

FIGURE 4.24 *Hydra Rig 480 Injector with Guide Arch*

FIGURE 4.25 *NOI Folding Guide Arch*

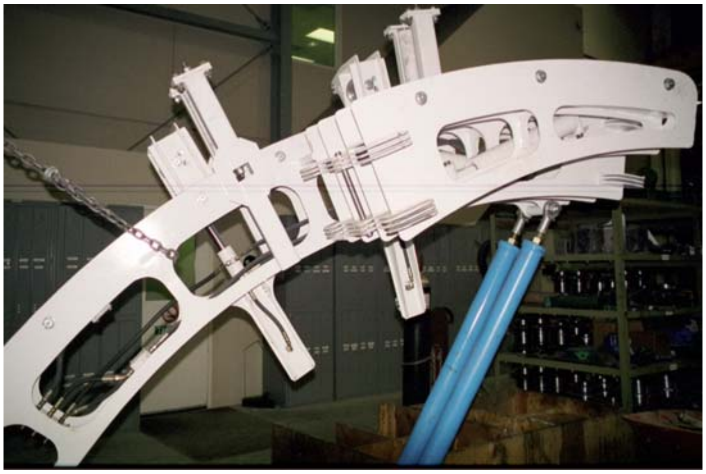


FIGURE 4.26 *Stewart and Stevenson Injector with Large Radius Guide Arch*

FIGURE 4.27 *CT Injector Head and Guide Arch (Semco)*

The “Big Wheel” Configuration

Heartland Rig International offers an injector head, commonly called the “Big Wheel”, that doesn’t use chains at all. The heart of their design is a large grooved wheel. The CT lies in the groove and small rollers on the fixed frame surrounding the wheel force the CT into the groove. The pressure applied to the CT by the guide rollers provides the gripping force as the CT moves around the circumference of the wheel. Figure 4.28 and Figure 4.29 show the “Big Wheel” injector head.

FIGURE 4.28 *“Big Wheel” CT Injector (Fleet Technology)*

FIGURE 4.29 *"Big Wheel" CT Injector*

TUBING REEL

The CT reel, Figure 4.30, is a storage device for the CT string. The reel's drive mechanism has only enough power to wrap/unwrap CT onto/off the drum.

FIGURE 4.30 *Empty CT Reel – Offshore Configuration (Hydra Rig)*

The reel assembly shown in Figure 4.30 is a stand-alone modular unit designed for offshore use with normal workover CT equipment. This design can also be temporarily mounted on a truck or trailer for land operations (see Figure 4.58). Most land CT units have a reel permanently mounted to a truck chassis or trailer, Figure 4.31 and Figure 4.32, respectively.

FIGURE 4.31 *Truck-mounted CT Unit (Stewart and Stevenson)*

FIGURE 4.32 *Large-diameter CT Reel Trailer (Halliburton)*

Some CT units use a “cartridge” reel system of interchangeable reels. This allows changing CT strings without spooling from one reel to another. Figure 4.33 shows examples of such interchangeable reels.

FIGURE 4.33 *Cartridge-type CT Reels (Schlumberger Dowell)*

Figure 4.34 shows the largest CT reel operating at the time of this writing. The flanges are approximately 24 ft in diameter. This reel is part of BHI’s Galileo #2 CTD rig (see Chapter 15 "Purpose-Built CTD Rigs", page 15-54). The huge level-wind supports a small injector head used to control the shape of the free standing arch formed by the CT between the reel and the main injector head (Figure 4.35).

FIGURE 4.34 *Giant CT Reel (BHI)*

FIGURE 4.35 *Large Reel, No Guide Arch, and 2 Injectors (BHI)*

Reel Drive Mechanism and Level-wind

Most reels use a chain drive connecting the hydraulic motor mounted on the support frame to a large sprocket on the side of the drum. The reel drive motor also functions as a dynamic brake during slackoff to maintain tension on the CT between the drum and the guide arch. The reel brake locks the reel in position when the CT is static, but is not used for dynamic braking. During pickup, the reel drive motor applies more torque to the drum than required to pace the injector head pulling speed. This excess torque keeps the CT taut and tightens the wraps on the drum. Figure 4.36 is an example of a fully-loaded reel.

FIGURE 4.36 *Fully-loaded CT Reel*

The CT operator obtains the desired reel tension by controlling the hydraulic pressure to the motor. Figure 4.37 illustrates the disastrous mess that can occur when control of the CT running into the well is lost, and a "run away" occurs. Once the CT reaches the bottom of the well, the CT stops. It is impossible to stop the reel as quickly, causing this type of mess.

FIGURE 4.37 *Result of Losing Control of the Coiled Tubing*

The level-wind, Figure 4.38, serves to guide the wraps of CT onto the drum during pickup and to ensure smooth unwrapping during slackoff. Normally, the double diamond lead screw on the level-wind automatically paces the drum rotation. If necessary, the operator can override the automatic function and move the level-wind manually.

FIGURE 4.38 *Typical CT Reel Level-wind and Mechanical Depth Counter*

Depth Measurement

The tubing depth counter usually consists of a small “drive” wheel bearing against the CT and aligned to roll along its surface in the axial direction. Another wheel on the opposite side of the CT squeezes the CT between the two wheels. Due to friction between the “drive” wheel and CT, the wheel rotates as the CT passes by. A mechanical digital counter (like the odometer in a car), Figure 4.38 and Figure 4.39, or encoder (electronic measurement), Figure 4.40, attached to the shaft of the wheel senses its revolutions. The digital display or data acquisition unit at the operator's console converts the wheel revolutions into linear distance the CT travels (depth). Slippage between the wheel and CT is a source of error in the depth measurement.

FIGURE 4.39 *CT Reel Level-wind and Mechanical Depth Counter (BJ)*

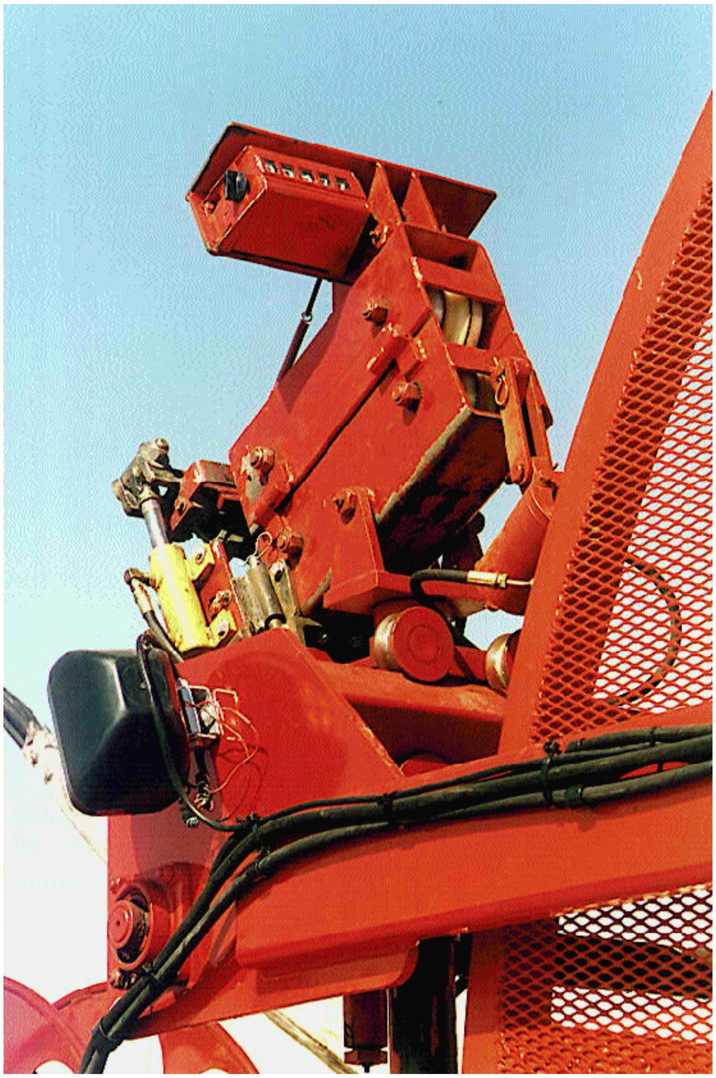
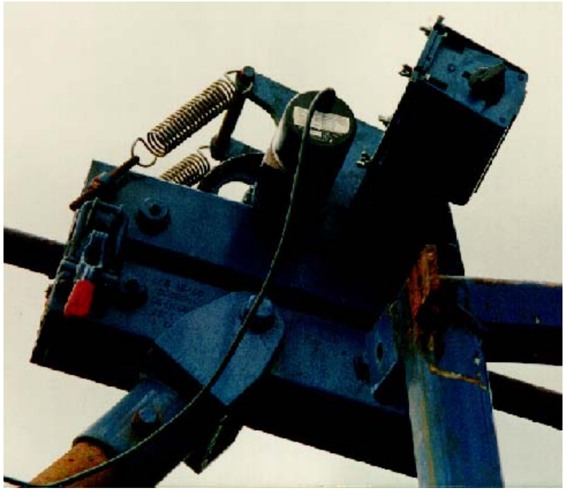


FIGURE 4.40 *Electronic Depth Encoder*



Auxiliary Depth Measuring System

For CT operations requiring more accurate depth measurement than commonly available at the injector head or reel level wind, auxiliary depth measuring systems such as Figure 4.41 are available. These mount over the CT between the guide arch and the level wind. The system operating software detects and compensates for slippage of the friction wheels to provide a nominal measurement accuracy of ±10 ft in 10,000 ft.

FIGURE 4.41 *Auxiliary Depth Measuring System*

Fluid and Electrical Connections

Figure 4.30 does not clearly show the high-pressure swivel, electrical slip-ring assembly, and ball launcher manifold usually mounted on the side of the reel. The swivel connects the CT on the reel to external piping. The slip ring provides a rotating connection between electric line in the CT and external wiring, such as a logging truck. The ball launcher provides a means to insert balls, plugs, or other objects into the CT. Figure 4.42 and Figure 4.43 are close-up views of this equipment.

FIGURE 4.42 *CT Reel Swivel, Power Swivel and Ball Launcher*

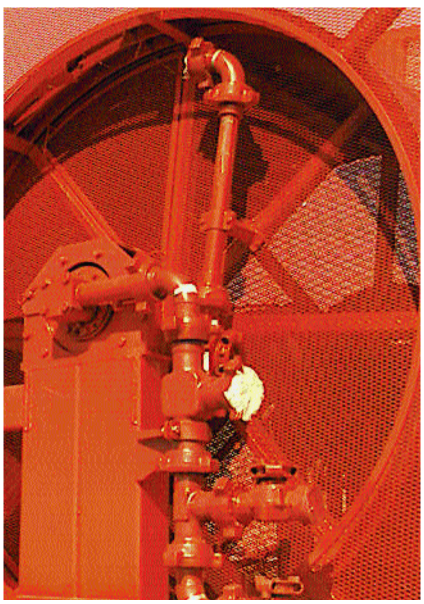


FIGURE 4.43 *CT Reel Inlet Manifold*

Reel Capacity

Equation 4.1 through Equation 4.3 present the method recommended in API RP 5C7 for calculating the capacity of a CT reel. The result is somewhat conservative because the method assumes each wrap of CT is directly over/under the wrap in the adjacent layer.

EQUATION 4.1 *Calculation for the number of layers*

$$N = \text{integer}\left\{\frac{A-F}{d}\right\}$$

EQUATION 4.2 *Calculation for the number of wraps*

$$M = \text{integer}\left\{\frac{B}{d}\right\}$$

EQUATION 4.3 *Calculation for reel capacity (ft)*

L=0.2618NM (C+dN)

Where:
F = freeboard (in.)
A = flange height (in.)
B = flange width (in.)
C = core diameter (in.)
d = CT diameter (in.)

FIGURE 4.44 *Parameters in Reel Capacity Calculation*

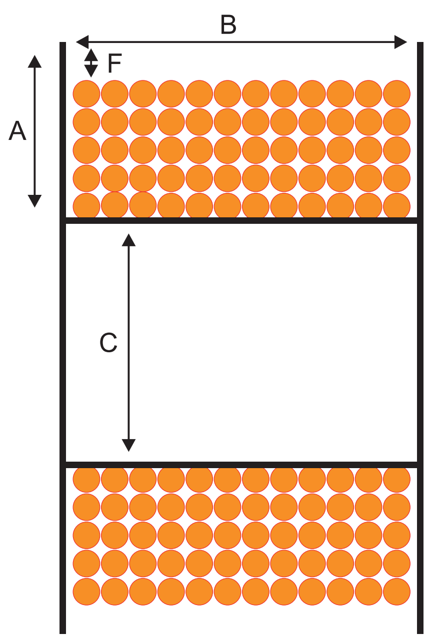


Table 4.3 lists typical dimensions, weights, and CT capacity for common workover CT reels, according to the manufacturer.

TABLE 4.3 *Sizes, Weights, and Capacities of Typical CT Reels (Hydra Rig)*

Overall Dimensions (in.)	**Drum Dimensions (in.)**	**Reel Capacity (ft) for CT Sizes**				**Empty Weight**
L x W x H	**F x C x W**	**1.25 in**	**1.50 in**	**1.75 in**	**2.00 in**	**(lbs)**
148x98x122	119x76x70	24,000	15,100	—	—	10,800
164x98x138	135x84x70	25,000	20,000	15,000	—	13,000
164x116x138	135x84x82	—	24,000	18,000	11,000	15,000
168x112x142	139x90x82	—	23,000	17,500	13,000	15,000
L= length, W = width, H = height, F = flange OD, C = core OD						

POWER UNITS

A hydraulic power unit operates typical CT surface equipment. This unit must supply relatively high-volume, low-pressure hydraulic fluid to dynamic equipment like the injector head and reel and relatively low-volume, high-pressure hydraulic fluid to static devices like the stripper and BOP. Consequently, most CT unit power packs have several pumps powered by a diesel engine or electric motor. The following figures show examples of different power unit configurations.

FIGURE 4.45 *Typical Skid-mounted CT Power Unit (Hydra Rig)*

FIGURE 4.46 *Typical Truck-mounted CT Power Unit (BJ)*

FIGURE 4.47 *Modular CT Power Unit for Offshore Operations (Hydra Rig)*

CONTROL CAB AND OPERATOR'S CONSOLE

The control cab or operator's cab contains the console with the analog gauges, digital displays, and electrical and hydraulic controls necessary to operate the CT unit. The configuration of the cabin and console vary widely with manufacturer and each customer's specifications. In most cases, the CT operator sits at a console as shown in Figure 4.48 and Figure 4.49 with a view over the reel much like Figure 4.50.

FIGURE 4.48 *CT Unit Control Console*

FIGURE 4.49 *CT Unit Control Console (Stewart and Stevenson)*

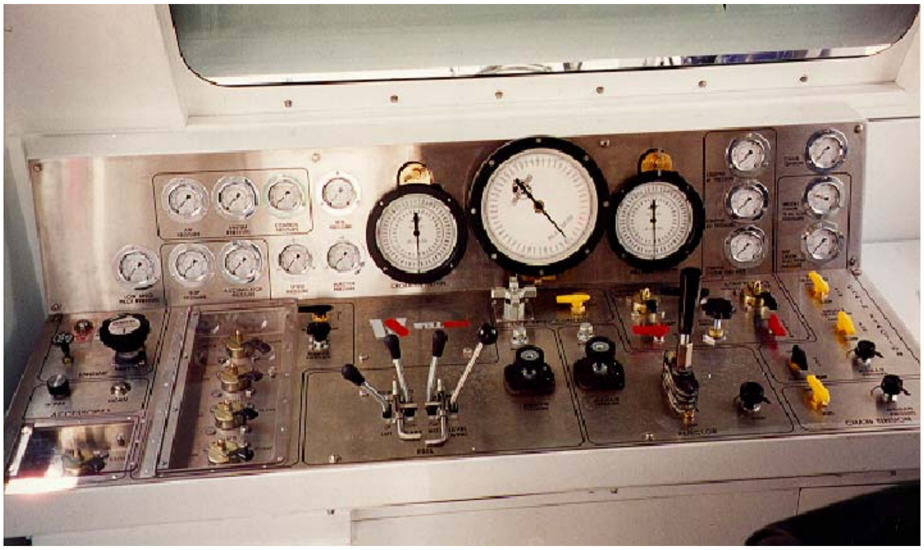


FIGURE 4.50 *Typical CT Operator's View from the Control Cab*

Hitec has built a number of electric/hydraulic control systems for drilling, snubbing, and workover rigs. Figure 4.51 and Figure 4.52 show two views of the control console and operator's station for the Nabors/Transocean CDR#1 CTD rig. (See Chapter 15 "Hybrid CTD Units", page 15-32)

FIGURE 4.51 *Hitec Control Display*

FIGURE 4.52 *Hitec Control Chair*

The "leading edge" of CT unit control is the electric-over-hydraulic process control system developed by BHI for their CTD rigs. Their all-digital system uses touch screen computer consoles and sophisticated software to communicate with the hydraulically operated surface equipment. Figure 4.53 shows the operator's console for the Galileo #1 CTD rig. (see Chapter 15 "Purpose-Built CTD Rigs", page 15-54)

FIGURE 4.53 *Touch Screen Control Console for the Galileo #1 CTD Rig (BHI)*

CT LIFTING FRAME

A CT lifting frame is required when performing operations from a floating vessel where motion-compensation is required. The lifting frame is a high strength component in which the injector head and pressure control equipment is mounted inside the structure, see Figure 4.54 and Figure 4.55. The rig picks up the lifting frame in the traveling block. The traveling blocks on floating vessels are motion compensated by the use of an accumulator system, which allows the blocks to maintain at relatively steady pull while the rig heaves. These frames are generally rated to a capacity of at least 300 tons.

The bottom connection is general connected into the tubing, casing or testing flowhead. To simplify the RU/RD process, a hydraulic connection is used to nipple up the lifting frame to the wellhead. The top connection latches into the traveling block elevators.

The lifting frame usually contains a main winch mounted at the top, which is used for lifting the injection head and pressure control equipment inside the frame. Having the winch mounted in the lifting frame isolates the system from any movement of the vessel. Additional utility winches are used for handling small equipment or BHA.

FIGURE 4.54 *Devin Lifting Frame*

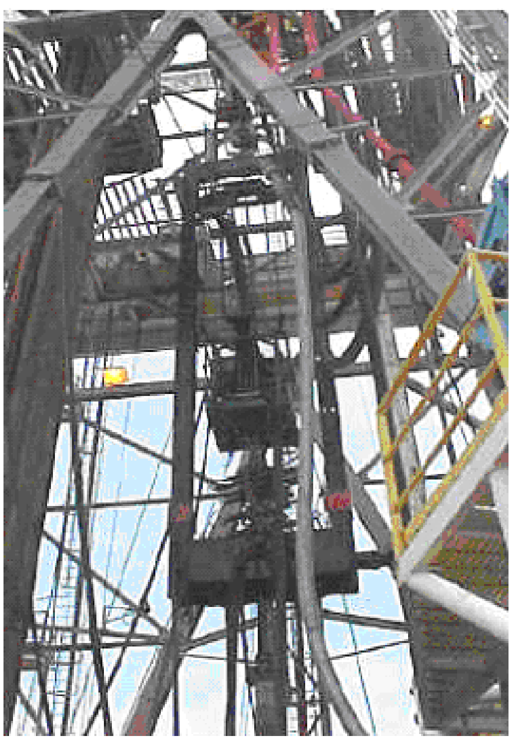


FIGURE 4.55 *Alternative Lifting Frame*

CT DATA ACQUISITION SYSTEM (DAS)

The use of computer based data acquisition systems on CT units has expanded rapidly since about 1994. These systems can electronically record all information pertinent to operating a CT unit and estimating the performance of the CT below the stripper. Typical measurements include:

- Pump (circulating) pressure
- Wellhead pressure (WHP)
- CT depth
- CT axial speed
- CT weight (load cells)
- Stripper hydraulic pressure
- Hydraulic power supply pressure

Even if the CT operator uses the analog gauges or digital displays on the control console as the primary information for operating the CT unit, the data acquisition system provides a permanent record of the entire CT operation. (See Chapter 17 "Data Acquisition and Real-Time Monitoring", page 17-52 for a detailed discussion about real-time monitoring of CT operations.) Figure 4.56 looks inside a modern CT data acquisition system, and Figure 4.57 shows a similar system installed inside a small CT unit control cab.

FIGURE 4.56 *Orion™ CT DAS (CTES)*

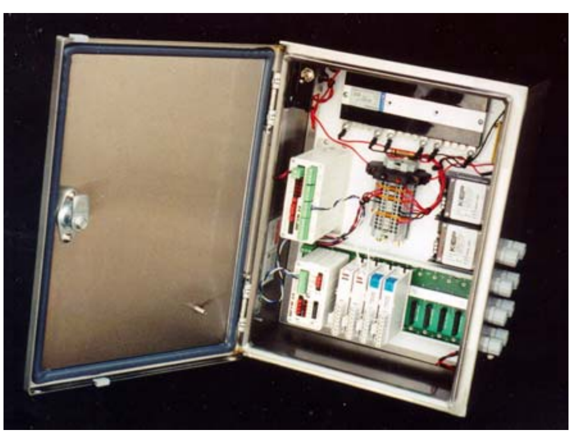


FIGURE 4.57 *Orion™ CT DAS Installed*

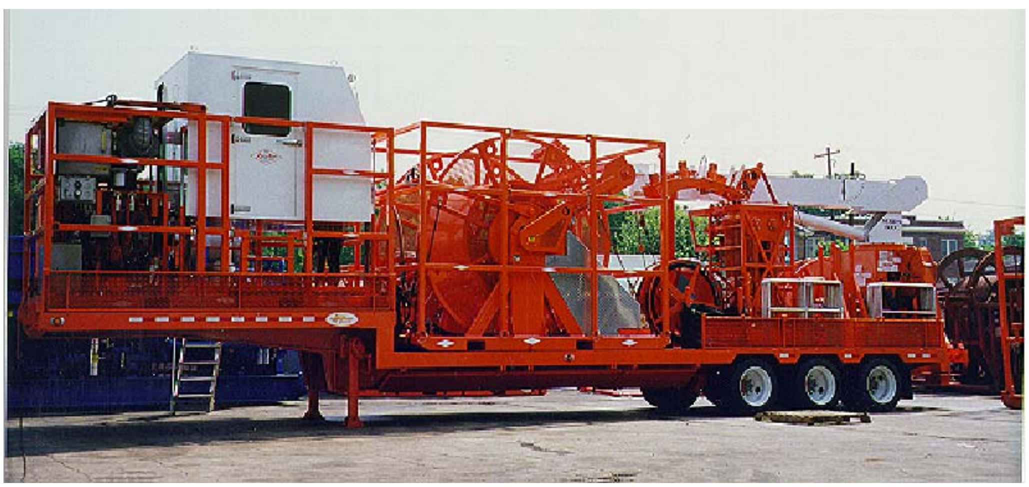
TYPICAL CT WORKOVER UNIT CONFIGURATIONS

CT workover units come in a wide range of configurations and sizes, depending on their manufacturer, customer (CT service company), and intended application. This manual cannot do justice to the diverse assortment of equipment available to the CT industry, but the following sections provide a few typical examples.

Modular

Modular CT units consist of individual components packaged in their own skid or "crash" frame. These units are ideal for use offshore or other locations with severe space limitations. Figure 4.58 shows a modular unit mounted on a trailer for land operations.

FIGURE 4.58 *Modular CT Unit Mounted on a Trailer (Stewart & Stevenson)*



Truck-mounted

FIGURE 4.59 *Small Truck-mounted CT Unit (Stewart and Stevenson)*

FIGURE 4.60 *Truck-mounted CT Unit (Stewart & Stevenson)*

Trailer-mounted

FIGURE 4.61 *Trailer-mounted CT Unit (Hydra Rig)*

FIGURE 4.62 *Trailer-mounted CT Unit (Camco)*

FIGURE 4.63 *Trailer-mounted CT Unit (Semco)*

FIGURE 4.64 *"Big Wheel" CT Unit (Heartland Rig)*

FIGURE 4.65 *Trailer-mounted CT Unit for Arctic Conditions (Hydra Rig)*

FIGURE 4.66 *CT Express (Dowell)*

FIGURE 4.67 *Bodyload CT Unit (Halliburton)*

TYPICAL LOCATION LAYOUTS

The rig up and equipment layout is unique for each location. The examples shown in the following sections are typical only for the terrain, environmental conditions, and equipment depicted.

Land Operations

FIGURE 4.68 *CT Unit Rig Up on Land (Camco)*

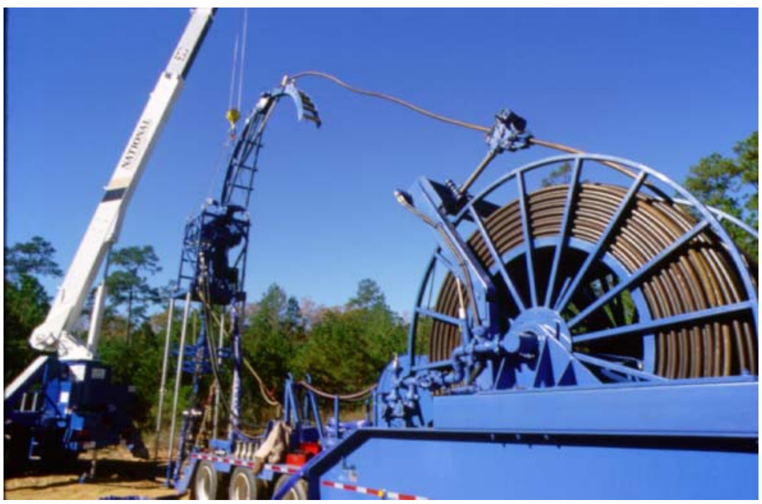


FIGURE 4.69 *CT Unit Rig Up on a Drilling Rig*

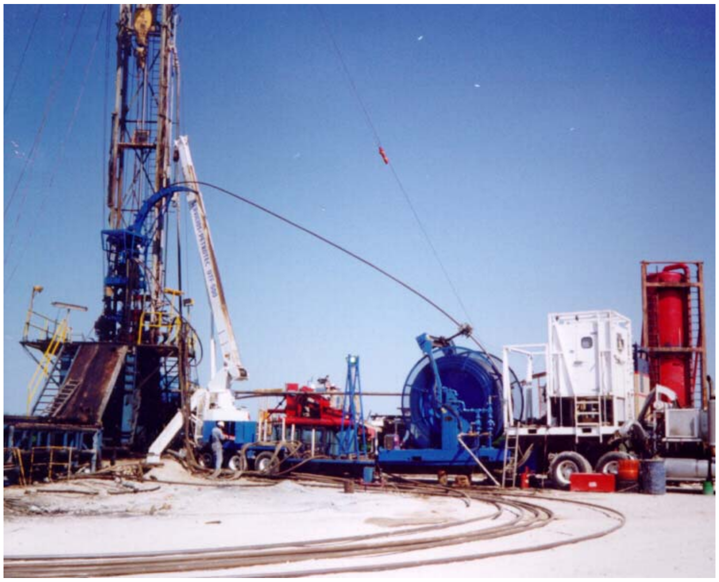


FIGURE 4.70 *Typical CT Unit Land Rig Up*

FIGURE 4.71 *CT Unit Slant Well Rig Up (Nowsco)*

FIGURE 4.72 *CT Unit with Nitrogen Tank*

FIGURE 4.73 *CT Unit Rig Up for Arctic Operations*

Offshore Operations

FIGURE 4.74 *Barge CT Unit (Dowell)*

FIGURE 4.75 *CT Unit Offshore (Camco)*

FIGURE 4.76 *CT Operations from a Lift Boat (Spirit Energy)*

FIGURE 4.77 *CT Operations from a Lift Barge (Dowell)*

FIGURE 4.78 *CT Operations Offshore Dubai (Dowell)*

5

CT SUBSURFACE EQUIPMENT—DOWNHOLE TOOLS

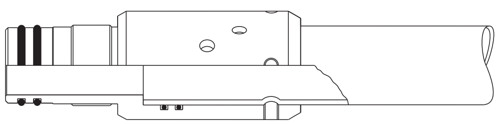
The following section describes typical subsurface equipment, downhole tools, used for CT operations. The CT industry offers a wide variety of such tools, and those presented herein represent only a small sample. Most CT service companies have equipment comparable to the examples shown in this section. Also, a host of third-party tool suppliers offer common as well as highly-specialized CT subsurface equipment. Except where noted, Pressure Control Engineering (PCE) provided the figures and technical information in this chapter.

CT CONNECTORS

Grub Screw/Dimple Connector

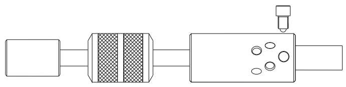
CT Grub Screw/ Dimple Connectors allow the attachment of CT to the BHA with a threaded connection. The connector attaches to the CT by grub (set) screws that engage in preformed dimples in the tubing wall. The dimples are formed with the Dimple Tool that places the indents in identical positions to the screws on the connector.

FIGURE 5.1 *Grub Screw/Dimple Connector*



A Dimple Tool is used to accurately produce the indentations in the CT wall, required when using the Grub Screw/Dimple type CT connectors. The dimples are produced by screwing the round headed cap screws into the tubing wall by the same amount. The slide hammer on the Dimple Tool aids installation and removal of the tool.

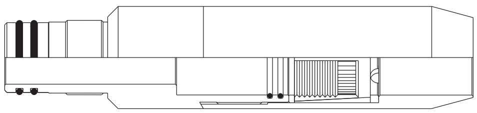
FIGURE 5.2 *Dimple Tool*



External Slip Type Connector

CT External Slip Type Connectors allow the attachment of CT to the BHA with a threaded connection. The External Slip Type Connector utilizes a set of “wicker” type slips that grip the tubing in a wedging action. Thus, an increase in tension increases the grip. The inclusion of the slip bowl assists in the make-up by preventing rotation of the slips. A special feature of this design is that the upper wickers are vertical and also stop the connector from rotating on the CT.

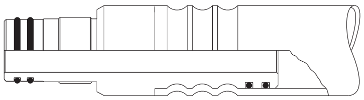
FIGURE 5.3 *External Slip Type Connector*



Roll-On Connector

CT Roll-On Connectors allow the inline attachment of CT to the BHA with a threaded connection. Roll-On Connectors have the same outside diameter as the CT. Roll-On Connectors attach to the CT's internal diameter. The connector is secured by crimping the tubing into the connector's preformed channels with a special tubing crimping tool.

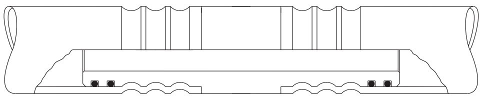
FIGURE 5.4 *Roll-On Connector*



Double Ended Roll-On Connector

Double Ended Roll-On Connectors allow splicing two lengths of CT. Double Ended Roll-On Connectors have the same outside diameter as the CT. Double Ended Roll-On Connectors attach to the CT's internal diameter. The connector is secured by crimping the tubing into the connector's preformed channels with a special tubing crimping tool.

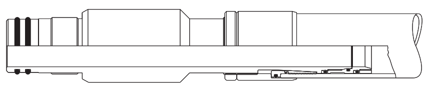
FIGURE 5.5 *Double Ended Roll-On Connector*



Internal Slip Connector

CT Internal Slip Connectors allow the attachment of CT to the BHA with a threaded connection. Internal Slip Connectors attach to the CT's internal diameter. The connector is secured with tapered slips.

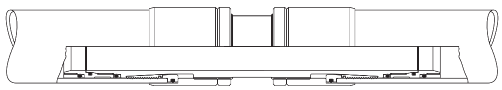
FIGURE 5.6 *Internal Slip Connector*



Double Ended Internal Slip Connector

Double Ended CT Internal Slip Connectors allow splicing two lengths of CT. Double Ended Internal Slip Connectors attach to the CT's internal diameter. The connector is secured with tapered slips.

FIGURE 5.7 *Double Ended Internal Slip Connector*



Commonly Used CT Threads

The following section shows six thread forms commonly found with CT operations.

TABLE 5.1 *1.7 - 10 Stub Acme*

Size	A	B	C	D	E	F	G
1.7-10	1.00 in.	1.749 in.	1.440 in.	1.260 in.	0.120 in.	0.130 in.	1.500 in.

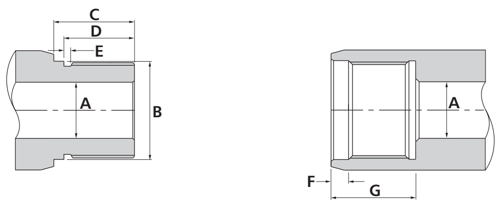


TABLE 5.2 *Stub Acme*

Size	A (max)	B	C	D	E	F	G	H	I
1.5 -10	.937 in.	1.336 in.	2.850 in.	1.668 in.	1.175 in.	0.15 in.	1.340 in.	1.686 in.	2.810 in.
1.812-10	1.25 in.	1.682 in.	2.850 in.	1.668 in.	1.195 in.	0.15 in.	1.687 in.	1.686 in.	2.880 in.
2.062-10	1.500 in.	1.91 in.	2.850 in.	1.660 in.	1.195 in.	0.15 in.	1.914 in.	1.686 in.	2.880 in.

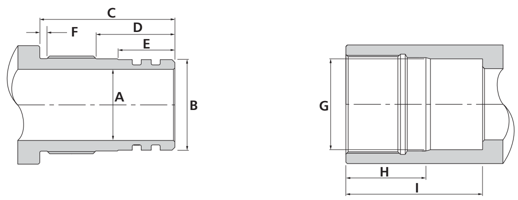


TABLE 5.3 *Ammt with O-ring Groove*

Size	A (max)	B	C	D	E	F	G	H
1.00 in.	.63 in.	1.56 in.	1.75 in.	1.50 in.	.44 in.	1.301 in.	2.13 in.	2.00 in.
1.50 in.	1.00 in.	2.00 in.	2.25 in.	2.00 in.	.44 in.	1.688 in.	2.63 in.	2.50 in.

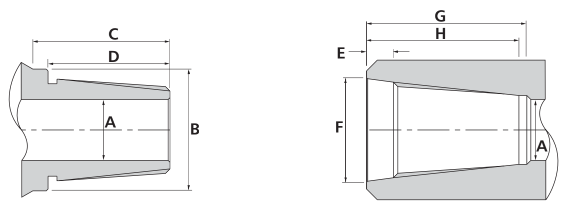


TABLE 5.4 *1 1/4 in. Ammt*

Size	A (max)	B	C	D	E	F	G	H	I
1.254"	.75".	1.421"	2.00"	1.625"	1.75"	1.489"	.44"	2.50"	2.00"

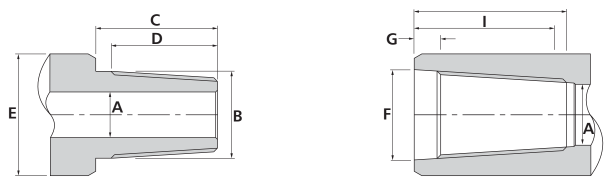
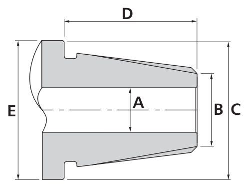


TABLE 5.5 *A.P.I. Regular with O-ring Groove*

Size	A (max)	B	C	D	E	F	G	H
2 375 in.	1.25 in.	1.639 in.	3.015 in.	3.00 in.	3.13 in.	4.250 in.	1.69 in.	2.678 in.



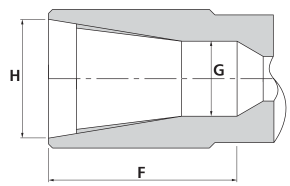
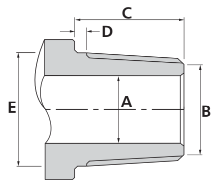
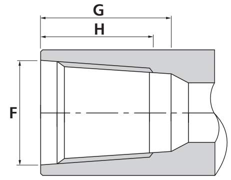


TABLE 5.6 *PAC*

Size	A (max)	B	C	D	E	F	G	H (min)
2.375 in.	1.375 in.	1.833 in.	2.25 in.	.25 in.	2.362 in.	2.406 in.	3.00 in.	2.50 in.



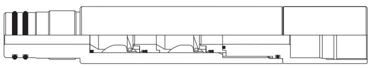


CHECK VALVES

Twin Flapper Check Valve

The Twin Flapper Check Valve is a standard CT string component. It provides a means of preventing the back flow of well fluids into the CT in the event of failure or damage to the CT string or surface equipment. The Twin Flapper Check Valve incorporates a dual sealing system in each flapper assembly for increased safety. A teflon seat provides the primary low pressure seal, while at higher pressures the flappers seat on a metal to metal sealing arrangement.

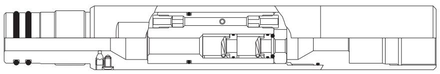
FIGURE 5.8 *Twin Flapper Check Valve*



Twin Flapper Check Valve with Bypass

The Twin Flapper Check Valve with Bypass is a CT string component with the added facility for use in logging cable bypass operations. It provides a means of preventing the back flow of well fluids into the CT in the event of failure or damage to the CT string or surface equipment. The Twin Flapper Check Valve incorporates a dual sealing system in each flapper assembly for increased safety. A teflon seat provides the primary low pressure seal, while at higher pressures, the flappers seat on a metal to metal sealing arrangement.

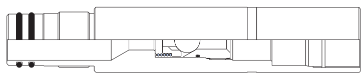
FIGURE 5.9 *Twin Flapper Check Valve with Bypass*



Ball Check Valve

A Ball Check Valve is a standard CT string component. It provides a means of preventing the back flow of fluids into the CT in the event of failure or damage to the surface equipment. Ball Check valves are used when devices such as balls and darts do not need to pass through the valve. If dropping a ball or dart is part of the operation a Flapper Valve must be used.

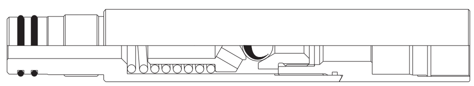
FIGURE 5.10 *Ball Check Valve*



Back Pressure Valve

The CT Back Pressure Valve is a CT string component that provides a circulation path against a predetermined back pressure. It is ideally suited to operations when the hydrostatic pressure within the CT needs to be higher than the pressure in the annulus. The Back Pressure Valve allows for an on-site determination of back pressure to be set at surface. This is achieved with the use of different ball diameters to increase/decrease the piston area and pressure required to open the valve.

FIGURE 5.11 *Back Pressure Valve*



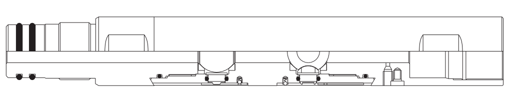
Dual Ball Kelly Cock Valve

Dual Ball Kelly Cock Valves are designed to be used in conjunction with the Combination Anti-Rotation Self Aligning Connector (C.A.R.S.A.C.), in order to safely deploy CT downhole assemblies in or out of the wellbore. (See Section “CT Straight Bars & Joints”)

The dual ball valves can be opened or closed at surface by the use of an Allen wrench. By sliding a locking plate to allow a wrench to be inserted into the ball key, the locking slot can be rotated into the horizontal or vertical position. When both balls have been turned into the open position, pressure can be bled off via the bleed screws and balls.

A locking feature incorporated in the design holds the balls securely in the open position when run into the wellbore.

FIGURE 5.12 *Dual Ball Kelly Cock Valve*

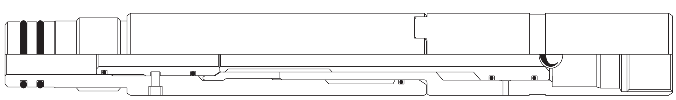


CT Disconnects (Release Joints)

B.O.S.S. Release Joint

The ball operated safety shear or ball operated shear sub (B.O.S.S.) Release Joint allows the release of the CT tool/work string at a predetermined point. B.O.S.S. Release Joints operate on the principle of a dropped ball locating on a seat within the tool. Hydraulic pressure applied to the tool will activate the release mechanism at a predetermined pressure. Once released, circulation through the coil is re-established through the upper part of the tool. The lower part of the release joint can be retrieved using a conventional “GS” Type Running/Pulling Tool or with a Release Joint Retrieval Tool.

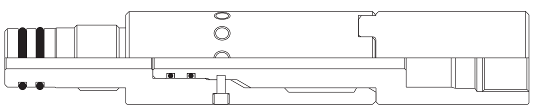
FIGURE 5.13 *B.O.S.S Release Joint*



Shear Release Joint

Shear Release Joints allow the parting of the CT work string by applying predetermined tension. The Shear Release Joint was designed for and used primarily in cement stinger operations as a simple effective emergency release. Shear Release Joints incorporate shear screws that can be used in various combinations to allow a wide range of predetermined shear settings. The released part of the Shear Release Joint can be retrieved using a “GS” type pulling tool or a Release Joint Retrieval Tool.

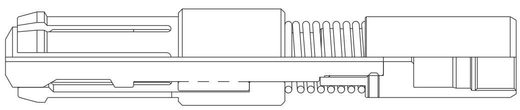
FIGURE 5.14 *Shear Release Joint*



Release Joint / Retrieval Tool

The Release Joint Retrieval Tool is a CT service tool designed to retrieve the lower portion of a release joint after activation of the release mechanism. The heavy duty lugs are designed to engage the standard size fish neck inside the released joint. Shear pins facilitate release of the tool from the fish neck if required. The shear pin values are preset at surface to suit operational restrictions or maximum pull available.

FIGURE 5.15 *Release Joint / Retrieval Tool*

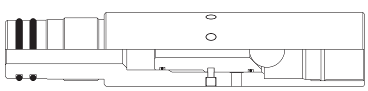


CT Circulation and Control Valves

Ball Activated Circulation Valve

Ball Activated Circulation Valves allow circulation above the BHA. Dropping a ball activates the tool, which can be adjusted on surface to shear out by varying the number and type of shear pins. Pressure applied to the drop ball causes the pins to shear and the sleeve to move down allowing circulation via the side ports.

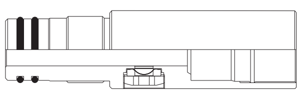
FIGURE 5.16 *Ball Activated Circulation Valve*



Burst Disc Circulation Sub

The Burst Disc Circulation Sub is a standard CT tool string component that is used in conjunction with tools that require drop balls and also need circulation through the CT. Burst Disc Circulation Subs are incorporated into the CT tool string just below the tool that requires a drop ball. Should circulation be lost due to a down hole restriction, a predetermined pressure applied to the coil will burst the disc in the sub and re-establish circulation.

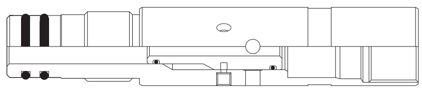
FIGURE 5.17 *Burst Disc Circulation Sub*



Dual Circulation Valve

A Dual Circulation Valve can be operated by either a conventional drop ball or by over pressuring the fluid in the tool string. Simply by varying the configuration of shear pins, the tool can open the circulation ports by either a predetermined over pressure on the pressure differential piston or by simply dropping a ball.

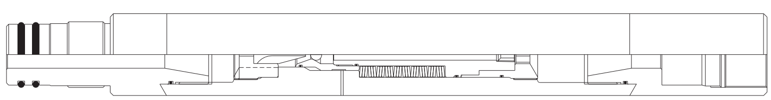
FIGURE 5.18 *Dual Circulation Valve*



Cement Valve

The CT Cement Valve is designed to support a column of fluid, until such time as an increase in pressure is applied to the column from above. Once the valve senses the increased pressure, it will open and allow the column of fluid to flow through the valve. By reducing pressure to the column of fluid to less than the valve set point, the valve will close. Pressure applied to the column of fluid works against the selected cross sectional area and begins to compress the disc springs. The disc springs are compressed before the ball reaches the lift sub. At this point, the fluid is being held by the spring pressure, against the force of the hydrostatic pressure acting on the piston. Increasing the pressure activates the lift sub, which lifts the ball from its seat and allows the fluid to flow past the ball.

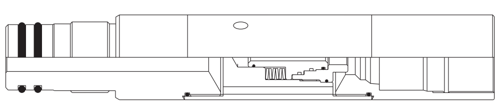
FIGURE 5.19 *Cement Valve*



Flow Activated Sequencing Tool

The Flow Activated Sequencing Tool actuates downhole CT tools at a predetermined pressure. The design of the Flow Activated Sequencing Tool allows normal circulation, while RIH, up to a given flow rate (pressure differential) at the tool. Once the design differential pressure is exceeded, the flow path is closed and diverted into the internal bore of the tool-string, thereby enabling hydraulic activation of any tools in the lower end of the tool string.

FIGURE 5.20 *Flow Activated Sequencing Tool*



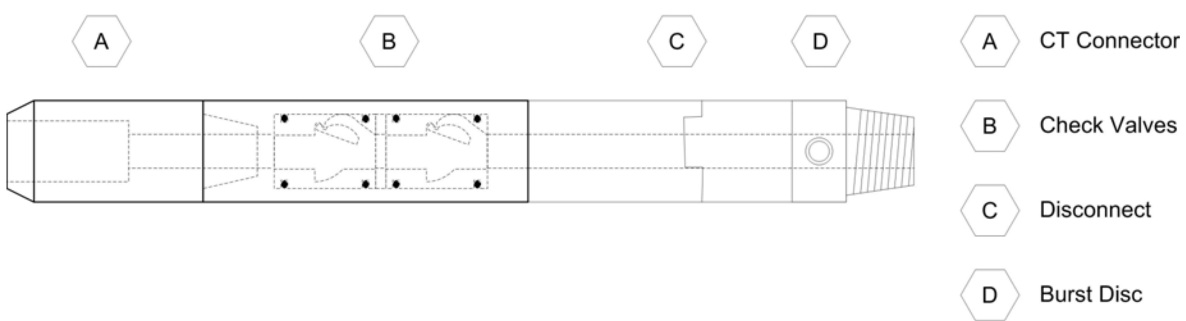
MOTOR HEAD ASSEMBLY

The Motor Head Assembly (MHA) is basically the combination of a coiled tubing connector, check valve and a disconnect which is incorporated into a single tool to minimize the tool length. Sometimes the MHA incorporates a burst disc to provide an alternative fluid path if the downhole tools become plugged. These tools come in a variety of sizes, but typically correspond with the standard motor sizes. The tools are arranged in the following order to provide maximum safety and functionality:

- CT Connection (Top)
- Check Value
- Disconnect (Bottom)
- Circulation Sub
- Burst Disc (optional)

This arrangement provides a means of disconnecting from the downhole tools, while still maintaining the pressure integrity of the coiled tubing sting. Disconnects have an internal fishing profile to retrieve any tools after releasing. This tool should always be run just below the end of the CT to minimize the risk of becoming stuck.

FIGURE 5.21 *Motor Head Assembly*



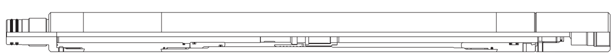
revised 6/27/14

CT JARS & ACCELERATORS

Upstroke Hydraulic Jar

CT Upstroke Hydraulic Jars are incorporated as a part of the BHA when an upward jar action is required. They should be run with an Upstroke Accelerator. Pulling up on the CT energizes the jar. This draws up the single piece mandrel, contained within a closed and balanced hydraulic system. When the jar fires, the tool string above the jar moves rapidly upward until the mandrel strikes out on it's hammer stop creating the sudden upward impact. The impact force can be controlled by the amount of overpull at surface. A large overpull rate will result in a high impact. A small overpull will result in a softer impact.

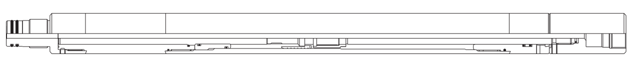
FIGURE 5.22 *Upstroke Hydraulic Jar*



Upstroke Accelerator

CT Upstroke Accelerators are used in conjunction with the CT Upstroke Hydraulic Jars to store upward energy in a compression spring to boost the strike force of a jar.

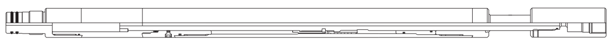
FIGURE 5.23 *Upstroke Accelerator*



Downstroke Hydraulic Jar

CT Downstroke Hydraulic Jars are incorporated as a part of the BHA when an downward jar action is required. They should be run with a Downstroke Accelerator. Pushing down on the CT energizes the jar. This draws up the single piece mandrel, contained within a closed and balanced hydraulic system. When the jar fires, the tool string above the jar moves rapidly downward until the mandrel strikes out on it's hammer stop creating the sudden downward impact. The impact force can be controlled by the amount of SDW. A large SDW will result in a high impact. A small SDW will result in a softer impact.

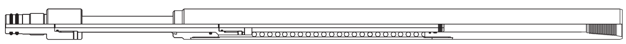
FIGURE 5.24 *Downstroke Hydraulic Jar*



Downstroke Accelerator

CT Downstroke Accelerators are used in conjunction with the CT Downstroke Hydraulic Jars to store downward energy in a compression spring to boost the strike force of a jar.

FIGURE 5.25 *Downstroke Accelerator*

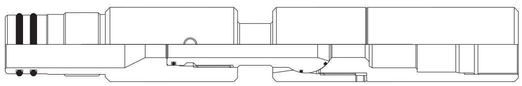


CT Straight Bars & Joints

Knuckle Joint/Torque-Thru Knuckle Joint

These knuckle joints are incorporated within the BHA tool to provide angular movement in any direction. The ball and socket of the knuckle have a key that prevents rotation but still allows full angular movement.

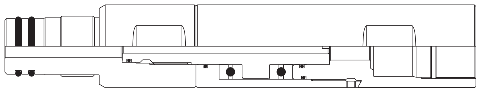
FIGURE 5.26 *Knuckle Joint/Torque-Thru Knuckle Joint*



Swivel Joint

The CT Swivel Joint is a standard tool string component which permits full rotation of all tools made up below the joint. The CT Swivel Joint has sealed bearings which ensure full integrity of flow through the joint.

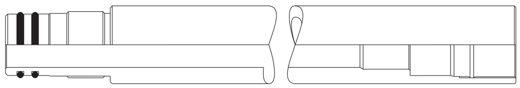
FIGURE 5.27 *Swivel Joint*



Straight/Weight Bar

Straight/Weight Bar adds weight and length to the BHA as necessary. Straight Bar has a full flow through bore allowing the passage of darts or drop balls.

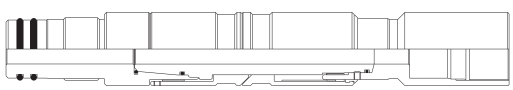
FIGURE 5.28 *Straight/Weight Bar*



C.A.R.S.A.C. Connector

The Combination Anti-Rotation Self Aligning Connector (C.A.R.S.A.C.) assists with the tubing make-up where it is difficult to rotate the tools to engage threads. It is especially helpful when used in conjunction with integral ball valves and deployment bars. The C.A.R.S.A.C. allows a high degree of torque to be transmitted through it. This is achieved by the combination of a locking taper (which permits easy stabbing) and a self aligning anti-rotation collar. The tool is made up by stabbing the upper assembly, complete with locking collar and anti-rotation collar, into the lower female sub and screwing the locking collar down to lock the assembly together. The design also allows the upper jacking collar to be used as an additional locking feature when screwed down on the locking collar.

FIGURE 5.29 *C.A.R.S.A.C. Connector*



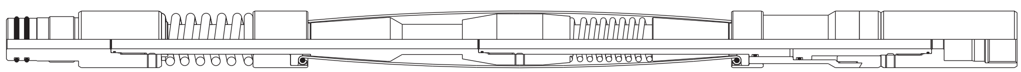
CT CENTRALIZERS

Flow Activated Bow Spring Centralizer

The Flow Activated Bow Spring Centralizer allows tool strings or parts of tool strings to be centralized in the wellbore. The bow springs are normally retracted. They only expand when a pressure differential is achieved across the tool. This enables the centralizer to pass through restrictions and expand into the wellbore below without any unnecessary wear on the bow springs.

As a safety precaution, the bow springs are mounted above a coil spring. This is to allow the bow springs the necessary movement they require in order to pass through a restricted bore while still expanded. However, this action can damage the tool.

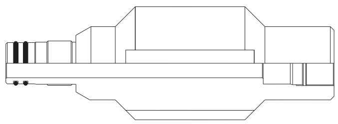
FIGURE 5.30 *Flow Activated Bow Spring Centralizer*



Fluted Centralizer

Fluted Centralizers can be included as part of the BHA to provide centralization, to allow easier location of tools during fishing, or to provide general stability in the tubing. A Fluted Centralizer has a full flow through bore allowing passage of darts or drop balls.

FIGURE 5.31 *Fluted Centralizer*

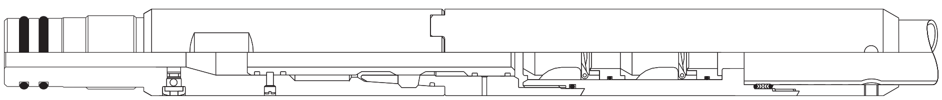


CT Toolheads & Deployment Bar Systems

Multi-Purpose (M.P.) Tool Head

The M.P. Tool Head combines the three basic tools required for all CT runs into one assembly, i.e. the coil connector, twin flapper check valve and an emergency release joint.

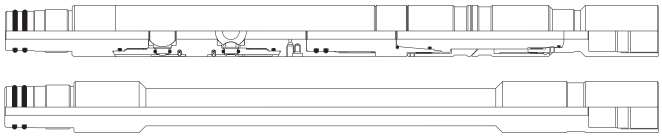
FIGURE 5.32 *M.P. Tool Head*



Deployment Bar System

CT Deployment Bar Systems are used to install long BHAs into wells where lubricator height is restricted. By installing the lower part of the BHA below the deployment bar, the CT pipe rams can be closed around the bar's waist. Closing the integral ball valves in the modified C.A.R.S.A.C. (See Section "CT Straight Bars & Joints") connector gives a double barrier to the wellbore.

FIGURE 5.33 *Deployment Bar System*

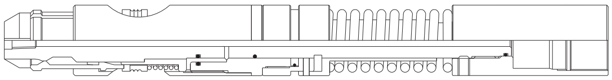


CT RUNNING - PULLING & SHIFTING TOOLS

Flow Activated "GS" Type Running/Pulling Tool

The Flow Activated "GS" Type Running/Pulling Tool is designed to run and retrieve downhole tools with conventional internal fish necks. The latching mechanism is a dog/core design which releases positively from the internal fish neck when a hydraulic differential is applied to the tool. The tool does not require shear pins or drop balls since the differential required to activate the tool is provided by circulating through a choke insert in the core.

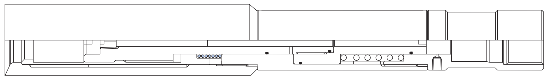
FIGURE 5.34 *Flow Activated "GS" Type Running/Pulling Tool*



Flow Activated Heavy Duty Running/Pulling Tool

The Flow Activated Heavy Duty Running/Pulling Tool is a collet type running/pulling tool designed to run or retrieve downhole tools that have conventional external fishing necks. The running/pulling tool design allows a full 360 degree engagement of the fishing neck to be latched. The tool is fully hydraulically activated and does not require the use of shear pins or drop balls to operate. Circulating through a choke in the core of the tool activates the release mechanism.

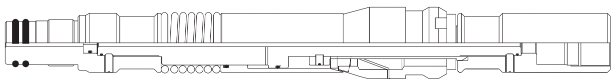
FIGURE 5.35 *Flow Activated Heavy Duty Running/Pulling Tool*



Flow Activated Shifting Tool

Flow Activated Shifting Tools are designed to be used as a work tool for opening and closing sliding sleeves. The normally closed shifting tool is flow-activated and does not require the use of drop balls to activate it. The Flow Activated Shifting Tools are available to suit all sizes and makes of Sliding Sleeves and can be supplied with either positive or selective keys.

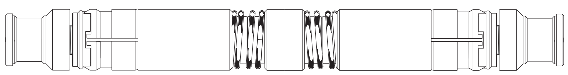
FIGURE 5.36 *Flow Activated Shifting Tool*



Double Ended Selective Shifting Tool

The CT Double Ended Selective Shifting Tool (DESST) has been designed specifically to selectively shift Otis, Camco, or Baker sliding sleeves (SSD's) in horizontal well bores. The DESST shifting keys are normally retracted during the running operation and are activated by the flow to the open shift position. The DESST can selectively open or close multiple SSD's in a single CT trip.

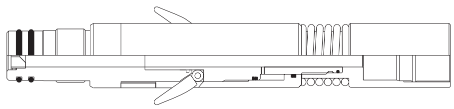
FIGURE 5.37 *Double Ended Selective Shifting Tool*



CT TUBING END LOCATOR

A Flow Activated Multi-Shot Tubing End Locator allows location of the end of the production tubing for depth correlation. The Tubing End Locator is flow-activated and offers the ability to "re-tag" the end of the tubing as many times as required without needing removal from the well for redressing. Changing the flow rate alters the pressure drop across the tool and the corresponding force required to retract the "fingers" or "dogs".

FIGURE 5.38 *Flow Activated Multi-Shot Tubing End Locator*



CT NIPPLE LOCATOR

The CT nipple locator is designed to locate nipples in the completion while performing CT operations. The tool can be located almost anywhere in the BHA and operates mechanically without any hydraulic pressure. The spring-loaded collet provides a reliable and repeatable increase in weight (800-1000 lbs, depending on the nipple profile) upon pickup through the nipple. The tool does not offer any internal upset or restriction to flow.

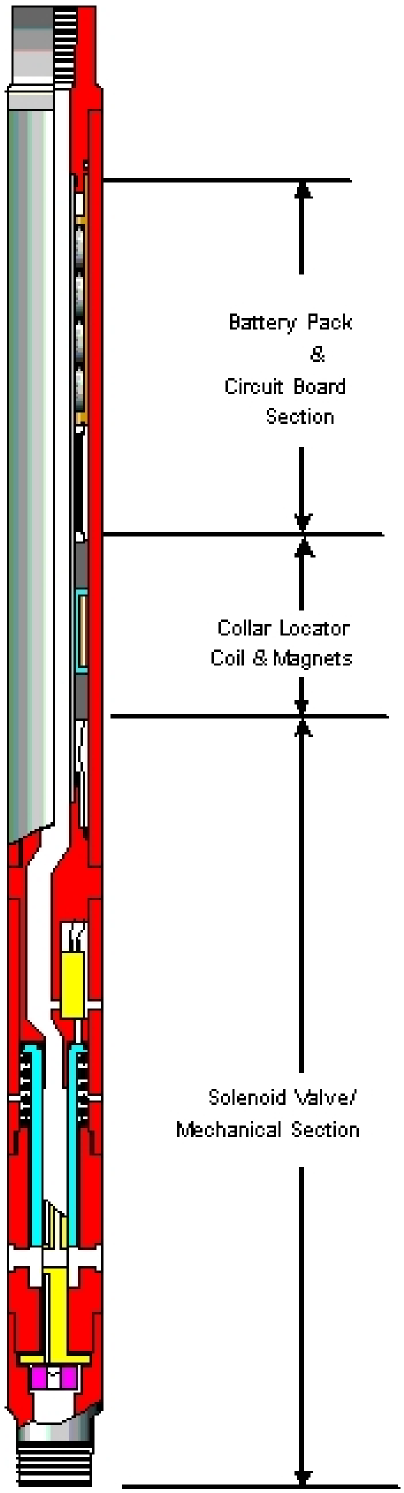
FIGURE 5.39 *CT Nipple Locator*

WIRELESS CT COLLAR LOCATOR

Accurate depth measurement, or more specifically, determining the precise location of the BHA is of major importance during CT operations such as perforating, setting plugs and packers, and cutting tubulars. The most reliable method for locating the BHA is to correlate the depth measured at the surface equipment with a known location (depth) in the wellbore. This can be done with a mechanical tubing end locator that causes a distinctive change in the weight indicator reading when the tool passes through a restriction in the wellbore (see Section “CT Tubing End Locator” page 5-23). An electronic method is a casing collar locator (CCL) in the BHA connected to the surface with an electric cable inside the CT. The latter approach is more sensitive, registers every collar within its sensing range (multiple correlations), and doesn’t require any restriction in the wellbore. However, it requires electric line inside the CT with associated potential problems (see Chapter 12 "Logging with CT (Stiff Wireline)", page 12-44).

Halliburton Services has developed a wireless CCL for CT operations that is based on standard MWD technology. Therefore, a potential drawback to this new tool is that the user must pump liquid through it in order to get signals to the surface receiver. The battery-powered tool sends a pressure pulse signal to the surface corresponding to the location of each collar it passes. Figure 5.40 is a cutaway schematic of the tool. The standard tool is 2.25 in. OD, 7.0 ft long, and weighs about 45 lbs.

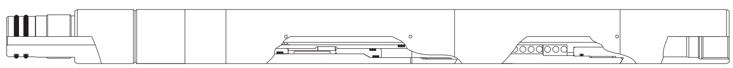
FIGURE 5.40 *Halliburton's Wireless CT Collar Locator*



INDEXING TOOLS

The Flow Activated Indexing Tool provides controlled rotation of the lower tool string. The tool is particularly useful for rotating fishing overshots onto the fish. Flow Activated Indexing Tools use a rotating cam principle. The tool does not stroke downward in order to index the cam, since this action is achieved internally.

FIGURE 5.41 *Flow Activated Indexing Tool*

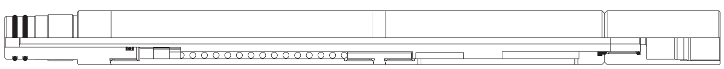


CT WASH TOOLS & WASH NOZZLES

Flow Activated Hydraulic Jetting Indexing Tool

The Flow Activated Hydraulic Jetting Indexing Tool is used to rotate jetting nozzles in a controlled 36° or 60° incremental manner by applying intermittent surface pump pressure. Downward movement of the lower half of the tool occurs during the indexing operation.

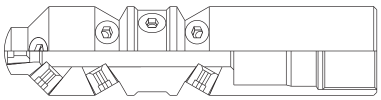
FIGURE 5.42 *Flow Activated Hydraulic Jetting Indexing Tool*



Multi-Jet Wash Tool

The CT Multi-Jet Wash Tool is a non-rotational wash tool with simple grub screw nozzles that are field adjustable. It is normally used in conjunction with the a Flow Activated Hydraulic Jetting Indexing Tool.

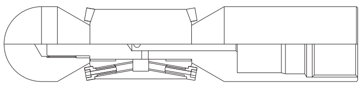
FIGURE 5.43 *Multi-Jet Wash Tool*



Rotary Jet Wash Tool

A Rotary Jet Wash Tool is designed to be used for both jetting and circulating operations when cleaning and washing the inside of the tubing. The Rotary Jet Wash Tool works on the principal of applied fluid pressure causing the nozzle to rotate and jet the fluid in a full 360 degree rotating action.

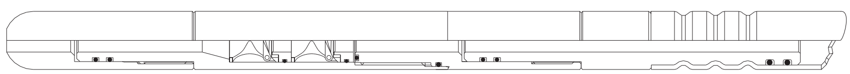
FIGURE 5.44 *Rotary Jet Wash Tool*



Slim Hole Jetting Head Assembly

The Slim Hole Jetting Head Assembly provides the operator with a tool assembly that is the same diameter as the CT and incorporates the basic requirements of any jetting or washing tool. The Flapper Check Valve Cartridge is the prime safety barrier to prevent back flow up the CT should control of the pump be lost at surface for any reason.

FIGURE 5.45 *Slim Hole Jetting Head Assembly*



Wash Nozzles

The six wash nozzles shown below serve to illustrate the wide variety of simple fixed nozzles available for CT operations.

FIGURE 5.46 *Single Port Flow Thru Nozzle*

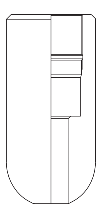


FIGURE 5.47 *Multiple Back Flow Port Nozzle*

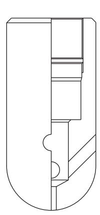


FIGURE 5.48 *Multiple Side Flow Port Nozzle*

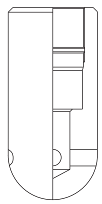


FIGURE 5.49 *Multiple Flow Port Nozzle*

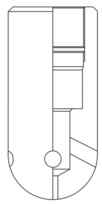


FIGURE 5.50 *Multiple Up Flow Port Nozzle*

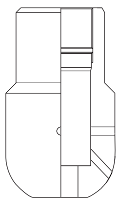
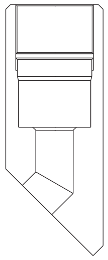


FIGURE 5.51 *Single Flow Port Muleshoe Nozzle*

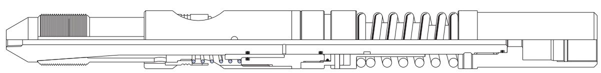


CT Fishing Tools

Flow Activated CT Releasable Fishing/Bulldog Spear

A Flow Activated CT Releasable Fishing/Bulldog Spear is a variable catch internal spear used to retrieve a lost cylindrical fish from the well bore. A complete range of slips is available for each size tool. To operate, simply run into the fish and set down weight, pick up and retrieve the fish. To release from the fish simply set down weight, and circulate in conjunction with a Hydraulic Sequencing Tool above the spear. The differential pressure across the tool will cause it to release the fish.

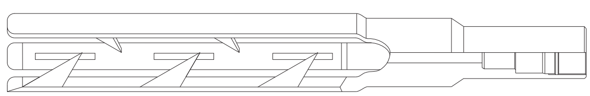
FIGURE 5.52 *Flow Activated CT Releasable Fishing/Bulldog Spear*



Fishing Grabs

CT Fishing Grabs are used to retrieve lost or broken wireline from the wellbore. CT Fishing Grabs are available in a range of sizes to suit standard tubing diameters.

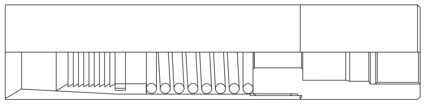
FIGURE 5.53 *Fishing Grabs*



Non Releasable Overshot

The Non Releasable Overshot is a fishing tool for catching CT or downhole tools without a fish neck. The latching mechanism of the tool utilizes hardened and tempered parallel slips to grip the outside diameter of the fish. Where required, threaded main bodies are available to enable the attachment of bell guides for fishing small diameter tools in large diameter tubing. They can also be supplied with internal or external fishing necks looking up to enable them to be used in conjunction with a Heavy Duty Running / Pulling Tool.

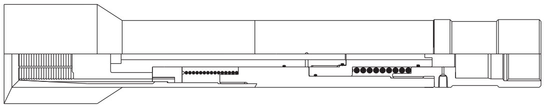
FIGURE 5.54 *Non Releasable Overshot*



Flow Activated CT Releasable Overshot

A Flow Activated CT Releasable Overshot is a variable catch external overshot used to retrieve a lost cylindrical fish from the well bore. A complete range of hardened and double tempered slips is available for each size tool.

FIGURE 5.55 *Flow Activated CT Releasable Overshot*

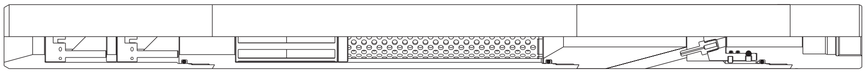


Venturi Junk Basket

The Venturi Junk Basket is a tool used to retrieve junk and small debris out of the well bore. Fluid pumped through the CT and out through the nozzles in the venturi chamber creates a vacuum in the venturi chamber. This sucks fluid from the bottom of the tool back through the venturi tubes. Most of this fluid mixes with the pressurized fluid to be re-circulated around the bottom of the tool.

The tool is essentially a vacuum cleaner that can be used with liquid, nitrogenated liquids, or gases. The nozzles in the tool are simply changed out for the available pump rate and fluids. A debris filter screen before the venturi chamber prevents debris from blocking the venturi tubes. A hollow magnetic section with a finger type trap catches junk and debris, which the tool carries out of the well when POOH. Barrel extensions are available to increase the volume of junk which may be carried.

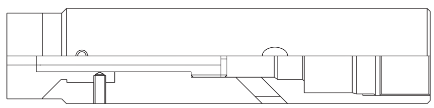
FIGURE 5.56 *Venturi Junk Basket*



Lead Impression Block

A Lead Impression Block is a standard wireline service tool adopted for CT and used to obtain impressions of foreign objects in the wellbore. The impression can help identify the object and aid in the selection of the correct fishing tool.

FIGURE 5.57 *Lead Impression Block*



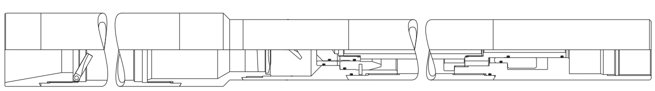
Hydrostatic Bailer

A Hydrostatic Bailer is used to bail sand and debris from horizontal wellbores. It works like a single-shot vacuum cleaner.

The main component of the Hydrostatic Bailer is a pressure chamber with a valve at the bottom end. Closing the valve and arming the activator with the tool at the surface traps atmospheric pressure inside the Hydrostatic Bailer. Overpressuring the CT with the tool in the wellbore fires the valve activator, which opens the chamber to the much higher pressure in the wellbore. This "vacuum" sucks sand and debris into the chamber. A flapper valve retains the sand, and fingers on the bottom sub act as a junk basket to retain any larger debris. A 3 in. diameter by 30 ft long Hydrostatic Bailer will bail approximately one cubic foot of sand per run.

The Hydrostatic Bailer is normally run in conjunction with a Sequencing Tool to allow circulation while running into the well and over pressuring to fire the bailer when desired.

FIGURE 5.58 *Hydrostatic Bailer*



IMPACT DRILLS

Probably the best-known impact drill for CT operations is the HIPP-TRIPPER™ rotating impact drill. It can deliver bit rotation, an impact force, and a high pressure pulse with each cycle, but will not reciprocate unless meeting resistance, i.e., WOB. Thus, the HIPP-TRIPPER™ allows circulating while RIH and POOH without adding wear to the tool or damaging the wellbore. The tool can operate with a wide range of liquids, including corrosive fluids and hydrocarbon solvents, at temperatures up to 600 ºF.

The impact stroke frequency is a function of the WOB and fluid flow rate. The blows per minute increases as the WOB decreases and ranges from about 50 to 800 blows per minute. The bit rotational speed depends on the impact frequency and tool stroke length but varies from about 7 to 30 rpm. The amount of torque at the bit is proportional to the WOB. Each stroke exhausts a high-pressure burst of fluid out of the bit nozzles.

Table 5.7 shows four standard single direction HIPP-TRIPPER™ models. A bi-directional model is also available that can serve as an impact drill, fishing jar, or combination of these two. It delivers downward blows when placed in compression and upward blows when placed in tension.

TABLE 5.7 *Standard Single Directional HIPP-TRIPPER™ Models*

OD (in.)	WOB (lbs)	Operating Pressure (psi)	Torque (ft-lbs)	Stroke (in.)	Length (in.)
1.375	400-1000	500-2000	40-150	0.25-1.00	27.13
1.687	800-1500	600-2000	100-250	0.25-1.00	36.38
2.125	800-2400	400-2100	120-360	0.25-1.50	43.25
4.750	500-31,000	250-2500	50-750	0.25-1.00	43.50

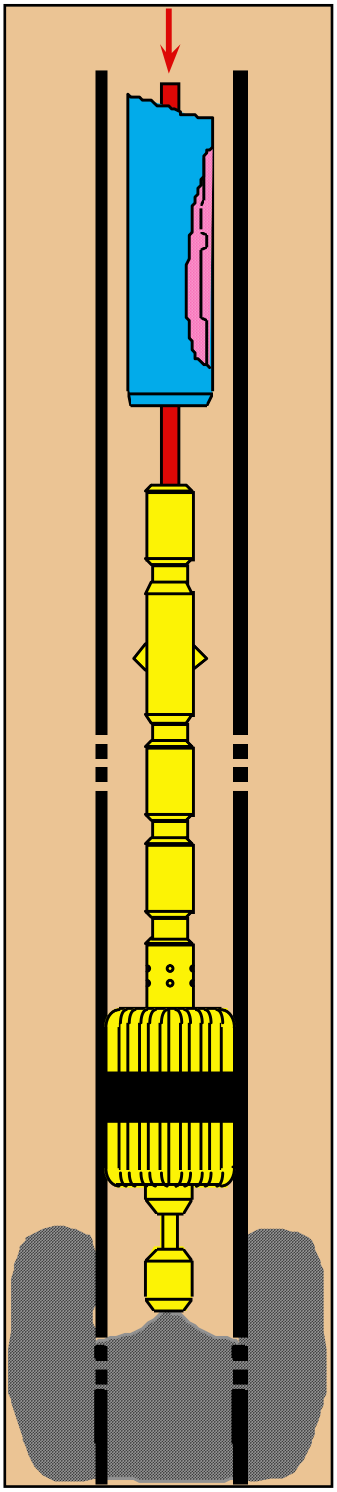
THROUGH-TUBING PACKERS AND BRIDGE PLUGS

Through-tubing packers (TTP) and through-tubing bridge plugs (TTBP) conveyed on CT have numerous applications, including:

- Temporary isolation of a wellbore section for stimulation treatments or zonal isolation
- Temporary isolation of zone(s) for production testing
- Permanent shutoff of unwanted production
- Platform (retainer) for cement or slurry plug
- Downhole choke for injection or production

The following figures, courtesy of Baker Oil Tools illustrate these applications.

FIGURE 5.59 *TTP Isolating Zone(s) for Selective Stimulation*



9i

FIGURE 5.60 *TTBP Isolating a Lower Zone for Stimulation of an Upper Zone*

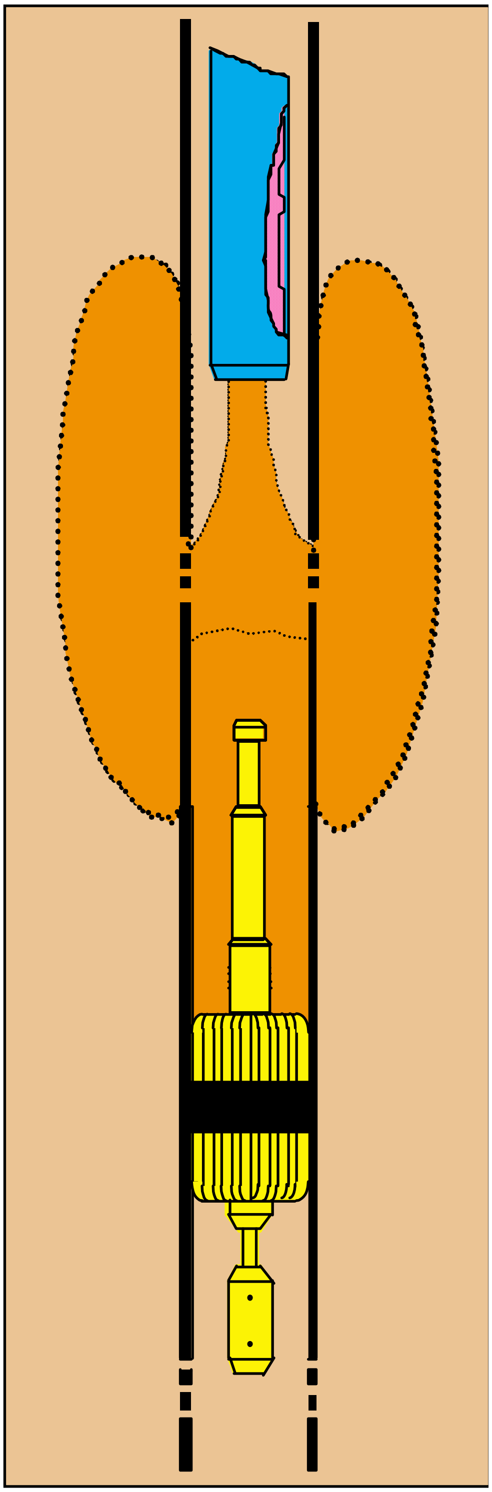


FIGURE 5.61 *TTP and TTBP Used in Combination to Isolate an Intermediate Zone*

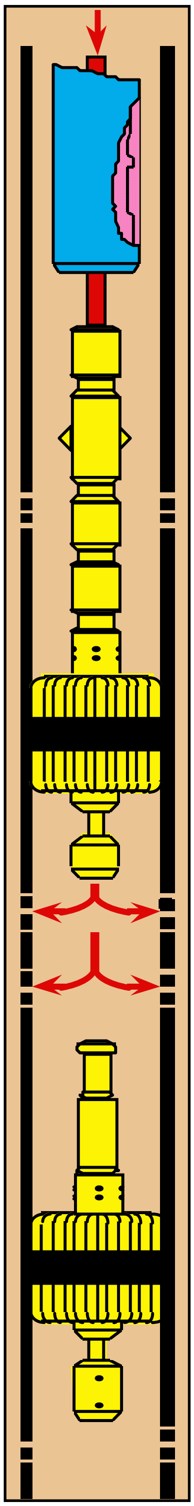


FIGURE 5.62 *TTBP Used as a Retainer (Platform) for a Temporary or Permanent Slurry Plug*

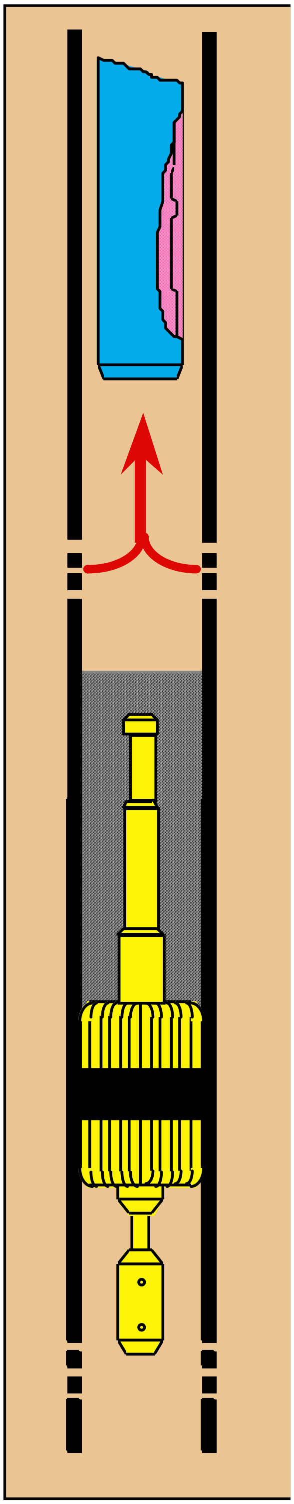


FIGURE 5.63 *TTP Used to Straddle Selected Zone(s) for Mechanically Diverting Stimulation Treatments*

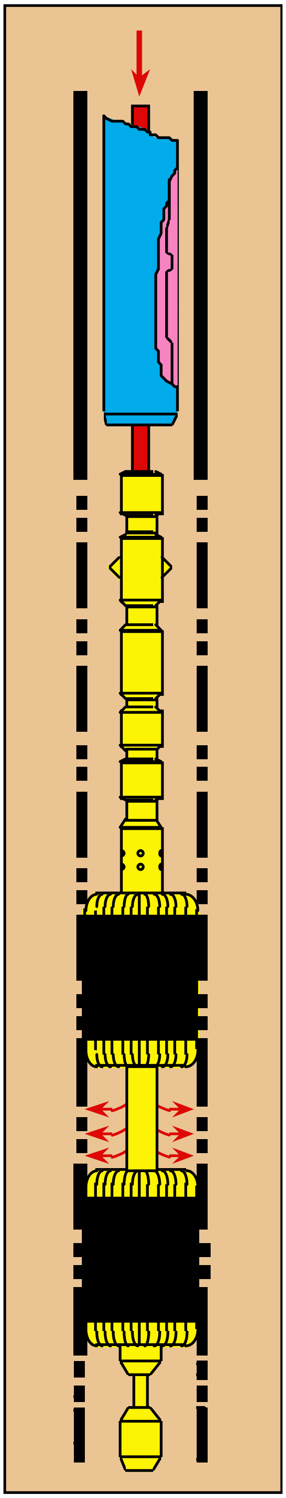


FIGURE 5.64 *TTP and Injection Choke*

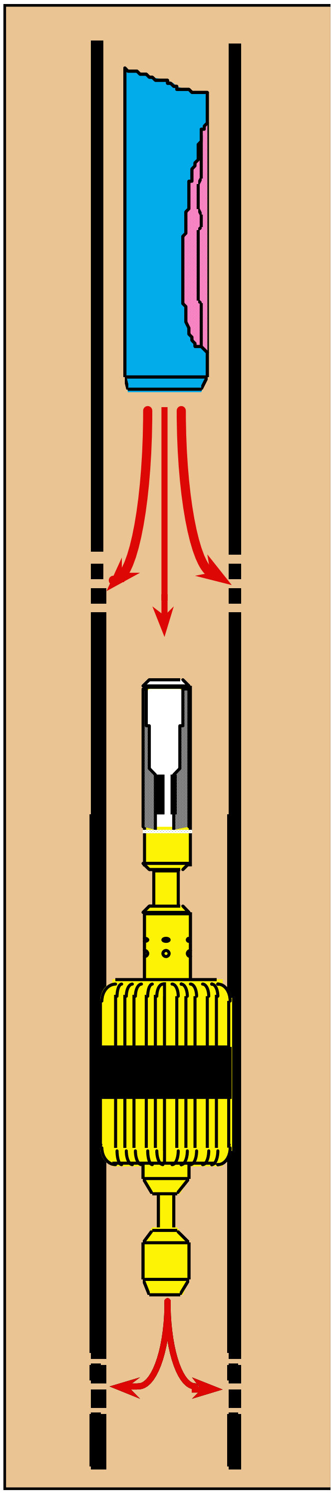


FIGURE 5.65 *TTP and Production Choke*

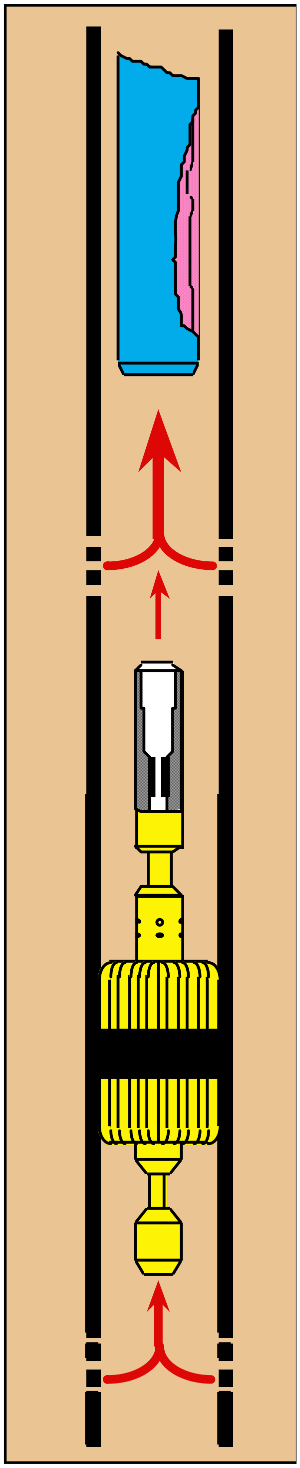


FIGURE 5.66 *TTP Isolating Unwanted Production from Intermediate Zone(s)*

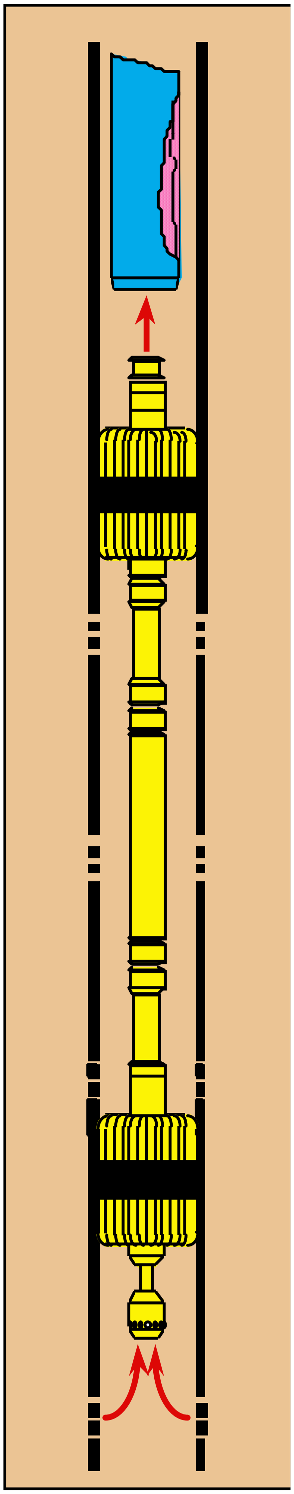
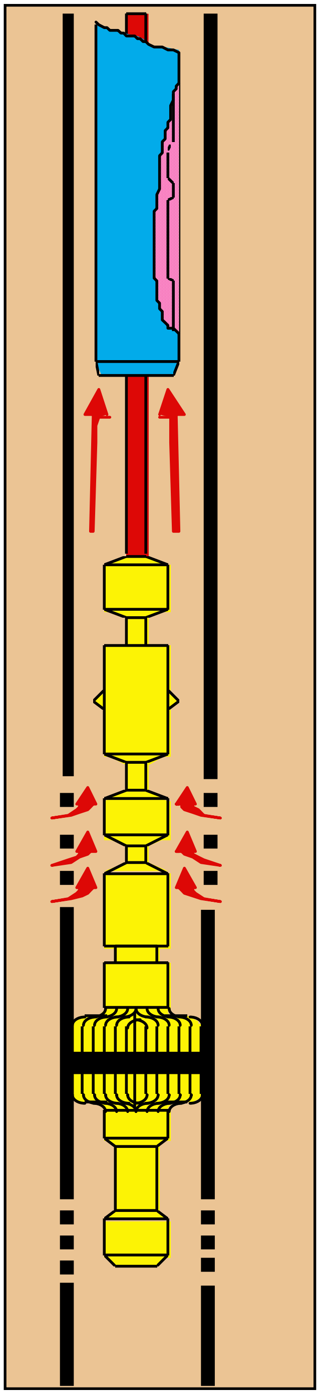


FIGURE 5.67 *TTP Isolating Lower Zones for a Production Test from Upper Zone(s)*



6

TUBING FORCES

FUNDAMENTAL QUESTIONS

Common mechanical operations for CT (see Chapter 12 "Mechanical Operations") include:

- Logging and drifting
- Perforating
- Setting/removing plugs and packers
- Operating sliding sleeves
- Drilling
- Milling (mechanical scale removal)
- Fishing

The choice of CT for these operations raises several questions about the possible outcome, including:

- For the present conditions, how far can the CT string RIH before lock-up?
- What can be done to extend the reach?
- If the CT string can reach TD, how hard can the BHA push on something (SDW or WOB)?
- If the CT string can reach TD, how hard can the CT pull on the BHA (overpull)?
- What can be done to increase axial force at TD?

The only way to answer these questions is to determine the forces acting on the CT string. Determining or predicting the mechanical performance requires knowledge of the following:

- Well path
- Tubing dimensions and properties
- BHA dimensions and properties
- Wellbore geometry
- Densities of the fluids inside and outside the tubing
- Pressures throughout the system
- Cf between the CT string and wellbore

The challenge is to deduce the effects of all these factors on the CT string from a single surface measurement, CT weight indicator (CTWI). The following sections explore the basic concepts surrounding this challenge.

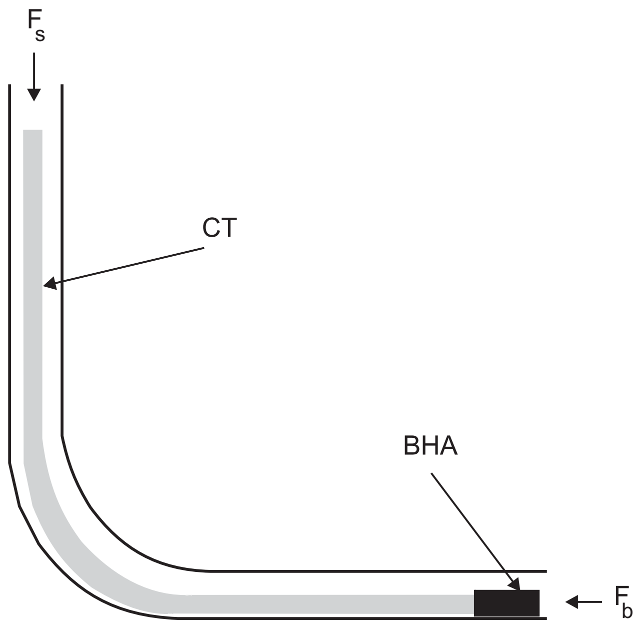
GENERAL FORCE BALANCE

Figure 6.1 shows CT and a BHA in a horizontal well with force F_b acting on the bottom of the BHA. F_b is the resultant of the axial force, i.e., setdown weight (SDW) or overpull, and torque. The fundamental problem is to find the resultant force F_s at the top of the CT, because it is the primary real-time indication of what is happening down-hole.

The choice of well configuration in Figure 6.1 is arbitrary. The following discussion applies to wellbore profiles.

CT weight measured at the surface (CTWI) is the sum of the axial component of F_s, stripper friction, axial pressure force, and reel tension.

FIGURE 6.1 *CT and BHA in a Well*



A typical method of finding F_s is to divide the CT and BHA into segments and **perform a three-dimensional force balance on each segment from the bottom up**. Segmentation is necessary because boundary conditions and geometry often change with depth. The objective is to calculate the force acting at the top of each segment (F_s) given the force acting at its bottom (F_b). Equation 6.1 and Equation 6.2 give the axial and torsional components of the force balance over any segment.

EQUATION 6.1 *Axial component of force balance*

$$\text{Axial force at Top} = \text{Axial force at Bottom} + \text{Weight Component} \pm \text{Axial Drag}$$

EQUATION 6.2 *Torsional component of force balance*

$$\text{Torque at Top} = \text{Torque at Bottom} - \text{Torsional Drag}$$

Since drag opposes motion, use the negative (–) sign for axial force running into hole (RIH) and torque, but use the positive (+) sign for axial force pulling out of hole (POOH). The forces acting on each CT and BHA segment could include:

Axial forces due to:

- Buoyed weight
- Frictional drag (in the stripper and against the wellbore)
- SDW, WOB, or overpull
- Pressure x area (wherever the CT passes through a seal, such as the stripper)
- Tension from the CT reel
- Hydraulic drag due to fluid flow

Normal Forces due to:

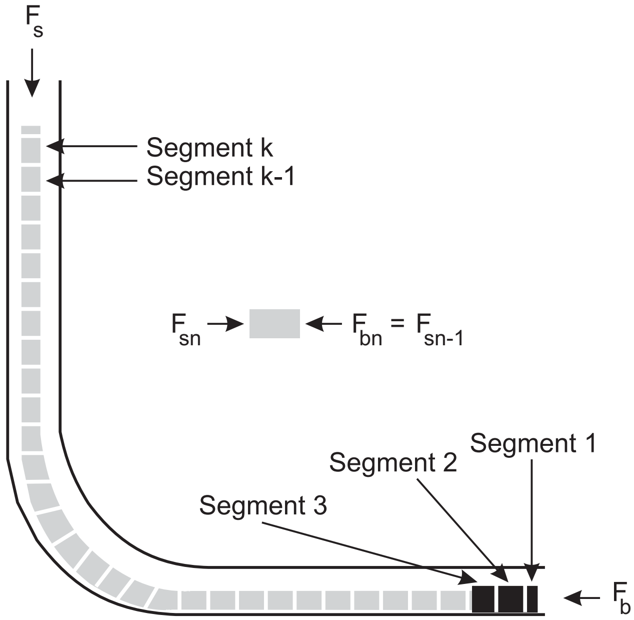
- Buoyed weight
- Curvature
- Buckling

Torsional forces from the BHA due to:

- An orienting device
- Motor (drilling reactive torque)

Segmenting the CT and BHA as shown in Figure 6.2, beginning at the lower end with segment 1 and ending at the upper end with segment k, produces the condition shown in Figure 6.2.

FIGURE 6.2 *CT String Segmentation*



Given the force acting on the bottom of segment 1 (F_b), the balance of all of the forces acting on segment 1 yields the force acting at its upper end (F_{s1}). This force becomes F_{b2}, the force acting on the bottom of segment 2. The balance of all the forces acting on segment 2 yields the force acting at its upper end (F_{s2}). Proceeding upward in this fashion for each segment in the string gives the force balance on the uppermost segment and yields F_s.

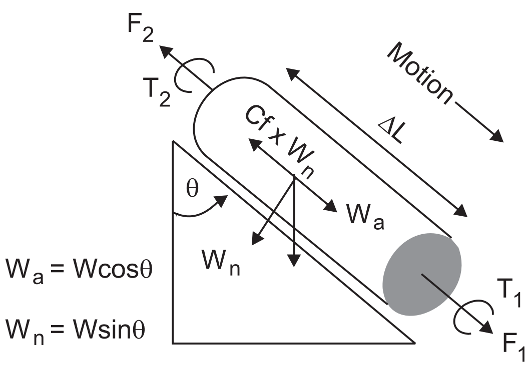
The correct force balance equations on any given segment depend upon its geometry, curvature, and buckling condition. The following section describes the force balance procedure for typical segments under various conditions. The "soft string" model described below neglects effects of moments on each segment. The sign convention used for axial force is positive (+) for tension and negative (–) for compression. Torque is always positive (+). For the sake of simplicity, also ignore effects of pressure from surrounding fluids in the following discussion of force balance.

FORCE BALANCE FOR STRAIGHT SEGMENTS

Consider a straight segment of length ΔL in the CT string (see Figure 6.3) where:

- The segment is a hollow cylinder
- The segment rests on a plane inclined at angle θ from vertical
- The axial force F_1 and the torque T_1 acting at the lower end of the segment are known.

FIGURE 6.3 *Force Balance on a Straight Segment*



The goal is to determine the axial force F_2 and torque T_2 acting on the upper end of the segment. W, the buoyed weight per unit length of the cylinder, depends upon the density of the fluids inside and outside the cylinder. If a unit length of the cylinder weighs W_{air} in air, the fluid inside has density ρ_i, and the fluid outside has density ρ_o, use Equation 6.3 to calculate the buoyed weight per unit length.

EQUATION 6.3 *Buoyed weight per unit length, general form*

$$W = W_{air} + \rho_i A_i - \rho_o A_o$$

where

$$A_o = \frac{\pi}{4} OD^2$$

$$A_i = \frac{\pi}{4}(OD - 2t)^2 = \frac{\pi}{4} ID^2$$

OD = the cylinder's outer diameter
t = the cylinder's wall thickness

NOTE: W=wl where w=unit weights and l=length

If the dimensions are inches and the densities are lb/gal (ppg), Equation 6.4 gives buoyed weight in lb/ft (ppf).

EQUATION 6.4 *Buoyed weight, using ppg*

$$W = W_{air} + \frac{(\rho_i A_i - \rho_o A_o)}{19.25}$$

If the densities are in lb/ft^3 (pcf), then use Equation 6.5 to calculate buoyed weight in ppf.

EQUATION 6.5 *Buoyed weight, using pcf*

$$W = W_{air} + \frac{(\rho_i A_i - \rho_o A_o)}{144}$$

EXAMPLE 0.1 *Buoyed Weight*

Given:	Assume:	From Equation 6.4,
• CT = 1.75 in. OD x 0.134 in. wall • w_{air} = 2.313 ppf • A_i = 1.725 in^2 • A_o = 2.405 in^2	• ρ_i = 0.20 ppg • ρ_o = 8.35 ppg	w = 1.288 ppf

W is the vector sum of two orthogonal components, W_a (axial) and W_n (normal). The axial component, W_a = W cosθ, enters the axial force balance as w_a x ΔL. The component normal to the surface of the plane, W_n = W sinθ, enters the axial force balance through frictional drag, Cf x w_n x ΔL, where Cf is the coefficient of friction. Thus, Equation 6.6 gives the axial force at the upper end of the segment.

EQUATION 6.6 *Axial force at the upper end of the segment*

$$F_2 = F_1 + w\cos\theta \times \Delta L \pm Cf \times w\sin\theta \times \Delta L$$

For RIH, $F_2 < F_1$ due to drag, so use the minus (-) sign. For POOH, $F_2 > F_1$ due to drag, so use the plus (+) sign.

For CT operations, the dynamic coefficient of friction (Cf) is independent of direction, speed, and normal force. Typical values for Cf from small-scale and large-scale drag tests appear in Table 6.1.

TABLE 6.1 *Typical Values for Cf*

Surface	Cf
Water-wet steel surfaces	0.30-0.35
Lubricated water-wet steel surfaces	0.20-0.25
Oil-wet steel surfaces	0.15-0.20
Steel on rock	0.40-0.50

EXAMPLE 0.2 *Axial Forces*

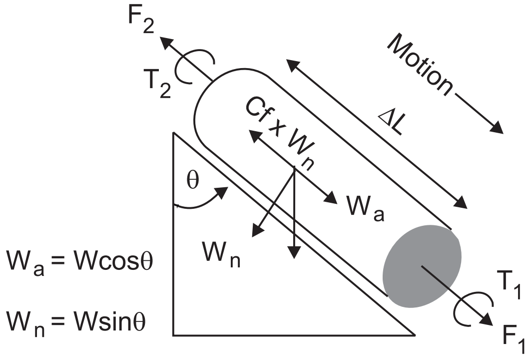
Problem: Determine the RIH and POOH forces at the upper end of the segment with the given conditions:

Given:	From Equation 6.6,
• F_1 = 100 lbf • w = 1.288 ppf (from Example 0.1) • $\theta = 80^o$ • ΔL = 10 ft • Cf = 0.30	• $W\cos\theta \times \Delta L$ = 2.237 lbf • Cf x $W\sin\theta \times \Delta L$ = 3.805 lbf • F_2 RIH = 100 + 2.237 - 3.805 = 98.43 lbf • F_2 POOH = 100 + 2.237 + 3.805 = 106.04 lbf

Equation 6.7 gives the torque at the upper end of the segment.

EQUATION 6.7 *Torque at the upper end of the segment*

$$T_2 = T_1 - \left(\frac{OD}{2}\right) \times Cf \times W\sin\theta \times \Delta L$$



Due to torsional drag, $T_2 < T_1$.

Since torque is always positive, subtract torsional drag. Due to friction between the CT and the wellbore, torque from an orienting device or motor in the BHA usually dissipates before reaching the surface in highly-inclined wellbores.

EXAMPLE 0.3 *Torsional Forces*

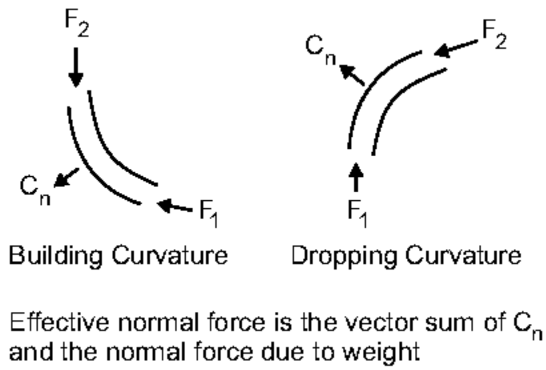
Problem: Determine the torque at the upper end of the segment with the given conditions:

Given:	From Equation 6.7,
• T_1 = 100 ft-lbf	• OD/2 = 0.073 ft
• OD = 1.75 in.	• Cf x Wsinθ x ΔL = 3.805 lbf
• W = 1.288 ppf (from Example 0.1)	• T_2 = 100 - 0.28 = 99.72 ft-lbf
• θ = 80º	• For T_2 = 0, ΔL = 3600 ft, the length of straight CT at 80º inclination required to fully dissipate the given torque.
• ΔL = 10 ft	
• Cf = 0.30	

FORCE BALANCE FOR SEGMENTS IN CURVED WELLBORES

A straight segment forced into a curved wellbore, as shown by Figure 6.4, exerts a normal force C_n against the wellbore in addition to the normal component of its buoyed weight. C_n, often called the "capstan" force, is distributed along the line of contact between the segment and the wellbore. The effective normal force for a curved segment is the **vector sum** of C_n and the normal force due to weight acting in a direction determined by the orientation and rate of curvature of the segment.

FIGURE 6.4 *Normal Force Due to Curvature of a Segment*



Equation 6.8 approximates the effective normal force for a "short" segment in a curved well-bore.

EQUATION 6.8 *Approximation of effective normal force for a short segment in a curved wellbore*

$$C_n = \Delta L \sqrt{\left[\left(F_1 \theta' + w \sin \bar{\theta} \right)^2 + \left(F_1 \phi' \sin \bar{\theta} \right) \right]}$$

where

ΔL, W, and F_1 are as defined previously

$\bar{\theta}$ = the average inclination of the segment

θ' = the local build rate

ϕ' = the local walk rate

Local build and walk rate have units of radians per unit length.

Equation 6.8 gives reasonable results for segments short enough that the total curvature angle of the segment is less than 1°. Since Equation 6.8 reduces to $C_n = \Delta L \times w \sin\theta$ for straight segments ($\theta' = \phi' = 0$), it can be applied to any unbuckled segment, curved or straight.

Therefore, Equation 6.9 and Equation 6.10 give the axial force and torque at the upper end of a curved segment.

EQUATION 6.9 *Axial force at the upper end of a curved segment*

$$F_2 = F_1 + w \cos\bar{\theta} \times \Delta L \pm Cf \times C_n$$

EQUATION 6.10 *Torque at the upper end of a curved segment*

$$T_2 = T_1 - \left(\frac{OD}{2}\right) \times Cf \times C_n$$

Note the similarity between Equation 6.9 and Equation 6.1 and between Equation 6.10 and Equation 6.2. As before, subtract drag from F_1 during RIH and add drag to F_1 during POOH. Always subtract torsional drag from T_1.

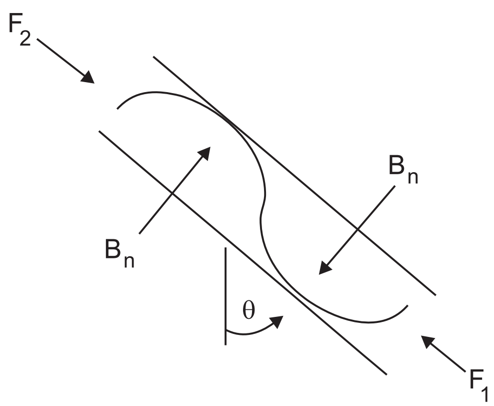
Direct measurements of axial force on the BHA from a tension head tool or auxiliary measurement sond (AMS) can improve the interpretation of down-hole conditions. Assuming the BHA does not buckle, use these data and Equation 6.9 to calculate Cf as the BHA traverses the wellbore. Such indirect measurements of Cf are extremely valuable for predicting CT performance.

FORCE BALANCE FOR HELICALLY BUCKLED SEGMENTS

The force balance equations for a helically buckled segment are different from those for an unbuckled segment.

Figure 6.5 illustrates a helically buckled segment in a straight wellbore. Pushing on the buckled segment causes the helix to expand outwards, thereby exerting a normal force, B_n, against the constraining wellbore. This normal force due to buckling adds to the effective normal force. B_n is distributed along the line of contact between the segment and the wellbore.

FIGURE 6.5 *Normal Force in a Helically Buckled Segment*



Equation 6.11 gives the normal force per unit length due to helical buckling[1].

EQUATION 6.11 *Normal force per unit length due to helical buckling*

$$B_n = \frac{r_c F^2}{4EI}$$

where

F = the net axial compressive force on the segment

EI = the segment's bending stiffness (flexural rigidity)

r_c = as defined in Equation 6.12

1. Mitchell, R.F., 1986, "Simple Frictional Analysis of Helical Buckling of Tubing", *SPE Drilling Engineering*, December 1986, pp. 303-310.

EQUATION 6.12 *Radial clearance (annular gap) between the CT and the wellbore*

$$r_c = \frac{ID_{hole} - OD}{2}$$

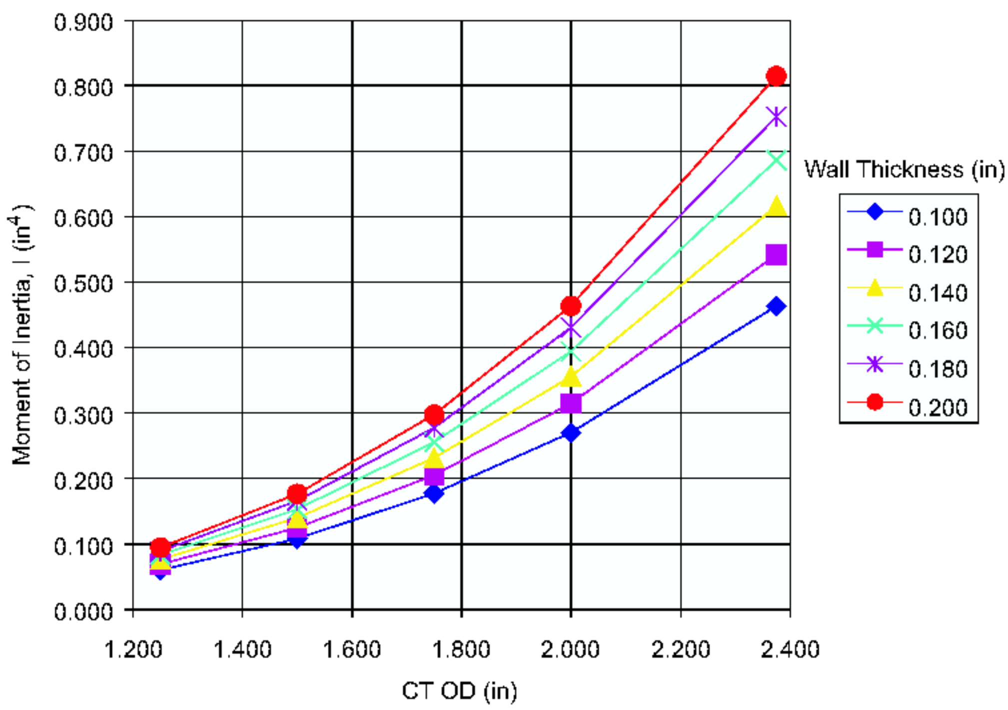
Young's modulus, E, for steel is about 30 x 10^6 psi in customary US units. Equation 6.13 gives the segment's moment of inertia, which has the units of in.^{4}, when the CT dimensions have units of in.

EQUATION 6.13 *Moment of inertia for a segment*

$$I = \frac{\pi[(OD^4 - (OD - 2t)^4]}{64}$$

Note that bending stiffness, EI, is independent of the yield strength of the CT material. Figure 6.6 shows how moment of inertia changes with CT diameter and wall thickness.

FIGURE 6.6 *Effects of OD and t on Moment of Inertia*



For buckled segments in a straight wellbore, effective normal force is $W_n + B_n$, and drag becomes $Cf \times (W_n + B_n)$. Thus, Equation 6.14 and Equation 6.15 give the axial force and torque at the upper end of a buckled segment of length ΔL.

EQUATION 6.14 *Axial force at the upper end of a helically buckled segment in a straight wellbore*

$$F_2 = F_1 + W\cos\theta \times \Delta L - Cf \times (W\sin\theta + B_n) \times \Delta L$$

EQUATION 6.15 *Torque at the upper end of a helically buckled segment in a straight wellbore*

$$T_2 = T_1 - \left(\frac{OD}{2}\right) \times Cf \times (W\sin\theta + B_n) \times \Delta L$$

Equation 6.14 and Equation 6.15 are valid only for short segments. Always subtract drag for buckled segments, because buckling only occurs while RIH.

NOTE: **B_n is proportional to axial force squared and radial clearance, while inversely proportional to a segment's bending stiffness.** Therefore, the drag term in Equation 6.14 and Equation 6.15 increases with the square of the axial force.

This explains why maximum reach of CT in a wellbore and SDW or WOB at a given depth are so sensitive to buckling. Decreasing radial clearance and increasing the segment's bending stiffness (larger OD or thicker wall) will decrease drag on a buckled segment for a given axial force. However, increasing the CT dimensions has the counter effect of increasing drag for unbuckled segments.

If helical buckling occurs in a CT segment in a curved section of the wellbore, total normal force is the **vector sum** $W_n + B_n + C_n$. However, $C_n << B_n$, so Equation 6.16 and Equation 6.17 give the axial force and torque at the upper end of a buckled segment of length ΔL in a curved wellbore.

$\bar{\theta}$ = the average angle of inclination over the segment

EQUATION 6.16 *Axial force at the upper end of a helically buckled segment in a curved wellbore*

$$F_2 = F_1 + W\cos\bar{\theta} \times \Delta L - Cf \times (W\sin\bar{\theta} + B_n) \times \Delta L$$

EQUATION 6.17 *Torque at the upper end of a helically buckled segment in a curved wellbore*

$$T_2 = T_1 - \left(\frac{OD}{2}\right) \times Cf \times \left(W \sin\bar{\theta} + B_n\right) \times \Delta L$$

Equation 6.16 and Equation 6.17 are valid only for short segments.

NOTE: The drag term in Equation 6.16 and Equation 6.17 **is proportional to the square of the axial force**, while the drag term in Equation 6.9 and Equation 6.10 varies linearly with the axial force. All else being equal, drag on a buckled segment is much greater than drag on an unbuckled segment in a curved wellbore.

PRESSURE-AREA FORCE

At the stripper, the wellhead pressure (WHP) imparts an upward compressive axial force to the CT given by Equation 6.18.

EQUATION 6.18 *Compressive axial force due to differential pressure across the CT stripper*

$$P_{area} = WHP \times \left(\frac{\pi \times OD^2}{4} \right)$$

If WHP has units of psi, and OD has units of inches, then P_{area} has units of lbf. The CT weight indicator "sees" this force as a reduction in the total axial force acting on the CT string immediately below the stripper, F_s in Figure 6.1 and Figure 6.2. Table 6.2 shows examples of pressure-area force for various combinations of CT diameter and WHP.

TABLE 6.2 *Pressure-area Force (lbf)*

OD (in)	Wellhead Pressure (psi)			
	1000	**2000**	**4000**	**8000**
1.250	1,227	2,454	4,909	9,817
1.500	1,767	3,534	7,069	14,137
1.750	2,405	4,811	9,621	19,242
2.000	3,142	6,283	12,566	25,133
2.375	4,430	8,860	17,721	35,441

OVERALL FORCE BALANCE

Assuming CTWI incorporates the effects of all axial forces acting on the CT string, Equation 6.19 and Equation 6.20 represent the axial force balance for RIH and POOH respectively.

EQUATION 6.19 *Axial force balance for RIH*

$$\text{Slackoff} = \text{Buoyed Weight} - \text{Drag} - P_{area} - \text{Stripper Friction} - \text{Reel Tension}$$

EQUATION 6.20 *Axial force balance for POOH*

$$\text{Pickup} = \text{Buoyed Weight} + \text{Drag} - P_{area} + \text{Stripper Friction} - \text{Reel Tension}$$

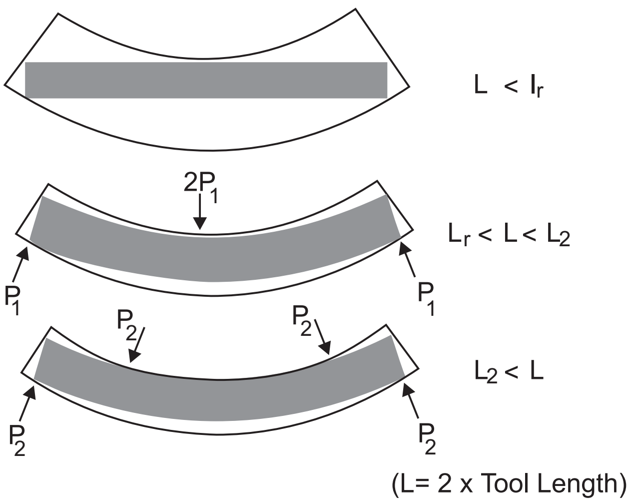
Where:
Slackoff = CTWI during RIH
Pickup = CTWI during POOH
Buoyed Weight = axial component of total buoyed weight of the CT string
Drag = **total drag** of the CT string against the wellbore
Stripper Friction = drag on the CT at the stripper
Reel Tension = axial force on the CT due to the force required to wrap/unwrap it onto/off the reel

RIGID TOOL CALCULATIONS

This section presents a simplified method of calculating the additional drag caused by forcing a rigid tool around a curved path. Here “rigid” means the bending stresses are elastic.

Figure 6.7 shows a rigid tool or BHA forced into a curved wellbore under three different conditions.

FIGURE 6.7 *A Rigid Tool in a Curved Wellbore*



- The top image in Figure 6.7 shows the maximum rigid (unbent) length, L_r, a BHA can have without causing any additional friction.
- The middle image in Figure 6.7 shows the BHA with some bending. The BHA only contacts the wellbore at one point on the inside of the bend. This is case 1 below. The total force against the wellbore wall is 4 x P_1. The drag caused by this force is Cf x 4 x P_1.
- The bottom image in Figure 6.7 shows the BHA with enough bending to wrap it around the wellbore with continuous contact for some distance. This is case 2 below. The total force against the wellbore wall is 4 x P_2 and the drag is Cf x 4 x P_2.

The nomenclature for Equation 6.21 through Equation 6.24 is:

- d = tool diameter
- R = wellbore centerline radius of curvature
- r_c = the radial clearance between the tool and the wellbore
- L_r = half-length of a rigid tool that will just span the curve
- L = half-length of a tool

- L_2 = the length of the tool not in contact with the wellbore on one end of case 2
- E = Young's modulus
- I = the moment of inertia for the tool

EQUATION 6.21 *Maximum half-length for a rigid tool to span a curve in the wellbore*

$$L_r = \sqrt{(4R + 2d)r_c}$$

Note that the total rigid tool length is $2L_r$.

Case 1 applies for all values of L such that $L_r < L < L_2$. Equation 6.22 calculates the maximum half-length before the tool makes continuous contact with the wellbore around the curve.

EQUATION 6.22 *Maximum half-length for a rigid tool prior to continuous contact with a curved wellbore*

$$L_2 = 2\sqrt{3R \times r_c}$$

Equation 6.23 calculates the force P_1 between the rigid tool and the wellbore at each of the four contact points.

EQUATION 6.23 *Rigid tool contact force when $L_r<L<L_2$*

$$P_1 = \frac{EI}{RL}$$

Case 2 applies whenever $L > L_2$. Equation 6.24 calculates the force P_2 between the rigid tool and the wellbore at each of the four points where the continuous contact ends.

EQUATION 6.24 *Rigid tool contact force when $L > L_2$*

$$P_2 = \frac{EI}{2\sqrt{3R^3 \times r_c}} = \frac{EI}{RL_2}$$

EXAMPLE 0.4 *Rigid Tool Lengths*

Problem: Determine the critical tool string length based on the given conditions:

Given:	From Equation 6.21 and Equation 6.22,
• 3.50 in. tool • 6.00 in. hole • 100 ft radius	• d = 3.50 in • r_c = 1.25 in $L_r = \sqrt{(4R+2d)r_c} = 6.46\,\text{ft}$ $L_2 = 2\sqrt{3R \times r_c} = 11.18\,\text{ft}$

EXAMPLE 0.5 *Rigid Tool Contact Force*

Problem: Determine the contact force of a tool string with a length of 7’, 9’, 11’ and 11.2’ with the given conditions:

Given:	From Equation 6.23 and Equation 6.24,
• $E = 30 \times 10^6$ psi • R = 100 ft • d = 3.50 in • t = 0.250 in • $I = 3.390\ \text{in}^4$	L = 7 ft, P_1 = 1009 lbf L = 9 ft, P_1 = 785 lbf L = 11 ft, P_1 = 642 lbf L > 11.2 ft, P_2 = 632 lbf

7 BUCKLING AND LOCK-UP

CT under axial compression can buckle into a sinusoidal or helical shape if the compressive force exceeds a certain “critical” value for that particular mode of buckling. Even though plastic deformation on the reel causes residual curvature in the CT, this is not a buckling state. Residual curvature is present only when the axial force is quite low. Figure 7.1 shows a CT string that was chopped into short lengths for scrap. The residual curvature in each piece is due to the residual stress (strain) caused by plastic deformation around the reel. Buckling is an elastic phenomenon; it does not plastically deform the CT.

FIGURE 7.1 *Residual Curvature in Scrap CT*

Buckling of drill pipe during drilling can have extremely serious consequences, including rapid fatigue failure of the drill pipe. Buckling of casing or tubing usually causes high stresses that weaken the tubular and degrade its pressure rating. Consequently, drillers take great pains to avoid buckling jointed tubulars. However, buckling of CT is common for operations in deep and/or extended reach wells. In fact, CT normally enters the wellbore in a “buckled” shape with residual curvature from its plastic deformation on the reel. This residual curvature is not a buckled state, but helps promote buckling as axial compressive force on the CT increases.

By itself, buckling of CT is not a serious problem. It is an elastic deformation that does not damage the CT. Under favorable conditions, buckled CT can continue to slide and transmit axial force. However, Equation 6.11 shows that **buckling significantly increases the normal force (drag) between the CT and wellbore.** This always reduces available WOB or SDW, and may lead to lock-up, if the compressive force above the buckled section increases high enough.

BUCKLING LIMITS

A CT segment inside a wellbore buckles into different shapes (modes) when the axial compressive force acting on it exceeds values determined by the particular combination of geometry and physical properties of the segment. The segment remains unbuckled for lower axial compressive force. This threshold between buckling modes is often called the “critical” compressive force.

When the axial compressive force increases to the critical sinusoidal buckling limit, the segment deforms into a sinusoidal or “snake-like” shape in continuous contact with the wellbore. The buckled segment does not move away from the wellbore nor lie in a plane. The segment continues to change shape as the axial force increases beyond the critical sinusoidal buckling limit, but the normal force exerted by the segment on the wellbore is due mainly to the weight of the segment. Sinusoidal buckling does not present a limiting condition for CT operations but is an intermediate condition on the path to helical buckling.

If the axial compressive force continues to increase past the critical helical buckling limit, the segment assumes a helical shape in continuous contact with the wellbore. After the segment is buckled helically, the normal force exerted by the segment on the wellbore gains a component proportional to the square of the axial compressive force, Equation 6.11. Thus, drag on a helically buckled segment increases rapidly with increasing axial compressive force. In order to account properly for this additional drag in the force balance, one must know when the axial force on a segment exceeds the critical limit for helical buckling. The following section discusses critical buckling limits for a CT segment.

BUCKLING IN VERTICAL SEGMENTS

Equation 7.1 gives the critical helical buckling limit for straight segments inclined at angles less than about 15°[1].

EQUATION 7.1 *Critical helical buckling limit for near-vertical, straight segments*

$$F_{VH} = 1.94\sqrt[3]{EI \times w^2}$$

where, as for Chapter 6 "Tubing Forces"
W = buoyed weight per unit length
EI = the segment's bending stiffness

Note that Equation 7.1 depends only on the stiffness and buoyed weight of the segment. The yield strength of the CT material is not a factor. For common CT sizes in vertical holes, F_{VH} is typically less than 200 lbf compression. This force may seem insignificant, but for many situations most of the CT in a vertical wellbore is in tension, and buckling is not an issue. If part of a CT string is in compression and the remainder is in tension, the location where axial force changes from tension to compression is called the neutral point.

1. Lubinski, A., Althouse, W.S., and Logan, J.L., 1962, "Helical Buckling of Tubing Sealed in Packers," *Journal of Petroleum Technology*, June 1962, pp. 655-670.

BUCKLING IN INCLINED SEGMENTS

Equation 7.2 gives the critical **sinusoidal** buckling limit for a straight segment inclined at an angle greater than about 15°[2].

EQUATION 7.2 *Critical sinusoidal buckling limit for an inclined segment*

$$F_{CS} = 2\sqrt{\frac{EI \times w \sin\theta}{r_c}}$$

where
r_c is defined in Equation 6.12

The axial compressive force required to helically buckle an inclined segment is about 41% greater than F_{CS}. Equation 7.3 gives the critical **helical** buckling limit for a straight inclined segment[3].

EQUATION 7.3 *Critical helical buckling limit for a straight inclined segment*

$$F_{CH} = 2\sqrt{2}\sqrt{\frac{EI \times w \sin\theta}{r_c}}$$

Note that Equation 7.2 and Equation 7.3 contain only the CT stiffness, buoyed weight, and geometric terms. They are independent of the CT yield strength. For common CT sizes, F_{CH} for a segment can be 20-30 times the axial compressive force required to helically buckle the segment in a vertical position. This partially explains why CT usually buckles first near the bottom of the vertical portion of a well during RIH. Another reason is that drag is much higher on curved and inclined segments leading to higher axial compressive force at the bottom of the vertical section.

2. Dawson, R. and Paslay, P.R., 1984, “Drillpipe Buckling in Inclined holes,” *Journal of Petroleum Technology*, October 1984, pp. 1734-1738.
3. Chen, Y., Lin, Y., and Cheatham, J.B., 1990, “Tubing and Casing Buckling in Horizontal Wells,” *Journal of Petroleum Engineers*, February 1990, pp. 140-191.

Note that F_{CH} increases with decreasing radial clearance and increasing segment bending stiffness, weight, and inclination. This provides several options for reducing the tendency of a segment to buckle helically. If buckling could be a problem, larger diameter CT simultaneously increases I and W while decreasing r_c. Another alternative is to increase the CT wall thickness, which simultaneously increases I and W.

NOTE: Both alternatives increase the drag between the CT and the wellbore. Depending on the conditions, this can offset any benefit of greater stiffness. The only way to determine the effects of changing CT dimensions is to run the change through a CT simulator like Orpheus™.

If the CT dimensions are fixed, the only way to increase the critical helical buckling limit is to lower mud weight (increase W) or conduct the CT operation inside a smaller casing or hole size (decrease r_c).

EXAMPLE 0.1 *Helical Buckling Example*

Problem: Calculate the critical helical buckling limit with the given conditions.

Given: • CT = 1.75 in. OD x 0.134 in. Wall Assume: • θ = 80° • ID_{hole} = 5.00 in. • w = 1.288 ppf (from Example 0.1) • Young's Modulus, E = 27x10^6 psi	From Equation 6.13, $I = \frac{\pi \times [(OD^4 - (OD - 2t)^4]}{64} = 0.2236\,\text{in}^4$ From Equation 6.12, $r_c = \frac{ID_{hole} - OD}{2} = 1.625\,\text{in.}$ From Equation 7.3, $F_{CH} = 2\sqrt{2}\sqrt{\frac{EI \times w\sin\theta}{r_c}} = 1772\,\text{lbf}$

EFFECTS OF WELLBORE CURVATURE ON BUCKLING

Traditionally, Equation 7.3 has been used in curved holes by considering θ as the average inclination of the curved segment. However, this does not account for the stabilizing effect of curvature on the buckling. For example, Equation 7.3 will give a constant value for F_{CH} in a curved hole regardless of the direction or rate of curvature. An improved procedure accounts for the effect of curvature by including the normal force due to curvature as additional resistance to buckling[4]. This procedure, Equation 6.8, predicts results consistent with experimental observations.

Replacing W sinθ, the normal force due to segment weight in Equation 7.3, with C_n, the effective normal force from Equation 6.8, and simplifying, obtains a quadratic polynomial equation for the axial force required for helical buckling, F_H:

EQUATION 7.4 *Axial force required for helical buckling in a curved hole*

$$F_H^4 = \left(\frac{8EI}{r_c}\right)^2 \left[\left(F\theta' + w\sin\theta\right)^2 + \left(F\phi'\sin\theta\right)^2\right]$$

Note that Equation 7.4 is in terms of force per unit length. The required critical helical buckling limit is one of the four solutions of Equation 7.4. Since F_H is the axial compressive force (assumed positive here), only positive roots of Equation 7.4 are physically admissible. When only one positive root exists, it is the required critical helical buckling limit. If multiple positive roots exist, the selection process depends upon the curvature and the mechanics of buckling.

4. He, X, and Kyllingstad, A., 1993, "Helical Buckling and Lock-up Conditions for Coiled Tubing in Curved Wills", *Paper SPE 25370, presented at the SPE Asia Pacific Oil and Gas Conference*, Feb. 1993.

Comparing Equation 7.3 and Equation 7.4 yields the following:

- In building curvature, $F_H > F_{CH}$
- For moderately dropping curvature, $F_H < F_{CH}$
- For high dropping curvature, $F_H > F_{CH}$
- For purely azimuthal curvature, $F_H > F_{CH}$

In general, curvature stabilizes a segment against buckling. That is, CT buckles more easily in straight sections of the wellbore than in doglegs or build sections.

Does the foregoing mean that tortuosity or curvature in the wellbore is beneficial for CT operations? Reducing the buckled length of CT would extend its reach into a well. On the other hand, Equation 6.8 clearly shows that curvature causes higher drag which may shift the location of buckling upwards. Resolution of these conflicting effects requires modeling a CT operation with a sophisticated CT simulator, like Orpheus™.

EFFECTS OF FRICTION ON BUCKLING

Mobil Exploration and Producing Technical Center conducted detailed experimental buckling studies with small-scale laboratory equipment and actual CT inside 400 ft of casing to determine what factors affect the buckling and post-buckling behavior of tubulars. Results from these buckling experiments indicate that friction significantly affects buckling behavior of rods and tubing.[5,6]

Figure 7.2 shows the large-scale test apparatus for measuring buckling forces on CT inside casing. A load cell at each end of the CT recorded the axial force applied to the CT by a hydraulic ram.

FIGURE 7.2 *Large-scale Buckling Tests*

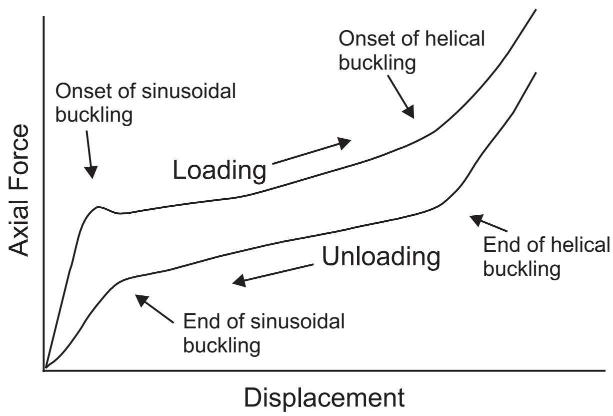
In general, friction stabilizes a tubular under compression to delay the onset of buckling. Friction also causes hysteresis in the post-buckling behavior. As a result of this hysteresis, buckling behavior is different from unbuckling behavior.

5. ASME 94-PET-1 “Experimental Study of Buckling and Post-Buckling of Laterally Constrained Rods - Part 1:Frictional effects”, P.V.R. (Suri) Suryananrayana and R.C. McCann.
6. R.C. McCann and P.V.R. (Suri) Suryananrayana, “Experimental Study of Curvature and Frictional Effects on Buckling”, OTC 7568, Offshore Technology Conference, May 1994.

Figure 7.3 shows typical results from buckling experiments. The data are for a rod subjected to buckling inside a horizontal acrylic tube. One end of the rod was fixed, while a remote-controlled linear actuator applied axial force on the other end. A load cell at each end of the rod measured axial forces, and an LVDT measured displacement of the linear actuator.

Figure 7.3 shows the behavior of the axial force at the stationary end of the rod as a function of axial displacement of the other end. The experiment actually continued to lock-up, but the plot was truncated for simplicity. The figure clearly shows that hysteresis is significant, and the axial compressive force at unbuckling is always lower than axial compressive force at onset of buckling.

FIGURE 7.3 *Effects of Friction on Buckling*



Comparison of these results with theoretical predictions shows that **current theory actually predicts axial compressive force at unbuckling**.

As a result, Equation 7.3 predicts critical helical buckling forces significantly lower than those determined experimentally. Since friction is always present in the real world, **predicted critical buckling forces are conservative**. Unfortunately, no theoretical work has studied frictional effects. Stability problems such as buckling are normally analyzed using “energy” methods limited to conservative forces. However, friction is very difficult to include in stability analyses because it is not a conservative force.

Friction has a stabilizing effect on helical buckling, i.e., it delays the onset of buckling compared to the frictionless case. One way of modeling this effect is to account for the additional drag force a segment must overcome to helically buckle. Based on the force balance for a segment, drag per unit length is Cf x Wsinθ. Adding this frictional stabilizing force to the normal force in Equation 7.3, gives **the adjusted critical helical buckling limit for an inclined segment with friction**.

EQUATION 7.5 *Adjusted critical helical buckling limit for an inclined segment with friction*

$$
\begin{aligned}
F'_{CH} &= 2\sqrt{2(1 + Cf)}\sqrt{\frac{EI \times w \sin\theta}{r_c}} \\
&= \left(\sqrt{1 + Cf}\right)F_{CH}
\end{aligned}
$$

The critical helical unbuckling limit, F_{CH}, is given by Equation 7.3.

Equation 7.5 provides a simple method to account for frictional effects that agrees better with experimental results than Equation 7.3. However, it still seems to **underestimate** the measured critical helical buckling force. Further theoretical and experimental work could improve the ability to model effects of friction on buckling.

Equation 7.5 implies that higher values of Cf are beneficial for CT operations. Higher friction does delay buckling, which results in lower drag and longer reach for RIH compared to buckled tubing. However, once the CT buckles, higher Cf means post-buckling drag will be significantly higher than drag for unbuckled CT. Any increase in drag on a segment of CT increases axial compressive force on segments above it. Thus, increasing Cf at one location may simply shift the buckling problem up the wellbore. A good CT simulator is required to model the macroscopic effects of friction.

GEOMETRY OF A HELIX

Equation 7.6 calculates the period of the helix whenever $F > F_{CH}$.

EQUATION 7.6 *Helix period*

$$\lambda = 2\pi\sqrt{\frac{2EI}{F}}$$

Equation 7.7 calculates the total length change in the CT caused by helical buckling with period λ.

EQUATION 7.7 *Total length change due to helical buckling*

$$\Delta L = L \times \left[\sqrt{\left(\frac{2\pi r_c}{\lambda}\right)^2 + 1} - 1\right]$$

EXAMPLE 0.2 *Helix Period and Length Change Example*

Problem: Determine the helix period and the change in length for a coiled string with the given conditions:

Given:

- Same conditions as Example 0.1
- F = -3000 lbf (note: F_{CH} = -1772 lbf)
- L = 2000 ft

From Equation 7.6, the helix period, λ, is

$$\lambda = 2\pi\sqrt{\frac{2EI}{F}} = 33.2 \text{ ft}$$

From Equation 7.7 the length change, ΔL, is

$$\Delta L = L \times \left[\sqrt{\left(\frac{2\pi r_c}{\lambda}\right)^2 + 1} - 1\right] = 0.66 \text{ ft}$$

Post-Buckling Lock-up

By itself, helical buckling is neither a critical problem nor a limiting condition for CT. It does not damage or plastically deform the CT. However, post-buckling lockup is the limiting condition for RIH. Lock-up not only limits SDW or WOB, it can also prevent the BHA from reaching TD. In simple terms, lock-up is a local phenomenon that occurs during RIH when the local increase in drag exceeds the axial compressive force from the CT segments above. When buckled CT reaches this condition, any further increase in axial compressive force at the top of the helix is lost completely to drag. Since normal force due to helical buckling increases as the square of axial compressive force (Equation 6.11) lock-up may occur almost immediately after a segment helically buckles. Attempting to force more CT into a hole after lock-up can damage the tubing. Proper modeling of post-buckling drag effects with a good CT simulator is necessary to determine whether lock-up occurs.

8 CT MECHANICAL LIMITS

OVERVIEW

When there is a large pressure differential across the CT wall, especially when combined with a large axial force, you run a risk of a CT failure (burst or collapse). Typically the greatest risk of burst or collapse in a CT job occurs at the wellhead. You can use a mathematical model to determine these limits prior to performing a job to make sure that the operation stays within safe working limits.

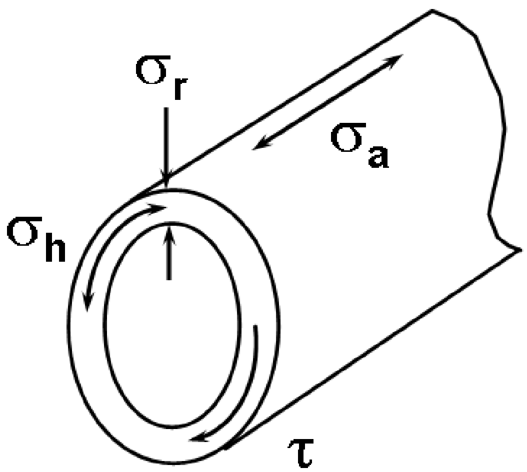
A widely accepted model uses the von Mises combined stress to predict tubing burst and collapse limits. You can also take into account helical buckling, maximum expected pressures, diameter growth, and torque.

CT STRESSES

A widely accepted method of predicting tubing failure due to pressure and tension limits is based on the von Mises stress. If the von Mises stress exceeds the yield strength of the material, the CT is assumed to fail.

The von Mises stress is a combination of the three principal stresses in CT and the shear stress caused by torque. The principal stresses are shown in Figure 8.1.

FIGURE 8.1 *Principal Stresses Acting on a Segment of CT*



axial stress (σ_a)
radial stress (σ_r)
tangential or hoop stress (σ_h)
shear stress (τ)

These stresses are determined by the geometry of the CT and the four applied loads which are:

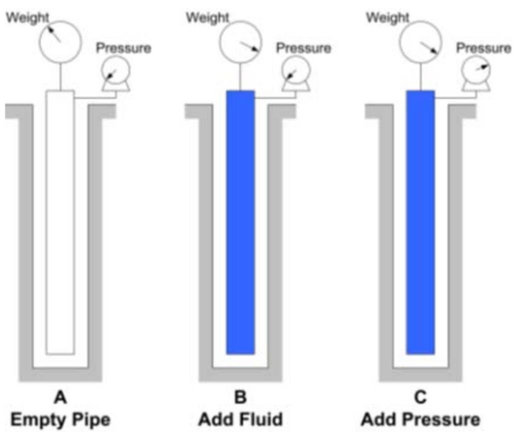
- internal pressure (P_i)
- external pressure (P_o)
- axial force (positive for tension, negative for compression) (F_a)
- applied torque (τ)

Axial Force Definition

Before axial stress can be defined, two types of axial force must be understood. These are known as the "real force", F_a, and the "effective force", F_e, also known as the "weight". The real force is the actual axial force in the pipe wall, as would be measured by a strain gauge. The effective force is the axial force if the effects of pressure are ignored.

To better understand these forces, consider the following simple example shown in Figure 8.2.

FIGURE 8.2 *Real and Effective Forces*



A closed ended piece of pipe is hung from a scale as is shown in case A. The scale is measuring the weight of the pipe. The real axial force at the top of the pipe is the same as the weight measured by the scale.

In case B the piece of pipe is full of fluid. The weight is increased by the weight of the fluid. The real axial force at the top of the pipe is still the same as the weight measured by the scale.

In case C, pressure is applied to the fluid inside the pipe. The weight remains the same as in case B. However, the real axial force in the pipe wall is now increased by the internal pressure multiplied by the cross sectional area. Thus, the weight (also known as the effective force) and the real force are not the same.

EQUATION 8.1 *Real and Effective Force*

$$F_a = F_e + A_i F_i - A_o P_o$$

Effective force, or weight, is important for two reasons:

- The weight indicator on a CT unit measures the weight, not the real force, just as the scale in Equation 8.1 above measures the weight.
- When buckling occurs depends upon the effective force. Thus the helical buckling load is an effective force.

The real force is important because it is the force required to calculate the axial stress, and thus to determine the CT limits.

Example 0.1 *Axial Force*

Problem: Calculate the real and effective forces for the given conditions (a), (b) and (c):

Given that

- CT = 1.75 in. OD x 0.134 in.
- W_{CT} = 2.313 ppf
- Length = 10,000 ft
- A_o = 2.405 in^2
- A_i = 1.725 in^2
- Internal Volume = 896 gal

Condition (a)

- Tubing empty
- P_{int} = 0
- P_{ext} = 0

Condition (b)

- Tubing filled with water (8.34 ppg)
- P_{int} = 0
- P_{ext} = 0

Condition (c)

- Tubing filled with water (8.34 ppg)
- P_{int} = 1,000 psi
- P_{ext} = 0

Results (a)

Calculate the weight of the CT using Equation 8.1.

$$F_a = F_e + A_i F_i - A_o P_o$$

= 23,130 lbf + 1.725in^2(0)-2.405in^2(0)
= 23,130 lbf

$$F_e = W_{CT} = W_{CT} \times L$$

= 2.313 ppf x 10,000 ft
= 23,130 lbf

Results (b)

Calculate the weight of the fluid

$$F_e = W_{CT} + W_{fluid} = 23{,}130\,\text{lbf} + 896\text{gal}(8.34\text{ppg}) = 30{,}602\,lb$$

$$F_a = F_e + A_i P_i - A_o P_o$$

= 30,602 lbf + 1.725in^2(1000 psi) - 2.405in^2(0) = 30,602 lbf

Results (c)

$$F_a = F_e + A_i P_i - A_o P_o$$

= 30,602 lbf + 1.725in^2(1000 psi) - 2.405in^2(0)
= 32,327 lbf

Axial Stress

The axial stress is caused by the axial force (tension or compression) applied to the CT. When the CT is in tension, the axial stress is the axial force divided by the cross-sectional area:

EQUATION 8.2 *Axial stress at any location in the segment*

$$\sigma_a = \frac{F_a}{A_{CT}}$$

where Equation 8.3 gives the cross sectional area of the coiled tubing.

NOTE: Use the real force (F_a) when calculating axial stress.

EQUATION 8.3 *Cross sectional area of the coiled tubing*

$$A_{CT} = \frac{\pi(OD^2 - (OD - 2t)^2)}{4}$$

Axial stresses have the same sign as axial forces, positive (+) for tension and negative (-) for compression.

If the compressive force exceeds the helical buckling load, the CT forms a helix in the hole. This helix causes an additional axial bending stress in the CT, which must be added to the axial stress. In a vertical well the helical buckling load is nearly zero. The CT buckles into a helix as soon as the effective force becomes compressive (which is defined as a negative force value). Assuming that the CT is buckled when the effective force is less than zero, Equation 8.4 calculates the bending stress.

EQUATION 8.4 *Bending stress when the CT is buckled (F_e < 0)*

$$\sigma_{bend} = \pm \frac{r_c \times F_e \times OD}{4I}$$

Since the bending stress is also axial in nature, total axial stress at any location in the segment is the sum of the stresses due to axial force (F_a) and bending, Equation 8.5.

EQUATION 8.5 *Axial stress while the CT is buckled*

$$\sigma_a = \frac{F_a}{A_{CT}} + \sigma_{bend}$$

This additional axial bending stress truncates the elliptical shape of the traditional von Mises limits curve.

EXAMPLE 0.2

Problem: Calculate the bending stress in the coiled tubing with the following conditions:

Given that

- CT = 1.75 in. OD x 0.134 in. wall
- F_{axial} = 4,000 lbf
- ID_{Hole} = 5.00 in.

From Equation 6.12

$$r_c = \frac{ID_{hole} - OD}{2} = 1.625\,in$$

From Equation 6.13

$$I = \frac{\pi[(OD^4 - (OD - 2t)^4]}{64} = 0.2236 in^4$$

Based on Equation 8.8, bending stresses are:

$$\sigma_{bend} = \pm\frac{1.625\,\text{in} \times 4000\,\text{lbf} \times 1.75\,\text{in}}{4 \times 0.2236\,\text{in}^4}$$

$$= \pm 12,718 \text{ psi}$$

Radial Stress

A pressure differential across the wall of the segment creates a radial stress, Figure 8.1, that vary with radial position. According to Lame's equation, the radial stress at a given location in the CT wall is the stress through the CT wall due to internal and external pressures. The maximum stress always occurs at the inner or the outer surface. Equation 8.6 gives the radial stress at any radial location r in the wall of the segment.

EQUATION 8.6 *Radial Stress at a Location in the Wall of a Segment*

$$\sigma_r = \frac{(P_o - P_i) r_i^2 r_o^2}{r^2 (r_o^2 - r_i^2)} + \frac{r_i^2 P_i - r_o^2 P_o}{(r_o^2 - r_i^2)}$$

Where the subscripts "i" and "o" refer to the ID and OD locations, Equation 8.7 and Equation 8.8, respectively.

EQUATION 8.7 *Radial Location for the ID*

$$r_i = \frac{OD - 2t}{2}$$

EQUATION 8.8 *Radial Location for the OD*

$$r_o = \frac{OD}{2}$$

From Equation 8.6 $\sigma_r = P_i$ at r_i, while $\sigma_r = -P_o$ at r_o

Hoop Stress

According to Lame's equation, the hoop stress at a given location in the CT wall is the stress around the circumference of the CT due to internal and external pressures. As with the radial stress, the maximum stress always occurs at the inner or the outer surface. Because yielding occurs first at the inner surface, hoop and radial stresses at the inner surface are used in the calculations.

Equation 8.9 gives the hoop (or tangential) stress at any radial location r in the wall of the segment. The maximum value of σ_{hoop} occurs at r_i.

EQUATION 8.9 *Hoop stress at any radial location r in the wall of the segment.*

$$\sigma_{hoop} = \frac{r_i^2 P_i - r_o^2 P_o}{(r_o^2 - r_i^2)} - \frac{(P_o - P_i) r_i^2 r_o^2}{r^2 (r_o^2 - r_i^2)}$$

Equation 8.6 and Equation 8.9 are known as Lame's equation[1].

1. Timoshenko, S., Strength of Materials, Part II, D. Van Nostrand Co., Inc. 1956.

EXAMPLE 0.3 *Hoop Stresses*

Problem: The following table shows the hoop stress for a range of internal and external pressures for a given CT of 1.75 in OD x 0.134 in.

TABLE 8.1

P_{in} (psi)	Hoop Stress (psi) at r_i — P_{out} (psi)					
	0	**1000**	**2000**	**3000**	**4000**	**5000**
0	0	-7071	-14143	-21214	-28285	-35357
1000	6071	-1000	-8071	-15143	-22214	-29285
2000	12143	5071	-2000	-9071	-16143	-23214
3000	18214	11143	4071	-3000	-10071	-17143
4000	24285	17214	10143	3071	-4000	-11071
5000	30357	23285	16214	9143	2071	-5000

Shear or Torque Stress

In some situations the CT may also be subject to a torque, T. If the torque is significant, then torsion of the CT occurs and causes the associated shear stress, t, which is given by:

EQUATION 8.10 *Maximum torsional stress*

$$\tau = \frac{Tr_o}{J} = \frac{TxOD}{2J}$$

Where J, the polar moment of inertia is J = 2I

The r_o actually ranges from r_i to r_o with the greatest shear stress occurring at r_o. Although the radial and hoop stresses are calculated for the inner CT surface, the shear stress is calculated for the outer surface, a more conservative approximation.

EXAMPLE 0.4

Problem: Calculate the torsional stress in the CT with the given conditions:

Given that	Using Equation 8.10
• CT = 1.75 in. OD x 0.134 in wall • T = 100 ft-lbf • J = 2 x I = 0.4472 in^4	$\tau = \frac{(100\text{ft lbf})(12\text{ in/ft})(1.75\text{ in})}{2(0.4472\text{ in}^4)} = 2348\text{ psi}$

The von Mises Yield Condition

In order to assess the suitability of a CT string for a given operations, one must determine the effects of the stresses inside the wall of each segment in the string. The objective is to insure that these stresses never exceed a given percentage (usually 80%) of the yield stress of the CT material. A common approach to this problem is to use the von Mises overall stress failure criteria to calculate the total equivalent stress in each segment of the CT string due to the combination of forces acting on it. The initial yield limit is based on the combination of the three principle stresses (axial stress, radial stress, and hoop stress) and the shear stress caused by torque.

EQUATION 8.11 *von Mises Yield Condition*

$$\sigma_{VME} = \sqrt{\frac{1}{2}\left\{(\sigma_h - \sigma_r)^2 + (\sigma_h - \sigma_a)^2 + (\sigma_a - \sigma_r)^2\right\} + 3\tau^2}$$

NOTE: If there is no torque, the shear stress term drops out of the equation.

The yield limits for CT are calculated by setting the von Mises stress, $\sigma_{VME,}$ to the yield stress, σ_y, of the material with the applicable safety margin.

NOTE: To provide a margin of safety, a yield factor of 0.8 is usually applied, which ensures that $\sigma_{VME} < 0.8 \times \sigma_y$. Nominal yield stress for common CT materials is 70-120 kpsi. Thus, "safe" σ_{VME} for these materials is 56-96 kpsi.

The VME approach ignores the following conditions prevalent with CT:

- Residual stresses
- Work softening
- Not elastic, perfectly plastic behavior
- Tension and compression yield stresses are different
- Yield stress changes with strain cycling
- Ovality

Despite these shortcomings, the VME stress failure criterion is a good method for calculating the mechanical limits for steel CT, due to its conservative results.

EXAMPLE 0.5 *von Mises Equivalent Stress*

Problem: Calculate the stresses in the CT that have the following conditions:

Given that,	The axial, hoop, radial, and von Mises stresses are:
• CT = 1.75 in. OD x 0.134 in. wall • σ_y = 80,000 psi • F_e = 10,000 lbf • no bending • P_i = 3000 psi • P_o = 4000 psi	$F_a = 10000\,\text{lbf} + 1.725\,\text{in}^2(3000\,\text{psi}) - 2.405\,\text{in}^2(4000\,\text{psi}) = 5555\,\text{lb}$ $\sigma_a = \frac{5555\,\text{lb}}{.68\,\text{in}} + 0 = 8169\,\text{psi}$ $\sigma_n = \frac{(.741)^2(3000) - (.875)^2(4000) + (10000)(.875)^2}{(.875)^2 - (.741)^2} = -10071\,\text{psi}$ $\sigma_r = -P_i = -3000\,\text{psi}$ $\sigma_{VME} = 15928\,\text{psi}$ thus, σ_{VME} = 27.6% of σ_y

Above the injector, the axial forces are relatively small (reel back tension), and the dominant failure mode is fatigue. CT internal pressure high enough to burst the tubing is extremely rare. Below the injector chains and above the strippers, the CT can experience compressive (snubbing) forces at the start of RIH due to the WHP force and stripper friction. For standard CT operations, this compressive force rarely poses any problems. Force generated from WHP > 3500 psi can buckle unsupported tubing. Even so, the σ_{VME} in this area due to combined compression and burst pressure is usually not a concern.

Below the stripper, the local forces depend on depth and the direction the CT string is moving, but the maximum axial force and highest collapse pressure are usually just below the stripper. This does not mean the highest stresses in the wall of the CT occur at that point. For a tapered CT string, the maximum vme could occur farther down the string at a thinner wall section. Collapse and tensile failure are most likely failure modes below the stripper. Therefore, the CT must have enough wall thickness to resist the combination of tension and collapse pressure. Below the stripper, excessive compression is not a problem unless the CT operator ignores the warning signs that the CT is approaching lockup or the CT runs at high speed into an obstruction.

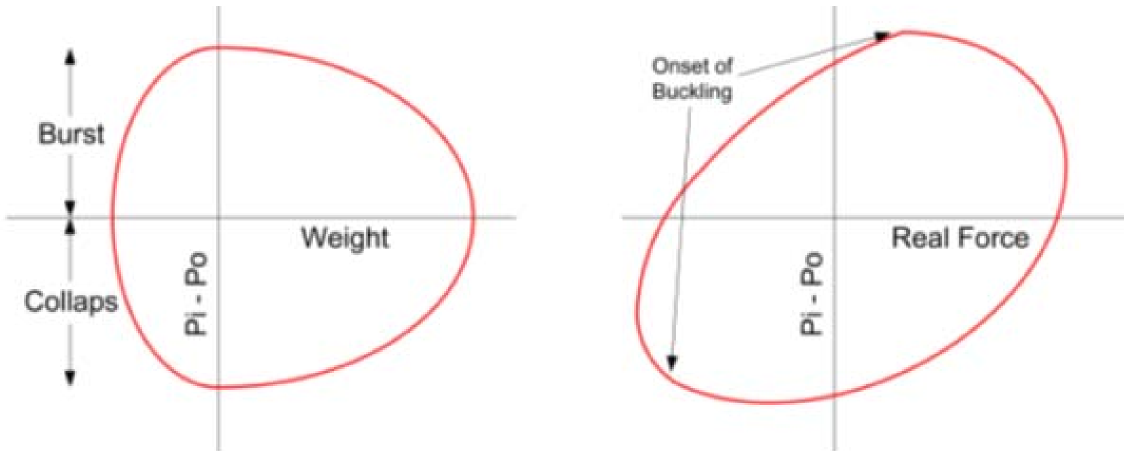
CT LIMITS

There are four forces which determine the combined stress limits in CT. They are the internal pressure (P_i), external pressure (P_o), the real axial force (Fa), and the torque (T). To simplify the presentation of the limits, the pressure difference (P_i - P_o) is calculated. A positive differential pressure represents a "Burst" condition. A negative differential pressure represents a "Collapse" condition.

One method of drawing the limit curve is to hold the external pressure constant at zero for the top or Burst half of the plot and hold the internal pressure constant at zero for the bottom or Collapse portion of the plot. The von Mises equation now has only two variables, real axial force and internal pressure for the Burst portion, and external pressure for the Collapse portion. The Weight can also be calculated using Equation 8.1. Thus, this curve can be drawn versus either the real axial force or the effective axial force, which will be called Weight for the remainder of this document.

The resulting plots of pressure difference versus axial force are elliptical, which are shown in Figure 8.3. In the Weight case, the ellipse is horizontal. In the Real Force case, the ellipse is inclined somewhat. The left side of the ellipse is truncated, due to the helical buckling stress. For the Weight case, the helical buckling begins at the Y axis, when the Weight becomes negative. For the Real Force case, the onset of buckling occurs at the maximum and minimum pressure difference points.

FIGURE 8.3 *Single Limit Curves with External Pressure Constant at Zero*

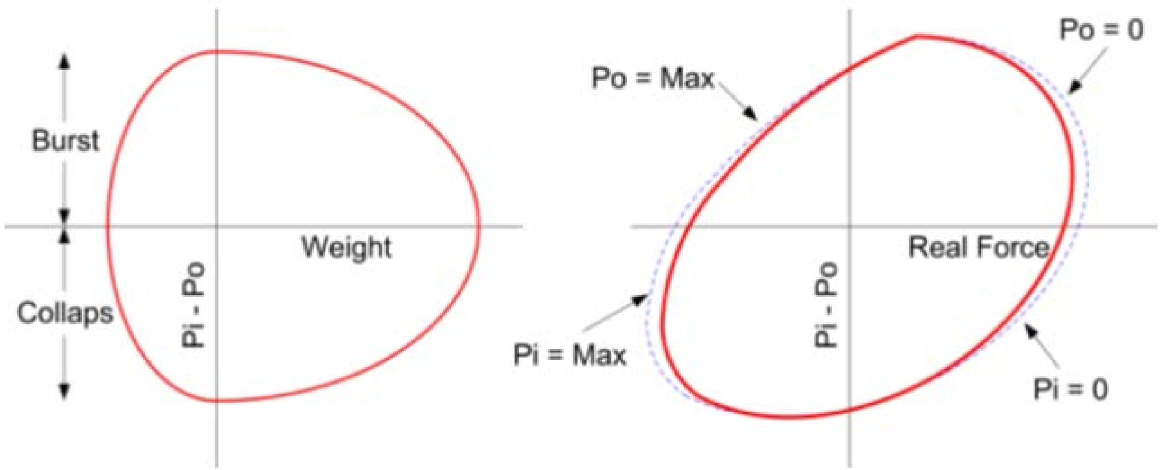


Maximum Pressure Considerations

Drawing the limits curve for a constant external (Burst case) or internal (Collapse case) pressure only shows the limits for that pressure. However, pressures do not stay constant throughout the CT job. To form a limits curve that addresses a range of pressures, one can create a composite of multiple limits curves.

First, a limit curve is drawn as in Figure 8.3, holding the external pressure at zero for the Burst case and the internal pressure zero for the collapse case. A second limit curve is drawn holding these same two pressures to their expected maximum values. The resulting set of limits curves are shown in Figure 8.4.

FIGURE 8.4 *Limit Curve for Zero and Maximum*



The inner most (closest to the origin) portion of these 2 curves in the Real Force plot, shown as a thick black line in Figure 8.4, is the limit curve produced by Hercules.

NOTE: This limit curve no longer represents the true yield limit of the CT. Rather, it represents a conservative combination of the actual limits.

NOTE: The curve of the limit versus Weight is exactly the same for 0 and maximum pressure. Thus absolute pressure does not affect the CT limits when considered with respect to weight.

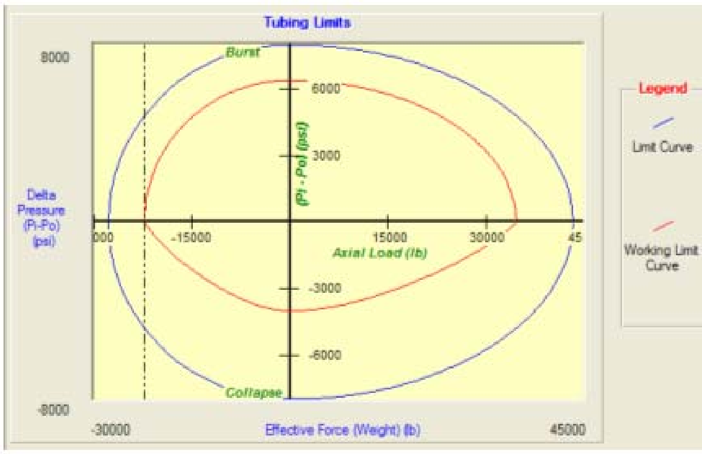
Diameter Growth Considerations

Depending upon the application, CT may have a tendency to increase in diameter during its life. This change in geometry changes the stresses, and thus the limits. If there is significant diameter growth and associated wall thinning, the use of the correct diameter and wall thickness will improve the accuracy of the limit calculation.

Applying Safety Factors

The limits curve calculated by the von Mises yield condition represents where the CT would begin to yield. Multiplying these von Mises curves by the appropriate safety factors will produce the "working limit" curves (Figure 8.5). There are different safety factors for burst and for collapse. The safety factor for collapse should be more conservative to account for ovality. Over the life, CT becomes somewhat oval due to bending across the reel and over the gooseneck. Increased ovality increases the likelihood of collapse. However, the von Mises stress does not take ovality into account.

FIGURE 8.5 *VME and Working Limit Curves for Effective Force (Weight)*



CT COLLAPSE

Collapse is a difficult failure mode to predict accurately because it depends on factors that are seldom known accurately. These factors include tubing ovality, yield stress, and wall thickness. Maximum tension in a CT string occurs just below the injector head at the start of POOH, but maximum σ_{VME} may occur elsewhere due to flowing or hydrostatic pressure of fluids in the wellbore annulus. Thus, CT can collapse far below the stripper.

CAUTION: Always calculate collapse pressure for each section in a tapered CT string using the maximum axial stress expected in that section.

CT Collapse Prediction—Plastic Hinge Theory

The use of plastic hinge theory has proven accurate in modeling CT collapse. Newman[2] first used this theory to develop a CT collapse calculation. This theory was again used by Luft[3] in 2002. Newman and Luft used slightly different definitions for ovality. When their theories are corrected for this difference, they yield exactly the same collapse pressure calculation results. In 1998, Zheng[4] used plastic hinge theory to develop another collapse pressure calculation.

NOTE: There is a sign error in Newman's paper, equations 4 through 7, the last P_i term should be added not subtracted.

2. Newman, K.R., "Collapse Pressure of Oval CT," SPE Paper 24988 European Petroleum Conference, Cannes France, November 1992.
3. Luft, H.B., Wright, B.J., Bouroumeau-Fuseau, P., "Expanding the Envelope of CT Collapse Ratings in High Pressure/High Temperature Wells," SPE Paper 77611, SPE ATCE, San Antonio, TX October 2002.
4. Zheng, A.S., Improved Model for Collapse Pressure of Oval CT", SPE Paper 55681, SPE/ICoTA Roundtable, Houston April 1999.

FIGURE 8.6 *Square Waveform Plastic Hinge Stress Distribution*

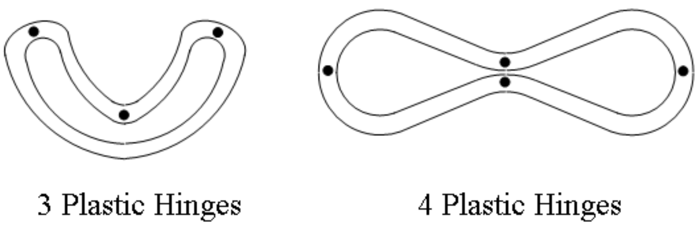


Figure 8.5 (which is figure 2 from Newman's paper) shows an oval CT cross section with a major axis A and a minor axis B. Internal and external pressures cause bending moments in the CT wall. The hoop stress distributions through the wall thickness caused by these bending moments reach the yield stress in both tension and compression as shown. When this happens, a hinge is formed and the CT collapses. A collapsed section may have 3 or 4 plastic hinges as shown in Figure 8.6.

CT Collapse Calculation—API RP 5C7

Equation 8.12 from API RP 5C7[5] predicts collapse pressure differential for oval tubing in the absence of tensile load.

EQUATION 8.12 *Collapse pressure (P_{co}) for oval tubing - API RP 5C7*

$$P_{co} = g - \sqrt{g^2 - f}$$

Equation 8.13 and Equation 8.14 describe the terms g and f.

EQUATION 8.13 *g term for API RP 5C7 collapse pressure calculation*

$$g = \frac{\sigma_y}{\left(\frac{OD}{t} - 1\right)} + \frac{P_c}{4}\left[2 + 3\left(\frac{OD_{max} - OD_{min}}{OD}\right)\frac{OD}{t}\right]$$

5. API Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services.

EQUATION 8.14 *f term for API RP 5C7 collapse pressure calculation*

$$f = \frac{2\sigma_y P_c}{\left(\frac{OD}{t} - 1\right)}$$

Except for P_c, all other terms in Equation 8.13 and Equation 8.14 are the same as defined previously. P_c is calculated from the appropriate formula of API Bulletin 5C3[6] for yield strength, plastic, or transition collapse pressure in the absence of tensile load. For CT subjected to tensile load, Equation 8.15 defines the maximum allowable external pressure, P_o, assuming $P_i = 0$.

EQUATION 8.15 *Maximum allowable external pressure with tensile load - API RP 5C7*

$$P_o = KP_{co}$$

Equation 8.16 shows the calculation for K, the collapse pressure correction factor for tensile load, assuming a safety factor, SF ≥ 1. L is the operating tensile load and L_y is the tensile load required to yield the CT. For the “safety factor” of 0.80 defined earlier, SF = 1.25.

EQUATION 8.16 *API RP 5C7 collapse pressure correction factor for tensile load*

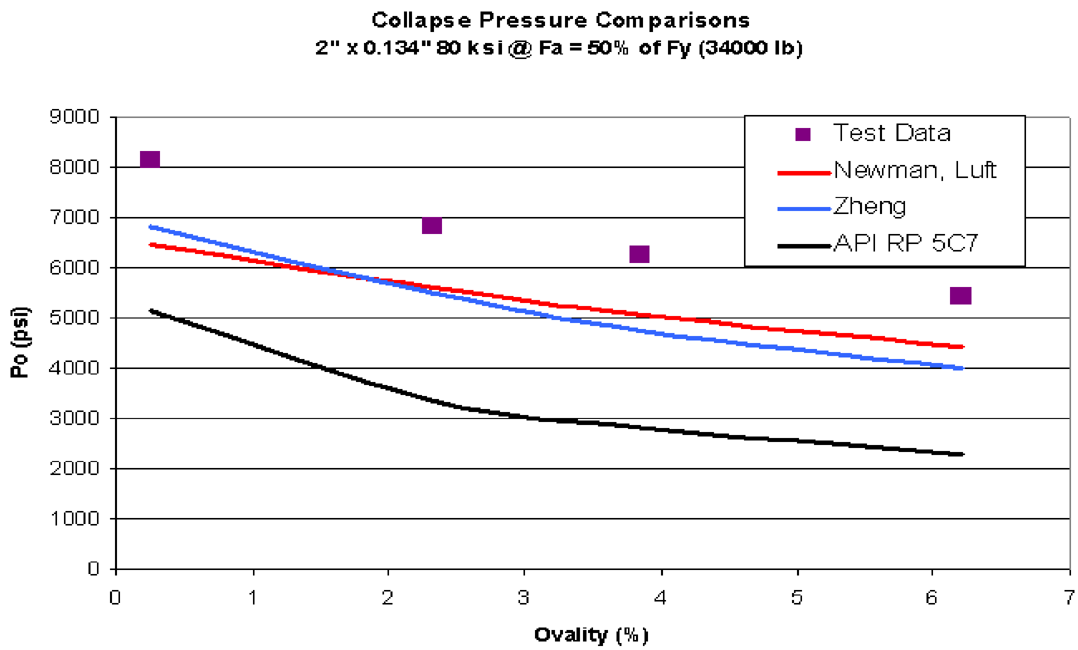
$$K = \left[\left(\frac{1}{SF}\right)^{4/3} - \left(\frac{L}{L_y}\right)^{4/3}\right]^{3/4}$$

Comparison with Measured Collapse

The Newman, Zheng and Luft collapse pressure calculations based upon plastic hinge theory agree much more closely with measured data than does the API RP 5C7 calculation. The following figure shows a comparison of these calculations with test data from Zheng’s work.

6. API Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties

FIGURE 8.7 *Collapse Pressure Comparisons*



The following figures show the Newman plastic-hinge collapse and the API RP 57C collapse along with 80% of the Von Mises yield limit, for real force and for weight. Obviously, API RP 5C7 collapse significantly reduces the working envelop.

FIGURE 8.8 *Collapse Comparison with Real Force*

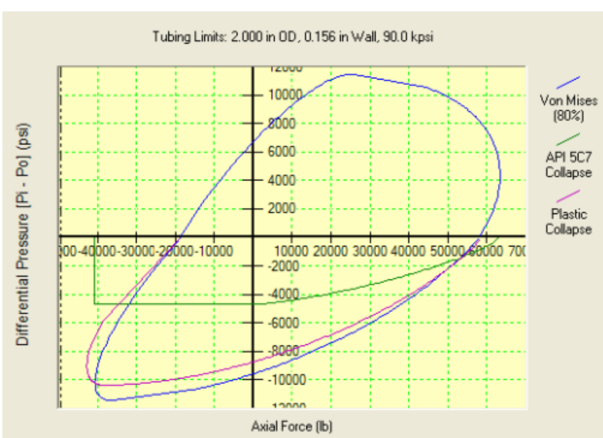
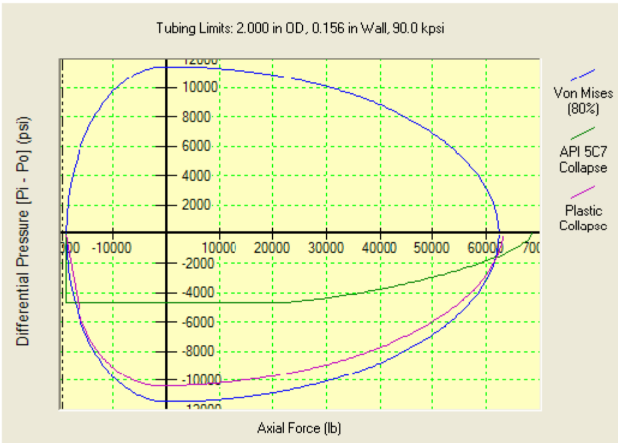


FIGURE 8.9 *Collapse Comparison with Weight (Effective Force)*



9

CT Working Life

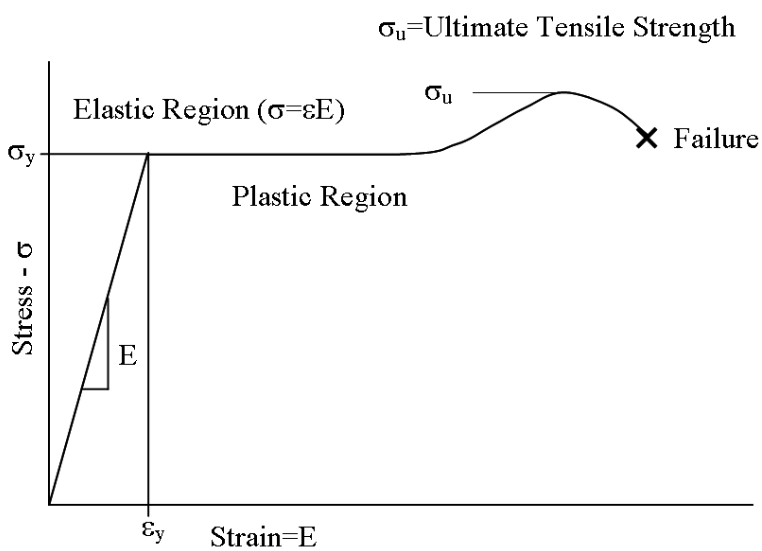
METAL FATIGUE

A metallic object subjected to alternating, dynamic stresses above a threshold level can endure progressive changes to its atomic structure with each cycle of loading. This phenomenon, known as fatigue, is associated with cyclic plasticity that causes systematic changes to the crystalline structure of the metal, and results in the development of microscopic cracks. These tiny cracks propagate incrementally with each cycle, growing in size and linking together to form large cracks that propagate to fracture. The number of cycles required for the crack to nucleate and propagate to failure is referred to as the "fatigue life" of the object.

There is some debate about whether microscopic cracks form and then propagate, or simply propagate from microscopic sizes associated with surface anomalies. However, from an engineering analysis point of view, each cycle of loading is considered to consume some portion of the available fatigue life and adds to a summation of "accumulated fatigue damage." When this quantity accumulates to 100%, failure is expected to occur. Estimating the working life (bending cycles or trips) remaining to failure for a CT string is an important part of designing a CT operation.

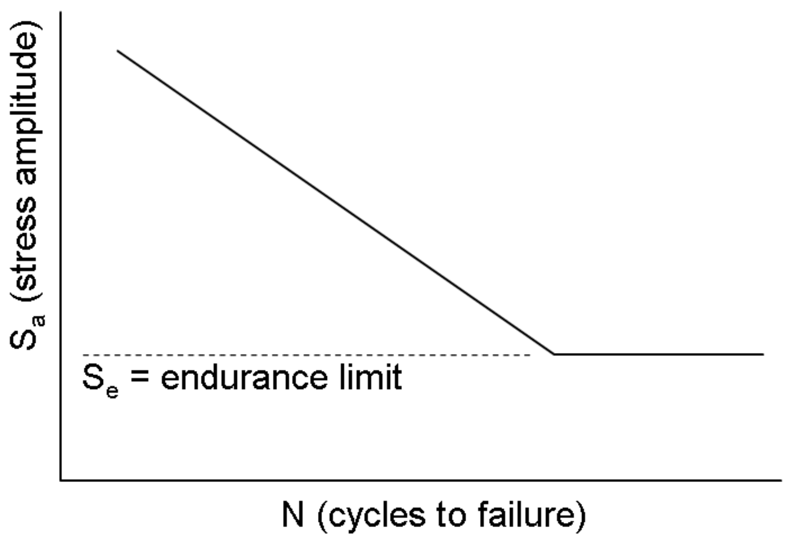
For the vast majority of mechanical design problems, the magnitude of cyclic stress in components subject to fatigue is within the elastic limit. This is the portion of the schematic stress-strain curve in Figure 9.1 labeled "Elastic Region".

FIGURE 9.1 *Elastic vs. Plastic Strain*



In such cases, although the stress state is macroscopically elastic, microscopic plasticity occurs within individual metallic grains that lead to fatigue failure. Fatigue life is estimated for such situations based on data from destructive fatigue tests generated with coupon samples of the component material. Non-destructive fatigue tests do not exist. The tests measure the number of cycles to failure at a given stress amplitude for the subject material. Since the cycles to failure for elastic deformation are extremely high, associated lives are referred to as “high cycle fatigue”. The fatigue lives of engine components and aircraft structures typically lie in this regime.

FIGURE 9.2 *Typical SN Curve*



If the forces acting on an object induce localized stresses and strains above the elastic limit (σ_y and ε_y), shorter fatigue lives can result that are said to lie in the “low cycle regime”. Automotive suspension components are designed in this regime, based on extreme events anticipated in their load history (e.g., curb and pot hole strikes).

If the reversed deformation becomes severe, an object experiences bulk cyclic plasticity well into the portion of the stress-strain curve in Figure 9.1labeled "Plastic Region". Fatigue lives in this "ultra low cycle" regime can be as short as a few to a few hundred cycles. The failure mechanisms in this regime are less well understood since few mechanical components are designed to endure such severe loading. However, CT material endures this loading regime on a routine, daily basis, as sections of tubing are bent and straightened on and off the spool and tubing guide arch.

Furthermore, the cyclic bending loads imposed on CT often occur simultaneously with high internal pressure due fluid being pumped through the tubing. This multiaxial stress state leads to complex plasticity and fatigue interactions described in the next section.

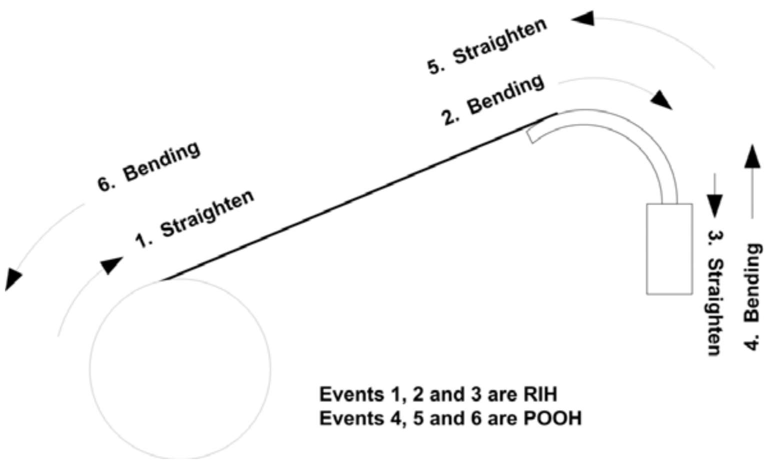
CT FATIGUE

CT begins its life plastically deformed, because it is wound on a reel. Moreover, each round trip into the well and back plastically deforms (bends) the tubing six times. These bending events are:

1. RIH – unwind and straighten from the reel
2. RIH – bend across the guide arch
3. RIH – straighten in the injector
4. POOH – bend onto the guide arch
5. POOH – straighten from the guide arch
6. POOH - wind back onto the reel

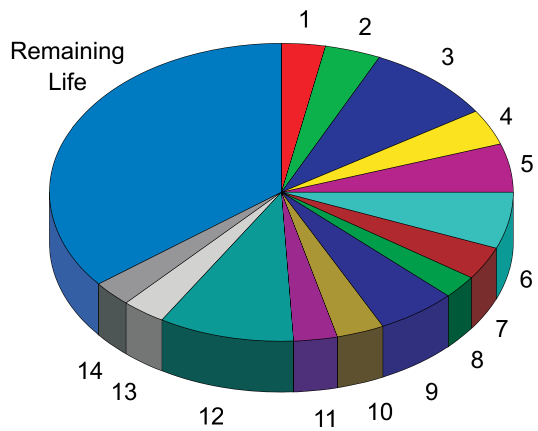
As Figure 9.3 shows, two-thirds of the bending cycles a CT segment experiences during a round trip are due to the guide arch. This does not mean that two-thirds of the fatigue damage occurs at the guide arch, but it does point to a feature of the surface equipment that can be modified to prolong the working life of a CT string. Note that all of the fatigue damage occurs in the surface equipment; none occurs in the well.

FIGURE 9.3 *Locations of CT Plastic Deformations*



The magnitude of plastic deformation with each bending cycle depends on the bending radius, CT dimensions, and material yield strength. Thus, the radius of the guide arch and the diameter of the reel have a profound affect on CT fatigue life. Internal pressure during plastic deformation amplifies the fatigue damage. In order to estimate the accumulated fatigue damage for a segment of CT, one must know the number of bending cycles and magnitude of plastic deformation and pressure at each cycle. Figure 9.4 depicts the working life of a CT segment, its ability to resist failure, as a pie. The whole pie is the working life for a given set of conditions.

FIGURE 9.4 *Accumulation of Fatigue with CT Operations*



The different size wedges indicate the variability of fatigue damage accumulated in a CT segment during successive CT operations. The larger “slices” of damage correspond to more bending cycles, higher pressure, higher plastic stress, or some combination of these factors. The total fatigue damage accumulated in the CT segment is the sum of the damage for operations 1-14. The balance of the pie is the remaining working life or resistance to failure. Furthermore, estimating the remaining working life for a CT segment is impossible without a complete and accurate history of the accumulated fatigue damage. The number of trips corresponding to the remaining life depends not only on the anticipated operating conditions, but also on the operating conditions for each preceeding trip.

Fatigue damage in CT usually starts as a microscopic crack at the inside surface of the wall. This crack propagates through the CT wall until it appears as a pinhole or tiny crack on the outside surface of the CT. Generally, a fatigue failure in CT does not result in a catastrophic failure because operating personnel detect the stream of fluid spurting from the leak. However, a hairline fatigue crack through the CT wall that escapes early detection can quickly grow to a disastrous size. Figure 9.5 shows some examples of CT fatigue failures from lab tests. Note the rippling of the wall on each side of the crack.

FIGURE 9.5 *CT Fatigue Failures from Lab Tests*

CT Fatigue Testing

Fatigue is a statistical phenomenon requiring destructive tests. No two samples of CT are exactly alike, so many tests are required to establish mean failure rates and to characterize the variability in the results. Large-scale testing with actual CT equipment provides realistic operating conditions but is expensive and requires long samples of CT. During 1990, Schlumberger conducted controlled fatigue tests on numerous CT samples using an actual CT unit. These were the first “scientific” tests on CT fatigue to appear in the open literature. Their objectives were two-fold:

- Quantify effects of CT dimensions, guide arch radius, and pressure
- Provide data for validating their fledgling fatigue model, CoilLIFE™

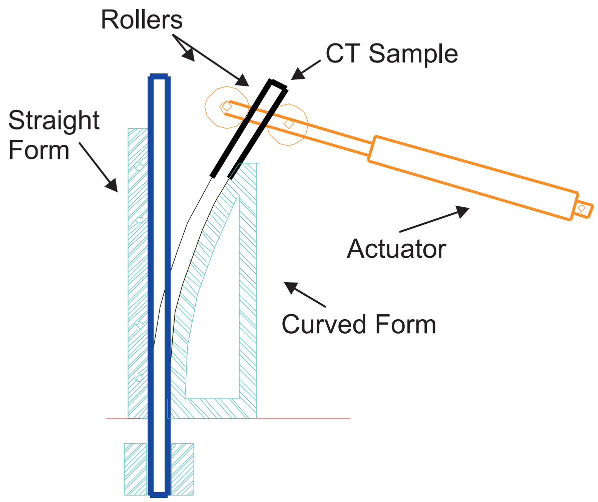
About this same time, BJ Services privately designed, built, and operated a large-scale CT fatigue test machine to aid the development of their proprietary CT fatigue model, CYCLE™. BJ Services test machine consisted of a large-diameter grooved wheel (sheave). They wrapped the CT sample around the wheel like a rope around a pulley and alternately pulled on each end of the sample. The equipment also provided a means to pressurize the CT sample. Late in 1991 Halliburton started their own CT fatigue testing program using actual CT surface equipment.

Small-scale testing is an economical method of providing controlled plastic deformations to short samples of CT. Depending on the fatigue test machine and operating conditions, these small-scale tests can provide a reasonable facsimile of the bending events CT experiences while running through the CT surface equipment. In 1993, Schlumberger coordinated a joint industry project (JIP) with objectives that included:

- Development and operation of a small-scale CT fatigue test machine
- Determination of factors affecting CT fatigue life

Figure 9.6 is a schematic of the CT fatigue test machine (FTM) developed during the JIP[1]. The basic principle is to alternately bend (plastically deform) the CT sample around the curved form then straighten the sample against the straight form. A small pump is used to pressurize the CT sample with water. The simple control system regulated the stroking speed of the actuator and counted the number of bending cycles.

FIGURE 9.6 *FTM Schematic*



The FTM has the following capabilities:

- CT size = 1.25-3.50 in. OD
- CT pressure = 10,000 psi
- Bending radii = 48-72 in.

1. Newman, K.R. and Brown, P.A., "Development of a Standard Coiled-Tubing Fatigue Test", SPE 26539, Annual Technical Conference and Exhibition, Houston, TX, October 3-6, 1993.

A big advantage of the FTM compared to large-scale testing is that it requires a much smaller sample of CT, less than 96 in. Figure 9.7 is a photograph of a FTM built by Stewart and Stevenson as part of the JIP. Both CT mills use this type of machine for routine fatigue testing of their products and for technical service work.

FIGURE 9.7 *FTM*

On the FTM, three complete bending/straightening cycles correspond to a round trip through the CT surface equipment (assuming a guide arch radius is equal to the spool curvature radius). Results from testing with the FTM compare favorably with Schlumberger's full-scale tests. From these small-scale tests, CT fatigue life increases with:

- Increasing guide arch radius
- Increasing reel diameter
- Decreasing internal pressure
- Increasing tubing wall thickness
- Decreasing OD
- Increasing material yield strength (when cycled at high pressure)

Due to reel back tension, the CT is always in tension while plastically deforming in the surface equipment. Also, the CT tends to rotate around its longitudinal axis a few degrees with each round trip into/out of the well. The FTM cannot investigate the effects of these factors on CT fatigue life. In 1997, the Gas Research Institute (GRI) commissioned CTES to develop a new CT test machine (CTTM). The purpose of the CTTM is to simultaneously apply tension, bending, and internal pressure to CT samples while measuring these forces and axial strain. Figure 9.8 is a picture of the CTTM facility. Figure 9.9 and Figure 9.10 show a side view of the bending fixture.

FIGURE 9.8 *CTTM Facility*

FIGURE 9.9 *CTTM Bending Fixture – Sample Straight*

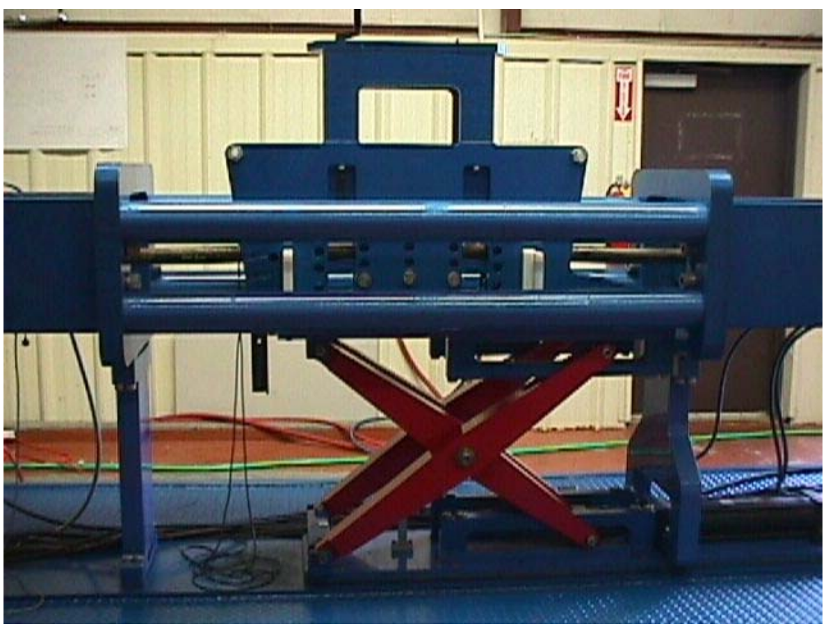
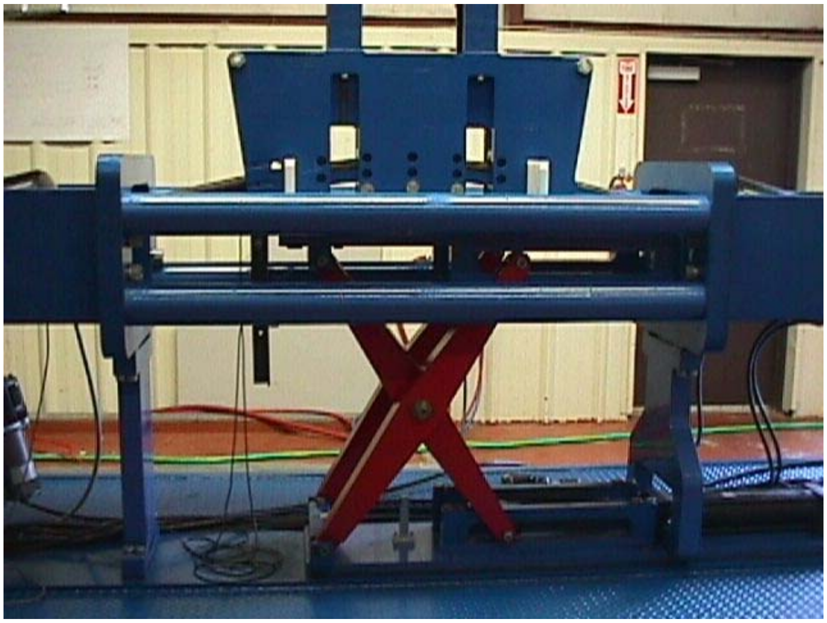


FIGURE 9.10 *CTTM Bending Fixture – Sample Bent*



This machine, which became operational in mid-1998, has the following capabilities:

1. CT OD = 1.25 in.- 3.50 in.
2. Tension
   - During bending = 10,000 lbs
   - Without bending = 200,000 lbs
3. Sample maximum internal pressure = 10,000 psi
4. Bending to yield = 3.5 in. OD x 0.25 in. wall CT, 100 kpsi material
5. Bending radii
   - 1.25 in. - 1.50 in. CT = 48 in.
   - 1.75 in. - 2.38 in. CT = 72 in.
   - 2.88 in. - 3.50 in. CT = 100 in.
6. Rotation of CT sample about longitudinal axis (azimuth increment = 10º)
7. Short CT sample length (nominally 109 in.)
8. Automatic or manual control

9. One-man operation

10. No welding on CT sample (hydraulically-operated slips)

To reiterate, the only valid method for measuring the fatigue life of a CT sample is to subject it to cyclic plastic deformations until it fails. Therefore, all fatigue tests are destructive tests. Unfortunately, conducting such tests on CT samples removed from the free end of a used CT string does not indicate anything about the remaining fatigue life of segments at other locations in the string. Each segment in the string has experienced a different history of plastic deformations and pressure. Thus, numerous CT fatigue models have been developed to predict the accumulated fatigue damage in a CT segment.

CT Fatigue Modeling

The CT industry has three different fatigue models to determine the working life of CT. These models were developed by:

- Steve Tipton of the University of Tulsa
- Vladamir Avakov of Halliburton
- BJ Services

CTES uses Tipton's model in the Cerberus™ software (non-Halliburton version). Schlumberger uses Tipton's model for CoilLIFE™. The Halliburton version of Cerberus™, Tubing Analysis Software by Medco, and Maurer Engineering software use Avakov's model. The BJ Services model is proprietary to BJ.

The objective for each fatigue model is to predict the remaining working life for a segment of CT:

- At any location in a string of varying properties
- After a complex sequence of bending events
- Subjected to changing pressure conditions

Numerous factors affect the ability of these models to accomplish this objective, including the:

- Accuracy of the fatigue model itself
- Accuracy of the input data
- Completeness of the operational history for the CT string
- Accounting (tracking) method used to apply the fatigue model to a CT string

The input to these models includes:

- Initial accumulated fatigue damage
- Locations of physical damage (dents, corrosion, scrapes, etc.)
- CT diameter
- CT wall thickness
- Locations of welds (bias and butt)
- Bending radius for each bending event
- Pressure inside the CT at each bending event

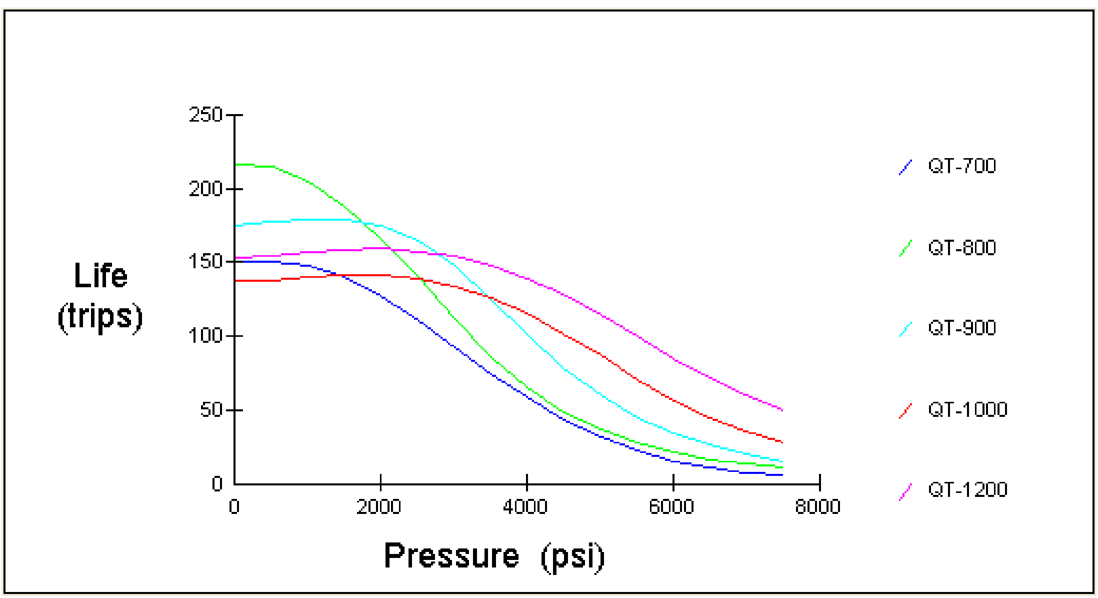
- CT material properties
- Number of bending events

Plasticity theory is the basis for Tipton's fatigue model. This theory uses a damage algorithm to determine the relationship between strain or stress and the reduction in the ability of a CT segment to support additional forces.

Figure 9.11 through Figure 9.18, produced from Tipton's fatigue model, show the effects of various factors on CT fatigue life in terms of trips to failure. A trip means the three bending events for RIH plus the three bending events for POOH. Failure for all of the figures except Figure 9.12 is crack initiation, meaning the first appearance of a crack in the material. Figure 9.12 compares this failure mode to the pressure loss failure criterion where a pinhole leak in the CT first appears.

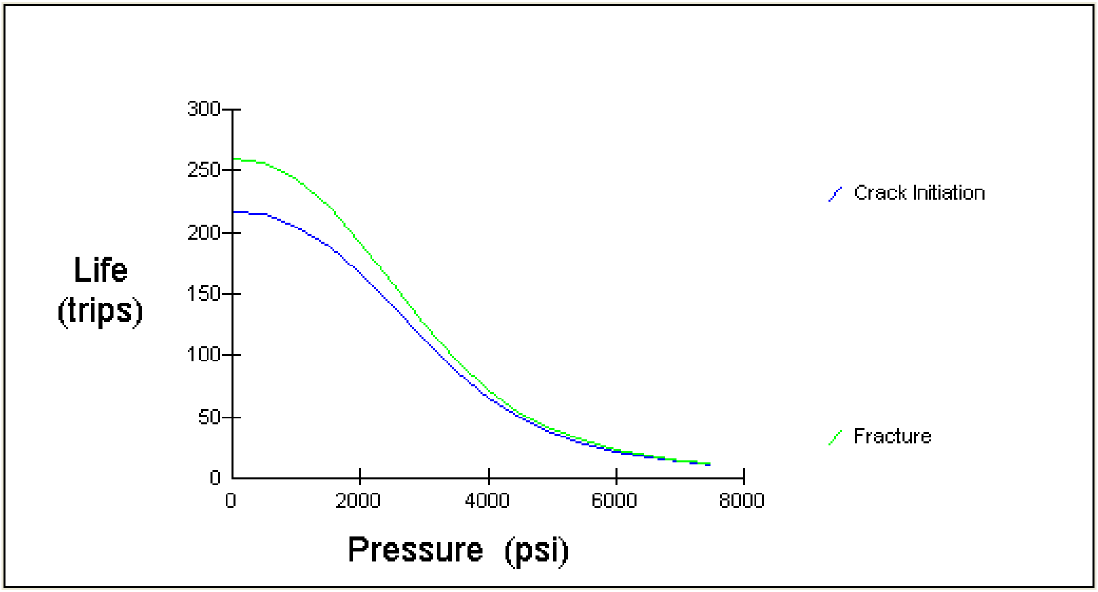
NOTE: These graphs do not include any safety factor and are meant for qualitative use only. Also, these graphs assume starting with virgin CT.

FIGURE 9.11 *Effect of Yield Strength on CT Fatigue Life*



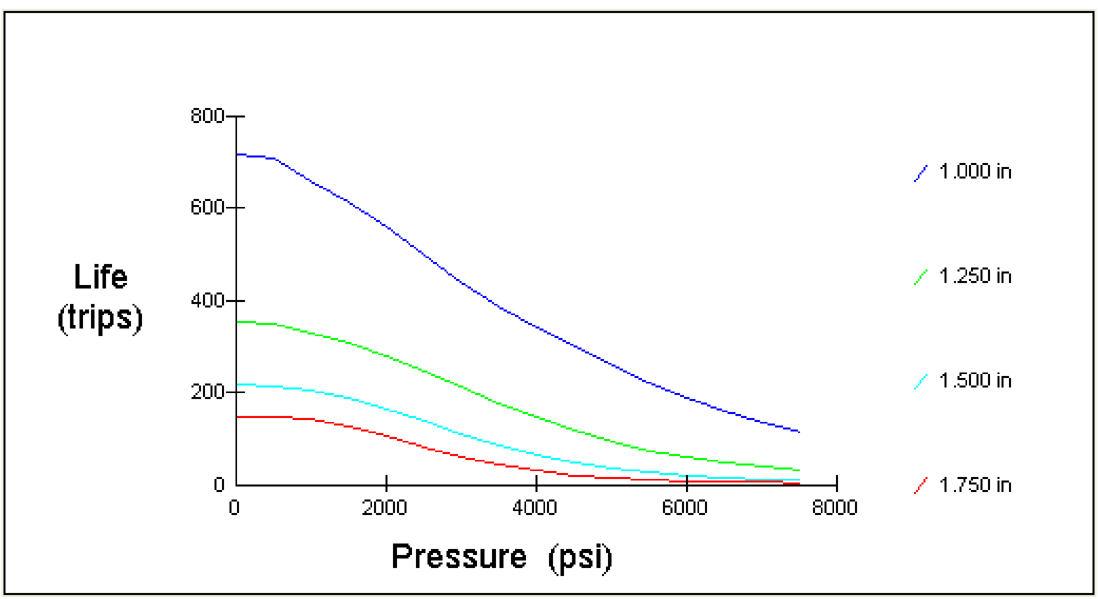
CT Diameter :	1.500 in	Reel Diameter :	84 in	Material :	(varies)
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.12 *Effect of Failure Criterion on CT Fatigue Life*



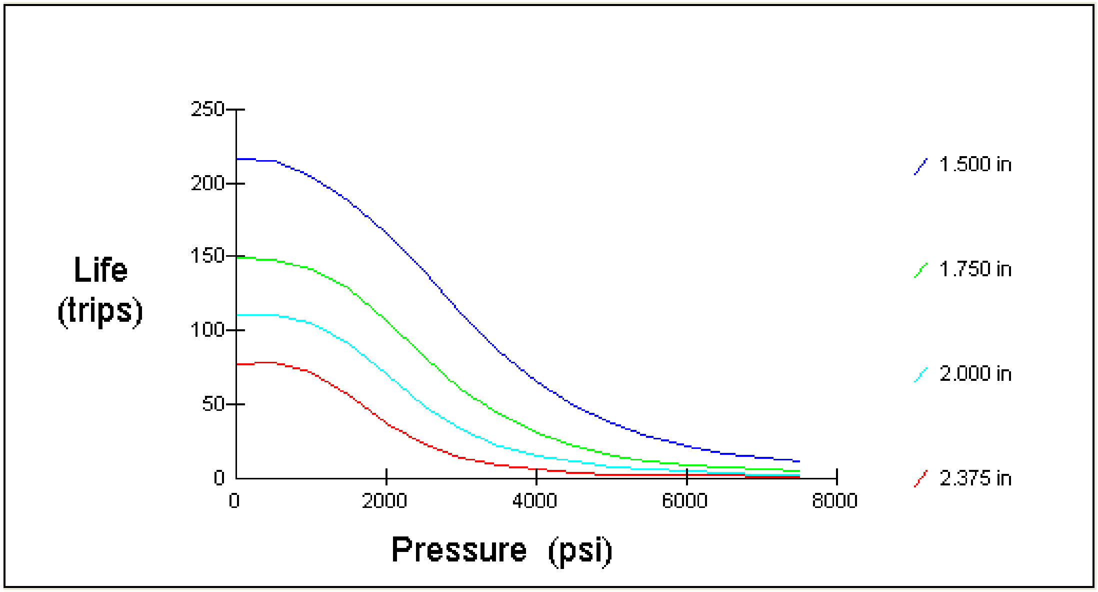
CT Diameter :	1.500 in	Reel Diameter :	84 in	Material :	QT-800
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	(varies)

FIGURE 9.13 *Effect of OD on CT Fatigue Life for OD < 2.0 in.*



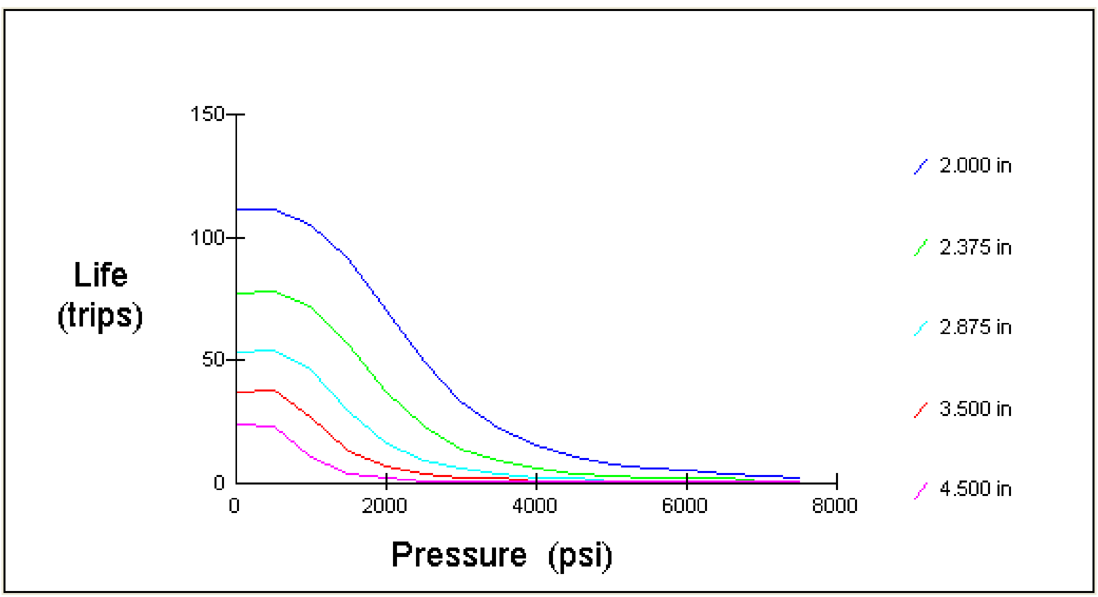
CT Diameter :	(varies)	Reel Diameter :	84 in	Material :	QT-800
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.14 *Effect of OD on CT Fatigue Life for Medium Size Tubing*



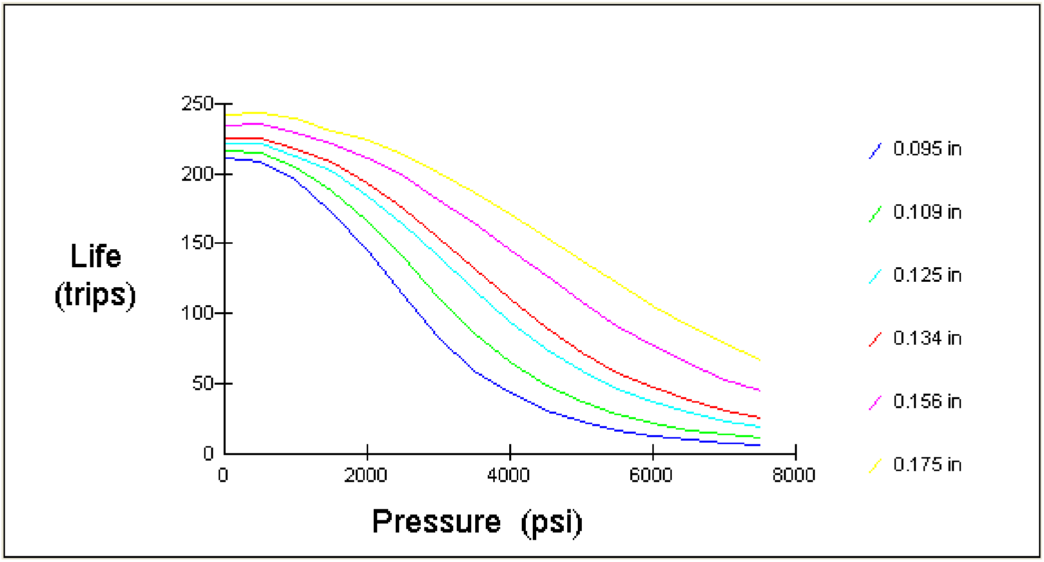
CT Diameter :	(varies)	Reel Diameter :	84 in	Material :	QT-800
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.15 *Effect of OD on CT Fatigue Life for Large Tubing*



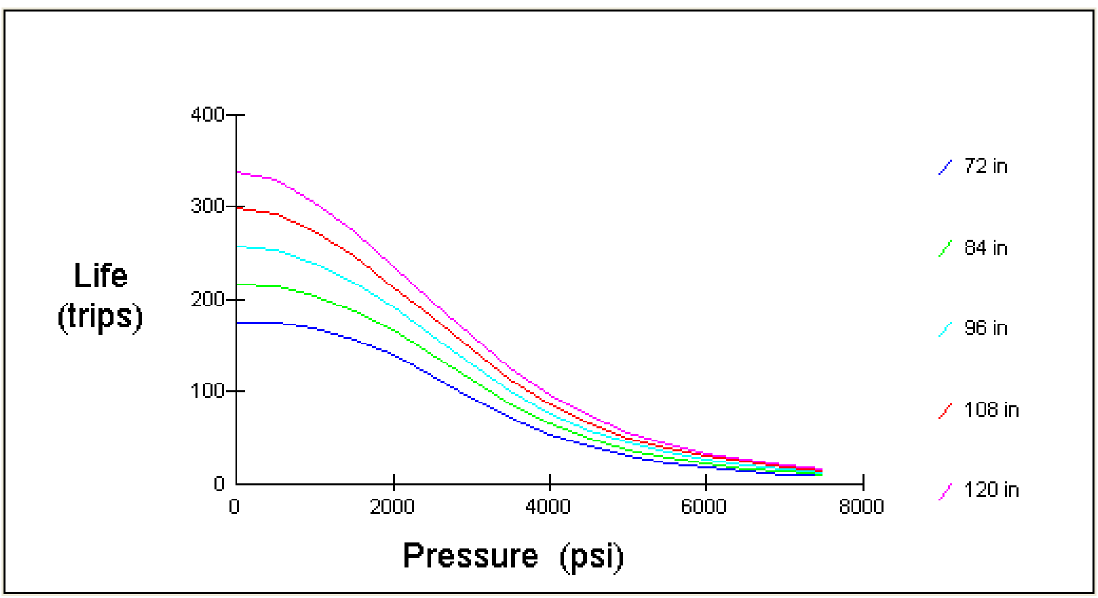
CT Diameter :	(varies)	Reel Diameter :	84 in	Material :	QT-800
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.16 *Effect of Wall Thickness on CT Fatigue Life*



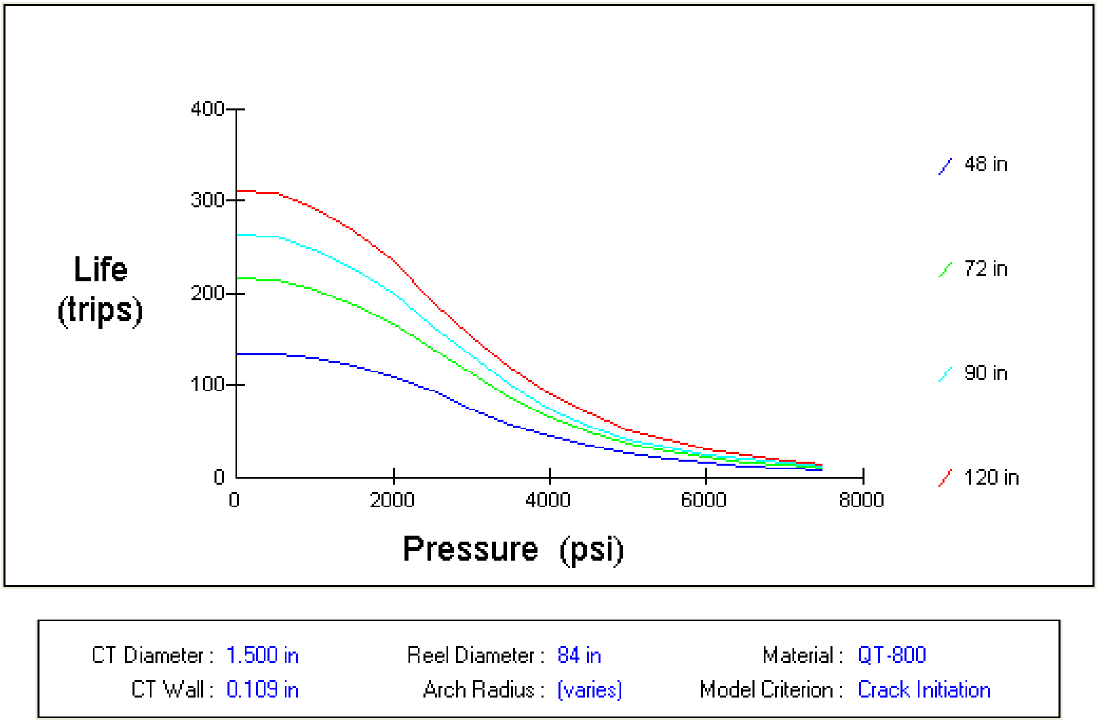
CT Diameter :	1.500 in	Reel Diameter :	84 in	Material :	QT-800
CT Wall :	(varies)	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.17 *Effect of Reel Diameter on CT Fatigue Life*



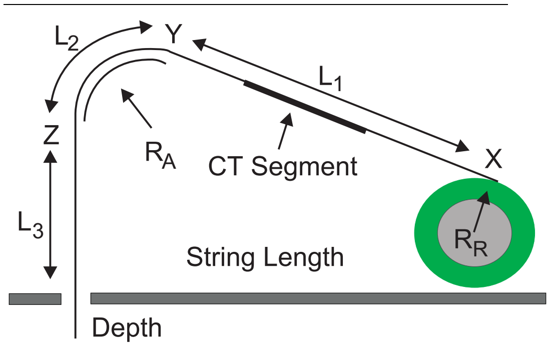
CT Diameter :	1.500 in	Reel Diameter :	(varies)	Material :	QT-800
CT Wall :	0.109 in	Arch Radius :	72 in	Model Criterion :	Crack Initiation

FIGURE 9.18 *Effect of Guide Arch Radius on CT Fatigue Life*



Advanced fatigue modeling software like Reel-Trak™ from CTES divides a CT string into manageable segments and applies the fatigue model (Achilles™) to each segment in order to determine the distribution of fatigue along the string. Based on the geometry of the surface equipment, the location of the segment in the CT string, and the current CT depth, the model tracks the position of each segment relative to the bending locations. The software activates the fatigue model whenever the segment is between the reel and the stripper and increments the fatigue damage to the segment. Figure 9.19 is a schematic of a fatigue model in operation. The figure indicates the information describing the geometry of the surface equipment.

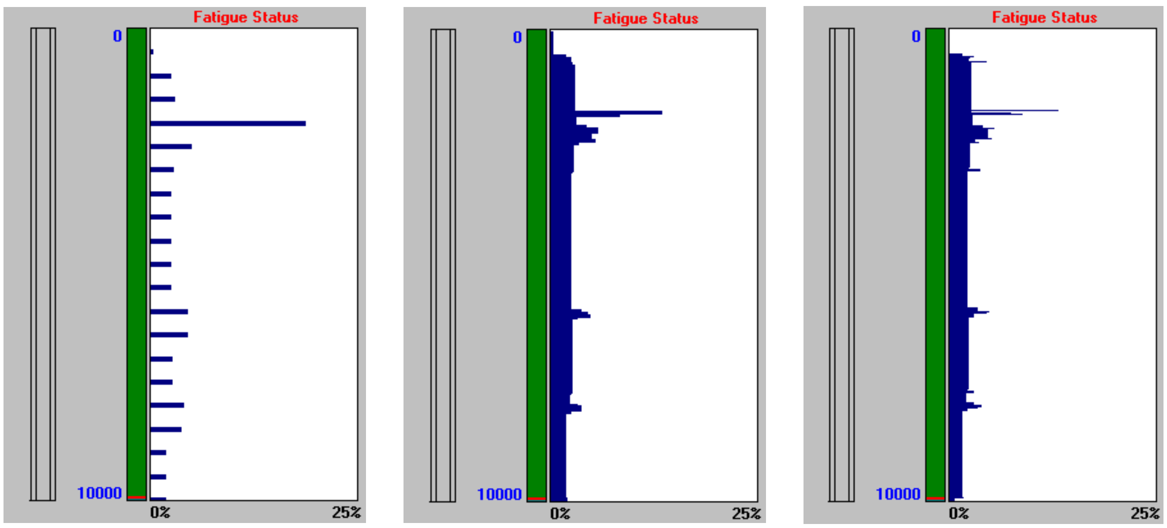
FIGURE 9.19 *Segment Tracking Schematic*



The software follows each CT segment from the reel through the injector and back again. Most fatigue modeling software operates off-line with data input manually. Advanced fatigue monitoring software like Reel-Trak™ can operate on-line with a data acquisition system like Orion™ to provide real-time information about accumulated fatigue in a CT string. Either way, the CT segment length determines the resolution or detail in the result. Figure 9.20 shows the effects of segment length on the fatigue distribution displayed to the operator.

FIGURE 9.20 *Effect of CT Segment Length on Fatigue Monitoring*

500 ft segments   50 ft segments   5 ft segments



Minimizing CT Fatigue

Both fatigue testing and computer modeling show that CT working life increases with:

- Increasing tubing wall thickness
- Decreasing tubing OD
- Increasing guide arch radius
- Increasing reel diameter
- Decreasing internal pressure
- Increasing material yield strength (at low pressure, higher stresses are generated in higher strength tubing that can cause shorter fatigue lives)

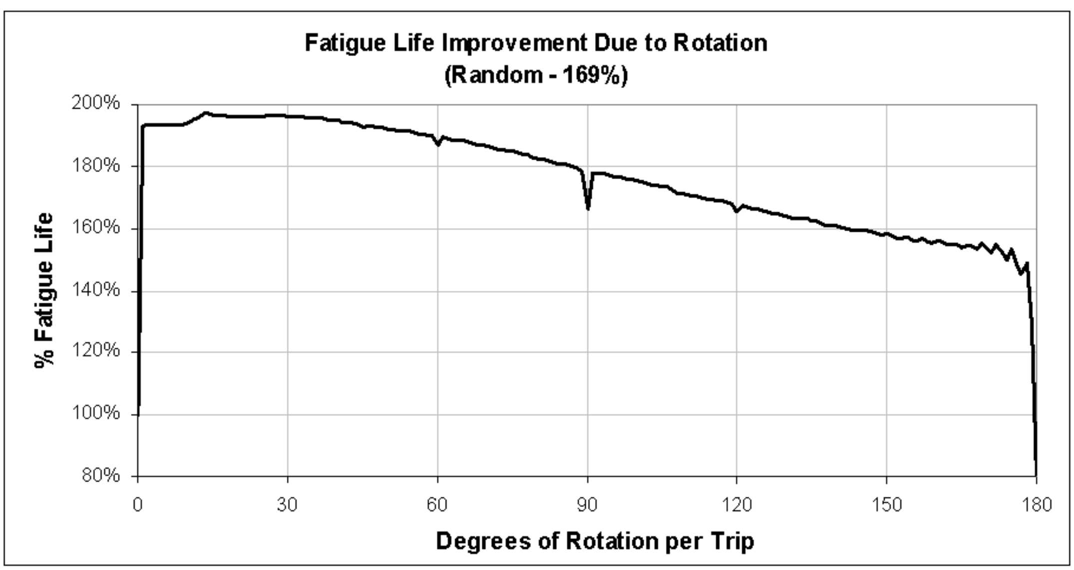
A CT operator can take several practical steps to minimize the risk of CT fatigue failure including:

- Reducing CT internal pressure during trips

- Minimize cycling the same segment and and off the spool
- Using the largest reel diameter available
- Designing CT strings with the thickest wall possible
- Using the largest guide arch radius possible
- Using the highest yield strength material possible when operating at high pressures

Any operation that repeatedly cycles a given segment of tubing on and off of the spool (short-cycling) significantly increases the risk of fatigue failure in that segment. Such an operation concentrates fatigue damage over a relatively short length of tubing. Pumping through the CT during short-cycling compounds this fatigue damage. Regularly cutting a length of tubing from the free end can greatly prolong the service of a string by moving the most heavily fatigued CT away from the source of the damage, the surface equipment.

Current fatigue models ignore the fact that the CT rotates during its life. They assume that the CT does not rotate, which is usually the worst case scenario. SPE 60737 shows that the CT does indeed rotate, and gives an estimate of the increased fatigue life due to this rotation. Figure 1 from that reference[2] shows the estimated increase in fatigue life assuming that the CT rotates a fixed amount on each trip. For example, if a given section of the CT rotated 30°, the fatigue life of that section of CT will increase from 100% without rotation to 195% with rotation.



2. Newman, K.R., Stein, D., and Ackers, M., “Rotation of Coiled Tubing”, SPE 60737, SPE/ICoTA Coiled Tubing Roundtable held in Houston, TX, 5-6 April 2000.

Thus the current fatigue models are conservative by an unknown amount due to unknown rotation. If the CT happens to rotate exactly 180º on each trip, the fatigue life will actually be decreased, but this is highly unlikely.

Data Acquisition

As was mentioned above, accurate input data is required for fatigue modeling to be accurate. During a CT operation the depth and pumping pressure must be recorded by a data acquisition system. This recorded data is then used by the fatigue model to calculate the percentage of the fatigue life used in the string.

CTES has developed the Orion data acquisition system that work with the Reel-TrakTM modeling software to calculate the fatigue along a string. More than 150 of these systems are now working around the world.

Cost Savings

A CT fatigue tracking system, including the data acquisition system and modeling software, saves significant amounts of money. Intelligent decisions can be made about how to improve the fatigue life, and when to scrap the CT. The following figures give an example of a CT string that was used for CT drilling. Problems were encountered in the first job which caused excessive fatigue in one portion of the string as shown in Figure 9.21. A portion of this string was identified based upon the fatigue plot, shown in Figure 9.22, and removed. The remaining two sections of the string were welded together with a resulting string as shown in Figure 9.23. This operation resulted in a large cost savings to the service company.

FIGURE 9.21 *Highly Fatigued String from CT Drilling Operation*

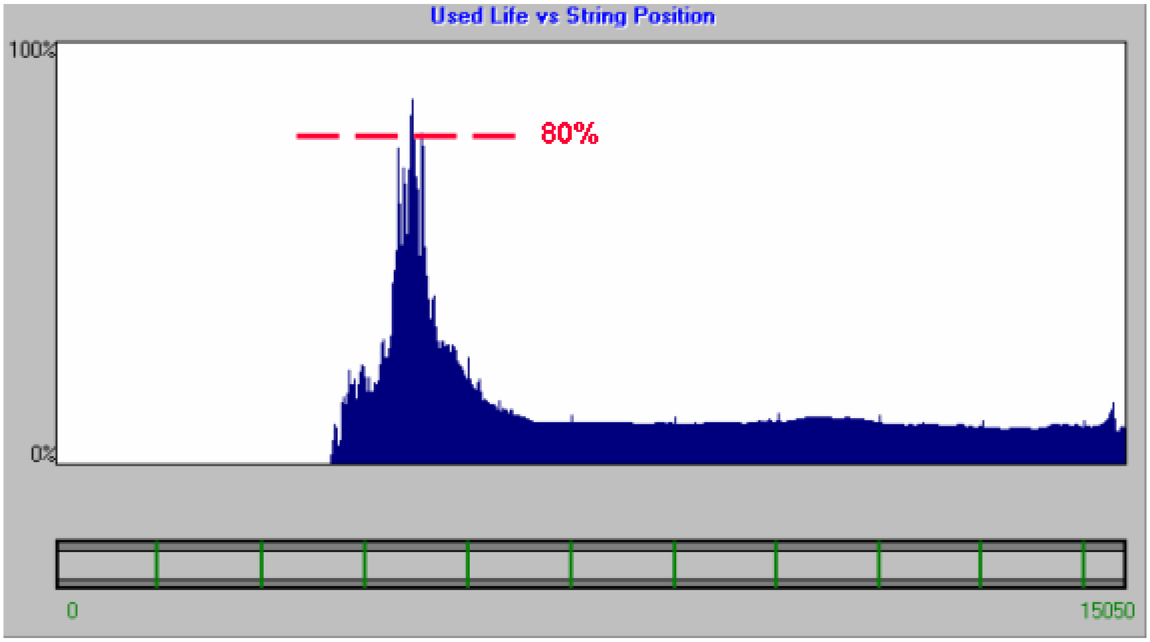


FIGURE 9.22 *Section with Excessive Fatigue Damage Identified*

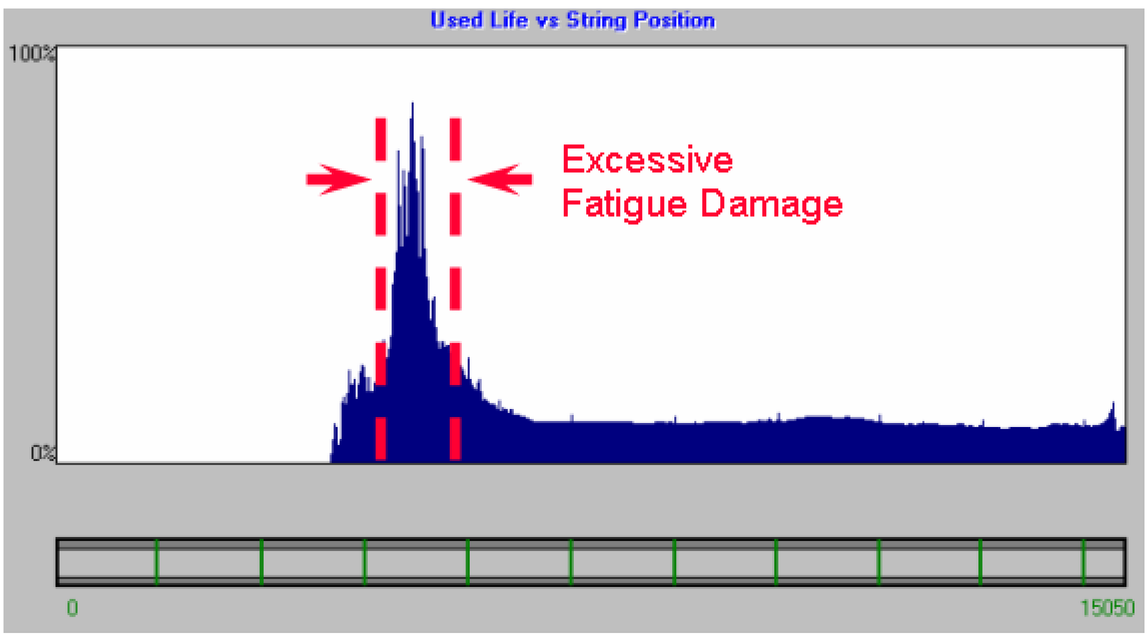
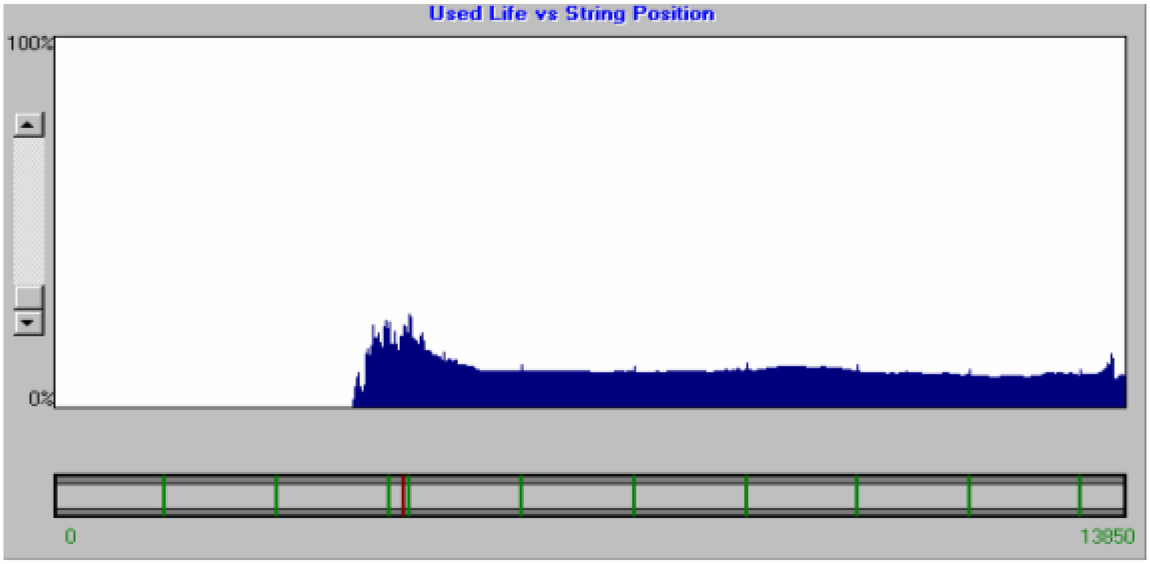


FIGURE 9.23 *CT String with Excessive Damage Removed and Weld Repair Added*



Monitoring Tubing Life with Running Feet

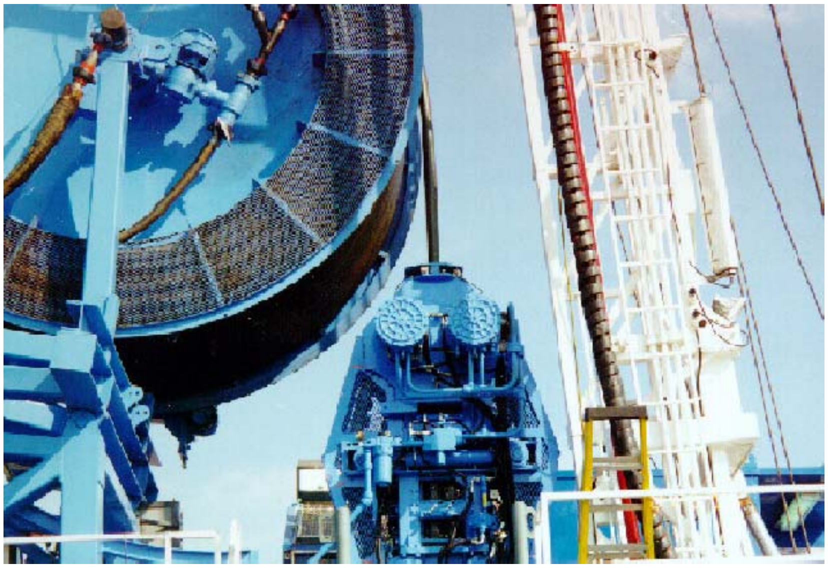
The life of the tubing is dictated by several factors that included internal pressure, gooseneck radius, reel dimensions, erosion, corrosion are just a few. There are a several methods used in determining the tubing life, these include tracking pressure cycles or monitoring running feet. Tracking pressure cycles is a more accurate method, but tedious when doing the excise by hand. The other method of monitoring running feet is an accepted practice when the works-cope, equipment and environment are similar. The key in using this method (running feet) is consistency between the jobs. If jobs are significantly different, the reliability of monitoring running feet is reduced and a large safety margin must be utilized. Check the Operations Manual and local guidelines when using this method.

The options for changing the geometry of CT surface equipment used for typical workover operations are fairly limited because most of the equipment manufacturers offer only “standard” models. CT equipment designed for special applications like drilling is a different matter. Figure 9.24 shows one solution for enlarging the guide arch radius. BHI designed a 20-ft radius for their *Copernicus* CTD rig.

FIGURE 9.24 *Extreme Guide Arch Radius for Reducing CT Fatigue Damage*

Transocean decided to eliminate the guide arch entirely from their CDR #1 (*Chameleon*) CTD rig. The CT unwinds directly from the large-diameter reel into the top of the injector head. Figure 9.25 shows this unique combination of features that dramatically increases the working life of their CT strings. The reel tilts toward or away from the vertical axis of the injector to keep the CT properly aligned with the chains and moves back and forth on its axis of rotation to perform the function of a level wind.

FIGURE 9.25 *Large-Diameter Reel and Elimination of the Guide Arch for Reducing CT Fatigue Damage*



BHI developed another solution for minimizing CT fatigue for their Galileo #2 CTD rig, by using what has become known in the industry as a "parabolic arch". Figure 9.26 shows the giant reel (approximately 24 ft diameter) with a small injector on the level wind and the main injector operating in concert to maintain a stable free-standing arch in the CT. This system eliminates the need for a conventional guide arch, and the small guide arch in the picture does not cause any plastic deformation in the CT. The CT does not undergo plastic deformation except at the reel. The large bending radius of the parabolic arch causes little or no plastic strains.

FIGURE 9.26 *A CT Parabolic Arch Minimizes Fatigue Damage*

BHI implemented parabolic arches on three Galileo CTD rigs. Figure 9.27 and Figure 9.28 show two of these implementations. In general, a parabolic arch reduces the fatigue damage to about one third of the damage that would occur with a conventional guide arch arrangement.

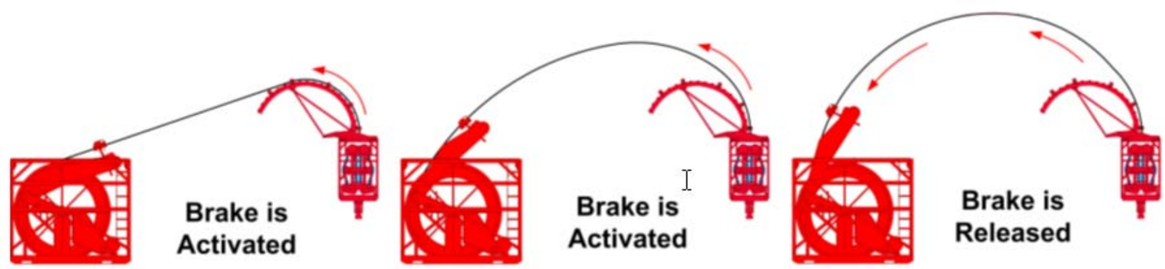
FIGURE 9.27 *Parabolic Arch - BHI Barge on Lake Maracaibo*

FIGURE 9.28 *Parabolic Arch - BHI CT Drilling Rig in Oman*

Another system was developed to reduce the fatigue induced by repetitive movements over a small interval. A few examples of these operations are fishing, window milling, multi-laterial re-entry and downhole manipulations. The benefit of this system is its ability to eliminate the major fatigue peaks by allowing the pipe to cycle up and down without inducing any plastic deformation. The system works by keeping the reel in a stationary position while making small movements. Depending on the circulating pressure and pipe movement schedule, the fatigue can be reduced by 10 to 15%. This reduction in pipe fatigue only occurs at the peak points where small movements occur, but is normally the highest fatigue areas and usually determines when the string is scrapped.

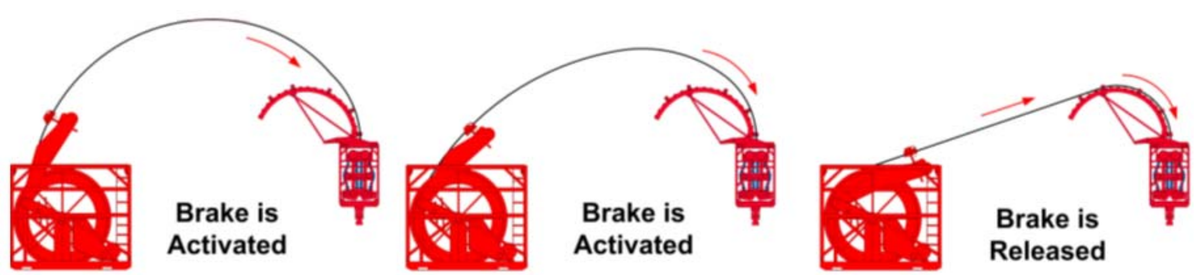
The systems works by activating a brake system on the levelwind assembly that stops the reel from spooling, see Figure 9.29. As the pipe is POOH, the tubing lifts off the gooseneck and a continuous arch is formed between the injector head and reel. When the upper limit is reached, the reel speeds up to match the speed of the injector head.

FIGURE 9.29 *Steps when POOH*



When the system is RIH after forming a continuous arch between the reel and injector head, the arch is height is reduced until the tubing rest on the gooseneck and the system is run in the conventional way, Figure 9.30.

FIGURE 9.30 *Steps when RIH*



10 CT Hydraulic Performance

THE FUNDAMENTAL HYDRAULICS CHALLENGE

A large number of CT operations involve pumping some type of fluid(s) into a well. Such operations include:

- Removing fill or sand (liquid and foam)
- Unloading a well with nitrogen
- Stimulating a formation (liquid and foam)
- Removing scale (high pressure jetting)
- Abrasive jet cutting (abrasive in a liquid)
- Isolating zones (cement and resin)
- Pumping slurry plugs
- Drilling/milling
- Gravel packing
- Fracturing

The fundamental challenge in each case is to pump fluid(s) through a long, small-diameter tube, some of which is wound on a reel, with enough flow rate or pressure to perform a specified task. The solution to this challenge appears simple enough; provide adequate hydraulic horsepower (flow rate and pressure) at the reel inlet. The engineer must determine the pump pressure (P_{pump}) required for a given flow rate or the flow rate provided by a given pump pressure.

The governing equation for this problem is straightforward.

EQUATION 10.1 *Pump pressure*

$$P_{pump} = P_{bottomhole} - P_{hydrostatic} + P_{losses}(+P_{safety\,margin}) + P_{injection}$$

The subscript “bottomhole” refers to the formation pressure at the bottom end of the CT string. The subscript “hydrostatic” refers to the pressure exerted by the fluid in the annulus when the fluid is static. Equation 10.2 is the general form of the equation for calculating hydrostatic pressure in a fluid.

EQUATION 10.2 *Hydrostatic pressure in a static fluid – general form*

$$P_{hydrostatic} = \frac{\rho g h}{g_c}$$

where ρ is the average fluid density, g is the local gravitational acceleration, h is the vertical height of the fluid, and g_c is the universal gravitational constant. Equation 10.3 presents the calculation for hydrostatic pressure in typical oilfield terms and units.

EQUATION 10.3 *Hydrostatic pressure in a static fluid – typical oilfield units*

$$P_{hydrostatic}(psi) = TVD(ft) \times MW(ppg) \times 0.052$$

The subscript "losses" refers to frictional pressure losses around the flow path. Equation 10.4 is the general form for calculating frictional pressure loss in a conduit.

EQUATION 10.4 *Frictional pressure loss in a conduit – general form*

$$\Delta P = f_H \left(\frac{\rho V^2 L}{2 D_e} \right)$$

where f_H is the hydraulic friction factor (see Section "The Relationship Between Pressure and Flow Rate" and Section "Hydraulic Friction Factor for Straight Tubes"), V is the average or bulk fluid velocity, L is the length of the conduit, and D_e is the equivalent hydraulic diameter of the conduit.

Equation 10.5 describes the pressure losses around the flow path.

EQUATION 10.5 *Pressure losses for the flow path*

$$P_{losses} = P_{surface} + P_{CT} + P_{BHA} + P_{annulus}$$

The subscripts in Equation 10.5 identify the portions of the flow path from the pump to the choke in the return line at the surface.

Accurately predicting the relationship between flow rate and pressure is a tough challenge despite the variety of methods published in the open literature. Discrepancies between predicted and measured hydraulic performance may be due to several factors including:

- Improper hydraulic model

- Ignoring extra pressure loss of tubing on the reel
- Poor characterization of fluid(s) properties
- Wireline or control lines inside the CT
- Effects of temperature and shear on the fluid properties
- Fluid path thru BHA

The following sections describe a general procedure for estimating pressure loss in the CT string. The same procedure can be applied to jointed pipe and annuli by substituting the appropriate equivalent hydraulic diameter for the ID of the CT.

THE RELATIONSHIP BETWEEN PRESSURE AND FLOW RATE

A convenient way to relate pressure loss to flow rate for CT is through a hydraulic friction factor as in Equation 10.6. The concept is similar to the relationship between drag and friction coefficient for sliding friction. Equation 10.6 is the general form for CT hydraulic friction factor that applies to both straight and curved tubing.

EQUATION 10.6 *Hydraulic friction factor for CT*

$$f_H = 2\left(\frac{\Delta P}{L}\right)\left(\frac{OD - 2t}{\rho V^2}\right)$$

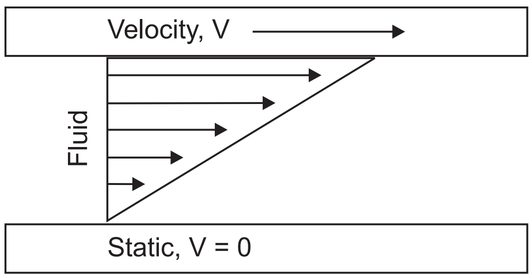
L is the length of tubing contributing to ΔP, ρ is fluid density, and V is the average fluid velocity in the tubing. Determining f_H means simply measuring ΔP for a range of flow rates and applying Equation 10.6. The empirical relationship between f_H and flow rate can be used to estimate ΔP at any flow rate in the measured range (extrapolation is not wise) assuming the fluid's properties are constant.

However, during the planning phase of CT operations, this relationship is unknown, and f_H must be modeled. The model for f_H depends on the rheological model for the fluid, the flow regime, and the geometry of the CT (straight or on the reel). The following sections describe commonly-used fluid models for CT applications.

Fluid Rheological Models

The literature offers a selection of fluid rheological models that might apply for CT operations. For liquids these include Newtonian, Bingham plastic, power law, and Herschel-Buckley. Each model relates the shear stress (τ) in a fluid to the shear rate (γ). Figure 10.1 is a simplistic representation between τ and γ for two flat plates separated by a fluid. Assuming the fluid does not slip at the solid boundary, τ is the force per unit area on each plate caused by their relative movement V, and γ is the rate of change in V across the gap.

FIGURE 10.1 *Representation of τ and γ for two flat plates separated by a fluid*



In a couette viscometer, such as a Fann VG meter, the static plate is the inner cylinder (bob) connected by torsion spring to the dial and the moving plate is the outer cylinder (rotor). The shear stress is the dial reading, and the shear rate is proportional to the rotor rpm.

Newtonian Fluid

The Newtonian model describes the rheological behavior of many pure liquids such as water, brines, acids, and hydrocarbons.

Equation 10.7 describes the simple linear relationship between shear stress and shear rate for a Newtonian fluid. The constant of proportionality, μ, is the absolute viscosity. Generally, μ depends on the temperature, and for compressible liquids, it depends on the pressure as well.

EQUATION 10.7 *Newtonian fluid model*

$$\tau = \mu \times \gamma$$

Power Law Fluids

Fluids containing suspended solids or polymers require a different model, because the relationship between τ and γ is decidedly non-linear. A model that adequately describes many such fluids is the power law model, Equation 10.8.

EQUATION 10.8 *Power law fluid model*

$$\tau = K \times \gamma^n$$

The parameter K is the consistency index and n is the flow behavior index. When $n = 1$, Equation 10.8 reduces to the Newtonian model with $\mu = K$. Fluids with $n < 1$ are known as pseudoplastic fluids. These fluids become less viscous with increasing shear rate or mixing. Typical examples are fluids containing xanthan gum (XC polymer), bentonite, or hydroxy ethyl cellulose (HEC). Dilatant fluids have $n > 1$ and display increasing viscosity with increasing shear rate. Such fluids are rare in the petroleum industry, but an example is a slurry having a higher volume fraction of solid than liquid.

Bingham Plastic Fluids

The relationship between shear stress and shear rate for a Bingham plastic fluid can be written as

EQUATION 10.9 *Bingham plastic fluid model*

$$\tau = \tau_y + \mu_p \gamma$$

where τ_y and μ_p are the yield stress and plastic viscosity respectively. Like power law fluids, Bingham plastic fluids have a non-linear relationship between shear stress and shear rate. Note that when yield stress is zero (0), Equation 10.9 reduces to the Newtonian model described by Equation 10.4.

The three fluid models presented above can adequately describe the rheological behavior for most of the liquids used in CT operations. However, f_H also depends on the flow regime. The next section introduces the concept of a dimensionless quantity, the Reynolds number, which can be used to determine the flow regime.

REYNOLDS NUMBER

In the 1880's, an English engineer named Osborne Reynolds proposed that the ratio of inertial force to viscous force would indicate whether a fluid flow was laminar (parallel stream lines) or turbulent (mixing or transverse flow). Equation 10.10 shows the dimensionless number that bears his name.

EQUATION 10.10 *Reynolds Number for Newtonian fluids*

$$N_{\mathrm{Re}} = \frac{\text{inertial force}}{\text{viscous force}} = \frac{V \times ID \times \rho}{\mu}$$

Based on his observations of dye injected into various Newtonian fluid flows, Reynolds determined that such flows are laminar when $N_{Re} < 2100$ and fully turbulent when $N_{Re} > 2900$. Between these two extremes is an unpredictable regime of transitional flow that exhibits characteristics of both. Although developed for flow inside cylinders, Equation 10.10 applies reasonably well to certain other cross sections where ID is the diameter of a circle with the same flow area. Example 0.1 calculates N_{Re} for a simple Newtonian fluid (water) flowing inside CT.

EXAMPLE 0.1 *Reynolds number calculation for Newtonian fluid*

Problem: Calculate the Reynolds number for a Newtonian fluid.

Assumptions	Calculations
• OD = 1.75 in and t = 0.134 in. • ρ = 8.4 ppg (62.83 lb_m/ft^3) • μ = 1.0 cp (6.72 x 10^{-4} lb_m/ft-sec) • Q = 50 gpm	• ID = OD-2t = 0.124 ft • A = 0.0120 ft^2 • V = Q/A = 9.301 ft/sec $N_{\mathrm{Re}} = \frac{V \times ID \times \rho}{\mu} = 107{,}832$ The lower limit for turbulent flow is 2900, therefore, the flow is highly turbulent.

The Reynolds number for power law fluids is much more complicated than the Newtonian case.

EQUATION 10.11 *Reynolds number for power law fluids*

$$N_{\text{Re}} = \frac{\rho V^{(2-n)}(OD-2t)^n}{K8^{(n-1)}}\left(\frac{4n}{3n+1}\right)^n$$

For power law fluids, the flow is laminar when N_{Re} < (3470-370n) and turbulent when N_{Re} > (4270-1370n). Note that Equation 10.11 reduces to Equation 10.10 with K = μ when n = 1. Also, the transition values become 2100 and 2900 for n = 1. Example 0.2 shows a calculation of Reynolds number for a power law fluid.

EXAMPLE 0.2 *Reynolds number calculation for power law fluid*

Problem: Calculate the Reynolds number for a power law fluid.

Assumptions	Calculations
• OD = 1.75 in., t = 0.134 in. • Q = 50 gpm • ρ = 8.6 ppg (64.32 lb_m/ft^3) • n = 0.669 • K = 0.1942 $lb_f\text{-}sec^n/100ft^2$	• ID = OD-2t = 0.124 ft • A = 0.0120 ft^2 • V = Q/A = 9.301 ft/sec $N_{\text{Re}} = \frac{\rho V^{(2-n)}(OD-2t)^n}{K8^{(n-1)}}\left(\frac{4n}{3n+1}\right)^n = 9102$ The lower limit for turbulent flow = 4270-1370 x 0.669 = 3353. Therefore, the flow is turbulent.

Equation 10.12 can be used to calculate the Reynolds for Bingham plastic fluids by replacing the absolute viscosity with the plastic viscosity.

EQUATION 10.12 *Reynolds number for Bingham plastic fluid*

$$N_{RE} = \frac{V \times ID \times \rho}{\mu_p}$$

The criterion for turbulence of a Bingham plastic fluid is dependent on another dimensionless number called the Hedstrom number. In consistent units, the Hedstrom number[1] is

EQUATION 10.13 *Hedstrom number for Bingham plastic fluids*

$$He = \frac{\rho \tau_y D_e^2}{\mu_p^2}$$

Simultaneous solution of the following two equations gives the critical Reynolds number for Bingham plastic fluids[2].

EQUATION 10.14 *Equation A for calculating Bingham plastic critical Reynolds number*

$$\frac{\left(\frac{\tau_y}{\tau_w}\right)}{\left(1 - \frac{\tau_y}{\tau_w}\right)^3} = \frac{He}{16800}$$

EQUATION 10.15 *Equation B for calculating Bingham plastic critical Reynolds number*

$$\mathrm{Re}_{cr} = \frac{1 - \frac{4}{3}\left(\frac{\tau_y}{\tau_w}\right) + \frac{1}{3}\left(\frac{\tau_y}{\tau_w}\right)^4}{8\left(\frac{\tau_y}{\tau_w}\right)} He$$

Here, τ_w is the wall shear stress. One solves Equation 10.14 and Equation 10.15 iteratively to determine the critical Reynolds number. The flow is laminar if $Re < Re_{cr}$ and turbulent if $Re > Re_{cr}$.

1. Bourgoyne Jr., A. T., Millheim, K. K., Chenevert, M. E., Young Jr., F. S.: “Applied Drilling Engineering,” *SPE Textbook Series, Vol. 2* (1991).
2. Hanks, R. W. and Pratt, D. R.: “On the Flow of Bingham Plastic Slurries in Pipes and Between Parallel Plates,” *Soc. Pet. Engg. J.* (Dec., 1967), 342-346.

HYDRAULIC FRICTION FACTOR FOR STRAIGHT TUBES

Equation 10.16 shows the hydraulic friction factor for Newtonian, power law, and Bingham plastic fluids in straight tubes.

EQUATION 10.16 *f_H for fluids in straight tubes*

$$f_{HS} = \frac{a}{N_{\mathrm{Re}}^{b}}$$

For laminar flows, a = 16 and b = 1.0. For turbulent flows, Equation 10.17 and Equation 10.18 calculate a and b respectively. The flow behavior index, n, has the value of 1 for Newtonian and Bingham plastic fluids.

EQUATION 10.17 *Coefficient “a” for f_H calculation*

$$a = \frac{\log_{10} n + 3.93}{50}$$

EQUATION 10.18 *Exponent “b” for f_H calculation*

$$b = \frac{1.75 - \log_{10} n}{7}$$

EXAMPLE 0.3 f_H *Calculation for a Newtonian fluid*

Problem: Calculate the hydraulic friction factor for a Newtonian fluid.

Assumptions: same as Example 0.1

n = 1

$$a = \frac{\log_{10} n + 3.93}{50} = 0.0786$$

$$b = \frac{1.75 - \log_{10} n}{7} = 0.25$$

From Example 0.1, N_{Re} = 107,832.

Therefore,

$$f_{HS} = \frac{a}{N_{\text{Re}}^{b}} = 0.0043$$

EXAMPLE 0.4 f_H *Calculation for a power law fluid*

Problem: Calculate the hydraulic friction factor for a power law fluid.

Assumptions: same as Example 0.2

n = 0.669

$$a = \frac{\log_{10} n + 3.93}{50} = 0.0751$$

$$b = \frac{1.75 - \log_{10} n}{7} = 0.2749$$

From Example 0.2, N_{Re} = 9102.

Therefore,

$$f_{HS} = \frac{a}{N_{\text{Re}}^{b}} = 0.0061$$

HYDRAULIC FRICTION FACTOR FOR CT ON THE REEL

Experimental and theoretical work on flows in curved pipes first appeared in the literature during the 1920's. Of the numerous formulas in the public domain derived for Newtonian fluids flowing in curved pipes, Equation 10.19 gives hydraulic friction factors for CT on a reel that agree closely with measured values.[3]

EQUATION 10.19 *f_H for Newtonian fluids in CT on a reel*

$$f_{HC} = \frac{0.084}{N_{\mathrm{Re}}^{0.2}}\left(\frac{OD - 2t}{D_{reel}}\right)^{0.1}$$

where
D_{reel} = the reel's core diameter

Generalizing Equation 10.19 to power-law fluids gives Equation 10.20.[3]

EQUATION 10.20 *Generalized f_H for power law fluids in CT on a reel*

$$f_{HC} = \frac{1.069a}{N_{\mathrm{Re}}^{0.8b}}\left(\frac{OD - 2t}{D_{reel}}\right)^{0.1}$$

Equation 10.20 gives hydraulic friction factors for power law fluids that agree closely with measured values.

3. McCann, R.C. and Islas, C.G.: "Frictional Pressure Loss during Turbulent Flow in Coiled Tubing," SPE 36345 presented at the 1996 SPE/IcoTA North American Coiled Tubing Roundtable, Montgomery, TX (Feb. 26-28, 1996).

EXAMPLE 0.5 f_{HC} *Calculation for a Newtonian fluid*

Problem: Calculate the hydraulic friction factor for a Newtonian fluid on the reel.

Assumptions: same as Example 0.1 with D_{reel} = 100 in.	From Example 0.1, N_{Re} = 107,832.
	Therefore,
$a = \dfrac{\log_{10} n + 3.93}{50} = 0.0786$	$f_{HC} = \dfrac{0.084}{N_{\mathrm{Re}}^{0.2}} \left(\dfrac{OD - 2t}{D_{reel}} \right)^{0.1} = 0.0054$
$b = \dfrac{1.75 - \log_{10} n}{7} = 0.25$	

EXAMPLE 0.6 f_{HC} *Calculation for a power law fluid*

Problem: Calculate the hydraulic friction factor for a power law fluid on the reel.

Assumptions: same as Example 0.2 with D_{reel} = 100 in.	From Example 0.2, N_{Re} = 9102.
	Therefore,
$a = \dfrac{\log_{10} n + 3.93}{50} = 0.0751$	$f_{HC} = \dfrac{1.069a}{N_{\mathrm{Re}}^{0.8b}} \left(\dfrac{OD - 2t}{D_{reel}} \right)^{0.1} = 0.0071$
$b = \dfrac{1.75 - \log_{10} n}{7} = 0.2749$	

Taking the ratio of Equation 10.20 and Equation 10.16 gives the relationship between ΔP for CT on a reel compared to ΔP for the same length of straight tubing.

EQUATION 10.21 *Relationship between ΔP on a reel and straight tube*

$$\frac{\Delta P_C}{\Delta P_S} = 1.069 N_{\mathrm{Re}}^{0.2b} \left(\frac{OD - 2t}{D_{reel}} \right)^{0.1}$$

From Equation 10.21, the effect of curvature increases with increasing flow rate (N_{Re}) and decreasing reel core diameter (increasing curvature). Typical CT reels have core diameters in the range 84-108 in. Equation 10.19 and Equation 10.20 show that ΔP for a given flow rate varies less than 3% across this range. Therefore, the actual reel diameter and position of the tubing on the reel are less important than the fact that ΔP in tubing on a reel is significantly higher (20-40%) than ΔP for the equivalent length of straight tubing.

PRESSURE LOSSES IN GASES

Gases are compressible and behave according to the real gas law, expressed as

EQUATION 10.22 *Real gas law*

$$\frac{P}{\rho} = ZRT$$

where Z is the compressibility factor, R is the gas constant, and T is the temperature of the fluid. Using Equation 10.22 in the differential form of the mechanical energy balance yields an expression for the friction pressure loss of gases in conduits[4]

EQUATION 10.23 *Friction pressure loss for gases*

$$\Delta P_{fg}^{s} = P_1^2 - P_2^2 = f\left(\frac{L}{D_e}\right)\left(\frac{\dot{m}^2 ZRT}{g_c A^2}\right)$$

where $\dot{m}$ is the mass flow rate of gas and A is the cross-sectional area of the conduit (pipe or annulus). Unlike most liquids where the density is independent of pressure, gas density is a strong function of pressure and changes with location along the flow path.

Most gases are Newtonian in their fluid behavior and thus can be described by Equation 10.7. However, gas viscosity is a function of both pressure and temperature. One can estimate the viscosity of pure gases or gas mixtures from the following equation.

EQUATION 10.24 *Dimensionless reduced viscosity*

$$\mu^{\#} = \mu / \mu_o$$

4. McClain, C. H.: “Fluid Flow in Pipes,” The Industrial Press, New York (1952).

Here, μ is the gas viscosity at a given pressure and temperature, and μ_o is the gas viscosity at atmospheric pressure and the same temperature as a function of dimensionless reduced temperature and pressure[5]. The reduced pressure and temperature can be evaluated from the critical properties of the gas.

The criterion for turbulence in gas flow is similar to that of Newtonian fluids. Use Equation 10.10 to calculate the Reynolds number for gas flow by replacing the liquid viscosity with the gas viscosity. Use Equation 10.16 through Equation 10.18 to calculate f_H for gas flow. Currently, no friction factor correlation is available for the flow of gases in CT on the reel.

5. Carr, N. L., Kobayashi, R., Burrows, D. B.: "Viscosity of Hydrocarbon Gases under Pressure," *Trans. AIME* 201 (1954), 264-272.

PRESSURE LOSSES IN FOAMS

Foams are multiphase fluids composed of liquid(s), a gas, and a surfactant (foaming agent). Their rheological behavior is similar to that of Bingham plastic fluids. Foams can be water-based or oil-based depending on the liquid phase. The gas phase is usually nitrogen, but air and carbon dioxide can also be used. The gas phase exists as microscopic bubbles and may occupy 10-95% of the total foam volume. The ratio of volume fraction of gas (V_g) to the total volume of foam (V) is the foam quality (q) defined as:

EQUATION 10.25 *Foam quality*

$$q = \frac{V_g}{V}$$

Since gas is compressible, the quality of foam depends on both temperature and pressure. Thus, the foam quality varies with location in the flow path.

For practical purposes, one can express the rheological behavior of foams in terms of an effective viscosity[6] (μ_e) per the following equation.

EQUATION 10.26 *Effective viscosity for foams*

$$\mu_e = \mu_{foam} + \frac{g_c \tau_y D_e}{6v}$$

Here μ_{foam} is the plastic foam viscosity, a function of q. For $q < 0.52$, the gas exists as uniformly dispersed, non-interacting spherical bubbles in the liquid medium. For such cases, Equation 10.27 adequately describes the plastic foam viscosity as

EQUATION 10.27 *Plastic foam viscosity, q < 0.52*

$$\mu_{foam} = \mu_l (1 + 2.5q)$$

6. Blauer, R. E., Mitchell, B. J., and Kohlhaas, C. A.: "Determination of Laminar, Turbulent, and Transitional Foam Flow Losses in Pipes," SPE 4885 presented at the 44th Annual California Regional Meeting of the Society of Petroleum Engineers of AIME, San Francisco, CA (Apr. 4-5, 1974).

where μ_l is the viscosity of the liquid phase. For 0.52 < q < 0.74, the spherical gas bubbles interact with one another during flow, and the expression for plastic foam viscosity is

EQUATION 10.28 *Plastic foam viscosity, 0.52 < q < 0.74*

$$\mu_{foam} = \mu_l (1 + 4.5q)$$

When q > 0.74, the gas bubbles deform from spheres to parallelepipeds, and the expression for plastic foam viscosity is

EQUATION 10.29 *Plastic foam viscosity, q > 0.74*

$$\mu_{foam} = \mu_l \frac{1}{1 - q^{1/3}}$$

Use Equation 10.27 through Equation 10.29 in Equation 10.26 to evaluate the effective foam viscosity. The yield stress of the foam (τ_y) in Equation 10.26 is zero for q < 0.52. However, for q > 0.52, τ_y depends on q.

Equation 10.30 gives the "rule of mixtures" for calculating the foam density (ρ_{foam}), where ρ_ε is the density of the gas phase from the real gas law (Equation 10.22).

EQUATION 10.30 *Foam density*

$$\rho_{foam} = \rho_l (1 - q) + \rho_g q$$

Use the foam properties from Equation 10.25 through Equation 10.30 with Equation 10.10 and Equation 10.16 to calculate the pressure loss of foam in straight CT. No friction factor correlation is available for foam flowing in curved tubing.

PRESSURE LOSSES IN LIQUID-GAS FLOWS

The bases for calculating pressure losses of liquid-gas flows in straight CT are correlations developed for two-phase flow through production tubing. Currently, no correlations exist for two-phase flows in curved tubing. Four two-phase flow models have gained widespread acceptance in the petroleum industry:

- Duns and Ros (1963)
- Hagedorn and Brown (1965)
- Orkiszewski (1967)
- Beggs and Brill (1973)

Although most of these were developed for upward, two-phase flow in production tubing, they have been adapted to downward flow through tubing and upward flow through an annulus. The following four sections summarize the main features of these correlations. A detailed explanation of each is beyond the scope of this manual.

The density and viscosity of multiphase fluids can be evaluated by the simple "rule of mixtures" where *H* is the liquid hold-up or volume fraction of the pipe occupied by the liquid phase. The subscripts *s* and *ns* below refer to slip and non-slip, respectively, between the phases of the mixture.

EQUATION 10.31 *Two-phase fluid density with slip*

$$\rho_s = \rho_l H_s + \rho_g (1 - H_s)$$

EQUATION 10.32 *Two-phase fluid density without slip*

$$\rho_{ns} = \rho_l H_{ns} + \rho_g (1 - H_{ns})$$

EQUATION 10.33 *Two-phase fluid viscosity with slip*

$$\mu_s = \mu_l H_s + \mu_g (1 - H_s)$$

EQUATION 10.34 *Two-phase fluid viscosity without slip*

$$\mu_{ns} = \mu_l H_{ns} + \mu_g (1 - H_{ns})$$

Evaluation of liquid hold-up is a critical part of the multiphase computations. Liquid hold-up depends on the flow regime. In vertical flow, the flow regimes are usually bubble, slug, froth, transition, and mist. In horizontal flow, flow regimes are usually segregated, intermittent, transition, and distributed.

Duns and Ros Correlation

The Duns and Ros correlation[7] is for vertical flow of gas and liquid mixtures in wells. Although the correlation was developed for “dry” oil/gas mixtures, it can be applied to wet mixtures with a suitable correction. For water contents less than 10%, the Duns-Ros correlation (with a correction factor) reportedly gives acceptable results in the bubble, slug (plug), and froth regions.

The liquid hold-up calculation in the Duns and Ros model involves defining a slip velocity (v_s) as

EQUATION 10.35 *Slip velocity for Duns and Ros correlation*

$$v_s = \frac{S}{(\rho_l / \sigma_l g)^{0.25}}$$

In this equation, S is the dimensionless slip velocity and depends on the flow regime. One can calculate the liquid hold-up from

EQUATION 10.36 *Liquid hold-up for Duns and Ros correlation*

$$H_s = \frac{(v_s - v_m) + \left[(v_m - v_s)^2 + 4 v_s v_{sl}\right]^{1/2}}{2 v_s}$$

Equation 10.37 defines the multiphase mixture velocity.

EQUATION 10.37 *Multiphase mixture velocity*

$$v_m = v_{sl} + v_{sg}$$

7. Duns, H., Jr. and Ros, N. C. J.: “Vertical Flow of Gas and Liquid Mixtures in Wells,” *Proc. Sixth World Pet. Congress,* Frankfurt (Jun. 19-26, 1963) Section II, Paper 22-PD6.

However, in the mist flow regime, the correlation assumes both liquid and gas phases move at the same velocity without any slippage, so *S* is zero. In that case, the liquid hold-up is the non-slip hold-up defined as

EQUATION 10.38 *Non-slip hold-up for Duns and Ros correlation*

$$H_{ns} = \frac{v_{sl}}{v_m}$$

In bubble and slug flow, use the liquid viscosity (μ_l) to calculate the Reynolds number from Equation 10.10. In mist flow, use the gas viscosity (μ_g) to calculate the Reynolds number from Equation 10.10. Calculate the single-phase friction factor from Equation 10.16. The Duns and Ros correlation uses this single-phase friction factor, the pipe diameter number given by Equation 10.39, and the superficial gas and liquid velocities to calculate a two-phase friction factor:

EQUATION 10.39 *Pipe diameter number for Duns and Ros correlation*

$$N_D = D_e \sqrt{(\rho_l g / \sigma)}$$

Hagedorn and Brown Correlation

Hagedorn and Brown used data obtained from a 1500 ft vertical well to develop a correlation for two-phase flows[8]. Their correlation is independent of flow pattern and uses the multiphase mixture density (ρ_s) calculated from Equation 10.31. However, to compute the friction pressure loss using Equation 10.4, replace the density term with the mixture density from Equation 10.40.

EQUATION 10.40 *Mixture density for Hagedorn and Brown correlation*

$$\rho_m = \frac{\rho_{ns}^2}{\rho_s}$$

8. Hagedorn, A. R. and Brown, K. E.: “Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small Diameter Vertical Conduits,” *J. Pet. Tech.* (Apr. 1965) 475-484.

In order to compute the two-phase friction factor, calculate a two-phase Reynolds number using Equation 10.10 with the non-slip mixture density (ρ_{ns}), mixture velocity (v_m), and a multiphase mixture viscosity defined as

EQUATION 10.41 *Multiphase mixture viscosity for Hagedorn and Brown correlation*

$$\mu_m = \mu_l^{H_s} * \mu_g^{1-H_s}$$

One can calculate the friction factor from Equation 10.16 using this two-phase Reynolds number.

Orkiszewski Correlation

The Orkiszewski correlation is valid for vertical two-phase flow[9]. In the bubble flow regime, the liquid hold-up is

EQUATION 10.42 *Liquid hold-up in the bubble flow regime*

$$H_s = 1 - 0.5\left[1 + \frac{v_m}{v_s} - \sqrt{\left[(1 + v_m / v_s)^2 - 4v_{sg} / v_s\right]}\right]$$

Here, the slip velocity, v_s, is assumed to be a constant value of 0.8 ft/sec. Use the liquid hold-up to calculate the Reynolds number from

EQUATION 10.43 *Reynolds number for Orkiszewski correlation*

$$\mathrm{Re} = \frac{\rho_l v_{sl} D_e}{\mu_l H_s}$$

In the slug flow regime, the computation of two-phase fluid properties is somewhat different than the other models. The following equation defines the mixture density for slug flow in terms of a bubble velocity (v_b) as

9. Orkiszewski, J.: “Predicting Two-Phase Pressure Drops in Vertical Pipe,” *J. Pet. Tech.* (Jun. 1967), 829-838.

EQUATION 10.44 *Mixture density for Orkiszewski correlation*

$$\rho_s = \frac{\rho_l (v_{sl} + v_b) + \rho_g v_{sg}}{v_m + v_b} + \rho_l \Gamma$$

where Τ is the liquid distribution coefficient evaluated using the data from the Hagedorn and Brown model. The bubble velocity in Equation 10.44 is a function of the bubble Reynolds number and the Newtonian Reynolds number given by

EQUATION 10.45 *Bubble Reynolds number for Orkiszewski correlation*

$$\mathrm{Re}_b = \frac{\rho_l v_b D_e}{\mu_l}$$

EQUATION 10.46 *Liquid Reynolds number for Orkiszewski correlation*

$$\mathrm{Re}_l = \frac{\rho_l v_m D_e}{\mu_l}$$

The calculation procedure for v_b is iterative, and beyond the scope of this text. The friction pressure loss in the slug flow regime is

EQUATION 10.47 *Friction pressure loss for slug flow*

$$\Delta P_f^s = f \ \frac{\rho_l v_m^2 L}{2 g_c D_e} \left[\left(\frac{v_{sl} + v_b}{v_m + v_b} \right) + \Gamma \right]$$

where *f* is calculated from Equation 10.16 using the Reynolds number from Equation 10.46.

Beggs and Brill Correlation

Unlike the other three two-phase flow models presented above, the Beggs and Brill correlation was developed for tubing strings in inclined wells and pipelines[10]. This correlation resulted from experiments using air and water. For all flow patterns, the hold-up at any inclination angle (θ) can be expressed in terms of the hold-up when the pipe is horizontal (θ=π/2) as

EQUATION 10.48 *Hold up at any inclination for Beggs and Brill correlation*

$$H_s(\theta) = H_s(\theta = \pi/2) * \Psi$$

The ψ term is a correction factor accounting for the effect of pipe inclination. The hold-up that would exist at the same conditions in a horizontal pipe is:

EQUATION 10.49 *Equivalent holdup in a horizontal pipe for Beggs and Brill correlation*

$$H_s(\theta = \pi/2) = \frac{c_1 H_{ns}^{c_2}}{Fr^{c_3}}$$

Here, H_{ns} is the non-slip hold-up and C_i is a constant determined from the flow pattern. Equation 10.50 gives the correction factor as

EQUATION 10.50 *Correction factor for Beggs and Brill correlation*

$$\Psi = 1 + C\left[\sin(1.8\phi) - 0.333\sin^3(1.8\phi)\right]$$

where $\phi = \theta - \pi/2$ is the angle from the horizontal. For vertical upward flow ($\theta = \pi$, $\phi = \pi/2$), ψ takes the form

EQUATION 10.51 *Correction factor for vertical upward flow for Beggs and Brill correlation*

$$\Psi = 1 + 0.3C$$

In Equation 10.50 and Equation 10.51, C is given by

10. Beggs, H. D. and Brill, J. P.: “A Study of Two-Phase Flow in Inclined Pipes,” *J. Pet. Tech.* (May 1973), 607-617.

EQUATION 10.52 *C for Beggs and Brill correlation*

$$C = (1 - H_{ns})\ln(c_4 H_{ns}^{c_5} N_{lv}^{c_6} Fr^{c_7})$$

with the restriction that $C \geq 0$.

The Reynolds number is calculated from

EQUATION 10.53 *Two-phase Reynolds number for Beggs and Brill correlation*

$$\mathrm{Re}_l = \frac{\rho_{ns} v_m D_e}{\mu_{ns}}$$

where ρ_{ns} and μ_{ns} are the non-slip mixture density and viscosity respectively. Use this Reynolds number to compute the non-slip friction factor from Equation 10.16. The following equation defines the two-phase friction factor.

EQUATION 10.54 *Two-phase friction factor for Beggs and Brill correlation*

$$f_m = e^X f_{ns}$$

where X is a complex function of both H_{nl} and H_l (θ). Use f_m, ρ_{ns}, and v_m in Equation 10.4 to calculate the frictional pressure loss.

THE HYDRAULICS OF SOLIDS TRANSPORT

The amount of fill (solid particles) picked up from a deposit for any given flow rate in a clea-nout operation depends on the lifting ability of the fluid. The lifting ability of the fluid is:

EQUATION 10.55 *Fluid lifting ability*

$$L_A = Q\lambda$$

where Q is the flow rate and λ is the maximum loading (concentration of particles in the fluid medium) for that particular flow rate. The penetration rate into a deposit of solid particles can be found from the lifting ability as

EQUATION 10.56 *Penetration rate into a deposit*

$$R_P = \frac{L_A}{(1-\varphi)\rho_P A_F}$$

where ρ_p is the density of the fill particle, φ is the porosity (void volume fraction) of the deposit, and A_F is the fill cross-sectional area. The term $(1 - \varphi)\rho_p$ in Equation 10.56 is sometimes referred to as the fill packing density.

In order to keep the solid particles suspended in the fluid, the fluid velocity must be sufficiently greater than the terminal settling velocity (v_{TV}) of the particles. An expression for v_{TV} obtained from Stokes law[11] is

EQUATION 10.57 *Particle settling velocity*

$$v_{TV} = \left[\frac{4}{3}\frac{g}{C_d}d_P\frac{\rho_P - \rho}{\rho}\right]^{\frac{1}{2}}$$

11. Moore, P. L.: *Drilling Practices Manual*, Petroleum Publishing Co., Tulsa (1974).

where d_P is the diameter of the fill particle (assumed to be spherical) and C_d is the drag coefficient. The value of C_d depends on the magnitude of the particle Reynolds number defined for power law fluids as

EQUATION 10.58 *Particle Reynolds number*

$$\mathrm{Re}_P = \frac{\rho v_{TV} D_e}{\mu_a}$$

where μ_a, the apparent viscosity, is:

EQUATION 10.59 *Apparent viscosity for power law fluids*

$$\mu_a = K\gamma^{n-1}$$

The following equations give the value of C_d for different ranges of particle Reynolds number.

EQUATION 10.60 *C_d for turbulent flow, $Re_P > 300$*

$$C_d = 1.5$$

EQUATION 10.61 *C_d for laminar flow,* $\mathrm{Re_P} \geq 3$

$$C_d = \frac{40}{\mathrm{Re}_P}$$

EQUATION 10.62 *C_d for the intermediate region*

$$C_d = \frac{22}{\sqrt{\mathrm{Re}_P}}$$

Equation 10.63 presents an alternative method[12] for calculating particle settling velocity.

12. Chien, S. F.: "Settling Velocity of Irregularly Shaped Particles," SPE 26121 presented at the 69th Annual Technical Conference and Exhibition, New Orleans, LA (Sept. 25-28, 1994).

EQUATION 10.63 *Particle settling velocity*

$$v_{TV} = 0.0002403e^{5.030\alpha}\left(\frac{\mu}{d_P\rho}\right)\left[\sqrt{1+920790.49e^{5.030\alpha}d_p\left(\frac{\rho_P}{\rho}-1\right)\left(\frac{d_P\rho}{\mu}\right)^2}-1\right]$$

The units of μ and d_P are centipoise (cp) and inches respectively. The density terms ρ and ρ_P are in pounds per gallon (ppg). The term α is the sphericity of the fill particle defined as the ratio of the surface area of a sphere having the same volume as the particle to the surface area of the particle.

Hydraulic Horsepower Requirement

Critical to the effective performance of the pumping equipment is having the equipment that is properly sized, installed and operated as per the objectives of the well. It is important to note that the limitation of the pump equipment is based on the engine, transmission, power end and fluid end. All these components have a specific operating range and duty cycle that must be evaluated to ensure the proper pump is utilized. To evaluate the equipment, information on the following items are needed:

- Horsepower developed by the prime mover
- Flowrate and pressure requirement for the treatment
- Gear ratio and lockup speed of the transmission
- Power end gear ratio for the pump
- Mechanical efficiencies of the transmission and power end
- Fluid end specifications for the pump

To determine the volumetric displacement of a reciprocating pump, Equation 10.64 is used.

Equation 10.64 *Volumetric displacement for a reciprocating pump*

$$VD = \frac{\Pi}{4} * (OD)^2 * l * VE * n$$

where
OD = OD of the plunger or piston
l = Stroke length of the pump
VE = Volumetric efficiency of the pump
n = number of plungers in the pump

Based on the operating speed and the output horsepower developed by the prime mover, the Maximum Outlet Pressure (MOP) can be determined from Equation 10.65.

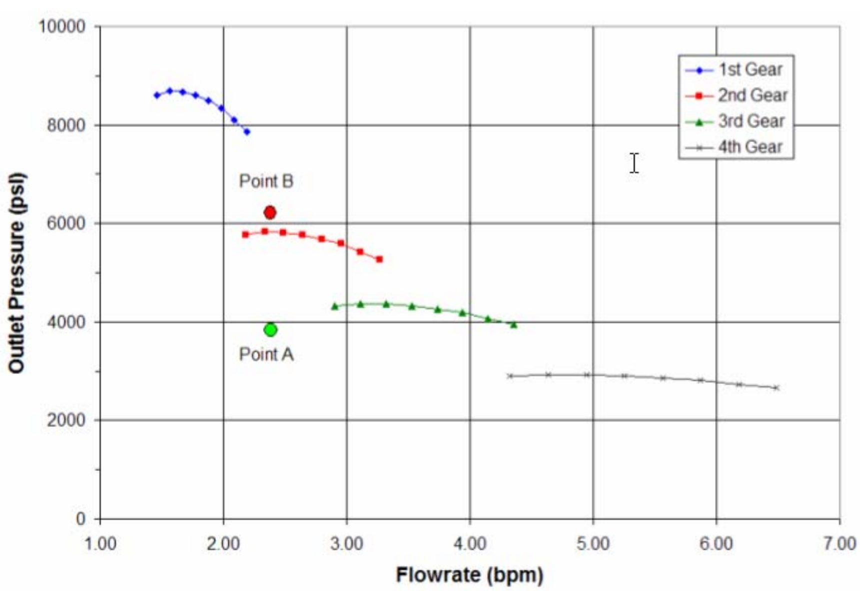
EQUATION 10.65 *Maximum outlet pressure developed for a given speed*

$$MOP = \frac{40.8 * HP_{@S} * \eta_T * \eta_{PE} * R_T * R_{PE}}{VD * S} \quad \text{(psi)}$$

where
$HP_{@s}$ = Prime mover output horsepower at S (hp)
η_T = Mechanical efficiency of the transmission
η_{PE} = Mechanical efficiency of the power end
R_T = Gear ratio of the transmission
R_{PE} = Gear ratio of the power end of the pump
VD = Volumetric displacement of the fluid end (bbl/rev)

A pump curve from a typical well servicing pump is shown in Figure 10.2. This figure shows the range in flowrates and pressures developed for the given pump. To ensure the pump meets or exceeds the operating requirements, a comparison of the predicted pressure against the MOP (Equation 10.65) is made. If the predicted pressure falls below the MOP (Point A in Figure 10.2), the pump will meet the desired objective. When the predicted pressure exceeds the MOP (Point B in Figure 10.2), changes are needed to either the equipment or job procedures. One way to adjust the operating envelope is by changing the plungers/pistons size. By decreasing the plunger/piston size, the pump will develop higher pressures but will reduce the flowrate potential. Operating the equipment outside the limits can result in overheating and shortening the life of the equipment.

FIGURE 10.2 *Pump curves for a typical well servicing pump with automatic transmission*



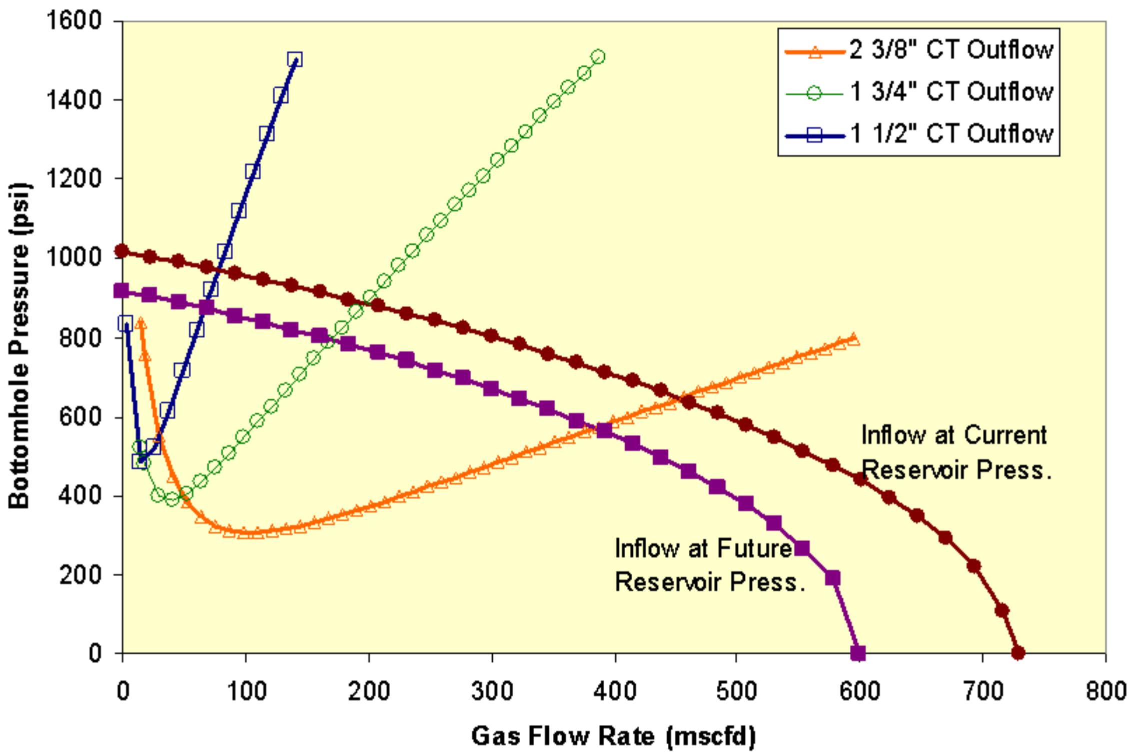
VELOCITY STRING HYDRAULICS

Coiled tubing velocity strings can be installed as a solution for liquid loading problems for gas wells (Figure 13.1 - Figure 13.4). The smaller diameter of a velocity string reduces the flow section area, thus increasing the velocity of the moving fluid and its liquid transport capability.

While the selection of CT size depends on many factors, and an economic analysis is required to select the optimum CT size, hydraulic analysis should be applied to evaluate the projected production rate and liquid carrying capability.

A nodal analysis is usually applied at the well bottom to calculate the production rate of a well. The inflow performance (IPR) curve of the reservoir is plotted against the outflow performance curve ("J" curve) of tubing (Figure 10.3), the intersection point of the two curves indicates the rate at which the well will flow.

FIGURE 10.3 *Nodal Analyses at Bottomhole*



Minimum Critical Velocity

Each tubing size has a minimum critical velocity for unloading liquid. Below this point liquid will accumulate and eventually the well will stop flowing. A rule of thumb for minimum velocity at the bottom of the flow conduit is 10 ft/s. A more rigorous method for calculating the minimum velocity is calculated by using the entrained liquid droplets model[13]

EQUATION 10.66 *Minimum Critical Velocity (ft/s)*

$$V_{\min} = 1.60 \frac{\sigma^{1/4}(\rho_L - \rho_g)^{1/4}}{\rho_g^{\ 1/2}}$$

where
σ = interfacial tension between gas and liquid phases, dynes/cm
ρ_L = density of liquid phase, lbs/ft³
ρ_g = density of gas phase, lbs/ft³

Notice that interfacial tension and gas density vary with fluid temperature and pressure, and therefore $V_{\min}$ varies with depth.

Inflow Performance

An Inflow Performance (IPR) curve describes the relationship between inflow rate Q and bottomhole flowing pressure P_{wf}. Such relationship depends on properties of the reservoir and the reservoir fluid as well as the completion of the well.

13.R.G. Tuner, et al., Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells, 1969. SPE 2198

A commonly used equation for an IPR curve of gas condensate wells is:

EQUATION 10.67

$$Q_{sc} = C(P_R^{\ 2} - P_{wf}^{\ 2})^n$$

Where
Q_{sc} = Gas flow rate in standard condition, mscfd
P_R = shut-in static reservoir pressure, psi
P_{wf} = bottomhole flow pressure, psi
C = Coefficient determined from well test data, mscfd/psi
n = Exponent determined from well test data, dimensionless

An accurate IPR curve of the well at current reservoir pressure is essential for selecting velocity strings. The constants C and n can be calculated from well back-pressure test data.

To ensure adequate flow velocity at a future depleted reservoir pressure, a second IPR curve at that pressure should also be considered (Figure 10.2).

Outflow Performance

An outflow performance curve for a CT is determined by calculating the friction and hydrostatic pressures for multiphase fluid flow inside the pipe. Many models exist and are discussed in the previous section "Pressure Losses in Liquid-Gas Flows".

An outflow performance curve initially goes downward to indicate the well is being loaded with liquid and the hydrostatic pressure is the governing factor in BHP. Then it increases as the well is being unloaded and friction pressure becomes the governing factor. This is the reason why a tubing performance curve has a "J" shape.

Each tubing size has its own performance curve that will intercept with the IPR curve. The interception point indicates the production rate for this tubing size. In selecting a CT size for velocity strings, this intercept needs to be at a higher flow rate than that for the minimum velocity requirement.

A smaller CT size will create more friction pressure loss and its performance curve will intercept with the IPR curve at a lower flow rate. When more than one CT size will satisfy the requirement of minimal critical velocity, an economic decision must be made between the increased production rate and the cost of CT.

11 PUMPING OPERATIONS

BASIC CONSIDERATIONS

This chapter discusses pumping applications, which make use of the "circulating system", i.e., the equipment and facilities for mixing, processing, storing, and pumping the treatment fluid. In all cases, follow the guidelines in Chapter 17 "Minimizing Risk For CT Operations" for planning, selecting equipment for, and executing CT pumping operations.

This section describes the key factors that affect a CT pumping operation. Subsequent sections in this chapter discuss eight types of CT pumping operations.

Fluid Characteristics

Rheology

Due to the relatively small internal diameter of a CT string, the rheological properties of a fluid can be critical to the success of a pumping operation. Excessive friction pressure losses can deplete available hydraulic horsepower downhole, or the high shear conditions inside the CT string can alter the fluid's properties. Chapter 10 "CT Hydraulic Performance" discusses CT hydraulic performance. Always use actual rheological measurements, when available, for hydraulics modeling and calculations. Consult the mud company or fluid supplier for data.

Solids-Carrying Ability

Fluids for suspending or carrying solid particulates must be capable of functioning adequately given the flow rates and annular velocities feasible through a specific CT string in given wellbore conditions.

Corrosion Protection

The requirement for corrosion protection of the CT and wellbore tubulars may be obvious for applications where highly corrosive fluids are used, e.g., acidizing/stimulation treatments. However, corrosion protection may be an issue for less corrosive fluids, e.g., certain brines that remain within the CT string or wellbore for an extended period.

CAUTION: Always use results of actual corrosion tests to determine the correct formulation and applications of corrosion inhibitor(s).

Compatibility

The mixing of different fluids under the temperature and pressure conditions present in many wellbores can often yield undesirable results. In mild cases the fluid performance may decline. However, in severe cases, the resulting reaction products can be extremely damaging to producing formations. Treatment fluids must be compatible with all materials in the wellbore.

Pumping or Exposure Time

Certain types of fluid are "time sensitive", i.e., a physical or chemical reaction within the fluid limits the time the fluid may be safely pumped, e.g., cement, resins or gels. Similarly, it may be desirable to limit the contact time with corrosive fluids, e.g., stimulation fluids, although in most cases an appropriate inhibition schedule enables corrosive fluids to be safely pumped even over extended periods.

Monitoring

Monitor and record key job parameters, e.g., pump pressure, flow rate, fluid density, continuously with a DAS, per Chapter 17 "Minimizing Risk For CT Operations".

Surface Equipment and Facilities

Fluid Mixing

The mixing sequence and procedure is often critical to provide the desired performance of the fluid. Review mixing procedures along with the available equipment configuration to confirm compatibility.

CAUTION: Always thoroughly mix treatment fluids immediately prior to pumping.

Fluid Storage

The volume of fluid required depends on the actual conditions encountered during the operation. Consequently, ensure that additional fluid supply and storage volumes are available on demand. Disposal of excess treatment fluids can be a significant problem. Consider potential disposal problems before preparing large volumes of fluid which may not be required.

CAUTION: Many treatment fluids degrade rapidly in storage. Always thoroughly mix, then test a stored fluid's properties before using the fluid on a job.

Fluid Processing

Fluids circulated from the wellbore often require some processing before storage, disposal, or recirculation. In most cases some hydrocarbons will be present in wellbore returns, so providing the necessary monitoring equipment and implementing appropriate procedures are vital. In addition, adequately train and assess personnel in emergency responses, e.g., H_2S, fire, pollution prevention.

Fluid Pumps

Providing the required hydraulic horsepower is relatively straightforward given the typical dimensions and fluid flow rates associated with CT operations. However, with the growing use of CT strings larger than 2 in OD, significant hydraulic horsepower may be required to maintain the designed treatment parameters. Pump horsepower should be specified in terms of "continuous" capability, not "peak demand".

CT String

CT String Dimensions

The string ID and total length are key factors in most pumping applications. For a given fluid, the internal flow area and total length of the CT string limit the flow rate available for the pumping operation.

Unlike other intervention methods, the CT string length and volume remain constant regardless of the BHA position in the wellbore. This influences the fluid volumes required for accurate spotting and displacement of treatment fluids, e.g., placing plugs or pills in depth-critical applications. Moreover, the pressure in the string changes as the length of tubing on the reel changes. When planning the operation, at least 250 ft of tubing should remain on the reel with the tool string at treatment depth (to allow for contingency operations and compensate for inaccurate record keeping). Chapter 10 “CT Hydraulic Performance” describes the hydraulic performance of CT.

CT String Preparation

The advantages of live well intervention disappear if debris, sludge or corrosion products from within the CT string are injected into the reservoir. Strings that have been improperly stored can contain significant volumes of iron-based corrosion products. These products can react with stimulation fluids within the reservoir matrix to form insoluble precipitate that can destroy permeability in the near-wellbore area. This problem is especially pervasive offshore where CT regularly pumps seawater. In addition to flushing and cleaning the CT string prior to use, drift the string with an appropriately sized ball or plug. This ensures the string is open and free of obstructions or tight spots.

CT String Mechanical Performance

Although this section deals primarily with the hydraulic performance of a CT string and BHA, the CT must be able to safely RIH to the target depth and return. Always evaluate the mechanical performance of the CT string with a reliable tubing forces simulator, such as Orpheus™. Chapter 6 “Tubing Forces”, Chapter 7 “Buckling and Lock-up”, Chapter 8 “CT Mechanical Limits”, and Chapter 9 “CT Working Life” discuss the mechanical performance of CT.

Tool String or BHA

Design and Construction

The design and construction of all tools and equipment in the BHA must be compatible with the fluid (corrosive fluid, particulates), flow rate (erosion, flow restriction), and pressure (supply pressure, BHP).

The tool string OD must be compatible with wellbore restrictions and the ID must be compatible with flow rate constraints (internal and annular). In addition, the internal profiles of all tool string components must be compatible with any balls, darts, or plugs required for operation. Drift and check the bore of the entire tool string for potential hang-up points.

CAUTION: All tool strings must contain dual check valves, preferably flapper-type.

CAUTION: Unless stated otherwise for a specific CT operation, roll-on tubing connectors are acceptable only for pumping operations.

Operation

The operating parameters of tools and equipment (pressure, temperature, tension, compression) must be compatible with the planned pumping schedule and the ability to control and monitor tubing movement, e.g., when set/release packers are to be used.

Wellbore

Annular Profile

The ID of the wellbore has significant bearing on the flow characteristics of fluids in the wellbore. Worst case conditions for solids transport exist in large eccentric annuli, e.g., horizontal wells having an eccentric annulus due to gravity. In deviated wells, solids can settle out of the fluid to form continuous beds or isolated dunes. The deposit of solids in the build section and deviated portions of the wellbore must be monitored to avoid sticking the CT string or BHA.

Wellbore Restrictions

Some completion components can restrict the movement of large solids through the annulus. These tight spots can also be eroded by abrasive particles during periods of high flow rate. Sudden expansion of the wellbore creates a local region of lower velocity that can cause solid particles to fall out of suspension. Thus, the fluid flow rate must be adequate to suspend solids along the entire flow path.

REMOVING FILL OR SAND FROM A WELLBORE

An accumulation of solid particles in the wellbore impedes fluid flow and constrains production. The problem is worse in horizontal wells, where settling is most likely to occur. Historically, removing fill material from producing wells is the most common application of CT services. The process has several names, including sand washing, sand jetting, sand cleanout, and fill removal.

The principal objectives of fill removal operations include the following:

- Restoring the production capability of the well.
- Allowing wireline or service tools to pass freely through the wellbore.
- Ensuring the proper operation of downhole flow control devices.
- Maintaining a sump (space) below the perforated interval to allow complete passage of tools or as a contingency tool disposal area.
- Removing material that can interfere with future well service or completion operations.

Common types of fill materials include the following:

- Formation sand or fines
- Produced proppant or fracturing operation screenout
- Gravel-pack failure
- Workover debris, e.g., scale particles
- Cuttings from drilling and milling

Fill materials fall into three broad categories:

- Sludge or very fine particulates
- Unconsolidated particulates
- Consolidated particulates

In most cases, CT is the only viable means of removing fill from a wellbore. The ability to continuously circulate through CT while maintaining a high level of well control minimizes any disruption to production.

The basic procedure is to circulate a fluid through the CT while slowly penetrating the fill with an appropriate jetting nozzle. The fill material becomes entrained in the fluid flow and circulates out of the wellbore through the CT/production tubing annulus. It is crucial that the annular fluid velocity be significantly greater than the settling velocity of the fill material in the fluid.

Another approach is to pump down the CT/production tubing annulus and return solids-laden fluid though the CT string. This procedure, called reverse circulation, is particularly useful for removing large quantities of particulates, such as frac sand, from the wellbore. However, reverse circulation is suitable only for dead wells.

A third method of removing fill uses a concentric CT string and a jet pump to literally vacuum particulates from the wellbore. The working fluid travels down to the jet pump through the inner CT string, and solids-laden fluid returns to the surface through the annulus between the CT strings. This method is suitable only for dead wells. However, the method is particularly useful when the reservoir pressure is too low to support a wellbore full of water.

Chemical or mechanical techniques can be used to assist removal. Chemical removal of fill may not be a viable method due to the low solubility of common fill materials. Mechanical removal may simply involve jetting and circulation. Where consolidated fill is present, the assistance of a downhole motor and bit or impact drill may also be required. (See Section “Removing Scale Mechanically”.)

Planning a Fill Removal

The sources and types of fill material in the well are important data for designing a fill removal treatment. These data help to determine the most appropriate removal technique and may indicate that a secondary treatment at the source will prevent further production of fill material.

Job Plan Inputs

One must know the following information to plan a fill removal operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Producing interval or intervals (depths and pressures)

- Wellhead and surface equipment configuration
- Options for disposing of fill material and treatment fluid
- Fill characteristics

  1. location of fill

  2. particle size and geometry

  3. material density

  4. solubility

  5. consolidation

  6. estimated volume of fill material

  7. presence of viscous material

  8. presence of junk in the fill

Planning Considerations

The optimum penetration rate into the fill depends on the effect the jetting has on the fill, hole-cleaning ability (fluid flow rate and solids carrying performance), and maintaining the desired downhole pressure conditions. An important factor affecting the penetration rate is fill volume. Since larger tubulars can contain more fill, they require lower penetration rates, while smaller tubulars can be cleared with relatively high penetration rates. Keep the penetration rate below the rate at which the maximum fluid loading occurs (Table 11.1). During staged treatments, i.e., nitrogen/gelled fluid, only attempt penetration when the fluids designed to carry the fill material are exiting the CT nozzle or tool.

TABLE 11.1 *Recommended Maximum Fluid Loading*

Fluid Type	Maximum weight of fill material per gallon of fluid (lbm)
Water	1
Gelled Fluid	3
Foam	5

Reservoir Considerations

When choosing the most appropriate fill removal technique, take into consideration the following reservoir parameters:

- Reservoir Pressure—Reservoir pressure is one of the most important considerations when determining an appropriate fill removal technique. Accurate BHP data is needed to design a pumping schedule to carry the fill material to the surface without incurring losses. Under ideal conditions, the annular fluid column hydrostatic pressure plus friction pressure (ECD) should balance the BHP.

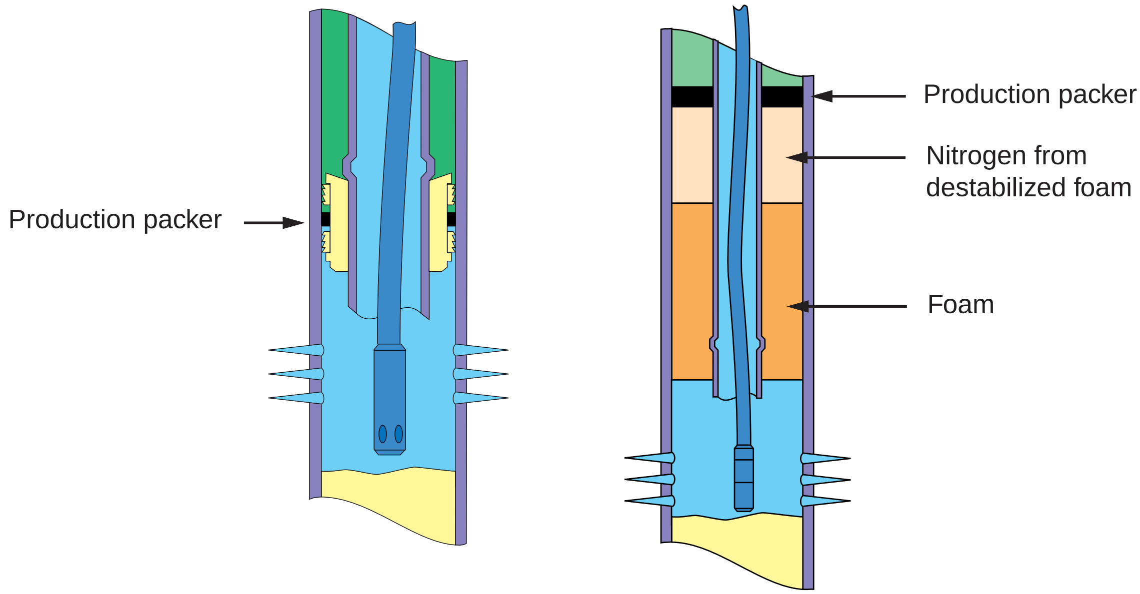
  One can apply additional system pressure by adjusting a surface choke located on the fluid return line. If the reservoir pressure is insufficient to support a full liquid column, fluids such as foam, nitrified fluids, or nitrogen and liquid slugs are possible alternatives.

- Reservoir Temperature—Due to the relatively low circulation rates associated with CT, use the BHST to design treatments. Accurate reservoir temperature data is essential for treatments containing foam or nitrogen slugs. Temperature also affects the rheology and density of many other fluids.
- Formation Sensitivity to Certain Fluids—The sensitivity of the formation can limit the selection of fluids or dictate their properties.

Wellbore and Completion Geometry Considerations

- Tubular Size—The size of the tubular or the minimum restriction determines the maximum OD for the CT string and BHA. Large tubulars complicate conventional fill removal because they require higher pump rates to achieve adequate annular velocity between the CT and the wellbore.
- Restrictions—Nipples and other internal restrictions in the completion are possible bridging points and locations for erosion. In a completion with a small annulus or restriction, the annular pressure loss may be excessive at the flow rate necessary for effective conventional fill removal.
- Completion Packer—Oil in an uphole completion packer can destabilize foams. Figure shows conventional and uphole packer completions.

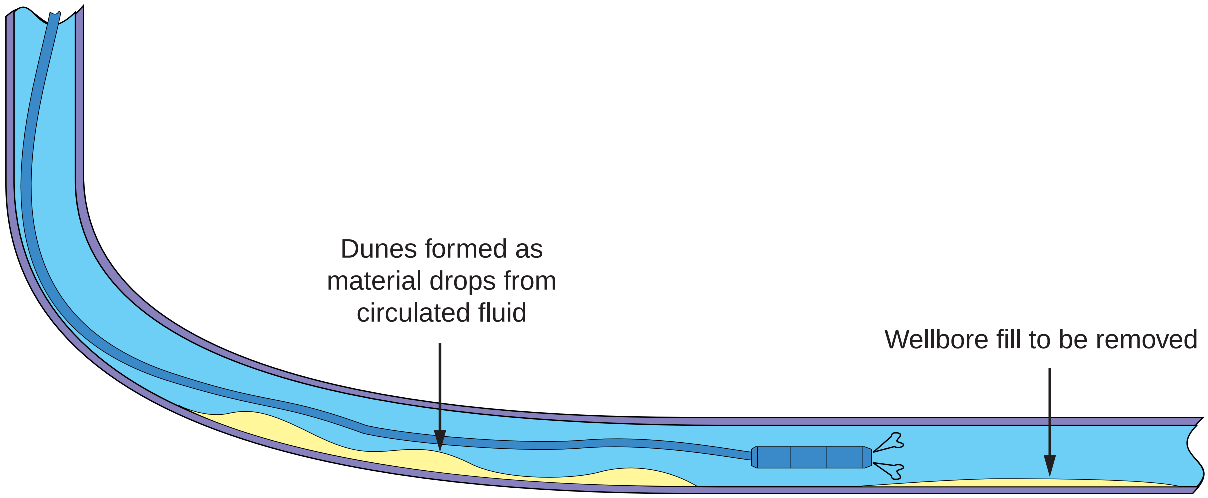
Conventional and Uphole Packer Completions



- Deviated Wells—Highly deviated and horizontal wellbores require several special considerations. Fill material can rapidly accumulate on the low side of the wellbore during production and during conventional removal operations. In some cases, the fluid velocity can carry fill along horizontal sections, but cannot lift it through the build angle into the vertical wellbore (Figure 11.1). Gravity causes the particles to accumulate and slide down the low side of the wellbore, especially at inclinations of 30° to 60°. Once the fill has settled, it is difficult to re-establish particle transport.

  Turbulent flow significantly improves hole cleaning in a horizontal wellbore. However, in many cases, turbulent flow is not possible, due to the flow and pressure restrictions imposed by the CT work string, or the relative size of the completion tubular. To compensate, modify the rheology of the fluid. For conventional fill removal operations, the annular velocity can be maintained above the critical rate by pumping slugs of nitrogen and liquid. In such cases, the liquid selected should be capable of achieving turbulent flow at relatively low rates (i.e., Newtonian fluids, see Chapter 10 "Fluid Rheological Models", page 10-6).

FIGURE 11.1 *Particle Behavior in Horizontal Wellbore*



Fill Considerations

In order to ensure the greatest efficiency of any fill removal operation, one must know the physical properties of the fill material. Obtain a sample of material and perform physical and chemical analyses on it. If it is impractical to obtain samples, such as for compacted fill materials, make estimates based on local experience and well history. The following information will aid the planning process:

- Particle Size and Density—The settling rate of a particle in a carrying fluid must be less than the velocity of the fluid. The particle settling rate depends on particle size, shape and density, along with fluid properties. (Table 11.2, Table 11.3, and Figure 11.2). Make sure the settling rate is lower than the minimum annular velocity anticipated during the operation.

  Since a sample of fill material can contain a range of particle sizes, use the largest particle size in annular fluid velocity calculations.

TABLE 11.2 *Standard Mesh Sizes*

US Standard Mesh Size	Particle Diameter (in.)
3	0.2500
4	0.1870
5	0.1320
8	0.0937
10	0.0787
12	0.0661

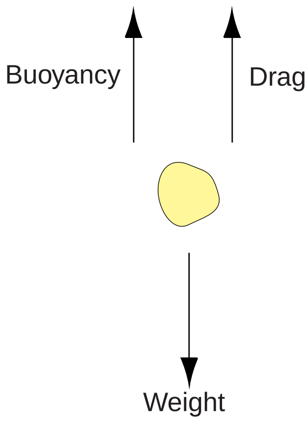
TABLE 11.2 *Standard Mesh Sizes*

US Standard Mesh Size	Particle Diameter (in.)
16	0.0469
20	0.0331
30	0.0232
35	0.0197
40	0.0165
50	0.0117
60	0.0098
100	0.0059
200	0.0029
270	0.0021
325	0.0017

TABLE 11.3 *Typical Wellbore Fill Particle Material Size and Density*

Fill Material	US Standard Mesh Size Range	Density (SG)
Sand	12 to 70	2.65
Resin-Coated Sand	12 to 40	2.56
ISP	12 to 40	3.20
Sintered Bauxite	16 to 70	3.70
Zirconium Oxide	20 to 40	3.15
Barite	none	4.33
Calcium Carbonate	none	2.71
Steel	none	7.90
Brass	none	8.50
Common Elastomers	none	1.20

FIGURE 11.2 *Forces Acting on Particle During Removal*



- Particle Solubility—Fill removal operations can be simplified if acid or solvents can chemically dissolve the fill. Jetting some special fluids can also help remove compacted fills. Since obtaining samples of compacted fill materials is often impractical, formulate treatment fluids based on local experience and well history.

NOTE: Totally soluble fills are uncommon and are generally the result of plugs or pills placed during previous workover operations.

- Compressive Strength—Heavily compacted or consolidated fill often requires some mechanical means of breaking or loosening of the material. Since obtaining samples of compacted fill material is often impractical, determine the level of mechanical assistance required based on experience or availability of tools.
- Junk Removal—If the wellbore fill contains workover debris or large solids, e.g., cement lumps, that cannot be removed by circulation, special fishing equipment may be required. (See Chapter 12 "Fishing", page 12-13.) A variety of magnetic tools, junk baskets, and custom tools are available for this purpose. The risk of sticking the CT can be high, so design the tool string carefully to reduce this risk. Also include an appropriate release tool in the tool string.

Selecting Fluids

Select fluids based on the following criteria (not ranked):

- Bottomhole pressure
- Particle carrying ability
- Friction pressure loss
- Logistical constraints
- Ease of disposal

- Compatibility with formation fluids and completion components
- Cost

Water and Light Brines

These popular fluids are commonly used where the BHP is greater than the hydrostatic pressure exerted by the fluid column, and the annular space is small enough to ensure the high annular velocities required by such fluids. As Newtonian fluids, water and light brines can be easily placed in turbulent flow, which provides a useful scouring action. They also generally provide excellent jetting action when removing compacted fill. However, they may not be suitable for formations that are sensitive to aqueous fluids. These fluids cannot suspend particles under static conditions. Therefore, it is vital to maintain an adequate annular fluid velocity throughout the operation.

Oil, Diesel, and Synthetic Fluids

Light (low viscosity) oils are suitable for use in a broader range of wells than water-based fluids. These fluids are compatible with more formations. Their lower fluid densities also make them suitable for wells with lower BHPs. As Newtonian fluids, light oils can be easily placed in turbulent flow, which provides a useful scouring action. They also generally provide excellent jetting action when removing compacted fill. Potential concerns about using light oils for fill removal include:

- These fluids are flammable. Personnel safety, logistics, and environmental protection are important issues.
- These fluids have higher viscosity than water and brines and, therefore, higher frictional pressure loss.
- Larger volumes of fluid are required because it is impractical to separate and recirculate flammable fluids.
- The fluids are not necessarily compatible with the formation. Perform laboratory compatibility tests between the proposed treatment fluid and produced fluids.
- These fluids cannot suspend particles under static conditions. Therefore, it is vital to maintain an adequate annular fluid velocity throughout the operation.

Gelled Fluids

Water-based gels (polymers) are the most popular fluids for applications that require improved particle carrying and suspension. The high viscosity of some gels results in increased friction pressures, which can restrict the pump rate. The viscosity of gelled fluids depends on their formulation and temperature. The fluid design must reflect the anticipated wellbore temperatures, and the field mixing procedures must follow the designed formulation.

Formulations and rheology data for most gel types are available in various stimulation manuals. However, one should always run laboratory tests to obtain rheology data for the designed gel at the applicable temperature.

Liquid and Nitrogen Stages

Staged treatments are effective for conventional fill removal where single-phase fluids are limited. These include:

- The CT/wellbore annulus size is too large to achieve the necessary velocity for transporting the fill particles.
- The friction pressure loss in the CT work string limits the desired pump rate.
- A single-phase fluid column exerts too much hydrostatic pressure.
- Foam is not a practical alternative.

The solution is to pump liquid and nitrogen in alternating stages, rather than simultaneously as when generating foam. The expansion of the gaseous nitrogen increases the annular velocities. The nitrogen also greatly reduces the hydrostatic pressure of the fluid column. However, base the particle carrying ability of the combined system solely on the base fluid.

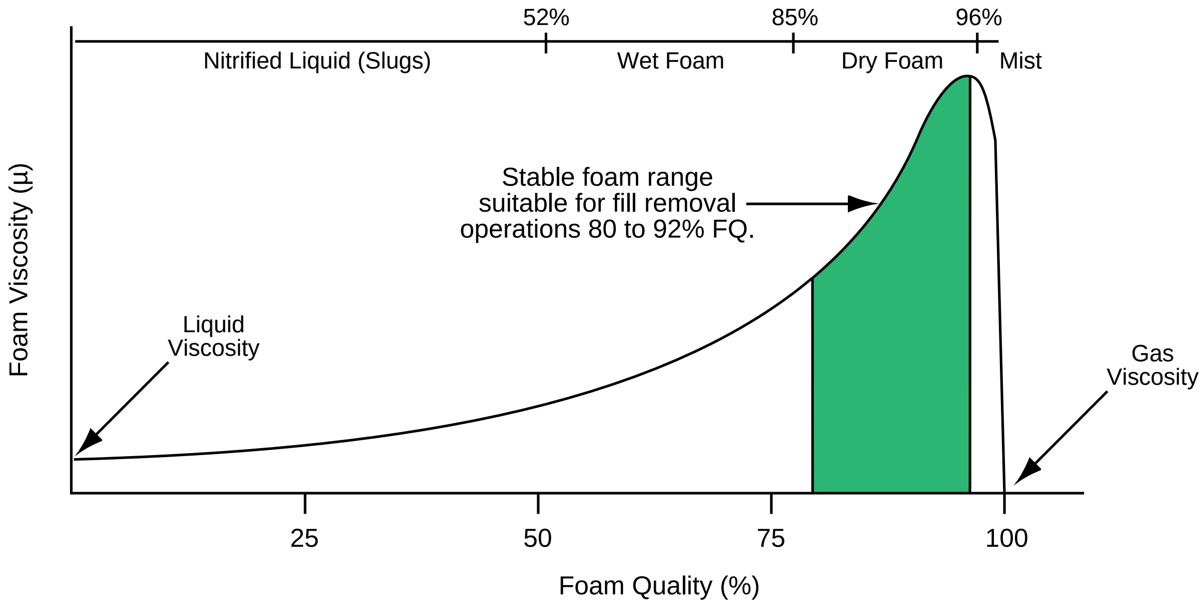
CAUTION: Design the pumping schedule and CT movement to ensure that the CT penetrates the fill only when liquids are at the nozzle. When N_2 is at the nozzle, the CT should be stationary or withdrawn from the fill.

Foam

Foam can be used with a wide range of BHP conditions. Although foam treatments are closely associated with low and very low BHP treatments, they can also be used in very large wellbores. A good quality, stable foam provides the best particle carrying capability of any fluid. Foams are formed by combining nitrogen gas with a base fluid and a foaming agent. The base fluid can be water or oil based. Foaming a gelled base fluid can generate higher viscosity foams. Laboratory testing is essential to determine the proper concentration of surfactant.

Two factors influence the properties of the foam: the base fluid composition and the proportion of gas added to the liquid. Figure 11.3 shows the types of fluid/foam generated in various foam quality ranges. For fill removal operations, the foam quality should be in the 80-92% range. The objective is stable foam, i.e. foam that will not collapse, degrade, or disintegrate for a long time.

FIGURE 11.3 *Foam Quality Versus Foam Viscosity*



Foam quality is highly dependent on pressure and temperature. Use a choke to keep the foam quality at the surface below 92%.

Stable foams can only exist in the foam qualities shown in Figure 11.3. An approximate measure of foam stability is foam half-life. The foam half-life is the time required for 50% of the foam liquid to separate. However, such tests have poor reproducibility and the results cannot be extrapolated to conditions other than those under test. To improve the foam stability, increase the strength of the bubble walls by using a more viscous base liquid.

Foam has a few disadvantages, including:

- Foams are subject to more logistical and operational constraints than most other fluids.
- Foam is a poor jetting fluid and is unsuitable for compacted fill.
- Hydrocarbons destroy water-based foams. If the treatment uses water-based foams, reservoir fluids must not enter the wellbore.
- Breaking foam returns in the surface equipment can be difficult and requires additional chemicals

Logistical Considerations

- Generally, complex job designs require more equipment. If space at the wellsite is constrained (e.g. offshore), some job design options may be precluded. An additional space constraint can be included if the returned fill/fluid is not to be processed by normal production facilities, and additional surface equipment is required. A small solids control system (e.g. shale shaker, sand trap, and hydrocyclones) is the most compact equipment arrangement.

- Disposing of the treatment fluid and fill material can be a problem for some locations. Straightforward circulation treatments can be designed to reduce the volumes required and minimize subsequent disposal. However, more complex job designs can result in large volumes of fluid for disposal.
- Some types of fill or scale, such as strontium and barium sulfates, are low specific activity (LSA) radiation sources. Take appropriate monitoring and protective measures to ensure safe operations. Adhere to the governing requirements or regulations associated with the processing and disposal of LSA solids. However, a system of several large tanks with weirs to settle out the solids is the simplest approach.

Reverse Circulation

As the name implies, this method of removing fill is the reverse of conventional circulation. Clean fluid travels down the CT/wellbore annulus, and solids-laden fluid returns up the CT. This requires removal of the dual check valves.

WARNING: Reverse circulation is suitable only for dead wells.

Due to the relatively small flow area of the CT and the high friction loss in the string, controlling the solids loading of the returning fluid is critical. Small increases in suspended solids can have a large effect on friction pressure loss in the CT string and hence the pump pressure (WHP). Thus, controlling the rate of penetration into the fill is a crucial part of reverse circulation. Also, the viscosity of the wellbore fluid has a significant effect on the operating conditions. Once the pump pressure (WHP) reaches the maximum allowed, the friction pressure loss in the CT/wellbore annulus and inside the CT string will govern the maximum fluid flow rate.

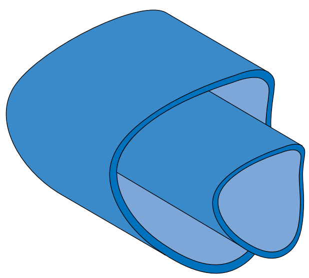
Since reverse circulation means pumping solids through the CT string, the danger of plugging the CT is always present. Moreover, the fluid velocity must always be high enough to prevent solids from settling out inside the wraps on the reel. This presents the CT operator with a dilemma. On one hand, he must limit the pump rate to maintain the WHP within acceptable limits. On the other hand, he must keep the flow rate high enough to prevent plugging the CT. The trade-off usually means the BHP is high enough during reverse circulation to cause partial loss of returns to the open formation. Another potential hazard is collapsing the CT below the stripper, because the pressure outside the CT (the WHP) is much greater than the pressure inside the CT. The operator must have a clearly defined safe operating envelope for combined tension and WHP. (See Chapter 8 “CT Mechanical Limits”.)

Using Concentric CT

A number of techniques exist for the removal of sand from vertical wells, but most are inefficient in horizontal wellbores. Hole orientation and horizontal reach hamper bailing techniques. Cleanout circulation operations (such as with conventional CT) are limited by low formation pressures and the high velocities required to prevent particle re-settling.

A technique using concentric CT (CCT) effectively removes sand from horizontal wells. Concentric CT is composed of two CT strings, one installed within the other (Figure 11.4).

FIGURE 11.4 *Concentric CT*



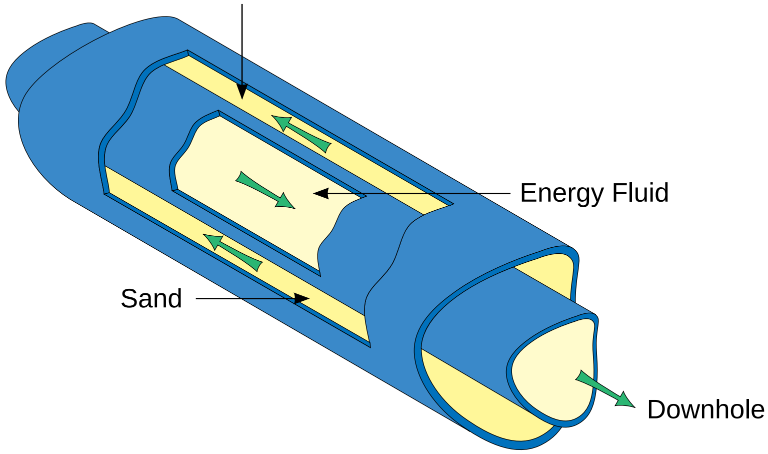
CCT uses a jet pump, which is powered by pumping fluid through the internal CT string. "Spent" power fluid, wellbore fluid, and sand return to surface through the CCT annulus (Figure 11.5).

NOTE: The jet pump negates the use of check valves in the BHA.

WARNING: This method is suitable only for dead wells.

WARNING: The shear rams in the BOP must be capable of shearing both CT strings with a single stroke. This may require special shear rams and/or a hydraulic booster on the ram piston.

FIGURE 11.5 *Concentric CT Flow*



A number of different liquids are suitable for powering the jet pump. Formation water is best due to the following properties:

- Low cost
- Non-damaging
- Low viscosity, high turbulence
- Sand settles out quickly in the surface equipment

The pump is configured to optimize both intake rates and drive pressures, based on the fluid rates available through the internal CT string. Front and rear facing jets provide turbulent energy to fluidize the settled sand before it is drawn into the intake ports. The pump has no internal moving parts, which could be affected by abrasion. The affects of abrasion are therefore limited to the nozzle and throat assembly.

In the CCT annulus, liquid velocities are sufficiently high to ensure that particle re-settling does not occur. (See Figure 11.5).

The entire cleaning operation is performed with a steady, balanced pressure. The use of CCT also allows the operation to be continuous - both running in and pulling out. Figure 11.6 and Figure 11.7 illustrate these processes.

FIGURE 11.6 *Sand Cleaning - Running In*

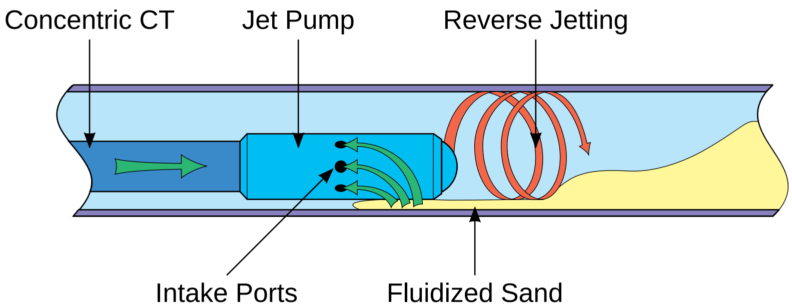
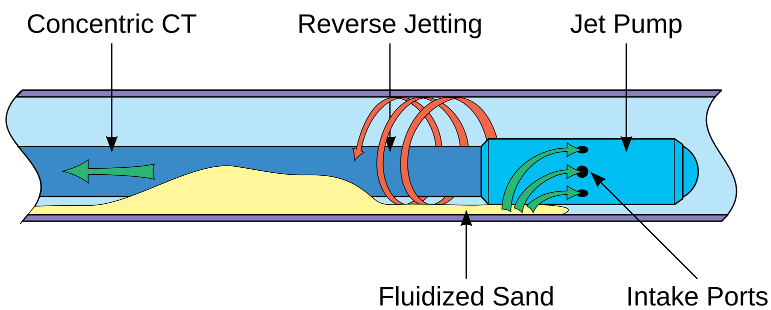


FIGURE 11.7 *Sand Cleaning - Pulling Out*



Jetting

Jetting provides a simple and effective aid in removing slightly compacted fill. Most applications are treated with low-pressure jetting through fixed nozzles or jetting subs. Low-pressure jetting can generally be conducted with a minimal effect on annular velocity. High-pressure jetting can be effective in removing compacted material; however, the high-pressure drop at the nozzle can effectively reduce the flow rate below that required for a suitable annular velocity.

The jetting sub should be designed to provide good jetting action and sufficient coverage of the tubular wall. Swirl or rotating nozzles can improve coverage and optimize removal. However, jetting has two disadvantages:

- Full bore cleaning cannot be assured
- Large cuttings can be produced which the annular fluid cannot suspend

Configure jetting tools to maximize the available fluid rate and pressure. In addition to improving the efficiency of consolidated fill removal, this will ensure the circulation rate is maximized to aid fill dispersion and removal of solids from the wellbore.

Computer Simulator Modeling

A fill removal is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model, such as Hydra™, to select the CT string and calculate the relationship between the fluid flow rate and the pump pressure for different operating conditions. Determine or evaluate the following:

- The minimum annulus velocity necessary for effective hole cleaning in each section of the wellbore

> *NOTE:* The highest minimum velocity sets the minimum flow rate for the fill removal operation.

- The maximum flow rate possible without exceeding the maximum allowable ECD (pumping annulus fluids into the reservoir) for a given solids loading
- The maximum solids loading (mass fraction) in the annulus before exceeding the maximum allowable ECD for a given flow rate

> *NOTE:* The maximum solids loading sets the maximum penetration rate of the nozzle into the fill.

- For staged pumping schedules, the effects of nitrogen injection rate and total volume injected at a given fluid flow rate

Use a reliable tubing forces model, such as Orpheus™, to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH, and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

A basic job plan for a fill removal includes the following:

- Minimum flow rate
- Maximum flow rate for a given penetration rate
- Optimum penetration rate for a given flow rate

- For staged pumping schedules, the rate and duration of nitrogen injection and the total volume of nitrogen required.

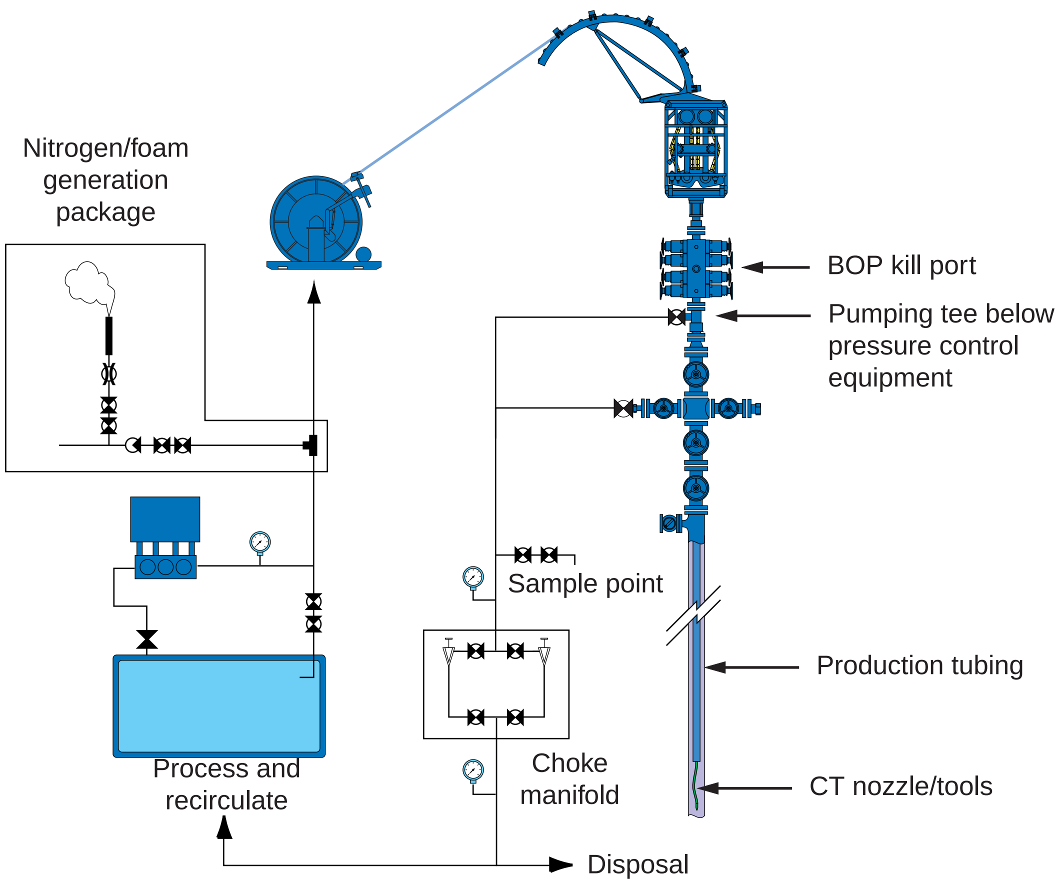
Prepare contingency plans for the following situations:

- The maximum flow rate attainable is not high enough for effective hole cleaning in certain sections of the wellbore.
- The ECD exceeds the reservoir pressure and annulus fluid enters the formation.
- The solids control equipment or surface equipment cannot handle the volume of fill material delivered to the surface.

Selecting Equipment for a Fill Removal

Figure 11.8 shows a typical equipment schematic for fill removal operations.

FIGURE 11.8 *Typical Foam Equipment Configuration for Fill Removal*



CT Equipment

Fill removal operations can induce significant levels of fatigue from repeated cycling of the tool string over a localized area and from high pressure jetting operations. The CT string must be able to withstand the predicted fatigue effects.

Use a CT string with the largest possible OD to decrease the friction pressure loss inside the CT string for a given flow rate. The large OD will serve to increase the annular velocity for a given flow rate.

For reverse circulation, install a reversing manifold ahead of the reel inlet so that the CT operator can easily switch the flow path from forward (down the CT string) to reverse (up the CT string). Use piping with ID of 2 in. or more to minimize pressure loss.

Pressure Control Equipment

Configure the pressure control equipment to avoid circulating corrosive or solids-laden annular return fluids through the secondary BOP. Install a pump-in tee between the secondary BOP and hydraulic master valve for fluid returns.

Auxiliary Equipment

Ensure that the fluid mixing, handling, and pumping equipment have adequate capacity. Configure them to minimize cross contamination of the fluid stages.

For live well operations, use a choke manifold to control annular returns. Ensure that the CTU, pump, and choke manifold operators have a clear line of communication between each other and the Customer well-site supervisor.

Ensure that the solids removal equipment can operate efficiently at the fluid flow rate necessary for the job.

Downhole Tools

The following are some basic requirements for tools for fill removal operations:

- The tool string must not restrict the flow rate required to provide the desired annular velocity.
- Tools must be capable of operating with high solids content fluid.

- The operation and components of the tool must be compatible with treatment fluids.
- The OD profile of the tool string should be as slim as practical. In addition, the profile must not contain sudden or large changes in OD, which can induce sticking.

The BHA used for fill removal should include the following components, from the top down:

1. CT threaded connector.
2. Dual flapper type check valves.
3. Straight bar—Use approximately 6 ft. This optional item is especially helpful for running through upsets in the completion, such as side pocket mandrels.
4. Jetting nozzle—There are no special nozzle requirements for conventional fill removal. It can be as simple as a few holes drilled in a bull plug. For reverse circulation, use a nozzle with a large hole (about 0.75 in.) on the axis of the CT and four smaller holes (about 0.25 in.) equally spaced around the circumference of the nozzle.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, fluid flow rates, and total fluid volumes pumped. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for a Fill Removal

Whenever possible, refer to similar case histories and adjust procedures to meet local conditions.

Operational Considerations

In removing fill from the wellbore, it is necessary to ensure the following:

- Transport materials to an appropriate place for separation and disposal.
- Do not place fill materials in areas where they could interfere with the operation of the wellhead, production, or pressure control equipment.

- Maintain wellbore conditions to avoid introducing the fill material into the formation and damaging the formation.

Preparing the Wellbore

If required for safety, fluid compatibility, or production reasons, kill the well. In most cases the risk of damaging the near wellbore area by bullheading the wellbore fluid is unacceptable. Consequently, the well kill operation may be a part of the wellbore preparation conducted through the CT string.

Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position and install a protective sleeve.

Preparing the Equipment

1. Prepare the wellhead and surface facilities.

2. Rig up the surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and connect it to the CT.

4. Conduct wellsite pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Preparing Fluids

Either batch prepare fluid in advance, or mix it on the fly as the operation proceeds. Allow sufficient residence time to enable the desired fluid characteristics to develop (and be tested). Regardless of the fluid mixing procedure, prepare adequate volumes. Once the operation has commenced, any interruption to circulation is undesirable.

Performing the Fill Removal

1. RIH while pumping inhibited water at a slow rate.

> WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Gently tag the targeted obstruction.

> WARNING: Do not tag the fill unless pumping through the nozzle. Running into the fill without circulation could plug the nozzle.

3. Pick up about 25 ft and increase the pumping rate to the planned maximum rate. Wait for the treatment fluid to reach the BHA.

4. After the pumping pressure stabilizes, RIH slowly while watching for signs of sand accumulation around the BHA and CT (pump pressure increasing or CTWI decreasing abnormally).

5. Keep the BHA moving at all times. However, keep in mind that multiple passes over a short interval can rapidly fatigue the CT string. Closely monitor the accumulation of fatigue to avoid a failure in the CT string.

6. Periodically pick up the BHA to the original top of the fill to ensure that the tubing is not restricted by sand.

7. In deviated wellbores, perform wiper trips as necessary to prevent the formation of excessive beds or dunes in the transition area between vertical and horizontal sections. Gauge the number of wiper trips by the volume of fill recovered for the volume of the wellbore penetrated. If the drop-out volume is small, one can perform fewer wiper trips to avoid excess fatigue and control operating time.

8. Pump high viscosity fluid pills if necessary to suspend entrained solids.

9. Continue pumping at a high rate until the required depth interval has been traversed.

10. At the bottom of the clean out interval, continue pumping at a high rate until sand production ceases. Pump high viscosity fluid pills if necessary.

11. POOH while pumping inhibited water at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

12. If in doubt about the condition of the wellbore, perform a drift run.

13. If the well does not flow naturally or aided by gas lift, prepare to conduct nitrogen lifting operations (Section “Unloading a Well with Nitrogen”).

Monitoring a Fill Removal

Monitor the following parameters during a fill removal:

- Fluid flow rate—It is relatively easy to determine the appropriate fluid flow rate for single-phase fluids. Monitor the returning fluid for fill material. If the returns do not contain enough solids, increase the fluid flow rate.

NOTE: For two-phase fluids, such as foams, co-ordinate the flow rate of each phase to ensure the correct foam quality is generated downhole.

- Fluid composition—Carefully mix and store fluids that are specifically engineered for optimum solids carrying capacity (e.g. gells) under conditions that will prevent contamination, dilution, or settling of active components.
- Wellbore returns (liquid)—Monitor the fluid rate and volume recovered from the wellbore to confirm that pumped fluid is not being lost.
- Wellbore returns (solid)—Measure and assess the rate and volume of removed fill to confirm progress and to gauge the efficiency of the operation. Compare variations in treatment rate or fluid composition with solids removal efficiency. The production or reservoir engineer ultimately determines how much fill material must be removed and how to evaluate the success of the operation.

Safety Issues for a Fill Removal

Always conduct a pre-job safety meeting prior to RIH.

Potential safety hazards for a fill removal include:

- Erosion of surface components by abrasive fill materials could create leaks or damage valves.
- Some fill materials (LSA) could be hazardous to personnel.
- Operations involving nitrogen gas pose the same hazards as unloading a well with nitrogen. See Section “Safety Issues for Unloading a Well with Nitrogen” for details.

STIMULATING A FORMATION (ACIDIZING)

Various types of formation damage occur, and several types may coexist in a single well. The most common type of damage is plugging of the formation around the wellbore. Stimulation treatments either remove the damage (in sandstones), or create channels to bypass the damaged zone (in carbonates). Such matrix stimulation treatments are designed to restore the natural permeability of the formation by injecting treatment fluids at a pressure less than the formation fracture pressure. Careful evaluation of the wellbore and reservoir parameters can identify the type and degree of damage. If the reservoir permeability is low, the well may be a candidate for hydraulic fracturing. However, if near-wellbore damage is the culprit, matrix stimulation may be an appropriate solution.

CT is a common method for performing matrix treatments. It has several advantages over conventional treatment techniques:

- The CT pressure control equipment configuration allows the treatment to be performed on a live well. This avoids potential formation damage associated with well killing operations.
- Associated operations can be performed as part of an integrated service, e.g. wellbore fill can be removed prior to the matrix treatment and nitrogen or artificial lift services may be applied to restore production following the treatment if required.
- Performing the treatment through CT avoids exposing the wellhead or completion tubulars to direct contact with corrosive treatment fluids.
- Spotting the treatment fluid with CT will help ensure complete coverage of the interval. Using an appropriate diversion technique will help ensure uniform injection of fluid into the target zone. Spotting the treatment fluid also avoids the need to bullhead wellbore fluids into the formation ahead of the treatment.
- Long intervals can be more effectively treated using techniques and tools that have been developed for use with CT, e.g. a selective treatment system using straddle-pack isolation tools. This is particularly important in horizontal wellbores.

By recognizing the limitations of the CT and associated equipment, treatments can be designed to achieve the maximum benefit to the zone while operating within safe limits and approved techniques. For example, the relatively high friction pressures and low pump rates associated with CT can extend the duration of large volume treatments beyond viable limits. In many cases, a lower volume treatment selectively applied will achieve similar, or better, results.

Planning for Stimulating a Formation

Job Plan Inputs

One must know the following information to plan a matrix stimulation operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Producing interval or intervals (depths, pressures, composition)
- Wellhead and surface equipment configuration
- Location, composition, properties, and origin of the formation damage
- Benefit/cost ratio for different levels of success for removing the formation damage

Planning Considerations

Potential Additional Damage from the Treatment

Without proper planning and adequate safeguards, a stimulation treatment can actually cause further damage to the formation. Potential sources of trouble are:

- Wellbore fill material near the treatment zone
- Scale, asphalt, wax, or solids in the production tubing/liner
- Rust and scale deposits inside the CT work string

Removing these potential damage sources before conducting the matrix stimulation treatment is essential. Flushing the CT and wellbore with fluid containing inhibited acid, solvents, iron reducing agents, and solids suspending agents will minimize additional formation damage, especially from high concentrations of dissolved iron.

Base Treatment Fluid

The appropriate treatment fluid depends on the type of damage and its location. The location of the damage is important because the treatment fluid may contact several other substrates before reaching the damaged zone, e.g. rust or scale on well tubulars or carbonate cementing materials. The treatment fluid must still be potent enough to effectively remove the formation damage.

Often the exact type of damage cannot be identified with absolute certainty, or more than one type of damage is present. Therefore, many stimulation treatments incorporate fluids to remove more than one type of damage. The following list summarizes the criteria for selecting matrix stimulation fluids.

- Physical characteristics of the damage – This determines the nature of the base fluid (e.g. acid or solvent).
- Reaction of the treatment fluid with the formation - Adverse reactions between the formation and treatment fluid can create new damage and exacerbate productivity problems. Additives in the treatment fluid, a preflush, and an overflush control such potential reactions.
- Prevention of excessive corrosion, both to the CT string and completion equipment.
- Use of friction reducers to optimize the treatment rate.
- Compatibility of treatment fluid with wellbore and reservoir fluids. Fluid additives can prevent sludge or emulsions, disperse paraffins, and prevent precipitation of reaction products.
- Compatibility of treatment fluid with diverting agent.

Preflush/Overflush

Some matrix stimulation treatments, especially in sandstone reservoirs, require preflush and overflush fluids to prevent adverse secondary reactions and the creation of precipitates from the main treatment fluid. The preflush separates the connate water and treatment fluid and, in sandstone treatments, reacts with carbonate minerals in the formation to prevent their reaction with the hydrofluoric acid (HF). Brine, solvent, or hydrochloric acid (HCl) are typical preflush fluids. The primary purpose of an overflush is to displace potentially damaging precipitates deep into the reservoir, away from the wellbore. Special fluids formulations can facilitate diverter cleanup. Ammonium chloride brine, HCl (3%-10%), and light hydrocarbons (e.g., diesel) are common overflush fluids. The correct volume of preflush or overflush depends on the radial displacement required.

Injection Pressure and Rate

The design of matrix acid treatments should not only specify the volumes and types of fluid to be injected, but also the maximum permissible injection rate and treating pressure, to avoid fracturing the formation.

Inject the treatment fluid at the maximum rate possible, without exceeding constraints. Constraints include the reservoir fracture pressure, and the maximum differential pressure allowable across the packer or diversion system. One can use a friction reducing agent to increase the fluid pump rate. A high pump rate improves treatment efficiency, reducing job time, which is important in large volume treatments.

Treatment Volume

The amount of treatment fluid required to remove formation damage depends on the same factors that influence the choice of treatment fluid, i.e., the characteristics of the damage, formation, and treatment fluid. Previous experience in a field is an excellent starting point for determining the required treatment volume. Without any history for guidance, laboratory tests can provide data for estimating treatment volume.

The following factors influence procedures for matrix stimulation:

- Treatment stages—If the treatment involves discrete stages, e.g., using a straddle packer system, closely co-ordinate the operational procedures, pumping schedule, and CT string movement schedule.
- Treatment interval and volume—The treatment volume, injection rate, and maximum pumping parameters are typically inter-related. Generally, conduct matrix treatments at a high fluid flow rate.
- Completion type—The ability to ensure adequate diversion or isolation can affect how the treatment progresses. For example, gravel pack completions generally cannot be successfully treated in stages.
- Wellbore profile—Horizontal and vertical wellbores require different techniques to achieve efficient treatment and diversion.
- Flowback—If the reservoir is unable to produce spent treatment fluids, energize the treatment fluid with nitrogen. Energizing the fluid can often improve treatment efficiency. It also enables the reservoir to “clean-up” without artificial lift. However, it also makes the treatment procedures more complex.

Fluid Additives

While the base treatment fluid is designed to remove the damage, most treatments benefit from additives for improving reactions and controlling potential damage to the formation, completion tubulars, or CT work string. Common additives are:

- Acid corrosion inhibitors (required on all jobs)—to reduce the rate of corrosion on treating and completion equipment to an acceptable level.
- Alcohol (often used in gas wells)—to lower surface/interfacial tension, increase vapor pressure, and improve cleanup.
- Anti-foam agents—to prevent formation of excess foam when mixing fluids on the surface.

- Clay stabilizers—to prevent damage from the dispersion, migration, or swelling of clay particles.
- Diverting agents—to help ensure complete coverage of the damaged zone by the treatment fluid.
- Formation cleaner—to kill and remove bacteria and polymer residues.
- Iron stabilizers—to prevent the precipitation of gelatinous ferric iron in the formation.
- Mutual solvents—to serve as a wetting agent, demulsifier, and surface/interfacial tension reducer.
- Organic dispersants and inhibitors—to remove and inhibit the deposition of organic materials.
- Surfactants—to enhance the penetration of fluids through the formation during treatment and flowback.

Many of these additives can present a hazard to personnel and the environment if handled incorrectly. Planning for a matrix stimulation operation must include procedures for the safe handling, mixing, cleanup, and disposal of treatment fluids and additives.

Corrosion Inhibitors

When selecting a corrosion inhibitor, consider the following conditions:

- Type and concentration of acid
- Maximum temperature
- Duration of acid contact
- Type of tubular/completion goods which will be exposed
- Presence of H_2S

Using inhibitor aids can extend the effective range of corrosion inhibitors.

H_2S Protection

The presence of H_2S affects the design of matrix stimulation jobs in several ways. Acid reactions in the wellbore frequently liberate H_2S, so base equipment selection, operating procedures, contingency plans, and personnel safety on the sour well conditions. Verify that all CT surface equipment, BOP components, and downhole tools are rated for H_2S service. H_2S significantly reduces the efficiency of some additives, especially corrosion inhibitors, so increasing the concentration of these additives may be necessary for sour conditions. An H_2S scavenger applied to the exterior surface of the CT and included in the main treatment fluid can reduce or eliminate the effects of H_2S

Friction Reducers

A friction reducing agent can significantly increase the fluid flow rate available for a given pump pressure or decrease the pump pressure for a given flow rate. In addition to improving treatment efficiency, higher flow rate reduces job time, an important consideration in large volume treatments. For a given flow rate, lower pump pressure means less fatigue damage to the CT string during the treatment operation (see Chapter 9 "CT Fatigue", page 9-5).

> **CAUTION:** Always thoroughly mix treatment fluids immediately prior to pumping.

Diversion

Successful matrix treatments depend on the uniform distribution of the treating fluid over the entire production (or injection) interval. When fluids enter a well, they naturally tend to flow into the zones with the highest permeability (least damage). Diverting the flow of treatment fluid to the areas of lesser permeability achieves a more effective treatment. Identifying high-permeability zones or thief zones from production log data will enable the design of an efficient placement/diversion technique. The criteria for selecting a diversion technique include the following:

- The diversion agent must provide uniform distribution of treating fluid into zones of widely different permeability.
- The diversion agent must not cause permanent damage to the formation.
- A rapid and complete cleanup must be possible to avoid secondary damage from precipitates.
- The diversion agent must be compatible with the main treatment fluid, additives, and overflush fluids.
- The diversion agent must be effective at the applicable treatment temperature.

Diversion techniques come in three forms, mechanical devices, chemicals, or foam.

Mechanical Diversion

Mechanical diversion methods for CT matrix stimulation treatments incorporate bridge plugs, packers, and straddle packers. Methods using ball sealers are not compatible with CT because of the restricted internal diameter and relatively low flow rates available with CT. Packers and plugs can isolate selected zones for treatment and effectively reduce the required treatment volume.

The following issues are important for designing a matrix treatment with mechanical diversion.

- The maximum treatment interval is shorter than the maximum tool length that can be safely deployed into and out of the well.
- The specifications and expansion of the packers determine the maximum injection pressure.
- All fluids must be free of suspended solids that could block restricted passages within the tool string.
- Unless the BHA includes a circulating sub above the packer, circulation through the work string is not possible while running and retrieving the packer(s), because the packer elements will inflate. Premature inflation could damage the packer or cause pressure fluctuations (surge or swab) in the wellbore.

Chemical Diversion

Most chemical diverters function by forming a filter cake (an artificial skin) of lower permeability on the formation face. This soluble cake dissolves during cleanup and subsequent production (or injection). The efficiency of chemical diversion techniques improves with higher injection or treating rates. An appropriate chemical diversion agent must meet several physical and chemical requirements including:

- Permeability—The cake formed on the formation face should be as impermeable as possible to achieve maximum diversion. The permeability of the cake must be less than that of the tightest zone to be effective.
- Invasion—Deep invasion of diverter into a producing formation is undesirable. Reducing invasion increases the efficiency of cleanup.
- Dispersion—If the diversion agent is a suspension of solid particles, the particles must be uniformly dispersed in the carrier fluid.
- Compatibility—Diverting agents must be compatible with the base treating fluid, additives, and overflush fluids. They must be inert toward the carrier fluid at the well treating temperature.
- Cleanup—The diverting agent must be soluble in the production (or injection) fluid or cleanup fluid to enable a rapid and complete cleanup.

Foam Diversion

Foam can be an effective diversion tool in many matrix stimulation treatments, particularly those performed in horizontal wellbores. Unlike a suspension of solids that requires fluid contact to assist cleanup, foam will break or be produced to allow a rapid and efficient cleanup. A typical foam diversion treatment generates and maintains stable foam in the formation (thief zone) during the treatment. Diverting the treatment fluid from the thief zone to the damaged zone achieves a complete and effective treatment.

A foam diversion process generally consists of five distinct and orderly steps.

1. Clean the near wellbore region (except dry gas wells)—Brine with mutual solvent or similar is injected to remove oil from the near wellbore region (oil destroys foam) and to water wet the formation.

2. Saturate the near wellbore area with foamer—Inject HCl or brine containing a foaming agent to displace the mutual solvent (solvents are detrimental to foam), to minimize the absorption of the foaming agent from the foam and ensure a stable foam is generated in the matrix.

3. Foam injection—A 55 to 75% quality foam fluid is injected into the matrix to generate a stable viscous foam, resulting in an increased bottom hole treating pressure.

4. Shut-in (recommended)—A ten minute optional shut-in period decreases the time required to reach maximum diversion.

5. Inject treating fluids containing surfactant—The treating fluid containing foaming agent is injected at a low rate. Omission of the foaming agent at this step will reduce the foam stability and consequently reduce the diversion efficiency.

Cleanup and Flowback

Using CT to perform a matrix treatment provides the means to quickly initiate production following treatment. If the reservoir pressure cannot overcome the hydrostatic pressure exerted by the spent treatment fluid, nitrogen kickoff techniques may be performed (see Section “Unloading a Well with Nitrogen”). In most cases, attempt to flowback the spent fluids as soon as possible. Detrimental reaction products and precipitates can form within the formation if some spent-acid products remain for an extended time. In some cases (especially clay damage treatments), the production rate should be gradually increased to minimize the migration of fines. Monitor the pH of wellbore fluids during the cleanup period to determine when the last of the treatment fluid has returned to the surface.

One must remove the treatment chemicals from the wellbore before the corrosion inhibitors lose their potency. The volume and type of displacement fluid used during the treatment determine how much post-job flushing and neutralizing is required.

Certain spent-acid products can form detrimental products and precipitates.

- Residence time—Flow back spent treatment fluids soon after final placement and overflush. One may have to assist the process with CT (and nitrogen), so prepare the surface equipment and CT string accordingly.

- H_2S Hazard—Many stimulation reactions can liberate a small volume of highly concentrated H_2S that reaches the surface. Even a small volume of H_2S is hazardous. Deploy detection and protection equipment.

Computer Simulator Modeling

A matrix stimulation is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model, such as Hydra™, to select the CT string and calculate the relationship between pump pressure and fluid flow rate at the target depth.

Use a reliable tubing forces model, such as Orpheus™, to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH, and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

Prepare a pumping schedule detailing each fluid stage of the treatment. The schedule is a summary of the total operation. It should include the following:

1. Anticipated pump rates and times
2. Volume and density of each fluid stage
3. Description of each fluid used, including:
    - Fluids circulated while RIH with the CT
    - Fluids used to circulate out wellbore fluids or fill material that could damage the formation
    - Fluids used to clean the completion tubulars
    - Preflush and injectivity test fluids
    - Main treatment fluid (including diverter stages)
    - Overflush fluids

Selecting Equipment for Stimulating a Formation

CT Equipment

Use a standard CT workover unit.

Pickle the internal surface of the CT work string before performing the matrix treatment. This treatment provides the following benefits:

- It removes rust and scale deposits that, if injected, can damage the formation.
- Inhibition from the main treatment fluid is more effective if the inhibitor is absorbed onto a clean surface.

Pressure Control Equipment

Use only H_2S service pressure control equipment, as significant quantities of H_2S may be liberated during an acid treatment.

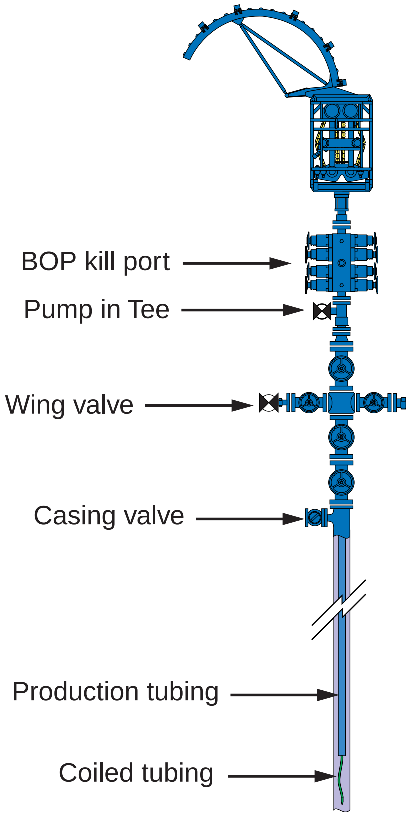
If acid will be pumped through the production tubing, as well as through the CT work string, place the acid injection point below the CT pressure control equipment. Similarly, avoid flowing spent treating fluids through the CT pressure control equipment (Figure 11.9).

Auxiliary Equipment

Ensure that the fluid mixing, handling, and pumping equipment have adequate capacity. Configure them to minimize cross contamination of the fluid stages.

For live well operations, use a choke manifold to control annular returns. Ensure that the CTU, pump, and choke manifold operators all have a clear line of communication with each other and the Customer well-site supervisor.

FIGURE 11.9 *Pressure Control Equipment Configuration*



Downhole Tools

The BHA used for matrix stimulation should include the following components, from the top down:

1. CT threaded connector.

2. Dual flapper type check valves.

3. Straight bar—Optional but useful for running through upsets in the completion, such as side pocket mandrels.

4. Nozzle—A simple passive nozzle is adequate in many cases, as long as it has lateral ports. Some applications require rotating wash nozzles.

Downhole sensors provide real-time data that can be used to monitor bottom hole temperature (BHT) and pressure (BHP). During a matrix treatment, these data can be invaluable for determining the efficiency and progress of the stimulation treatment. Real-time downhole sensor data allow for last minute changes in a treatment design or real-time adjustments to the pumping schedule. For example, BHP is an excellent indicator of the effectiveness of a foam diversion stage.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, fluid flow rates, and total fluid volume pumped. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Stimulating a Formation

Matrix stimulation treatments are commonly conducted on a regular basis within some fields or areas. Whenever possible, refer to similar case histories and adjust procedures for local conditions.

Preparing the Wellbore

1. Remove potential damage sources before conducting the main treatment.

2. Depending on the nature of the treatment and the sensitivity of production components, arrange for alternative surface production equipment and lines, in case corrosive fluids flow back after the treatment.

3. If necessary, remove completion equipment components, such as gas-lift valves or safety valves. Use wireline or CT, whichever is appropriate.

4. Kill the well, if required for safety, fluid compatibility, or production reasons. In most cases the risk of damaging the near wellbore area by bullheading the wellbore fluid is unacceptable. Consequently, the well kill operation may be a part of the wellbore preparation conducted through the CT string.

5. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position and install a protective sleeve.

Preparing the Equipment

1. Pickle the internal surface of the CT work string with a low-concentration inhibited acid. The pickling process can be performed before or after the equipment arrives at the job site. The method for disposing of the fluids from the pickling treatment determines where to perform the process. In many cases, the wellsite production or disposal facility provides the most convenient disposal method.

2. Clean all fluid mixing, pumping, and storage equipment and ensure they are free from solids.

3. If using cementing equipment, perform a pickling/acid treatment on the equipment and lines to prevent solid particles from being released during the treatment.

4. Check that all tanks have accurate volume markers or strip charts to ensure correct treatment volumes.

5. Flush the equipment and lines with clean water to remove potentially damaging solids or liquids.

6. Define pressure and rate limits for every stage of the operation, and note them on the pumping schedule.

7. Prepare surface facilities for separation and disposal of returned fluids and solids.

8. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

9. Assemble the BHA and connect it to the CT.

10. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Preparing Fluids

Monitor the fluid preparation process closely. The efficiency and predictability of any stimulation treatment depends largely on the delivery of the fluid within design specifications. Some checks can be made when the fluid is prepared, such as SG to determine acid strength. However, other critical parameters cannot be confirmed, such as concentration and distribution of corrosion inhibitor, which may have significant effect on the treatment.

Either batch prepare fluid in advance, or mix it on the fly as the operation proceeds. Regardless of the fluid mixing procedure, prepare adequate volumes. Once the operation has commenced, any interruption to the treatment may impair the diversion process. Suspended particulates may require special preparation and storage equipment to ensure that their proper characteristics are maintained.

CAUTION: Always thoroughly mix treatment fluids immediately prior to pumping.

Performing the Matrix Stimulation

1. RIH while circulating water at a slow rate.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

WARNING: Do not pump any treatment fluids before reaching the treatment depth.

2. Stop RIH at the target depth, and start pumping treatment chemicals at the required rate while reciprocating the CT over the treatment depth interval. The treatment depth interval should extend above and below the affected zone by approximately 50 ft.

3. Pump the entire volume of treatment chemicals specified in the work program, unless directed otherwise by the Customer supervisor.

4. After expending the treatment chemicals, POOH while circulating inhibited water to displace the treatment chemicals from the CT. Completely displace the CT and surface piping to water before the CT reaches the surface.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

5. Allow sufficient time for the treatment chemicals to act. Then flow the well while continuously monitoring the pH of the produced fluids.

Flowback and Clean-up

1. In general, flow back spent fluids as soon as possible. Following clay damage treatments, however, only gradually increase the production rate to minimize the migration of fines.

2. Monitor the pH of wellbore fluids during the cleanup period.

3. Clean the equipment internally and inspect it following every operation. The extent to which the pressure control equipment should be flushed and the fluids neutralized depends on the likelihood of corrosive fluid contact. Due to the nature of the equipment, assume that it was exposed to acid.

4. If the well does not flow naturally or when aided by gas lift, prepare to conduct nitrogen lifting operations (Section “Unloading a Well with Nitrogen”).

Post-job Tool Maintenance

Service all downhole tools that have been exposed to corrosive fluids as soon as possible following retrieval. At a minimum, break the tools at all service joints and flush clean.

Monitoring for Stimulating a Formation

Monitor and record the fluid injection rate, BHP, and surface pressure during the matrix operation. This data indicates the efficiency of the damage removal.

Typical parameters to monitor or record during any matrix stimulation operation include the following:

- Injection pressure—to monitor injectivity and ensure predetermined limits are not exceeded.
- BHP (real time)—for maximum efficiency in crucial treatments.
- Injection rate—to evaluate response to initial treatment and check effect of any diversion systems used
- Fluid quality—to ensure that the fluids are injected as designed, e.g., acid concentration, foam quality. Take samples of all raw and mixed fluids and keep them until the job is completed and fully evaluated. For all fluids, record the pH and specific gravity (SG).
- Safety and environmental monitoring—continuously monitor wellbore returns during and after a stimulation treatment for the presence of H_2S which may be liberated as a result of the treatment. In addition, monitor the pH of return fluids to ensure that process plant or disposal issues are satisfied, e.g., appropriate disposal of spent acid products which may still be significantly corrosive.

Analyze the improvement in reservoir flow characteristics to judge the success of the matrix acidizing treatment. Compare the response of the reservoir with the model of an ideal reservoir to assess the degree of damage.

Safety Issues for Stimulating a Formation

Always conduct a pre-job safety meeting prior to RIH.

All personnel involved in the execution of matrix stimulation services must be familiar with the relevant safety standards for handling the treatment chemicals.

H_2S might be liberated following any acid treatment, and corrosive treatment fluids may be produced to surface. Take appropriate precautions during post-treatment work. Use a scavenger to protect against the effects of H_2S. In most cases, apply H_2S protection to the exterior surface of the CT, and include it in the treatment fluid.

Safety precautions for using acid or hazardous chemicals in CT operations should include the following:

- Provide a readily accessible and abundant supply of water (usually fire hoses).
- Provide an ample supply of soda ash (to neutralize acid).
- Position eye baths at strategic locations around the area.
- Require face guards and protective clothing for all personnel likely to contact the treatment chemicals.
- Whenever possible, use pre-mixed acid. Always add acid to water, not vice versa. Use extreme caution when mixing acid or hazardous chemicals.
- Properly train all personnel to safely handle the treatment chemicals and follow emergency procedures in case of spills or exposure.
- Prominently display large, weather-proof safety signs around the location with the following information:

    1. Types of chemicals in use and their constituents
    2. Relevant safety precautions for each chemical.
    3. Emergency actions in event of chemical spill.
    4. First aid treatment in case of human contact.

5. Emergency telephone number(s) for additional information.

- Thoroughly wash and rinse all equipment after exposure to the treatment chemicals.

CUTTING TUBULARS WITH FLUIDS

Two common applications for tubing cutters are:

- Severing a stuck work string (CT or jointed pipe) in preparation for fishing
- Severing casing or production tubing as part of workover applications to retrieve the pipe

The two types of fluid-based cutters come in a variety of sizes to suit most wellbore tubulars, from drill pipe to CT.

- Chemical cutters
- Abrasive jet cutters

Abrasive jet cutters create a focussed high-pressure jet of fluid containing abrasive particles. The nozzle on the cutting tool rotates 360º to cover the entire circumference of the surface to be cut. The abrasive particles entrained in the high velocity jet rapidly erode the target material. Hydraulic HP (impact force) delivered to the target surface, hence the performance of the tool, decreases rapidly as the tool stand-off from the target surface increases. The cutting tool must be concentric with the pipe to be cut and the annular space between the two as small as possible for the most efficient cutting. This may be a problem where the surface to be cut is below a wellbore restriction (e.g., landing nipple) that limits the size of cutting tool which can be run.

Mechanical and explosive cutters are also available for use with CT. Chapter 12 "Cutting Tubulars Mechanically", page 12-70 describes these other tubing cutters.

Planning for Cutting Tubulars with Fluids

Job Plan Inputs

One must know the following information to plan an operation for cutting tubing with fluids:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Target tubing dimensions and properties
- Tubing cutter operating characteristics

- If abrasive jetting, the treatment fluid (slurry) properties
- If abrasive jetting, the properties of the solid particles
- Wellhead and surface equipment configuration

Abrasive Cutters

Abrasive cutters operate on the principal of concentrated erosion from a hard abrasive material entrained in the fluid flow. Abrasive cutters direct a particle laden fluid onto the target tubular at high pressure. The cutter has a rotating nozzle to provide a circumferential cut.

Select a cutter to minimize the stand-off, the distance between the cutter jet and the surface to be cut. Cutter efficiency quickly deteriorates with increased stand-off. Obtaining a small stand-off can be difficult if the area to be cut is below a wellbore restriction that constrains the size of the tool.

Consider the following factors when designing a cutting operation using an abrasive fluid:

- Tool selection—tool size and jet(s) diameter for the given geometry (stand-off) and fluid flow rate available.
- Fluid selection—Water and polymer (gelled) fluids are suitable for this application. However, the latter is more effective at suspending the dense abrasive particles and removing the debris from the wellbore.
- Abrasive particles selection—The type and size of particles depends primarily on the properties of the target material. The concentration of particles in the fluid depends on the size of the nozzle(s) in the tool. The total volume of particles required depends on the circulating volume and the quantity of particles that drop out of the fluid with each circulation.
- Pump pressure—Abrasive jet cutting tools operate best at pressures above 5000 psi. Depending on the CT string, the pump pressure may exceed 10,000 psi. Verify that adequate hydraulic HP is available for the job.
- Monitoring fluid properties—Most abrasive particles are quite dense, and some will drop out of the carrier fluid during each circulation. A means of monitoring the concentration of particles is necessary to ensure uniform cutting performance throughout the job. Due to the high shear rate created at the cutter nozzle(s), any shear-sensitive polymer added to the fluid will degrade quickly. Monitoring the fluid rheological properties is necessary to ensure the fluid meets the job design specifications.
- Depth control—Precise depth control is essential. A depth correlation run with a TEL or CCL prior to running the tubing cutter will reduce the risk of severing the pipe at the wrong location.

Chemical Cutters

Chemical cutters operate on the principal of extremely rapid corrosion. One lowers a jet cutter containing a highly corrosive fluid to the depth where the tubular is to be cut. Then an electrical detonation activates the jet cutter, discharging the corrosive fluid through radial jets at high pressure onto the tubular surface.

Select a cutter to minimize the stand-off, the distance between the cutter jet and the surface to be cut. Cutter efficiency quickly deteriorates with increased stand-off. Table 11.4 shows typical specifications for a chemical cutter. Table 11.5 shows the OD of chemical cutter to be used for each size of CT.

TABLE 11.4 *Typical Internal Tubing Cutter Specifications*

Specifications	
Dimensional Specifications	
Length (in.)	
Minimum	84
Maximum	108
OD (in.)	
Minimum	0.687
Maximum	4.687
Weight (lb)	±80
Operating Specifications	
Maximum Operating Temperature (F)	325
Maximum Operating Pressure (psi)	10,000
Deployed by:	Wireline/CTL

TABLE 11.5 *CT Internal Cutter Specifications*

CT OD	**Cutter OD (in.) (Chemical)**
1.00 in.	0.687 or 0.750
1.25 in.	0.937 or 1.000
1.50 in.	1.063 or 1.125
1.75 in.	1.250

A major advantage of chemical cutters is that they cause virtually no distortion to the severed ends of the tubing, even for CT or ductile material. These clean ends simplify any subsequent fishing operations.

Computer Simulator Modeling

Cutting tubulars with abrasive jetting is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model such as Hydra™ to select the CT string and predict the relationship between the fluid flow rate and the pump pressure for different operating conditions. Determine or evaluate the following:

- For jetting, the pump pressure required for the minimum effective jetting pressure (flow rate)
- For jetting, the flow rate at the maximum allowable pump pressure
- The minimum annulus velocity necessary to remove the abrasive particles in each section of the wellbore

---

NOTE: The highest minimum velocity sets the minimum flow rate for the jetting operation.

Use a reliable tubing forces model such as Orpheus™ to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

A basic job plan for cutting tubulars with abrasive jetting includes the following:

- Minimum flow rate for effective cutting
- Maximum flow rate
- Estimated time required for severing the target tubing

Prepare contingency plans for the following situations:

- The maximum flow rate attainable is not high enough for optimum cutting action
- The abrasive particles returning to surface damage the choke or other pressure control equipment
- The cut does not go completely through the target
- The severed ends of the tubing are extremely ragged

Selecting Equipment for Cutting Tubulars with Fluids

CT Equipment

Any CT string is suitable for an abrasive jet cutter operation. However, the larger the ID of the CT, the higher the fluid circulation rate and annular velocity for a given pump pressure.

For chemical cutters, any CT string that can safely deliver the cutter to and retrieve it from the target depth is acceptable.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for abrasive jet cutter operations. Configure the equipment to avoid circulating corrosive or solids-laden return fluids through the BOP. In the event some treatment fluid inadvertently reaches the BOP or choke manifold, thoroughly clean that equipment, disassemble it, and inspect it for any residual solids.

Pumping Equipment

Mixing and storage equipment must be capable of maintaining the abrasive particles in suspension in the treatment fluid. Pumps must be sized to provide the hydraulic HP required for jetting operations.

Downhole Tools

The BHA used for cutting tubular should include the following components, from the top down:

1. CT threaded connector.

2. Dual flapper type check valves.

3. Straight bar—Optional, but useful for running through upsets in the completion.

4. TNL or TEL - For depth correlation.

5. Cutting tool—Either chemical cutter or abrasive jetting tool.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, and fluid flow rates. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Cutting Tubulars with Fluids

The steps required to successfully cut a tubular depend on the particular conditions encountered in each case. This generic procedure is simply an outline for the key steps.

Preparing the Wellbore

1. Determine as accurately as possible the depth (location) for making the cut.

2. Kill the well, if required.

3. Conduct any slick line or wireline work such as pulling gas lift valves.

4. Prepare the wellhead and surface facilities for circulation of returned fluids and solids. Take precautions to prevent abrasive or corrosive fluids from circulating through the BOP.

5. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position and install a protective sleeve.

Preparing the Equipment

1. Prepare the fishing tools or other means of retrieving the piece(s) of severed tubular.

2. If using an abrasive cutter, batch mix the treatment fluid.

3. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

4. Assemble the BHA and connect it to the CT.

5. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Cutting the Tubular

1. RIH to a depth about 25 ft above the profile nipple or end of the tubing targeted for depth correlation and stop.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. RIH slowly to the profile nipple or end of the tubing and correlate the indicated depth with the actual depth. Flag the CT.

3. While pumping inhibited water at a slow rate, RIH or POOH to the target depth for the cut.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

4. Activate the chemical cutter or switch to the treatment fluid and increase the fluid flow rate to the designated operating level for the abrasive cutter.

5. Wait for the prescribed length of time for the cutting chemical or abrasive jet to make the cut.

6. After the waiting period, begin pumping water at a high rate.

7. POOH while pumping water at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring for Cutting Tubulars with Fluids

The only requirement is to wait for the specified amount of time to allow the cutter to work.

Safety Issues for Cutting Tubulars with Fluids

Always conduct a pre-job safety meeting before RIH.

The contents of chemical cutters are extremely dangerous. Only the tool supplier or other qualified personnel should handle a chemical cutter.

PUMPING SLURRY PLUGS

Slurry plugs include several different types of fluids. Different types are used for different applications.

- Permanent plugs—For example, place a cement plug to abandon a lower production zone.
- Temporary plugs—For example, place a sand plug to protect lower perforations from treatments conducted on upper intervals. Also a temporary plug might serve as a platform to support cement or resin during a zonal isolation squeeze job (see Section “Isolating Zones (Controlling Flow Profiles)”).

The most common types of pumped plug/platform include:

- Cement—a solid plug or base for a variety of applications, e.g., zone abandonment, side-track, or kick-off. Cement can be placed at the bottom of the wellbore or balanced to provide an intermediate plug within the wellbore.
- Gypsum—a fairly high integrity plug of ground gypsum that can be removed relatively easily by acidizing, e.g., temporary abandonment or isolation plug. As with cement, this type of plug may be placed at the bottom of the wellbore or balanced to provide an intermediate plug within the wellbore.
- Sand/barite—a nearly impermeable plug of mixed particle size that can subsequently be circulated from the wellbore. Since this plug does not “set” it can only be placed at the bottom of the wellbore.
- High-viscosity polymer—a non-damaging, easily-removed fluid plug. Depending on the performance and characteristics, polymers can be set as balanced plugs within the wellbore.

See Chapter 12 "Setting a Plug or Packer", page 12-4 for a discussion of mechanical plugs.

Planning for Pumping Slurry Plugs

The primary objective of the job plan for placing a slurry plug is a pumping schedule with the volume, flow rate, CT running speed, and squeeze pressure for each treatment fluid stage in the operation.

Job Plan Inputs

One must know the following information to plan for pumping a slurry plug:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties

- Treatment fluid properties
- Target zones (depths, pressures, temperatures, permeability, porosity, fluids)
- Wellhead and surface equipment configuration
- Perforations (location and size)
- Volume of the work string

Planning Considerations

Although the nature and composition of the plug systems described above are quite different, the main tasks for pumping a plug are very similar. These include:

- Determine the job's objective—permanent or temporary plug or platform.
- Acquire accurate design data—the accuracy of data used to design the operation is crucial to success. Temperature and pressure conditions will affect the performance of cement and polymer and wellbore/formation conditions will affect the required treatment volume.
- Select or design the slurry plug—based on the treatment objectives and design data. If appropriate, test the fluid at simulated operating and wellbore conditions to insure that pumping time will be adequate and the slurry will perform properly.
- Prepare the wellbore—remove any fill, cuttings beds, scale, asphalt, or wax across the target zone.
- Depth correlation—run a TEL or CCL to determine the precise MD of the target zone according to the CT depth indicator and flag the CT
- Prepare the retaining platform (cements and polymer)
- Place the slurry at the target depth—the procedure may require a squeeze or static period for the treatment fluid to set or achieve the desired properties.

Slurry Volume

A number of factors influence the volume of slurry required for placing a plug. These factors include:

- Length of plug and capacity of the wellbore.
- Void areas behind the perforations, washouts (open hole), cuttings beds, and junk in the hole.
- The effects of the slurry on the force and stress applied to the tubing. Heavy slurry inside the CT would increase both.
- The configuration of surface mixing and pumping equipment. Reducing the volume of surface lines reduces the likelihood of slurry contamination.
- Use of wiper plugs, pigs, or darts to ensure separation of slurry in the CT string reduces the excess slurry volume necessary to provide a buffer against contamination.

Slurry Pumping Schedule

The pumping schedule for placing a pumped plug depends on the number and volume of treatment fluid stages. Note the pressure limit and range of acceptable flow rates for every stage of the operation on the pumping schedule.

Plug Placement

- Plug stability—Do not place a slurry column over a lighter fluid. Use a “temporary retaining platform”, such as a mechanical plug to stabilize the column. Under some conditions, one can place the slurry column from the bottom of the rat hole.
- Depth correlation—In order to accurately place the plug, one must place the CT nozzle with a high degree of accuracy. Surface measurements alone are inadequate, due to the effects of stretch, buckling, and residual bend. Instead, use a downhole reference point to achieve accurate placement.

Slurry Considerations

One must mix and pump the slurry carefully in order to maintain predictable slurry characteristics.

- Design data—Obtain data on the temperature and pressure conditions, which affect fluid characteristics, and wellbore and formation conditions, which affect treatment volumes. If unable to obtain accurate data, make assumptions based on local experience. Use this data to select the additives in the slurry.
- Slurry mixing—When mixing additives in the field, use the same proportions that were used in laboratory testing to replicate laboratory characteristics.
- Slurry contamination—Contaminated slurry can cause unpredictable slurry characteristics, such as a reduction in the compressive strength of the set cement, and incorrect placement, due to the change in slurry volume. To avoid contaminating the slurry, pump spacer fluids, such as fresh water, ahead of and behind the slurry.

Computer Simulator Modeling

Pumping a slurry plug is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model such as Hydra™ to select the CT string and calculate the relationship between the fluid flow rates and the pump pressures for each stage of the pumping operation. Determine the maximum flow rate possible for each fluid without exceeding the maximum allowable ECD. For a given flow rate of slurry, calculate the speed for POOH with the CT.

Use a reliable tubing forces model such as Orpheus™ to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

A basic job plan for pumping a slurry plug includes the following:

- Depth correlation method
- Method of placing a supporting platform
- Formulation and properties for the slurry
- Mixing procedures
- Volume of each fluid stage
- Pump rate for each fluid stage
- CT running speed (if any) for each fluid stage
- Squeeze pressure (if any) for the slurry
- Waiting period for each stage

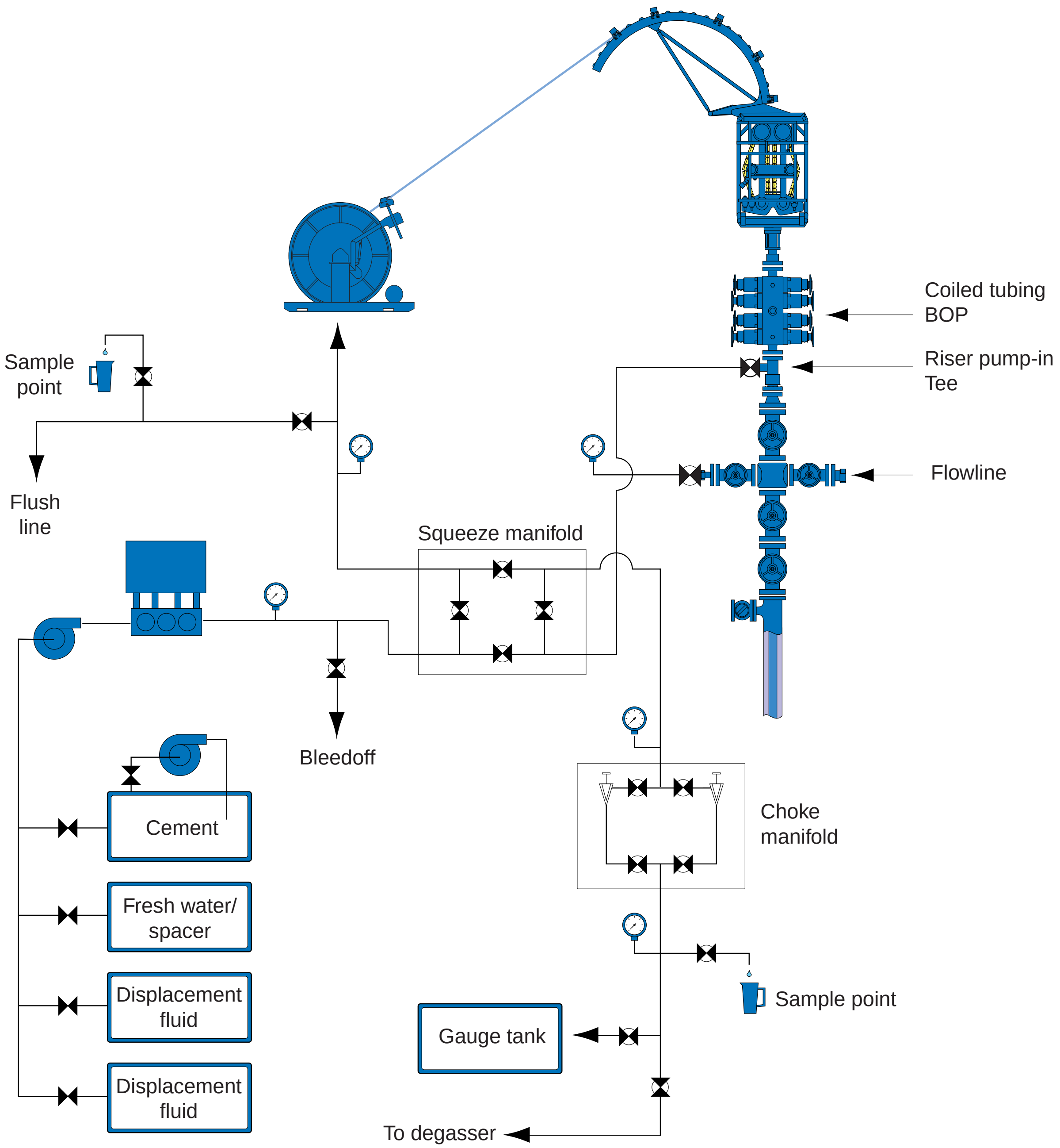
Prepare contingency plans for the following situations:

- The treatment fluid setting or curing time after placement is much longer than planned
- Unable to pump at the planned rate
- The supporting platform for the plug fails
- Cannot maintain the desired squeeze pressure
- For cementing, cannot circulate out the excess cement

Selecting Equipment for Pumping Slurry Plugs

Figure 11.10 shows a schematic diagram of typical equipment layout for pumping a slurry plug.

FIGURE 11.10 *Typical Equipment Configuration for Pumping a Slurry Plug*



CT Equipment

Any CT string, even one containing and electric cable that will provide the necessary flow rate is suitable for pumping a slurry plug. However, CT strings containing electric cable negate the use of ball-activated tools and wiper plugs, are more difficult to clean thoroughly, and are much more costly to replace in the event the slurry can't be removed completely.

Rig a flushing or sampling manifold on the CT reel to minimize contamination.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for pumping slurry plugs. In the event some slurry inadvertently reaches the BOP or choke manifold, thoroughly clean that equipment, disassemble it, and inspect it for any residual solids.

After the operation, flush all manifolds and valves to remove all traces of solids.

Pumping Equipment

Define pressure and rate limits for each stage of the operation, and note them on the pumping schedule.

Clean and configure all fluid mixing, pumping, and storage equipment to avoid contaminating or diluting the slurry.

After the operation, flush all manifolds and valves to remove all traces of solids.

Downhole Tools

The BHA used for pumping slurry plugs should include the following components, from the top down:

1. CT threaded connector.
2. Dual flapper type check valves.
3. Straight bar—Use approximately 6 ft. This optional item is especially helpful for running through upsets in the completion, such as side pocket mandrels.
4. TEL or TNL - For depth correlation.
5. Jetting nozzle—There are no special nozzle requirements. It can be as simple as a few holes drilled in a bull plug.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, and fluid flow rates. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Pumping Slurry Plugs

Preparing the Wellbore

1. Perform any slick line work, such as fitting dummy gas-lift mandrels.
2. Confirm and correlate depths with CT and flag the tubing if appropriate.
3. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position and install a protective sleeve.
4. Place a stable platform, if required, for the plug slurry. See Chapter 12 "Setting a Plug or Packer", page 12-4.

Preparing the Equipment

1. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.
2. Accurately measure the volume of the CT by drifting it with the largest wiper plug required for the upcoming plug job. Pump the drift through the CT with water from a calibrated displacement tank.
3. Assemble and install the BHA on the CT.
4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.
5. Make contingency plans for disposing slurry that fails to meet the required specifications.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Pumping (Placing) the Slurry Plug

1. RIH while pumping inhibited water at a slow rate.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

WARNING: If cementing on top of a bridge plug, keep the pressure differential across the plug as low as possible.

---

2. Reduce running speed per Chapter 18 "CT Running Speeds", page 18-18 near profile nipples or the bottom of the production tubing. Correlate the depth using the TEL.

3. Slackoff to a depth of approximately 5 ft above the bridge plug or to the depth specified in the work program.

4. Mix and pump the slurry in batches. The maximum batch size is the wellbore volume between the pumping depth and the tubing tail pipe.

- Mix the slurry according to the recipe in the work program.

CAUTION: Keep the slurry well mixed (agitated) at all times.

- Conduct job-site quality control tests on the slurry. Dispose of slurry that fails to meet the required specifications.
- Open the vent valve on the CT reel and close the reel inlet valve.
- Pump the slurry from the mixing tank to the CT reel.
- After clean slurry discharges from the reel vent valve, open the reel inlet valve and close the reel vent valve.
- Chase each slurry batch with plugs and a spacer fluid.

5. While displacing the slurry from the CT, POOH, keeping the CT nozzle about 10 ft below the slurry interface.

6. After pumping the total volume of slurry required by the work program and bumping the plugs, slowly pull the CT clear of the slurry by approximately 100 ft. Shear the top plug.

7. When squeeze cementing, close the production wing valve and apply approximately 1000 psi squeeze pressure for 15 minutes.

8. Pump water at the highest rate possible until the CT reel is free of slurry and POOH.

9. When squeeze cementing, wait on the cement to set for the time specified in the program. When placing other slurries, allow the plug time to settle.

10. After the slurry has set, RIH slowly while pumping inhibited water at a slow rate. Gently tag the plug.

WARNING: Pay close attention to the maximum running speeds per Chapter 18 "CT Running Speeds", page 18-18

Monitoring for Pumping Slurry Plugs

Test the plug once it stabilizes. The duration and pressure of the test depends on the local conditions. For example, test injection wells to the injection header maximum pressure. Pressure test wells to be re-perforated and fractured to the maximum BHP anticipated in during the fracturing treatment.

Safety Issues for Pumping Slurry Plugs

Always conduct a pre-job safety meeting prior to RIH. However, this operation does not pose any job-specific safety issues.

ISOLATING ZONES (CONTROLLING FLOW PROFILES)

Zonal isolation using cement, resin, or polymer is a common CT application for preventing the production of unwanted oil, gas, or water from a specific interval.

- Cement—Usually includes additives to enhance performance under the bottom hole temperature and pressure, and formation permeability. It performs its blocking function outside the rock matrix. Due to the maturity of the technology and its relatively lower cost, squeeze cementing is the most frequently used technique.
- Resin—Similar to cement, resins form a solid mass after being placed in the formation matrix. Also, like cement, they have a limited pumping time.
- Polymer—Unlike the cement or resin, polymers typically form a permanent, highly viscous gel that reduces permeability through the reservoir matrix.

NOTE: Zonal isolation materials have a higher viscosity than most types of workover fluid. This higher viscosity significantly reduces the maximum allowable pump rate.

Although the nature and composition of the three systems described are quite different, the main tasks for a zonal isolation operation are very similar. These include:

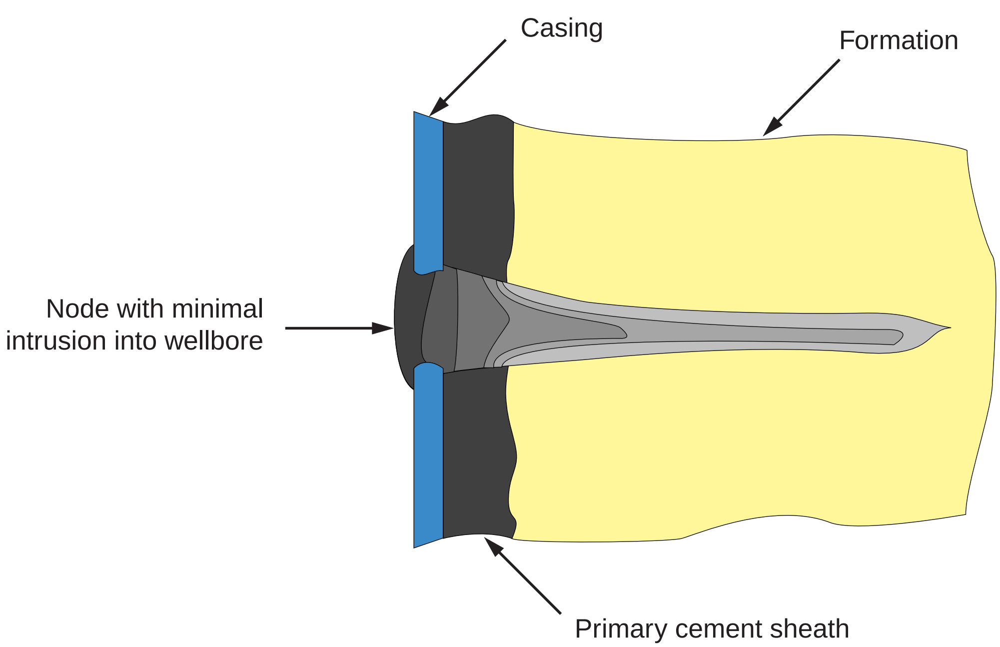
- Determine the treatment objectives—shut off selected perforations, stop a gas or liquid leak in the primary cement sheath, redirect injected fluids into another zone, stop inflow from certain zones, etc.
- Preparation—Investigate the need for pre-job treatments, such as removal of wellbore fill to ensure complete and effective coverage.
- Acquire accurate design data—the accuracy of data used to design the operation is crucial to success. Temperature and pressure conditions will affect the performance of the treatment fluid, and wellbore/formation conditions will affect the required treatment volume.
- Select or design the treatment fluid—based on the treatment objectives and design data. Test the fluid at simulated operating and wellbore conditions to insure that pumping time will be adequate and the treatment fluid will perform properly.
- Prepare the wellbore—remove any fill, cuttings beds, scale, asphalt, or wax across the treatment zone.
- Depth correlation—run a TEL or CCL to determine the precise MD of the treatment zone according to the CT depth indicator and flag the CT
- Prepare the retaining platform (cements and resins) or diversion method (polymers)
- Place the treatment fluid across the zone of interest—The procedure may require a squeeze or static period for the treatment fluid to set or achieve the desired properties. Placing uncontaminated treatment fluid accurately is imperative.

- Post placement period—The fluid might require a residence period under “static” conditions after it has been placed. This waiting time may conflict with an operational desire to clear the wellbore of excess material or to return the well to production.
- Evaluate the treatment results

Squeeze Cementing

When cement slurry is forced against a permeable formation, some of the liquid phase enters the formation matrix while the slurry solids filter out on the rock face. A CT squeeze consists of gradually increasing the pressure against the cement in predetermined increments. With a properly designed slurry and squeeze procedure, a firm filter cake will form at the rock face allowing the final squeeze pressure to exceed the formation fracture pressure. Cement squeezed into a perforated interval forms a tough node (plug) at each perforation (see Figure 11.11) that will stay in place during removal of the excess cement in the wellbore. A good method of cleaning out the wellbore is to contaminate the cement before it begins to set and simply flush it from the wellbore. This procedure avoids drilling or underreaming operations to clean the wellbore.

FIGURE 11.11 *Cement Node Buildup*



CT squeeze cementing is a reasonable solution to the following conditions:

- Water or gas channeling as a result of an incomplete primary cementing job
- Injection water or gas breakthrough.
- Gas or water coning caused by production or reservoir characteristics.

- Isolation of unwanted or depleted perforated intervals.
- Losses to a thief zone or inefficient injection profile on an injection well.

CT squeeze cementing techniques offer several advantages over conventional workover rig practices for treating these conditions. These advantages include:

- The CT pressure control equipment configuration allows the treatment to be performed through the completion tubulars.
- Preliminary or associated operations can be performed as part of a packaged service, e.g. remove wellbore fill before the job or conduct nitrogen lift services afterwards to restore production.
- Placing the treatment fluid through CT avoids contamination from wellbore and displacement fluids.
- CT allows continuous placement of treatment fluid while the work string is moving.
- CT requires smaller treatment volumes
- Removal of excess slurry and cleaning of the wellbore is simpler.
- Trip times are shorter.

Resins and Polymers

Resins provide a hard impenetrable mass once cured. They typically have a limited pumping time, after which the resin hardens and becomes extremely difficult to remove.

Polymers differ from cement and resins in that they form a highly viscous mass within the formation matrix. The treatment fluid is generally easier to mix than a cement or resin, is easier to place in varying permeability, and has more predictable performance.

The design and placement of resin and polymer treatments is a complex process requiring specialist assistance and highly specialized fluids. A comprehensive description of fluid formulations and explanation of various job designs is beyond the scope of this manual.

Planning for Isolating Zones

The primary objective of the job plan for zonal isolation is a pumping schedule with the volume, flow rate, CT running speed, and squeeze pressure for each treatment fluid stage in the operation.

Job Plan Inputs

One must know the following information to plan a zonal isolation operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Treatment fluid properties
- Target zones (depths, pressures, temperatures, permeability, porosity, fluids)
- Wellhead and surface equipment configuration
- Perforations (location and size)
- Volume of the work string
- Method of creating a cementing platform (see Section "Cement Column Stability")

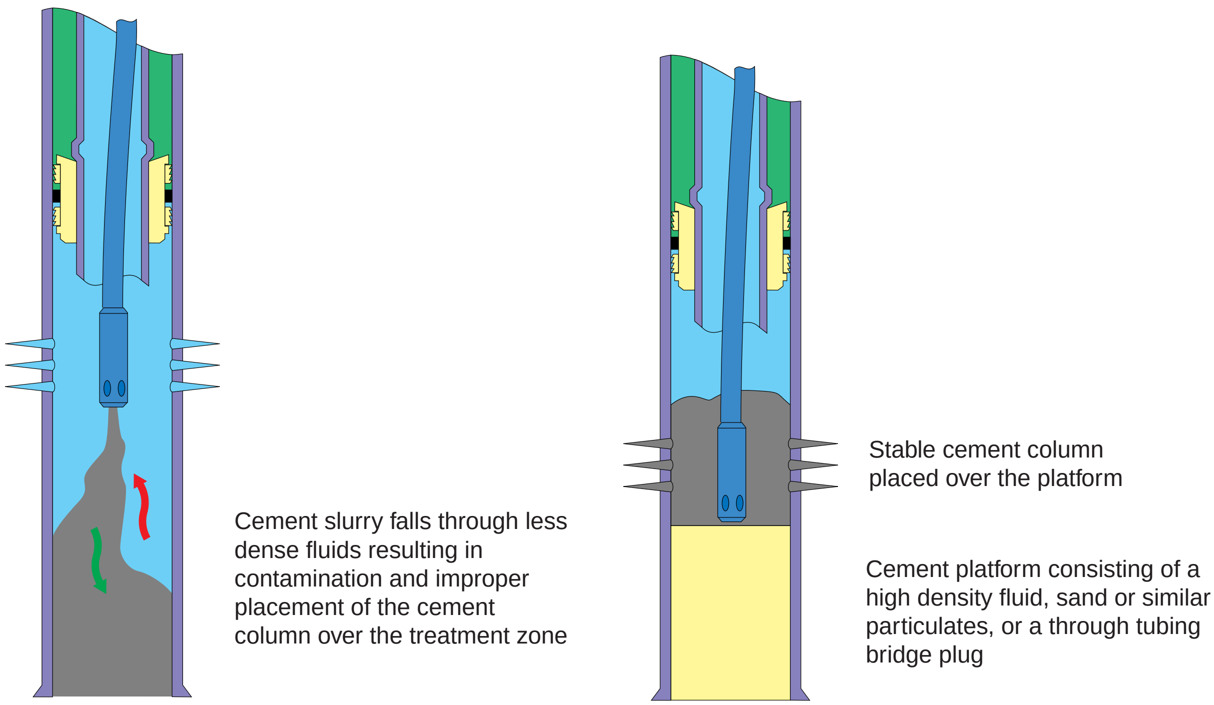
A number of factors influence the volume of slurry required for a CT cement squeeze. These factors include:

- Length of perforated interval and capacity of liner/casing.
- Void areas behind the perforations resulting from the erosion of friable and unconsolidated formations or from stimulation treatments.
- The effects of the cement on the force and stress applied to the tubing. Heavy cement inside the CT would increase both.
- The configuration of surface mixing and pumping equipment. Reducing the volume of surface lines reduces the likelihood of slurry contamination.
- Use of cement plugs, pigs or darts to ensure separation of slurry in the CT string reduces the excess slurry volume necessary to provide a buffer against contamination.

Cement Column Stability

A stable cement column cannot be placed off-bottom over a less dense fluid (Figure 11.12).

FIGURE 11.12 *Cement Placement with and without a Retaining Platform*



To ensure correct cement placement, a retaining platform must be used. Another reason to use a cementing platform is to temporarily block perforations below the zone to be squeezed. The nature and size of an appropriate platform depends on each case. Under some conditions it may be appropriate to place the cement column from the bottom of the rat hole. Cementing platforms include:

- Excess cement slurry
- Weighted gel
- Sand
- Calcium carbonate
- Bridge plug

Except for excessive cement slurry, each of these platforms is removable after performing a cement squeeze on a shallower zone. (See Section “Pumping Slurry Plugs” and Section “Setting a Plug or Packer”.)

Laboratory Testing of Materials

Zonal isolation materials must undergo special laboratory testing that simulates actual conditions for CT. The purpose of this testing is to determine the correct composition and mixing procedures for the material.

The principal characteristics of zonal isolation material are the following:

- Thickening or setting time
- Filter-cake properties/fluid loss
- Rheology

A cement slurry only becomes stable when it receives sufficient shear energy. Enough shear energy must be imparted to the slurry to achieve stable characteristics, both during laboratory testing, and in the field (by mixing it and pumping it through the CT).

Resins and polymers just need enough mixing to thoroughly combine their components. In fact, most polymers are shear sensitive and degrade with too much mixing.

Cement Thickening Time

Typically, the thickening times of squeeze cementing slurries are tested according to API testing schedules developed for use with drill pipe or tubing placement. For a CT cement squeeze, make sure testing is performed with appropriately modified versions of the API schedules. A typical modified test schedule for CT operations is shown in Table 11.6.

TABLE 11.6 *Typical CT Cement Slurry Test Sequences*

Slurry Type	Stage	Description
Squeeze Slurries	Mixing	Two hours at surface temperature and atmospheric pressure to simulate batch mixing and surface operations.
	Placement	Two times the placement time (calculated from slurry and displacement volumes using anticipated pump rates for the CT size to be used). Apply a constant gradient increase to bottomhole pressure (BHP) and temperature (BHST).
	Squeeze	A 30 min period during which the temperature is kept constant and the pressure is increased to the bottomhole squeeze pressure.
	Post-squeeze	Five hours during which temperature is kept constant at BHST and the pressure is decreased from squeeze pressure back to BHP + 500 psi.
Plug Slurries	Mixing	Two hours at surface temperature and atmospheric pressure to simulate batch mixing and surface operations.
	Placement	Two times the placement time (calculated from slurry and displacement volumes using anticipated pump rates for the CT size to be used). Apply a constant gradient increase to bottomhole pressure (BHP) and temperature (BHST).
	Curing	Five hours during which temperature is kept constant at BHST and the pressure is decreased from squeeze pressure back to BHP.

Instead of conducting tests with the bottomhole circulating temperature (BHCT), as in conventional API test schedules, conduct thickening or setting time tests with the bottomhole static temperature (BHST).

The test procedure should closely simulate the anticipated mixing and pumping procedure, because the mixing energy imparted to the material also influences its performance. The recommended thickening or setting time is typically the predicted job time plus a safety factor of 40-50%.

Cement Fluid Loss

Cement slurries require additives to control fluid loss. The proper amount of fluid loss ensures the creation of good quality filter cake on permeable surfaces in and around the perforation tunnel. Ultimately, this filter cake should cure to form an impermeable cement node with sufficient compressive strength to remain secure at the anticipated differential pressure. Excessive fluid loss can cause dehydrated cement to bridge the well bore tubulars. Too little fluid loss can cause an insufficient buildup of filter cake on the formation surface.

Depth Correlation

Zonal isolation is very depth-sensitive, so the CT nozzle must be positioned with a high degree of accuracy. Surface measurements alone are inadequate, due to the effects of stretch, buckling, and residual bend. Instead, use a downhole reference point to achieve accurate placement.

Two methods for acquiring a depth reference include the following. (Note that although a depth reference can be acquired with a log correlation, this method is incompatible with zonal isolation operations.)

- Tagging bottom—This is a viable method, and is often used, except for wells containing fill, and in deviated wells or large completions which induce buckling of the CT.
- Tagging completion restrictions—The most practical method is to locate restrictions in the completion tubulars with a tubing end locator (TEL) or tubing nipple locators (TNL).

Protection Against Contamination

Contamination of the isolation material creates the following problems:

- Unpredictable material characteristics
- Reduction in the compressive strength of the set cement or resin, lower viscosity for a polymer
- Incorrect placement due to the change in treatment volume.

Sources of contamination include surface lines and pumping equipment. To avoid contamination, pump spacer fluids ahead of and behind the isolation material. The most commonly used, and generally most appropriate spacer fluid, is fresh water.

1. Rig a reel manifold sampling point and flush line to flush the surface lines each time a new fluid is pumped. (Figure 11.13).

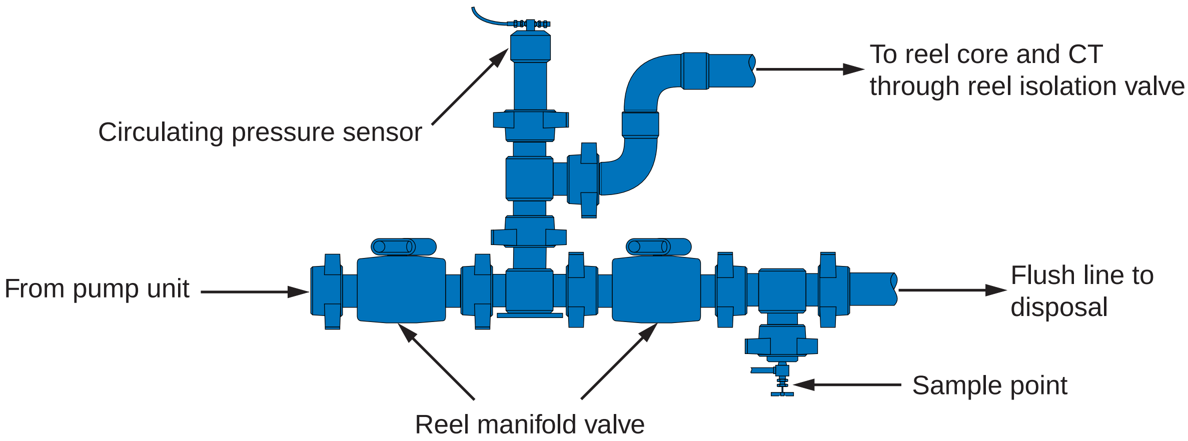
2. Isolate the CT reel and open the flush line at a sample point.

3. Pump the new fluid until uncontaminated fluid is observed at the sample point.

4. Realign the manifold values and take a fluid volume reference.

5. Recommence pumping downhole.

FIGURE 11.13 *Reel Manifold Sampling Point and Flush Line*



Zonal isolation materials can also be separated mechanically, using CT plugs (darts or pigs). Such plugs operate in the same manner as the casing plugs used in primary cementing operations. Plugs are fitted with rupture disks or land in a plug catcher, providing a positive indication of plug location. Plug launching equipment fitted to the reel allows several plugs to be pre-loaded and then launched in sequence without affecting the pressure integrity of the reel or manifold.

Squeeze

As the effect of placing and squeezing a material across the treatment zone is often unknown, prepare procedures detailing actions for several possible outcomes. In some cases, squeeze pressure may build quickly as the material contacts the formation face. However, in formations with fractures or void spaces behind the liner or casing, squeeze pressure may not be achieved.

Removal of Excess Fluid and Material

An important feature of CT workovers is the ability to complete operations and restore the well to production in a relatively short time. In squeeze cementing operations, efficient removal of excess cement from the wellbore is critical to the timely completion of the job. Efficient removal of the slurry without jeopardizing the integrity of the cement nodes can be achieved using several methods:

(A) Reverse Circulating Live Cement

Reverse circulation of live cement slurry (uncontaminated slurry) can be safely performed under the following conditions:

- The well is dead after placement of the cement.
- The designed slurry thickening time (including safety factor) allows for completion of the reversing phase of the operation.
- The CT penetration rate is controlled to effectively dilute the slurry as it is removed (maximum density of reversed fluid is 10 lb/gal).
- Reversing is continued until clean returns are observed at the surface.

(B) Reverse Circulating Contaminated Cement

Contamination of the excess cement is often necessary to extend the slurry thickening time, thereby allowing cleanout operations to be completed safely. In addition, contaminating the excess slurry can allow cleanout operations to be delayed until the cement nodes have increased to the desired compressive strength.

(C) Circulation of Contaminated Cement

If reverse circulation of the excess slurry cannot be safely supported under the operating conditions, conventional circulation may be used. For example, operations performed through 1.25 in. work strings cannot employ reverse circulation techniques, due to the excessive friction pressure encountered.

Material Mixing and Pumping

If a new material will be used, a yard test may be useful after lab testing has been completed. In a yard test, the material should be mixed in the service company's yard using the same type of equipment that will be used on location. This test is necessary because isolation materials can act differently when mixed in a field blender versus when mixed in a lab blender.

Key points in the mixing and pumping process include the following:

- Batch mix and shear the material, ensuring that additive proportions are accurately measured. Contingency plans should be made for disposing of material that fails to meet the required specifications.
- Conduct job-site quality control tests (filtercake, fluid loss, rheology).
- Prepare contaminant and spacer fluids as required.
- Confirm CT depth and coordinate tubing movement with pumped volumes.

Follow these guidelines to reduce the risks of operational failure when using cements and resins:

- Do not interrupt pumping while the cement or resin is inside the work string.
- Place the CT nozzle above the squeeze zone and pump down the production tubing or CT annulus while squeezing the material.
- Overdisplace the excess cement slurry or resin out of the wellbore. Once the slurry achieves a high initial gel strength, it may be impossible to clean the wellbore by circulation (or reverse circulation).

Computer Simulator Modeling

A zonal isolation is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model, such as Hydra™, to select the CT string and calculate the relationship between the fluid flow rates and the pump pressures for each stage of the zonal isolation operation. Determine the maximum flow rate possible for each fluid without exceeding the maximum allowable ECD. For a given flow rate of zonal isolation fluid, calculate the speed for POOH with the CT.

Use a reliable tubing forces model, such as Orpheus™, to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH, and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

---

WARNING: If performing a reverse circulation be sure to check for possible collapse conditions.

Job Plan Outputs

A basic job plan for zonal isolation includes the following:

- Depth correlation method
- Method of placing cementing platform or diverting treatment fluid to the intended zone
- Formulation and properties for the treatment fluids

- Mixing procedures
- Volume of each fluid stage
- CT running speed (if any) for each fluid stage
- Squeeze pressure for zonal isolation fluid
- Waiting period for each stage

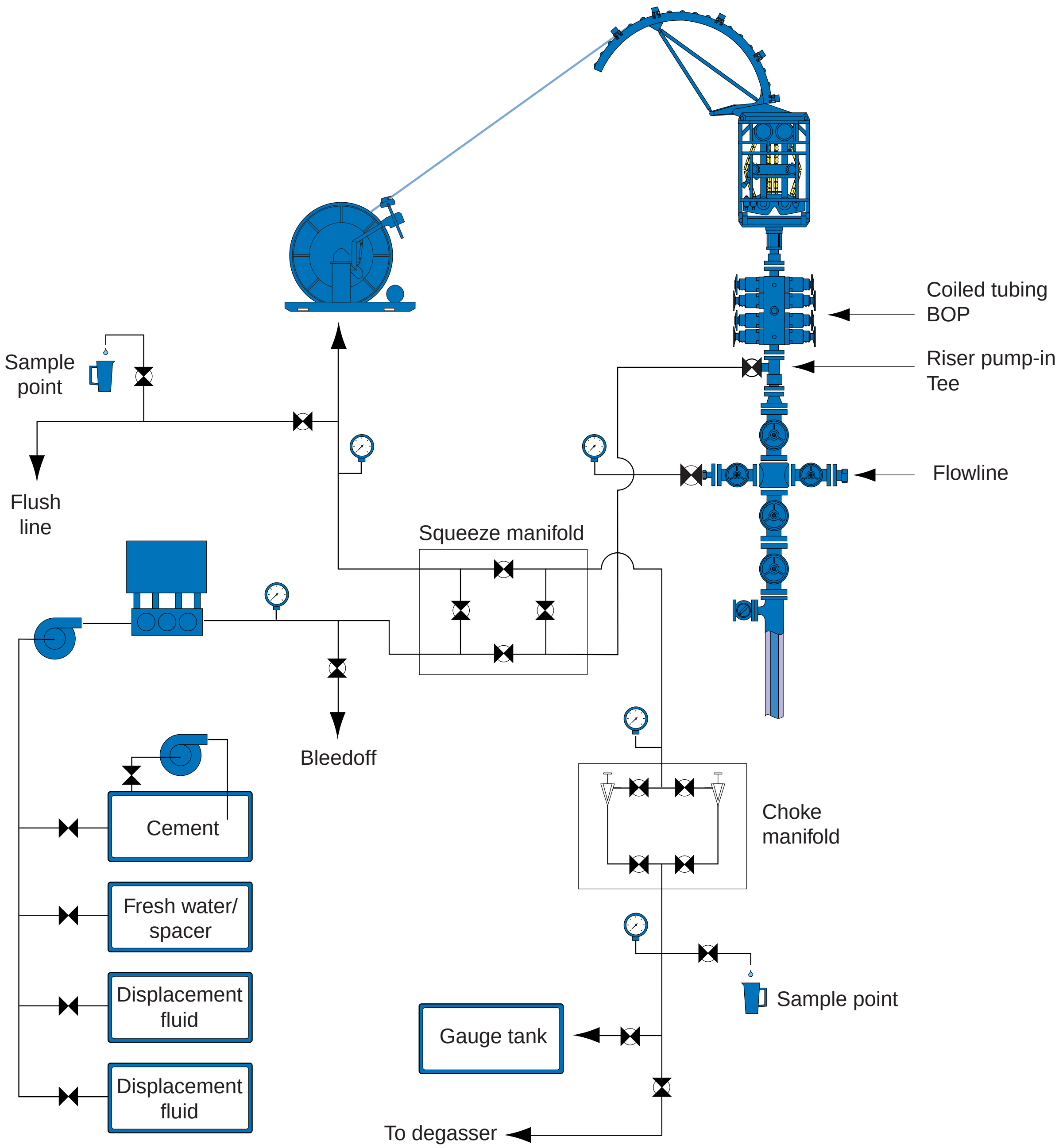
Prepare contingency plans for the following situations:

- The treatment fluid setting or curing time after placement is shorter than planned.
- The treatment fluid or curing time after placement is much longer than planned.
- Unable to pump at the planned rate.
- Cannot maintain the desired squeeze pressure.
- For cementing, cannot circulate out the excess cement.

Selecting Equipment for Isolating Zones

Figure 11.14 shows a schematic diagram of typical equipment layout.

FIGURE 11.14 *Typical Squeeze Cementing Equipment Configuration*



CT Equipment

Any CT string, even one containing and electric cable, that will provide the necessary flow rate is suitable for a zonal isolation job. However, CT strings containing electric cable negate the use of ball-activated tools and wiper plugs, are more difficult to clean thoroughly, and are much more costly to replace in the event the treatment fluid can't be removed completely.

Always check the work string volume by pumping a plug or foam pig through the string. This will confirm the pumping schedule for displacing the treatment fluids in the well. Combining a volume check with a pickling treatment (when necessary) will save time. The CT reel inlet must include a flushing/sampling manifold to minimize contamination of the fluid stages. Provide enough storage volume or arrange for disposal of contaminated fluids from flushing the surface piping and BOP stack.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for zonal isolation operations. Thoroughly clean the choke manifold and BOP, disassemble it, and inspect it for any residual solids.

Pumping Equipment

All fluid mixing, pumping and storage equipment must be clean and configured to avoid contamination or dilution of the treatment fluids.

Downhole Tools

Tool strings used in conjunction with zonal isolation operations should be kept to a minimum. The BHA used for zonal isolation should include the following components, from the top down:

1. CT threaded connector.

2. Dual flapper type check valves.

> *NOTE:* Check valves cannot be used when procedures call for reverse circulation of excess cement from the wellbore.

3. Depth Correlation—Use a TEL or TNL, if required by the job plan.

4. Plug Catcher—For use with plugs ahead or behind the cement slurry to catch and retrieve the plugs.

5. Straight bar—Optional.

6. Nozzles—A variety of jetting nozzles have been developed to improve the slurry placement. Some configurations require more than one nozzle or jet configuration.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, fluid flow rates, and fluid volume pumped. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Isolating Zones

Zonal isolation operations are frequently conducted in multiple well campaigns within a field or area. Consequently, procedures are often tuned to meet local conditions. Whenever possible, refer to previous case histories for similar applications.

Preparing the Wellbore

1. Conduct any necessary slick line or wireline work, such as removing gas lift valves or fitting dummy gas-lift mandrels.

2. Pressure test the production tubing annulus.

3. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position, and install a protective sleeve.

4. Establish hangup depth or TD.

5. Prepare the wellhead and surface facilities.

6. Remove fill from the rathole below perforated interval.

7. Perform pretreatment perforation wash or acidizing.

8. Place a stable platform for the cement slurry.

Preparing the Equipment

1. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

2. Accurately measure the volume of the CT by drifting it with the largest cement plug required for the upcoming cement job. Pump the drift through the CT with water from a calibrated displacement tank.

3. Assemble and install the BHA on the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

5. Confirm and correlate depths with CT and flag the tubing.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Performing the Zonal Isolation

1. RIH while pumping inhibited water at a slow rate.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations for pull tests (Section “Pull Tests”).

WARNING: If cementing on top of a bridge plug, minimize differential pressure across the plug.

2. Reduce running speed per Chapter 18 "CT Running Speeds", page 18-18 in the vicinity of profile nipples or the bottom of the production tubing and correlate the depth using the TEL.

3. Slackoff to a depth approximately 5 ft above the cementing platform or to the depth specified in the work program.

4. Mix and pump cement in batches less than the wellbore volume between the specified pumping depth and the tubing tail pipe or 10 bbls, whichever is less.

- Mix cement per the recipe in the work program.
- Open the vent valve on the CT reel and close the reel inlet valve.
- Pump cement from the mixing tank to the CT reel.
- After clean cement discharges from the reel vent valve, open the reel inlet valve and close the reel vent valve.
- Chase each cement batch with plugs and a spacer fluid.

5. While displacing the cement from the CT, POOH at a rate that keeps the CT nozzle about 10 ft below the cement interface.

6. After pumping the total volume of cement required by the work program and bumping the plugs, slowly pull the CT clear of the cement slurry approximately 100 ft. Shear the top plug.

7. When squeeze cementing, close the production wing valve and apply approximately 1000 psi squeeze pressure for 15 minutes.

8. Pump water at the highest rate possible until the CT reel is free of cement.

9. Wait on the cement to set for the time specified in the program. After the cement has set, RIH while pumping inhibited water at a slow rate and gently tag the cement.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

---

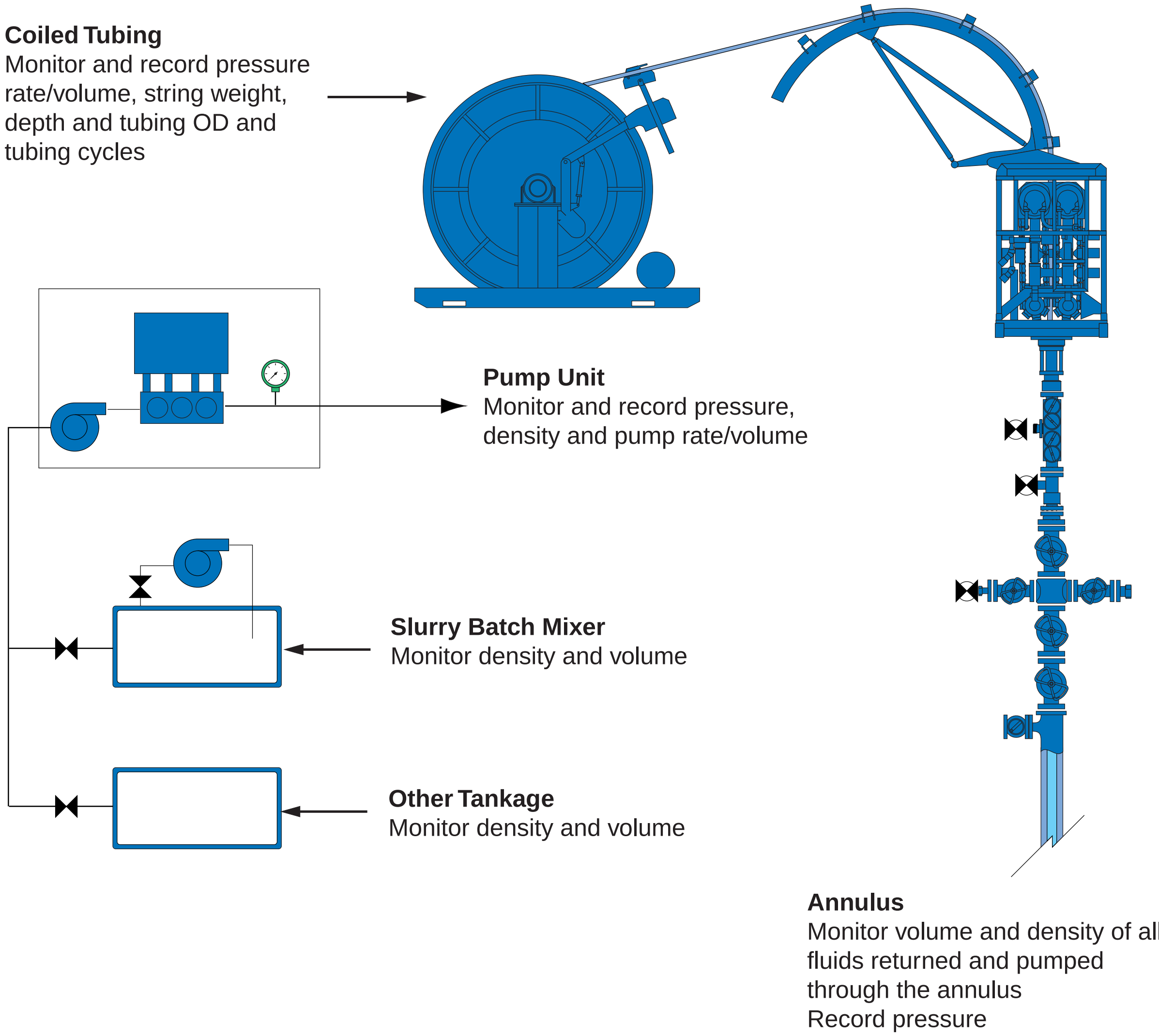
10. POOH while slowly pumping inhibited water.

WARNING: Pay close attention to the maximum running speeds per Chapter 18 "CT Running Speeds", page 18-18.

Monitoring a Zonal Isolation Job

Accurate monitoring and recording of the job parameters is essential to allow complete control of the job and preparation of post-job reporting and analyses. The schematic diagram in Figure 11.15 identifies typical job parameters and their point of measurement and recording.

FIGURE 11.15 *Squeeze Cementing Parameters to be Monitored and Recorded*



The methods used to evaluate the efficiency of a zonal isolation depend on the objectives of the treatment. The initial step in any evaluation process is to check the condition of the wellbore in the treatment zone with a wireline or CT conveyed drift tool of an appropriate size. If large cement nodes or buildup obstruct the wellbore, some drilling or underreaming may be required. In addition, check to ensure that the rathole is free from debris.

The duration and differential pressure to which any zonal isolation treatment is tested will vary depending on local conditions. For example, injection wells will typically be tested to the injection header maximum pressure. Wells to be re-perforated and fractured should be pressure tested to the maximum BHP anticipated during the fracturing treatment.

Safety Issues for Isolating Zones

Always conduct a pre-job safety meeting prior to RIH. However, this operation does not pose any job-specific safety issues.

Removing Scale Hydraulically

Deposits of solid inorganic materials in the completion reduce the flow area, impair the productivity of the well, and interfere with the running and operation of downhole tools and equipment. Section “Removing Wax, Hydrocarbon, or Hydrate Plugs” covers removal of organic deposits. Inorganic deposits (scale) precipitate as mineral solids from produced or injected water due to a reduction in temperature or chemical interaction with other fluids in the wellbore. The most common scale, calcium carbonate ($CaCO_3$), forms at high temperatures. Scale is a common problem in wellbores used for water injection to maintain the reservoir pressure.

Bullheading chemical treatments, wireline-conveyed cleaning tools, and total replacement of the completion are some of the conventional methods for removing scale deposits from wellbores. The first two are mostly ineffective and bullheading can damage the producing interval. Replacing the completion is 100% effective at removing the scale, but extremely expensive compared to CT scale removal techniques such as:

- Localized chemical treatment
- Jetting
- Drilling or milling with a downhole motor
- Impact drilling

This section addresses the first two scale removal methods. Chapter 12 "Removing Scale Mechanically", page 12-57 describes mechanical scale removal methods.

Planning for Removing Scale Hydraulically

The characteristics of the reservoir, wellbore tubulars, and scale deposit define the potential scale removal technique. However, deciding on the proper scale removal procedure is only part of the problem. Disposal of the spent treatment fluid and scale material circulated from the wellbore is a significant part of the job design. Protecting personnel and the environment from waste products containing low specific activity (LSA) radiation sources (e.g. strontium and barium sulfates) can be expensive.

Job Plan Inputs

A gauge survey can determine the presence of scale or wellbore deposits, but not indicate the primary cause of reduced production. Scale deposition within the formation matrix can cause severe skin damage that requires a matrix stimulation treatment to restore production (see Section “Stimulating a Formation (Acidizing)”).

One must know the following information to plan a hydraulic scale removal operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Scale properties and volume
- Treatment fluid properties
- Target zone or zones (depths, pressures, temperatures, permeability, porosity, fluids)
- Wellhead and surface equipment configuration
- Perforations (location and size)

Scale Deposit Properties

The essential first step in the process is to determine the exact nature of the scale deposit. The best approach is to obtain a sample of the material for analysis and testing with possible treatment fluids. Table 11.7 summarizes common organic and inorganic deposits in oil and gas wellbores.

TABLE 11.7 *Scale Deposit Characteristics and Treatment*

Deposit Type	Description	Treatment
Carbonate Scales ($CaCO_3$ and $FeCO_3$)	Carbonate scales are the most common type of scale which occurs in reservoirs rich in calcium and carbonates.	Hydrochloric acid will readily dissolve all carbonate scales.
Sulfate Scales ($CaSO_4$, $BaSO_4$, and $SrSO_4$)	Sulfate scales occur mainly as gypsum ($CaSO_4$, H_2O) or anhydrite ($CaSO_4$). The less common barytine or strontianite are more difficult to remove, but their occurrence is more predictable.	Calcium sulfate can be easily dissolved by EDTA. Barium and strontium sulfates can also be dissolved with EDTA if the temperature is high enough and the contact time is sufficient. However, due to slow reaction rates, mechanical removal methods are more commonly used on barium and strontium scales.
Chloride Scales		Chloride scales such as sodium chloride are easily dissolved in fresh water or very weak acidic solutions.
Iron Scales (FeS and Fe_2O_3)		Iron sulfide and oxide scales can be dissolved with hydrochloric acid. A sequestrant and iron reducing agent should be included to prevent the re-precipitation of damaging by-products.
Silica Scales	These generally occur as very finely crystallized deposits of chalcedony or as amorphous opal.	Hydrofluoric acid readily dissolves silica scales.

TABLE 11.7 *Scale Deposit Characteristics and Treatment (Continued)*

Deposit Type	Description	Treatment
Hydroxide Scales	These are magnesium ($Mg(OH)_2$) or calcium ($Ca(OH)_2$) hydroxides.	Hydrochloric acid is generally used to dissolve such deposits.
Mixed Deposits	In mixed wellbore deposits, three damage mechanisms are commonly identified: • Scale • Waxes and asphaltenes • Migrating formation fines	If possible a qualitative and quantitative analysis should be performed to aid the design of a successful treatment. Mixed deposits generally require a dual- or multi-solvent system for efficient removal. Typically a dispersion of aromatic hydrocarbon solvent in acid is used as a base fluid, with appropriate additives used to control or treat specific conditions. In most cases, it is helpful if an actual sample of scale is available for analysis. If a chemical treatment is to be considered, such analyses and compatibility testing is essential.

NOTE: The primary logistical problem for scale removal operations is disposal of the waste fluid and scale residue, especially LSA materials. Space availability, deck loading limits, and crane capacity can be logistics nightmares for offshore CT operations.

Chemical Treatments

Chemical treatments of scale are only effective when the material is readily soluble in the treatment fluid(s). The uncontaminated treatment fluid must contact the scale for sufficient time to dissolve the bulk of the deposit. Some dissolution reactions are quite rapid, e.g. carbonate scale dissolved with HCl. However, some types of scale require soaking time in the treatment fluid which are impractical under normal circumstances. An example is barium sulfate that may need to soak in EDTA for 24 hours before weakening enough to be removed. Rotary jetting or multi-port nozzles may be necessary ensure adequate distribution and contact of uncontaminated treatment fluid over the scale deposit. Selection of a suitable chemical treatment depends on several factors including:

- Composition of the scale or deposit
- Wellbore parameters—Generally, reaction rates and dissolution capacities increase as the temperature increases. Unfortunately, potential corrosion of wellbore tubulars and equipment increases with increasing temperature as well. Selecting the proper corrosion inhibitor is almost as important as selecting the base treatment fluid.
- Volume of material to be removed—The volume of treatment fluid is directly proportional to the volume of scale or deposit to be removed.
- Treatment fluid compatibility—The treatment fluid must be compatible with any fluids, materials, or equipment that it might contact during the operation.

Jetting

Jetting is one of the most direct methods of removing scale from wellbore tubulars. Low-pressure (pump pressure < 5000 psi) jetting operations do not require any special tools, nozzles, or treatment fluids. High-pressure (pump pressure > 5000 psi) jetting tools and equipment are more specialized and require more detailed job design. All jetting operations require working the BHA back and forth across the scale deposit. This imparts a high degree of fatigue damage to a relatively short section of the CT string. Accurate data acquisition and real-time fatigue monitoring are essential components of the job plan.

The high flow rate necessary to achieve annular velocity sufficient to remove solid scale particles can be prohibitive. Taking steps to reduce the pressure loss inside the CT string and BHA is essential. Such steps might include:

- Selecting the largest ID string available
- Reducing the length of the CT string as much as possible
- Use of hydraulic friction reducers
- Including a bypass valve in the BHA
- Increasing the pump pressure to the maximum value that will allow completion of the jetting operation without exceeding the fatigue limit for the string

Low Pressure Jetting

Low-pressure jetting is usually effective for removing only the softest scales. Relatively large jet nozzles provide good coverage of the wellbore target area and allow relatively high circulation rate for removal of material dislodged from the wellbore. The size and number of nozzles must be compatible with the available flow rate and BHP. The position and direction of the jets should suit the intended application. For example, lateral jets (perpendicular to the wellbore surface) are ideal for washing perforations. Severe scale deposits may require jets oriented at several angles.

Inert fluids like water or brine remove scale by hydraulic impact, unless the scale is water-soluble. Using reactive treatment fluids like acid or solvent can dramatically improve the effectiveness of low-pressure jetting. The turbulence in the jet increases the scale dissolution rate and forces the treatment chemicals deeper into the scale. In any case, the fluid must be capable of suspending and removing the scale particles from the wellbore.

High Pressure Jetting

High-pressure jetting can provide the hydraulic impact or cutting action to remove hard scale. Adding sand or ceramic beads to the fluid can significantly increase the destructive force of the jet. However, high-pressure jetting has several disadvantages. First, the high circulating pressure and constant movement of the BHA is detrimental to the working life of the CT string. Accurate data acquisition and real-time fatigue monitoring are essential for preventing premature failure of the CT string. Second, controlling the cutting action of a high-pressure jet is nearly impossible. If held stationary too long, the jet can damage the host completion tubular beneath the scale. Third, high-pressure jetting can produce large cuttings that can be difficult to remove from the wellbore with the relatively low flow rate possible with this scale removal method.

Jetting methods often produce large cuttings or flakes that can be problematic at tight spots in the wellbore. These can restrict the annular flow and increase BHP or cause higher drag for moving the CT. Sticking the BHA in an accumulation of scale fragments at a tight spot is a serious risk for jetting operations. Consequently, identifying these potential trouble spots in the operational plan is an important part of the job design. This step will alert operations personnel to closely monitor pump pressure and the CT weight indicator when the BHA approaches restrictions in the wellbore.

A problem with jetting scale from inside large-diameter tubulars is the large volume of scale material generated. Providing adequate fluids processing equipment (solids control) and means of disposing of the spent fluid and waste material are important aspects of the planning process.

The ability of a fluid to successfully suspend and remove particles from a wellbore decreases as the hole angle (inclination) increases. Highly deviated and horizontal applications require special design considerations. Typically, the annular velocity of liquid in a horizontal wellbore must be at least 3 times that for a vertical hole of the same diameter in order to achieve the same hole cleaning efficiency. Special fluid, high viscosity sweeps, or foam may be necessary to remove the jetting debris from the horizontal section of the wellbore. A hydraulic simulator like Hydra™ can help determine the best candidate fluid(s) and pumping schedule. Also, the axial forces on the CT are considerably different in a directional well compared to a vertical well. Buckling of the CT can limit the working depth in a directional well. Consequently, modeling tubing forces with a CT simulator like Orpheus™ is an essential part of planning scale removal operations in highly-deviated wells.

Scale Inhibition

Following the scale removal with an inhibition treatment may delay or prevent the scale from returning. Squeezing a concentrated solution of scale inhibitor into the producing interval, then allowing the formation to soak for a period of time (generally 12-24 hours) absorbs the inhibitor onto the reservoir rock. Subsequent production leaches small amounts of inhibitor out of the rock and reduces scale buildup in the wellbore. If possible, inject the inhibitor before POOH with the scale removal BHA. This saves time and maximizes the benefits of using the inhibitor. The scale inhibitor treatment design is well specific and dependent on the porosity, perforated interval, permeability and the treatment depth. Although basically inefficient in terms of chemical use, the technique is cost effective and generally accepted as preferable to downhole injection of inhibitor through an injection capillary or line.

Computer Simulator Modeling

Hydraulic scale removal is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model, such as Hydra™, to select the CT string and predict the relationship between the fluid flow rate and the pump pressure for different operating conditions. Determine or evaluate the following:

- For jetting, the pump pressure required for the minimum effective jetting pressure (flow rate)
- For jetting, the flow rate at the maximum allowable pump pressure
- The minimum annulus velocity necessary for effective hole cleaning in each section of the wellbore

> *NOTE:* The highest minimum velocity sets the minimum flow rate for the scale removal operation.

- The maximum solids loading (mass fraction) in the annulus before exceeding the maximum allowable ECD for a given flow rate

> *NOTE:* The maximum solids loading sets the maximum penetration rate of the nozzle into the scale deposit.

Use a reliable tubing forces model, such as Orpheus™, to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH, and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

A basic job plan for scale removal includes the following:

- Minimum flow rate
- Maximum flow rate for a given penetration rate
- Optimum penetration rate for a given flow rate

Prepare contingency plans for the following situations:

- The maximum flow rate attainable is not high enough for effective hole cleaning in certain sections of the wellbore.
- The ECD exceeds the reservoir pressure and annulus fluid enters the formation.
- The solids control equipment or surface equipment cannot handle the volume of scale material delivered to the surface.

NOTE: The capability (capacity) for collecting and disposing of LSA materials may govern the rate of scale removal.

Selecting Equipment for Removing Scale Hydraulically

CT Equipment

Any CT string is suitable for a scale removal job. Select the largest feasible diameter of work string to allow higher circulation rates and higher annular velocity.

Scale removal operations can induce significant levels of fatigue from repeated cycling of the tool string over a short length while high pressure jetting. Ensure that the predicted fatigue effects on the work string are within limits.

Pressure Control Equipment

Configure the equipment to avoid circulating corrosive or solids-laden annular return fluids through the secondary BOP. Install a pump-in tee between the secondary BOP and hydraulic master valve for fluid returns.

Pumping Equipment

All fluid mixing, pumping and storage equipment must be clean and configured to avoid contamination or dilution of the treatment fluids. Pumps must be sized to provide the hydraulic HP required for jetting operations.

Downhole Tools

Configure jetting tools to maximize the fluid rate or hydraulic impact force from the nozzles. A high flow rate will maximize the circulation rate to aid removal of solids from the wellbore and high impact force will improve the efficiency of scale removal.

The BHA used for scale removal should include the following components, from the top down:

1. CT threaded connector.

2. Dual flapper type check valves

3. Straight bar—Use approximately 6 ft. This optional item is especially helpful for running through upsets in the completion, such as side pocket mandrels.

4. Jetting nozzle—There are no special nozzle requirements. It can be as simple as a few holes drilled in a bull plug.

NOTE: Prepare an accurate fishing diagram for the tool string.

Auxiliary Equipment

Ensure sure that the fluid mixing, handling, and pumping equipment have adequate capacity. Configure them to minimize cross contamination of fluid stages.

For live well operations, use a choke manifold to control annular returns. Also ensure that the CTU, pump, and choke manifold operators all have a clear line of communication with each other and the Customer well-site supervisor.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, and fluid flow rates. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Removing Scale Hydraulically

The steps required to successfully complete a scale removal operation depend on the particular conditions encountered in each case. Procedures can be tuned to meet local conditions. Whenever possible, refer to previous case histories for similar applications.

Operational Considerations

Stopping or losing circulation while the annular fluid is laden with solids can have severe consequences. Carefully plan operations that involve the circulation of particulate material from the wellbore. Then, take precautions to ensure that the operation proceeds as planned.

- Rate of penetration—Hard scale may require localized reciprocation of the CT string (increasing CT string fatigue). Control the penetration rate to avoid overloading the annular fluid and causing sticking of the BHA or CT.
- Annular flow rate—Maintain an annular fluid flow rate high enough to ensure efficient transport of solids. Production of reservoir fluids may assist solids transport; however, if the annular fluid becomes overloaded (high fluid density) the production of reservoir fluids may be reduced to levels that are incapable of sustaining transport of the material.

Preparing the Wellbore

1. Recover wellbore scale samples for analysis. Use typical slick line methods or CT conveyed tools, whichever is appropriate. One can also analyze produced water samples to determine the nature of the scale.

2. If necessary, remove completion equipment components such as gas lift valves or safety valves. As the scale will often hamper retrieval, use CT conveyed methods, instead of wireline. With CT, one can circulate treatment fluids and exert more force.

3. Kill the well, if required for safety, fluid compatibility, or production reasons. In most cases the risk of damaging the near wellbore area by bullheading the wellbore fluid is unacceptable. Consequently, the well kill operation may be a part of the wellbore preparation conducted through the CT string.

4. Conduct any necessary slick line or wireline work, e.g., gas lift valve removal or tag scale restriction.

5. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position, and install a protective sleeve.

Preparing the Equipment

1. Prepare the wellhead and surface facilities for circulation, separation, and disposal of returned fluids and solids. If the scale is an LSA material, take appropriate precautions and provide protective equipment.

2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and connect it to the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Preparing Fluids

Either batch prepare fluid in advance, or mix it on the fly as the operation proceeds. Allow sufficient residence time to enable the desired fluid characteristics to develop (and be tested and checked). Regardless of the fluid mixing procedure, prepare adequate volumes, as once the operation has commenced, any interruption to circulation is undesirable.

Removing the Scale

1. RIH while pumping inhibited water at a slow rate. Gently tag the scale deposit or stop at the designated depth.

> *WARNING:* Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Pick up about 25 ft and increase the fluid flow rate to the operating level for the tool string.

3. Wait for the treatment fluid to circulate to the tool string before attempting to penetrate the scale deposit.

4. RIH slowly and penetrate the scale deposit. The optimum penetration rate is generally a compromise between scale removal ability, hole cleaning ability, and maintaining the desired ECD.

> *CAUTION:* Watch for signs of solids accumulating around the BHA, i.e., pump pressure increasing or CT weight changing abnormally.

5. Make a number of passes over the scale deposit area, unless the BHA includes a ring jetting assembly that can assure full bore cleaning. However, control the number of passes to prevent excessive localized fatigue to the CT string.

6. Periodically pick up the BHA to the original top of the scale deposit to ensure that the CT string can move freely.

7. Conduct wiper trips as designed (or required). In deviated wellbores, perform frequent wiper trips to prevent excessive buildup of material in the transition between vertical and horizontal sections. Determine the number of wiper trips necessary by monitoring the volume of material removed against the estimated volume of the scale deposit.

8. Pump high viscosity fluid pills if necessary to suspend scale and abrasive particles.

9. Continue pumping at a high rate through the entire treatment interval.

10. At the bottom of the target interval, continue pumping at the highest rate possible until solids stop discharging at the surface. Pump high viscosity fluid pills if necessary.

11. POOH while pumping inhibited water at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

12. If in doubt about the success of the scale removal operation, perform a drift run over the original target interval.

13. If the well does not flow naturally or aided by gas lift, prepare to conduct nitrogen kickoff operations (Chapter 11 "Unloading a Well with Nitrogen", page 11-96).

Monitoring for Removing Scale Hydraulically

Which parameters to monitor during scale removal operations depends on the complexity of the operation. For all operations, monitor the following items:

- Fluid parameters—Monitor the fluid rates and pressures pumped. Also monitor the pressures returned from the wellbore in low reservoir pressure circumstances.
- Tubing movement—Do not penetrate the scale deposit too quickly, or the CT string may become stuck. Optimize the penetration rate to ensure adequate wellbore cleaning.
- Returned solids—Monitor the volume and composition of the returned solids. If necessary, modify the design to improve the scale removal efficiency.

Safety Issues for Removing Scale Hydraulically

Always conduct a pre-job safety meeting prior to RIH.

In general, base precautions for scale removal operations on the potentially toxic, corrosive, and LSA nature of the treatment fluids and the returned scale or wellbore deposit. Use special monitoring and protection methods to ensure the safety of personnel, equipment, and the environment.

The job plan must take into account how the resulting scale material and carrier fluid will be disposed. For circulation treatments using motors or impact hammers and inert fluids, one can reduce the volume of fluid to be disposed by separating the carrier fluid and re-cycling it. More complex job designs using gelled fluids, foams, and nitrogen or gel slugs, require disposal of large volumes of fluid.

Certain types of scale (e.g. strontium and barium sulfates) are low specific activity (LSA) radiation sources. Personnel designing and executing the operation must know the requirements for processing and disposing of LSA solids.

Take appropriate monitoring and protection measures to ensure safe operations.

UNLOADING A WELL WITH NITROGEN

The purpose of unloading a well with nitrogen is to regain sustained production. These operations are also known as nitrogen lift or kickoff operations.

Typically, a dead wellbore contains a column of fluid with enough hydrostatic pressure to prevent the reservoir fluid from flowing into the wellbore. Displacing some of the fluid in the wellbore with nitrogen reduces the hydrostatic head, (i.e. the pressure differential between the formation and the wellbore). The lower BHP allows the reservoir fluid to flow into the wellbore. If the conditions (pressure, fluid phase mixture and flow rate) are suitable, production will continue after nitrogen pumping ceases.

The benefits of a nitrogen kickoff operation include the following:

- Flexibility—Nitrogen injection is adaptable (rate and depth of injection) to meet a broad range of conditions or responses.
- Production of uncontaminated oil and formation water samples—Extraneous fluids generally do not commingle with the production fluids.
- Operational simplicity—Only a small amount of equipment is required.

The main disadvantages of nitrogen lifting are the following:

- Erratic drawdown pressures—Fluctuations in the nitrogen injection rate, reservoir performance, and tubular plugging can cause unsteady drawdown.
- Formation gas contamination—Gas contamination and dilution can occur with nitrogen injection into the wellstream.
- Cost—The cost of nitrogen and its transportation can become considerable if extensive high rate flow periods are required.
- Equipment size and weight—Nitrogen tanks, generation units, and pumpers are large and heavy.
- Sticking the CT—There is an increased risk of sticking the CT if highly viscous, low gravity crudes are encountered.

Planning for Unloading a Well with Nitrogen

Job Plan Inputs

One must know the following information to plan a nitrogen kickoff:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Producing interval or intervals (depths and pressures)
- Wellhead and surface equipment configuration

Planning Considerations

Although a nitrogen kickoff is one of the simplest CT operations, calculating the gas required and the resulting fluid flow rate can be extremely complex (dynamic three phase fluids). Use a reliable hydraulics simulator, such as Hydra™ to calculate N_2 requirements.

- In order to lift a well efficiently, an adequate volume and uninterrupted supply of nitrogen must be available. Cryogenic nitrogen unit systems require skilled operators to ensure a good supply of nitrogen without incurring excessive product waste.
- Since the objective typically is to initiate production from a well, all completion and production equipment must be prepared to enable efficient rig down of the CT and nitrogen equipment following the treatment.

Computer Simulator Modeling

A nitrogen kickoff is primarily a hydraulic operation. Providing mechanical force is secondary. Use a reliable hydraulics model to select the CT string and calculate the N_2 flow rate necessary to lift the well from various depths. Also, calculate the maximum N_2 flow rate that can be used before exceeding the maximum allowable ECD at each depth.

Use a reliable tubing forces model, such as Orpheus™ to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble for RIH and POOH and generate mechanical performance curves for the operation that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at N_2 injection depth

Job Plan Outputs

The main feature of the job plan is the nitrogen injection rate. The injection rate depends on several factors at different points in the job. For example, the well configuration affects slippage of nitrogen “through” fluids in large diameter tubulars.

- As the CT string runs into the well, the nitrogen injection rate and pressure must increase to overcome the hydrostatic pressure at the end of the tubing.
- As the well unloads, the injection rate must decrease to prevent the annular friction pressure from becoming too high. If it becomes too high, it can create a back pressure in the annulus, which may cause fluids to re-enter the formation.

A basic job plan for a nitrogen kickoff includes the following:

- The depth to start injecting nitrogen while RIH.
- The range of nitrogen injection rates that will efficiently lift the wellbore fluids for regular depth intervals. This information can be in a table or a graph.
- The maximum nitrogen flow rate before the ECD exceeds the formation pressure for regular depth intervals. This information can be in a table or a graph.
- The total volume of nitrogen required.

Prepare contingency plans for each of the following situations:

- Nitrogen flow rate is too low.
- Running out of nitrogen before the end of the planned pumping schedule.
- ECD exceeds reservoir pressure and annulus fluid enters the formation.

Selecting Equipment for Unloading a Well with Nitrogen

CT Equipment

Nitrogen kickoffs do not create any special requirements for CT surface equipment. However, these operations always benefit from using the largest ID string that can fit in the wellbore.

Pressure Control Equipment

Normal CT pressure control equipment is adequate for nitrogen kickoff operations.

Nitrogen Unit & Storage Tanks

The nitrogen unit must be capable of delivering the maximum flow rate designated in the job plan.

- Cryogenic units convert liquid nitrogen to high pressure gas through a pump and thermal converter system. The entire supply of nitrogen is stored and transported in cryogenic vessels. These systems require skilled operators to ensure a good supply of nitrogen gas without wasting the liquid.
- Atmospheric nitrogen units use a membrane filtration system to extract nitrogen from the atmosphere and an array of high pressure compressors to boost the discharge pressure. Improper operation of these systems can introduce oxygen into the gas flow, which can cause corrosion problems.

The nitrogen storage tanks must provide sufficient volume for the operation, derived from experience and anticipated well conditions, plus a small excess for contingency purposes and natural losses.

The size and weight of the nitrogen equipment can also create a logistical problem. In some remote areas, one must use atmospheric units, as cryogenic nitrogen might not be available. On small locations, especially offshore, there may not be enough space to spot the equipment.

Downhole Tools

The BHA used for nitrogen kickoffs should include the following components, from the top down:

1. CT threaded connector.
2. Dual flapper type check valves.
3. Straight bar—Use approximately 6 ft. This optional item is especially helpful for running through upsets in the completion, such as side pocket mandrels.
4. Jetting nozzle—There are no special nozzle requirements. It can be as simple as a few holes drilled in a bull plug.

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS of monitoring the pump pressure, WHP, CT depth, CT weight, and N_2 flow rate. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, and fluid flow rates. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Unloading a Well with Nitrogen

The steps in a nitrogen kickoff depend on the particular conditions encountered. Adjust the procedures and nitrogen requirements to meet current local conditions.

> **CAUTION:** Once pumping commences, maintain an uninterrupted flow of nitrogen.

Preparing the Wellbore

1. Conduct any necessary slick line or wireline work to prepare the well for production.
2. Prepare the wellhead and surface facilities.
3. Remove or secure the SSSV. If securing it, hydraulically isolate it in the open position and install a protective sleeve.

Preparing the Equipment

1. Prepare all completion and production equipment for efficient rig down of the CT and nitrogen equipment following the treatment.
2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.
3. Assemble the BHA and connect it to the CT.
4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

> **NOTE:** Torque all threaded joints to the makeup torque recommended by the manufacturer.

Performing the Nitrogen Kickoff

1. RIH to the target depth while circulating nitrogen at a slow rate.

> WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. As the tubing runs into the well, steadily increase the nitrogen injection rate.
3. At the required depth, increase the nitrogen pumping rate as specified in the job design.
4. When the production fluids begin to flow, adjust the injection rate to achieve a sustained lifting action. As the well unloads, decrease the injection rate.
5. Continue pumping nitrogen until the well begins to flow.
6. Reduce the nitrogen pumping rate and POOH while circulating nitrogen at a slow rate.

> WARNING: Pay close attention to the maximum running speeds. (Chapter 18 "CT Running Speeds", page 18-18).

7. Retrieve the CT string and BHA.

Monitoring Unloading a Well with Nitrogen

Key parameters to be monitored during a nitrogen kickoff include the following:

- Nitrogen pump rate—The rate should be optimized to provide sustained lifting. Note that sustained lifting does not necessarily mean sustained production of liquids, since slugging will occur within the production tubular.
- Nitrogen pump pressure—Decreasing pump pressure should indicate progress in lifting the fluid column, depending on the rate and effect of friction through the CT string.
- Remaining nitrogen—Monitor the remaining volume of nitrogen and adjust the pump rate to make the most effective use of the remaining nitrogen. Do not interrupt the pumping schedule.

Safety Issues for Unloading a Well with Nitrogen

Always conduct a pre-job safety meeting prior to RIH.

Potential safety hazards for a nitrogen kickoff include:

- Cryogenic fluids—liquid nitrogen is a super-cooled fluid that can inflict severe freeze burns to flesh and cause severe structural damage to unprotected materials and equipment.
- High-pressure gas—any operation that involves pumping high pressure gas is hazardous, due to the enormous energy stored within the compressed gas. Controlled venting of high pressure gas can produce dangerously high noise levels, and uncontrolled releases can be explosive.
- Rarefied atmosphere—although nitrogen gas is miscible in air and disperses quickly, large releases can be hazardous. A high concentration of nitrogen gas in an enclosed space can asphyxiate a person. Releasing low pressure “cold nitrogen” from cryogenic systems can be especially hazardous, as the nitrogen may collect in low lying areas or spaces below the deck.

WARNING: Ensure that O_2 and H_2S in the well cellar are at safe levels before anyone enters the well cellar without a SCBA.

- Surface piping—Slugs of liquid and gas can create a “hammer” effect in surface piping that can cause it to move violently. Make sure all surface piping is adequately staked or tied down.

REMOVING WAX, HYDROCARBON, OR HYDRATE PLUGS

Deposits of solid or highly viscous organic materials in the completion reduce the flow area, impair the productivity of the well, and interfere with the running and operation of downhole tools and equipment. Section “Removing Scale Hydraulically” covers removal of inorganic scale deposits. Organic deposits such as wax, paraffin, and asphalt occur with certain types of crude oil, as a result of reduced temperature and pressure in or near the wellbore during production. Hydrate plugs are rare inside producing wellbores, because the temperature is usually high enough to prevent their formation. However, in regions of permafrost or water depths exceeding 2000 ft, conditions within the production tubing may be conducive for hydrate formation. Also, hydrate plugs are fairly common in underwater flow lines.

Bullheading chemical treatments to remove organic deposits can be expensive, are usually inefficient, and risk damaging the producing formation. Bullheading is ineffective against hydrate plugs because the treatment fluid (usually an alcohol) is lighter than the wellbore fluid. Techniques using CT, such as spotting a volume of a solvent at the deposit, jetting the treatment chemical across the affected zone, or circulating heated fluid across the affected zone are much more effective for removing organic deposits and hydrates.

In determining the most appropriate removal method, the characteristics of the reservoir, wellbore tubulars and the deposit must be studied. Disposal of the returned treatment fluid must be undertaken with due regard for the safety of personnel and the environment.

Increasing the wellbore temperature can soften and remove organic deposits and dissociate hydrate plugs. A simple way to increase the wellbore temperature is to circulate a heated fluid, such as hot oil, across the affected area of the wellbore. Hydrate plugs will also dissociate with decreasing pressure. However, dropping the pressure on only one side of the plug can be extremely dangerous. Always balance the pressure across a hydrate plug before beginning treatment.

Planning for Removing Wax, Hydrocarbon, or Hydrate

Plugs

Job Plan Inputs

One must know the following information to plan an operation to remove organic deposits or a hydrate plug:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Deposit properties and volume
- Treatment fluid properties
- Target zones (depths, pressures, temperatures, permeability, porosity, fluids)
- Wellhead and surface equipment configuration

Deposit Characteristics

Paraffins (wax) and asphalt are heavy hydrocarbons in the reservoir fluid that drop out of solution with decreasing temperature and pressure. Organic solvents that can be tailored to suit particular conditions generally resolubilize such deposits. Addition of heat can effectively lower their viscosity enough to circulate out of the wellbore or reenter solution with reservoir fluid.

Mixed wellbore deposits contain some combination of scale and organic deposit and/or formation fines. Careful analysis of the wellbore deposit is necessary for designing an effective treatment. Mixed deposits generally require combinations of treatment fluids and solvents for efficient removal of all components of the deposit. Typically, the base fluid is a dispersion of aromatic hydrocarbon solvent in acid. Special additives control or treat specific conditions.

Hydrates occur at elevated pressures when hydrocarbon gas molecules such as methane, propane, or butane become trapped inside a lattice of water molecules. The resulting crystal-like structure (clathrate) has properties similar to water ice but forms and remains stable at temperatures much higher than 32ºF. Hydrate plugs have relatively high compressive strength and can completely block a wellbore, even in the presence of high differential pressure. Certain alcohols, chloride salt solutions, and addition of heat can dissociate hydrates.

Chemical Treatments

Chemical treatments of organic wellbore deposits are only effective when the material is readily soluble in the treatment fluid(s). The uncontaminated treatment fluid must contact the deposit for sufficient time to dissolve the bulk of it. Some dissolution reactions are quite rapid. However, some deposits require soaking time in the treatment fluid which are impractical under normal circumstances. Rotary jetting or multi-port nozzles may be necessary to ensure adequate distribution and contact of uncontaminated treatment fluid over the deposit. Selection of a suitable chemical treatment depends on several factors including:

- Composition of the deposit
- Wellbore parameters—Generally, reaction rates and dissolution capacities increase as the temperature increases. Unfortunately, potential corrosion of wellbore tubulars and equipment increases with increasing temperature as well. Selecting the proper corrosion inhibitor is almost as important as selecting the base treatment fluid.
- Volume of material to be removed—The volume of treatment fluid is directly proportional to the volume of deposit to be removed.
- Treatment fluid compatibility—The treatment fluid must be compatible with any fluids, materials, or equipment that it might contact during the operation.

Jetting

Jetting can significantly improve removal of organic deposits from wellbore tubulars. Low-pressure (pump pressure < 5000 psi) jetting operations do not require any special tools, nozzles, or treatment fluids. High-pressure (pump pressure > 5000 psi) jetting tools and equipment are more specialized and require more detailed job design. All jetting operations require working the BHA back and forth across the deposit. This imparts a high degree of fatigue damage to a relatively short section of the CT string. Accurate data acquisition and real-time fatigue monitoring are essential components of the job plan.

The high flow rate necessary to achieve high jetting efficiency can be prohibitive. Taking steps to reduce the pressure loss inside the CT string and BHA is essential. Such steps might include:

- Selecting the largest ID string available
- Reducing the length of the CT string as much as possible
- Use of hydraulic friction reducers
- Including a bypass valve in the BHA
- Increasing the pump pressure to the maximum value that will allow completion of the jetting operation without exceeding the fatigue limit for the string

Low Pressure Jetting

Low-pressure jetting is usually effective for removing only the softest deposits. Relatively large jet nozzles provide good coverage of the wellbore target area and allow relatively high circulation rate for removal of dissolved material from the wellbore. The size and number of nozzles must be compatible with the available flow rate and BHP. The position and direction of the jets should suit the intended application. For example, lateral jets (perpendicular to the wellbore surface) are ideal for washing perforations. Severe deposits may require jets oriented at several angles. The turbulence in the jet increases the scale dissolution rate and forces the treatment chemicals deeper into the deposit.

High Pressure Jetting

High-pressure jetting can provide the hydraulic impact or cutting action to remove harder deposits. However, the high circulating pressure and constant movement of the BHA is detrimental to the working life of the CT string. Accurate data acquisition and real-time fatigue monitoring are essential for preventing premature failure of the CT string.

Computer Simulator Modeling

Removing organic deposits or hydrate plugs is primarily a hydraulic operation; providing mechanical force is secondary. Use a reliable hydraulics model such as Hydra™ to select the CT string and predict the relationship between the fluid flow rate and the pump pressure for different operating conditions. Determine or evaluate the following:

- The pump pressure required for the minimum effective jetting pressure (flow rate)
- The flow rate at the maximum allowable pump pressure

Use a reliable tubing forces model such as Orpheus™ to predict the mechanical performance of the proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at operating depth

Job Plan Outputs

A basic job plan for removing organic deposits or hydrate plugs includes the following:

- Minimum flow rate
- Optimum penetration rate for a given flow rate

Prepare contingency plans for the following situations when removing organic deposits:

- The maximum flow rate attainable is not high enough to effectively remove the deposit in certain sections of the wellbore.
- When pumping heated fluid, the fluid delivered to the deposit is only hot enough to partially remove the deposit
- The ECD exceeds the reservoir pressure and annulus fluid enters the formation.
- The BHA becomes stuck in the deposit.

Prepare contingency plans for the following situations when removing hydrate plugs:

- The differential pressure across the plug cannot be balanced.
- The plug dissociates faster than expected and releases a large volume of gas that reaches the surface.
- The plug suddenly releases from the wellbore and slams into the BHA.

Selecting Equipment for Removing Wax, Hydrocarbon, or Hydrate Plugs

CT Equipment

Any CT string is suitable for pumping chemicals or heated fluids to remove organic deposits or hydrate plugs. Use the largest feasible size of work string to allow higher circulation rates and a higher annular velocity.

Organic deposit removal operations can induce significant levels of fatigue from repeated cycling of the tool string over a localized area and from high-pressure jetting operations. The CT string must be able to withstand the predicted fatigue effects.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for these pumping operations. Verify that all BOP components are compatible with the treatment fluid(s).

Configure the pressure control equipment to avoid circulating corrosive or solids-laden annular return fluids through the BOP. If it is necessary to return fluids through a shear or seal BOP installed above the tree, take the returns through a pump-in tee installed in the riser.

Pumping Equipment

All fluid mixing, pumping, and storage equipment must be clean and configured to avoid contamination or dilution of the treatment fluids. Pumps must be sized to provide the hydraulic HP required for jetting operations.

Downhole Tools

The BHA for removing an organic deposit or hydrate plug should include the following components, from the top down:

1. CT threaded connector.

2. Dual flapper type check valves.

3. Straight bar—Use approximately 6 ft. This optional item is especially helpful for running through upsets in the completion, such as side pocket mandrels.

4. Jetting nozzle—There are no special nozzle requirements. It can be as simple as a few holes drilled in a bull plug.

NOTE: Prepare an accurate fishing diagram for the tool string.

Auxiliary Equipment

For live well operations, use a choke manifold to control annular returns. The CTU, pump, and choke manifold operators must also have a clear line of communication with each other and the Customer well-site supervisor. For operations involving heated fluids, ensure that surface piping is adequately insulated to protect personnel.

Real-time CT Fatigue Monitoring

Removing organic deposits requires moving the CT while pumping at high pressure. This can impart a significant amount of fatigue over a short section of the CT string. An accurate real-time fatigue monitoring system is necessary to prevent premature failure of the CT during the job.

Logistical Constraints

The primary logistical problem for organic deposit removal operations is disposal of the waste fluid and deposit residue. Space availability, deck loading limits, and crane capacity can be logistics nightmares for offshore CT operations. Special boilers or heat exchangers for heated fluid applications can be large and heavy.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rates. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, remaining working life, and fluid flow rates. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Removing Wax, Hydrocarbon, or Hydrate Plugs

Removing organic deposits is frequently a regular operation within a field or area. Whenever possible, refer to similar case histories and adjust procedures to meet local conditions.

Preparing the Wellbore

1. If possible, recover wellbore deposit samples for analysis. One can use CT conveyed tools in conjunction with preparatory work.

2. If required, remove completion equipment components such as gas lift valves or safety valves. One can use wireline or CT, but using CT is preferable because the deposit will hamper retrieval. With CT, one can circulate treatment fluids to facilitate removal. In addition, CT can exert greater forces than wireline equipment.

3. If necessary, kill the well for safety, fluid compatibility, circulation, or production reasons. In wellbores with known deposits and damage, avoid bullheading the wellbore and damaging the near wellbore area. Use CT well kill techniques to minimize potential damage.

4. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve.

5. Prepare the wellhead and surface facilities for circulation, separation, and disposal of the deposit and treatment fluid.

Preparing the Equipment

1. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

2. Assemble and install the BHA on the CT string.

3. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Preparing Fluids

Batch prepare the treatment fluid in advance, or mix it on the fly as the operation proceeds. Allow sufficient residence time to enable the desired fluid characteristics to develop and be checked. For heat treatments, circulate for a long enough period for all components to reach a steady temperature.

Performing the Wax, Hydrocarbon, or Hydrate Plug Removal

1. RIH while pumping inhibited water or treatment fluid at a slow rate.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Gently tag the deposit or stop at the designated depth while maintaining fluid circulation to avoid plugging the nozzle.

3. Pick up the CT string about 25 ft and increase the fluid flow rate to the operating level for the tool string.

4. Wait for the treatment fluid to circulate to the tool string before attempting to penetrate the deposit.

5. RIH slowly and penetrate the deposit. If trying to remove a hydrate plug, gently tag the plug again.

NOTE: The optimum penetration rate is generally a compromise between deposit removal ability, hole cleaning ability, and maintaining the desired ECD.

CAUTION: Ensure that the pressure across a hydrate plug stays balanced or higher on the CT string side.

6. Make a number of passes over the deposit area, unless the BHA includes a ring jetting assembly that can assure full bore cleaning. However, control the number of passes to prevent excessive localized fatigue to the CT string.

7. Periodically pick up the BHA to the original top of the deposit to ensure that the CT string can move freely.

8. Continue pumping at a high rate through the entire treatment interval.

9. POOH while pumping inhibited water at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

10. If in doubt about the success of the deposit removal operation, perform a drift run over the original target interval.

11. If the well does not flow naturally or aided by gas lift, prepare to conduct nitrogen kickoff operations (Section “Unloading a Well with Nitrogen”).

Monitoring for Removing Wax, Hydrocarbon, or Hydrate Plugs

The key parameters to be monitored while removing organic deposits depend on the complexity of the operation. In all cases, monitor the following items.

- Fluid parameters—Fluid flow rates and pressures.

- Penetration rate—Avoid penetrating the wellbore material too quickly, or the CT string can become stuck. Optimize the penetration rate to ensure adequate wellbore cleaning.
- Returned Material—Monitor the volume and composition of returned material to assess transport and removal efficiency. If recovered samples differ significantly from the sample used to design the operation, redesign or fine tune the fluid parameters to improve operation efficiency.

Safety Issues for Removing Wax, Hydrocarbon, or Hydrate Plugs

Always conduct a pre-job safety meeting prior to RIH.

Take precautions to avoid exposing operations personnel to the treatment fluids. Most solvents used for removing organic deposits are flammable and highly toxic. The same applies to most alcohols used to dissociate hydrate plugs. Operations involving circulation of heated fluids create potential fire and burn hazards.

Dissociation of hydrates liberates a large quantity of gas. The surface equipment must be able to handle the volume of gas released.

A hydrate plug can withstand a high differential pressure. The plug could become a dangerous projectile if the differential pressure is too high when the plug begins to dissociate.

12

MECHANICAL OPERATIONS

BASIC CONSIDERATIONS

This chapter discusses mechanical applications, which depend on the strength and rigidity of the CT string to deliver a tool to a downhole location, apply an axial force, or both. Circulation through the CT string is secondary. In all cases, follow the guidelines in Chapter 17 "Minimizing Risk For CT Operations" for planning, selecting equipment for, and executing CT mechanical operations.

This section describes the key factors that affect a CT mechanical operation. Subsequent sections in this chapter discuss eight types of CT mechanical operations.

CT String

CT String Properties

Chapter 6 "Tubing Forces", Chapter 7 "Buckling and Lock-up", Chapter 8 "CT Mechanical Limits", and Chapter 9 "CT Working Life" discuss the mechanical performance of a CT string. In general, increasing the CT wall thickness or material yield strength improves the mechanical performance. Increasing the CT OD increases its stiffness and usually its tensile load capacity. However, resistance to fatigue and collapse decrease with increasing OD.

CT String Preparation

In addition to flushing and cleaning the CT string prior to use, frequently drift the string with an appropriately sized ball or plug. This ensures clear passage of balls or darts for contingency tool string operation, e.g., ball activated release tool.

Safe Working Life

Every time the CT string is bent and straightened in the surface equipment the safe working life of the string decreases. Mechanical applications often require reciprocating the CT over a short interval of the wellbore. This concentrates fatigue damage over a short section of the CT string. A real-time fatigue monitoring and management program, consistently applied during all CT operations performed by a specific string is the single most effective means of avoiding CT string failure due to fatigue. Chapter 9 "CT Working Life" provides a detailed discussion of CT fatigue and real-time monitoring.

Surface Equipment and Facilities

Modern CT strings and injector heads are capable of applying high levels of force. The wellhead and riser (if so equipped) must be able to safely withstand the high axial forces and sometimes high lateral forces exerted by the injector head. A support stand or other means to distribute the forces may be necessary.

Reels for CT strings equipped with internal conductors or control lines must have hydraulic swivels or collectors.

Tool String or BHA

The design and construction of all tools and equipment in the BHA must be compatible with the following:

- All wellbore and treatment fluids
- The applied forces
- The anticipated temperature and BHP

Wellbore

The path (survey) and internal dimensions of the wellbore significantly influence the mechanical performance of a CT string. Chapter 6 "Tubing Forces" and Chapter 7 "Buckling and Lock-up" describe these effects.

Completion components often create local restrictions or upsets in the wellbore. Applications requiring the running or retrieval of "unusual" downhole components e.g., fishing, require extra care when the BHA is passing these locations.

SETTING A PLUG OR PACKER

Mechanical plugs and packers provide temporary or permanent isolation within the production tubulars (casing/liner and production tubing). Common applications for bridge plugs include:

- Isolate a zone of unwanted production, e.g., water
- Hold a production interval in reserve for an extended period of time
- Plugging and abandonment of specific intervals of entire wellbore
- Stable platform for a balanced cement or slurry plug
- Isolate a lower interval from upper interval to be treated, e.g., stimulation treatment on upper zone.
- Isolate a zone from producing zones above and below it (straddle packer)

Some bridge plugs are retrievable, but most serve as permanent plugs or support platforms. Bridge plugs are available for through tubing applications. Packers are generally used for temporary plugs or support platforms, e.g., isolating the CT/tubing annulus from treatment fluid and pressures. Packers connected together with tubing, i.e., straddle packers, can isolate a section of wellbore to localize subsequent treatments.

(Also see Chapter 11 "Pumping Slurry Plugs", page 11-54.)

Planning to Set a Plug or Packer

The specific steps to run and set a packer or plug are much the same for each type of operation. The events after setting and testing the packer depend on whether the packer is permanent or temporary. If the latter, the job design might include a wellbore treatment such as zonal isolation or matrix stimulation.

The principal considerations for setting bridge plugs and packers are:

- Operating temperature
- Operating pressure
- Fluid compatibility
- Setting mechanism
- Recoverability

- Accurate depth measurement
- Accurate measurement and control of CT weight and movement

Job Plan Inputs

One must know the following information to plan for setting a plug or packer:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Target depth
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration

Operating Temperature

Packers and plugs use elastomers to form a hydraulic seal against the wellbore. Many of these materials have relatively low operating temperature. Accurately determining the downhole temperature is the critical first step to selecting the appropriate packer materials. A packer or plug may appear to set successfully but later fail due to temperature degradation of its sealing elements.

Operating Pressure

BHP affects the running, setting, and static performance of packers and plugs in two ways. First, the pressure required to inflate a packer depends directly on the local pressure around the sealing elements. Second, the differential pressure the plug or packer can withstand after being set depends on how tightly it seals against the wellbore and/or how tightly its slips grip the wellbore.

Fluid Compatibility

Many elastomers can be sensitive to produced or treatment fluids at wellbore temperature and pressure. Test packer materials with the anticipated downhole pressure and temperature conditions to ensure that the materials can withstand prolonged exposure to the downhole environment. Some of the issues regarding fluid compatibility are:

- Gas absorption—Gas absorbed by the packer elastomers from fluids in the wellbore can degrade their performance or damage them due to explosive decompression if the pressure around the packer decreases, e.g. retrievable packers returned to the surface.
- Treatment fluid—Many elastomers are sensitive to aromatic hydrocarbons, solvents, and chemicals used for wellbore treatments.
- Inflation fluid—The fluid used to activate inflatable devices must be compatible with the packer components and free from particles that could plug the small ports and passageways inside most inflation tools.

Setting Mechanism

Three types of plug and packer setting mechanism are available for CT applications. These are:

- Compression set—Compressive force generated by slacking off (setting down) the CT string against the plug energizes the slips and/or packing element.
- Tension set—Tensile force applied by the CT string energizes the slips and/or packing element.
- Hydraulic (inflatable) set—Fluid pumped through the CT into the plug inflates a bladder or expands an elastomer chamber to energize the slips and/or packing element.

In each case the running tool contains a remotely activated release (axial force, hydraulic, or electrical) that will separate the plug (packer) from the CT work string.

The specific setting procedure depends on the type of plug or packer. Consult the tool supplier for the exact sequence of steps and the force or pressure required to set the plug. Also, determine the maximum axial force (tensile and compressive) and maximum differential pressure the plug can tolerate when set properly. The job plan should clearly identify these operating limits and state the range of set down weight to apply with the CT for testing the integrity of the plug.

Recoverability

All packers and bridge plugs operate on the principle of expanding to fill the wellbore. In most cases, the elastomer cannot fully resume its original geometry after being deflated. Therefore, the diameter of a retrieved packer or plug is usually larger than its original diameter. This often hampers recovery of the complete tool assembly. Several precautions during the retrieval process can minimize this problem. These include:

- Equalizing pressure—Equalizing the pressure across a plug or packer before unseating (releasing) it is extremely important. Otherwise, the plug could move violently or release high pressure fluid trapped behind it.

- Relaxation period—After disengaging the packer (plug) from the wellbore, wait as long as practical for the elastomers to relax before attempting to move the packer.
- Limit forces—Do not exceed the rated operating pressure or axial forces applied to the packer, because this can distort the packer components.
- Decrease running speed at restrictions—When POOH, slow down at restrictions in the wellbore to allow the packer to squeeze into the restriction.

Computer Simulator Modeling

Running and setting a plug or packer is primarily a mechanical operation. Pumping a small amount of fluid to hydraulically set or energize the packer elements is secondary. Use a reliable tubing forces model such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth during setting or releasing the plug

Job Plan Outputs

A basic job plan for setting or unsetting a plug or packer includes the following:

- Depth correlation method
- Wellbore cleanout and preparation required
- Axial force (if any) to set or unset the plug or packer—direction and magnitude
- The maximum allowable setdown weight and overpull
- Pump pressure (if any) to set or unset the plug or packer
- Maximum allowable axial force and pressure that can be applied to the plug after setting it in the wellbore
- If unsetting a packer, the waiting period before attempting to POOH

Prepare contingency plans when designing the job. As a minimum, describe responses for each of the following scenarios:

- The tool string sets and cannot be “unset”.
- The tool string becomes stuck in a restriction during retrieval.

- The packer or plug leaks.

Selecting Equipment for Setting a Plug or Packer

CT Equipment

Any CT string that can supply the axial forces required by the operation is suitable for setting a plug or packer. However, if the plug setting operation is just a preliminary step for another wellbore treatment, e.g., zonal isolation, matrix stimulation, or drilling, the succeeding operation may dictate the requirements for the CT string. CT depth and weight are critical parameters for setting a plug or packer. Monitoring and recording equipment must be calibrated and fully operational.

Precise control of the injector head is required in order to operate downhole tools. Apply and release tension in the work string smoothly to avoid damaging downhole tools or surface equipment.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for running and setting plugs. The exception is a long straddle packer that may require longer lubricator length.

Downhole Tools

The specific BHA depends on the plug or packer and its associated running (setting) tool. One must understand the operating method of each tool in the sequence. Check the compatibility of tools to make sure that the tool string will operate as intended. This check is especially important for catch-tool release mechanisms associated with plug setting and retrieval.

A typical BHA for setting a plug or packer consists of the following components, from the top down:

1. CT threaded connector—Dimple or slip-type connector
2. Dual flapper type check valves
3. Disconnect
4. Circulating sub

5. TEL for depth correlation

6. Setting tool

7. Bridge plug or packer

NOTE: Prepare an accurate fishing diagram for the BHA.

Pumping Equipment

Unless subsequent operations require large circulating volume and/or high flow rate, a small pit and cementing pump are adequate for setting plugs and packers. Generally, CT operations following setting a plug will determine the pumping equipment available.

Monitoring and Recording Equipment

Zero the depth measuring equipment with the CT connector against the stripper. Then correct for actual depth using the tool string length and the distance from a wellhead reference point.

Zero the weight indicator after making up the tool string and opening the swab valve. That is, zero the weight indicator with wellhead pressure applied.

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Setting a Plug or Packer

The steps required to successfully complete an operation relying on packers or plugs depend on the particular conditions encountered in each case, e.g., wellbore conditions and tool operating principals. The following sections outline the key points in each phase of the operation.

Packer/plug operations generally comprise four basic steps:

1. Preparing the wellbore
2. Preparing the equipment
3. Setting the plug or packer
4. Unsetting the packer or plug and recovering the tool string

Preparing the Wellbore

Some procedures are usually necessary to prepare the wellbore for accepting a packer or plug.

1. Modify the lubricator or riser to accommodate the tool string and packer as necessary. Some straddle packer assemblies can be quite long.
2. Remove or secure the SSSV (if present) to reduce the risk of sticking the tool string and/or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. The consequences of accidentally closing a safety valve with the CT in the wellbore can be disastrous.
3. Install dummy gas lift mandrels, as necessary, to reduce the risk of sticking the tool string and/or damaging a gas lift mandrel
4. Remove any fill, cuttings bed, scale, asphalt, or wax present in the wellbore from the surface to the packer setting depth
5. Drift the wellbore to ensure free passage of the tool string through the completion.
6. Depth correlation—run a TEL or CCL to determine the precise MD for setting the plug according to the CT depth indicator and flag the CT.
7. Caliper the wellbore at the setting depth to ensure the internal geometry of the wellbore is compatible with the setting capabilities of the packer or plug. If the wellbore has collapsed or become oval, the plug might not set properly.
8. Milling (reaming) the wellbore ID to a rounder shape or larger size at the plug setting depth may be necessary for the plug to properly engage and seal against the wellbore.

Preparing the Equipment

1. Verify that the bridge plug or packer and setting tool are correct for the planned operation and match the specifications in the work program.
2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and connect it to the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Setting the Plug or Packer

1. RIH while pumping inhibited water at a slow rate.

WARNING: Pay close attention to the maximum running speeds per Chapter 18 "CT Running Speeds", page 18-18, or the maximum running speeds for the tool string, whichever is less.

CAUTION: Generally, avoid pull tests while running a tension or compression set tool. Otherwise conduct pull tests per Chapter 18 "Pull Tests", page 18-19.

WARNING: Make sure that circulation is compatible with the tool string operation.

---

2. Reduce the running speed per Chapter 18 "CT Running Speeds", page 18-18 near profile nipples or the bottom of the production tubing. Correlate the depth using the TEL and flag the CT.

3. Slackoff to a depth approximately 25 ft below the intended setting depth for the bridge plug or packer.

4. Pick up the bridge plug or packer until it arrives at the required setting depth.

5. Set the bridge plug or packer and release the setting tool as specified in the work program. Specific setting procedures vary depending on the manufacturer and model of the bridge plug or packer being employed.

6. Pull up about 25 ft, stop, slowly RIH, and gently tag the bridge plug or packer. Push on the bridge plug or packer according to the job plan to ensure that it is securely anchored.

7. POOH while slowly pumping inhibited water.

WARNING: Pay close attention to the maximum running speeds per Chapter 18 "CT Running Speeds", page 18-18.

8. Refer to Chapter 11 "Pumping Slurry Plugs", page 11-54 for placing a slurry plug on top of a bridge plug or packer. Avoid causing any differential pressure across the bridge plug or packer.

Unsetting the Packer and Recovering the Tool String

1. Equalize the differential pressure across the plug or packer before unsetting it.

2. If the packer or plug must pass through any restrictions, wait at least 15 minutes to allow the elastomers to relax. Wait longer for packers or plugs with large expansion ratios.

3. When POOH, reduce the running speed at each location in the wellbore where the annular gap between the packer and the wellbore decreases.

Monitoring a Plug or Packer Job

Document the setting sequence, pumping schedule, and tubing movement. It is crucial to maintain a complete job record. The operation of many tools depends on a specific sequence of tubing movement and pumping schedule.

Key factors include:

- Pumping—if using pressure-activated tools, it is essential to closely monitor and control the pump parameters. Take into consideration any changes in wellbore or pumped fluid that may influence CT string weight (buoyancy).
- Tubing movement and weight—Monitor and record changes of direction (up/down) and the associated changes in weight. For example, one can tell a packer or plug is set when it “takes weight”.
- Pressure and force—Ensure that the pressures (inflate, treatment, and differential) and forces (up/down) remain within limits.

Safety Issues for Setting a Plug or Packer

Always conduct a pre-job safety meeting before RIH.

Attempting to unset (release) a plug with higher pressure below it can cause the plug to move violently uphole. Always balance the pressure across a plug before unsetting it.

FISHING

Fishing is the removal of broken, dropped, or stuck tools and equipment (the “fish”) from a wellbore. In this section, fishing does not include running, retrieving, or operating intentionally set plugs, packers, or other downhole equipment, even though these operations are similar.

A wide variety of tools and techniques are available for fishing operations. The tools and techniques vary for each operation, depending on the nature and configuration of the fish, the wellbore, completion, and surface equipment. Consequently, each fishing job is unique and requires careful design and execution.

Fishing with CT has several advantages over alternative fishing methods including:

- CT is considerably stronger than slick line or braided line, allowing the application of greater tensile forces.
- The stiffness of CT allows access to highly deviated or horizontal wellbores.
- CT can push on a fish; sometimes the best solution is to push a fish into the rathole, e.g., spent perforating guns.
- Fluid circulated through the CT (washover tools) can improve access to the fish.
- CT allows use of flow-activated or hydraulic tools.

Planning a Fishing Job

The tool string used to conduct CT fishing operations must be capable of the following functions:

- Catching and holding the fish.
- Applying sufficient tension, or energy through jars to permit retrieval of the fish.
- Releasing the fish in the event it cannot be retrieved.

For fishing operations in a live well, sufficient riser or lubricator length must be available to allow the entire fish to be pulled above the master valve or lowest pressure control valve. Only in this way can the CT, BHA, and fish be safely removed while maintaining pressure control.

NOTE: Accurate depth and CT weight measurements are vitally important to any CT fishing operation.

Due to the extraordinary diversity of fishing tools, most CT service companies rely on third party suppliers or fishing service companies. However, fishing is usually an emergency operation requiring rapid response. Contingency plans for any CT operation should include a list of fishing tool and service providers in the area. Also, the contingency plans should include an accurate diagram of the BHA showing the dimensions of all the component parts that could become a fish.

While CT fishing techniques can be successful for a wide range of applications, medium- to heavy-weight through-tubing operations performed on live wells are most common. Conventional wireline fishing techniques are generally more useful for lighter-weight operations. Wireline equipment is considerably more sensitive and easier to manipulate than CT equipment, making the retrieval of small objects easier. In addition, rig up times and running speeds for wireline or slick line are faster than for CT. Finally, wireline services are less expensive than CT services.

Job Plan Inputs

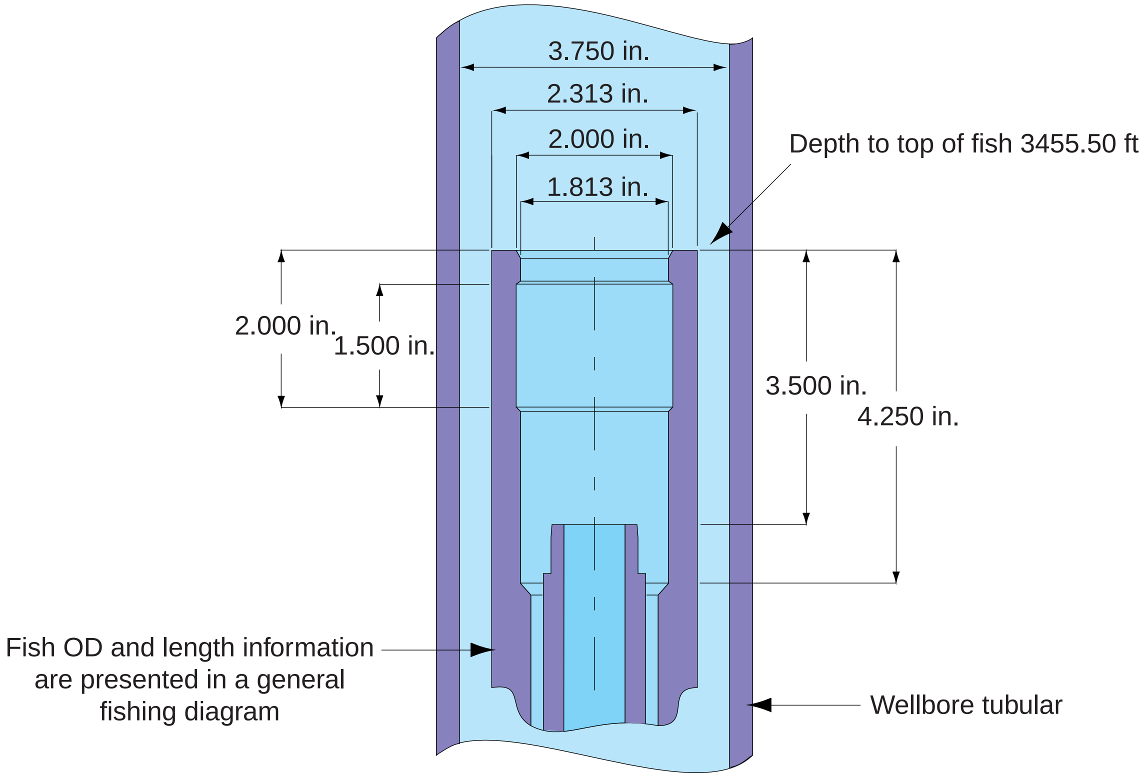
One must know the following information to plan a fishing operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Location (depth) of fish
- Condition of fish
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration

Fish Properties

Precise details of fish type and dimensions are seldom available. However, whenever possible, prepare an accurate dimensional diagram of the fish. Figure 12.1 is an example.

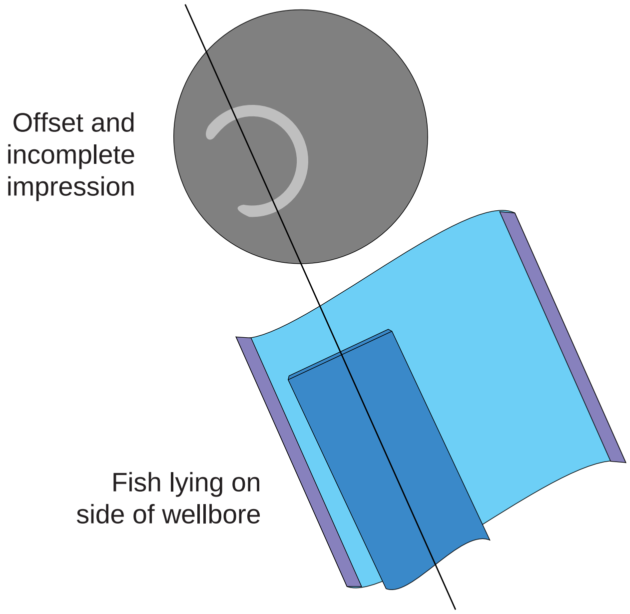
FIGURE 12.1 *Fishing Diagram - Fishing Neck Detail*



Condition of the Fish

Determining the condition of a fish and/or its orientation in the wellbore is often quite difficult. However, this information is crucial to selecting the proper fishing tool and designing a procedure for acquiring the fish. Lead impression blocks are the simplest means of obtaining information on the profile and orientation of the fish. However, the recovered impression is often confusing and requires some experience for correct interpretation (Figure 12.2).

FIGURE 12.2 *Lead Impression Interpretation*



In the right wellbore conditions, downhole cameras can transmit real-time images of a fish to the surface through logging cable. However, this service depends on relatively clean fluid in the wellbore and can be quite expensive.

Prepare a diagram showing the wellbore or completion diagram with the location and orientation of the fish plus the location and dimensions of nipples and restrictions which could hamper its retrieval. The fishing plan must also address the following concerns that affect the choice of fishing tool.

- Is the fish stuck or free? The answer to this question also affects the choice of CT string (pulling power).
- Is the fish surrounded by or covered with junk (debris), sand, or cuttings? The answer to this question determines the need for pumps and fluid handling equipment and affects the choice of CT string (hydraulics).
- What material(s) is the fish made of? If the fish is made of ferrous materials and light enough, a simple magnet might be able to retrieve it.

Wellbore Geometry

The ID in the wellbore will determine the maximum OD of CT and fishing tool that can be used for the job. The wellbore geometry and well path affect the mechanical performance of the CT string, i.e., setdown weight and overpull.

Surface Equipment

If the fishing operation is for a live well, then adequate lubricator or riser height must be available to retrieve the BHA and fish. If the fishing operation calls for washover tools or fluid circulation, then fluid handling and pumping equipment must be available.

Logistical Constraints

The variety of fishing tools is enormous, but their distribution around the world coincides with areas of high drilling activity. Consequently, the proper tools for the fishing job at hand may not be available without advanced preparation. Every CT job plan should anticipate potential fishing operations and include contingencies for acquiring the necessary tools.

Computer Simulator Modeling

Fishing is primarily a mechanical operation. Pumping fluid to hydraulically activate a tool is secondary. The exceptions are fishing operations that include circulating the wellbore clean or washing over a fish. Use a reliable tubing forces simulator such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at the depth of the fish

If the fishing operation involves significant pumping, use a reliable hydraulics simulator such as Hydra™ to

- Predict the relationship between flow rate and pump pressure for different operating conditions.
- Estimate the flow rate required for efficient hole cleaning.

Fishing usually requires moving the CT back and forth over a short distance many times. This adds a significant amount of fatigue to the corresponding section of the CT string. Run the entire fishing operation on a fatigue simulator such as Reel-Trak™ starting with the known fatigue history of the CT string selected for the operation. The results will indicate if any portion of the string might accumulate an unacceptable amount of fatigue before the end of the fishing job.

Job Plan Outputs

A basic job plan for fishing includes the following:

- Depth correlation method
- Wellbore cleanout and preparation required, if necessary
- Axial force (if any) to capture the fish
- The maximum allowable setdown weight and overpull
- Pump pressure (if any) to capture the fish

Prepare contingency plans as part of the job design. At a minimum, include actions to take in each of the following scenarios:

- The available tool or tools cannot capture the fish.
- The fish remains stuck and cannot be retrieved.
- The fish remains stuck and the catch tool won't release.
- The fish remains stuck, the catch-tool cannot be released, and the release joint fails.
- The fish cannot be retrieved far enough into the pressure control equipment to close the master valve or other isolation device.
- A section of the CT string reaches the pre-established fatigue limit.

NOTE: If cutting the CT is the only option, cut it inside the production tubing.

Selecting Equipment for Fishing

CT Equipment

Any CT string that can supply the axial forces required by the operation is suitable for fishing. However, if the fishing operation requires significant pumping, the hydraulic operations may dictate the requirements for the CT string. CT depth and weight are critical parameters for fishing. Monitoring and recording equipment must be calibrated and fully operational. These operations require precise control of the injector head functions for proper operation of setting tools. Apply and release tension in the work string smoothly to avoid damaging downhole tools or surface equipment.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for fishing. The exception is a long fish that may require longer lubricator length for live well operations.

Downhole Tools

The specific BHA depends on the fishing operation. In general, the BHA consists of the following components, from the top down:

1. CT threaded connector—dimple or slip type

2. Dual flapper type check valve

3. Disconnect—mechanical, hydraulic, or both

4. Accelerator

5. Weight bars—as necessary

6. Jar

7. Fishing tool

NOTE: Prepare an accurate fishing diagram for the tool string.

The following summarizes the main considerations for selecting appropriate tools for a particular fishing job.

Standard BHA Components

The threaded CT connector used on fishing operations must be strong enough to withstand the anticipated forces exerted during the job. This eliminates roll-on connectors from consideration. To reduce the chance of tubing failure adjacent to the connector, plan on trimming several feet of CT from the end of the string and replacing the connector after each fishing run that includes jarring. Tandem flapper check valves should be incorporated in the fishing BHA unless reverse circulation is a necessary component of the job plan. The BHA must include a disconnect for separating the CT string from the fishing tool.

WARNING: Removing the check valve(s) and reverse circulating up the CT string is a specialized CT operation requiring additional planning and operational oversight. This procedure is suitable only for dead wells.

Catch Tool Release Mechanism

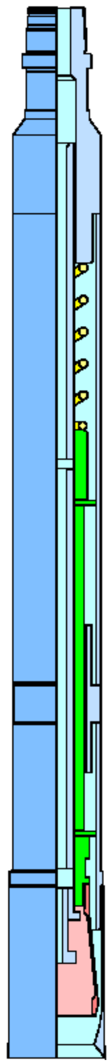
All catch tools must have at least one means of disengaging from the fish in the event it cannot be retrieved. Such release mechanisms may require additional axial force (setdown weight or overpull) or operate hydraulically (overpressure or flow rate). Single-shot tools can engage and disengage the fish only once. After disengaging the fish, single shot tools must be rebuilt. Allow extra running time in the job plan when using such tools. Multi-shot tools can release and re-engage a fish many times. This provides more flexibility for the actual operation and significantly reduces potential unproductive time.

NOTE: An internal release mechanism does not preclude the use of a separate disconnect for releasing the CT string from the fishing tool.

Overshot

The overshot is designed to latch and grip on the outside diameter of the fish (Figure 12.3*)*. This is a good option when sufficient clearance exists between the fish and wellbore.

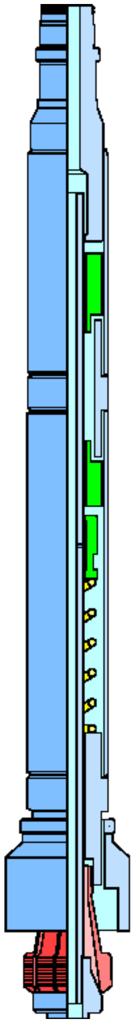
FIGURE 12.3 *Typical Overshot Configuration*



Spear

Spears are designed to latch and grip on the internal diameter of a fish (Figure 12.4). These can be used in any wellbore, but are the only option when wellbore ID limits the size of the fish. Also, they may be a good option if the release joint on the fish is exposed.

FIGURE 12.4 *Typical Spear Configuration*



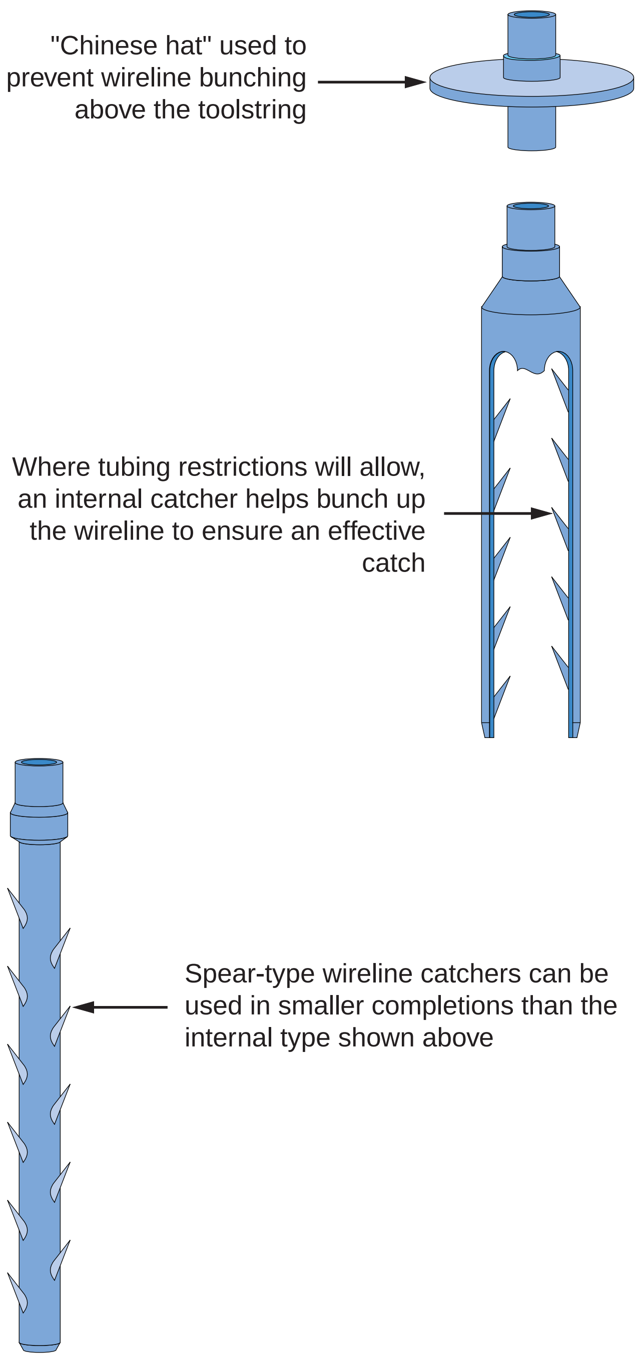
Magnetic Tools

Magnetic fishing tools can retrieve small ferrous objects from the wellbore. The weight of the fish determines the strength of the magnet required. These tools have special shipping, handling and storage requirements.

Wireline Catcher

The most common tools for fishing wireline or other cable have barbs or some other means of snagging the wire (Figure 12.5*)*.

FIGURE 12.5 *Wireline Catching Tools*



Jars

The normal use for jars in fishing operations is to deliver an upward impact force for freeing the fish. Sometimes downward jars are used to operate the release mechanism of the catch tool. Most jars operate in one direction only, but some are bi-directional. Computer simulation of the fishing operation should indicate whether a jar is necessary, and if so, what type.

NOTE: An accelerator with matching performance must accompany each jar. If possible, install a weight (straight) bar between the accelerator and the jar.

Accelerator

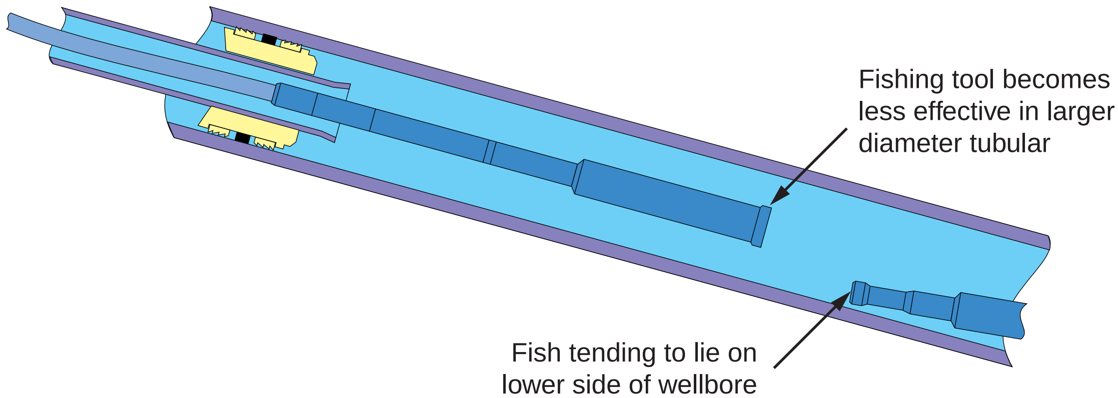
The accelerator stores energy to enhance the operation of the companion jar and shields the CT string from shock loads.

NOTE: Accelerator performance must match that of the companion jar.

Orientation and Locating Tools

Through-tubing fishing operations, i.e., fishing in larger ID pipe below the production tubing, restrict the diameter of the fishing tools. Capturing a fish with a "small" tool can be difficult under that condition, especially in highly deviated or horizontal wellbores (Figure 12.6).

FIGURE 12.6 *Orientation and Location*



A number of tools, adapted from slick line tools, can assist in locating and engaging the fish.

- Centralizers—Centralizers help locate and engage a fish that is centralized in the wellbore. These tools come in a variety of designs and sizes. For wellbores with multiple internal diameters, use springbow or arm centralizers. However, note that centralizers cause additional friction that can induce premature lock up in highly deviated and horizontal wells. Hydraulically-activated centralizers prevent this problem by opening on demand, but they require pumping through the CT string.
- Knuckle Joints—Use pump-through knuckle joints in deviated wells, in crooked tubulars, and where gas-lift mandrels hinder the operation of the tool string. Where necessary, use two knuckle joints or a dual knuckle joint to ensure the necessary flexibility and alignment.
- Orientation Tools—Orientation tools adjust for the inability to rotate a CT work string. They are controlled and powered by fluid pumped thought the CT. They are an example of the rapidly increasing range of specialty fishing tools. Slow turning motors and indexing bent subs are also under development for this type of application.

There are many ways to assemble a tool string for a fishing operation. Select tools based on tool availability, operator preference, availability of technical support, and previous experience. Figure 12.7 through Figure 12.10 show typical fishing tool assemblies for a variety of conditions.

FIGURE 12.7 *Basic Fishing Tool String Configuration*

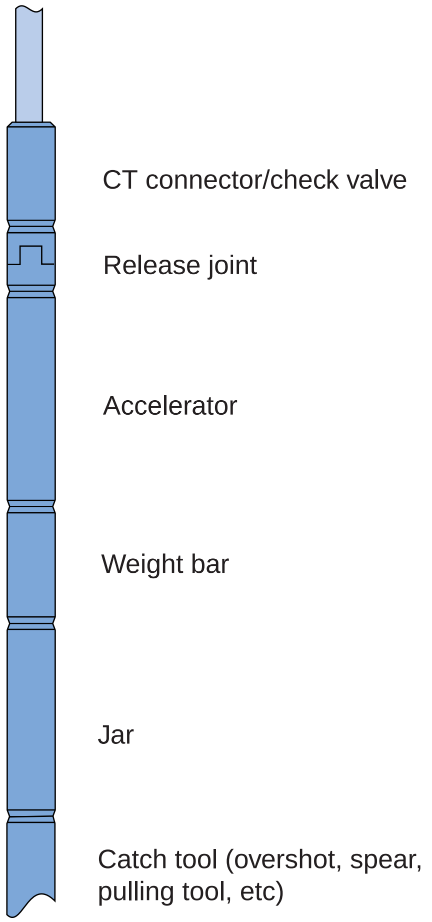


FIGURE 12.8 *Fishing Tool String Incorporating Fishing Motor and Bent Sub*

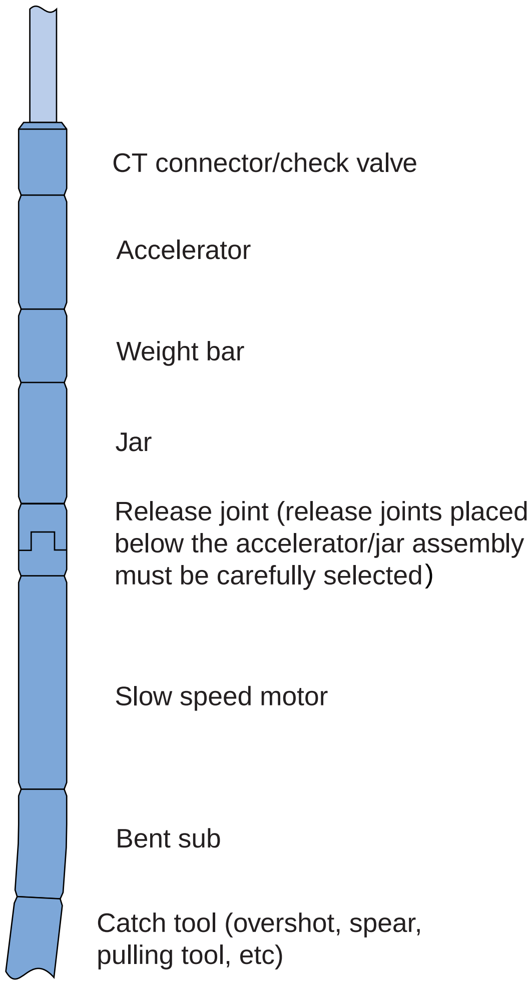


FIGURE 12.9 *High Angle Fishing Assembly*

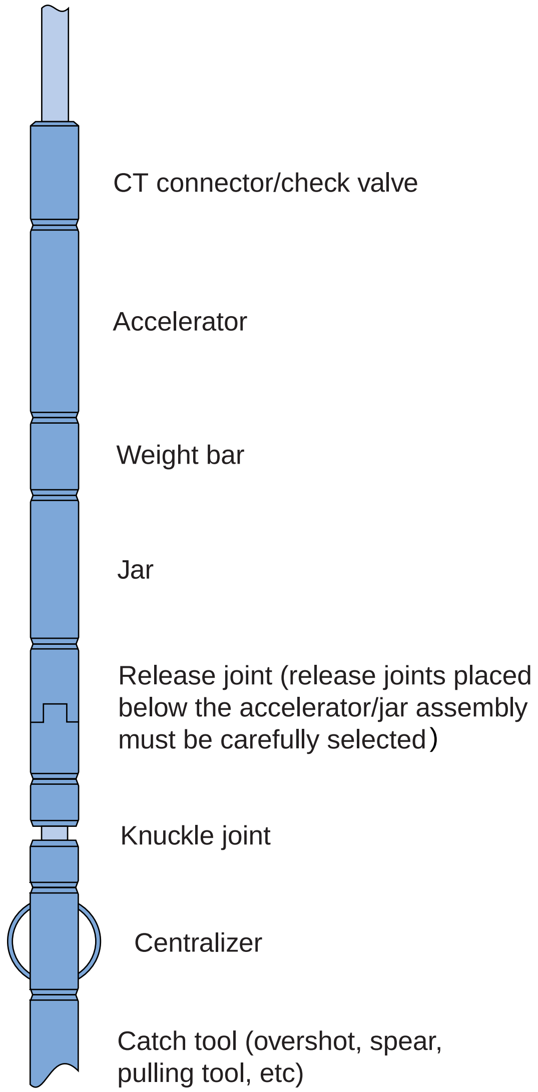
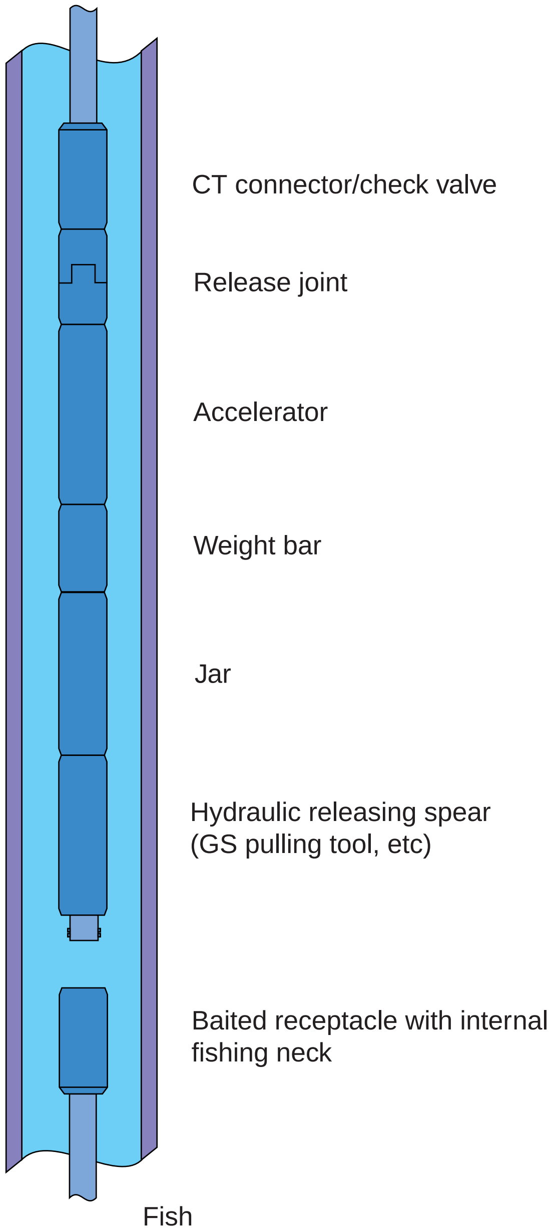


FIGURE 12.10 *Baited Fish and Fishing Assembly*



Pumping Equipment

Unless the operation requires a large circulating volume and/or high flow rate, a small pit and cementing pump are adequate for operating hydraulic fishing tools.

Monitoring and Recording Equipment

Zero the depth measuring equipment with the CT connector against the stripper. Then correct for actual depth using the tool string length and the distance from a wellhead reference point.

Zero the weight indicator after making up the tool string and opening the swab valve. That is, zero the weight indicator with wellhead pressure applied.

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 “Minimizing Risk For CT Operations”.

Fishing operations often require moving the CT string up and down over a short interval. This increases the fatigue damage in that portion of the CT string in the surface equipment. Real-time fatigue software, such as Reel-Trak™, is essential to prevent a fatigue failure during the fishing operation.

Generic Procedure for Fishing

Each fishing operation involves different steps, depending on the particular conditions encountered. This section includes some general key points for each phase of the fishing operation. When performing a fishing operation, review these key points, incorporating applicable points into your procedure as required.

Fishing operations generally include the following steps:

1. Preparing the wellbore
2. Preparing the equipment
3. Capturing the fish

Preparing the Wellbore

1. If using slick line or wireline services, check lubricator or riser connections for compatibility.
2. Conduct any necessary slick line or wireline work, such as gas lift valve removal.

3. Remove or secure the SSSV to reduce the risk of sticking the tool string or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. Accidentally closing a safety valve with the CT in the wellbore can have severe consequences.

4. Place dummy gas lift mandrels to reduce the risk of sticking or damage.

5. Drift the wellbore to the top of the fish to ensure that the tool string can pass freely. If necessary, the tool string can include an impression block to identify the presence of fill or debris on top of the fish.

6. If there is a significant volume of fill or debris, prepare a detailed fill removal procedure. Completely remove the fill material before attempting to capture the fish. (See Chapter 11 "Removing Fill or Sand From a Wellbore", page 11-7.)

7. If desired, bait the fish with a tool to provide a fishing neck that is easily latched and released for subsequent CT fishing.

NOTE: If desired, kill the well to simplify several aspects of the job. Killing the well is an especially good idea if the fish is very long and cannot be easily contained within the available riser or lubricator.

Preparing the Equipment

1. Verify that the fishing tool is correct for the planned operation.

2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and connect it to the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Capturing the Fish

1. RIH to the fish or hold-up depth.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and perform pull tests (Chapter 18 "Pull Tests", page 18-19).

---

2. Clean the top of the fish, if necessary, by circulating fluid.

3. If necessary, dress the fish to assist the fishing tool. For example, a tapered mill can ease the entry of a spear into the fishing neck.

4. Latch onto the fish and apply jarring action as necessary to release the fish.

5. Closely monitor accumulated fatigue in the CT string. If necessary, retrieve the tool string and cut tubing off the end of the work string to spread out the fatigue damage.

6. When repeatedly firing hydraulic jars, be prepared to dissipate the built up heat to prolong the life of the tool.

WARNING: After each run that involves jarring, cut back the CT and replace the connector to reduce the chance of tubing failure next to the connector.

---

7. After capturing and freeing the fish, POOH with the CT string.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

CAUTION: Slow down at each location in the wellbore where the annular gap between the fish and the wellbore decreases.

Monitoring a Fishing Job

Maintain a complete record of the job. The operation of many tools depends on a specific sequence of tubing movement and pumping schedule.

- Pumping—Closely controlling and monitoring pump parameters is essential for pressure activated tools. Also, note any changes in wellbore and pumped fluids. Changes in CT buoyancy affect weight indicator readings.

- Tubing movement and weight—Monitor and record changes of direction (up/down) and the associated changes in weight. For example, a fish “taking weight” indicates progress in the job.

Safety Issues for Fishing

Always conduct a pre-job safety meeting before RIH. However, this operation does not pose any job-specific safety issues.

PERFORATING

CT is one of three methods for conveying perforating guns into highly deviated and horizontal intervals. The technology resembles the well-established method of perforating with jointed pipe with several notable exceptions.

- CT permits much faster trip times.
- Live well deployment with CT is much safer and simpler.
- Internal e-line permits real-time monitoring of the entire CT operation.
- CT accommodates pumping while tripping

Since 1996, wireline tractors have offered another option for conveying perforating guns into highly deviated wellbores. These tools offer the convenience and lower cost of wireline operations, but are limited to shorter gun lengths than CT and don't provide any pumping capability. One big advantage of CT is the ability to circulate the wellbore clean or lift the well to start production after the perforating job.

Planning a Perforating Job

Job Plan Inputs

One must know the following information to plan a CT perforating operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Target depth of perforations
- Reservoir conditions at target depth
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration

Depth Control

Precise depth measurement and control are essential for perforating operations. A depth correlation run with a TEL and flagging the CT prior to RIH with the guns is one option. If the CT string includes an e-line, real-time monitoring with a CCL is an excellent way to accurately place the perforating guns.

Firing Mechanism

Perforating guns can be fired in two ways:

- Electrical firing—This requires an electric cable inside the CT and an electric firing head on the BHA. Conventional electrical detonators can be accidentally detonated by induced currents from stray voltage. Stray voltage can come from many sources, such as faulty electrical equipment, welding equipment, cathodic protection equipment, and radio frequency (RF) transmission.

> *WARNING:* Ensure that the gun firing mechanism is adequately protected against the effects of stray voltage. Maintain radio silence during the operation. Use a radiowave filter (or safesystem) when working in close proximity to a production manifold, gas plant, or other facility with a high wattage radio transmitter.

- Pressure activated firing—Internal pressure in the CT initiates the firing. These systems do not need a cable in the CT. However, they cannot be run with correlation logging tools to confirm the location of the guns.

Gun and Carrier Selection

Select a perforating system based on tool availability, operator preference, availability of technical support, and previous experience.

The size, type, and condition of the carrier also affect the performance of the perforator. Retrievable guns, such as HyperDome™/Scallop guns, lie inside a rugged hollow carrier. The carrier contains the gun debris after firing. The carrier provides better retrieval, and allows the guns to be used at higher temperature and pressure. However, gun carriers tend to swell from the extreme pressures encountered during perforating. Make sure the OD of the gun system after firing will fit through the smallest restriction in the wellbore.

The most influential element of perforator performance is the basic design of the perforating charge. However, the size, type, and condition of the gun carrier affect how the charge impacts the wellbore. To achieve the maximum performance from a charge, the distance between the charge and the casing must be within a certain range.

A detailed description of perforating technology is beyond the scope of this manual. The following discussion presents a brief summary of some of the perforating guns available.

Casing Guns

Large-diameter guns (3.375 in. to 7 in. OD) normally run on wireline or drill pipe inside casing.

Through-tubing Guns

Small diameter guns (1.688 in. to 2.875 in. OD) commonly used with CT. These guns fall into three categories.

- Expendable guns—45° phased Enerjet™ guns are an example, used in applications where a significant amount of debris is not a problem.
- Semi-expendable guns—0° phased Enerjet™ guns are an example, used in applications where moderate debris is acceptable.
- Retrievable guns—HyperDome™/Scallop guns are an example, used in applications that won’t tolerate any debris. A rugged hollow carrier contains the guns and confines the gun debris after firing. Also, the carrier allows the guns to operate in higher temperature and pressure. Hollow gun carriers tend to swell as a result of the extreme pressures encountered during perforating. Therefore, anticipate larger OD for the guns after firing and plan for the effects of this on POOH.

High Temperature and Pressure

High temperature and pressure influence the choice of explosive type and carrier design. Explosives in perforating guns generally have time-temperature ratings, such as a 1 hour rating and a 100 hour rating. For example, if an explosive has a 1 hour rating of 150°C, do not subject it to 150°C for more than 1 hour. Do not exceed the time-temperature rating for an explosive, or it can auto-detonate. Accidental auto-detonation can destroy the carrier, cause the gun to stick, and damage the well.

The carrier also has a maximum pressure rating. Exceeding the maximum pressure rating can cause fluid to flood the guns or crush the carrier. High pressures and temperatures also affect the elastomers in the pressure seals. In high-temperature or high-pressure operations, change the seals between runs into the well to avoid failures.

H_2S and Acids

If H_2S or acids are present in sufficient concentrations, they will attack the perforating guns. The resulting corrosion and possible hydrogen embrittlement can lead to material failure. Follow these safety points:

- If using inhibitors, make sure they do not affect the elastomers in the pressure seals.
- For environments with hydrogen sulfide concentrations of 2% or more, use hollow-carrier perforating guns instead of exposed guns.

Computer Simulator Modeling

Perforating with CT is primarily a mechanical operation. Pumping a small amount of fluid to hydraulically fire the guns is secondary. Use a reliable tubing forces simulator such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH.
- Maximum setdown weight versus depth.
- Maximum overpull versus depth.
- Axial force and VME stress versus depth for the BHA at the target depth.

Job Plan Outputs

A basic job plan for CT perforating includes the following:

- Depth correlation method
- Wellbore cleanout and preparation required, if necessary
- Equipment and procedures for live well deployment, if necessary
- Pump pressure (if any) to fire the guns
- Procedure for nitrogen kickoff, if necessary

The job plan must address possible failure modes and suggest contingency actions. Potential problem scenarios for perforating include:

- The guns become stuck while RIH or POOH.
- The guns won’t fire.
- The guns fire while RIH or POOH.

- The spent guns won’t release from the BHA (when trying to drop the spent guns in the rat hole).
- The guns release from the BHA during RIH or POOH.

Selecting Equipment for Perforating

Perforating with CT generally requires the following equipment.

CT Equipment

Any CT string that can supply the axial forces required by the operation is suitable for perforating. However, if the guns are electrically fired, the CT string must include an electric cable. (See Section “Installing Electric Cable Inside CT”.) CT depth is a critical parameter for perforating. Monitoring and recording equipment must be calibrated and fully operational.

NOTE: This operation requires precise depth control.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for perforating. Live well deployment requires a lubricator tall enough to accommodate the guns or a special deployment system (see Chapter 18 "Deploying a Long Tool String in a Live Well", page 18-53).

Downhole Tools

The specific BHA depends on the gun configuration, depth correlation tool, and firing mechanism. Live well deployment may require special connectors between the individual BHA components to permit remote assembly of the BHA through the pressure barrier. In general, the BHA consists of the following components, from the top down:

1. CT threaded connector—dimple or slip type
2. Dual flapper type check valves
3. Disconnect—mechanical, hydraulic or both
4. Depth correlation tool—TEL, TNL, or CCL

5. Firing head

6. Perforating guns

NOTE: Prepare an accurate fishing diagram for the tool string.

Pumping Equipment

Unless subsequent operations require large circulating volume and/or high flow rate, a small pit and cementing pump are adequate for firing hydraulically actuated guns. Generally, CT operations following perforating will determine the pumping equipment available.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Perforating

The steps required to successfully complete a perforating operation depend on the conditions encountered. However, perforating operations generally involve the following steps:

1. Preparing the wellbore

2. Preparing the equipment

3. Assembling and deploying the gun

4. Correlating depth and perforating

5. Recovering the gun

NOTE: A valuable means of minimizing risk for an operation like perforating is to conduct CT test runs prior to the actual job. These consist of substituting a “dummy” BHA for the real one, then running the CT operation as planned. The dummy BHA should resemble the real BHA as much as possible in weight and dimensions, but need not perform the planned functions of the real BHA. CT test runs are more than a pass/fail tests because they provide a full dress rehearsal for the actual CT operation and data for validating simulations. Updating simulations with better estimates of Cf is particularly important if the CT test run deviates from the predicted results.

Preparing the Wellbore

Wellbore preparation procedures performed prior to CT perforating operations can include the following:

1. If using slick line or wireline to prepare the wellbore, check lubricator or riser connections for compatibility before the operation begins.
2. Remove or secure the SSSV to reduce the risk of sticking the tool string or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. Accidentally closing a safety valve with the CT in the wellbore can have severe consequences.
3. Drift the wellbore to ensure that the tool string can pass freely to the target depth.

Preparing the Equipment

1. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.
2. Assemble the BHA components above the guns and connect them to the CT.
3. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Assembling and Deploying the Gun

Prepare detailed procedures for assembling and deploying the gun assembly. The procedures must reflect the well conditions, tools, and equipment used.The procedures should contain the following components:

1. Remove all non-essential personnel to a safe distance.

2. Maintain electrical isolation and radio silence for all equipment not under the direct control of the perforating engineer or operator. All personnel within range of the perforating operation must understand the importance of maintaining these precautions.

3. Rigorously follow the manufacturer's procedures for handling and preparing explosives, and observe all established safety precautions.

WARNING: Only personnel from the perforating contractor should handle the explosives.

---

4. Pick-up the gun assembly.

Correlating Depth and Perforating

Firing the perforating guns at the correct location in the wellbore is critical. Perforating the correct "place" is more important than perforating the correct "depth", as the depth itself can be slightly inaccurate. Take into account the following factors:

1. RIH at the speed recommended by the perforation contractor, but heed the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18). Perform pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Correlate depth with at least two surface-mounted CT depth measurement systems and some means to correlate downhole depth, such as gamma ray and/or CCL correlation or tubing end location.

3. Create or maintain the desired wellbore conditions for perforating, e.g., underbalance.

4. Fire the perforating charges electrically or hydraulically, depending on the type. Make sure the associated personnel (e.g. pump operators for hydraulic firing heads) understand when and how to fire the perforating guns.

Gun Recovery

Retrieve the guns with the same care used to deploy them.

1. Drop off (release) the spent gun assembly and push the remains to the bottom of the rat hole, or prepare to retrieve the spent guns.

2. POOH.

> CAUTION: Gun bodies expand slightly when fired. Gun debris can hamper recovery of the expended gun assembly.

> WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

3. Lay down the gun assembly.

> CAUTION: Some explosive charges might not have fired downhole and could still be live.

4. Immediately relieve the guns of any trapped pressure.

5. If any guns did not fire, immediately disarm the lowermost gun. Only then disconnect the gun from the cable.

Monitoring a Perforating Job

There are no special requirements for monitoring a perforating job, other than to operate the data acquisition system whenever the BHA is in the wellbore.

Safety Issues for Perforating

Safety precautions principally relate to the safe handling of guns, both armed and spent.

> WARNING: Use a radiowave filter (or safesystem) when working in close proximity to a production manifold, gas plant, or other facility with a high wattage radio transmitter.

Before the Operation

- Hold a safety meeting.
- Make sure the casing-to-rig voltage does not exceed 0.25 V.

During the Operation

- Do not allow anyone but qualified personnel to arm a perforating gun.
- Maintain electrical isolation and radio silence for all equipment not under the direct control of the perforating supervisor.
- Do not leave the perforating guns in high temperatures longer than their ratings allow.
- Keep the BHP within the ratings of the perforating guns.
- In high-temperature or high-pressure operations, change the pressure seals between runs into the well.

After Firing

- Assume that some charges might have misfired and can still detonate. Follow the same procedures and safety requirements used for running the gun assembly.
- Immediately after removing guns from the well, relieve them of any trapped pressure.
- If any guns did not fire, immediately disarm the lowermost gun. Only then disconnect the gun from the cable.

LOGGING WITH CT (STIFF WIRELINE)

CT logging (CTL) uses CT to convey logging tools and return data to the surface. A logging cable in the CT work string transmits power and data between the surface and the logging tools. At the surface, the CT and cable connect to a standard logging service unit through a collector (slip ring) on the CT reel. Downhole, the CT and cable are connected to the logging tool string with a CT logging head (CTLH) or adapter (CTHA).

The main types of CTL service include the following:

- Openhole logging—Use this service to evaluate a formation before setting a casing or liner.
- Cased hole logging—Use this service to confirm or identify characteristics of a reservoir or completion.
- Special applications—These services include downhole video camera, subsidence monitoring, and electromagnetic fishing.

Openhole Logging

In most cases, an openhole logging suite consists of several tools with different functions. The most common tools and their corresponding measurements are:

- Gamma ray—lithology identification and correlation.
- Dual induction—measures formation resistivity.
- Litho density—measures porosity and identifies lithology.
- Compensated neutron—measures porosity and identifies lithology, locates gas and fluid contacts.
- Sonic measurement—measures acoustic velocity for porosity and identifies lithology.
- Stratigraphic—identifies bed orientation, fracture location, hole direction and geometry.
- Rock sampling—provides side wall cores.
- Fluid sampling—retrieves fluid samples under reservoir conditions and estimates permeability.
- Borehole seismic—recovers seismic data.

Cased Hole Logging

The most common cased hole logging tools and their functions are:

- Production logging—measurement of temperature, pressure, density and flow velocity; may include fluid sampling, noise tool and gravel-pack tool.
- Reservoir monitoring—gamma ray spectroscopy and thermal decay time logs.
- Corrosion monitoring—multi-finger caliper or borehole televiewer
- Free point indicator—stuck point determination
- Cement evaluation—cement bond log, cement evaluation tool, ultrasonic imaging tool.
- Gyro compass—wellbore survey
- Downhole seismic array

Special Applications

- Downhole video camera—One can visually inspect wellbore conditions with downhole video camera systems. When conveyed on wireline, such video systems are only effective in wellbores filled with gas or clear fluid. However, with CT, one can circulate clear fluids to allow visual inspection of the wellbore. If it is difficult to maintain sufficient downhole water clarity, one can displace the wellbore fluids with nitrogen.
- Subsidence monitoring—Formation subsidence and compaction monitor require extremely accurate depth measurement and precisely controlled tool movement. One can obtain satisfactory results with CT.
- Electromagnetic fishing tools—Special electromagnetic fishing tools can be used to remove metallic debris from horizontal wellbores. (See Section “Fishing”.)

Logging Cable

Electrical cable types commonly used for CTL are heptacable, monocable and coaxial cable. Heptacable is usually the choice for openhole logging tools. Production logging tools and the majority of cased hole logging tools normally use monocable or coaxial cable. The latter has the higher data transmission rate. The electrical requirements of the logging tool determine the choice of cable. Optical fibre cables have been used for video transmissions.

Benefits for CTL

CTL has a number of desirable features including:

- Stiffness to convey logging tools over long distances in highly deviated and horizontal wellbores
- Continuous logging in each direction (up or down) with a high degree of speed and depth control
- Protection of the logging cable inside the CT work string
- No side entry subs or wet connectors
- Stiffness to push long tool strings through doglegs or obstructions that would block the passage of wireline conveyed tools

- Circulation of fluids at any time during the operation (when allowed by the logging application)
- Constant well pressure control for live well operations
- The ability to hold a logging tool in position against the fluid flow during production logging of prolific wells
- Real-time measurement of bottomhole conditions while performing treatments
- Fast running speed

Planning a CT Logging Job

Job Plan Inputs

One must know the following information to plan a CT logging operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Depth interval to be logged
- If open hole logging, the reservoir conditions over the logging interval
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration
- Weight limitations for transporting and handling stiff wireline CT reels
- Method for installing cable inside CT

Logistical Constraints

CTL commonly uses long tool strings that may be difficult to handle, especially for live well deployment. For locations with adequate overhead clearance, a lubricator or riser is usually the method for deploying the tool. In that case, the tool string length determines the amount of riser or lubricator required and the reach and capacity of the crane necessary for handling the tool. However, when overhead clearance is less than the length of the tool string, a remotely operated pressure deployment system is required that assembles shorter components of the tool string inside the pressurized environment (see Chapter 18 "Deploying a Long Tool String in a Live Well", page 18-53).

CT containing logging cable (stiff wireline) is considerably heavier (0.3-0.7 lb/ft) than empty CT. The additional weight can be a problem for offshore operations where crane capacity is usually severely limited. An alternative to lifting a reel of stiff wireline onto a platform is to lift the reel with an empty CT string, then use a cable injector to install the logging cable on location. After the logging operation, reverse the process by removing the cable from the CT string with the cable injector before lifting the reel and CT string off the platform.

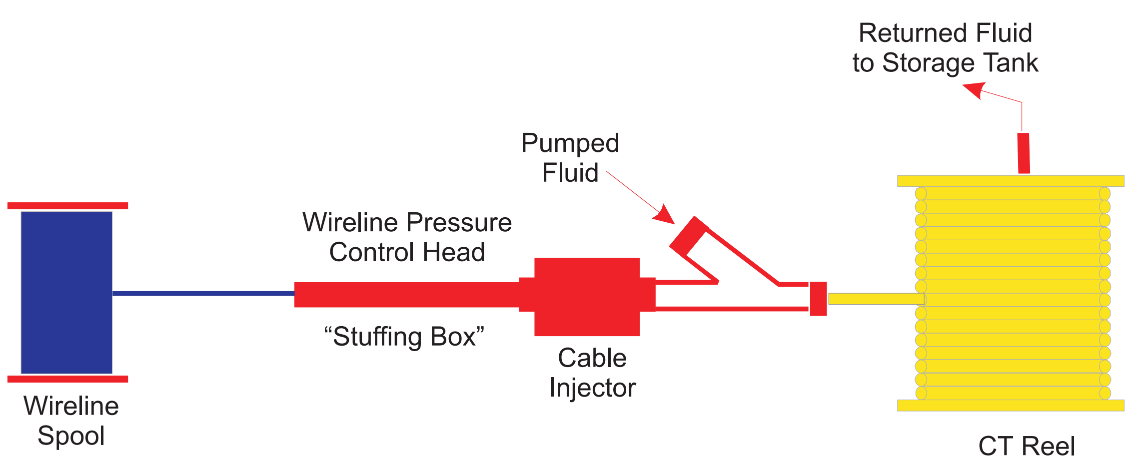
Installing Electric Cable Inside CT

Four methods are available to the industry for installing electric cable inside a reel of CT.

- Hang the CT in a vertical well and drop the electric cable into it.
- Unreel the CT string and lay it out straight, attach a plug to the end of the electric cable, then pump the electric cable through the CT.
- Manufacture the CT string with a pull cable inside, unreel the CT and lay it out straight, then pull the electric cable through the CT.
- Use a cable injection system to install electric cable while the CT string is on the reel.

The cable injection system is the most versatile and cost-effective of the four methods. It is suitable for small locations, such as offshore, and can convert any CT string into stiff wireline. The cable injector can also operate as a cable extractor to remove the electric cable from the CT string after the logging operation. Figure 12.11 shows a schematic of a cable injector invented by CTES, L.P. and developed to commercial operation by a joint industry project.

FIGURE 12.11 *Cable injector schematic*



The basic operating principle for the cable injector is relatively simple. A capstan (friction wheel) inside a pressurized vessel pulls wireline from its spool and inserts the cable through a small diameter tube (accelerator) into the CT. Pumping water at a high rate through the accelerator creates a differential pressure that literally squirts the cable into the CT string. The high water flow rate serves two other purposes as well:

- Creates turbulence inside the CT that keeps the cable suspended near the centerline of the CT thereby minimizing the frictional drag between the cable and the CT.
- Provides axial force in the form of hydraulic (skin friction) drag that moves the cable in the direction of the flow

As long as the capstan provides most of the tension necessary to pull the cable from the spool, the hydraulic drag inside the CT string will distribute the cable around the wraps on the reel. Cable up to 26,000 ft long has been installed in this manner. Reversing the process can remove the cable from the reel.

Figure 12.12 shows a cable injector rated for 10,000 psi operating pressure.

FIGURE 12.12 *10,000 psi Cable Injector*

Figure 12.13 shows an actual cable installation using a 10,000 psi cable injector. The wireline cable spool is out of the picture to the right.

FIGURE 12.13 *Cable Installation Operation*

Regardless of the cable installation method, managing the slack in the electric cable is crucial. The radius of curvature of each wrap of CT on the reel is approximately 1% greater than the radius of curvature of the cable inside it. Therefore, the cable, when relaxed, must be longer than the CT string by at least 1%. During stiff wireline operations, the cable tends to migrate towards the free end of the CT string. After several round trips into/out of a well, the cable can be slack in some sections of the CT string and near tensile failure in other sections. Occasionally pumping through the CT in the reverse direction (from the free end towards the reel) can redistribute the cable inside the CT string and prolong the useful life of the wireline.

Computer Simulator Modeling

CTL is primarily a mechanical operation. Use a reliable tubing forces simulator such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at the maximum logging depth

> ***NOTE:*** The electric cable adds weight but not stiffness to the CT string. Be sure to include the effects of the cable in the tubing forces calculations.

Job Plan Outputs

A basic job plan for CT logging includes the following:

- Wellbore cleanout and preparation required, if necessary
- Equipment and procedures for live well deployment, if necessary
- Cable installation method, if necessary

The job plan must address possible failure modes and suggest contingency actions. Potential problem scenarios for CTL include:

- The tool becomes stuck while RIH or POOH
- The tool cannot reach the maximum desired depth
- Electrical contact with the tool is lost
- The pads or arms on the tool (if so equipped) malfunction

Selecting Equipment for CT Logging

CT Equipment

Any CT string that contains the appropriate logging cable and can supply the axial forces required by the operation is suitable for logging. However, if the logging operation includes circulating fluids, that task may dictate the requirements for the CT string (flow capacity). CT depth is a critical parameter for logging. Monitoring and recording equipment must be calibrated and fully operational.

The CT reel for stiff wireline operations must have a pressure bulkhead (PBH) and a collector. The PBH is a pressure barrier at the reel end of the CT string that allows electrical connections between the cable inside the CT and cable outside the CT. The reel collector allows an electrical connection between the rotating reel drum and the stationary surface electrical equipment.

Precise control of the injector head is crucial. The depth and weight measurement must be accurate.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for logging. Live well deployment requires a lubricator tall enough to accommodate the logging tool or a special deployment system (see Chapter 18 "Deploying a Long Tool String in a Live Well", page 18-53).

Having a long tool string and a cable in the CT also raises additional pressure control considerations:

- Maintain a dual barrier against wellbore pressure and fluids at all times: during rig up, rig down, and during the operation.
- Make sure all cutting or shear seal devices can cleanly sever both the CT and cable.
- When pressure deploying tool strings, it is necessary to handle heavy equipment above the wellhead and pressure control equipment. Exercise extreme care and control to avoid injuring personnel or damaging equipment.

NOTE: Physically measure the ID and length of all equipment. Prepare a diagram showing the configuration and lengths. Make sure the OD of the tool string will fit through the ID of the pressure control equipment

---

Downhole Tools

The specific BHA depends on the logging tools. Live well deployment may require special connectors between the individual BHA components to permit remote assembly of the BHA through the pressure barrier. Some logging BHAs include a tension/compression measurement tool to measure the axial force applied to the top of the logging tool. In general, the BHA consists of the following components, from the top down:

1. CT threaded connector—dimple or slip type
2. Dual flapper type check valves
3. Disconnect—mechanical, hydraulic, or electrical
4. Cable head
5. Tension/compression measuring tool—optional
6. Logging tool

NOTE: Prepare an accurate fishing diagram for the tool string.

Pumping Equipment

Unless the logging operation is in conjunction with pumping operations, i.e., zonal isolation or matrix stimulation, no special surface equipment is necessary.

Cable Injector

If the correct stiff wireline string is not available for the job, a cable injector will be necessary for installing logging cable in an alternate CT string. The cable injector can also remove the cable at the conclusion of the logging operation to release the CT string for other applications. (See Section “Installing Electric Cable Inside CT”.)

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 “Minimizing Risk For CT Operations”.

Zero the depth measuring equipment with the CT connector against the stripper. Then correct for actual depth using the tool string length and the distance from a wellhead reference point.

Synchronize the depth counters in the logging control station and the CT control cabin. One can also correct the depth to match previous logs or wellbore markers. Be sure to record the depth correction.

Zero the weight indicator after making up the tool string and opening the swab valve. That is, zero the weight indicator with wellhead pressure applied.

Generic Procedure for CT Logging

The steps required to successfully complete a logging operation depend on the particular conditions.

Logging operations generally include the following steps:

1. Preparing the wellbore
2. Preparing the equipment
3. Correlating depth
4. Performing the logging operation

NOTE: A valuable means of minimizing risk for an expensive operation like CTL is to conduct CT test runs prior to the actual job. These consist of substituting a "dummy" BHA for the real one, then running the CT operation as planned. The dummy BHA should resemble the real BHA as much as possible in weight and dimensions, but need not perform the planned functions of the real BHA. CT test runs are more than a pass/fail tests because they provide a full dress rehearsal for the actual CT operation and data for validating simulations. Updating simulations with better estimates of Cf is particularly important if the CT test run deviates from the predicted results.

Preparing the Wellbore

1. If using slick line or wireline to prepare the wellbore, check lubricator or riser connections for compatibility before the operation begins.
2. Remove or secure the SSSV to reduce the risk of sticking the tool string or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. Accidentally closing a safety valve with the CT in the wellbore can have severe consequences.
3. Spot special fluids, if necessary.
4. In existing completions, drift wellbore tubulars with slick line to ensure that the tool string can pass freely through completion restrictions or scale build up.

Preparing the Equipment

1. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.
2. Assemble the BHA and connect it to the CT string.
3. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

4. Verify that the logging tool is operating normally.

Correlating Depth

Correlating the data with the correct interval is critical. For example, logging the correct “place” is more important than logging the correct “depth”. Correlate depth with at least two surface-mounted CT depth measurement systems and some means to correlate downhole depth, such as a gamma ray tool, CCL, or TEL.

Performing the Logging Operation

1. RIH to the target depth for the start of the logging run.

WARNING: Use the running speed recommended by the logging supervisor, but do not exceed the maximum running speeds. (Chapter 18 "CT Running Speeds", page 18-18).

WARNING: Perform pull tests, unless the logging supervisor requests otherwise. (Chapter 18 "Pull Tests", page 18-19). Some logging personnel are reluctant to subject their tools to pull tests fearing that they will damage the centralizers, arms, or pads. All personnel must agree before the job starts to eliminate or include the pull tests.

2. At the starting depth, RIH or POOH according to the logging job plan.

WARNING: Control the running speed as required by the logging supervisor, but do not exceed the maximum running speeds. (Chapter 18 "CT Running Speeds", page 18-18).

CAUTION: Watch for abnormal changes in the CT weight or tool force measurements (if so equipped) to indicate excessive drag on the BHA, such as an accumulation of solids.

3. At the end of the logging interval, POOH.

WARNING: Use the running speed recommended by the logging supervisor, but do not exceed the maximum running speeds. (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring a CT Logging Job

Accurate depth information is one of the most important measurements in any logging operation. This information will affect most future completion activities. Depth encoders mounted on the injector head connect to the CT unit control cabin and the logging unit acquisition system. In most cases, one must convert the depth signal to fit the input requirements of the logging computer.

Accurate weight indicator information is essential during CTL operations because:

- The tool string contains a specified weak point. Accidentally exceeding the tension rating of the weak point, will release the tool string, a major operating failure.
- The CT string can apply more force than many slimhole logging tools can withstand.

Safety Issues for CT Logging

Always conduct a pre-job safety meeting before RIH.

CTL services involve two distinct business lines or companies. Both groups must have good communication and be aware of the potential hazards.

Prepare clear and precise procedures for the entire logging operation. These procedures should include actions for normal, contingency, and emergency situations. Review these procedures and safety requirements in the job design process, and discuss them during the pre-job safety meeting.

The logging company representative must inform all personnel of precautions for storing, handling and using radioactive materials. It is the responsibility of all personnel to implement those safety precautions.

Personnel and Communications

All personnel must comply with the safety requirements of the logging company representative.

The CTU operator and logging engineer must be able to communicate clearly, even though they are typically in separate control cabins. Set up and maintain a good communication system for them.

Pressure Control

CTL operations frequently use long riser or lubricator assemblies. When recovering the tool string, a large volume of gas can accumulate in the surface pressure control equipment. Use extreme caution when depressurizing the riser to avoid releasing flammable and toxic gases to the atmosphere.

The job design procedures must include the circumstances for using the emergency shear/seal equipment. Restate them at the pre-job safety meeting. During normal operations (not an emergency requiring immediate action), only the CT unit operator or supervisor may operate the pressure control equipment.

REMOVING SCALE MECHANICALLY

In many wells, fields, or areas, the buildup of solid deposits in wellbore tubulars and wellbore production equipment is a significant problem.

- Deposits of solid materials in the tubular reduce the flow area and, in severe cases, reduce the production capability of the well.
- Scale and similar deposits also interfere with running and operating downhole tools and equipment.

Scale or inorganic deposits are precipitated mineral solids. The materials typically, but not always, precipitate out due to decreases in temperature and pressure. The most common scale, $CaCO_3$, forms at high temperature. Scale can also occur when incompatible waters mix, such as formation water and a fluid filtrate or injection water. Scale is prevalent in wellbores where water injection is used to maintain the reservoir pressure.

Bullheading chemical treatments, wireline-conveyed cleaning tools, and total replacement of the completion are some of the conventional methods for removing scale deposits from wellbores. The first two are mostly ineffective and bullheading can damage the producing interval. Replacing the completion is 100% effective at removing the scale, but extremely expensive compared to CT scale removal techniques such as:

- Drilling or milling with a downhole motor
- Impact drilling
- Localized chemical treatment
- Jetting

This section addresses the first two scale removal methods. Chapter 11 "Removing Scale Hydraulically", page 11-82 describes hydraulic scale removal methods.

Planning to Remove Scale Mechanically

Job Plan Inputs

One must know the following information to plan a mechanical scale removal operation:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey

- Annulus fluid properties
- Scale properties and volume
- Treatment fluid properties
- Target zone or zones—depths, pressures, temperatures, permeability, porosity, fluids
- Motor or impact tool operating characteristics
- Wellhead and surface equipment configuration

General Considerations

The characteristics of the reservoir, wellbore tubulars, and scale deposit define the potential scale removal technique. However, deciding on the proper scale removal procedure is only part of the problem. Disposal of the spent treatment fluid and scale material circulated from the wellbore is a significant part of the job design. Protecting personnel and the environment from waste products containing low specific activity (LSA) radiation sources (e.g. strontium and barium sulfates) can be expensive.

A gauge survey can determine the presence of scale or wellbore deposits, but not indicate the primary cause of reduced production. Scale deposition within the formation matrix can cause severe skin damage that requires a matrix stimulation treatment to restore production (see Chapter 11 "Stimulating a Formation (Acidizing)", page 11-29).

The essential first step in the process is to determine the exact nature of the scale deposit. The best approach is to obtain a sample of the material for analysis and testing with possible treatment fluids.

Scale/Deposit Characteristics

The following types of inorganic deposits are common in oil or gas wellbores.

- Carbonate Scales ($CaCO_3$ and $FeCO_3$)—Carbonate scales are the most common types of scale that occur in reservoirs rich in calcium and carbonates. Hydrochloric acid (HCl) will readily dissolve all carbonate scales.
- Sulfate Scales ($CaSO_4$, $BaSO_4$ and $SrSO_4$)—Sulfate scales occur mainly as gypsum ($CaSO_4$, H_2O) or anhydrite ($CaSO_4$). The less common barytine or strontianite are more difficult to remove. EDTA can easily dissolve calcium sulfate. EDTA can also dissolve barium and strontium sulfates if the temperature is high enough and the contact time is sufficient. However, due to slow reaction rates, mechanical removal methods are more effective on barium and strontium scales.
- Chloride Scales—Fresh water or a very weak acidic solution easily dissolves chloride scales such as sodium chloride.

- Iron Scales (FeS and Fe_2O_3)—HCl dissolves iron sulfide and oxide scales. The treatment should include a sequestrant and an iron-reducing agent to prevent the precipitation of damaging by-products.
- Silica Scales—These generally occur as very finely crystallized deposits of chalcedony or as amorphous opal. Hydrofluoric acid (HF) readily dissolves silica scales.
- Hydroxide Scales—These are magnesium ($Mg(OH)_2$) or calcium ($Ca(OH)_2$) hydroxides. HCl can dissolve such deposits.
- Mixed Deposits—Mixed wellbore deposits contain some combination of scale and organic deposit and/or formation fines. Careful analysis of the wellbore deposit is necessary for designing an effective treatment. Mixed deposits generally require combinations of treatment fluids and solvents for efficient removal of all components of the deposit. Typically, the base fluid is a dispersion of aromatic hydrocarbon solvent in acid. Special additives control or treat specific conditions.

Hole Cleaning

Milling and impact drilling often produce large cuttings or flakes that can be problematic at tight spots in the wellbore. These can restrict the annular flow and increase BHP or cause higher drag for moving the CT. Sticking the BHA in an accumulation of scale fragments at a tight spot is a serious risk for mechanical scale removal operations. Consequently, identifying these potential trouble spots in the operational plan is an important part of the job design. This step will alert operations personnel to closely monitor pump pressure and the CT weight indicator when the BHA approaches restrictions in the wellbore.

A problem with removing scale from inside large-diameter tubulars is the large volume of scale material generated. Providing adequate fluids processing equipment (solids control) and means of disposing of the spent fluid and waste material are important aspects of the planning process.

The ability of a fluid to successfully suspend and remove particles from a wellbore decreases as the hole angle (inclination) increases. Highly deviated and horizontal applications require special design considerations. Typically, the annular velocity of liquid in a horizontal wellbore must be at least 3 times that for a vertical hole of the same diameter in order to achieve the same hole cleaning efficiency. Special fluid, high viscosity sweeps, or foam may be necessary to remove the scale debris from the horizontal section of the wellbore. A hydraulic simulator like Hydra™ can help determine the best candidate fluid(s) and pumping schedule.

Logistical Constraints

The primary logistical problem for scale removal operations is disposal of the waste fluid and scale debris, especially LSA materials. Space availability, deck loading limits, and crane capacity can be logistics nightmares for offshore CT operations.

Drilling / Milling / Underreaming with a Downhole Motor

Drilling, milling, and underreaming with a downhole motor are common methods of removing hard wellbore deposits. A downhole motor fitted with a drill bit or milling assembly can remove scale from a wellbore down to the first restriction. Below the first restriction, an underreamer is required. An underreamer is the only mechanical method for removing hard scale from larger diameter pipe below the production tubing. Figure 12.14 shows an example of a typical underreamer for scale removal operations. A drilling tool string containing a positive displacement motor is relatively long. This will affect the choice of pressure control equipment and method of live well tool deployment.

FIGURE 12.14 *Typical Underreamer*

Impact Drilling

Impact drills provide an efficient means of removing hard deposits. They are typically less costly than positive displacement motors and are suitable for use in higher temperatures. However, they cannot be used with underreamers.

Impact drills provide rotation, impact, and a pressure pulse at the bit with each blow. The impact drill can be operated with a variety of fluids including nitrogen, foam, water-based fluids, hydrocarbon solvents, and some acids. By powering the impact drill with a solvent or an acid, chemical and mechanical treatments can be combined for greater scale removal efficiency.

The impact drill does not operate without sufficient resistance to collapse the tool between impacts. This allows full circulation through the tool during RIH and POOH without damaging the wellbore. The tool stroke frequency depends on the setdown weight and the fluid flow rate. The tool components are self-tightening and will not store reverse torque in the event of a stall. An impact drill tool string is generally significantly shorter than a comparable drill motor string.

Bit Selection

The selection of the bit, mill, or underreamer has a direct impact on the quality and speed of the scale removal operation. Consult the bit supplier and/or records from scale removal operations in the subject well or offset wells for guidance on the appropriate bit.

Circulating Fluid

A prerequisite for the circulating fluid is compatibility with both the BHA components and wellbore fluids. The fluid must also be capable of entraining the cuttings and carrying them to the surface. A hydraulics simulator such as Hydra™ can predict the relationship between flow rate and pump pressure for different operating conditions and to estimate the flow rate required for efficient hole cleaning. A friction reducer will increase the circulating rate for a given pump pressure and also improve the motor efficiency.

The circulating fluid(s) must remove all cuttings and solid debris from the wellbore. If a single fluid is not effective for hole cleaning, then periodic high viscosity pills (sweeps) or slugs of nitrogen or foam may be necessary to carry the cuttings out of the wellbore. Another alternative, when conditions permit, is to use production from the well to augment the circulating fluid. This approach has the added benefit of keeping the perforations and formation free of contamination. A circulating sub or bypass above the motor will allow higher circulation rate during POOH.

Scale Inhibition

Following the scale removal with an inhibition treatment may delay or prevent the scale from returning. Squeezing a concentrated solution of scale inhibitor into the producing interval, then allowing the formation to soak for a period of time (generally 12-24 hours) absorbs the inhibitor onto the reservoir rock. Subsequent production leaches small amounts of inhibitor out of the rock and reduces scale buildup in the wellbore. If possible, inject the inhibitor before POOH with the scale removal BHA. This saves time and maximizes the benefits of using the inhibitor. The scale inhibitor treatment design is well specific and dependent on the porosity, perforated interval, permeability and the treatment depth. Although basically inefficient in terms of chemical use, the technique is cost effective and generally accepted as preferable to downhole injection of inhibitor through an injection capillary or line.

Computer Simulator Modeling

Milling or drilling scale combines mechanical and hydraulic operations. Use a reliable tubing forces simulator such as Orpheus™ to select the CT string and BHA for the operation or predict the mechanical performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum WOB versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at the operating depth

Use a reliable hydraulics simulator such as Hydra™ to predict the relationship between flow rate and pump pressure for different operating conditions and to estimate the flow rate required for efficient hole cleaning. Run the entire operation on a fatigue simulator such as Reel-Trak™ starting with the known fatigue history of the CT string selected for the operation. The results will indicate if any portion of the string might accumulate an unacceptable amount of fatigue before the end of the scale removal job.

Job Plan Outputs

The job plan must include:

- The selection of motor and bit, or impact tool
- The results of the computer simulator modeling

The job plan must address possible failure modes and suggest contingency actions. Potential problem scenarios for mechanical scale removal include:

- The BHA becomes stuck while RIH or POOH.
- The blades (mill or underreamer) fail to extend fully at operating pressure.
- The blades (mill or underreamer) fail to retract upon releasing the pressure.
- The motor stalls frequently.
- The mill or underreamer loses a blade.
- The impact tool won't cycle.

Selecting Equipment for Removing Scale Mechanically

CT Equipment

Operations with a downhole motor always benefit from using the largest diameter CT that can fit in the wellbore. The axial force, flow rate, and torque available all increase with increasing CT diameter. Also, a CT work string with the largest possible OD provides higher annular velocity for a given fluid flow rate. CT depth and weight are critical parameters for milling with a downhole motor. Monitoring and recording equipment must be calibrated and fully operational. This operation requires precise control of the injector head functions for maximum performance from the mill.

Scale removal operations can induce significant levels of fatigue from repeated cycling of the tool string over a localized area and from high pressure jetting. Ensure that the predicted fatigue effects on the work string are within limits.

Pressure Control Equipment

Configure the equipment to avoid circulating corrosive or solids-laden annular return fluids through the BOP. If it is necessary to return fluids through a shear or seal BOP installed above the tree, take the returns through a pump-in tee installed in the riser.

Downhole Tools

A typical milling BHA consists of:

1. CT threaded connector—slip type, due to high torque
2. Dual flapper type check valves
3. Disconnect—mechanical or hydraulic
4. Circulating sub
5. Straight bar—optional
6. Downhole motor or impact drill
7. Mill, bit, or underreamer

NOTE: Prepare an accurate fishing diagram for the tool string.

Pumping Equipment

Pumps must be sized to provide the hydraulic HP required for the motor plus any additional flow rate necessary for efficient hole cleaning. The fluids processing equipment (solids control) must have the capacity to process all of the return flow plus cuttings.

WARNING: Magnetic traps or “ditch magnets” on the return line are essential to prevent any metallic cuttings from being sucked into the pumps.

Auxiliary Equipment

Make sure that the fluid mixing, handling, and pumping equipment are of adequate capacity.

For live well operations, use a choke manifold to control annular returns. Also ensure that the CTU, pump, and choke manifold operators all have a clear line of communication with each other.

Monitoring and Recording Equipment

Mechanical scale removal requires moving the CT while pumping at high pressure. This can impart a significant amount of fatigue over a short section of the CT string. An accurate real-time fatigue monitoring system is necessary to prevent premature failure of the CT during the job.

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, CT weight, and fluid flow rate. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Removing Scale Mechanically

The steps required to successfully complete a scale removal operation depend on the particular conditions. Scale removal treatments are frequently designed and conducted on a regular basis within a field or area. Adapt procedures from similar case histories to meet local conditions.

Stopping or losing circulation while the annular fluid is laden with solids can have severe consequences. Take adequate precautions to ensure that the operation proceeds as planned without interrupting circulation once the operation begins.

Mechanically removing scale involves the following steps:

1. Preparing the wellbore
2. Preparing the equipment
3. Preparing fluids
4. Removing the scale

Preparing the Wellbore

1. Recover wellbore scale samples for analysis. Use typical slick line methods or CT conveyed tools, whichever is appropriate. Another option is to analyze produced water samples to determine the nature of the scale.

2. Remove completion equipment components such as gas lift valves or safety valves. As the scale will often hamper retrieval, use CT conveyed methods, instead of wireline.

3. Kill the well, if required for safety, fluid compatibility, or production reasons. In most cases the risk of damaging the near wellbore area by bullheading the wellbore fluid is unacceptable. Consequently, the well kill operation may be a part of the wellbore preparation conducted through the CT string.

Preparing the Equipment

1. Prepare surface facilities for circulation, separation, and disposal of returned fluids and solids. If LSA scales are present, ensure that appropriate procedures and protective equipment are available.

2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and install it on the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

5. Function test the tool string, if possible, as part of the rig-up and testing procedure.

    - Function test drill motor assemblies before running in hole. Perform this test after the assembly has been made up to the work string and is hanging inside the lubricator/riser.
    - Function test impact drill assemblies before running in hole. Perform the test after the tool string is assembled, attached to the work string, and circulation has been established. Carefully control the injector head to place the bit on a firm wooden surface and collapse and test the tool.

6. With the BHA suspended just below the BOPs, determine the fluid flow rate and reel inlet pressure for the following situations. Use this data and the fluid properties to estimate the reel inlet pressure for these situations with the BHA at the working depth.

    - the downhole motor starts operating

- the downhole motor operates most efficiently
- the downhole motor stalls

CAUTION: Do not pump nitrogen or acid through the motor unless it is certified for that service. Consult the manufacturer first.

7. If using an underreamer, determine the pump rate and reel inlet pressure for opening the blades. Use this data and the fluid properties to estimate the reel inlet pressure to open the blades at the working depth.

Preparing Fluids

Either batch prepare fluid in advance, or mix it on the fly as the operation proceeds. Allow sufficient residence time to enable the desired fluid characteristics to develop (and be tested and checked). Regardless of the fluid mixing procedure, prepare adequate volumes, as once the operation has commenced, any interruption to circulation is undesirable.

Removing the Scale

1. While RIH, pump fluid through the CT slowly enough so the motor does not turn and the underreamer blades stay closed.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Gently tag the targeted obstruction. Do not tag the scale without fluid circulation.

3. Pick up the BHA about 25 ft and increase the pumping rate to the optimum rate determined in the job plan. If using gelled fluids, wait until the appropriate fluid is at the BHA.

4. After the pump pressure stabilizes, lower the BHA slowly onto the obstruction. The weight should decrease. Watch the pressure. A high pressure surge indicates the motor stalling. Relatively steady pressure increases indicate the bit is milling.

NOTE: The optimum penetration rate is generally a compromise between scale removal ability, hole-cleaning ability (fluid flow rate and solids carrying performance), and maintaining the desired downhole pressure conditions, e.g., overloading the annulus fluid may “kill the well”. Since the primary influence on this condition is solids/scale volume, the penetration rate depends largely on the volume of casing/liner to be cleaned, i.e., larger tubulars, and large volumes of scale, require lower penetration rates, while smaller tubing sizes can be cleared at relatively high penetration rates.

5. Increase WOB (decrease CT weight) as required for satisfactory milling progress. If the motor stalls, repeat steps 3 and 4.

WARNING: Watch for steel shavings in the return flow to help prevent milling the completion.

6. Repeat steps 3 and 4 at regular intervals to enhance hole cleaning. Pump high viscosity pills if necessary to remove cuttings from the wellbore.

7. If the penetration rate decreases to an unacceptable level or the CT between the reel and stripper approaches its fatigue life, whichever comes first, do the following:

a. Stop milling and POOH. (Heed maximum running speeds in Chapter 18 "CT Running Speeds", page 18-18.)

b. Disconnect the BHA and remove the CT end connector.

c. Cut off at least 50 ft of CT.

d. Perform routine maintenance on all CT equipment and BHA components per manufacturers' specifications.

e. Inspect the bit and replace it if required.

f. Install the CT end connector and connect the BHA.

g. Repeat steps 1 through 6.

8. After the obstruction has been milled out perform a cleanup pass. Pick up to a depth above the original top of the obstruction. Make a cleanup pass with the motor operating over the interval of the obstruction.

9. After the cleanup pass, activate the circulation sub and pump high viscosity pills until the returning fluid is clear of milled debris.

10. POOH while pumping constantly at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring a Mechanical Scale Removal Job

The parameters to monitor during scale removal operations depend on the complexity of the operation. For all operations, monitor the following items:

- Fluid parameters—Monitor the fluid rates and pressures pumped. Also monitor the pressures returned from the wellbore in low reservoir pressure circumstances.
- Tubing movement—Do not penetrate the wellbore material too quickly, or the CT string may become stuck. Optimize the penetration rate to ensure adequate wellbore cleaning.
- Returned solids—Monitor the volume and composition of the returned solids. If necessary, modify the design. Stop milling immediately if the returned solids contain steel shavings from the completion.

Safety Issues for Removing Scale Mechanically

Always conduct a pre-job safety meeting before RIH.

In general, base precautions for scale removal operations on the potentially toxic, corrosive, and LSA nature of the treatment fluids and the returned scale or wellbore deposit. Use special monitoring and protection methods to ensure the safety of personnel, equipment, and the environment. Dispose of all waste according to Customer Environmental Department guidelines.

CUTTING TUBULARS MECHANICALLY

Two common applications for mechanical tubing cutters are:

- Severing a stuck work string (CT or jointed pipe) in preparation for fishing
- Severing casing or production tubing as part of workover applications to retrieve the pipe

Several different types of tubing cutters are available in a variety of sizes to suit most wellbore tubulars. This section discusses mechanical cutters (mills) and explosive cutters. Abrasive jet cutters and chemical cutters are other options for cutting tubing with CT. Chapter 11 "Cutting Tubulars with Fluids", page 11-46 describes those methods.

Planning to Cut Tubulars Mechanically

Job Plan Inputs

One must know the following information to plan for mechanically cutting tubing:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Annulus fluid properties
- Target tubing dimensions and properties
- Tubing cutter operating characteristics
- Wellhead and surface equipment configuration

Depth Control

Precise depth control is essential for all tubing cutting operations. A depth correlation run with a TEL or CCL prior to running the tubing cutter will reduce the risk of severing the pipe at the wrong location.

Milling with a Downhole Motor

Mills are specialized cutting tools with retractable blades (cutters) that mount on a downhole motor. The configuration of the blades and their extension from the tool body determine whether the mill performs as a reamer for enlarging the pipe ID or a tubing cutter for severing the pipe. Many cutter designs are available incorporating different cutting action, such as insert teeth or carbide chip matrix. The cutter arm configuration may be single or double action.

In either case the cutter blades operate hydraulically with the same fluid used to power the downhole motor. The power (torque) requirements of the mill must match the power (torque) output available from the motor, or the motor will stall frequently and interrupt the milling operation.

Milling often produces large cuttings that can be problematic at tight spots in the wellbore. These can restrict the annular flow and increase BHP or cause higher drag for moving the CT. Sticking the BHA in an accumulation of milled fragments at a tight spot is a serious risk for milling operations. Consequently, identifying these potential trouble spots in the operational plan is an important part of the job design. This step will alert operations personnel to closely monitor pump pressure and the CT weight indicator when the BHA approaches restrictions in the wellbore.

A problem with milling inside large-diameter tubulars is the large volume of metal cuttings generated. Providing adequate fluids processing equipment (solids control) and means of disposing of the cuttings are important aspects of the planning process.

WARNING: Magnetic traps or “ditch magnets” on the return line are essential for preventing the cuttings from being sucked into the pumps.

The ability of a fluid to successfully suspend and remove particles from a wellbore decreases as the hole angle (inclination) increases. Highly deviated and horizontal applications require special design considerations. Typically, the annular velocity of liquid in a horizontal wellbore must be at least 3 times that for a vertical hole of the same diameter in order to achieve the same hole cleaning efficiency. Special fluid, high viscosity sweeps, or foam may be necessary to remove the milling debris from the horizontal section of the wellbore. A hydraulic simulator like Hydra™ can help determine the best candidate fluid(s) and pumping rate.

The axial forces on the CT are considerably different in a directional well compared to a vertical well. Buckling of the CT can limit the working depth and axial forces available in a directional well. Consequently, modeling tubing forces with a CT simulator like Orpheus™ is an essential part of planning milling operations in highly-deviated wells.

The high flow rate necessary to achieve annular velocity sufficient to remove cuttings from milling operations can be prohibitive. Taking steps to reduce the pressure loss inside the CT string and BHA is essential. Such steps might include:

- Selecting the largest ID string available
- Reducing the length of the CT string as much as possible
- Use of hydraulic friction reducers
- Including a bypass valve in the BHA
- Increasing the pump pressure to the maximum value that will allow completion of the milling operation without exceeding the fatigue limit for the string

Explosive Cutters

One advantage of explosive cutters is their availability. Most companies that offer a perforating service also provide explosive cutters. Another advantage is that an explosive cutting tool and its associated wireline connectors form a relatively short assembly. This makes an explosive cutter ideal for running through tight spots.

A disadvantage of explosive cutters is that they distort the cut ends of the tubing (Figure 12.15). This can cause problems in subsequent attempts to fish the parted tubing.

FIGURE 12.15 *Typical Tubing Profile When Severed by Explosive Cutter*

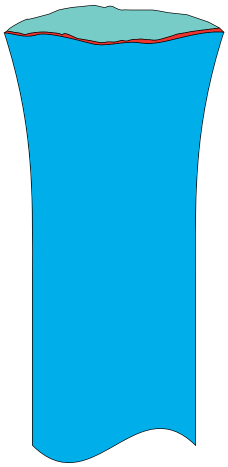


Table 12.1 shows typical specifications for an explosive cutter. Table 12.2 shows the size of cutter required for various sizes of CT.

TABLE 12.1 *Typical Explosive Cutter Specifications*

Specifications	
Dimensional Specifications	
Length (in.)	
Minimum	36
Maximum	84
OD (in.)	
Minimum	0.718
Maximum	+5.00
Weight (lb)	± 50
Operating Specifications	
Maximum Operating Temperature (F)	350
Maximum Operating Pressure (psi)	10,000
Deployed by:	Wireline/CTL

TABLE 12.2 *Typical Explosive CT Cutter Dimensions*

CT OD (in.)	**Cutter OD (in.)**
1.00	0.718
1.25	0.948
1.50	1.187
1.75	1.250

Computer Simulator Modeling

All Tubing Cutters

Use a reliable tubing forces model such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth

- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at the cutting depth

Milling with a Motor

Use a reliable hydraulics simulator such as Hydra™ to predict the relationship between flow rate and pump pressure for different operating conditions and to estimate the flow rate required for efficient hole cleaning.

Job Plan Outputs

A basic job plan for cutting tubulars mechanically includes the following:

- Depth correlation method
- The maximum allowable setdown weight and overpull
- Method for recovering the severed sections of pipe
- Minimum flow rate for effective cutting
- Maximum flow rate
- Estimated time required for severing the target pipe

The job plan must address possible failure modes and suggest contingency actions.

Prepare contingency plans during the job design process. As a minimum, include reactions for the following scenarios:

Explosive Cutters

Potential problem scenarios for operations with explosive tubing cutters include:

- The tool becomes stuck while RIH or POOH.
- The tool fires while RIH or POOH.
- The tool does not fire at all.
- The cut is incomplete.
- The cut is ragged (distorted).

Milling with a Downhole Motor

Potential problem scenarios for milling with a downhole motor include:

- The tool becomes stuck while RIH or POOH.
- The blades fail to extend fully at operating pressure.
- The blades fail to retract upon releasing the pressure.
- The motor stalls frequently.
- The mill loses a blade.
- The cut is incomplete.
- The cut is ragged (distorted).

Selecting Equipment for Mechanically Cutting Tubulars

CT Equipment

Any CT string that can safely run the cutting tool to the target depth and return is suitable for running explosive cutters. If the cutters fire electrically, then the CT string must include an electric cable. CT depth is the most critical parameter for placing one of these tools. Monitoring and recording equipment must be calibrated and fully operational.

Milling operations always benefit from using the largest diameter CT that can fit in the wellbore. The axial force, flow rate, and torque available all increase with increasing CT diameter. Also, a CT work string with the largest possible OD provides higher annular velocity for a given fluid flow rate. CT depth and weight are critical parameters for milling with a downhole motor. Monitoring and recording equipment must be calibrated and fully operational. This operation requires precise control of the injector head functions for maximum performance from the mill.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for these operations.

Pumping Equipment

Pumps must be sized to provide the hydraulic HP required for the motor plus any additional flow rate necessary for efficient hole cleaning. The fluids processing equipment (solids control) must have the capacity to process all of the return flow plus cuttings.

WARNING: Magnetic traps or "ditch magnets" on the return line are essential to preventing the cuttings from being sucked into the pumps.

Downhole Tools

Explosive Cutters

The specific BHA depends on the cutting tools. In general, the BHA for explosive cutters consists of the following components, from the top down:

1. CT threaded connector—dimple or slip type
2. Dual flapper type check valves
3. TEL
4. Cablehead—for electrically actuated tools, otherwise not installed in the BHA.
5. Cutting tool

NOTE: Prepare an accurate fishing diagram for the tool string.

Milling Assembly

In general, the BHA for a milling assembly consists of the following components, from the top down:

1. CT threaded connector—a slip type connector, due to the high axial forces and torque experienced during milling
2. Dual flapper type check valves
3. Disconnect—mechanical, hydraulic, or both
4. Circulating sub
5. TEL
6. Downhole motor

7. Mill

NOTE: Prepare an accurate fishing diagram for the tool string.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Mechanically Cutting Tubulars

Each cutting operation involves different steps, depending on the particular conditions encountered. This section includes some key points for each phase of the operation.

Tubing cutting operations generally involve the following steps:

1. Preparing the wellbore

2. Preparing the equipment

3. Making the cut

Preparing the Wellbore

1. Conduct any necessary slick line or wireline work, e.g., gas lift valve removal.

2. Place dummy gas lift valves to reduce the risk of sticking or damage.

3. Remove or secure the SSSV to reduce the risk of sticking the tool string or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. Accidentally closing a safety valve with the CT in the wellbore can have severe consequences.

Preparing the Equipment

1. Install magnetic traps or “ditch magnets” on the return line to the solids control equipment to prevent metal cuttings from damaging the pumps.

2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

3. Assemble the BHA and install it on the CT.

4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

---

5. For milling operations, conduct the following tests.

   With the BHA suspended just below the BOPs, determine the fluid flow rate and reel inlet pressure for the following situations. Use this data and the fluid properties to estimate the reel inlet pressure for these situations with the BHA at the working depth.

   - The downhole motor starts operating.
   - The downhole motor operates most efficiently.
   - The downhole motor stalls.

Making the Cut

1. RIH to a depth about 25 ft above the profile nipple or end of the tubing targeted for depth correlation and stop.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

---

2. RIH slowly to the profile nipple or end of the tubing and correlate the indicated depth with the actual depth. Flag the CT.

3. While pumping inhibited water at a slow rate, slackoff or pickup to the target depth for the cut.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

4. Activate the explosive cutter or switch to the treatment fluid and increase the fluid flow rate to the designated operating level for the downhole motor.

5. When milling, wait for the prescribed length of time for the mill to make the cut.

6. After the waiting period, activate the circulating sub and begin pumping water at a high rate.

7. POOH while pumping water at the highest rate possible.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring for Mechanically Cutting Tubulars

Monitor fluid, pumping, and tool operating parameters to ensure that they remain within the operating limits of the tools and equipment. If using pressure-activated tools, it is essential to closely monitor and control the pump parameters. Take into consideration any changes in wellbore or pumped fluid that may influence CT string weight (buoyancy).

Safety Issues for Mechanically Cutting Tubulars

Always conduct a pre-job safety meeting before RIH.

Explosive tubing cutters are extremely dangerous. Use the same precautions for handling them as for handling perforating charges. (See Section “Safety Issues for Perforating”.)

Operating a Sliding Sleeve

Sliding sleeves in production tubing control communication between the tubing (production conduit) and annulus. They open and close with mechanical shifting tools. When closed, they prevent the flow of fluids. When open, they provide a flow path between the completion tubing and the reservoir.

In some applications, sliding sleeves control flow from separate intervals in a wellbore. For example, a horizontal completion can have an uncemented liner with external casing packers and sliding sleeves. Operating the sliding sleeves allows selective production or treatment of specific intervals. They offer a repeatable method of zonal isolation for selective stimulation treatments or rerouting production. In near-vertical completions, a shifting tool and jarring assembly run on wireline or slick line is the usual means of operating a sleeve. In highly deviated or horizontal completions, either CT or a wireline tractor is required to convey the shifting tool.

A common operational problem with sliding sleeves is the deposition of scale or wellbore debris around the opening. These deposits can effectively lock the sleeve in its current position. CT is ideally suited to remove these deposits and restore the sliding sleeve to full operation. Thus, CT offers an advantage over wireline and wireline tractors for sliding sleeves.

Planning to Operate a Sliding Sleeve

Job Plan Inputs

One must know the following information to plan operations with sliding sleeves:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Location (depth) of sleeve or sleeves
- Reservoir conditions at target depth
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration
- Type of sleeve(s)

- Axial force required to operate the sleeve(s)

Planning Considerations

Precise depth measurement and control are essential for latching onto and operating sliding sleeves. Monitoring and recording equipment must be calibrated and fully operational to provide reliable indication of the status of the sleeve.

In conventional applications, one operates sliding sleeves with slick line or wireline shifting tools that use a jarring assembly. Generally, upward jarring opens the sliding sleeve, and downward jarring closes it.

Besides jarring assemblies, hydraulic force amplifiers are available for CT applications. These tools use pressure from the CT string to stroke a piston over a short distance. External slips on the tool body grab the completion to counteract the axial force exerted by the piston on the sleeve. If the CT string alone cannot generate enough axial force to move the sleeve, these tools can provide the required force locally.

As sliding sleeves are non-retrievable, they must function efficiently for the lifetime of the completion. A common problem hindering operation is the deposition of scale or wellbore debris. Deposits, which build up in both the open and closed position, prevent the sleeve from cycling. Remove scale and debris with tools or treatment fluids. In severe cases, use a separate treatment or cleanout operation. There are special jetting tools, brush tools, and suction tools for maintaining sliding sleeves.

Assemble the tool string options based on tool availability, operator preference, availability of technical support, and previous experience. One must understand the operating method and sequence of each tool. Check compatibility to ensure the tool string will operate as intended, especially for catch and release functions.

Computer Simulator Modeling

Sliding a sleeve is a mechanical operation. Pumping a small amount of fluid to hydraulically activate a tool is secondary. Use a reliable tubing forces simulator such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH

- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth during operation of the sleeve

Job Plan Outputs

A basic job plan for operating a sliding sleeve includes the following:

- Depth correlation method
- Wellbore cleanout and preparation required, if necessary
- Equipment and procedures for live well deployment, if necessary
- Pump pressure (if any) to operate the shifting tool
- Axial force required to operate the shifting tool

Prepare contingency plans during the job design process. As a minimum, include responses for the following scenarios:

- The shifting tool cannot latch onto the sleeve.
- The sleeve is stuck in position.
- The shifting tool won't release the sleeve.
- The sleeve only partially opens or closes.
- The sleeve leaks despite being completely closed.

Selecting Equipment for Operating a Sliding Sleeve

CT Equipment

Any CT string that can supply the axial forces required by the operation is suitable for sliding a sleeve. However, if the wellbore requires cleanup prior to RIH with the shifting tool, the cleanup operation may dictate the requirements for the CT string (flow capacity). CT depth and weight are critical parameters for manipulating a sleeve. Monitoring and recording equipment must be calibrated and fully operational. This operation requires precise control of the injector head functions for proper operation of the shifting tool. Apply and release tension in the work string smoothly to avoid damaging downhole tools or surface equipment.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for sliding sleeves.

Downhole Tools

The specific BHA depends on the sleeve configuration, its associated shifting tool, and the axial force required to move the sleeve. In general, the BHA consists of the following components, from the top down:

- CT threaded connector—dimple or slip type
- Dual flapper type check valves
- Disconnect—mechanical, hydraulic, or both
- Jarring assembly or force amplifier
- Shifting tool

NOTE: Prepare an accurate fishing diagram for the tool string.

CAUTION: Check the compatibility of the tools in the string to ensure they will operate together as intended.

Pumping Equipment

Unless preliminary operations require large circulating volume and/or high flow rate, a small pit and cementing pump are adequate for shifting sleeves.

Monitoring and Recording Equipment

Zero the depth measuring equipment with the CT connector against the stripper. Then correct for actual depth using the tool string length and the distance from a wellhead reference point.

Zero the weight indicator after making up the tool string and opening the swab valve. That is, zero the weight indicator with wellhead pressure applied.

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 “Minimizing Risk For CT Operations”.

Generic Procedure for Operating a Sliding Sleeve

The steps required to successfully operate sliding sleeves depend on the particular conditions encountered. If these operations are conducted on a regular basis within a field or area, adapt “standard” procedures to meet local conditions.

Sliding sleeve operations generally involve the following steps:

1. Preparing the wellbore

2. Preparing the equipment

3. Operating the sleeve

Preparing the Wellbore

1. Conduct any necessary slick line or wireline work, e.g., gas lift valve removal.

2. Remove or secure the SSSV to reduce the risk of sticking the tool string or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. Accidentally closing a safety valve with the CT in the wellbore can have severe consequences.

3. Minimize the pressure differential or flow across the sleeve to reduce damage to the pressure sealing components of the sliding sleeve.

4. If the wellbore in the vicinity of the sleeve contains deposits or debris, spot or circulate fluids to wash the area or dissolve scales and wax that can interfere with the tool string. (See Chapter 11 "Removing Fill or Sand From a Wellbore", page 11-7, Chapter 11 "Removing Scale Hydraulically", page 11-82, or Chapter 11 "Removing Wax, Hydrocarbon, or Hydrate Plugs", page 11-103.

Preparing the Equipment

1. Verify that the shifting tool is correct for the planned operation.
2. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.
3. Assemble the BHA and connect it to the CT.
4. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Operating the Sleeve

1. RIH to the sleeve.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. If necessary, circulate fluid to clean around the sleeve.
3. Engage the sleeve with the shifting tool and apply the necessary action (jarring or up/down force) to operate sleeve. In deep or deviated wells, the opening or closing of the sleeve might not register on the weight indicator. Closely monitor annulus and tubing pressures to judge the success of the operation.
4. Release the shifting tool from the sleeve.
5. POOH with the CT string and shifting tool.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring for a Sliding Sleeve Operation

During the operation it is crucial to maintain a complete record. The operation of many tools depends on a specific sequence of tubing movement and pumping.

Key factors include:

- Pumping—If using pressure-activated tools, closely monitor and control the pump parameters. Take into consideration any changes in wellbore or pumped fluid that could influence CT string weight (buoyancy).
- Tubing movement and weight—Monitor and record changes of direction (up/down) and the associated changes in weight.
- Annulus and tubing pressures—Monitor and record changes in the annulus and tubing pressures to judge the success of the operation.

Safety Issues for Operating a Sliding Sleeve

Always conduct a pre-job safety meeting before RIH.

A sudden influx of produced fluids can substantially change bottomhole conditions. Prepare the pressure control equipment and surface production equipment ahead of time to handle the new wellbore conditions.

RUNNING A COMPLETION WITH CT

Access to tight spaces or weight restricted locations, short time on location, relatively low cost, safe live well deployment, and reduced risk of reservoir damage are potential benefits of running (installing) completions with CT. The mobility and small footprint of a typical work-over CT unit allows it to work on locations too confining or environmentally sensitive for a drilling rig. CT units can be much quicker to rig up/down than a drilling or workover rig and CT running speeds are much faster than with jointed pipe. These reduce the time on location, the time the well is off production, and possibly the total cost of running the completion. In some cases, a drilling rig or derrick is not available, e.g., removed from an offshore platform or too expensive to mobilize. Live well intervention dispenses with the need to kill the well and risk damaging the producing interval. This section discusses the process of running or pulling completions with CT.

Planning to Run a Completion

Job Plan Inputs

One must know the following information to plan for running a completion:

- Well configuration (ID versus depth, location of completion hardware)
- Well directional survey
- Wellbore fluid properties
- Target depth for landing or hanging the completion
- Completion details (OD and wall thickness vs. depth, location completion hardware, hanger mechanism)
- Method for hanging (installing) the completion
- Running tools and forces required to operate them
- Pressure and temperature at target depth
- Wellhead and surface equipment configuration

Planning Considerations

The principal considerations for running/pulling completions with CT are:

- Mechanical performance of the CT

- Setting mechanism
- Accurate measurement and control of CT weight and movement

Running a heavy BHA, e.g., slotted liner, pre-packed screen, or ESP, subjects the CT to high axial forces, especially in a live well. The CT string must have the mechanical strength to safely tolerate these forces. In a highly deviated well the CT must have enough stiffness to resist buckling while pushing the completion to TD. In both cases the setting method might require additional axial force (setdown weight or overpull) to lock the completion if place. These forces are the primary criteria for selecting a CT string for running or pulling a completion.

Three types of setting mechanism are available for running completions. These are:

- Compression set—Compressive force generated by slacking off (setting down) the CT string against the setting tool energizes the slips or hanger.
- Tension set—Tensile force applied by the CT string energizes the slips and/or packing element.
- Hydraulic set—Fluid pumped through the CT into the setting tool energizes the slips and/or packing element.

In all cases, the completion hanger will perform properly within a limited range of dimensional tolerances for the surrounding wellbore. If the wellbore is too large, too small, or too oval, the hanger will not set correctly. Caliper the location for the hanger and be prepared to condition the wellbore by milling or reaming.

Accurate measurement of CT weight and precise control of CT movement are essential to successfully running many completions. Verify that the weight indicator is calibrated and fully operational prior to the job. Service the injector head to insure that the gripper blocks, chains, and hydraulic components are in good working order. Test the injector prior to the job to determine its low speed capability.

Allow plenty of time in the job plan for RIH. Attempting to RIH at high speed with a completion is an invitation to disaster. RIH at high speed with a large diameter string can surge (increase) the BHP to levels that are damaging to the formation. Hitting an obstruction or restriction at high speed can damage the completion and/or cause it to set prematurely. Identify every location in the wellbore that poses a hazard for RIH, e.g., valves, nipples, liner tops, or other restrictions in the wellbore. Slow the CT running speed to a virtual crawl when approaching any of the hazardous locations.

The specific setting procedure depends on the type of hanger or slips. Consult the supplier for the exact sequence of steps and the force or pressure required to set the hanger or slips. Also, determine the maximum axial force (tensile and compressive) and maximum differential pressure the seals can tolerate when set properly. The job plan should clearly identify these operating limits.

Computer Simulator Modeling

Running a completion is primarily a mechanical operation. Pumping a small amount of fluid to hydraulically activate a setting tool or energize packer elements is secondary. Use a reliable tubing forces model such as Orpheus™ to select the CT string and BHA for the operation or predict the performance of a proposed CT string and BHA. Identify the locations of potential trouble spots for RIH and POOH and generate mechanical performance curves for the operations personnel that show:

- CT weight versus depth for RIH and POOH
- Maximum setdown weight versus depth
- Maximum overpull versus depth
- Axial force and VME stress versus depth for the BHA at the completion setting depth
- Axial force and VME stress versus depth upon application of the force required to set the completion hanger

Job Plan Outputs

A basic job plan for running a completion includes the following:

- Depth correlation method
- Wellbore cleanout and preparation required
- Axial force (if any) to set the completion—direction and magnitude
- The maximum allowable setdown weight and overpull
- Pump pressure (if any) to set the completion

The job plan must address possible failure modes and suggest contingency actions. Potential problem scenarios for running completions include:

- The completion becomes stuck while RIH.
- The hanger or slips prematurely sets while RIH.
- The completion prematurely releases from the running tool.

- The running tool won't release the completion.
- The well, if dead, begins to flow with the completion across the BOPs.

Selecting Equipment for Running a Completion

Running a completion with CT generally requires the following equipment.

CT Equipment

Any CT string that can supply the axial forces required by the operation is suitable for running a completion. CT weight is a critical parameter for running a completion. Monitoring and recording equipment must be calibrated and fully operational. This operation requires precise control of the injector head functions for proper operation of setting tools.

Pressure Control Equipment

The normal CT pressure control equipment is adequate for running completions. However, the size of the BOP components must be compatible with the largest diameter of the completion. Live well operations may require a tall lubricator or special remotely activated deployment system.

Downhole Tools

The specific BHA depends on the running/setting tools. In general, the BHA consists of the following components, from the top down:

1. CT threaded connector—a slip type connector, due to the high axial forces encountered with running a completion
2. Dual flapper type check valves
3. Disconnect—mechanical, hydraulic, or both
4. Running/setting tool
5. Completion

NOTE: Prepare an accurate fishing diagram for the tool string.

Pumping Equipment

Unless subsequent operations require large circulating volume and/or high flow rate, a small pit and cementing pump are adequate for running completions.

Monitoring and Recording Equipment

The CT unit must include a DAS capable of monitoring the pump pressure, WHP, CT depth, and CT weight. The data acquisition software should provide the operator with a real-time display of tubing forces, operating limits, and remaining working life. See Chapter 17 "Minimizing Risk For CT Operations".

Generic Procedure for Running a Completion

The steps required to successfully run a completion with CT depend on the specific conditions for each case. This generic procedure is simply an outline for the key steps.

Preparing the Wellbore

Preparing the wellbore for accepting a completion may include the following steps.

1. Modify the lubricator or riser to accommodate the completion sections as necessary.
2. Remove or secure the SSSV (if present) to reduce the risk of sticking the completion and/or damaging the safety valve. If securing the SSSV, hydraulically isolate it in the open position and install a protective sleeve. The consequences of accidentally closing a safety valve with the CT in the wellbore can be disastrous.
3. Install dummy gas lift mandrels, as necessary, to reduce the risk of sticking the completion and/or damaging a gas lift mandrel
4. Remove any fill, cuttings bed, scale, asphalt, or wax present in the wellbore from the surface to the depth at the bottom of the completion
5. Drift the wellbore to ensure free passage of the tool string through the wellbore.

6. Caliper the wellbore at the setting depth to ensure the internal geometry of the wellbore is compatible with the setting capabilities of the hanger or slips. If the wellbore has collapsed or become oval, the tool might not set properly.

7. Milling (reaming) the wellbore ID to a rounder shape or larger size at the setting depth may be necessary for the hanger or slips to properly engage and seal against the wellbore.

Preparing the Equipment

1. Prepare, layout, or pre-assemble the completion as required to expedite the operation.

2. Verify that the running/setting tool is correct for the planned operation.

3. Rig up surface CT and pressure control equipment per Chapter 18 "Rig Up", page 18-9.

4. Assemble the BHA and connect it to the CT.

5. Conduct well-site pressure tests per Chapter 18 "Well-Site Pressure Testing", page 18-13.

NOTE: Torque all threaded joints to the makeup torque recommended by the manufacturer.

Running the Completion

1. RIH to a depth about 25 ft above the designated setting depth.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18) and locations of pull tests (Chapter 18 "Pull Tests", page 18-19).

2. Slackoff slowly to the setting depth.

3. Set the completion hanger and release the running/setting tool as specified in the job plan.

4. POOH while slowly pumping water.

WARNING: Pay close attention to the maximum running speeds (Chapter 18 "CT Running Speeds", page 18-18).

Monitoring Running a Completion

Document the setting sequence, pumping schedule, and CT movements.

Safety Issues for Running a Completion

Always conduct a pre-job safety meeting before RIH.

Moving a completion in or out of a wellbore too quickly can surge or swab the formation. Surging can damage the productivity of the formation. Swabbing can lead to an uncontrolled influx of fluid. Always use the slowest practical running speeds.

13

PERMANENT CT INSTALLATIONS

REELED COMPLETIONS

For the purpose of this manual, a reeled completion is any combination of CT and jointed tubulars installed in a well with a CT unit and serving as a velocity string or the production conduit. In the earliest reeled completion applications, CT was installed in existing production tubing as siphon or velocity strings. This concept later expanded to include gas lift applications with the CT providing a single-point gas injection system. The low efficiency of such gas lift applications led to the development of a gas lift system that utilized existing gas lift technology and equipment adapted for CT completions. A logical development of this technology was a completion string with components that could be passed through the CT surface equipment.

Reduced time, cost, and risk of formation damage are the principal benefits of reeled completions.

- Time reduction—The cost of most completion activities is directly related to the time required. Compared to a drilling rig, a CT unit can mobilize, rig up, run a completion, and demobilize much faster. The reduction of time translates directly into cost savings. In addition to the rapid initial deployment of the reeled completion, the future workovers will also be quicker.
- Cost reduction—In remote, logistically difficult, or space-limited areas, using a drilling rig or derrick may not be practical or financially justified. In many locations, the drilling rig or derrick has been removed, e.g., offshore. The cost of providing a temporary drilling or workover rig may not be a viable option for conventional jointed completion types. Therefore, reeled completions can offer economic advantages by eliminating the need for a drilling rig, mast unit, or a derrick and by minimizing the time required to bring the well on production. Live well intervention dispenses with the need for potentially expensive well kill procedures. Similarly, well kick-off procedures and equipment are not required.
- Reduced risk of reservoir damage—Many reservoirs, particularly depleted ones, will suffer severe formation damage from any attempt to kill the well. The inherent advantages of live well operations permitted by CT equipment have further increased interest in and development of reeled completions.

Although reeled completions offer many advantages, they also suffer certain disadvantages including:

- Increased Christmas tree height—may be a problem in fixed installations, e.g., offshore
- Potential logistics problems due to the weight of the tubing reel (transportation on land and cranes offshore)
- Components not generally suitable for “sand” service
- CT is not readily available in corrosion resistant alloys

Candidate Selection

A well is a candidate for a reeled completion under the following conditions:

- The completion is a slim hole design
- The existing completion requires remedial work such as,

  1. Through-tubing gravel pack

  2. Casing/tubing repair and zonal isolation

  3. Reinstating the safety valve function

- A rig would not be available in the future for difficult pulling jobs

  1. Dual completions

  2. Failed gravel packs

  3. Collapsed casing

- Killing the well would be expensive or damage the reservoir
- A conventional jointed pipe completion is not economical

  1. The cost of a rig cannot be justified

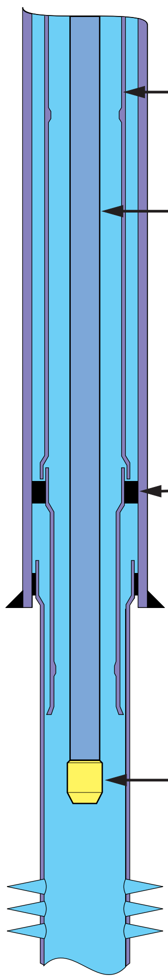
  2. The application or location requires a special rig configuration

  3. The cost of upgrading the existing derrick or rig is prohibitive.

Velocity Strings

The installation of a velocity string to reduce the flow area of the production conduit is a common practice, especially in depleted gas wells. The objective is to increase the velocity of the produced gas so that it will carry produced liquids to the surface. (Figure 13.1).

FIGURE 13.1 *Principal Velocity String Components - Typical Installation*



Velocity string installations are the simplest type of reeled completion. Small diameter (OD < 2 in.) velocity strings are often assembled from used CT work strings, while larger strings (OD >2 in.) are more commonly new tubing.

A hydraulic simulator like Hydra™ can estimate the performance of a velocity string for a range of operating conditions. However, the choice of CT size and installation hardware may depend more on the economic analysis.

Reeled Production Conduit

Reeled production conduits can include externally upset components, valves, pumps, and multiple strings, e.g. dual completions and injection strings. Externally upset jointed connections (Figure 13.2) require a special injector head or special handling with standard CT equipment. Spoolable™ completion (Camco trademark) is an example of a uniform OD tubing string containing all of the necessary completion components which a standard CT injector can handle.

FIGURE 13.2 *Externally Upset Reeled Completion*

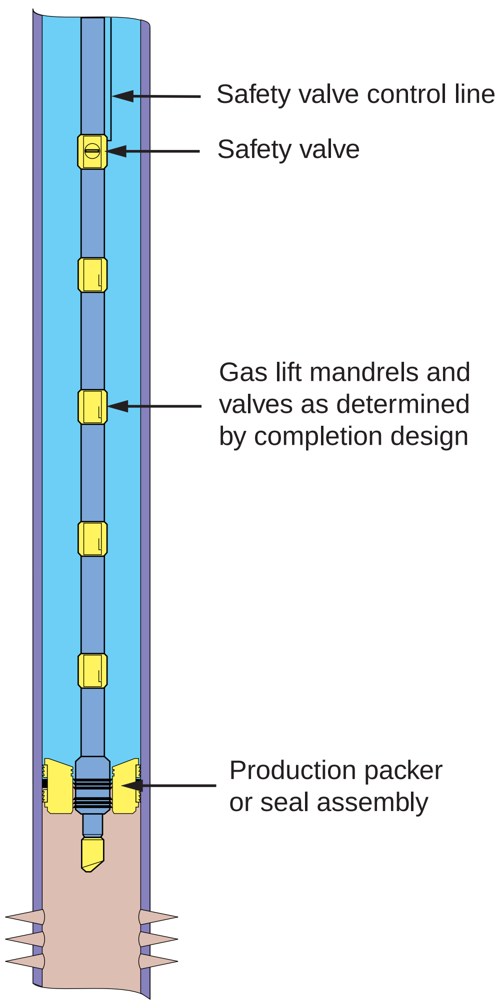
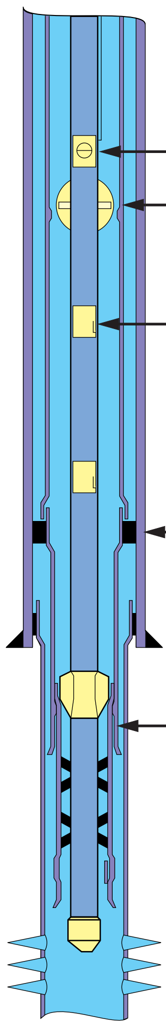


FIGURE 13.3 *Spoolable Completion*



Most CT injectors cannot run externally upset completions. Therefore, the completion must be assembled on location using special running equipment, e.g., access window and/or annular BOP. A few special injectors, such as the modified Hydra Rig 480 injector designed for the *Copernicus* CTD rig (see Chapter 15 "Purpose-Built CTD Rigs", page 15-54) or the Hydra rig 5200 injector, can dynamically expand the gap between the chains to pass external upsets.

Uniform OD completions offer two advantages over those with external upsets. First the completion can be assembled and tested in controlled conditions away from the wellsite. This significantly reduces the time on location with the CT unit. Second, a uniform OD completion can be run in a live well using only standard CT pressure control equipment.

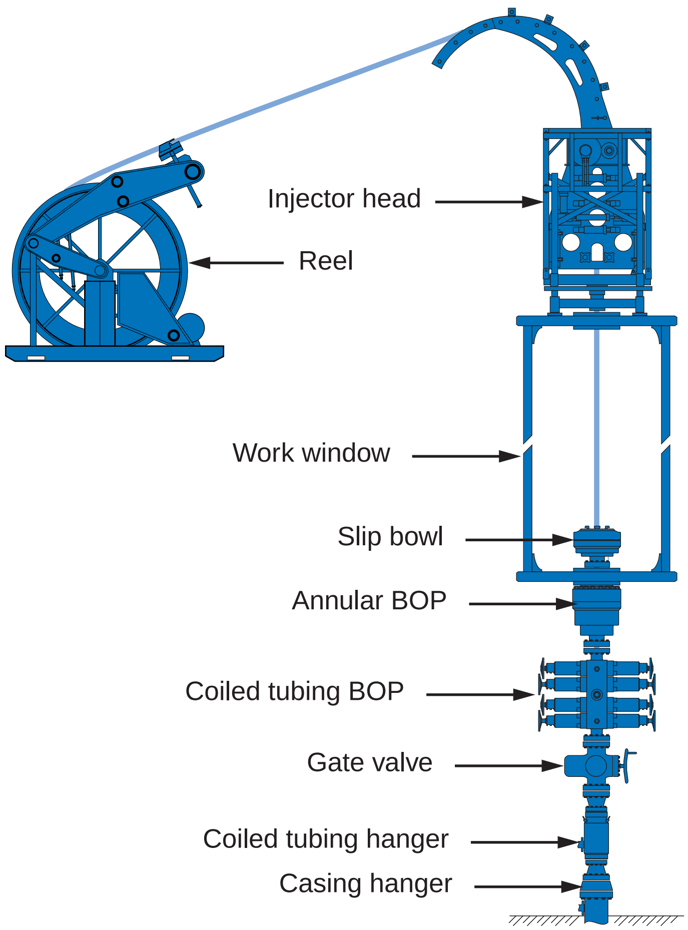
Reeled completions offer a variety of functions and options including:

- Gas lift
    1. Externally upset
    2. Spoolable™
- Electric submersible pumps
    1. External cable
    2. Internal cable
- Velocity string hardware
- Sand control screens
- Remedial installations
    1. Through-tubing gravel pack
    2. Casing/tubing repair and zonal isolation
    3. Re-instate safety valve function
- Concentric injection string, e.g., steam or chemical injection

Pressure Barrier during Completion Installation

The design and configuration of the wellhead components for hanging a velocity string will determine the steps and procedures required to complete the installation (Figure 13.4).

FIGURE 13.4 *Wellhead Equipment Configuration*



Depending on the complexity of the installation, some of the wellhead work may be performed before the CT unit arrives on location. This can reduce the total charges for the CT service. Many of the tubing hangers and wellhead components for velocity string applications are suitable for live well installation.

Adequate pressure control barriers must be in place during removal of existing wellhead equipment and installation of the new hanger. This typically requires closing the master or downhole safety valves or setting a temporary plug (see Chapter 11 "Pumping Slurry Plugs", page 11-54). The job plan must include a procedure for confirming the pressure integrity of the barrier(s). Temporary barrier options include:

- Closing lower master valve—Installing the CT hanger above this valve renders it useless once the velocity string is in place.
- Closing the downhole safety valve—If the existing completion contains a downhole safety valve, and Customer or regulatory requirements permit, closing this valve can provide a viable pressure barrier.

- Downhole tubing plug—Run and set on slickline, wireline, or CT and retrieved after the wellhead has been reconfigured and tested.
- Tubing head plug—Similar to downhole plugs but set in the tubing head or hanger recess.

Tubing Connectors

Reeled completions often consist of several lengths of CT joined together. Mechanical connectors provide a convenient alternative to welding which is often difficult to perform properly in the field. The two types of slip connector generally used for reeled completions are:

- External Connector (Figure 13.5 and Figure 13.6)
- Internal Spoolable™ connector (Figure 13.7)

The tensile strength of CT connectors is generally equal to or greater than that of the CT string. In larger, heavy-walled CT, fitting and aligning the connector can be relatively difficult due to the residual bend in the tubing string.

FIGURE 13.5 *External Threaded Connector*

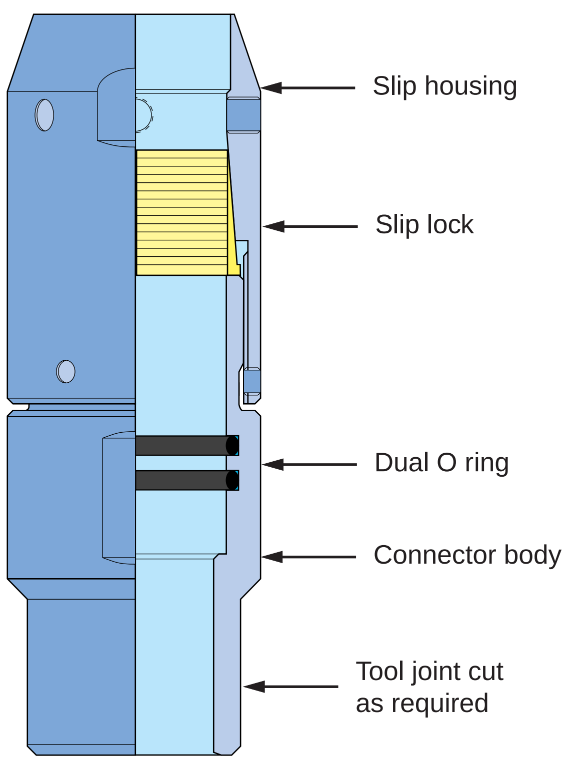


FIGURE 13.6 *External CT-to-CT Connector*

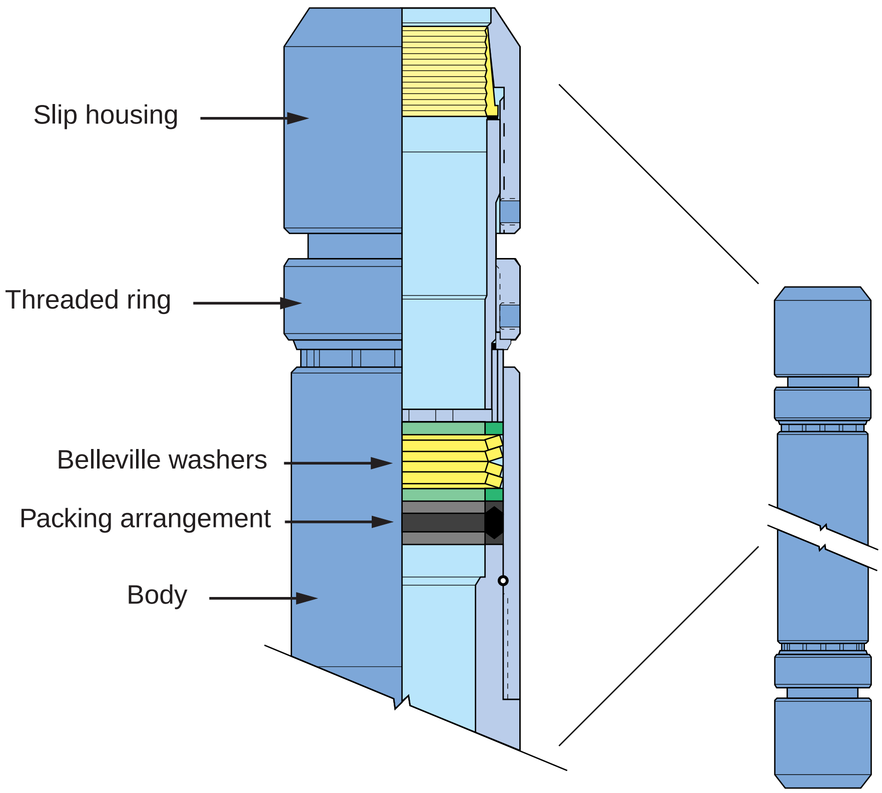
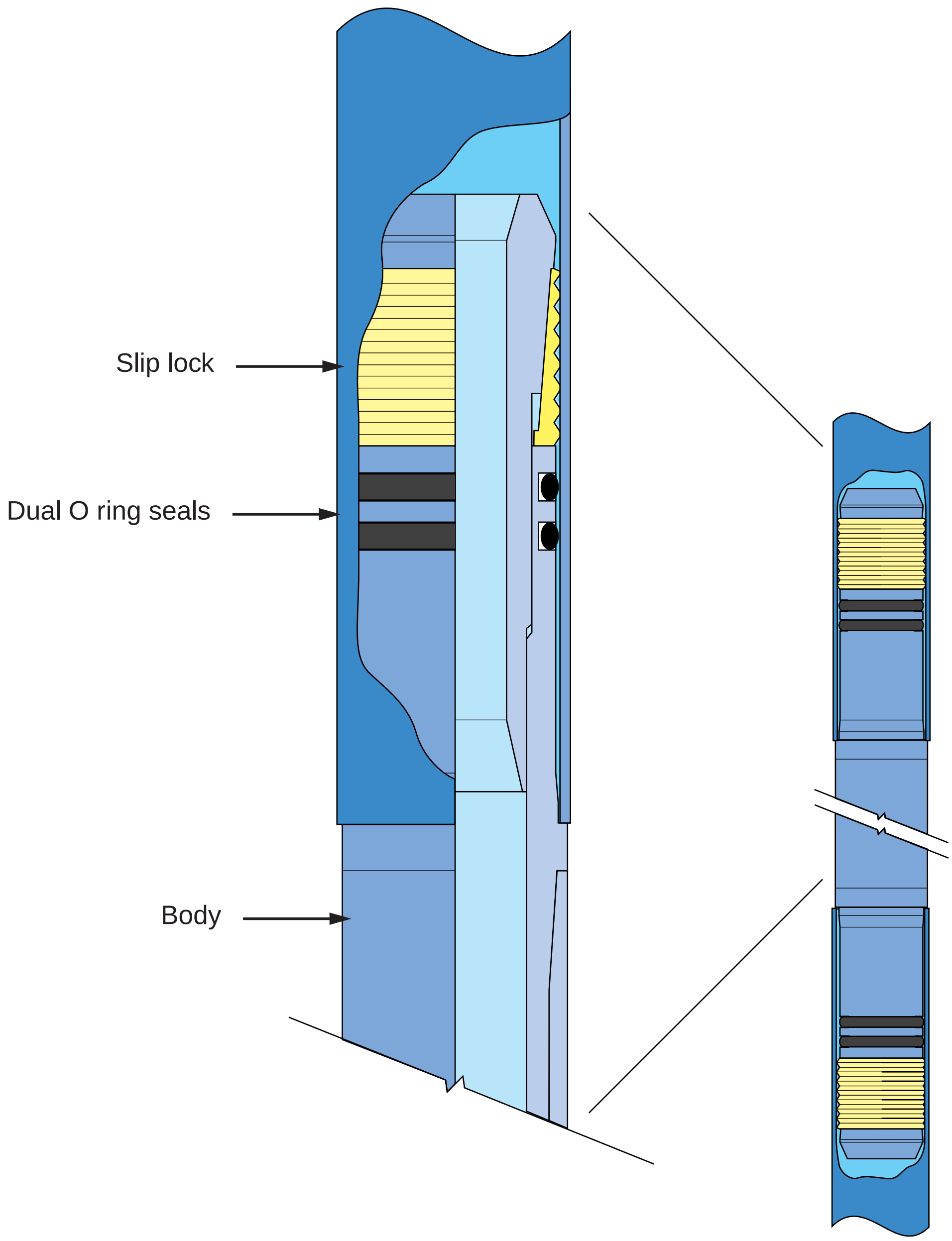


FIGURE 13.7 *Spoolable Connector*



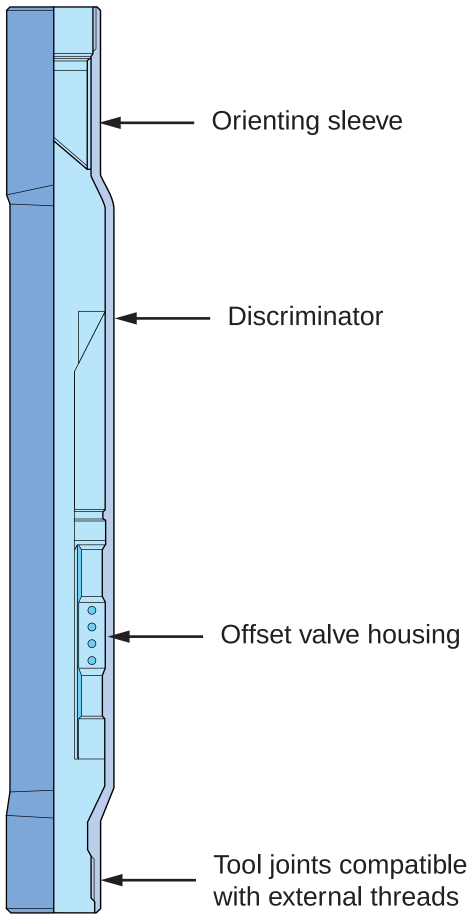
Gas Lift Valves and Mandrels

Remedial or secondary completion installations often require gas lift valves. While this adds to the complexity of the reeled completion design and installation process, gas lift valves provide significant benefits for production or kick-off purposes.

External upset and spoolable designs are available. External upset versions (Figure 13.8) are available over a wide range of sizes and offer several benefits, including:

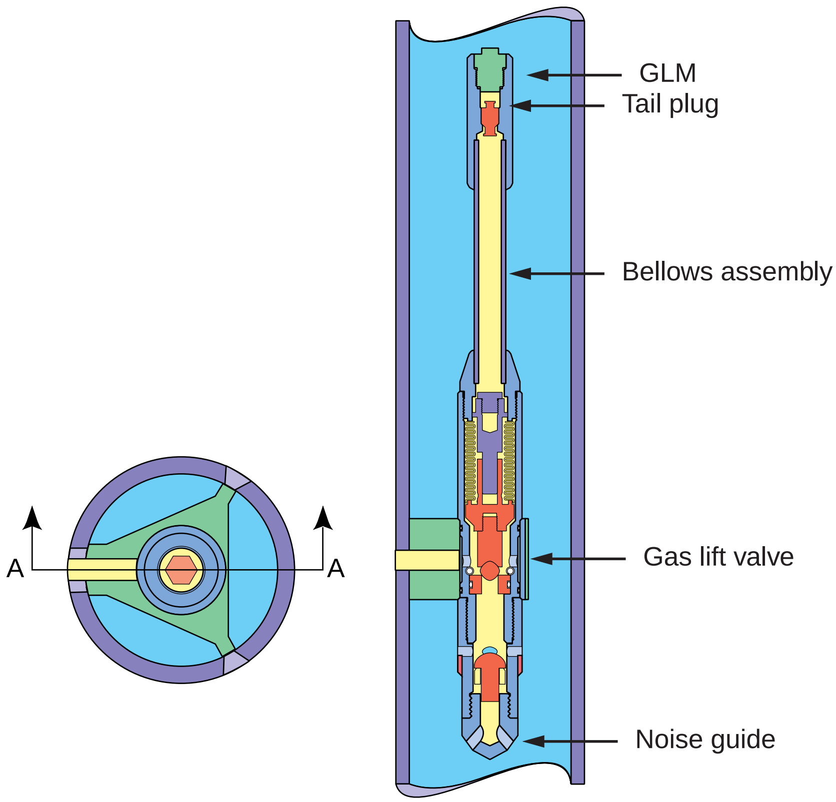
- Conventional gas lift equipment – proven design
- Serviced by conventional slickline tools and techniques
- Slimhole and side pocket mandrel designs

FIGURE 13.8 *External Gas Lift Mandrel*



Spoolable components (Figure 13.9) are a relatively recent product and are available in sizes up to 3.50 in.

FIGURE 13.9 *Spoolable Gas Lift Mandrel*



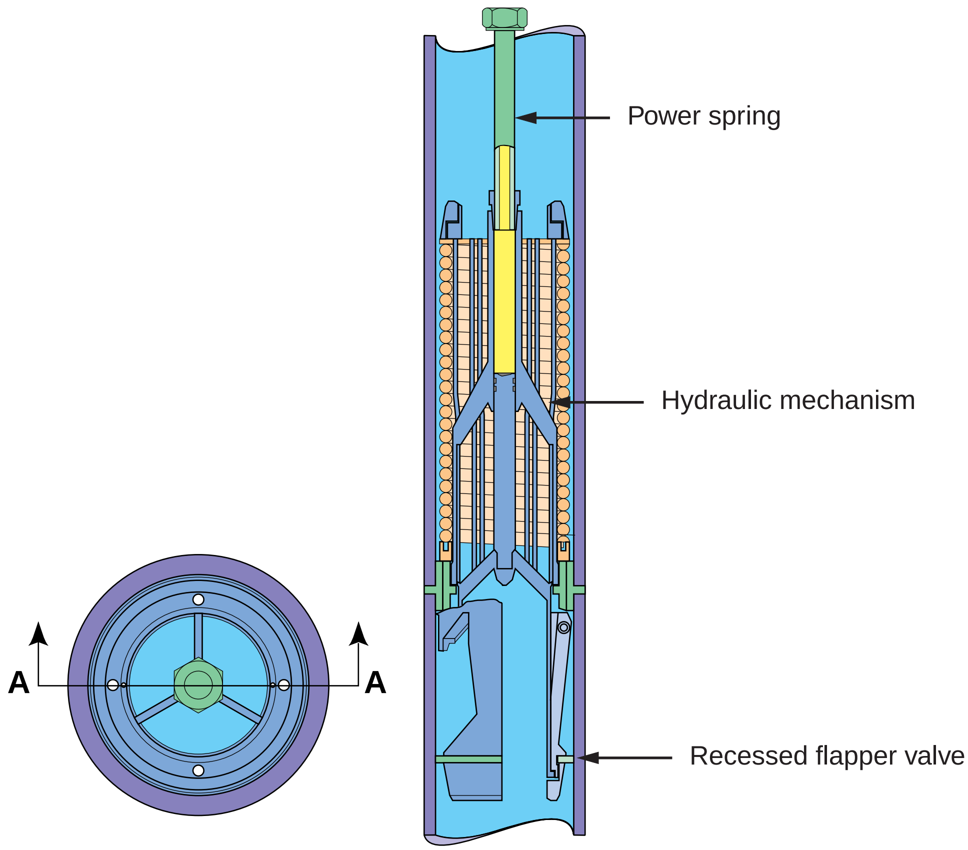
Gas lift valves currently enable four production modes:

- Injection pressure operated, tubing production
- Injection pressure operated, annular production
- Fluid pressure operated, tubing production
- Fluid pressure operated, annular production

Spoolable Safety Valve

A spoolable safety valve is now available for 2.375 in. and 3.50 in. tubing. The control line is installed inside the CT string and exits the wellhead/surface production equipment through a special adapter.

FIGURE 13.10 *Spoolable Safety Valve*



Additional Reeled Completion Hardware

Additional items of completion equipment are generally adapted from conventional stock and installed in the string using the CT connectors described above. Typical components include:

- Packers
- Nipples and landing profiles
- Flow control devices
- Circulation devices
- Pumps

OFFSHORE FLOWLINES

CT can provide an economical alternative to jointed pipe for offshore flowlines[1,2]. Gulf of Suez Petroleum Company (GUPCO) has realized cost savings of 55-75% with the use of CT flowlines compared to laying welded line pipe with a conventional pipe-laying barge. These savings are mainly the result of faster installation time with CT. Due to lower internal surface roughness, CT flowlines exhibit lower frictional pressure loss than equivalent size jointed pipe. GUPCO has observed a 15-20% reduction in pressure loss (pump horsepower) in CT flowlines compared to conventional jointed pipelines. This translates into further economic benefits from lower operating and maintenance costs.

The largest CT flowline installed through 2000 is 4.50 in. OD. However, PTT has produced short lengths of tubing up to 6.625 in. OD. The raw steel used for CT flowline is either ASTM A-606 Type 4 modified or ASTM A607 Grade 55. These steels have similar properties to comparable API 5L grade steel:

- X-52, minimum yield strength = 52 Kpsi
- X-70, minimum yield strength = 70 Kpsi
- X-80, minimum yield strength = 80 Kpsi

Currently, no industry specification or technical code covers CT flowline, i.e., API Standard 5L. An API Workgroup is investigating specifications and guidelines for the manufacture of CT pipeline.

The manufacturing process for CT flowlines is the same as for CT work strings (see Chapter 3 "The Tubing"). Both CT mills maintain a quality assurance (QA) system consistent with ISO-9001. This QA program includes:

- independent chemical and mechanical verification of raw steel properties
- radiography of all welds
- manual and automatic dimensional inspection of flat strip and tube
- eddy current and ultrasonic NDT inspection of the tube

1. Hoffman, J.G, et.al., "Coiled Pipeline Technology: a Gulf of Suez Case History", SPE Paper 36942, 1996 European Petroleum Conference, Milan, Italy, October 22-24, 1996.
2. Kenawy, F.A., et.al., "Coiled Tubing Pipelines: the Technology and Cost Effectiveness Challenge", OTC Paper 8718, 1998 Offshore Technology Conference, Houston, Texas, May 4-7, 1998.

- tests of end samples from each tube string - tensile, elongation, microhardness, metallographic, crush and flare
- hydrostatic pressure test

After the flowline has been inspected and tested, it receives an external coating to protect it from corrosion and mechanical damage. Coatings include:

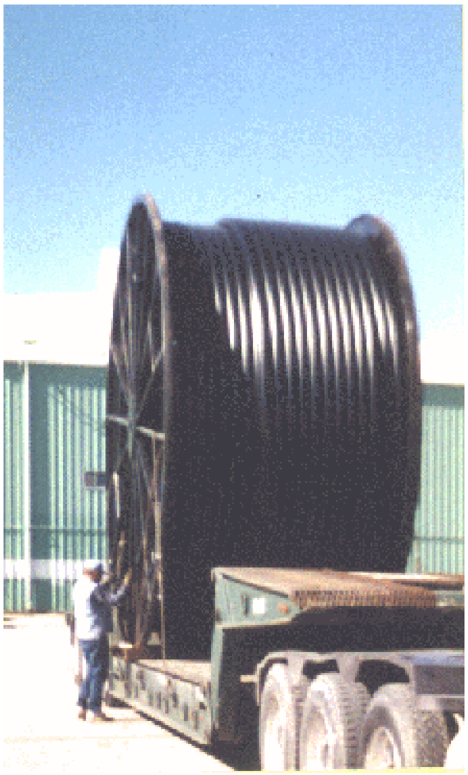
- Fusion bond epoxy (F.B.E.) - 15 to 17 mils total thickness
- 2-layer copolymer or mastic/high density polyethylene (H.D.P.E.) - 50 to 90 mils typical coating thickness
- 3 layer F.B.E./copolymer/H.D.P.E. or high density polypropylene (H.D.P.P.) - 60 to 90 mils typical coating thickness
- Advanced butyl rubber/polyethylene tape wrap systems
- Duval™ 2-layer H.D.P.P.

The CT mills perform QA and process control steps throughout the coating process. They verify the properties and performance of both the raw coating materials and the applied coating, including:

- coating thickness
- cathodic disbondment
- impact resistance
- bend and bond strengths

The tubing can be manufactured onto metal reels suitable for use with a powered support stand that feeds the pipe-laying equipment. This method requires lifting or handling equipment onboard the vessel that is capable of moving fully loaded reels. This type of reel may also be used to spool the tubing from a convenient dockside location onto a reel on a vessel. Another method is to connect short sections of flowline onshore, and then spool the longer continuous section onto a large collector reel that is lifted onto the vessel. Figure 13.11 shows a reel of 4.5 in. flowline being readied for transport from the CT mill to the dock.

FIGURE 13.11 *A Reel of 4.5 in. CT Flowline*



Vessels capable of installing flexible pipe or subsea umbilicals can also be used to install CT flowlines. GUPCO used a 300-ft class diving support ship with dynamic positioning capability. This type of vessel offers three important benefits over conventional pipe-laying barges.

- precise positioning
- excellent station-keeping ability – especially important in areas of strong currents or high winds and during storms
- immediate access to divers for underwater connections, trouble-shooting, and inspections

The vessel GUPCO used had open deck space of 9700 ft^2 and a 70-ton deck crane. Figure 13.12 shows the open deck of the vessel with 9 loaded reels of flowline plus one in the power spooler. Each reel contained about 4300 ft of 4.5 in. CT flowline.

FIGURE 13.12 *Laying CT Flowline in the Gulf of Suez*

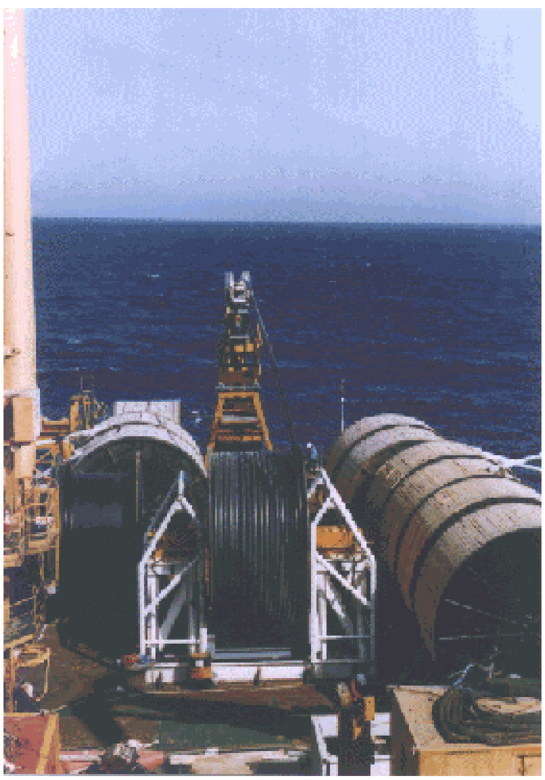


Figure 13.12 shows the powered reel support containing one reel of pipe, guide arch, and part of the lay ramp support. The lay ramp support contained a tubing straightener and a tensioner to maintain the proper tension in the CT above and below the water.

Individual sections of flowline can be connected mechanically (slip-type connectors) or by welding, but the latter is more common. GUPCO uses “full bore” socket connections. These are installed and inspected at the CT mill. On location the socket requires only a single weld and inspection for each new reel added to the flowline. This decreases the overall time required to connect sections. The full bore does not disrupt the flow or pigging operations.

CT UMBILICALS (CONTROL LINES)

CT is often used to connect subsea equipment and production facilities with hydraulic control lines. Generally, more than one line is required for each installation. Bundling these separate lines together saves installation costs and increases the ruggedness of the installation. Figure 13.13 shows a CT umbilical developed by the DEEPSTAR joint industry project. It consists of four separate 0.75 in. X 0.080 in. 80 Kpsi CT strings surrounded by insulation and protected by two layers of armor wire. Approximately 33,000 ft of this umbilical was installed in the North Sea in 1995.

FIGURE 13.13 *CT Umbilical Developed by DEEPSTAR*

Figure 13.14 shows a prototype of a different design for a CT umbilical. This one has not been produced in commercial quantities.

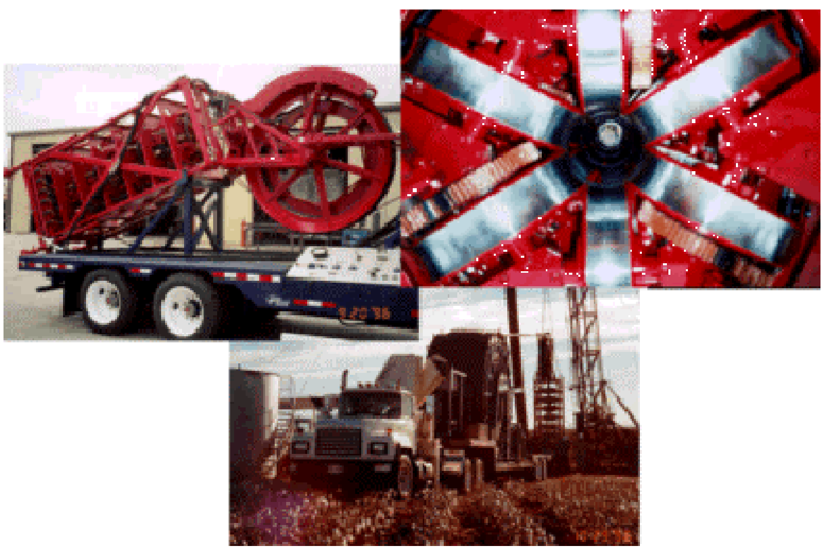
FIGURE 13.14 *Prototype CT Umbilical*

CASING AND TUBING REPAIRS

The industry has investigated several different methods for using expandable tubing and pipe for monobore completions and repairing existing casing and tubing strings. The primary motivation is to be able to install new pipe with little or no ID restriction below or inside an existing completion. Some of these concepts involve expanding round tubing, such as CT, to a larger diameter after RIH while other techniques use tubing that has been flattened and folded axially before spooling it onto a reel.

Figure 13.15 illustrates several features of a novel concept for repairing corroded casing with a reeled plastic liner. The upper left photo shows the unique injector head with its guide wheel in place of a conventional fixed guide arch. The upper right photo shows the friction wheels inside the bore of the injector that grip and push/pull the plastic tubing. The bottom photo shows the equipment on location.

FIGURE 13.15 *System for Installing Plastic Liner (Amoco)*



The fundamental principal of this system is simple. The normal OD of the plastic tubing is slightly larger than the ID of the existing completion. Weight bars attached to the free end of the plastic tubing provide enough tension to stretch the plastic tubing. Stretching the tubing decreases its OD enough to fit inside the completion. After RIH to a depth that places the plastic tubing across the damaged section of the completion, the weight bars are released. This allows the plastic tubing to resume its normal OD and create an interference fit that seals the leaking completion tubular. Amoco has used this technology for repairing leaks in numerous CO_2 injector wells in New Mexico.

14

NON-STANDARD CT OPERATIONS

CT Operations in Pipelines and Flowlines

CT has numerous applications in pipelines and flowlines including:

- Removing organic deposits and hydrate plugs (see Chapter 11 "Removing Wax, Hydrocarbon, or Hydrate Plugs", page 11-103)
- Removing sand (see Chapter 11 "Removing Fill or Sand From a Wellbore", page 11-7)
- Setting temporary plugs (see Chapter 12 "Setting a Plug or Packer", page 12-4)
- Transporting inspection tools (see Chapter 12 "Logging with CT (Stiff Wireline)", page 12-44)
- Placing a patch or liner to repair minor leaks (see Chapter 13 "Casing and Tubing Repairs", page 13-21)

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

CT operations in pipelines and flowlines on land are similar to CT operations in horizontal wellbores with a few important exceptions. First, the injector must supply all of the force required to RIH with the CT. The lack of a vertical section means that none of the CT weight is available to push on the CT ahead of it. Second, the injector must be oriented horizontally at the entrance to the pipeline. This requires a special mounting frame and an injector that will operate efficiently lying on its side. Third, the injector will have to snub the CT into the pipeline during RIH, so the weight cell(s) must be configured for accurate measurement of snubbing forces.

Regardless of the operational environment, post-helical buckling lockup of the CT is the most serious operational issue, because it limits both the CT’s reach into the pipeline and the force it can push on an object. The radial clearance between the CT and the conduit is usually quite large. This decreases the critical force for helical buckling (Equation 7.3 on page 7-5) and increases the post helical buckling normal force (Equation 6.11 on page 6-12). Oil pipelines generally have an internal coating of highly viscous oil or wax that significantly increases the sliding friction coefficient[1]. The excessive drag of this coating against the CT substantially reduces the length of CT that can be pushed into the pipeline prior to buckling.

A reasonably successful solution to this problem is the addition of “skates” to the CT string at regular intervals. A skate resembles a rigid centralizer or stabilizer with a roller on the end of each arm (blade). The skates support the CT and prevent it from dragging against the inside of the pipeline. This effectively converts the drag from sliding friction to rolling friction and reduces the effective friction coefficient for the operation by about 75%.

Ambar’s StarTac® system is one commercial application of skates for extending the reach of CT inside pipelines. The StarTac system can also utilize hydraulic thrusters, backward pointing jets, at the free end of the CT string to apply a tensile force. The thrusters literally pull the CT string along the pipeline. Ambar claims that the combination of skates and thrusters will permit CT operations in horizontal pipelines up to five miles from the injector head.

1. Baugh, B.F, et. al., “Extended Reach Pipeline Blockage Remediation”, OTC paper 8675, 1998 Offshore Technology Conference, Houston, TX, May 4-7, 1998.

COPING WITH WEIGHT AND SPACE LIMITATIONS OFFSHORE

Limitations on deck loading, space, and/or crane lifting capacity can seriously hinder CT operations on many offshore platforms and wellhead installations. Generally, the offshore installation can accommodate the injector head without any trouble. The hydraulic power supply and control cab do not pose much of a problem either. However, the heavy reel of CT and the deck space required to position it relative to the injector poses the biggest obstacle to offshore CT operations.

Several options are available to overcome these obstacles, including:

1. Break down the CT equipment package into the smallest, lightest lifts possible, e.g. remove components and reassemble the equipment on the platform.

2. Cut the CT string into sections, spool each section onto a lightweight shipping reel, lift the reels onto the platform, then reconnect the sections on the platform.

3. Use a barge or jackup with a heavy-lift crane to hoist all of the CT equipment intact onto the platform.

4. Lift the CT unit minus the CT string (an empty CT work reel) onto the platform. Spool the CT string onto the work reel from a loaded reel on a floating vessel.

5. Install only the CT injector on the wellhead, leaving the CT reel and other CT unit components on a barge, workboat, or jackup alongside the platform.

The first four options apply to situations where the existing crane lift capacity is the main problem. The loaded CT reel is the heaviest component of a CT unit. CT service companies operating offshore have developed special lightweight reels they can remove from the support frame for lifting onto the platform. This typically constitutes Option 1. Option 2 has been used successfully numerous times in the North Sea and is a viable option anywhere high quality CT welding service is available. Chapter 3 "Repairs and Splicing", page 3-32 describes welding and other methods for splicing CT. Options 1 and 2 are relatively inexpensive compared to the others.

Options 3-5 require more equipment and personnel than for a "standard" CT operation. Also, the weather or sea state is an important factor for barge and workboat operations. Consequently, Options 3-5 significantly increase the cost of a CT operation. Option 3 is not common due to the high cost and scarcity of floating cranes. The following sections discuss spooling CT from a floating vessel to a platform and conducting CT operations with the reel on another vessel.

Spooling CT between a Floating Vessel and a Platform

This operation requires two CT reels, an empty one on the platform and a loaded one on the vessel. Typically the injector mounted on the platform is adequate for controlling the movement of CT between the two locations. However, a second injector on the vessel may be necessary to safely handle large diameter CT. Several factors influence the feasibility and efficiency of spooling CT between a floating vessel and a platform. These include:

- Sea state
- Vessel station-keeping
- Coordinating operations between a fixed and moving location

Two characteristics generally determine the sea state, i.e., wave height (heave) and frequency. These conditions affect the axial forces on the CT string, hence all of the equipment contacting the CT, due to the relative movement between the vessel and the platform. Even if the vessel can successfully maintain its lateral position relative to the platform, the vertical heave, roll, and pitch must be within certain limits for the spooling operation to safely proceed. The period of acceptable operating conditions can be only hours or many days, depending on the location and the weather. This can create a logistics nightmare and tie up equipment and personnel waiting for a window of opportunity. Thus, sea state is a major factor when planning and executing spooling operations between a floating vessel and a fixed platform. Figure 14.1 shows a CT spooling operation with fairly calm sea state.

FIGURE 14.1 *CT Spooling Operations between a DP Vessel and a Platform*

CT spooling operations are extremely sensitive to the relative position of the vessel and the platform. The vessel must stay within a specific area relative to the platform in order not to exceed the fleet angle limits for the CT reel and injector(s). The sea state significantly influences the ability of the vessel to keep on station throughout the CT spooling operation. A moored vessel must keep the proper tension on its anchor cables to maintain a fixed position. A dynamically positioned (DP) vessel must have adequate thrusters to counteract wind, currents, and the axial force from the CT. Each type of vessel will have operating limits for sea state that directly influence the potential operating window of opportunity. Therefore the choice of vessel can have a major impact on the cost and outcome for a CT spooling operation.

Coordinating the operations of the equipment over a span of open water to keep the spooling operation going smoothly and the dynamic forces within acceptable limits is a monumental task. Excellent communication between both locations is essential. Moreover, accurate real-time measurements of the forces on the CT string and equipment are vital to prevent damaging any component in the system. Generally the CT operator on the platform should lead the overall spooling operation.

Unlike fixed platform or land-based operations, contingency planning for spooling CT between a floating vessel and a platform must contend with the relative motion between different pieces of equipment and the likelihood that the reel could literally “wander” off the location.

CT Operations from a Vessel alongside the Platform

Many offshore platforms are small structures without enough deck space to accommodate a CT unit. Consequently, the only way to conduct CT operations on those platforms is to install the injector on the wellhead, and supply it with power and CT from a vessel alongside. Figure 14.2 shows an example for such an operation from a lift boat off the coast of Louisiana. This is a fairly common method of providing CT services to small platforms in relatively shallow water of the Southern North Sea, Persian (Arabian) Gulf, and S.E. Asia. Once the lift boat (or jack up rig) is in place, the CT operation can commence as though the location was a single fixed structure.

FIGURE 14.2 *CT Operations from a Lift Boat (Spirit Energy)*

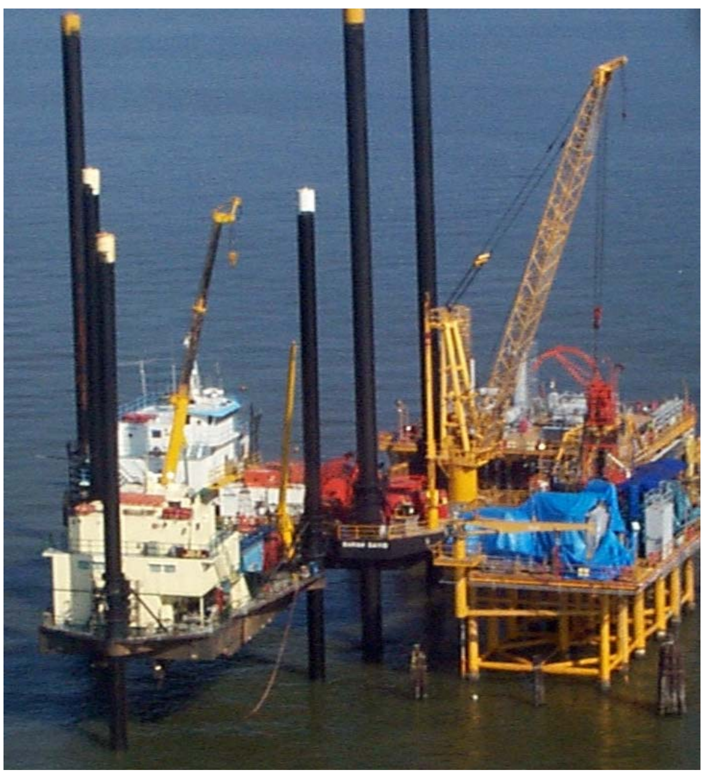


Figure 14.3 shows an example of another type of CT operation from a vessel that is common to shallow inland waters or coastal waterways protected from open-ocean swells. The barge anchors next to the platform and transfers the injector to the wellhead in much the same way a land CT unit would. The resulting CT operation is very similar to its land-based counterpart.

FIGURE 14.3 *CT Operations from a Barge (Lake Maracaibo)*

A third example of coping with weight and space limitations offshore is conducting CT operations with the reel on a DP vessel and the injector on the platform. In addition to the problems caused by sea state and relative motion between the vessel and platform, this operation is further complicated by:

- the CT string may be pumping treatment fluids into the well
- the CT string is exposed to wellbore conditions
- dynamic loading between the guide arch and the reel (uncontrollable reel back tension)

The treatment fluid(s) in the CT string and the potential for pressurized wellbore fluids to enter the CT string pose serious problems whenever the relative position between the vessel and platform exceeds safe operating limits. If cutting the CT at either the platform or the vessel becomes necessary, the fluid inside the CT will escape to the surroundings, and the free end of the CT could violently whip around, injuring personnel or damaging equipment. Maersk and Dowell developed a special fairlead with a emergency disconnect for the platform and another for the DP vessel that included a set of CT shear and slip rams to cut and hold the CT in case the vessel moved too far off station[2]. The well control procedures and contingency planning for such an operation are considerably more complex than for "standard" CT operations.

The dynamic loading in the CT between the fixed injector and moving CT reel affects the weight indicator, lateral forces on the wellhead and/or platform, reel back tension, and fatigue life of the CT string. Extensive modelling of these forces and their effects must be an important part of the planning process. As for the simpler CT spooling operations, coordinating the operations of the equipment over a span of open water requires excellent communication between both locations. Moreover, accurate real-time measurements of the forces on the CT string and equipment are vital to prevent damaging any component in the system. The CT operator must control the operation from the platform.

2. Pearson, J.E. and Starck, P.E., "Coiled-Tubing Operations Performed from a Vessel", SPE paper 46049, 1998 SPE/ICoTA Coiled Tubing Roundtable, April 15-16, 1998, Houston, TX.

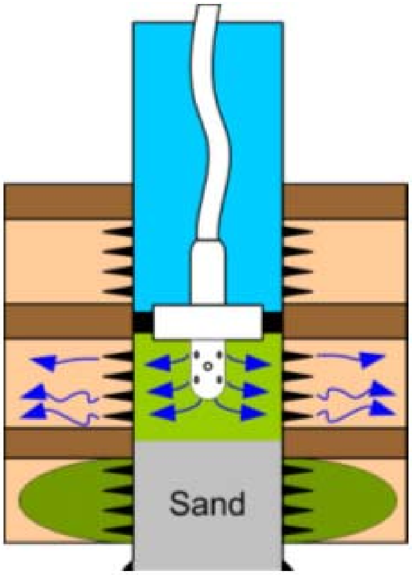
Fracturing Through CT

Several CT service companies have developed and applied technology for fracturing (TVD < 10000 ft) gas wells and coal bed methane wells through CT[3]. These wells are cased to bottom with perforations across each producing interval. The fracturing operation uses standard CT surface equipment (see Chapter 4 “CT Surface Equipment”) and either a straddle packer (see Chapter 5 "Through-tubing Packers and Bridge Plugs", page 5-36) or a combination of single packer (see Chapter 5 "Through-tubing Packers and Bridge Plugs", page 5-36) and a temporary pumped slurry plug (see Chapter 11 "Pumping Slurry Plugs", page 11-54). The fracturing fluid is typically water based polymer and graded frac sand. Due to the potentially high lateral forces on the wellhead caused by hydraulic “hammer” during pumping, the injector must be firmly supported over the wellhead. The best solution is a support stand that takes most of the injector forces away from the wellhead. Also, accurate depth correlation is extremely important to guarantee precise placement of the packer(s). Otherwise the operation is a typical formation stimulation (see Chapter 11 "Stimulating a Formation (Acidizing)", page 11-29)

There are two basic techniques in fracturing wells with CT. The first option uses a single packer with the use of a sand plug, Figure 14.4. The sand plug isolates the lower reservoir from the subsequent fracturing treatment while the packer provides the upper seal. The single packer technique requires the precise control over the quantity of sand pumped between treatment intervals. Too little sand exposes the lower perforations that were just treated, while too much sand covers perforations that need to be treated. This approach does have several advantages. By using a single packer, the risk of becoming stuck is lowered and the treatment interval is not limited by the lubricator length at surface. This technique does impose additional steps for spotting and washing out the sand plugs after the well is completed.

3. Lemp, S., Zemlak, W., and McCollum, R., “An Economical Shallow-Gas Fracturing Technique Utilizing a Coiled Tubing Conduit”, SPE paper 46031, 1998 SPE/ICoTA Coiled Tubing Roundtable, Houston, TX, April 15-16, 1998.

FIGURE 14.4 *CT Fracturing using a Single Packer*

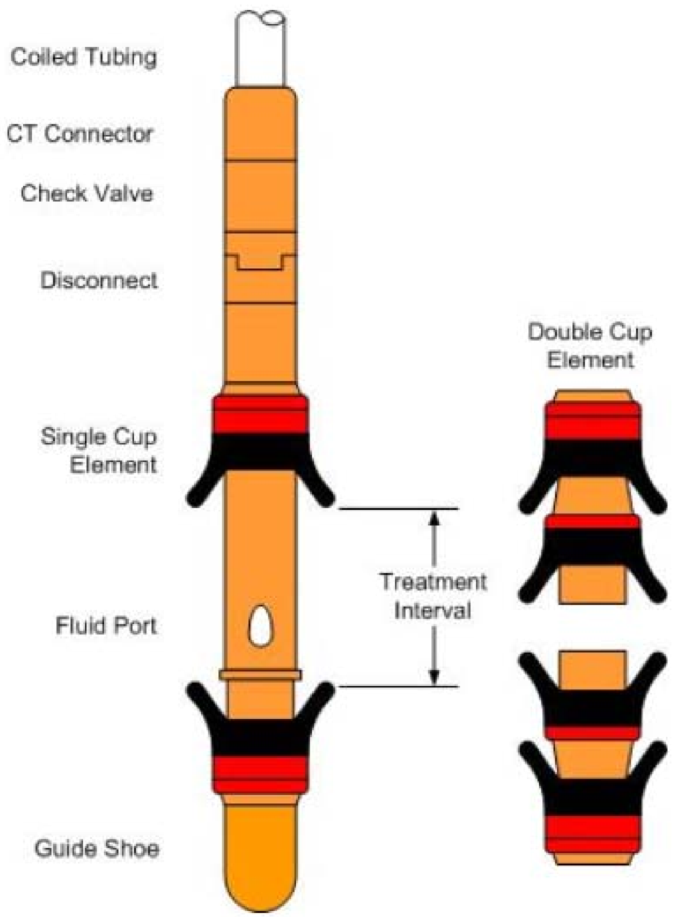


The second technique uses a straddle packer to provide isolation in the zone of interest. The two-packer arrangement is spaced out based on the treatment intervals, but limited to the length of lubricators at surface. This technique allows for continuous treatment and eliminates the need to set a bridge or sand plug prior to treating the zone. There are several different styles of straddle packers used in CT fracturing, with the main styles listed below:

- Single cup element
- Double cup element
- Packer element
- Combination cup and packer element

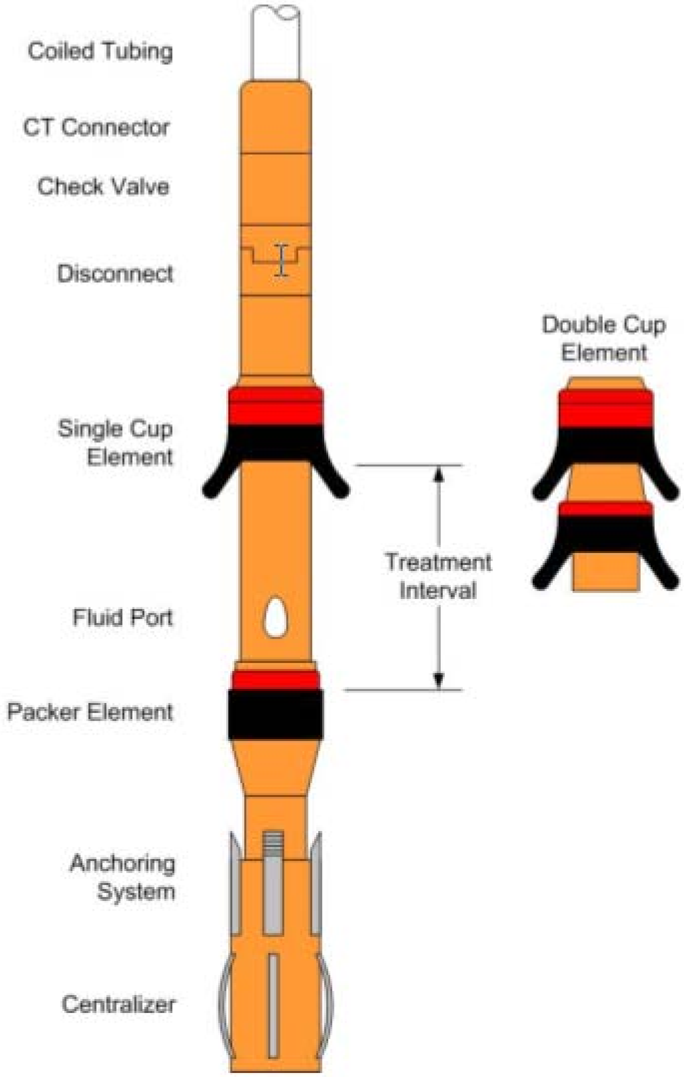
The most common sealing mechanism in downhole fracturing tools is the cup style element, Figure 14.5. Cup elements use a differential pressure as the sealing mechanism, but the pressure differential is typically limited to 5000-psi. The design of the cup makes them susceptible to damage when moving pipe. The upper element is susceptible to damage when RIH while the lower element is susceptible when POH. When depths exceed 6000 ft, it is recommended to run a double cup system for backup protection. The double cup system is still susceptible to the same type of damage, but the redundancy makes it a more reliable system for the deeper work. This system uses the weight of the pipe and the pressure trapped between the cups to keep the system in equilibrium. If the lower cups do not seal, the downhole treatment pressure can force the tool up hole and possibly outside the zone of interest.

FIGURE 14.5 *Cup Style Fracturing Tool*



The packer elements make the downhole tools more resilient when compared with the cup style element, but these elements are more difficult to seal. When a packer element is used in a system, the inflation is usually accomplished by the use of tension or compression. Some tools use both a cup and packer element in the same tool, Figure 14.6. These systems have an anchoring mechanism to help set the packer element and prevent movement when the balance of pressure is not equalized. An internal by-pass valve allows the trapped pressure to escape before moving pipe and damaging the elements.

FIGURE 14.6 *Downhole Fracturing Tools*

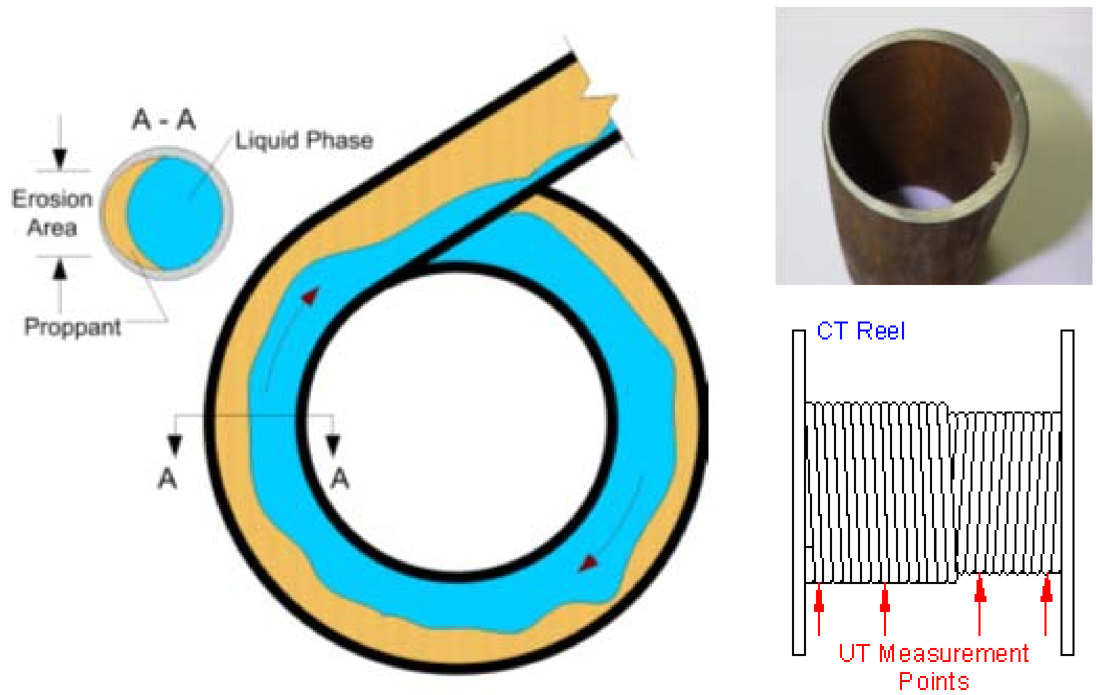


One of the major concerns with CT fracturing is the effects of erosion that occurs while pumping proppant. This erosion takes place on the inside of the tubing while on the reel. The centripetal force causes the heavy proppant to move outward against the tubing wall, resulting in a reduction in wall thickness, Figure 14.7. Several factors influence the magnitude of this erosion:

- Amount of proppant
- Type of proppant
- Pumping rates
- Flowback rates
- Carrying fluid properties

To determine the amount of erosion, an ultrasonic thickness (UT) gauge must be used on location to measure the wall thickness at various locations during the job. The UT data should be used to adjust the wall thickness in the fatigue model. When measuring the wall thickness it is important to get as close to the bed-wrap as possible, due to the fact that most of the erosion occurs in this region. When starting a new CT fracturing operation, strings should be retired when the life reaches 50 to 70 percent. Once a baseline is developed that takes into account all of the factors that affect pipe fatigue, the operating limits can be extended.

FIGURE 14.7 *Erosion while Pumping Proppant*



SUBSEA WELL INTERVENTION

Subsea well intervention with CT is not a common practice. This fact has little to do with CT technology and much to do with vessel availability (economics) and riser technology. The Texaco DeepStar project evaluated the feasibility of this application for a subsea well in 6000 ft of water from a large dynamically positioned (DP) monohull vessel. The study determined that such a vessel must have the following features for CT subsea well intervention:

- full DP system
- minimum clear deck space = 8000 ft^2
- deck load capacity = 1000 tons
- vessel stability OTM = 30 x 10^6 ft-lb
- moonpool minimum size = 16 ft x 16 ft
- personnel capacity = 75
- deck crane = 30 tons at 65 ft reach
- hydrocarbon handling capability

In 1998, approximately 18 vessels met these requirements, but most were under long-term contract, and the remaining few on the open market were too expensive to apply to CT operations.

In addition to the vessel and CT equipment, subsea intervention would require:

- tie-back riser and handling system
- a remotely-operated vehicle (ROV) system
- workover control system
- fluid handling and other service equipment

After the vessel, the tie-back riser is the key component in the system. Two different systems are under development, (1) rigid from the surface to the seabed and (2) a combination of rigid and flexible sections. The former requires the usual riser tensioning gear and should be suitable for water depths to 3000 ft. This is the type of system Coflexip Stena Offshore tested in Shell's Gannet Field in late 1997[4]. XL Technology Limited is developing a much different

4. McGennis, E., "Coiled Tubing Performance Underlies Advances in Intervention Vessels", Offshore, February 1998, p.46.

riser system as part of a DEA Europe joint industry project. Their riser consists of a vertical section of steel CT extending from the subsea wellhead to approximately 300 ft below the surface. A buoyancy module holds this vertical CT in tension. A flexible riser connects the top of this section to the vessel with an S-shaped curve that absorbs the effects of vessel movement. XL claims this riser system could operate in water depths to 8200 ft. However, the S-shaped portion of the riser will add significant drag to the CT inside and could limit the axial force available in the well.

High Temperature (T > 350°F)

Temperature and pressure generally increase almost linearly with depth, and the average thermal gradient for the earth is about 1ºF/100 ft. This means that under normal, average conditions, CT would not experience T > 250ºF until reaching depths of approximately 18,000 ft TVD. However, many CT operations encounter high temperatures at much shallower depths due to:

- nearby geothermal or volcanic activity
- faulting that has displaced hot rock from deeper formations
- geological features, such as salt domes, that prevent heat from escaping a formation

An example is in the Gulf of Thailand where bottom hole temperature is about 400°F at 7000 ft. TVD. Except for CT operations in live geothermal wells or hot gas wells, the primary problem with high wellbore temperature is its effect on downhole tools. The reliability of many completion and service tools decreases rapidly for T > 250ºF. Therefore, planning for a high temperature CT operation must carefully consider the selection of BHA components and the effect of temperature on their performance and working life.

Basic Considerations for High Temperature Operations

Pressure Control Equipment (Stripper and BOP)

Generally, the pressure control equipment will not be exposed to high temperature except for geothermal applications or operations on live hot gas wells. However, prudence dictates that the pressure control equipment is capable of operating at the maximum potential surface temperature. This usually means replacing the standard elastomer seals with high temperature materials, using extended bonnets on valves and BOP rams, or both.

BHA Components

The primary temperature limitation for most CT operations is the reliability and working life of downhole tools at high temperature. Tools containing electrical components and elastomer seals are especially vulnerable to elevated temperature. The typical downhole electronics package is limited to T < 300ºF, but some can operate at higher temperatures for short periods with special thermal shielding or internal flow paths for cooling from fluids pumped through the CT string. Motors and other tools with elastomer pressure seals are generally limited to T < 350ºF.

CT Equipment for High Temperature Operations

Except as noted above, no special CT equipment is required for operations in high temperature wells.

> **CAUTION:** Unless forcibly cooled by water spray or other means prior to spooling, the CT exiting the well can contract sufficiently upon cooling that it collapses the work reel.

Safety Issues for High Temperature Operations

The greatest safety concern for high temperature operations is that the CT string and everything it contacts can become dangerously hot. Moreover, superheated steam is invisible. The origin of a leak around the stripper or BOP may not be obvious. Always use extreme caution and wear proper protective clothing when working on or near the pressure control equipment during a high temperature operation.

Monitoring High Temperature Operations

In addition to the parameters normally monitored and recorded during a CT operation (see Chapter 17 "Data Acquisition and Real-Time Monitoring", page 17-52), monitor the temperature of the wellhead and fluid returning from the wellbore.

15

CT DRILLING

OVERVIEW

Coiled tubing drilling has been a commercial service for many years. Although CT drilling provides many advantages, it should not be thought of as a direct replacement for conventional rotary drilling. It has specific limits and cost drivers, which must be understood before applying this technology. This application combines the use of joint pipe handling and coiled tubing to accomplish the overall well objectives. Coiled tubing drilling encompasses multiple services and personnel, which are involved in the complete well package. Past experience has shown that many projects have failed when the total workscope was not considered.

There are many advantages of coiled tubing drilling, but understanding the appropriate selection criteria is the most influential factor to ensure a successful drilling project. To work through a project feasibility requires an understanding of the capabilities and limitations of coiled tubing and the drilling equipment. It must be stressed that coiled tubing is just a small part of the overall project considerations and the following are other factors to consider when preparing for a project:

- Location construction
- Maintenance of equipment
- Well preparation
- Contingency plans
- Living accommodations and crew structure
- Drilling tools and directional services
- Openhole well control
- Completions
- Cementing
- Mobilization and transportation

Well design and construction go hand-in-hand with coiled tubing drilling. Both processes require a combined effort and interaction of many groups. Typically in new projects most people involved do not completely understand the limitations and requirements of coiled tubing, so they apply conventional rig needs. This usually results in over designing the project, which drives the cost and workscope beyond the desired level of the project. When preparing for a new project, start with the simplest workscope and increase the difficulty as the project matures. Tailor the requirements to take full advantage of the benefits offered from coiled tubing and avoid a direct comparison of the workscope used by conventional drilling.

Coiled tubing drilling can be divided into two main categories consisting of directional and non-directional wells. Each of these categories can be subdivided to over-balance and under-balanced drilling. Each of these categories play an important role in the tools and equipment selected for the operations.

The downhole tools required for each of these categories are completely different. Directional drilling requires the use of an orienting device to steer the well trajectory in a particular direction. Non-directional wells use a more conventional drilling assembly with the use of a downhole motor. Both types of wells are typically limited by the depth and hole size, which are effected by:

- Reel Capacity
- Transportation logistics
- Number of casing points
- Overpull margins
- Torque requirements
- Circulating pressures
- Flowrates for hole cleaning
- Weight-on-bit

When comparing the capability of conventional drilling with coiled tubing drilling the potential wellbore depth and size are significantly reduced. These limitations are based on the achievable flowrates through the coiled tubing and the available weight-on-bit (WOB). For low angle wells the weight-on-bit limits can be overcome with the use of drill collars and changing the configuration of the bit/motor. For high angle wells the WOB is limited to the weight of the coiled tubing and the ability of the injector head at surface to push the pipe. Hole size affects both the cuttings carrying capabilities and the achievable WOB. As the hole size increases, the cuttings carrying capabilities and the weight transfer are diminished.

The general rules for annular velocity in the vertical section is 40 fpm and a maximum pumping pressure of 4000-psi. Exceeding the 4000-psi pumping pressure results in shortening the fatigue life of the coiled tubing and would typically exceed the limitation of a mud pumps (piston/liners). When ROPs are high, the minimum annular flow velocity may need to be increased to prevent loading up the hole with solids and increasing the ECD.

Non-Directional Wells

Non-directional wells are defined as any well in which the direction, inclination and/or azimuth is not controlled by means of downhole tools. This definition does not imply that the well trajectory lacks any inclination and/or azimuth, but simply the tools required to control these parameter are not in use.

Many non-directional wells have been drilled with coiled tubing, which represents the largest drilling application for coiled tubing. Most of this work was completed in Canada in the shallow gas market. These wells were drilled from surface, or just below the surface casing, in a relatively conventional drilling technique with the used of a downhole motor. In determining the feasibility, careful consideration should be used in defining the workscope. The vast majority of the footage drilled with CT has been with hole sizes smaller than 7", but hole sizes up to 13-1/4" have been successfully drilled. The main advantage that CT drilling brings to the non-directional wells is speed of assembling and disassembling the equipment and the continuous rate of penetration.

Using drill collars (spiral) in low angle wells to control the build up of inclination and apply WOB. The number of drill collars used will depend on the drillability of the formation and the bit/motor combination, but typically the number ranges between 2 and 10 collars. The typical BHA used in drilling the non-directional wells consist of the following:

CT Connector, Check Valve, Release Joint, Drill Collars, Surveying Tool, Motor, Bit

FIGURE 15.1 *BHA Components (Non-Directional)*

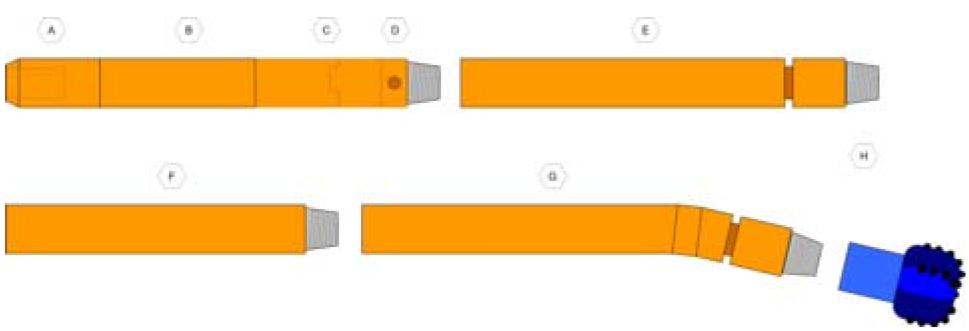
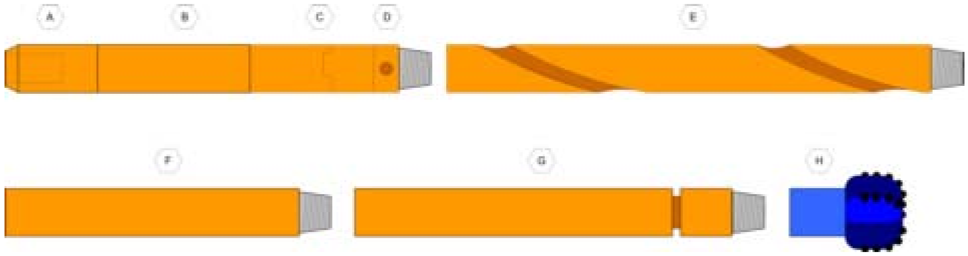


FIGURE 15.2 *BHA Components (Directional)*



Directional Wells

Directional drilling is defined as any well in which the azimuth and/or inclination is controlled by the use of downhole tools to obtained a desired well path. This well type employs an orienter device in the bottom hole assembly to control the wellbore trajectory. The complexity of these wells is typically greater due to the BHA and drilling requirements. Usually the rate of penetration is compromised by the requirement to maintain directional control and difficulties transferring weight to the bit.

Many of these directional drilling applications are performed on existing wells to obtain new targets in the reservoirs. These wells can be new wells, extensions, side-tracks through existing completions or side-track where the completions are pulled. Directional drilling is very sensitive to the existing wellbore ID and the hole size. As the size increases the weight transfer diminishes and the flowrate requirements increases. These wells are also limited by the downhole tools, which are most likely to be the orienting device.

When multi-phase fluids are required, additional requirements are imposed on the BHA. Multi-phase fluids negate the use of mud pulse telemetry for the transmission of data for the downhole tools and the use of fluid powered orienting tools. With these fluids the control, power and data transmission of the BHA is conductive by dedicated electrical and/or hydraulic lines. As the percentage of liquid fluid decreases, the dampening effects of the fluids also decrease to a point where the failures in the BHA will result.

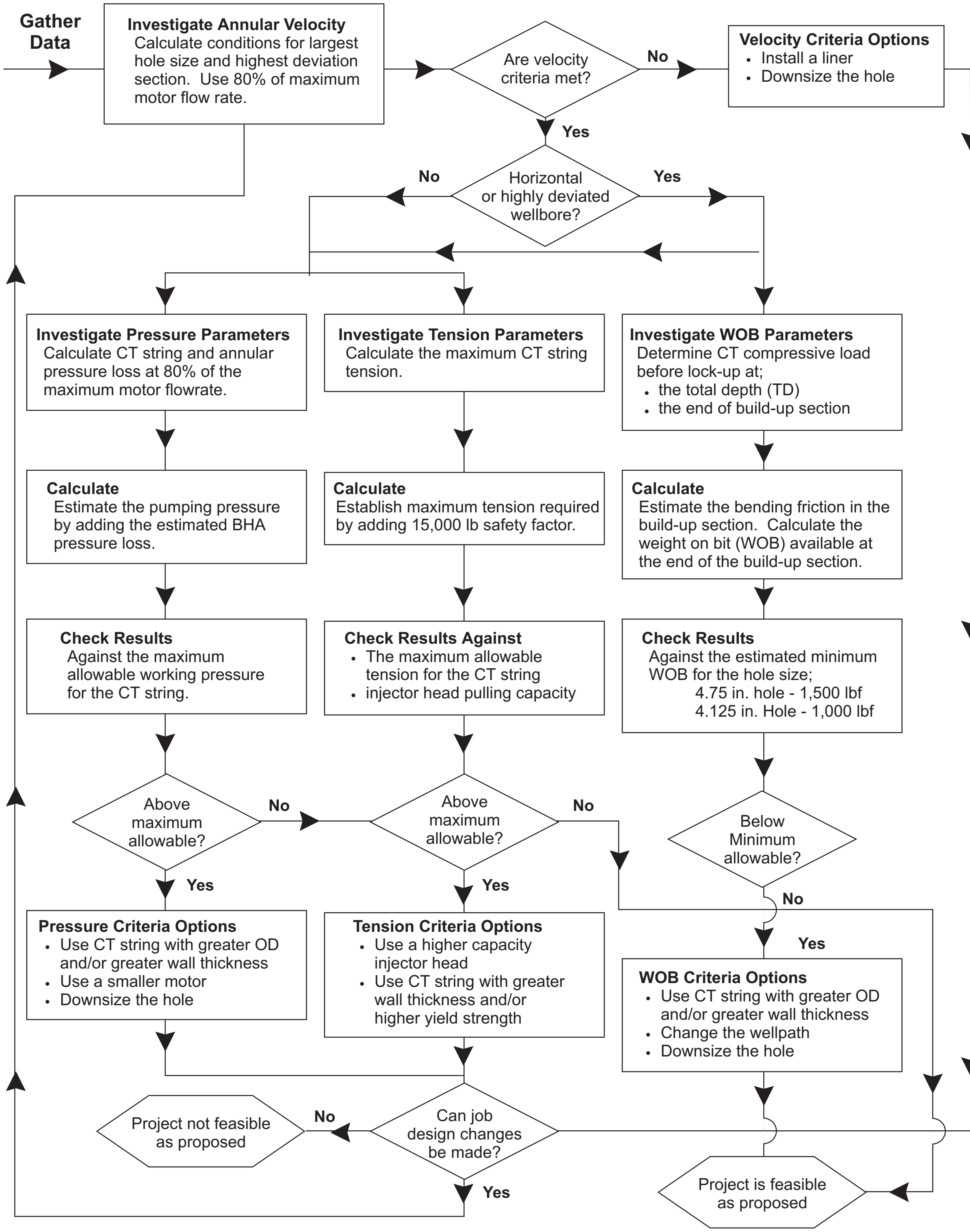
The typical bottom hole assembly is arranged in the following fashion:

CT Connector, CV, Disconnect, Direction and Inclination Package, Orienting device, downhole motor and drill bit.

The economics of drilling operations depend on too many factors to generalize a comparison between CTD and conventional methods. However, once a specific well or project is identified, the planner can develop a cost estimate for each drilling technology and make a meaningful comparison. Section “Planning a CTD Operation” page 15-100 summarizes the process for planning a CTD project.

Technical evaluations are easier to generalize, because a CT simulator can evaluate the effects of different conditions on a proposed CTD operation. Figure 15.3 is a flow chart for evaluating the technical feasibility of a proposed CTD project. Chapter 17 "CT Simulators", page 17-11 describes the data requirements and calculations for each block.

FIGURE 15.3 *Evaluating the Technical Feasibility for CTD*



Bottom Hole Assembly

Since each well profile has its own unique objectives, planning a coiled tubing directional project, prior to the commencement of an actual operation, is probably the most important factor of the project. This stage will help ensure that all the objectives are met with the proper tools selected. Overall, directional drilling is basically drilling a hole from one point in space to another point in space in such a way that the hole can be completed and used for its intended purpose. During this phase the BHA limitation and formation drillability must be considered so achievable targets can be obtained.

A directional drilling BHA for CTD contains the following major components listed from the top down:

1. CT connector—slip or dimple type

2. Emergency disconnect(s)—electric, hydraulic, or mechanical

3. Orientating tool to rotate the bent sub in the desired direction

4. Steering tool

5. Motor with a bent sub

6. Bit

The steering tool measures inclination, azimuth, and tool face orientation. Inclination and azimuth determine the current position of the BHA and tool face orientation indicates which direction the bent sub is pointed. In the configuration above, the steering tool is below the orienting tool so that the steering tool can measure the orientation of the bent sub. In some cases (with electrical steering tools), the steering tool is located above the orienting tool to avoid running electrical conductors through a rotating tool. In this case, a rotating mechanical pin transmits the orientation of components below the orienting tool to the steering tool.

Some of the early BHAs for CTD included a “thruster” to increase the weight on bit for drilling or apply steadier axial force for milling. However, these tools are not commonly used for CTD today.

Drill Collars

Drill collars are stiff tubulars that provide weight and rigidity to the BHA. Drill collars (DC) come in either flush or spiral surfaces. To reduce the wall contact area and minimize the chance of differential sticking, spiral drill collars are preferred in CT drilling. This is due to the lack of rotation in coiled tubing. They also come in a wide range of OD and ID, but generally the OD should be kept consistent with the rest of the BHA.

Non-Magnetic Drill Collars

Non-magnetic drill collars (NMDC) normally have flush surfaces and made from a non-magnetic material. The purpose of NMDC is to reduce the magnetic interference for any downhole surveying tools that measures the earth's magnetic flux. The actual tools are located inside the NMDC and transmit the data to surface via conductors in the coiled tubing, electro-magnetic technology or pressure pulses.

Steering Tools

CTD uses two basic types of steering tools. Electric steering tools transmit the measured data to surface through a cable inside the CT. The CT industry has adapted some of the electric steering tools developed by the conventional directional drilling industry. Mud pulse steering tools transmit the measured data to surface by generating pressure pulses in the mud. These are smaller versions of the pressure pulse systems used in conventional directional drilling. Dowell Schlumberger and Sperry Sun are two companies with mud pulse steering tools. Dowell Schlumberger can package this tool in a 2.375 in. diameter, allowing through tubing drilling with only a 2.75 in. bit.

Orienting Tools

With the inability of coiled tubing to rotate the drilling assembly, the development of an orienter was required. The orienter provides the directional control of the BHA. There are several different types of orienters available that are powered by fluid flow, hydraulic, electrical, pads or articulated joints. All these orienters have good and bad points. With the increased complexity of these tools the reliability of the tools is reduced.

Directional drilling with coiled tubing has some fundamental differences compared conventional rotary drilling. One of the basic differences is the need for an orienting device to control the well trajectory. These devices control the direction by rotating a bent housing to a particular orientation (toolface) or controls the side loading at the bit to push the assembly in a particular direction. The use of stabilizers in bottom hole assembly are typically not used due to the lack of rotation, which increase the chances of hanging up downhole. There are several different types of orienters on the market:

Electrical/Hydraulic with Rotation

Electric/hydraulic orienting tools rotate the lower portion of the BHA using an electrically-powered hydraulic pump and gear train. These tools require an electric cable in the CT. These tools provide bi-directional orientation in increments of ±1º that is independent of mud flow. The tool consists of three main components:

- AC electric drive unit—operates the hydraulic unit
- Hydraulic drive unit—houses the hydraulic pump that supplies pressure to the spiral drive unit
- Spiral drive unit—converts hydraulic pressure to rotation

Another tool design uses a series of DC electrical motors housed in the top section of the tool to drive high-pressure hydraulic pumps, which actuate a splined piston. Advancing this piston acts on the splined output shaft, causing the bottom sub of the tool to rotate. Reversing the direction of the motors pressures the other side of the piston, causing the bottom sub to rotate in the other direction. The bottom sub can rotate ±400º with 1500 ft-lb of torque. The orienting tool is approximately 29 ft long.

Total Electrical with Rotation

There are several different designs for a total electrical orienter that rotates. Typically these systems use a high speed/low torque motor, which is geared down to increase the output torque. These tools provide a means to continuously rotate the bent housing that allows for controlling the tortuosity of the hole. The output torque is in the range of 800 to 1000 ft-lb from a 3" OD tool.

Total Hydraulic with Rotation

Two types of all-hydraulic orienting tools have been developed. One type requires two small-diameter hydraulic control lines (capillaries) inside the CT. Applying hydraulic pressure to one line rotates the tool clockwise, and hydraulic pressure in the other line rotates the tool counter clockwise. Several companies operate their tools on this principal. The two control lines in the CT add significant weight and reduce the available flow area, but this type of tool is simple to operate, reliable, and capable of generating high torque. Both of these companies also use electric steering tools that require an electric cable in the CT string in addition to the control lines. This adds more weight to the string and may limit the use of such systems on offshore applications where crane capacity is a problem.

Another type of hydraulic orienting tool has only one hydraulic control line inside the CT. This type also requires an electric cable. The hydraulic pressure supplies the power to rotate the tool while the electric signal operates solenoid valves that determine the direction of rotation. The disadvantage of this tool is the necessity to stop drilling to orient, but it can orient to any angle. This tool was not very successful and saw only limited use.

Fluid Power with Rotation

Two types of mechanical orienting tools are available. One type uses a “J-slot” mechanism containing a spring-loaded orifice. At high mud flow rate (high pressure loss across the orifice), the orifice moves downwards against the spring. At low mud flow rate, the spring returns the orifice upwards to its resting position. This up and down motion of the orifice mechanism causes the tool to rotate a specific amount. Repeatedly cycling the mud flow rate causes the tool to rotate incrementally to the desired position. Dowell Schlumberger and Sperry Sun use this type of orienting tool with their mud pulse steering tools. This type of system can orient while drilling but has the disadvantage of only being able to orient to certain angles.

Another type of mechanical orienting tool has a lead screw mechanism which causes the lower section of the BHA to rotate when weight is applied to the BHA during periods of no mudflow. Starting the mudflow locks the tool in position. Changing tool orientation necessitates shutting down the mudflow, picking up on the CT to remove the WOB, and then slacking off slowly to achieve the desired rotation of the screw mechanism. When the steering tool data indicate the desired tool orientation has been achieved, starting the mudflow locks the orienting tool. This type of orienting tool works only with an electric steering tool because there is no mudflow for pressure pulse communication during orienting. This type of tool was developed by Ensco and later purchased by Halliburton. The main disadvantage of this tool is the requirement to stop drilling to orient. However, it can rotate to any angle.

The performance of both types of mechanical orientor suffers as the compressibility of the circulating fluid increases. Thus, mechanical orientors are not well-suited for operation with foam or nitrogen.

Reactive Torque

The reactive torque rotational orienter is a device that uses the reactive torque generated from the downhole motor. This orienter is comprised of a hydraulic loop, which is controlled by an internal valve. This valve is controlled from surface through fluid pulses or an electrical conductor. When the valve is opened, fluid is allowed to move through the loop by the torque generated by the motor. The speed of the orientation is controlled by the use of an orifice in the loop that restricts the flow of fluid. When the valve is closed, the toolface is hydraulically locked in place.

This orienter has a very simple design, but there are several limitations that must be considered during the planning phase. One requirement to generate a reactive torque the tool must be on-bottom. Due to the fact that this tool does not generate any output torque, force the toolface into a particular direction will be difficult. Therefore, this tool should only be used in wells with low dog-leg severity.

Powered Articulated Joints

Instead of have a motor with a bent housing and an orienter to rotate the tool to a particular direction, the powered articulated joint combines both these components into one device. The system incorporates several wedges the force the bit into a particular direction. The system is controlled from surface and can be adjusted on the fly. The system is located below the power section of the motor and is powered electrically from system. The use of specially made motors that have conductors imbedded in the outer layers is required. Halliburton developed this system for the Anaconda assembly.

Other BHA Sensors

In addition to the sensors and functions described in the preceding sections, some BHAs for CTD can also be equipped for the following measurements:

- gamma ray—The gamma ray tool is useful for geo-steering, formation evaluation, and depth correlation with previous logs or a radioactive tag in the whipstock.
- casing collar locator—The CCL is for depth correlation.
- accelerations (shock loads)—Accelerometers in a BHA provide good indications of drilling performance, especially motor stalling.
- pressure (internal and annulus)—Annulus pressure measurements are invaluable for controlling ECD in underbalanced drilling.
- WOB—The WOB sensor gives direct feedback to the driller on the effectiveness of slacking off or picking up the CT.

Orienting/Steering Tool Combinations

The orienting and steering tools discussed above are combined in the following ways to produce different types of directional BHAs.

- Fully electric—both the steering tool and orienting tools are electrically operated. This has the advantage of high speed telemetry.
- Mud pulse/mechanical—A mud pulse steering tool is combined with a mechanical orienting tool. This does not require a cable inside the CT. However, the mud pulse tool doesn’t function for underbalanced drilling. This is the type of system BP and Arco have used for CTD at Prudhoe Bay, Alaska.
- Electric/hydraulic from surface—An electric steering tool is combined with a hydraulic orienting tool powered from a hydraulic pump on the surface. These systems require both an electric cable and a hydraulic control line in the CT, but the BHA is simple and reliable. Fracmaster (now BJ) and Transocean used this type of system.
- Electric/hydraulic from BHA—An electric steering tool is combined with a hydraulic orienting tool powered from a hydraulic pump in the BHA. Nowsco (BJ) and BHI use this type of system.
- Electric/mechanical—An electric steering tool is combined with a mechanical orienting tool. These systems don’t need hydraulic control lines in the CT and have high telemetry rate. However, the mechanical orienting tools have the disadvantages mentioned previously.

The following tables give some general specifications for selected CTD BHAs.

TABLE 15.1 *BHA Assembly Matrix*

Manufacturer	**Weatherford**	**Weatherford**	**Sperry-Sun**	**Wenzel**	**HES**	**BHI**	**BHI**	**Antech**	**SLB**	**Weatherford**
BHA Name					Anaconda	OrientXpress	CoilTrak	COLT	Viper	
Size	3" & 4 3/4"	3"	3"	3" & 4 3/4"	3"	3 1/8"	2 3/8"		3"	3"
OT Type	Mechanical Rotation	Mechanical Rotation	Mechanical Rotation	Reactive Tool	Powered Articulated Joint	Electric/ Hydraulic	Electric/ Hydraulic	Total Electric	Total Electric	Mechanical Rotation
Functionality	Gamma Ray Toolface Azimuth Inclination	Gamma Ray Toolface Azimuth Inclination	Gamma Ray Toolface Azimuth Inclination	Gamma Ray Toolface Azimuth Inclination	Resistivity Gamma Ray Toolface Temperature Azimuth Inclination Int.Pressure Ext. Pressure WOB CCL	Resistivity Gamma Ray Toolface Temperature Azimuth Inclination Int.Pressure Ext. Pressure WOB CCL	Gamma Ray Toolface Temperature Azimuth Inclination Int.Pressure Ext.Pressure WOB CCL	Gamma Ray Toolface Temperature Azimuth Inclination Int.Pressure Ext.Pressure WOB	Gamma Ray Toolface Temperature Azimuth Inclination Int.Pressure Ext.Pressure	Gamma Ray Toolface Azimuth Inclination
Power Source for OT	Fluid Powered	Hydraulic at Surface	Hydraulic at Surface	Reactive Torque (wireline on pulse)	Electrical	Electrical	Electrical	Electrical	Electrical	Fluid Powered
Communication	Mud Pulse	Hydraulic at surface	Mud Pulse	Mud Pulse	Electrical	Electrical	Electrical	Electrical	Electrical	Mud Pulse
Hole Size	3 1/2" - 7 7/8"	3 1/2" - 6 1/4"	3 1/2" - 6 1/4"	3 1/2" - 7 7/8"	3 1/2" - 5 7/8"	3 1/2" - 4 3/4"	2 3/4" - 3 1/2"		3 1/2" - 5 7/8"	3 1/2" - 6 1/4"
Environment	OBD	OBD/UBD	OBD	OBD	OBD/UBD	OBD/UBD	OBD/UBD	OBD/UBD	OBD/UBD	OBD

Downhole Motors for CTD

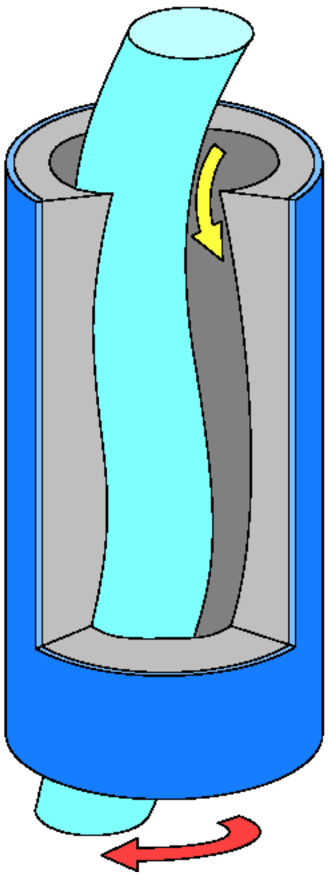
Drilling with CT is very similar to slide drilling with jointed pipe, both require some form of downhole motor. Also, in both cases, the cost of the motor is a significant portion of the total drilling cost. Downhole motors are essentially hydraulic motors powered by the drilling fluid.

The positive displacement motor (PDM) is the most common motor configuration found in CTD. Turbine motors have been used on occasion for CTD. Air hammers or percussion drills are used for certain CTD applications. An electric downhole motor for CTD is an alternative for future consideration.

Progressive Cavity PDM

The progressive cavity PDM uses a helical-shaped rotor that rotates inside an elastomer stator having helical-shaped lobes. Figure 15.4 shows this configuration.

FIGURE 15.4 *Progressive Cavity PDM Configuration*



The dissimilar shapes of the rotor and stator form cavities between the two components. As the power (drilling) fluid forces its way through these cavities, the rotor must rotate. As the rotor turns, a given cavity "travels" along the rotor/stator interface in a helical path. The fluid travelling along this progressive cavity continues to force the rotor to turn.

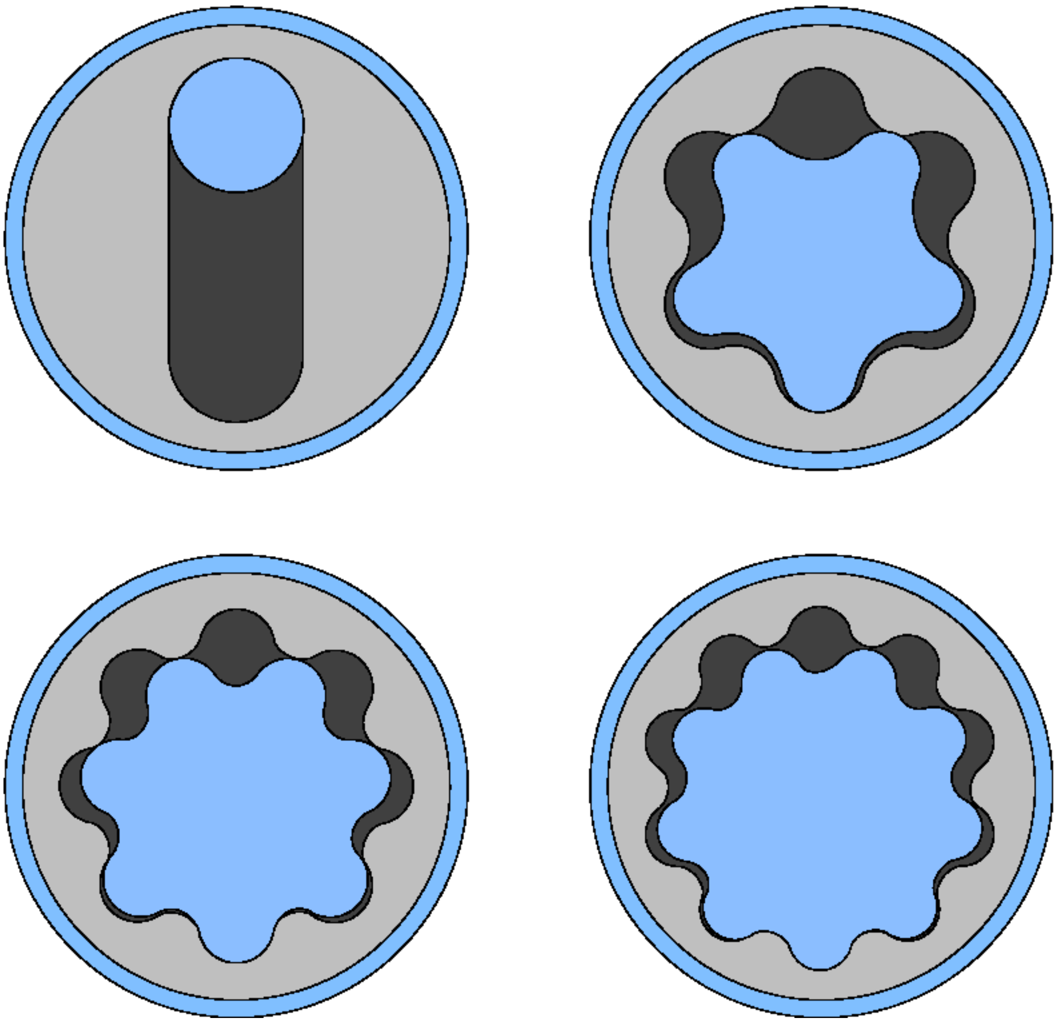
Progressive Cavity PDM Components

The three main components of a progressive cavity PDM are the power section, connecting rod assembly, and bearing assembly.

Power Section

The helical rotor is usually chrome-plated alloy steel. The elastomer stator is bonded to a hollow steel housing. The rotor profile matches that of the stator, but has fewer lobes. Increasing the number of lobes in a motor increases the output torque while lowering the rotating speed (RPM). Figure 15.5 shows different PDM lobe configurations.

FIGURE 15.5 *PDM Lobe Configurations*



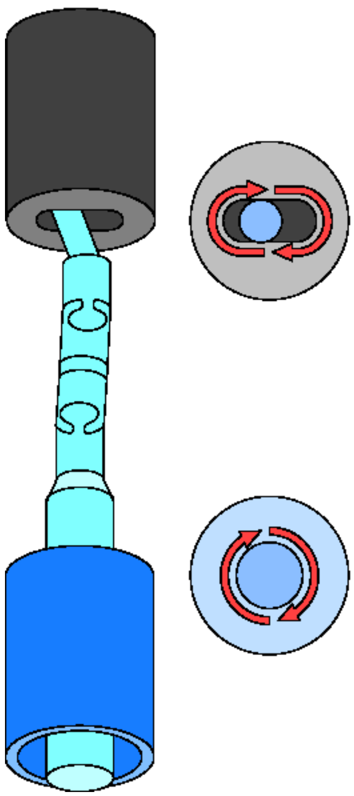
The interference fit between the rotor and stator is supposed to form a continuous seal around the helical line of contact between the two. The efficiency of the motor decreases rapidly as the rotor and stator wear (clearance between them increases). However, motor manufacturers sometimes loosen the fit between the rotor and stator to accommodate higher temperature or swelling of the stator due to certain fluids.

Each complete spiral of the stator is called a stage. The design, configuration and materials used in the power section determine most of the operating specifications for the motor. For example, the lobe configuration determines the operating flow rate and pressure, while the characteristics of the stator elastomer determine the operating temperature and fluid exposure limits. Some elastomers are highly susceptible to gas absorption at high pressure (downhole), and explosively decompress when returned to surface conditions.

Connecting Rod Assembly

The output shaft of the power section rotates with an eccentric motion that must be translated into an axial (concentric) rotation for the bit. The connecting rod, (Figure 15.6) assembly attached to the lower end of the rotor accomplishes this.

FIGURE 15.6 *PDM Connecting Rod Assembly*

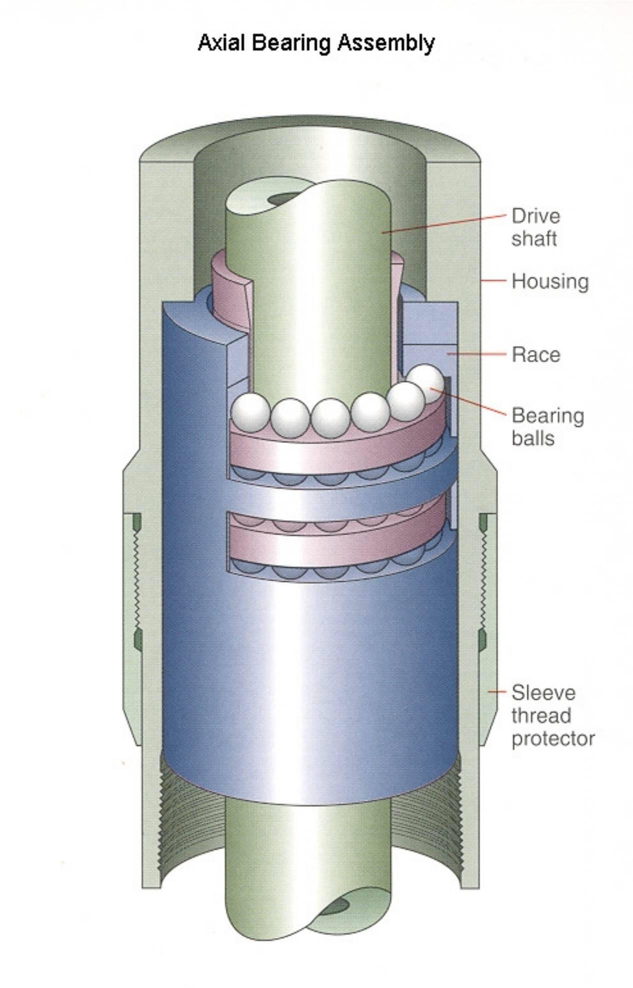


The connecting rod is designed with the necessary flexibility, using universal joints or flexible components, to convert the eccentric rotation into concentric rotation.

Bearing and Drive Shaft Assembly

Radial and axial thrust bearings (Figure 15.7) support the hollow drive shaft within the bearing housing. The bearing assembly transmits force from the motor housing to the drive shaft. Depending on the size and design of the motor, most of the mud flows through the center of the drive shaft to the bit. Some motor designs utilize a small bypass flow of drilling fluid to lubricate and cool the bearing assembly.

FIGURE 15.7 *Typical PDM Bearing Assemblies*



A typical PDM bearing assembly incorporates the following principal components:

- Off-bottom thrust bearings—These provide support for the hydraulic forces acting on the rotor and the weight of components below the rotor, (i.e., rotor, connecting rod, drive shaft and drill bit) when the BHA is hanging off bottom.
- On-bottom thrust bearing—These transmit the drilling load (WOB) from the non-rotating motor housing to the rotating bit box. The off-bottom thrust bearings are either ball bearings or diamond friction bearings.
- Radial support bearings—These provide radial support for the driveshaft and are typically configured as sleeve-type bearings in both upper and lower radial bearing assemblies. Some motors use tungsten carbide-coated sleeves.

Bent-housing Motors

Directional drilling BHAs use bent housing motors to “build angle” or steer a wellpath in a specific direction. A bent housing motor is usually a high-torque, multi-lobe model with the housing (adjacent to the connecting rod assembly) having an offset angle of 0.25° to 1.5°. This tilts the axis of the bit relative to that of the CT string so that the weight of the CT string (WOB) has a lateral component. This forces the bit to drill at an angle relative to the axis of the CT string. Surface-adjustable bent housings (Figure 15.8) enable adjustment of angle from 0° (i.e. equivalent to a straight-housing motor) up to 3°, in small increments.

FIGURE 15.8 *Adjustable Bent Housing Steerable Motor*

The BHI Navi-Drill Mach 1/AD is a bent-housing progressive cavity PDM with elastomer stator designed for directional (or straight) drilling with air, mist, or foam. It is a good example of the motors available for CTD. The Mach 1/AD is available with several different elastomers depending on temperature and fluid requirements. This motor has participated in numerous successful CTD operations.

Drilling Fluid Requirements

Most progressive cavity PDM assemblies can operate reliably with a variety of power fluids (drilling fluid). However, to enable optimum performance and avoid premature failure consider the following:

- The maximum recommended drilling fluid density is 17 ppg.

- Sand content should be less than 1%. Sand content above 5% will reduce motor life by as much as 50%.
- Some elastomers are sensitive to diesel and other aromatic hydrocarbons. Verify that the elastomer is compatible with the drilling fluid.
- Use LCM with caution to avoid damaging the motor bearings or plugging the motor.

Sources for Progressive Cavity PDMs

Progressive cavity PDMs suitable for CTD are available from numerous sources, including:

- Sperry Sun
- Baker Hughes INTEQ
- Drilex
- Weatherford
- Black Max
- Vector Oil Tool (Trudril)
- ANADRILL (for VIPER)
- Smith International

Vaned-rotor PDM

The MacDrill™ motor from Weatherford is a vaned design with stainless steel stator, using elastomers only for O-ring seals around the rotor shaft. This allows the motor to operate at much higher temperature than conventional PDMs. This relatively new entry into the market is designed for operation with clean liquid or gas, comes in four sizes from 1.688 in. to 4.75 in., and has a maximum operating temperature of 600 ºF. The MacDrill motor is designed for straight hole drilling but is short enough to add a bent sub above for directional work. Due to its concentric rotation, this motor does not use a universal joint. The manufacturer claims this reduces vibrations in the BHA and improves both drilling efficiency and MWD signal-to-noise ratio.

Table 15.2 shows the specifications for this type of PDM.

TABLE 15.2 *MacDrill General Specifications*

Tool Size (in)	3.125 in.	4.75 in.
Tool Length (in)	74.4	127.5
Weight (lbs)	112	280

TABLE 15.2 *MacDrill General Specifications*

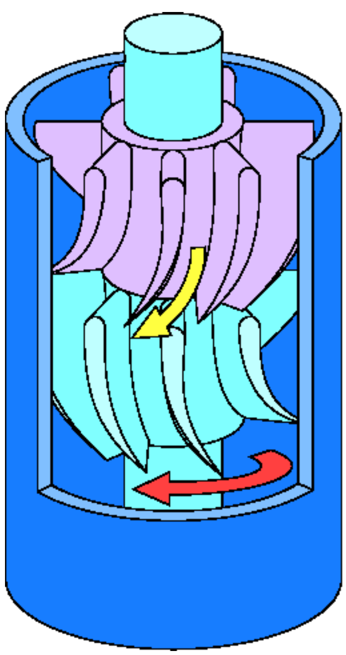
Flow Rate (scfm)	1150	2500
Flow Rate (gpm)	110	250
Operating Pressure (psi)	1200	1200
Bit Speed (rpm)	800	450
Maximum Torque (ft-lbs)	280	1050
Maximum Setdown (lbs)	20,000	46,500
Steerable (AKO sub)	No	No

Turbine Motors

The operating principle of a turbine motor is the reverse action of an axial or centrifugal pump. In order to operate efficiently, turbines require relatively high flow rate and/or many blade sections (long length). This makes them unsuitable for many CTD applications. However, the lack of elastomers in turbine motors makes them ideal for high temperature and gas environments.

Figure 15.9 illustrates the operating principle of a turbine motor.

FIGURE 15.9 *Turbine Operating Principle*



Impact Tools

The most common application for these tools has been drilling and milling cement or scale from production tubing. (see Chapter 5 "Impact Drills", page 5-35 and Chapter 12 "Planning to Remove Scale Mechanically", page 12-57) However, they are gaining acceptance for special drilling applications where the working fluid must be a gas or the operating environment is too extreme for conventional PDMs. Sandia National Labs (SNL) and Los Alamos National Lab (LANL) have occasionally worked on percussion drilling for geothermal applications, but don't have any commercially available hardware. A December 1984 JPT article, "Investigation of Percussion Drills for Geothermal Applications", by J.T. Finger is a good source of background material for these special high temperature motors.

Electric Downhole Motor

In 1995, CTES conducted a study for the Gas Research Institute (GRI) on electric downhole motors. SPE paper 36343, "The Feasibility of Using an Electric Downhole Motor to Drill with Coiled Tubing", by Newman, Stone, and Wolhart discusses the project. A joint industry project conducted by XL Technology, Ltd. has also demonstrated the feasibility of electric CTD.[1] Although an electric downhole motor is feasible, developing a reliable drilling system based on this technology would be a major project.

1. SPE paper 46013, "Electric Coiled-Tubing Drilling: The First Steps Toward a Smart CT Drilling System", by P.F. Head, et. al.

DRILL BITS FOR CTD

The design and construction of a bit is largely dependent on the type of drilling action it provides, i.e., crushing (roller cone bits), tearing, gouging, shearing (drag bits), or some combination of these. While providing an efficient drilling action, bits must also:

- Enable cuttings to be removed from the area beneath the bit
- Create a wellbore ID at least the nominal bit size, throughout the life of the bit, i.e., resist gauge wear
- Connect securely to the motor

To provide these functions, most bits (regardless of specific design) have the following design elements:

- A cutter assembly that provides uniform drilling action within the nominal bit circumference
- Ports and nozzles directing the drilling fluid through the bit and around the bit face to remove cuttings and debris and to cool the cutters and bearings (if equipped with roller cones)
- "Gauge wear protection", i.e., typically hardfacing or hardened inserts to reinforce wear surfaces
- An appropriate tool joint capable of withstanding the axial and torsional forces generated by drilling.

In addition to bits for drilling, bits are also available for milling metals, hard materials and coring. Figure 15.10 shows an assortment of bits for drilling, milling, and coring.

FIGURE 15.10 *Assorted Bits for Drilling, Milling, and Coring*

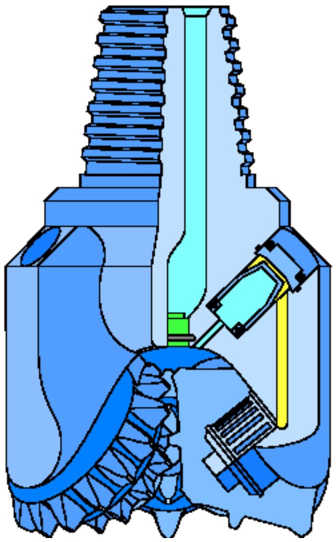
Roller Cone Bits

Roller cone bits can have two or three roller cones, but generally have the latter (tri-cone bits). Each cone is studded with cutters (integral “teeth” or hardened inserts) that contact a portion of the surface beneath the bit. Milled tooth bits generally perform well in soft to medium-hard formations while insert bits are better suited for medium hard to hard formations. The design of the bit ensures that the combination of cutters on all of the cones provides a complete cutting action within the bit circumference. Rotation of the bit rotates the cones causing the individual cutters to press against the rock face with high compressive force. If the WOB is high enough, the cutter crushes the rock and the rolling action of the cone dislodges the crushed rock into the high velocity stream of drilling fluid from the bit nozzles. Replaceable nozzles of extremely hard and wear resistant materials like carbide protect the bit body from erosion by the drilling fluid. The nozzles are available in a variety of sizes to optimize the hydraulic force available at the jets. Journal or roller bearings attach the cones to the bit body and are lubricated from sealed lubricant reservoirs within the bit body or by the drilling fluid. Roller bearing bits are designed for higher speeds and typically come in sizes larger than 6 in. OD.

Milled-Tooth Bits

The cutters on milled-tooth bits (Figure 15.11) are milled as an integral part of the cone. The length of the teeth depends on the target formation hardness - the softer the formation, the longer the tooth. Milled tooth bits drill by cutting, tearing, and gouging the formation material. The most common use for this type of bit is in relatively soft, shallow sections of a well.

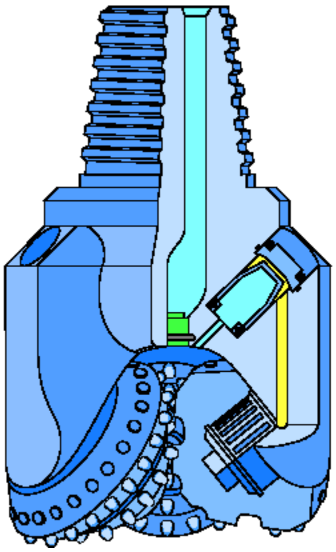
FIGURE 15.11 *Milled-tooth Bit*



Insert Bits

The roller cones on insert bits (Figure 15.12) are fitted with relatively blunt button inserts, i.e., bullet-nose or wedge-shaped, made from very hard materials that act to crush the formation. The material and configuration of the button insert depends on the characteristics of the target formation.

FIGURE 15.12 *Insert Bit Cutter Options*



Fixed Cutter Bits

Fixed cutter bits have a simpler construction than roller cone bits. The cutting components of fixed cutter bits are embedded in the face of the bit, which means that they contain no moving parts. The cutting action of this bit design is a shearing or scraping of the rock face as the cutter drags across it. These bits are most suitable for hard formations and materials. Three basic types of fixed cutter bit are commonly available:

- Diamond rock bits—Industrial diamonds are embedded into the face of the bit in a special matrix incorporating fluid channels for the drilling fluid. The cutting action of diamond bits is typically suited to drilling medium to hard formations because the small cutters remove relatively small amounts of material with each pass.
- PDC—Polycrystalline Diamond Compact bits (Figure 15.13) are similar to diamond bits. The PDC cutters are typically larger than those on diamond bits, making PDC bits suitable for soft to medium-hard formations.
- TSP—Thermally Stable Polycrystalline bits (Figure 15.14) have cutters similar to those on PDC bits, but they are smaller and more heat resistant. This makes a TSP bit suitable for hard formations.

FIGURE 15.13 *PDC Bit*

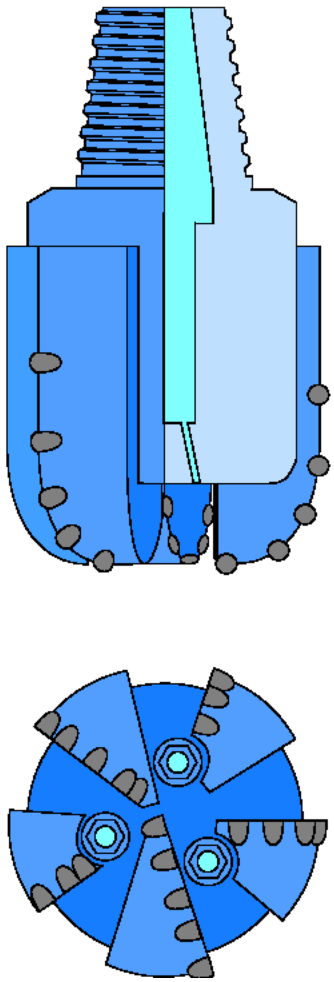
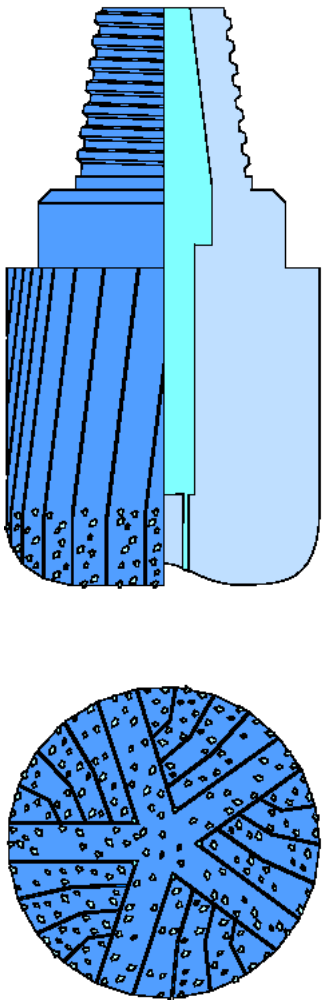


FIGURE 15.14 *TSP Bit*



Fixed cutter bits are generally not as robust as roller cone bits and are easily damaged by metal at the drilling face. This makes them more sensitive to junk in the wellbore. Since fixed cutter bits drill by shearing the rock face, controlling the WOB is essential to avoid damaging the bit face and dislodging the embedded cutting elements. Fixed cutter bits operate more efficiently with less WOB than roller cone bits but are more sensitive to rate of rotation. Having no moving parts, the fixed cutter bits can generally operate at higher rotary speeds than roller cone bits for extended periods of time.

Drilling Bit Selection

The best indicator of how a bit will perform under given conditions is from bit records of offset wells or similar conditions. This is another good reason for keeping detailed and accurate records throughout a CTD operation. Key issues relating to the bit selection generally include the following.

- Size—The engineer planning a CTD project generally identifies the required bit sizes early in the process based on the intended completion size and presence of wellbore restrictions. Special bi-center bits allow drilling a hole with a larger diameter than the hole section above it. The selection of roller cone bits available decreases with decreasing hole size.
- Cutter configuration—The cutter type, size, and configuration determine the bit's compatibility with the target formation and its tolerance to junk or debris that may be present in the wellbore.
- Operating speed (RPM)—Bits and motors usually operate most efficiently within relatively narrow range of rotational speed. In general terms, roller cone bits operate at lower speeds than fixed cutter bits
- Gauge protection—Bits wear in two principal areas, the cutter surfaces (resulting in slower ROP), and the bit circumference (resulting in an under-gauge hole).
- Formation type, hardness, and abrasiveness
- Motor torque—In general roller cone bits have the lowest torque requirements while PDC bits have the highest.
- Available WOB—In general roller cone bits require high WOB, while PDC bits drill efficiently with low WOB.
- Drilling fluid type and flow rate

The fundamentals of bit design and selection apply equally to CTD and conventional rotary drilling. However, CTD generally uses higher bit speeds at lower WOB. Always seek recommendations from the bit supplier for bits suitable for the specific conditions expected during a CTD project.

CTD RIG SYSTEMS

CTD technology has evolved rapidly in the last five years, especially in the equipment area. For the first few years, CTD equipment consisted of conventional CT units combined with some additional equipment to support the drilling process. CT service companies tried to minimize the risk associated with testing a new technology. As the demand for CTD services grew and the technology evolved, the CT service companies have invested more in specialized drilling equipment. These additions include specialized mud systems, substructures, snubbing/casing jack systems, and masts for handling jointed pipe. The following sections trace the evolution of CTD rig systems beyond the use of conventional workover CT units.

Hybrid CTD Units

Hybrid CTD units combine a CT unit with a mast, casing jacks, or a snubbing system for handling jointed pipe. Generally, these units are a compromise between competing requirements for ease of mobilization, drilling functionality, and low cost. In most cases, they are capable of functioning independently from a conventional drilling or workover rig. This makes them more efficient than a conventional CT unit for handling jointed pipe, but they still use a downhole motor for all of the drilling. Thus, a hybrid CTD rig doesn't have any advantage over a conventional CT unit when the BHA is in the wellbore. The choice of hybrid CTD unit for a specific drilling job is no different than choosing from a group of conventional drilling rigs. The choice depends on many factors including equipment availability in the area, the selection of service company, logistics, and location size.

Units with Casing Jack Systems

The earliest modification to conventional CT units to make them more suitable for drilling was a heavy-duty frame that could support the injector and a set of slips for holding jointed pipe. This frame is usually a modified casing or snubbing jack. Sometimes the frame includes a light crane for handling BHA components and tongs for making and breaking connections on jointed pipe. Figure 15.15 shows a typical example of such a unit. These systems have been and continue to be used successfully for all types of CTD projects.

FIGURE 15.15 *Hybrid CTD Unit in Oman (Dowell)*

The purpose of the jacking system and slips is to run or pull jointed pipe. These allow such a hybrid CT unit to operate independently of workover or drilling rigs for casing sizes up to about 7 in. However, jointed pipe operations are much slower with such a hybrid because they don't have an integral mast with traveling block. The stroke length and speed of the jacking frame limits the vertical travel of the pipe. The operating limit for a casing jack unit is simply the weight of casing it will safely support.

Fixed Mast Units

Considering the shortcomings of the hybrid CTD units with jacking frames, adding a mast to an otherwise conventional CT unit was a natural way to gain more of the surface operations capability of a rotary drilling or workover rig. One approach to this objective is an injector mounted on a platform under a fixed mast. Figure 15.16 shows a hybrid CTD unit with a fixed mast supported on a substructure of individual stacking modules. This massive structure erected much like a conventional rotary drilling rig. Nowsco used this unit for CTD operations in Europe and similar units for CTD in Canada. The heavy-duty mast and draw works were rated for 200,000 lbs.

FIGURE 15.16 *Nowsco Germany CTD Rig Elevation View*

Figure 15.17 shows the injector supported under the mast on an adjustable frame. The frame could move vertically on the screw jacks to adjust for different BOP stacks and horizontally on rails to clear the wellhead for jointed pipe operations with the draw works. A work platform below the injector level gave the crew access to the lubricator between the BOP and the CT stripper. This hybrid CT unit had about the same operating capabilities as the self-erecting mast units described below, but required a separate crane to rig up or down. This increased the time and cost for these functions. However, this fixed mast rig could fit on a smaller location than comparable self-erecting mast rigs because the substructure modules occupied less surface area than a trailer.

FIGURE 15.17 *Nowsco Germany CTD Rig Injector Stand*

Self-Erecting Mast Units

Fracmaster (now BJ)

Fracmaster improved on the fixed mast unit described above with a self-erecting mast design that combined features of CT units and workover rigs into a self-contained hybrid CTD rig. Their design had a much larger mast (80 ft crown height) with heavy duty draw works mounted on a trailer that links with another trailer containing the CT reel. The two trailers combined to form a complete drilling rig with a “footprint” of approximately 10 ft x 95 ft. A third trailer contained the power pack and operator’s control cabin. Figure 15.18 through Figure 15.20 show different views of this large hybrid CTD rig with its self-erecting mast. This rig ceased operations in 1999.

FIGURE 15.18 *Fracmaster CTD Rig Mast and Injector Stand*

FIGURE 15.19 *Fracmaster CTD Rig Reel Trailer*

FIGURE 15.20 *Fracmaster CTD Rig*

Fracmaster mounted the injector on a heavy-duty platform that doubled as a work floor with slips and power tongs. The injector could move horizontally on the support frame to a position over the wellhead for CT operations or to a "parking" position away from the base of the mast so the crew could use the draw works to handle the BHA or jointed pipe. The work floor/support frame collapsed for transport. The special injector on this rig could pull up to 120,000 lbs, and the draw works capacity was 150,000 lbs. The reel had the capacity for approximately 10,200 ft of the 2.875 in. CT Fracmaster used for most of its CTD operations.

The Fracmaster CTD rig was suitable for the type of reentry drilling required over much of the Canadian oil and gas fields where location size and logistics are usually not problems. However, it could not operate on tight locations or where overhead space was limited. This illustrates one of the dilemmas facing CTD service companies, how to efficiently combine CT technology and drilling hardware in a package that retains the best attributes of each. On one hand, standard CT units offer compact size, portability, and the capability to safely and efficiently operate in live wells. On the other hand, drilling and completion operations require substantial surface equipment for handling heavy pipe strings and processing large fluid volumes. The challenge for the CTD service company is to strike a balance between competing objectives to meet its customer's needs.

Nowsco (BJ)

Nowsco (BJ) in Canada introduced their own self-erecting mast CTD rig in 1998 that closely resembles the Fracmaster rig in form and function. The primary purpose of the short mast is to handle the drilling BHA. Figure 15.21 through Figure 15.25 show the Nowsco CTD Rig #2.

FIGURE 15.21 *Nowsco CTD Rig #2 in Transport Mode (BJ)*

FIGURE 15.22 *Nowsco CTD Rig #2 Erecting the Mast (BJ)*

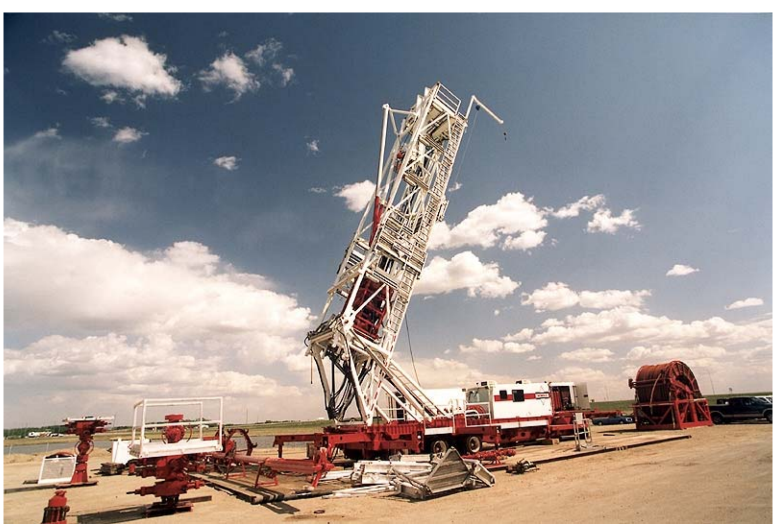


FIGURE 15.23

FIGURE 15.24 *Nowsco CTD Rig #2 Control Room (BJ)*

FIGURE 15.25 *NOWSCO CTD Rig #2 (BJ)*

Heartland Rig International (HRI) CISCO CT Drilling Unit

HRI designed the CISCO to optimize mob/demob operations and handling of both CT and jointed pipe for relatively shallow (less than 3000 ft) CTD operations. The objective was to minimize the unproductive (non-drilling) time for such projects where actual drilling time is relatively short. The product of their development project with Fleet Coil Technology (now Plains Energy) in Canada is a package of six trailer-mounted modules providing the following functions:

- CT unit based on the friction wheel/injector design
- Automated jointed pipe handling system
- Control cabin, water tank, tool room, and hydraulic power pack
- Mud tank, mixing shack, and choke manifold
- Mud pump and air compressor
- Dry storage, BOP accumulators, generator, crew accommodations

Figure 15.26 through Figure 15.28 show the layout and features of this unique CTD rig. During 1997 and 1998, Plains Energy drilled more than 320 wells with this rig at depths averaging 2460 ft and has been able to move onto location, rig up, drill to 1476 ft, install and cement casing, rig down, and move to the next job in only 6 hours. The average ROP for these wells is approximately 870 ft/hr.

FIGURE 15.26 *CISCO Rig - CTD Mode (HRI)*

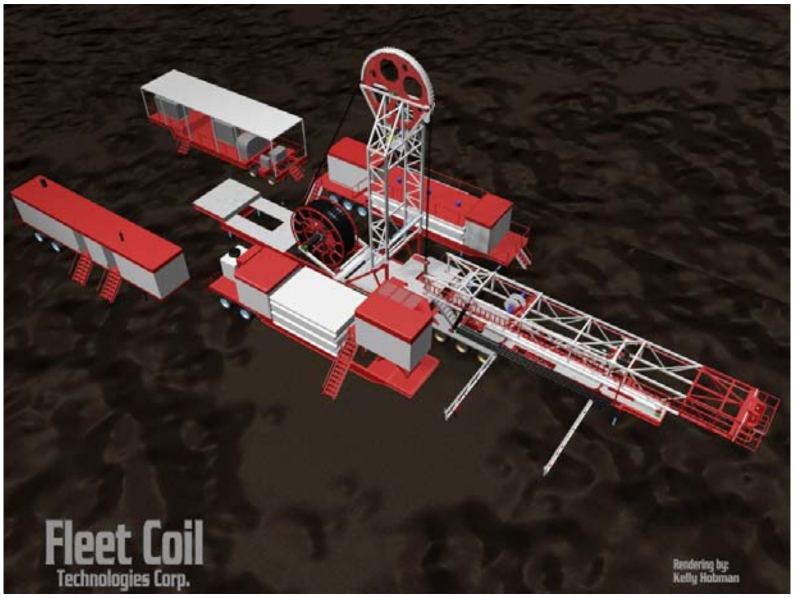


FIGURE 15.27 *CISCO Rig - Casing Handler Mode (HRI)*

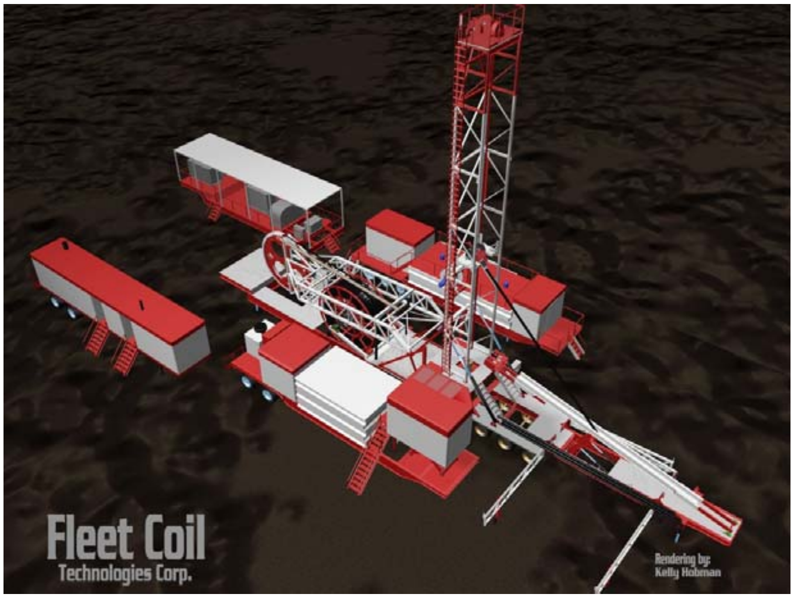


FIGURE 15.28 *CISCO Rig on a Parking Lot in Calgary, Alberta (HRI)*

The following tables give the specifications of the CISCO CTD rig system.

TABLE 15.3 *Coiled Tubing Unit*

Trailer Dimensions – 16 Wheeler	54 ft-8 in x 12 ft
Work Reel Capacity – 2.875 in coiled tubing	4920 ft
Work Reel Capacity – 2.375 in coiled tubing	7875 ft
Work Reel Diameter	12 ft
Spooling Force	15,000 lbf
Injector Reel Diameter	12 ft
Injector Pull Capacity	60,000 lbf
Injector Speed	100 ft/min
Winch Rating	8000 lbf
Lubricator Winch Rating	8000 lbf
Ground clearance for highway moves	12 in
Ground clearance while drilling	24 in

TABLE 15.4 *Casing Handler / Catwalk / Substructure*

Trailer Dimensions – Tri-axle	48 ft x 10 ft
Lift Capacity	100,000 lbf
Joint Length Capacity	46 ft
Travelling Speed	400 ft/min
Top Drive Maximum Make-Up Torque	5000 ft-lbf
Rotating Speed Range	0–120 rpm
Swivel Range From Vertical	85°
Pin Connection	3.5 in I.F.
Sub-Floor Rating *(note: BOP hanger for transport)*	100,000 lbf
Working Floor Dimensions	10 ft x 10 ft
BOPs and Handling Tools: • 7.063 in Annular Preventer • 2 x 7.063 in Single Gate Ram Preventers • Power tongs • Air slips • Elevators and bails if needed • Pac-man pipe indexer • Telescoping pipe cradle	

TABLE 15.5 *Control Cabin /Water Tank / Tool Room / Hydraulic Power Pack*

Trailer Dimensions - Tandem	50 ft x 8 ft-6 in
Diesel Fuel Capacity	250 gal
Water Tank Capacity	200 bbls
Water Tank Capacity While Moving	100 bbls
Hydraulic Power Pack Rating	300 hp
Tool Room Features: • Repair facility with oil storage tanks and cabinets • Working bench with vice, tool board	
Control Cabin Features: • Telescoping vertically • Control panel for drilling and casing running device • Main lockout system for hydraulic functions for all operations • Remote BOP operating device • Data acquisition	

TABLE 15.6 *Mud Tank / Mixing Shack / Choke Manifold*

Trailer Dimensions – Tri-axle	50 ft-4 in x 10 ft
Shaker Tank Capacity	104 bbls
Settling Tank Capacity	96 bbls
Suction Tank Capacity	96 bbls
Trip Tank Capacity	20 bbls
Mud Tank Features: • 7.5 hp electric agitators (3) • Volume level indicators • Poor-boy degasser mounted in shaker tank • Mixing/manifold shack (10 ft x 15 ft) • 50 hp electric mixing motor c/w 4 in x 5 in mixing pump and mixing hopper • 50 hp electric 5 in x 6 in supercharger	
DFTS 3-Screen 8G Linear Motion Shaker	
3 in x 2 in Flanged Choke Manifold Rating	3000 psi

TABLE 15.7 *Mud Pump / Air Compressor*

Trailer Dimensions – 16-Wheeler	46 ft x 12 ft
Diesel Fuel Capacity	1500 gal
Wh-1000-B Ellis Williams Triplex Mud Pump with 10-in stroke	1000 hp
Liner Sizes	4 in, 5 in
3512 Caterpillar Engine with Chain Case Drive to Pump	
Air Compressor Pressure Rating	2500 psi
Air Compressor Storage Volume	6000 scf

TABLE 15.8 *Dry Van / Accumulator Shack / Generator / Change Shack / Boiler*

Trailer Dimensions - Tandem	48 ft x 8 ft-6 in
Diesel Fuel Capacity	1200 gal
Diesel Generator Rating (60 Series Detroit Diesel c/w Stamford Generator)	300 kW
Type 80, 8 Bottle Accumulator c/w 2 Nitrogen Bottles	80 gal
Boiler Rating	80 hp
Change Room with 10 Lockers for Crew	

Arctic CT Unit + Workover Rig

Arco has conducted most of its through tubing CTD jobs in Alaska with equipment similar to that shown in Figure 15.29. The CT unit is essentially a standard arctic workover unit with a mast and cantilever for supporting the injector head over the well house. The workover rig can be used for light-duty rotary drilling, but is normally used for pulling and running completions and other well workover operations. For drilling with CT, the injector is positioned alongside the rig's derrick over the rotary table. The derrick's function is to handle the BHA and to pull or run any jointed pipe. This combination of equipment and functions could easily be adapted to other CTD operations on land.

FIGURE 15.29 *Arco CTD Rig Elevation View*

BP/Schlumberger Nordic Rig

The Nordic Rig began its operating career as a self-propelled, heavy-duty arctic workover rig working for Arco at Prudhoe Bay. The fully self-contained rig can move from location to location under its own power. BP acquired the rig and with assistance from Schlumberger, added a CT unit so that the Nordic could be a self-contained CTD system. Figure 15.30 shows an elevation view of this rig, with the orange CT unit cantilevered out from the right side. Figure 15.31 shows the Nordic in operating position over a well house. The control room combines the controls for CT operations with those for standard rig operations (pumping, draw works, rotary table, etc.), Figure 15.32 and Figure 15.33 respectively. Figure 15.34 shows a view over the CT reel from the vantage point of the CT operations control console. This rig concept is adaptable to other land drilling operations where a large number of wells are clustered in a relatively small area. However, the cost of such equipment might not be justifiable in less harsh operating environments.

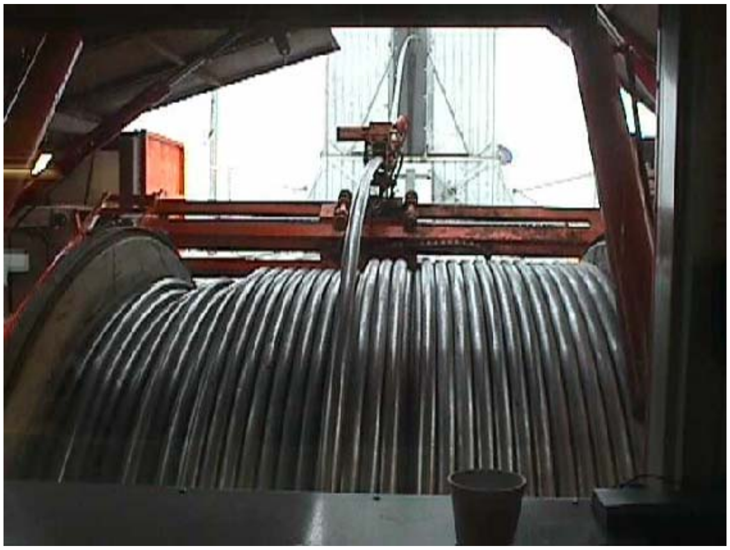
FIGURE 15.30 *Nordic Rig Elevation View (BP)*

FIGURE 15.31 *Nordic Rig Positioned Over a Well House (BP)*

FIGURE 15.32 *Nordic Rig Control Room, CT Operations*

FIGURE 15.33 *Nordic Rig Control Room, Rig Operations*

FIGURE 15.34 *Nordic Rig CT Reel, Looking Towards the Derrick*



Transocean CDR #1, “Chameleon”

Transocean’s first hybrid CTD rig, CDR #1 or *Chameleon*, was a trailer mounted, self-erecting mast unit resembling the Fracmaster rig. However, the unique arrangement of oversize reel and injector on *Chameleon* is a radical departure from the other hybrids described above. Figure 15.35 through Figure 15.37 show the 15 ft diameter reel positioned directly over the Hydra Rig HR480 injector. This direct feed arrangement eliminates the guide arch to reduce CT fatigue and increase the working life of the CT string. (see Chapter 9 "Minimizing CT Fatigue", page 9-20)

FIGURE 15.35 *Transocean CDR #1 Elevation View in Canada*

FIGURE 15.36 *Transocean CDR #1 Reel & Injector*

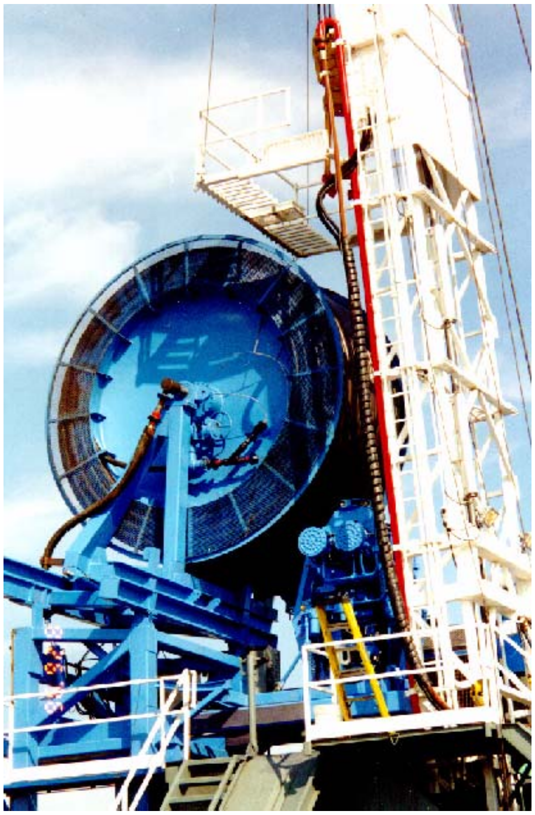


FIGURE 15.37 *Transocean CDR #1 Reel and Injector Closeup*

The injector is mounted on a moveable platform between the two box frame legs of the mast. The platform can move horizontally to position the injector over the wellbore or retract it out of the way. The reel translates from side to side on its axis of rotation to keep the CT wound uniformly and tilts towards or away from the injector to keep the CT on the axis of the injector chains. The reel has a core diameter of 122 in. and width between flanges of 84 in. giving it a maximum capacity of 11,000 ft of 2.875 in. CT. However, Transocean tested the *Chameleon* with a special string of 3.25 in. CT in Canada in 1997.

Transocean teamed up with Nabors drilling to modify CDR #1 for arctic operations and moved the rig to Prudhoe Bay to drill for Arco. Figure 15.38 shows the rig in operation at Prudhoe Bay in the summer of 1998. Figure 15.39 shows the unique control console for this rig designed and built by Hitec. The futuristic-looking operator’s chair contains all of the controls to operate the rig.

FIGURE 15.38 *Transocean/Nabors Rig at Prudhoe Bay, Alaska*

FIGURE 15.39 *Transocean/Nabors Rig Control Console by Hitec*

Purpose-Built CTD Rigs

The first two purpose-built CTD rigs that use a single device for moving jointed and continuous pipe became operational in 1996. These fully integrated, modular rigs look nothing like a conventional CT unit for well servicing, and they are quite different from each other. However, BHI designed both to perform all drilling and completion operations independently of other rigs or support equipment with efficiency not possible with conventional CT units or hybrid CTD rigs.

BHI designed *Copernicus* for the high-cost offshore market, primarily in the North Sea, where drilling loads might be supported either by the well's jacket or the surrounding platform. For its initial field trial, this rig performed the first CTD project in the Gulf of Mexico.[2] Unfortunately, this project was not very successful and Baker Hughes INTEQ retired *Copernicus* from service.

BHI designed *Galileo 1* for the low-cost land market and *Galileo 2* for drilling from a barge on Lake Maracaibo. Their substructure and mast are fundamentally different from *Copernicus* and distribute drilling loads over a fairly large area. Consequently, the *Galileo* rigs are not well suited for installation on most offshore platforms.

2. Young, L.M., Burge, P.M., and Johnson, C.A, "Fit for Purpose Reeled Systems: A Case History", SPE/IADC paper 37653, 1997 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 4-6, 1997

All three modular rigs could perform the following tasks:

1. pull existing production tubing

2. drill vertical and directional wells using CT and jointed pipe

3. run and cement liners and casing

4. run jointed pipe and CT completions

5. drill underbalanced with gasified fluids, foam, or air

6. deploy BHA's into live wells

7. pull and run BHA's or jointed pipe with the injector over the wellhead

Due to a sophisticated process control system on each rig and specially trained operating personnel, BHI can reduce the manpower required for a typical drilling project. The designated operating crew for each rig consists of four specialists and a wellsite manager, the person responsible for execution of the drilling program. Each specialist is responsible for one of the following areas:

1. Downhole operations including drilling, milling, window cutting, fishing, and surveying

2. CT surface operations

3. Fluids and solids processing, cementing, and control of the underbalanced fluids module

4. Maintenance and repair of all rig modules

BHI "Copernicus"

Figure 15.40 shows the modular CTD rig system, *Copernicus*, built by Hydra Rig, Texas Oil Tools (TOT), and Dreco. The following sections describe some of the innovative features of this system.

FIGURE 15.40 *Elevation View of Copernicus*

Pipe and Tubing Handling

The prime mover for CT and jointed pipe up to 7.625 in. diameter was a modified Hydra Rig HR480 injector mounted under the rig floor. This arrangement made pipe handling equipment and tongs more accessible on the rig floor. The injector had a continuous pulling capacity of 100,000 lbs (closed loop mode) and a snubbing capacity of 40,000 lbs. The injector chains could separate to a bore of 12 in. This allowed deployment of the BHA or other large objects through the injector.

For greater lifting and snubbing capacity, *Copernicus* included a dual cylinder jacking system with a 10 ft stroke, a pulling capacity of 300,000 lbs, and a snubbing capacity of 130,000 lbs. This system contained two stationary and two traveling slip bowls. Both sets of bowls were split to provide a minimum open bore of 12 in. The working platform contained a passive (not motorized) rotary table to assist with orienting tubing strings.

Substructure

Stackable modules allowed the substructure to adapt to any BOP stack and riser height from conventional overbalanced operations to underbalanced drilling on land and offshore.

CT Guidance System

CTES helped design the special 15 ft radius guide arch system shown in Figure 15.41. This system could improve the CT working life by 30% over that due to more typical guide arch radii. (see Chapter 9 "CT Fatigue", page 9-5)

FIGURE 15.41 *Copernicus Guide Arch*

CT Reel

The unique reel had a 96 in. core diameter, 98 in. width between flanges, and the capacity for 13,120 ft of 2.375 in. CT. The reel drive, braking, and tension system was electronically controlled. All plumbing on the reel was rated for 10,000 psi and H_2S service.

Well Control and BHA Deployment

The TOT “Sidewinder” CT stripper, 7.06 in. combi BOP, and 7.06 in. shear/blind safety head were rated for 10,000 psi and H_2S service. These formed the drilling BOP and combined with the 5000 psi annular BOP and pipe handling system to form the BHA deployment system for underbalanced operations.

Conventional Fluids Handling

This modular tank and piping system was adaptable to a variety of applications and included solids control equipment, pumps, cement and fluids mixing tanks, and bulk storage. A high-capacity linear motion shale shaker, variable speed centrifuge, and degasser module were the primary solids control equipment. The fluids processing tank modules had 200 ft^3 capacity and could be plumbed together to achieve the necessary total volume. The twin diesel-powered triplex pumps were rated at 300 BHP (270 HHP) continuous output.

Underbalanced Fluids Handling

This module, rated for 50 psi pressure, consisted of a four-phase separator, water surge tank, and oil surge tank. The separator had the capacity for 3000 scfm of injected gas, 250 gpm of drilling fluid, and 9 ft^3/hr of drill solids.

Power Module

Two diesel engine pump skids of 550 BHP each and a diesel engine hydraulic power pack of 500 BHP were the prime movers for *Copernicus*. Other power units could be added if necessary.

Downhole Tools

The downhole tools module contained the directional drilling, MWD, orienting, window cutting, and fishing tools plus the jointed drill pipe and collars.

Process Control Cabin

Figure 15.42 shows a view of the sophisticated process control system console for *Copernicus*. The unique computerized control system was an adaptation of the process logic control (PLC) commonly used by electrical generating plants, refineries, and many automated factory assembly lines. Virtually all communication with the other modules, prime movers, and controllers throughout the system was through the touch-screen consoles. These screens also displayed all of the operating parameters and alarm conditions for the other *Copernicus* modules.

FIGURE 15.42 *Copernicus Control Console*

Besides standard control functions normally found on a CT unit or drilling rig, the system provided a number of automated control functions. These included:

1. Speed and direction with force limits—allowed the injector to run at a specific speed and direction regardless of variations in the load up to the selected force limit.

2. Injector and reel coordination—automatically maintained proper tension between the reel and injector for proper spooling of the CT.

3. Operator override—prevented the operator from manually exceeding the pre-selected stress limits for the CT.

4. Depth pre-select—used in conjunction with (1), it allowed the system to automatically RIH or POOH at maximum safe speed to a predetermined depth.

5. Injector lubrication—automatically lubricated the injector based on footage of CT run.

6. BOP ram position pre-select—allowed the operator to program the position that each set of BOP rams would move to if activated.

7. Injector traction pressure—automatically adjusted traction pressure for CT size, direction of movement, and required force.

8. Chain tension—automatically adjusted chain tension according to the CT size, direction of movement and required force.

9. Weight on bit (WOB) control—based on feedback from sensors in the BHA, this allowed the system to maintain a WOB set by the operator.

BHI “Galileo 1”

Galileo 1 is fundamentally different from *Copernicus* in that BHI designed the injector head and mast to handle both CT and jointed pipe without the aid of a jacking system. The configuration shown in Figure 15.43 includes a two piece telescoping mast on a self-erecting “slingshot” substructure. The modified Hydra Rig HR 5200 injector can grip 2-7.625 in. OD pipe and pull/push with 200,000/100,000 lbs. The injector chains can retract to expand the injector bore to 12 in. For handling BHA components and jointed pipe, the injector can be locked in place at either of two elevations in the mast. The injector grips a length of stiff pipe with a swivel and hook mounted on the lower end. By moving the pipe up and down, the injector performs the function of a traveling block. A non-rotating slip bowl in the rig floor is used to grip the pipe or BHA components inserted in the well. Figure 15.44 shows the control console for *Galileo 1*. The process control system is similar to that on Copernicus.

FIGURE 15.43 *Galileo 1 Elevation Views (BHI)*

FIGURE 15.44 *Galileo 1 Control Console (BHI)*

BHI "Galileo 2"

The two piece telescoping mast and HR 5200 injector head for *Galileo 2* are the same as for its predecessor, but the resemblance ends there. Figure 15.45 shows the rig mounted on its special barge for operations on Lake Maracaibo, Venezuela. Moreover, *Galileo 2* uses a unique freestanding arch system for minimizing fatigue damage to the CT (see Chapter 9 "Minimizing CT Fatigue", page 9-20). The arch of CT is faintly visible in Figure 15.45 as a dark parabola extending from the injector on the left side of the picture. Figure 15.46 shows the reel and injector during testing of the freestanding arch system at Hydra Rig. The level wind on the giant reel has a small injector head for controlling the back tension on the reel and the amount of tubing in the arch. The *Galileo 2* control system coordinates the speed of the two injectors to maintain the desired arch configuration. Figure 15.47 shows the giant reel with the small injector removed from the level wind.

FIGURE 15.45 *Galileo 2 Mounted on a Barge on Lake Marcaibo (BHI)*

FIGURE 15.46 *Galileo 2 Reel, Injector, and Free-Standing CT Arch (BHI)*

FIGURE 15.47 *Galileo 2 Reel (BHI)*

BHI "Galileo 3"

The purpose-built "Galileo 3" is the land equivalent of the "Galileo 2" described above. Figure 15.48 shows this rig operating in Oman.

FIGURE 15.48 *Galileo 3 in Oman (BHI)*

DRILLING FLUIDS AND WELLBORE HYDRAULICS

The drilling fluid, or mud, is a crucial component in the success of any drilling operation. As the drive for efficient drilling techniques continues, the optimization of the drilling fluid and associated hydraulics becomes even more important. In CTD operations, the geometry of the CT string and the configuration of wellbores typically drilled present many challenges to drilling fluid performance. However, the unique features associated with CT equipment and related pressure control equipment simplifies many of the requirements of the drilling fluid and the circulation system.

The basic functions of conventional drilling fluids are:

- Cuttings transport—removing cuttings and drilling debris from the wellbore
- Cooling and lubrication of the bit and motor
- Well control—for overbalanced drilling, prevent influx of reservoir fluids
- Wellbore stability—prevent wellbore swelling and sloughing
- Buoyancy for the CT string
- Transmitting hydraulic power to the downhole motor and tools
- Optimizing penetration rate

In rotary drilling, the fluid must be capable of supporting the cuttings during periods of no circulation for drillpipe connections. Interruptions to circulation are much less frequent in CTD and usually much shorter, e.g., to recover from motor stall.

For directional drilling with jointed pipe, the pipe rotation helps agitate the cuttings beds and keep the cuttings suspended in the drilling fluid. The absence of tubing rotation in CTD makes hole cleaning much more difficult in horizontal and heavily deviated wellbores. Due to relatively low WOB and high bit rotational speed associated with CTD applications, the cuttings are relatively small. This tends to compensate for the lack of rotation. However, special visco-elastic fluids developed for CTD change their rheology according to the local shear rate, i.e., become more viscous in the annulus (lower shear rate) to improve cuttings suspension.

For all CT operations, the fluid travels through the entire tubing string regardless of the depth. Moreover, the frictional pressure loss for CT on the reel is considerably greater than for straight tubing. (see Chapter 10 “CT Hydraulic Performance”) For optimum hydraulic performance, the drilling fluid must behave as a low viscosity fluid inside the CT and as a high viscosity fluid in the annulus (for efficient cuttings removal). The special fluids developed for CTD, e.g., MI's Flo Pro™ system, exhibit this complex rheology.

Overbalanced Drilling

In overbalanced drilling operations, the drilling fluid is the primary tool for controlling the well pressure. Conventional drilling well control principles apply except that the CT string limits the fluid flow rate and the frictional pressure loss varies with the ratio of tubing on/off the reel. Key factors to consider for any overbalanced operation are:

- Maximum fluid flow rate versus depth—CT string (ID, length, on/off reel), geometry of toolstring components, rheology of drilling fluid(s)
- Fluid system pressures—pump pressure, pressure at the guide arch (fatigue considerations), separator or process equipment back pressure, ECD due to annulus frictional pressure loss and cuttings loading
- Pump hydraulic HP—system pressure losses, bit performance

- Fluid capacity and handling—safe method and equipment for preparing and storing different types of drilling fluids
- Solids control system—adequate processing capacity for the maximum circulation rate and cuttings loading.

Overbalanced drilling fluid systems are typically smaller versions of the systems used for conventional drilling. Due to the relatively small hole size drilled with CT, a single high capacity shale shaker and centrifuge are usually adequate. These are normally combined with a fluid processing tank and degasser to provide a compact, unitized system. Additional tanks provide mixing and storage capacity as required. Figure 15.49 shows a compact fluids handling and solids control system that Unocal Alaska used for a CTD project in the Cook Inlet. Figure 15.50 shows the solids disposal system for this well.

FIGURE 15.49 *Compact Mud System for CTD (Unocal Alaska)*

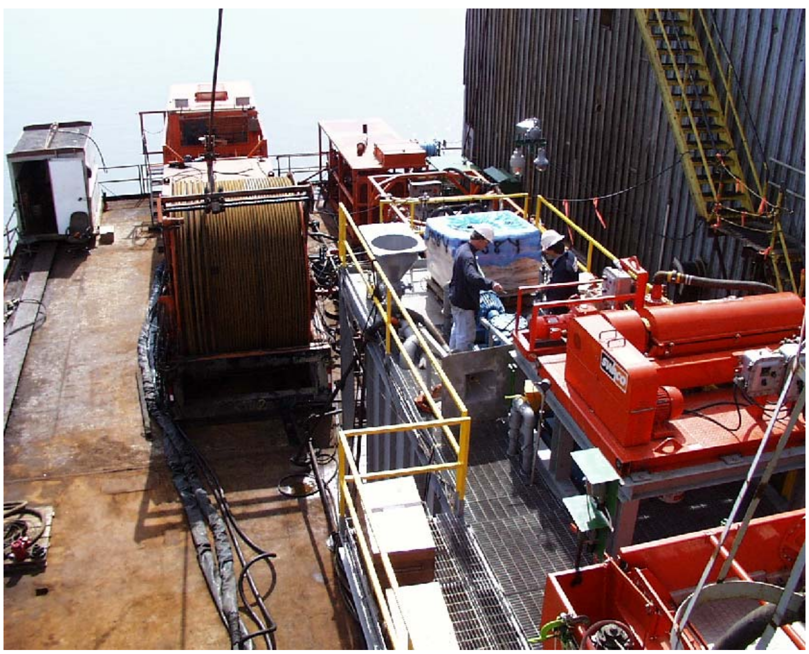


FIGURE 15.50 *Solids Disposal System for a CTD Well (Unocal Alaska)*

Underbalanced Drilling

Underbalanced drilling is suitable for situations where wellbore stability or preventing influx of formation fluids is not a problem. Thus far, all underbalanced CTD activity has been for reentries, but new wells could also benefit from the technology. Underbalanced drilling may be the most important market driver for CTD. Indeed, this drilling technique has become common practice in Canada and is gaining widespread popularity for reentry drilling. Drilling with a hydrostatic pressure lower than the reservoir pressure offers the following benefits:

- reduced risk of formation damage
- increased rate of penetration (ROP)

- a direct indication of any hydrocarbons in the formation
- ability to flow test the well while drilling, e.g., drawdown tests to evaluate the formation properties and productive capacity

CTD is ideal for this application because of the improved well control compared to conventional drilling. Increasing ROP directly reduces drilling time which should reduce the cost of a CTD operation. However, the cost savings due to increased ROP may be offset by the higher cost of:

- additional fluids or a large volume of gas (usually nitrogen)
- additional fluids handling components, e.g., separator systems
- extra safety precautions, especially in sour gas (H_2S) environments

Underbalanced finishing is a variation of underbalanced drilling used extensively in Canada and gaining acceptance in other areas. In this application, a conventional rig is used to drill to the top of the reservoir and run a casing string. Then, CTD is used to enter the reservoir with underbalanced drilling techniques. This approach attempts to gain from the strengths of each drilling technique. Conventional drilling is faster (less expensive) in the large diameter, unproductive intervals compared to CTD. On the other hand, underbalanced CTD is faster in the producing interval and safer than using jointed drill-pipe. One method of creating the underbalanced condition is to inject gas or nitrogen into the well through the casing string's gas lift system, if so equipped. Another method is to use a lightweight drilling fluid.

Designing and conducting an underbalanced drilling operation can be a complex process that requires a thorough knowledge of the risks and hazards. There are three general methods of achieving underbalance, and the method used depends on the relationship between formation pressure and normal pressure gradient. If the formation pressure is below normal pressure gradient, achieving underbalanced conditions requires the use of gas lift or foam. If the formation pressure is normal, a low density drilling fluid such as unweighted oil-base mud or native crude should be adequate. If the formation pressure exceeds the normal pressure gradient, the well will flow simply by decreasing the drilling fluid density below that which would normally be used in overbalanced drilling.

The drilling fluid design for underbalanced operations differs from conventional, overbalanced methods in several ways. First, filtration control additives are unnecessary because the formation pressure is higher than the annular pressure. Weighting materials are not required for the purpose of primary well control. Environmentally safe water-based fluids are unnecessary for reservoirs producing liquid hydrocarbons. As a result, inexpensive, simple fluids such as formation water, diesel, or native crude are suitable base fluids.

Liquids for Underbalanced Drilling

In cases where reservoir pressure is sufficiently high, gas injection may be unnecessary altogether. Water (fresh or formation brine), diesel, or native crude oil may be a suitable drilling fluid. The absence of a gas injection system simplifies the operation and reduces cost significantly. However, the only method of controlling the annular pressure (amount of underbalance) at a given flow rate is to adjust the flow line choke. This can be rather laborious to achieve manually. Also, a separate batch of kill fluid must be available on site to control the well under static conditions.

Two-phase Fluids for Underbalanced Drilling

Creating underbalanced conditions in low pressure reservoirs requires mixing gas with the base fluid through the CT string or gas lift system or using straight foam or gas through the CT string. Air has been used for this, but it poses a serious combustion risk when it contacts produced hydrocarbons. Exhaust gas from diesel engines is also a possibility, but it is corrosive due to the high CO_2 content. Nitrogen or hydrocarbon gas is a better choice than air or exhaust gas. Nitrogen is available for underbalanced drilling from two sources:

- Liquid nitrogen trucked to the site, then pumped and converted to gaseous phase at the required pressure.
- On-site nitrogen filtration units to generate nitrogen directly from the air.

Selection of the nitrogen supply depends largely on economics and depends on the anticipated nitrogen consumption, the local price of liquid nitrogen, and the mobilization cost of a filtration unit.

The safe concentration of oxygen in the injection gas depends on downhole pressure, temperature, and the hydrocarbon composition. As a general rule, an oxygen concentration less than 5% will prevent downhole combustion. Nitrogen gas from filtration units contains a low concentration of oxygen, usually less than 5%. However, even a small amount of oxygen in the drilling fluid increases the corrosion risk significantly. For this reason, many people prefer liquid nitrogen for underbalanced drilling. Regardless of the source for oxygen in the drilling fluid, a corrosion-monitoring program is prudent.

Foam Systems

If gas injected into a liquid does not decrease the BHP enough to achieve the proper amount of underbalance, a foam system may be a good solution. Foam is composed of gas bubbles uniformly dispersed in a continuous liquid phase. Mixing water, foaming agent, and gas in a closed chamber creates foam. Due to its viscosity, foam is excellent for suspending and carrying cuttings. The most significant disadvantage of using foam is the large volume of returns from the well. Usually, a defoaming agent (breaker) is necessary to separate the foam into its two phases prior to processing the returns. This significantly complicates the operation of a closed loop system. (See Chapter 11 "Foam", page 11-16 for more information about foams.)

Gas and Mist Systems

Gas and mist are also useful for underbalanced drilling. Mist is dispersal of liquid droplets in a continuous gas phase, usually compressed air or natural gas. Nitrogen is too costly because of the requirement for high flow rate and large volume. Gas drilling is mainly for hard rock or tight producing formations. One disadvantage of gas drilling is the sensitivity of some formations to introduction of even small amounts of water. Under those conditions, the cuttings form mud rings in the annulus that disrupt hole cleaning and create pipe sticking problems.

Gas Injection Methods

Two options, string injection and annulus injection, are available for injecting gas into the drilling fluid for maintaining an underbalanced condition. In the string injection method, gas enters the liquid stream through a manifold upstream of the CT reel. The two phases thoroughly mix in transit through the CT string. Foaming will not occur without injection of appropriate foaming agents or surfactants. Annulus injection makes use of existing gas lift facilities in the completion to inject gas at discrete locations in the annulus.

String Injection

String injection has the following advantages over the annulus injection method:

- Simplicity
- Low capital cost
- Achieving lower bottomhole pressure is easier because the entire annulus contains low-density fluid.
- The gas injection rate to maintain the desired BHP is lower resulting in lower gas consumption (and possibly cost).

However, string injection has numerous disadvantages, including:

- Conventional mud pulse telemetry will not function at high gas/liquid ratio.
- Gas cannot be injected during trips to keep the well underbalanced.
- Most downhole motors are less efficient with two-phase flow.

- Adjustments to the gas injection rate take a long time to have any effect on BHP.
- Frictional pressure loss in the CT string is generally higher for two-phase flow.

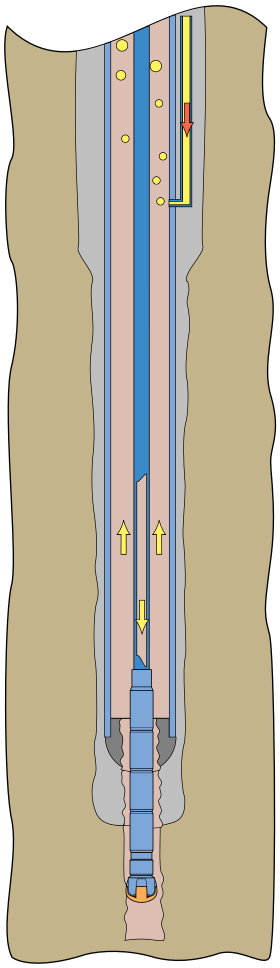
Annulus Injection

Injection points can be located anywhere along the wellbore, but the potential minimum BHP decreases as the injection depth increases. Annular injection methods fall into three groups.

Parasite String Injection

An external tubing string is run and cemented together with the production casing (Figure 15.51). The casing and tubing string communicate by means of a side entry sub. Gas enters the annulus through the parasite string. This method has two significant drawbacks. First the parasite string can be cumbersome and expensive to run. Second, the side entry sub may be a weak point in the casing.

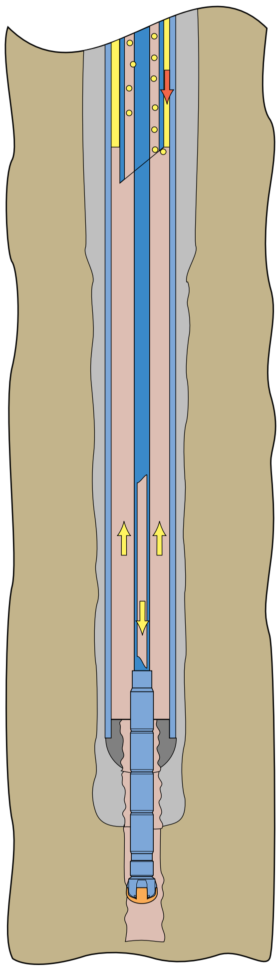
FIGURE 15.51 *Parasite String Injection*



Parasite Casing Injection

A casing string temporarily hung off inside the production casing provides an injection point at a single depth. Gas injected into the annulus between this parasite casing and the production casing (Figure 15.52) enters the drilling fluid at the bottom of the parasite casing. This annulus injection method is more versatile and easier to run than a parasite string, but it limits the size of hole drilled to the ID of the parasite casing. Also, the relatively large annular volume between the two casing strings results in long pre-charging times and more difficult control of BHP.

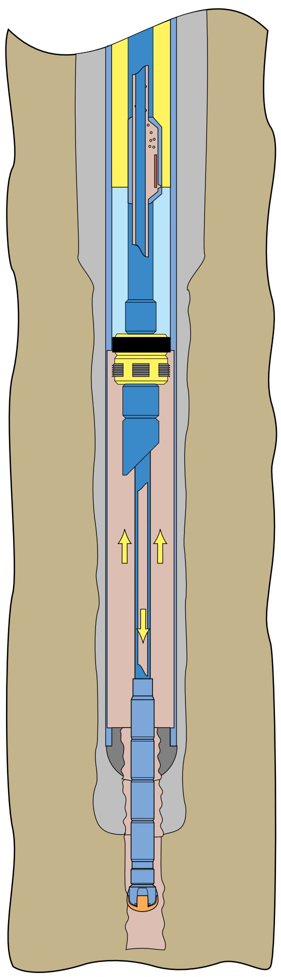
FIGURE 15.52 *Parasite Casing Injection*



Gas lift system

If the existing completion can stay in place during the drilling operation (through tubing reentry) the gas lift system (if so equipped) can be used for gas injection during drilling. This is an attractive option, because it doesn't require additional piping or preparation. Figure 15.53 illustrates this method.

FIGURE 15.53 *Injection through the Gas Lift System*



Underbalanced Drilling Surface Equipment

Early underbalanced drilling operations utilized fluid separator and handling systems consisting of:

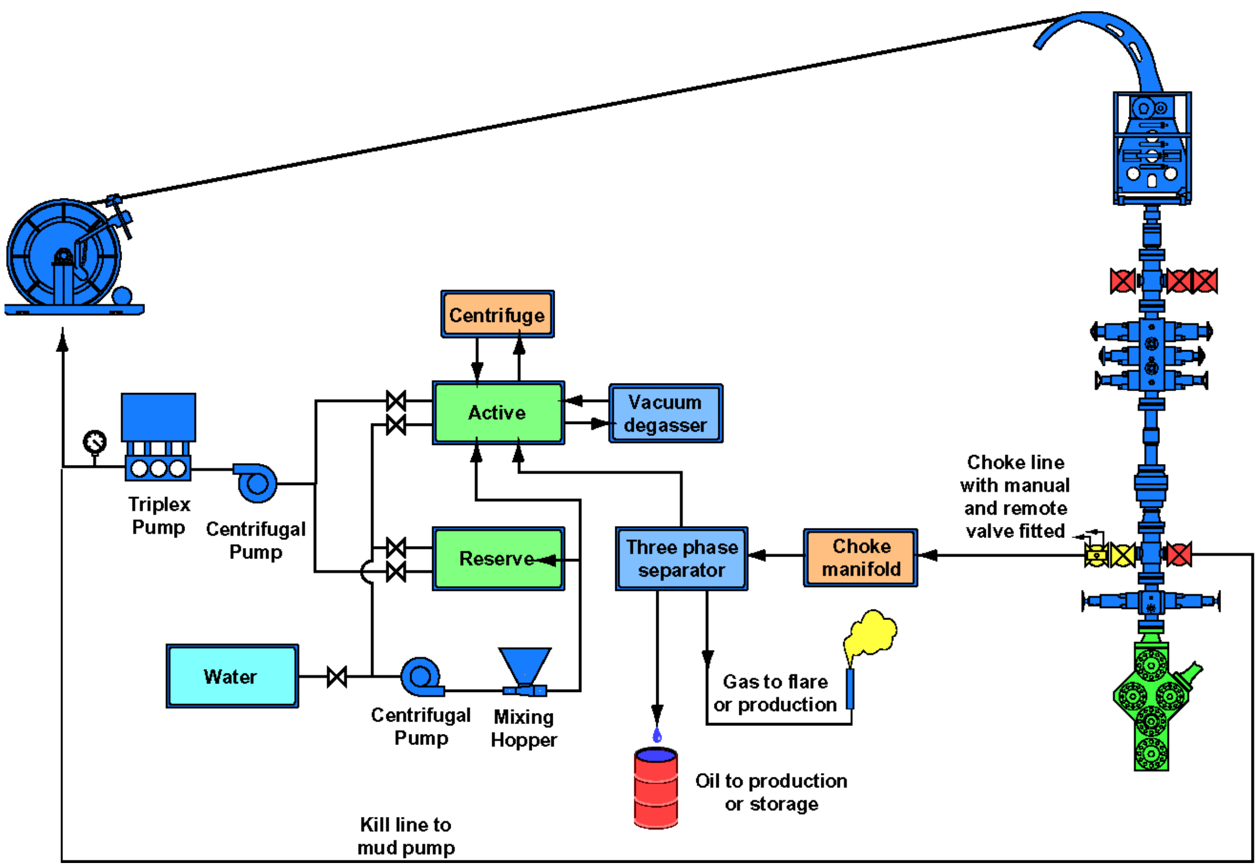
- A surface choke to control flow
- A multi-stage separations system
- Storage/disposal facilities for the separated gas, liquids and solids

While these simple systems are still in use, systems designed specifically for underbalanced drilling are now available. Surface systems can either be open or closed (pressurized). The purpose of a closed system is to handle potentially dangerous gases.

Open Systems

An open system is essentially the standard equipment used on many rigs for well testing (Figure 15.54). The fluid from the wellbore returns through an adjustable choke that helps regulate the flow rate and BHP. However, adjusting the gas/liquid injection rates is normally the main method for controlling BHP.

FIGURE 15.54 *Open System*

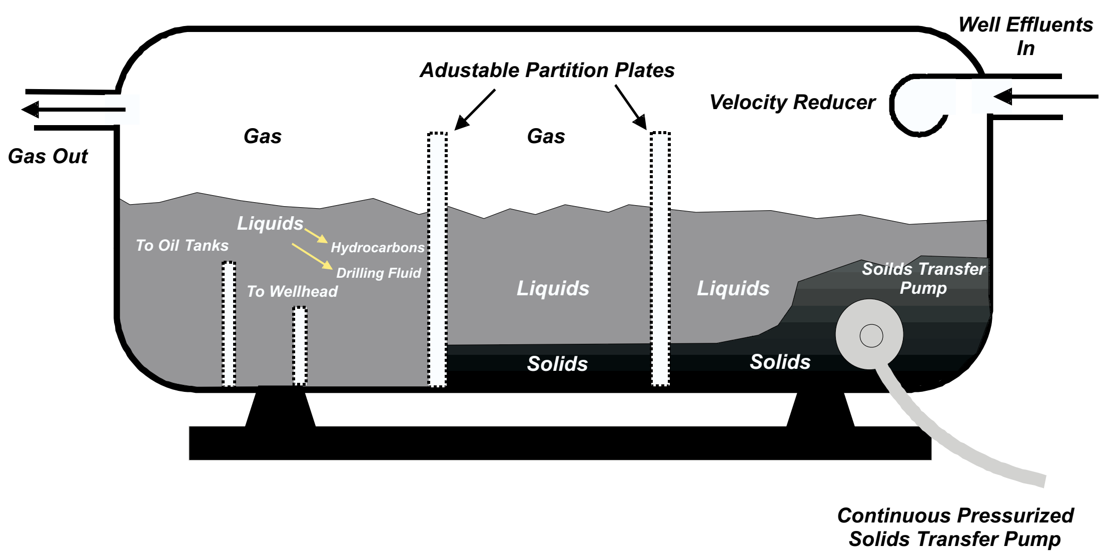


In the simplest system, an atmospheric de-gasser (or series of de-gassers) removes any gas in the return fluid. Sometimes a vacuum de-gasser is necessary for optimum performance. The fluid still contains oil, water, and cuttings. A series of settling and/or skimming tanks is the simplest method for removing the oil and the cuttings. A shale shaker and/or centrifuge can improve the cuttings removal, if necessary. The processed drilling fluid flows into a tank for re-use.

Closed Systems

Most underbalanced drilling operations use a four-phase separator (water, oil, gas, and solids) to process the returns at the surface. In cases where open returns pose a fire or safety hazard (H_2S), treating the well returns in a closed loop system is necessary to prevent their contact with air. Production type separation tanks can separate water, oil, and gas. A closed system precludes the use of traditional shale shakers, but a large separation vessel allows adequate settling time to remove the solids (Figure 15.55).

FIGURE 15.55 *Four Phase Separator*



Another approach is to use filters or cyclones to extract solids before they enter the separator. This reduces the required separator size considerably.

EXITING AN EXISTING WELLBORE

The development of CTD window milling systems for exiting an existing wellbore has progressed rapidly in the last few years. The challenge has been applications where the exit window is in the larger-diameter casing below the production tubing. However, many CTD re-entry operations have occurred from inside the production tubing or in wellbores with the production tubing removed. Four methods are available for exiting an existing wellbore.

- Removing the production tubing and kicking off from a whipstock set in the casing
- Kicking off from a through-tubing whipstock (TTW) set below the production tubing
- Time drilling from a cement plug
- Kicking off from a whipstock in a pilot hole in a cement plug

The most common method of sidetracking an existing wellbore is to set a whipstock in the casing to guide the milling assembly toward the direction of the new wellbore. A radioactive tag (source) on the whipstock can provide future depth correlation in the open hole section. The technology is available to perform the sidetrack with the completion pulled (conventional) or in place (through tubing). Hole sizes for the former have been as large as 6 in. while hole sizes for the latter are typically smaller than 4 in.

Production Tubing Pulled—Conventional Whipstock

If the production tubing has been removed, a conventional whipstock can be set in the casing to provide the kickoff point for the sidetrack. The decision to remove the production tubing hinges on the economics of the operation, i.e., availability of a suitable rig and the time required, and/or the planned hole size for the sidetrack. In addition, the absence of small diameter restrictions provides more options for tools. However, conducting CTD operations inside a large wellbore makes hole cleaning more difficult, i.e., requires higher fluid flow rate, and reduces the maximum possible WOB, due to lower critical helical buckling limit (see Chapter 7 "Geometry of a Helix", page 7-12).

The four phases of a conventional sidetracking operation are:

- Well preparation
- Preparing/setting the whipstock
- Milling the window
- Drilling the sidetrack

The following sections describe the primary steps and important considerations for each phase of a conventional sidetracking operation.

Well Preparation

1. Kill the well.

2. Nipple down the production tree and install the pressure control equipment.

3. Test the pressure control equipment.

4. Pull the production tubing and packer(s).

5. If required, isolate the current producing interval behind a cement squeeze, slurry plug, or bridge plug.

6. Run a CCL and gamma ray tool from surface to at least 100 ft below the proposed KOP to provide both an accurate depth correlation and choice of location for setting the whipstock. Milling through a casing collar can be difficult (time-consuming), therefore, expensive.

7. Run a cement bond log (CBL) or other cement evaluation tool to determine the quality of the cement sheath at the desired KOP. If the results show poor cement quality, try a remedial cement squeeze or move the KOP to a location with a solid cement sheath.

8. Run a casing caliper at least 100 ft above and below the proposed KOP. The location for setting the whipstock must be round as possible. If the casing is too oval or distorted, the anchor slips will not hold properly. Ream the whipstock setting interval as necessary to prepare the casing for the anchor.

NOTE: Install magnets in the flowline (ditch) to the solids control system and each shaker's possum belly to capture as much of the metallic cuttings from the milling operation as possible. Check and clean these magnets on a regular basis.

9. When running the whipstock without an anchor, install a bridge plug or cement plug at the KOP to support the whipstock until its slips set against the casing. If using a cement plug, dress the top of the plug to the kickoff depth.

Preparing/Setting the Whipstock without an Anchor

If azimuth control for the kickoff is not important, the whipstock can be set without an anchor on top of a wellbore plug (step 9 in Section 15 "Well Preparation", page 15-79). If the wellbore inclination is not too high, wireline may be suitable for setting the whipstock. However, the following assumes using the CT to run and set the whipstock.

1. Dress (adjust) the whipstock slips to fit the casing ID measured in step 8 in Chapter 15 "Well Preparation", page 15-79.

2. Assemble the BHA for running the whipstock. Two options are available. First, a simple BHA consisting of a CT connector, check valve(s), and a running tool. Second, a milling BHA consisting of a high torque CT connector, check valve(s), circulating (flow bypass) sub, disconnect, motor, flex-joint, and starting mill with a whipstock running lug. The latter eliminates a trip.

3. RIH with the whipstock and gently tag the wellbore plug.

4. Slowly slack off CT to provide the setdown weight specified by the whipstock supplier for setting the slips.

5. Release the running tool by shearing the stud connecting the whipstock to the tool. Some tools release with setdown weight, while others require overpull.

Preparing/Setting the Whipstock with an Anchor

If azimuth control for kickoff is essential, set a whipstock anchor in the casing.

1. Dress (adjust) the anchor slips to fit the casing ID measured in step 8 in Section “Well Preparation”.

2. RIH to the KOP with the anchor and set the anchor slips. After activating the slips on the anchor but prior to releasing the setting tool, set down 2000 lbs weight or a value recommended by the supplier, whichever is less, to insure that the anchor will hold.

3. Perform a gyro survey to determine the orientation (azimuth) of the anchor.

4. Set the azimuth of the whipstock key to orient the whipstock face in the proper direction for the kickoff.

5. Assemble the BHA for running the whipstock. Two options are available. First, a simple BHA consisting of a CT connector, check valve(s), and a running tool. Second, a milling BHA consisting of a high torque CT connector, check valve(s), circulating (flow bypass) sub, disconnect, motor, flex-joint, and starting mill with a whipstock running lug. The latter eliminates a trip.

6. RIH with the whipstock, gently tag the anchor, and engage the whipstock stinger into the anchor. The stinger will swivel to correctly align the whipstock key with the anchor receptacle.

7. After the whipstock engages fully into the anchor, set down enough weight to set the slips in the anchor. Apply overpull to the whipstock to confirm that it is anchored.

8. Shear the lug connecting the running tool or starting mill and the whipstock. POOH with the running tool and replace the BHA with a window milling assembly or stay at depth with the starting mill and prepare to open the window.

Milling the Window

Generally, a low speed, high torque motor is a good choice for window milling. A large selection of mills is available, ranging from diamond speed mills with small cutters to aggressive "metal muncher" mills with large carbide cutters. The proper choice of a mill for a given application depends on a number of factors including the motor speed and torque capability, CT size, and potential hole cleaning performance. The more aggressive the mill cutting action is, the more powerful the motor must be, and the larger the CT must be for torsional resistance and adequate flow rate for hole cleaning. A typical milling BHA might consist of a high torque CT connector, check valve(s), circulating (flow bypass) sub, disconnect, motor, flex-joint, and starting mill.

Figure 15.56 shows a window mill from Baker Oil Tools (BOT) with aggressive "metal muncher" cutting surfaces.

FIGURE 15.56 *Metal Muncher Window Mill (BOT)*

Figure 15.57 shows a turbine type window mill (at the bottom) combined with a string mill.

FIGURE 15.57 *Window Mill and String Mill Combined (BOT)*

Figure 15.58 shows a selection of mills (foreground) and whipstocks (background) used for CTD projects in Prudhoe Bay, Alaska.

FIGURE 15.58 *CTD Mills and Whipstocks (BOT)*

FIGURE 15.59 *CTD Mills (Weatherford)*

The following generic procedure starts after RIH with the milling BHA and gently tagging the whipstock.

1. Pick up approximately 5 ft and begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, slowly slack off the CT until the starting mill begins to cut into the casing, as indicated by an increase in pump pressure. Depending on the sensors in the BHA, alternative indications of mill performance might be increased BHA vibrations or WOB.

2. Patience is a virtue when milling a window with CT. Adding too much WOB, i.e., slacking off CT too fast, can stall the motor, cause the mill to cut into the whipstock, or force the mill out of the casing too early. The latter can create a lip at the bottom of the window that can snag the open hole BHA. Watch the pump pressure and/or BHA sensors for an indication of motor performance.

3. The starting mill will not effectively drill the formation. When the ROP becomes insensitive to WOB, activate the flow bypass in the BHA and circulate at the highest rate possible while POOH. Depending on the whipstock configuration and the mill, the initial hole in the casing should be 3-5 ft long.

4. Change the starting mill to a formation mill or window mill and add a string or watermelon mill above it. The purpose of the second mill is to enlarge the window and smooth its edges.

5. RIH to the window and tag bottom. Pick up approximately 5 ft and begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, slowly slack off the CT until the mill begins to cut into the casing.

6. Continue milling until the string or watermelon mill has exited the window and drilled about 5 ft of formation. Be patient and avoid slacking off CT too fast. Watch the pump pressure and/or BHA sensors for an indication of motor performance.

7. Make several passes across the window to insure that the edges are smooth and no lip exists to snag the open hole BHA. The window should be approximately 9 ft long at this point.

8. Activate the flow bypass in the BHA and circulate at the highest rate possible while POOH.

Figure 15.60 through Figure 15.63 illustrate the concept of milling a window from a conventional whipstock.

FIGURE 15.60 *Running and Setting the Whipstock with a Running Tool*

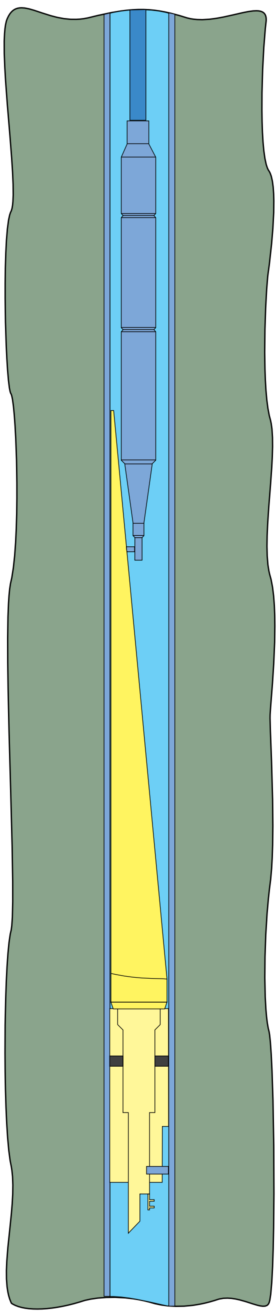


FIGURE 15.61 *Starting the Window*

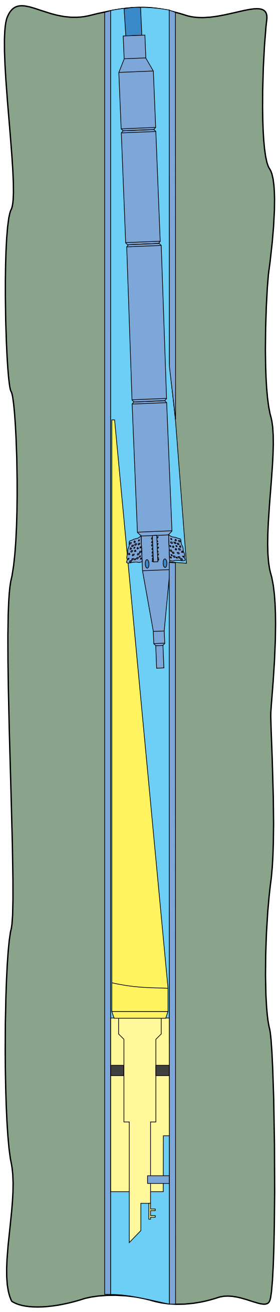


FIGURE 15.62 *Opening the Window with a Formation Mill*

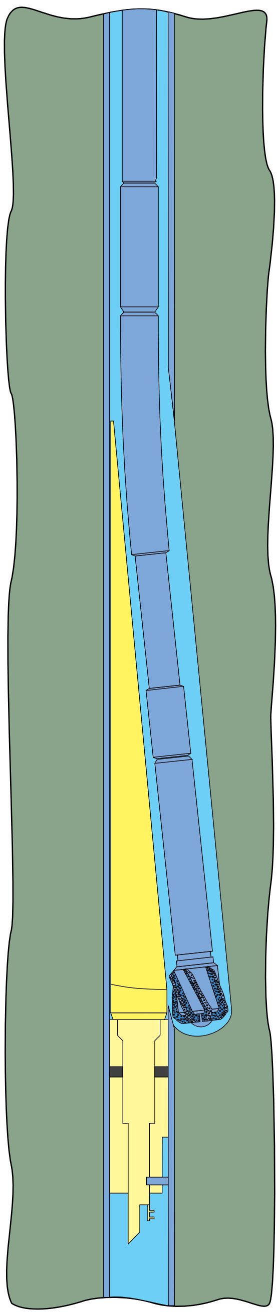
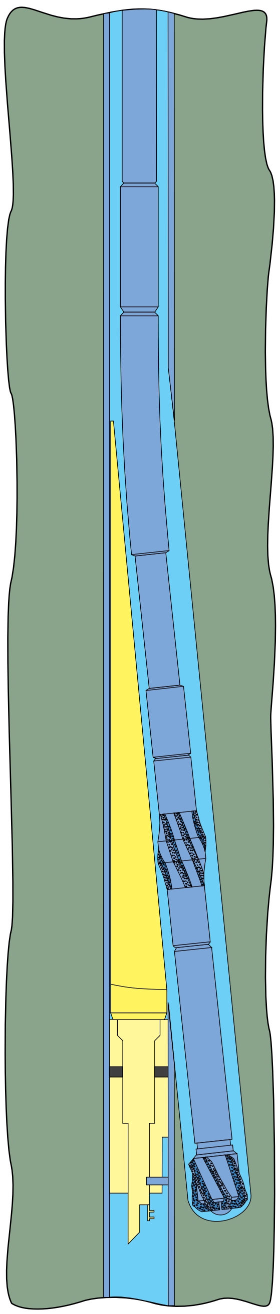


FIGURE 15.63 *Enlarging and Smoothing the Window with a Watermelon Mill*



Drilling the Sidetrack

Section “Downhole Motors for CTD” page 15-16 describe different options for directional drilling BHAs. A typical BHA for drilling the build section would consist of a high torque CT connector, check valve(s), disconnect, orienting tool, steering tool, bent-housing motor, and bit. The BHA for drilling a straight section would not require the orienting tool, and a straight-housing motor would replace the bent-housing motor.

1. RIH with the directional drilling assembly to the top of the window. If pumping while RIH, maintain the flow rate below that necessary to operate the motor.

2. Slowly slack off CT and gently tag bottom. Pick up approximately 5 ft and orient the tool face to the correct position. Begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, slowly slack off the CT (add WOB) until the bit begins to cut formation. Maintain the correct tool face angle.

3. Follow the drilling program or instructions from the directional driller to drill the build section.

4. Monitor cuttings removal at the solids control equipment to determine the hole cleaning efficiency. Make periodic wiper trips back to the window and/or regularly pump viscous sweeps to improve hole cleaning.

5. After reaching the end of the build section, pull the BHA to the window while pumping at the highest flow rate possible.

6. If possible, alternate drilling fluid with viscous sweeps until bottoms up.

7. If the BHA includes a circulation sub (flow bypass), activate the bypass and POOH while pumping at the highest rate possible. Otherwise pump at a rate below that necessary to operate the motor.

8. Change the BHA as required for the next hole section.

9. RIH with the new drilling assembly to the top of the window. If pumping while RIH, maintain the flow rate below that necessary to operate the motor.

10. Slowly slack off CT and gently tag bottom. Pick up approximately 5 ft and orient the BHA. Begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, slowly slack off the CT (add WOB) until the bit begins to cut formation.

11. Follow the drilling program or instructions from the directional driller.

12. Monitor cuttings removal at the solids control equipment to determine the hole cleaning efficiency. Make periodic wiper trips back to the bottom of the build section and occasional wiper trips back to the window.

13. Continue drilling to the end of the current hole section or until the bit stops drilling, whichever comes first. Pull the BHA to the window while pumping at the highest flow rate possible.

14. Repeat steps 6-13 as necessary.

Through Tubing Whipstock

Leaving the production tubing in place during the CTD operation is significantly less expensive than pulling the tubing. Prudhoe Bay, Alaska, where mobilizing a rig is extremely expensive, is a good example. Through tubing CTD may be the only alternative for sidetracking a well when a rig is unavailable. Also, drilling through the production tubing improves hole cleaning and allows higher WOB (see Chapter 7 “Buckling and Lock-up”).

BP’s CTD project in Prudhoe Bay, Alaska, has been successful because of the through tubing whipstock (TTW) developed by BOT. This tool allows reentering through and sidetracking below completions as small as 3.50 in. BP has set most of the TTWs in 7 in. 26 lb/ft and 29 lb/ft casing. Figure 15.64 is a schematic of the TTW installed in a typical Prudhoe Bay well.

FIGURE 15.64 *TTW Installed in a Well*

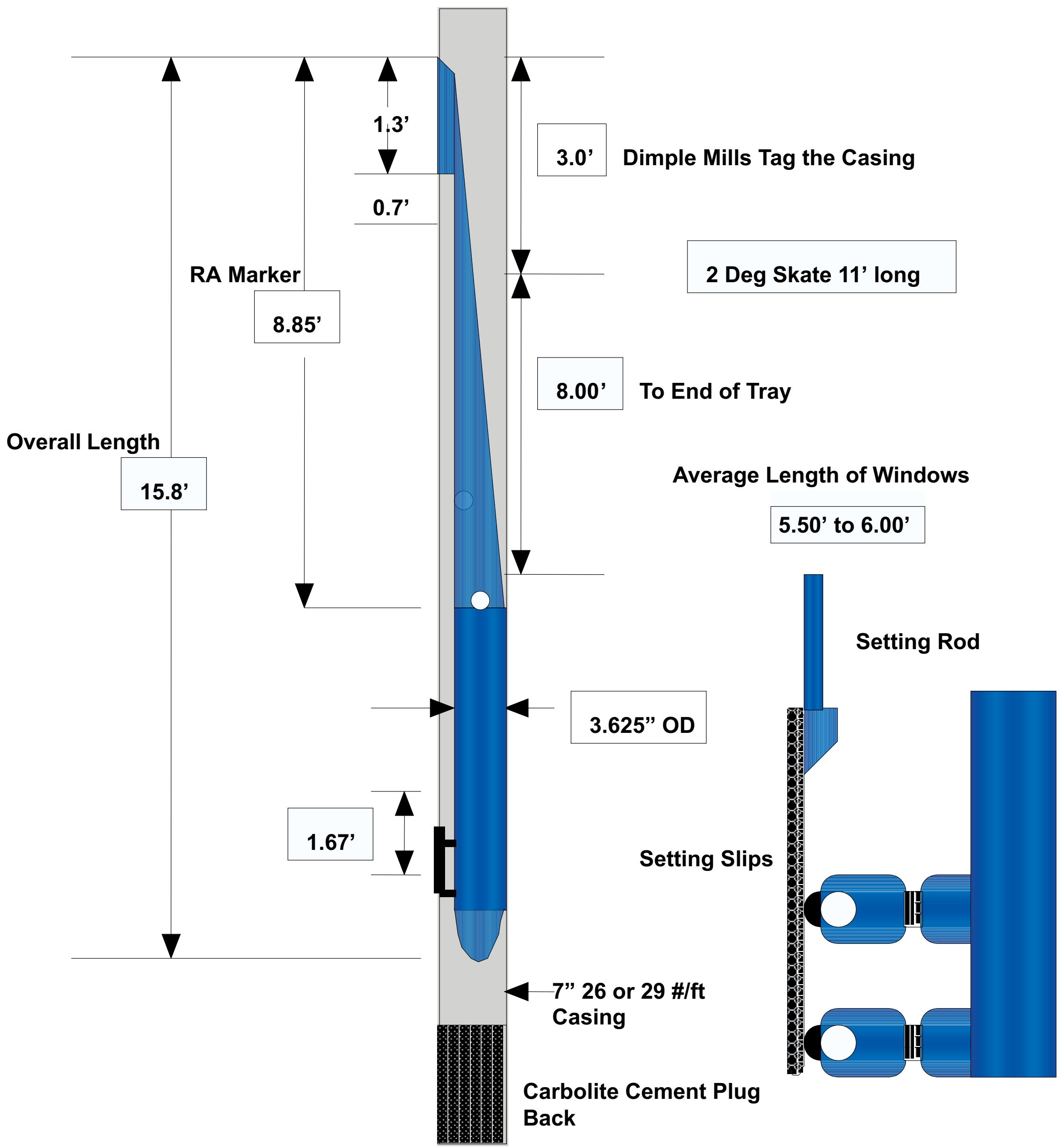


Figure 15.65 and Figure 15.66 show the upper and lower portions, respectively, of a TTW from BOT. The running tool connects to the top of the shear block. When the whipstock is in the correct position, activating the setting tool pulls on the shear block, which pulls on the setting rod, which cams the slips tightly against the casing.

FIGURE 15.65 *Top of a TTW Showing the Lower Shear Block (BOT)*

FIGURE 15.66 *Lower Section of a TTW Showing the Slips and Setting Rod (BOT)*

The four phases of a sidetracking through tubing are:

- Well preparation
- Preparing/setting the whipstock
- Milling the window
- Drilling the sidetrack

The following sections describe the primary steps and important considerations for each phase of a through tubing sidetracking operation.

Well Preparation

1. Drift the entire length of the production tubing with a tool having the same OD and length as the TTW. Remove (mill) any restrictions in the wellbore.

2. Unless the gas lift system will be used during drilling operations, replace the gas lift valves with dummy valves prior to the start of drilling operations.

3. Run a CCL and gamma ray tool from surface to at least 100 ft below the proposed KOP to provide both an accurate depth correlation and choice of location for setting the whipstock. Milling through a casing collar can be difficult (time-consuming), therefore, expensive.

4. Run a cement bond log (CBL) or other cement evaluation tool to determine the quality of the cement sheath at the desired KOP. If the results show poor cement quality, try a remedial cement squeeze or move the KOP to a location with a solid cement sheath.

5. Run a casing caliper at least 100 ft above and below the proposed KOP. The location for setting the whipstock must be round as possible. If the casing is too oval or distorted, the anchor slips will not hold properly. Ream the whipstock setting interval as necessary to prepare the casing for the anchor.

Preparing/Setting the Whipstock

The TTW does not use a packer/anchor and can be run in a single trip.

1. Dress (adjust) the anchor slips to fit the casing ID measured in step 5 in Section "Well Preparation" page 15-94.

2. Assemble the BHA for running the whipstock. The simplest BHA would consist of a CT connector, check valve(s), and the running/setting tool. An alternative BHA would consist of a high torque CT connector, check valve(s), disconnect, orienting tool, steering tool, and running/setting tool. This second BHA would allow setting the orientation (azimuth) of the whipstock face.

3. RIH with the whipstock to the setting depth. Orient the whipstock as required and activate the setting tool.

4. Shear the lug connecting the running tool and the whipstock. POOH with the running tool and replace the BHA with a window milling assembly.

Milling the Window

The procedure for milling the window is the same as described in Section "Milling the Window" page 15-82.

Drilling the Sidetrack

The procedure for drilling the sidetrack is the same as described in Section "Drilling the Sidetrack" page 15-90.

Time Drilling from a Cement Plug

Arco pioneered this window milling technique for reentry drilling at Prudhoe Bay, Alaska. Although developed primarily for through tubing re-entries, this method also works when the production tubing has been removed. The objective of this technique is to directionally drill through the cement and exit the casing at the desired KOP and pointing in the correct direction. The three phases of time drilling from a cement plug are:

- Well preparation
- Milling the window
- Drilling the sidetrack

The following sections summarize the primary steps and important considerations for sidetracking from a cement plug.

Well Preparation

1. Kill the well.

2. Nipple down the production tree and install the pressure control equipment.

3. Test the pressure control equipment.

4. If necessary, pull the production tubing and packer(s).

5. Run a CCL and gamma ray tool from surface to at least 100 ft below the proposed KOP to provide both an accurate depth correlation and choice of location for setting the whipstock. Milling through a casing collar can be difficult (time-consuming), therefore, expensive.

6. Run a cement bond log (CBL) or other cement evaluation tool to determine the quality of the cement sheath at the desired KOP. If the results show poor cement quality, try a remedial cement squeeze or move the KOP to a location with a solid cement sheath.

7. Place a cement plug with high compressive strength in the wellbore straddling the location for the window. Usually the cement contains nylon or other fibers to give it the mechanical strength necessary to withstand the abusive milling operation.

NOTE: Install magnets in the flowline (ditch) to the solids control system and each shaker's possum belly to capture as much of the metallic cuttings from the milling operation as possible. Check and clean these magnets on a regular basis.

Milling the Window

Low WOB and highly controlled ROP are the hallmarks of time drilling from a cement plug, so less aggressive cutting action, e.g. a diamond speed mill, is the best approach.

1. Assemble a directional drilling BHA consisting of high torque CT connector, check valve(s), circulating (flow bypass) sub, disconnect, orienting tool, steering tool, slightly bent (about 0.25º) housing motor, and diamond speed mill or drill bit appropriate for low WOB.

2. After the cement has cured adequately, drill a pilot hole in the cement while maintaining low WOB and the tool face orientation in the direction of the planned wellbore.

3. When the mill (bit) reaches the KOP for the sidetrack, activate the flow bypass in the BHA and circulate at the highest rate possible while POOH.

4. Adjust the bend in the motor to a higher angle, about 2.5º, and replace the drill bit, if used for the pilot hole, with a diamond speed mill.

5. RIH, and gently tag bottom.

6. Pick up approximately 5 ft and orient the BHA. Begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, slowly slack off the CT until the mill begins to cut into the cement plug or casing, as indicated by an increase in pump pressure. Depending on the sensors in the BHA, alternative indications of mill performance might be increased BHA vibrations or WOB.

7. Advance the CT in short steps of less than an inch with preprogrammed hold between each step. The length of each step and the following hold period should vary with the milling progress. These are best determined from yard tests.

NOTE: Patience is a virtue when time drilling from a cement plug. Adding too much WOB, i.e., slacking off CT too fast can stall the motor or cause the mill to cut a hole in the cement plug parallel to the casing. Watch the pump pressure and/or BHA sensors for an indication of motor performance.

8. After milling through the casing and drilling about 5 ft of formation, or when ROP drops to an unacceptable level, activate the flow bypass in the BHA and circulate at the highest rate possible while POOH.

9. If the diamond speed mill does not effectively drill the formation, replace the diamond speed mill with a formation mill, RIH, and drill about 5 ft of formation. Activate the flow bypass in the BHA and circulate at the highest rate possible while POOH.

10. Replace the mill with a string or watermelon mill having a bull nose (no bit) below it.

11. RIH to the top of the window and begin pumping at the rate required to operate the motor. After the pump pressure stabilizes, make several passes across the window to insure that the edges are smooth and no lip exists to snag the open hole BHA.

12. Activate the flow bypass in the BHA and circulate at the highest rate possible while POOH.

Drilling the Sidetrack

The procedure for drilling the sidetrack is the same as described in Section “Drilling the Side-track” page 15-90.

Whipstock in a Cement Plug

Although developed primarily for through tubing re-entries, this method also works when the production tubing has been removed. The objective of this technique is to drill a pilot hole in the cement plug and install a whipstock in the hole at the desired KOP. The four phases of kicking off from a whipstock in a cement plug are:

- Well preparation
- Installing the whipstock
- Milling the window
- Drilling the sidetrack

Well Preparation

The well preparation phase is the same as described in Section “Well Preparation” page 15-96, except for the additional step of drilling a straight pilot hole to a depth approximately 10 ft below the planned KOP.

Installing the Whipstock

1. Dress (adjust) the whipstock slips to fit the pilot hole ID.
2. Assemble the BHA for running the whipstock. The BHA would consist of a high torque CT connector, check valve(s), disconnect, orienting tool, steering tool, and running/setting tool. This BHA would allow setting the orientation (azimuth) of the whipstock face.
3. RIH with the whipstock and gently tag the bottom of the pilot hole. Orient the whipstock face as required.
4. Slowly slack off CT to provide the setdown weight specified by the whipstock supplier for setting the slips.
5. Release the running tool by shearing the stud connecting the whipstock to the tool. Some tools release with setdown weight, while others require overpull.

Milling the Window

The procedure for milling the window is the same as described in Section “Milling the Window” page 15-82.

Drilling the Sidetrack

The procedure for drilling the sidetrack is the same as described in Section “Drilling the Sidetrack” page 15-90.

Planning a CTD Operation

Preparation for a CTD project typically involves coordinating the efforts of several specialist disciplines to compile an overall job plan or procedure. Regardless of who is responsible for this task, the planner must have access to the relevant information held by all of the parties involved with the project. The planner should serve as the liaison between the customer and the contractor(s) and be available for operational support during the execution of the CTD project.

The Planner's Responsibilities

The tasks required to prepare for a CTD project are either technical or administrative. The following sections summarize some of these tasks and the checklists that can facilitate their completion.

Technical Preparation

Technical preparation covers the following principal areas.

- Basic equipment and services
- Procedures and planning
- Drawings and schematic diagrams
- Personnel

To enable the efficient management and coordination of these individual areas, the planner should prepare a list of tasks required to complete the technical preparation. This list should describe each task, designate a person or group responsible for the task, and identify a schedule for presenting the results. Section "CTD Procedure and Task List" page 15-117 provides a sample check list to aid the planning process.

Basic Equipment and Services

Comprehensive checklists for the headings shown below will help identify the source(s) of equipment, services, and expertise necessary to complete the project. Each checklist should include an accurate description of the item or service, the source for each, and relevant schedule or availability conflicts.

- Surface equipment

- Consumables
- Spare parts and supplies
- Dowhhole tools
- Associated services

Procedures and Planning

Due to the complex nature of the overall CTD operation, the planner should develop detailed procedures and plans for the principal project elements. These procedures must consider the specific well site, wellbore, and reservoir conditions anticipated during execution of the project. The planner should review all procedures and plans with the Customer, contractor, and regulatory personnel involved with the CTD project. In most cases, a formal review and approval process is an excellent method of ensuring all parties acknowledge acceptance of the procedures and plans.

> *NOTE:* Clearly identify each planning document with a date and/or version number. This will minimize confusion and potential problems between the parties involved with the project.

The following list includes typical elements of a generic CTD project. A specific project may have fewer or additional functions and requirements.

- Mob/demob organization
- Rigging up/down
- Setting whipstock & milling window (if required)
- Well control
- Well control equipment testing
- BHA deployment (regardless of wellbore pressure control)
- Running and setting liner or casing (if required)
- Running completion string
- Cementing job design
- Drilling fluid program
- Contingency plans
- Emergency responses

Drawings and Schematic Diagrams

The planner can simplify the explanation required for procedures and plans by providing concise and suitably detailed drawings and schematic diagrams. The following list includes typical examples of drawings or schematic diagrams for CTD projects.

> *NOTE:* Clearly identify each planning document with a date and/or version number. This will minimize confusion and potential problems between the parties involved with the project.

- Wellbore schematic (at each stage of the operation)
- Wellpath (survey)
- Surface equipment lay out with dimensions (or scale), indication of restrictive zoning where applicable, e.g., Zone II, and indication of restrictive surface loading (primarily for offshore operations)
- BOP stack schematic with heights and dimensions
- BHA schematics (fishing diagram for each assembly)
- High pressure and low pressure lines schematics
- Electrical wiring of surface equipment

Personnel

In addition to the availability and assignment of personnel, the planner may need to address several other personnel issues. The following examples may apply to the organization of CTD personnel for various applications and locations.

- Training and certification of personnel
- Personnel job descriptions
- Operations and support organization charts

Administrative Preparation

The planner must clarify and finalize arrangements between the customer and the contractor(s). The final agreement should include the following sections:

- Equipment list provided by contractor(s) and the customer
- Personnel list provided by contractor(s)
- List of services provided by contractor(s) and the customer

- Liability clauses
- Day rates, lump sums, incentives, and penalties

Planning Considerations for the Location

The location for the CTD project impacts the planning process at the same level as the well itself, because the location defines the operating environment, the logistics for the project, and applicable regulations. The planner must answer the following questions for a given location:

- Does the location have any physical constraints, e.g., dimensions, surface loading, equipment placement?
- What logistical constraints exist, e.g., limits to access, operational windows, distance from required services?
- What provisions may be necessary to adequately protect the environment, e.g., noise, spill protection, temporary chemical storage?
- Is a crane or mast and drawworks of adequate capacity available, and will it be able to service the needs of the proposed operations?
- Where is the personnel accommodation?
- What local weather, environmental, or seasonal conditions may restrict operations?

Planning Considerations for Well Type

The requirements or objectives for a given CTD well help to define the equipment, procedures, and personnel required to complete the project. These will be different for new wells compared to sidetracking existing wells.

New Wells and Vertical Deepenings

For new wells and vertical deepenings, the planner must answer the following questions:

- What are the exploration and production objectives for the well, e.g., oil or gas, production rate for each fluid?
- What are the requirements for data collection, e.g., electric logging, mud logging, rig instrumentation?
- What is the wellbore design, e.g., open hole sizes and TD for each section, casing program and depth for each shoe?
- If the wellbore is deviated, what is the projected well profile?
- If the wellbore is vertical, what is the maximum acceptable deviation?

- What are the expected downhole conditions, e.g., pressures and temperatures, lithology, risk of shallow gas, sloughing shales, likelihood of H_2S?
- How drillable are the formations, e.g., are offset well bit records available?
- What drilling fluid(s) are appropriate, e.g., under or overbalanced conditions, chances for lost circulation, sensitivity of formations?

At the time of this writing, the technical capabilities for drilling new wells or deepening existing vertical wells with CT are approximately:

- Hole sizes up to 12.25 in. subject to the torque and hydraulic limitations for the CT string. For hole sizes greater than 6.75 in., formations must be unconsolidated.
- Motors up to 6.5 in. OD subject to the torque and hydraulic limitations for the CT string.
- Depth to 10,000 ft depending on hole size, formation drillability, and mechanical and hydraulic limitations for the CT string.

The hydraulic limitations for drilling new wells with CT are due primarily to hole cleaning problems. Chapter 10 "CT Hydraulic Performance" provides a detailed discussion of CT hydraulics and explains the factors affecting the maximum possible flow rate and hole cleaning performance for a given CT string. The most direct solution is to use the largest diameter CT possible (available) for the job. Drill collars above the motor generally supply the necessary WOB in vertical wells, so that the entire CT string is always in tension. Consequently, the axial stiffness of the CT is not an issue, i.e., no buckling problems. However, the heavy BHA and powerful motor required for drilling large diameter holes can push the CT towards its mechanical limits (see Chapter 8 "CT Mechanical Limits"). Both the torque capacity and tension limits for the CT increase with increasing OD, allowing larger and deeper wellbores. The best method of determining the possibilities for applying CTD to new wells or vertical deepenings is to simulate the job with software like Cerberus™.

Existing Well Sidetrack (Reentry Wells)

For sidetracking an existing well, the planner must answer the following questions:

- What are the exploration and production objectives for the well, e.g., oil or gas, production rate for each fluid?
- What are the completion requirements, e.g., configuration, liner size(s), packer(s), cementing?
- What is the wellbore design, e.g., open hole sizes and TD for each section, existing completion sizes and depth for each shoe?
- If the existing wellbore is deviated, what is the well profile?
- What kickoff technique is most appropriate?

- What is the proposed profile for the new well section and what are the tolerances for hitting the target(s)?
- What are the expected downhole conditions, e.g., pressures and temperatures, lithology, risk of shallow gas, sloughing shales, likelihood of H_2S?
- How drillable are the formations, e.g., are offset well bit records available?
- What drilling fluid(s) are appropriate, e.g., under or overbalanced conditions, chances for lost circulation, sensitivity of formations?

At the time of this writing, the technical capabilities for sidetracking existing wells with CT are:

- For through tubing operations, minimum production tubing size is 3.5 in.
- CTD can drill hole sizes up to 4.75 in. with a maximum build rate of 60º/100 ft. and hole sizes up to 6.0 in. with a maximum build rate of 15º/100 ft.
- Achievable total depth depends on the well profile, hole sizes, WOB requirements, and limitations for the CT string, but is at least 15,000 ft.
- Achievable total horizontal drainhole length depends on the well profile, hole sizes, WOB requirements, and limitations for the CT string, but is at least 3000 ft.

The total depth and horizontal drainhole length limitations for sidetracks are due primarily to hole cleaning problems and inadequate WOB due to excessive drag. Chapter 10 "CT Hydraulic Performance" provides a detailed discussion of CT hydraulics and explains the factors affecting the maximum possible flow rate and hole cleaning performance for a given CT string. The most direct solution is to use the largest diameter CT possible (available) for the job. This also increases the stiffness of the CT, reducing buckling and generally increasing WOB for a given depth (see Chapter 7 "Buckling and Lock-up"). However, the best method of determining the possibilities for applying CTD to sidetracking existing wells is to simulate the job with software like Cerberus™.

Running and Pulling Wellbore Tubulars

Pulling the completion string from existing wells may be necessary before sidetracking or deepening them. In addition, running new completion strings may be part of the CTD project. Therefore, the planner must consider these requirements and provide for the equipment, procedures, and personnel to perform these operations. If a mast and drawworks are not available, the planner has two options, crane or jacking substructure. The choice depends on the weight of the tubulars to be run or pulled.

Crane

Providing the weight of the tubing or casing string does not exceed the crane capacity, this is the simplest method of running or retrieving the string. The crane becomes a substitute for the rig and must have a significant reserve capacity in case the string gets stuck. Most cranes can only handle singles, so pulling and running tubulars is slower than with a rig. Conventional drilling slips, elevators, and safety clamps are suitable for this application as well. A power tong is required to make up the connections.

Substructure with Jacking System

Dowell has designed and built three different systems combining a substructure and snubbing jacks to run or pull wellbore tubulars without the requirement for a mast. The jacks operate only with downward loading, i.e., they do not have any snubbing capability. The Hydra-Rig or Kremco systems have two jacks with a 160,000 lbf pulling capacity and an 11 ft stroke. The Hydra Rig system can only be used with 7.06 in. or smaller BOPs. Figure 15.67 shows one of these units. The Dreco system has four jacks with a 200,000 lbs pulling capacity and an 8 ft stroke. This system can be used with a 13.625 in. BOP stack, making it the best jacking system for CTD applications. These substructures accommodate a tubing power tong to make up or break the tubing connections. The crane handles single joints of tubing. All three systems allow the injector head to be skidded off the well.

FIGURE 15.67 *Substructure with Jacking System (Dowell)*

BHA Deployment for Underbalanced Drilling

In underbalanced drilling, the BHA must be deployed and retrieved under live well conditions (WHP > 0). The two options are (1) an external lubricator eg. wireline lubricator or riser above the BOP, or (2) an internal lubricator eg. The length of production tubing between the BOP and SSSV.

External Lubricator

The deployment procedures are similar to those used when deploying CT service tools. See Chapter 18 "Deploying a Long Tool String in a Live Well", page 18-53 for details about live well deployment. This technique can require substantial overhead clearance and may not be suitable for many locations. Other locations may not be able to accommodate a lubricator tall enough to house the entire BHA. In those cases, a method of assembling the BHA sections inside the pressure containment is necessary. An advantage of using an external lubricator is that the well can continue flowing during rigging up/down of the BHA.

Internal Lubricator

Using the production tubing between the BOP and the SSSV as a lubricator depends on the local regulations and well control practices. However it is a “low profile” option for locations with limited overhead clearance. A disadvantage of this approach is that it shuts in the well during rigging up/down of the BHA. Consequently, it is not a good alternative where the entire CTD operation must be conducted with the well underbalanced.

CTD “Good Practices”

The operational practices used in CTD are largely the same “good practices” developed for conventional drilling applications. The planner should incorporate as many of the following as possible into the procedures for the CTD operation:

- Bit selection depends on formation hardness, available WOB, and motor RPM. Choose a bit suitable for the formation; coned bits for soft-medium formations (high-speed bits are best); fixed-cutter, drag bits for harder drilling conditions.
- The drilling fluid system must be compatible with the formations and drilling conditions. In most cases a shear-thinning fluid system is a good choice for optimizing hole cleaning.
- Allow the hole cleaning performance to determine the maximum acceptable ROP. Drill only as fast as the hole can be cleaned based on size and volume of cuttings in the return fluid flow.
- Maintain the highest flow rate possible whenever the CT string is in the well and avoid shutting down the pumps unless absolutely necessary, e.g., flow checks.
- Regularly sweep the hole with a high-viscosity fluid, especially in larger hole sizes. Establish the required frequency for sweeps after observing the hole cleaning efficiency of the drilling fluid.
- Periodically circulate bottoms-up. Establish the required frequency based on ROP and hole cleaning efficiency.
- Conduct frequent, regular wiper trips. Establish the required frequency and distance to pick up after observing hole cleaning efficiency. Conduct a wiper trip any time the CT operator observes abnormal drag.
- To avoid stalling the motor, maintain a constant WOB that is appropriate for the motor pressure differential and ROP.
- Avoid swabbing the hole during POOH by maintaining a pulling speed that is consistent with the rate of back-filling the hole with fluid.
- Avoid surging the hole during RIH with excessive speed and excessive flow rate. A CT hydraulics simulator can help set the limits for running speed and flow rate during RIH.

NOTE: CTD techniques generally drill "near-gauge" holes, thereby increasing the potential for surging (RIH) and swabbing (POOH) the formation.

CTD Equipment Selection

Many factors affect the selection of equipment used for a CTD project including:

- Well location
- Well type
- Necessity for pulling/running jointed pipe
- Well control method (over or under balanced)
- BHA deployment
- Availability

However, the following list summarizes the principle equipment necessary for a typical CTD operation:

- CTD rig
- CT equipment
- BHA
- Pressure control equipment
- Kick detection system
- Drilling fluid system
- Pumping equipment
- Data acquisition system
- Jointed pipe handling equipment
- Ancillary surface equipment
- Safety and emergency equipment

An important function for the planner is to develop detailed checklists for all of the equipment and to designate the individual(s) responsible for confirming the arrival and condition of all of the equipment on location.

CTD Rig

The type, configuration, size, and performance capabilities for a substructure to support the injector head and handle jointed pipe depend primarily on the requirements for pulling/running jointed pipe. That is, the main consideration for choosing a CTD “rig” is the above ground activities. After the BHA is below the BOP, the rig is on standby. Therefore, chose a substructure, mast unit, or rig that will add value to the operations at the surface. Section “CTD Rig Systems” page 15-32 describes many of the CTD rig systems available at the time of this writing.

CT Equipment

The selection of CT equipment for a drilling operation depends primarily on the type of well planned and the expected downhole conditions. Chapter 4 “CT Surface Equipment” provides an overview of CT surface equipment used for well workover operations.

CT string

New and directional wells typically require CT larger than 1.75 in. OD with a wall thickness of at least 0.156 in. The CT material yield strength should be at least 80 Kpsi. For vertical wells and deepenings, 1.50 in. CT may be adequate. Determine the CT size, wall thickness, and material required for a given well from the results of a CT simulator like Orpheus™ (see Chapter 17 "CT Simulators", page 17-11). The installation of electric cable inside the CT string depends on the BHA selected. Chapter 12 "Logging with CT (Stiff Wireline)", page 12-44 describes the options available for installing and removing the electric cable.

Injector Head

New and directional wells require an injector head with a minimum pulling capacity of 60,000 Ibf. For vertical wells and deepenings, an injector head with pulling capacity of 40,000 Ibf capacity may be adequate. Use a guide arch with the largest possible radius to reduce CT fatigue damage (see Chapter 9 "Minimizing CT Fatigue", page 9-20). Determine the actual performance requirements for the injector head based on the surface weight predicted by a CT simulator for POOH in the planned well.

Reel

The reel must have adequate capacity for the CT string selected for the project. Use the largest core diameter possible to reduce CT fatigue (see Chapter 9 "Minimizing CT Fatigue", page 9-20).

Powerpack

If the CT unit powerpack will supply any non-standard equipment, e.g., high capacity injector head, or auxiliary equipment during the drilling operation it must have adequate reserve capacity to operate all of the equipment simultaneously without affecting the operation of the injector head.

Crane or Lifting Equipment

Onshore, the hydraulic crane attached to the CT unit or an independent hydraulic crane truck should be adequate for handling the injector head and BHA. Offshore, a crane on the platform or support vessel, e.g., lift boat or barge, would provide this function. If the drilling operation includes pulling/running jointed pipe, a more substantial crane or lifting structure will be necessary.

BHA

Section “Bottom Hole Assembly” through Section “Drill Bits for CTD” describe the components for CTD BHAs, and Section “Exiting an Existing Wellbore” suggests BHAs for exiting an existing wellbore and directional drilling. The choice of BHA for a particular project depends on a number of factors including:

- Hole size
- Requirements for directional control
- Requirements for downhole measurements, e.g., gamma ray, pressure, temperature, WOB
- Drilling fluid (MWD requires a liquid path to surface)
- Bottom hole temperature
- Deployment method (underbalanced)
- Availability of electric cable installed in the CT

Pressure Control Equipment

The BOP bore size for CTD depends on the planned wellbore and completion size. Two common BOP sizes used for drilling are 4.06 in. and 7.06 in. The former is usually a quad ram configuration, and the latter is usually a combined ram configuration. Larger BOP sizes may be needed for certain applications or nonstandard BHAs. For most CTD applications, a pressure rating of 5000 psi is adequate, but the actual pressure rating must be compatible with the expected bottom hole pressure. An annular BOP is also required to seal around the BHA during trips or around large diameter tubulars such as a completion.

The choke line, kill line, and choke manifold are the same as used for standard drilling operations. When using two BOP stacks, the drilling fluid return line must have a remotely-operated valve. All BOP controls must be operable from the Koomey unit and inside the CT unit cab.

Kick Detection System

Rapid detection of kicks or losses is essential when drilling overbalanced in a small diameter hole. Two methods are suitable for CTD, flow comparison and drilling fluid pit level monitoring.

The best way of detecting whether the well is flowing or losing fluid is to measure the difference between the flow rate into the well and the flow rate returning from the well. This requires an accurate measurement of the flow at the inlet of the CT reel and at the return line to the drilling fluid system. The best approach is to install a suitable flow meter, e.g., magnetic or MicroMotion™ type, at each location. However, an accurate pump stroke counter is an alternative for measuring the flow into the well if the volumetric output of the pump has been calibrated. Once in operation, the difference between the two flow measurements will indicate a kick or a loss. The “delta flow” signal is easy to monitor with a data acquisition system and use for triggering alarms.

Detecting a kick or a loss by measuring the change in the level of a drilling fluid pit is simple in theory but more difficult in practice. For small diameter wellbores, the drilling fluid pit must be small enough to register small volume changes. On the other hand, the drilling fluid pit must be large enough to accommodate the needs of the drilling operation. Also, the trend in the drilling fluid pit level is the actual indicator of a kick or loss. This is not as simple to monitor automatically as “delta flow” but a computerized data acquisition system can usually handle the task.

Drilling Fluid System

The drilling fluid system for CTD is the same as for conventional drilling, only smaller volume. Select the total volume of the active surface pit(s) based on recommendations from the drilling fluid service company. The active system includes the drilling fluid in the wellbore, so the surface pits must be sized for the desired round trip circulation time to accommodate additions of materials and treatment chemicals. A typical drilling fluid system for CTD has an active volume of approximately 50 bbl. Mixing and reserve pits may be added to accommodate bulk additions of materials or preparing whole volumes of new drilling fluid.

The solids control equipment for CTD usually consists of a high performance shale shaker with relatively fine-mesh screens and a centrifuge. The required processing capacity (performance capability) for each depends on the hole size being drilled and the expected drilling fluid flow rate. For new wells, sloughing shales, or unconsolidated formations, a conventional shaker with relatively coarse screens upstream of the high performance shaker can remove large and/or sticky cuttings. The centrifuge is necessary for removing the relatively fine cuttings generated by CTD.

For overbalanced drilling, a “poor boy” or vacuum degasser is adequate for separating produced gas from the drilling fluid. For underbalanced drilling, a three-phase separator sized for the expected flow rates of liquid(s), solids, and gas is required. Liquid hydrocarbons can be sent to the production facilities (if available) for processing or stored for processing later. Produced gas can be sent to the production line or flared. Removal and disposal of the solids (cuttings) depends on local regulations.

Pumping Equipment

The pumping equipment consists of low pressure centrifugal pumps for mixing the drilling fluid, agitating the pits, transferring fluid from pit to pit, and charging the high pressure pump(s), and at least one high pressure, positive displacement pump for circulating the drilling fluid through the CT and wellbore. The specifications for the high-pressure pump(s) depend on the flow rate and pressure (hydraulic HP) required by the drilling operation. Adding excess pumping capacity, e.g., for contingency operations or planned maintenance, is a prudent move. A set of controls for operating the high-pressure pump(s) must be located in the CT unit cab.

Data Acquisition System

A standard CT unit data acquisition system as described in Chapter 4 "CT Data Acquisition System (DAS)", page 4-51 should be adequate for a CTD operation with the addition of a few extra input channels, e.g., pit level(s) and/or “delta flow”.

Jointed Pipe Handling Equipment

Regardless of whether the CTD project includes pulling an existing completion and running a new one, the operations personnel will still have to assemble/disassemble the BHA. Section “Running and Pulling Wellbore Tubulars” page 15-105 describes cranes and substructures for pulling/running jointed pipe. The following list summarizes additional equipment for handling jointed pipe.

- Tubing spider slips to hold the BHA or jointed tubing when making or breaking joints
- Elevators to hoist single joints of pipe
- Safety clamps to prevent the string from falling into the hole if the slips fail
- Tubing power tong to make or break jointed connections with the proper torque

Ancillary Surface Equipment

Every CTD operation requires or benefits from additional equipment not described above. This ancillary equipment might include:

- Generator to provide electricity to the living accommodations, office(s), flood lights, centrifuge, monitoring equipment, etc.
- Electrical distribution panel for connecting the generator to the various electrical loads and providing circuit breakers
- Flood lights for safe night operations
- Air compressor for starting diesel engines, operating air-powered tools, and supplying instrument air
- Tools container or portable workshop stocked with hand and power tools
- Spare parts container

Safety and Emergency Response Equipment

A prudent planner acknowledges that accidents and emergencies happen and provides contingencies for such occurrences. The following list includes a few suggestions for safety and emergency response equipment for a CTD operation.

- Emergency shut-down (kill) control for each engine on location
- Fire fighting equipment, e.g., appropriate fire extinguishers at strategic locations around the equipment and in the accommodations
- Air packs, as necessary for sour gas operations or fire fighting
- H_2S detection system for sour gas operations
- Eye wash stations (precharged with pure water) at strategic locations around the drilling fluid system
- Protective clothing, e.g., apron, goggles, and long sleeve gloves, for handling chemicals
- First aid kits
- Portable communications equipment, e.g., radios or intercom

Well Control and Safety Issues

The primary objective of well control in overbalanced drilling is to prevent an influx of formation fluid(s) into the wellbore. This means the hydrostatic pressure generated by the drilling fluid must always slightly exceed the highest open hole formation pressure. The equipment and techniques used on CTD operations further minimize some of the risks when drilling overbalanced. Primarily these are fast shut-in time and the ability to RIH and POOH with pressure at the wellhead.

The primary objective of well control in underbalanced drilling is to allow a controlled influx of formation fluid(s) into the wellbore. This means the combined frictional pressure loss in the annulus and the hydrostatic pressure generated by the drilling fluid must be less than the open hole formation pressure. In other words, the primary well control mechanism is not the hydrostatic pressure of the drilling fluid. Instead, the primary barrier of the CT equipment (stripper) is the initial defense against a kick.

Considerations for Overbalanced Conditions

Important considerations for overbalanced CTD include:

- All personnel involved in the drilling process should be trained and qualified in well control theory and application.
- BOP equipment must be suited to the specific operating conditions and meet local regulatory requirements.
- The CT unit operator must have easy access to the BOP controls, but a redundant system should be located away from the CT unit for operation by other personnel.
- Test the BOP controls and personnel responses on a regular basis.
- Provide a system for monitoring fluid flow in and out of the well.
- Provide a system for monitoring the level(s) of the drilling fluid pit(s).
- Provide a gas detection system for combustible hydrocarbons and H_2S.
- Develop a procedure for shutting in the well for all potential scenarios.
- Develop a well-kill procedure based on the specific equipment on location.

Considerations for Underbalanced Conditions

For underbalanced drilling operations, the planner should document a means of returning the well to a static condition. The methods all depend on the relationship between the formation pressure and normal pressure gradient.

Formation Pressure Less Than Normal Pressure Gradient

For the well to flow, either gas lift or foam must be used to reduce the annular hydrostatic pressure. Reducing the gas injection rate or foam quality is a simple way to increase the bottom hole pressure and kill the well. However, this requires a thorough understanding of the affect of higher pressure on all of the open hole sections.

Formation Pressure Equal To Normal Pressure Gradient

The hydrostatic pressure exerted by a low density drilling fluid, e.g., native crude, is low enough for the open hole formation to flow. The amount of underbalance is not easy to adjust quickly, because the total fluid volume must be modified, i.e., weighted up or diluted. However, killing the well only requires adding a denser fluid to the circulating system.

Formation Pressure Greater Than Normal Pressure Gradient

The well will flow if the drilling fluid density is less than what would normally be used in overbalanced drilling. Killing the well requires significantly higher density fluid.

CTD PROCEDURE AND TASK LIST

The following list is a summary of procedures and tasks associated with planning and preparing a generic CTD operation. The purpose of this list is to provide the starting point for a specific CTD operation.

You can find a copy of this task list in a Microsoft Word document on the CD ("CTD Procedure and Task List.doc").

1. Well Planning
    1.1. CTD Engineer
        1.1.1. State Permit
            1.1.1.1. Notification/Reporting Requirements
            1.1.1.2. Contact Numbers
        1.1.2. Operations Procedure
            1.1.2.1. Target Definition
            1.1.2.2. Geologic Summary
            1.1.2.3. Mud/Fluids Design/specifications
            1.1.2.4. Emergency Response Plan
                1.1.2.4.1. Chain of Command
                1.1.2.4.2. Notification Chain
                1.1.2.4.3. Emergency Contact Numbers
                1.1.2.4.4. Plan Details
            1.1.2.5. Emergency Action Plan
                1.1.2.5.1. Chain of Command
                1.1.2.5.2. Notification Chain
                1.1.2.5.3. Emergency Contact Numbers
                1.1.2.5.4. Plan Details
            1.1.2.6. Reporting Requirements
            1.1.2.7. Drawings, Plots, and Schematics

1.1.2.7.1. Directional Plot

1.1.2.7.2. Target Map

1.1.2.8. Contingencies

1.1.2.9. Supporting technical information

1.1.2.9.1. CT specifications

1.1.2.9.2. Pressure drops

1.1.2.9.3. Predicted loads (CT simulator)

1.1.2.9.4. Motor performance curve

1.1.3. AFE/Cost Authorization

1.2. Wellsite Geologist

1.2.1. Possible Lost Circulation Zones

1.2.2. Possible Over-pressured Zones

1.2.3. Geologic Stratigraphic Column

1.2.4. Geologic Description of Intervals to be drilled

1.2.5. Location of faults

1.2.6. Drilling history of original well/primary cement job details (plus any production logging results verifying isolation)

1.2.7. Close approaches

1.3. Standard Operating Procedure

1.3.1. Notification of affected operations

1.3.2. Well History

1.3.2.1. Completion Diagram

1.3.2.2. Well Operations Telex File

1.3.2.3. Gyro Survey

1.3.2.4. Pertinent log copies

1.3.2.5. Site Plan/Footprint

2. Equipment Requirements

2.1. Drilling contractor

2.1.1. Drilling tower if required

2.1.1.1. Hazop/Hazid criteria met

2.1.1.1.1. Responsibilities

2.1.1.1.2. Chain of Command

2.1.1.1.3. Specific Skills Required

2.1.1.1.4. Support Requirements

2.1.1.1.5. Contingency Plans/Emergency Procedures

2.1.1.1.6. Safety Issues/Weather

2.1.1.2. Rig Up/Rig Down procedure

2.1.1.3. Crew training in Rig up/Rig down

2.1.1.4. Maintenance/Inspection

2.1.1.4.1. Maintenance Procedure

2.1.1.4.2. Inspection Procedure

2.1.1.5. Documentation

2.1.1.5.1. Materials

2.1.1.5.2. Manufacture

2.1.1.6. Equipment Checklist

2.1.2. CT Unit

2.1.2.1. Hazop/Hazid criteria met

2.1.2.1.1. Responsibilities

2.1.2.1.2. Chain of Command

2.1.2.1.3. Specific Skills Required

2.1.2.1.4. Support Requirements

2.1.2.1.5. Contingency Plans/Emergency Procedures

2.1.2.1.6. Safety Issues

2.1.2.2. Crew Training

2.1.2.3. Maintenance/Inspection

2.1.2.3.1. Maintenance Procedure

2.1.2.3.2. Inspection Procedure

2.1.2.4. Equipment Checklist

2.1.3. Downhole Drilling Tools

2.1.3.1. Hazop/Hazid criteria met

2.1.3.1.1. Responsibilities

2.1.3.1.2. Chain of Command

2.1.3.1.3. Specific Skills Required

2.1.3.1.4. Support Requirements

2.1.3.1.5. Contingency Plans/Emergency Procedures

2.1.3.1.6. Safety Issues

2.1.3.2. Procedures for pre-site preparations

2.1.3.2.1. Welding Procedure for Butt Welding CT

2.1.3.2.2. Inspection/X-ray Procedure of weld

2.1.3.2.3. Installation Procedure for CT Connector

2.1.3.3. Procedures for on-site pick up and make up of tools

2.1.3.3.1. Pick-up and Handling Procedure

2.1.3.3.2. Makeup Procedure CT Connector

2.1.3.4. MWD Company - Testing, inspections, and running in hole

2.1.3.4.1. Electronic Test Procedure

2.1.3.4.2. Hydraulic Test Procedure

2.1.3.4.3. Pressure Test Procedure

2.1.3.4.4. Pull Test Procedure

2.1.3.4.5. Troubleshooting Procedure

2.1.3.5. Information recovery and application

2.1.3.5.1. Calibration Procedure for Surface Read-out Equipment

2.1.3.5.2. Data Storage and Transmission Procedure

2.1.3.6. Equipment Checklist

2.1.4. CT

2.1.4.1. Hazop/Hazid criteria met

2.1.4.1.1. Responsibilities

2.1.4.1.2. Chain of Command

2.1.4.1.3. Specific Skills Required

2.1.4.1.4. Support Requirements

2.1.4.1.5. Contingency Plans/Emergency Procedures

2.1.4.1.6. Safety Issues

2.1.4.2. Maintenance/Inspection

2.1.4.2.1. Fatigue Tracking

2.1.4.2.2. Inspection Procedure

2.1.5. Surface Controls Systems

2.1.5.1. Hazop/Hazid criteria met

2.1.5.1.1. Responsibilities

2.1.5.1.2. Chain of Command

2.1.5.1.3. Specific Skills Required

2.1.5.1.4. Support Requirements

2.1.5.1.5. Contingency Plans/Emergency Procedures

2.1.5.1.6. Safety Issues

2.1.5.2. Maintenance/Inspection - Electric/Hydraulic Testing/Maintenance Procedure

2.1.5.3. Equipment Checklist

2.1.6. Reel - Maintenance/Inspection

2.1.7. Lubricator if required

2.1.7.1. Maintenance/Inspection

2.1.7.1.1. Maintenance Procedure

2.1.7.1.2. Inspection Procedure

2.1.7.2. Documentation

2.1.7.2.1. Materials

2.1.7.2.2. Manufacture

2.1.8. Injector Head/Guide arch - Inspection requirements

2.2. PDM Company / MWD Company

2.2.1. Downhole Motor/Steering Tools

2.2.1.1. Hazop/Hazid criteria met

2.2.1.1.1. Responsibilities

2.2.1.1.2. Chain of Command

2.2.1.1.3. Specific Skills Required

2.2.1.1.4. Support Requirements

2.2.1.1.5. Contingency Plans/Emergency Procedures

2.2.1.1.6. Safety Issues

2.2.1.2. Procedures for pre-site preparations

2.2.1.3. Procedures for on-site pick up and make up of tools (Make-up Procedure/Torque Requirements)

2.2.1.4. Maintenance/Inspection

2.2.1.4.1. Maintenance Procedure

2.2.1.4.2. Inspection Procedure

2.2.1.5. Drilling

2.2.1.6. Information recovery and application

2.2.1.6.1. Calibration Procedure for Surface Read-out Equipment

2.2.1.6.2. Data Storage and Transmission Procedure

2.3. Drilling Fluids

2.3.1. Solids Control

2.3.1.1. Operation Procedure

2.3.1.2. QA/QC Checks

2.3.1.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.3.1.3.1. H_2S/Methane/CO Monitors with remotes

2.3.1.3.2. Pit Level Monitors

2.3.1.3.3. Fluid Overflow

2.3.1.4. Personnel Experience/Training

2.3.2. Well Fluids

2.3.2.1. QA/QC during Make-up

2.3.2.2. Rheology Testing during/after Make-up

2.3.2.3. Rheology Testing On-site (Daily)

2.4. Fluid Pumping Equipment

2.4.1. Pumping Equipment

2.4.1.1. Operation Procedure - Equipment Limitations

2.4.1.2. Maintenance/Inspection

2.4.1.2.1. Maintenance Procedure

2.4.1.2.2. Inspection Procedure

2.4.2. Piping and Valves

2.4.2.1. Make-up Procedure

2.4.2.2. Testing Procedure - Pressure Limitations

2.4.2.3. Maintenance/Inspection

2.4.2.3.1. Maintenance Procedure

2.4.2.3.2. Inspection Procedure

2.5. Trucking Company

2.5.1. Winch Trucks

2.5.2. Vacuum Trucks

2.5.3. Cranes

2.5.3.1. Operation Procedure

2.5.3.2. QA/QC Checks

2.5.3.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.5.3.4. Personnel Qualification/Experience/Training

2.5.3.5. Ground Support Personnel Training

2.5.3.6. Weather Limitations/De-ratings

2.5.4. Personnel Lift

2.5.4.1. Operation Procedure

2.5.4.2. QA/QC Checks

2.5.4.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.5.4.4. Personnel Training

2.6. Miscellaneous Equipment

2.6.1. Heaters

2.6.1.1. Operation Procedure

2.6.1.2. QA/QC Checks

2.6.1.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.6.2. Light Towers

2.6.2.1. Operation Procedure

2.6.2.2. QA/QC Checks

2.6.2.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.6.3. Cranes

2.6.3.1. Operation Procedure

2.6.3.2. QA/QC Checks

2.6.3.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.6.3.4. Personnel Qualification/Experience/Training

2.6.3.5. Ground Support Personnel Training

2.6.3.6. Weather Limitations/De-ratings

2.6.4. Personnel Lift

2.6.4.1. Operation Procedure

2.6.4.2. QA/QC Checks

2.6.4.3. Verify Operation and Correct Settings of Safety Systems/Alarms

2.6.4.4. Personnel Training

2.7. Whipstock supplier

2.7.1. Materials traceability

2.7.2. Manufacturing QA/QC

- 2.7.3. Maintenance/Inspection
  - 2.7.3.1. Maintenance Procedure
  - 2.7.3.2. Inspection Procedure
- 2.8. BOP - Flow cross, hoses, choke manifold
  - 2.8.1. Materials traceability
  - 2.8.2. Manufacturing QA/QC
  - 2.8.3. Maintenance/Inspection
    - 2.8.3.1. Maintenance Procedure
    - 2.8.3.2. Inspection Procedure
- 2.9. Mills, Flex joints, String Mills/Reamers
  - 2.9.1. Materials traceability
  - 2.9.2. Manufacturing QA/QC
    - 2.9.2.1. Manufacturing Tolerances
    - 2.9.2.2. Heat Treating Procedure
  - 2.9.3. Maintenance/Inspection
    - 2.9.3.1. Maintenance Procedure
    - 2.9.3.2. Re-dressing Procedure
    - 2.9.3.3. Heat Treating Procedure
    - 2.9.3.4. Inspection Procedure
- 2.10. Wireline Company
  - 2.10.1. E-line Unit
  - 2.10.2. Whipstock Setting Tools
  - 2.10.3. Orienting/Correlating Equipment
  - 2.10.4. Lubricator and Pressure Control Equipment
- 2.11. Customer operations
  - 2.11.1. Squeeze/Fluid Handling Unit, if required
    - 2.11.1.1. Hazop/Hazid criteria met
      - 2.11.1.1.1. Responsibilities
      - 2.11.1.1.2. Chain of Command
      - 2.11.1.1.3. Specific Skills Required

2.11.1.1.4. Support Requirements

2.11.1.1.5. Contingency Plans/Emergency Procedures

2.11.1.1.6. Safety Issues

2.11.1.2. Spill Contingency Plan

2.11.1.3. Number of Personnel Required

2.11.1.4. Personnel Training

2.11.2. Fluid Storage Tanks

2.11.2.1. Spill Control/Dikes

2.11.2.2. Spill Contingency Plan

3. Pre-job Preparations

3.1. Customer operations

3.1.1.1. Site Preparation

3.1.1.2. Leveling

3.1.1.3. Access

3.1.1.4. Possible Obstructions to other operations

3.1.1.5. Shut-in surrounding wells for rig up

3.1.2. Agreement with production department regarding possibility of sending various fluids down flow line

3.1.3. Auxiliary equipment to location

3.1.3.1. Squeeze Unit

3.1.3.2. Light Towers

3.1.3.3. Heaters

3.1.3.4. Tanks

3.1.3.5. Bleed Trailer

3.1.4. Reserve Rig Up/Rig Down and Operations Equipment from contractor

3.1.4.1. Crane

3.1.4.2. Loader/Fork Lift

3.1.4.3. Trucks

3.1.4.4. Personnel lift

3.1.5. Well/Wellhead/Flow line Preparations

3.1.5.1. Tubing Integrity Test

3.1.5.2. Shoot Annulus Fluid Level

3.1.5.3. Grease all Christmas Tree Valves

3.1.5.4. Skid choke inspected

3.1.6. Maintenance, QA/QC checks, Inspection, Training Verification

3.2. Drilling contractor

3.2.1. Injector head

3.2.2. CT Upper Connector installed

3.2.3. Pull Test Connector

3.3. Motor supplier

3.3.1. Bit made up to Motor – Torque and Thread Lock per Make-up Procedure

3.3.2. Motor Bend verified

3.4. Whipstock supplier

3.4.1. Verify correct Setting Tool with Wireline Company

3.4.2. Verify correct Orientation to Wireline POL Tool

3.4.3. Verify Measurements and Length to CCL - Detailed Drawing including OD/ID/Length/Tray Length etc.

3.5. Wireline Services

3.5.1. Verify correct Setting Tool with Whipstock supplier

3.5.2. Verify correct Orientation to POL Tool

3.5.3. Verify Measurements and Length to CCL

3.5.4. Verify Tie-in Method and Correct Setting Depth

3.6. Customer Operations

3.6.1. Mill Window with General Service CT Unit

3.6.2. Drill Open Hole off Whipstock

3.6.2.1. Open Hole length

3.6.2.2. Information hand-over for Sidetrack Drilling

4. Operations

4.1. Transport to Location

4.1.1. Drilling contractor

4.1.1.1. CT Unit

4.1.1.2. Downhole Drilling Tools

4.1.2. Motor Supplier - Downhole Motor and Steering/GR Tools

4.1.3. Drilling fluids service company - Drilling Fluids

4.1.4. Support Contractor

4.1.4.1. Winch Trucks

4.1.4.2. Crane

4.1.4.3. Vacuum Trucks

4.1.4.4. Heaters

4.1.4.5. Light Towers

4.1.4.6. Crane

4.1.5. Whipstock supplier - Mills, Flex joints, String Mills/Reamers

4.2. Set In and Rig Up (Placement) of drilling rig – Drilling contractor

4.3. BOP Testing, Preparation, and Inspection

4.3.1. BOP Test Procedure

4.3.2. Pressure Test Frequency

4.3.3. Function Test/Inspection Frequency

4.4. Pick up Tools

4.4.1. Drilling contractor - Downhole Drilling Tools

4.4.1.1. Tool Pick-up and Make-up Procedure

4.4.1.2. Test "Wet Connect" to downhole Tools

4.4.2. Motor Supplier - Downhole Motor and Steering/GR Tools

4.4.2.1. Tool Pick-up and Make-up Procedure

4.4.2.2. Test "Wet Connect" to downhole Tools

4.4.3. Whipstock supplier - Tool Pick-up and Make-up Procedure

4.5. Pressure Test

4.5.1. BHA and CT

4.5.2. Lubricator

4.6. RIH and Drilling

4.7. Tripping

4.7.1. Monitor Hole Fill

4.7.2. Open Hole Stability

4.7.3. Hole Cleaning

4.7.4. Monitor Tower Movement

4.7.5. Ledges

4.7.6. Tool face Orientation for movement through window

4.7.7. Short Tripping

4.8. Finish Drilling and Condition Hole

4.9. Completion Procedure

4.10. Rig Down

4.10.1. Drilling contractor - Drilling Rig with CTD unit

4.10.2. Motor Supplier - Downhole Motor and Steering/GR Tools

4.10.3. Whipstock supplier - Mills, Flex joints, String Mills/Reamers

4.10.4. Drilling Fluids Service Company

4.11. Follow-Up Evaluation and De-Briefing

4.11.1. Customer engineering

4.11.2. Customer operations

4.11.3. Drilling contractor

4.11.4. Motor Supplier

4.11.5. Support Contractors

4.12. Contingencies

4.12.1. Stuck Pipe

4.12.1.1. Procedure for Working Stuck Pipe

4.12.1.1.1. Maximum Overpull

4.12.1.1.2. CT Cycles (With and Without Pressure)

4.12.1.1.3. Spotting fluid

4.12.1.1.4. Hydrostatic Reduction with N_2

4.12.1.2. Disconnect Procedure

4.12.1.2.1. Decision Making Process

4.12.1.2.2. Procedure for Disconnect

4.12.1.2.3. Hole Clean up before POOH

4.12.1.2.4. Fishing Considerations

4.12.2. Gas Kick/Blowout

4.12.2.1. Kick Recognition

4.12.2.2. Procedure for Circulating a Gas Kick Out to Surface Equipment to Kill

4.12.2.2.1. Gas Handling Equipment at Surface

4.12.2.2.2. Equipment and Personnel Safety

4.12.2.2.3. Kill Sheet Calculation and Pump Schedule

4.12.2.2.4. Personnel Assignments during Kill Operation

4.12.2.2.5. Decision Process

4.12.2.3. Procedure for Circulating a Gas Kick Down Flowline

4.12.2.3.1. Notify customer production department of Pumping down Flowline

4.12.2.3.2. Kill Sheet Calculations and Pump Schedule

4.12.2.3.3. Decision Process

4.12.2.4. Procedure for handling a gas kick while Under-Balanced Drilling

4.12.2.4.1. Switch to taking returns down Flowline and continue Drilling

4.12.2.4.2. Monitor Hole Condition with frequent Short Trips

4.12.2.4.3. Decision Process

4.12.2.5. Personnel Assignments

4.12.2.5.1. Customer Operations Supervisor

4.12.2.5.2. CT Unit Supervisor

4.12.2.5.3. CT Unit Crew Members

4.12.2.5.4. Service Co. Personnel

4.12.2.5.5. Visitors on Location

4.12.2.6. Emergency Response Plan

4.12.2.6.1. Chain of Command

4.12.2.6.2. Notification requirements

4.12.2.6.3. Emergency Numbers

4.12.3. Procedure for Handling Lost Circulation

4.12.3.1. Move Pipe to Avoid Sticking - Pull into Casing if Massive Lost Circulation occurs

4.12.3.2. Verify Rate of Lost Circulation

4.12.3.2.1. Monitor Returns to Surface

4.12.3.2.2. Circulate across Top of Hole through Mud Cross

4.12.3.3. Overcoming Lost Circulation

4.12.3.3.1. Spot LCM Pill

4.12.3.3.2. Treat Mud System with LCM

4.12.3.3.3. Cement or Gel Squeeze

4.12.3.4. Tool/BHA Plugging

4.12.4. Location Shutdown (pad or platform)

4.12.5. Spills

4.12.5.1. Assessment

4.12.5.2. Environmental Department Notification

4.12.5.3. Emergency Response Plan

4.12.6. Fishing

4.12.7. Unplanned Events

4.12.7.1. CT Failure (Parts)

4.12.7.1.1. Above Pack-off

4.12.7.1.2. Below Pack-off

4.12.7.1.3. Above Injector Head

4.12.7.1.4. Below Injector Head

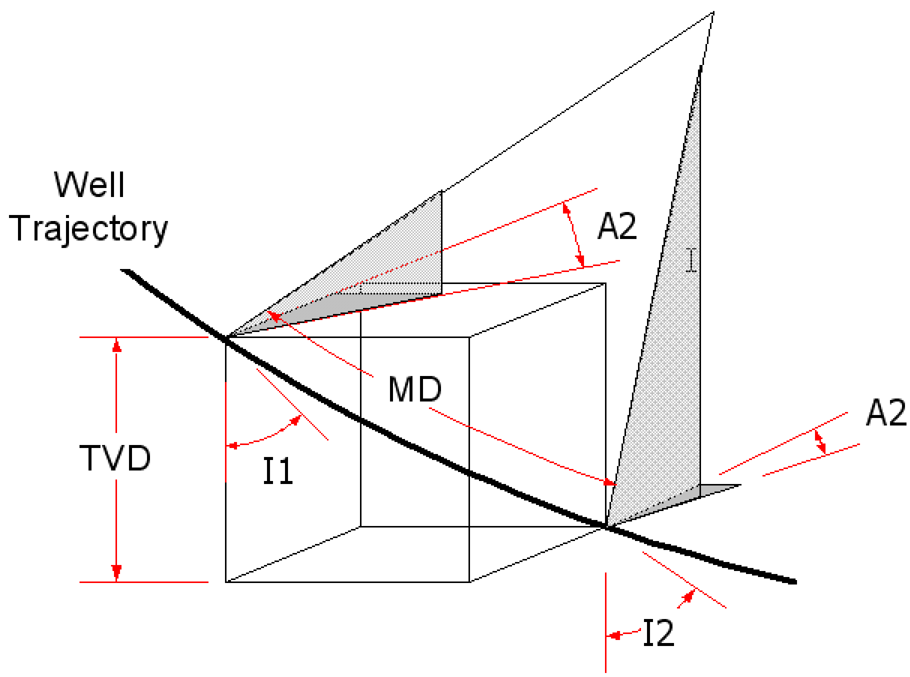
4.12.7.2. Hole in CT

4.12.7.2.1. Above Pack-off

Directional Drilling Calculations

There are several methods that can be used to calculate the well trajectory, but the most common and one of the most accurate method is the minimum curvature. This method effectively fits a spherical arc between two survey points. It takes the vectors defined by the inclination and azimuth at each of the survey points and smooths these on to a wellbore trajectory by the use of a ration factor, which is defined by the curvature of the wellbore. The following are the calculations used:

FIGURE 15.68 *Minimum Curve*



Survey Calculations for Minimum Curvature:

EQUATION 15.1 *Dogleg*

EQUATION 15.2 *Ratio Factor*

EQUATION 15.3 *ΔTVD*

EQUATION 15.4 *ΔNorth/South*

EQUATION 15.5 *ΔEast/West*

EQUATION 15.6 *Dogleg Severity*

where,
I_1 = Inclination at survey point 1 (degree)
I_2 = Inclination at survey point 2 (degree)
A_1 = Azimuth at survey point 1 (degree)
A_2 = Azimuth at survey point 2 (degree)
d = DLS interval (100-ft or 30-m)

16

HIGH PRESSURE OPERATIONS

This chapter summarizes guidelines for planning and conducting high-pressure (HP) CT operations that will minimize the risk of these operations to both the Customer and the service company. For the purposes of this chapter, the definition of “high pressure” is WHP between 3500 psi and 10000 psi.

This manual does not cover CT applications for WHP greater than 10000 psi. Such applications are uncommon and must be considered on an individual basis.

PLANNING CONSIDERATIONS FOR HPCT OPERATIONS

The planning process presented in Chapter 17 "Job Planning", page 17-4 applies to HPCT operations with the additional considerations described in this section.

CT Simulators

Any CT simulator used for planning HPCT operations must be capable of providing the following results:

1. The forces and stresses for each segment in a CT string (as from Orpheus™)
2. The buckling condition for each segment in a CT string (as from Orpheus™)
3. Safe mechanical operating limits for the CT (as from Hercules™)
4. The pressure distribution around the fluid flow path for a given flow rate or an estimate of the flow rate for given pump pressure (as from Hydra™)
5. The accumulated fatigue damage in each segment of the CT string prior to and after the proposed job (as from Reel-Trak™)

CT String Selection

Use a CT simulator to determine what CT string(s) will have adequate mechanical strength and fatigue life to perform the proposed operation(s). Model the operation(s) with a CT simulator to determine suitable outside diameter (OD), wall thickness, and material strength for the CT string. When the CT string could be exposed to H_2S or CO_2 during the job, use the lowest nominal yield strength material that meets the mechanical performance requirements. Generally, resistance to sulfide stress cracking and corrosion both increase with decreasing material yield strength.

NOTE: Adequate mechanical strength satisfies both of the following criteria:

- Maximum von Mises equivalent stress in the CT string is less than 80% of the material yield strength ($\sigma_{VME} < 0.8\sigma_y$). See Chapter 8 “CT Mechanical Limits” for details.
- Calculated collapse pressure (Pc) at the maximum expected tension is greater than 125% of the maximum possible wellhead pressure ($Pc > 1.25 \times WHP_{max}$). See Chapter 8 “CT Mechanical Limits” for details.

NOTE: Adequate fatigue life means that the maximum accumulated fatigue in the CT string at the end of the operation will be less than 80% of its predicted working life. See Chapter 9 “CT Working Life” for details.

Parametric Sensitivity

Parametric studies to assess the risks for a proposed HPCT operation are essential for pre-job planning. The objective is to determine the ranges of operating conditions that pose the lowest risk of failure. Therefore, run simulations for a range of input parameters. See Chapter 17 "CT Simulators", page 17-11 for guidelines for conducting parametric studies. **As a minimum, determine the sensitivity of the proposed HPCT operation to**:

1. CT buoyancy (affects drag and buckling)
2. Cf versus depth (affects drag)
3. Axial force applied at the BHA
    - SDW (affects lockup)
    - Overpull (affects mechanical limits)
4. Wellhead pressure (WHP) (affects collapse)

CT Simulator Output and Its Interpretation

Each CT simulator has a unique output format for tabular data and plots. Regardless of how the simulator presents them, **essential results for understanding the potential outcome of the simulated HPCT operation are**:

1. Predicted CT weight indicator (CTWI) versus depth during RIH and POOH
2. The distribution of axial forces acting on the CT string when it is static at a given depth

3. The distribution of stresses in the CT string when it is static at a given depth

4. The maximum SDW and overpull available at a given depth

5. Working life remaining in each segment of the CT string after the proposed operation plus contingency runs

6. For hydraulic operations at a given depth, the maximum flow rate possible for a given pump pressure

7. For hydraulic operations, the relationship between pump pressure and flow rate versus depth

See Chapter 17 "CT Simulators", page 17-11 for guidelines for interpreting these simulator outputs.

HPCT Job Program

As part of the planning process for each HPCT operation, the service company must submit a job proposal for the Customer's approval per Chapter 17 "Job Planning", page 17-4. The Customer must convert the service company job proposal into a Job Program per Chapter 17 "Job Planning", page 17-4. Avoid the temptation to plagiarize old programs too heavily. Even though some practices and procedures are common to every HPCT job, the combination of operating conditions and equipment for each job will be unique. Revise or amend the job program for a change in service company, equipment specifications, or expected operating conditions.

CAUTION: Do not use a job program for another service company.

WARNING: Do not start the actual HPCT operation until the Job Program accurately reflects the current plans and conditions.

Equipment Selection for HPCT Operations

This section describes the equipment modifications that are required to upgrade a standard CT unit (see Chapter 17 "Equipment Specifications", page 17-25) for HPCT operations.

CT String

1. When the CT string could be exposed to H_2S or CO_2 during the job, the maximum nominal yield strength for any section of the CT string should be 80,000 psi.

2. Butt welds are not acceptable for HPCT strings.

3. Perform a pre-job pipe inspection and confirm there is sufficient life remaining in the tubing.

Injector Head

1. Minimum performance capability of 60,000 lbs pull and 25,000 lbs push (snubbing).

2. Anti-buckling guide (pipe guide extension) that reduces the unsupported length of CT below the injector chains to less than 2 in.

3. A plot of applied tension and applied compression force vs. skate ram pressure for the injector used for the job should be posted in the CT unit control cab.

4. The weight sensor(s) must provide an electronic signal proportional to the CT weight that can be recorded by the data acquisition system (DAS) and displayed in the CT unit control cab. The weight sensor must be capable of measuring snubbing forces equal to the capabilities of the injector head.

Injector Performance Requirements

The injector head performance requirements are based on 1.75 in. OD x 0.156 in. wall CT with σ_y = 80,000 psi and WHP = 7500 psi. The pulling force (F_{axial}) required to yield the CT in pure tension (WHP = 0) is 62,500 lbf from Equation 8.1. The minimum snubbing force (no stripper friction) is the pressure-area force at WHP = 1000 psi acting across the stripper, P_{area} = 24,052 lbf, from Equation 6.18 on page 6-16. Assuming 5000 lbs of drag force at the stripper, the snubbing force would be about 30,000 lbs.

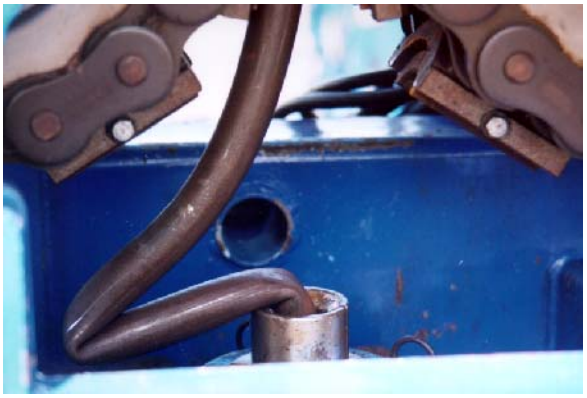
The criterion for determining damage to the CT caused by the injector is different than for standard CT operations. Damage to the CT for high pressure operations is any mechanical gouging or increase in ovality that reduces the collapse rating of the tubing by more than 5% compared to undamaged tubing as calculated by the method of Timoshenko or API RP 5C7. For example, round 1.75 in. OD x 0.156 in. wall CT with σ_y = 80,000 psi should collapse at 14,263 psi, in the absence of axial force according to Equation 8.12 on page 8-19 from Timoshenko. A reduction in wall thickness to 0.149 in. or an increase in ovality to 0.0022 would decrease the calculated collapse pressure by 5% to approximately 13,550 psi.

Anti-buckling Guide

During RIH, the CT can experience high compressive force below the injector chains and above the strippers. This compressive force is enough to buckle unsupported CT in the gap between the stripper and injector chains. Consequently, failure due to buckling is the most serious threat in this gap. A thick-walled cylinder (anti-buckling guide) inserted into the gap can eliminate this threat by providing lateral support for the CT. An anti-buckling is required for all high pressure CT operations.

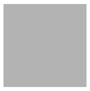
Figure 16.1 shows the catastrophic failure that results from excessive snubbing force on unsupported CT between the injector chains and the stripper.

FIGURE 16.1 *Consequence of Excessive Snubbing Force on Unsupported CT*



For unsupported columns, the slenderness ratio, ξ, determines what form of equation is appropriate to predict the axial force at buckling.

EQUATION 16.1 *Slenderness ratio*



L is the unsupported length of CT and Equation 16.2 defines the radius of gyration, r_g, when r_o = OD/2 and r_i = (OD-2t)/2.

EQUATION 16.2 *Radius of gyration*

Classical elastic buckling theory based on the Euler buckling equation does not apply for “short” columns with $\xi < 80$. The buckling problem illustrated in Figure 16.1 usually falls in this range of slenderness ratio. The Gordon-Rankine buckling equation, Equation 16.3, can be used to determine the critical buckling force for this case.

EQUATION 16.3 *Gordon-Rankine Buckling Equation (General Form)*

where
$F_y = A \times \sigma_y$
σ_y = yield stress of CT material
A = cross sectional area of CT wall = $0.25\pi[OD^2-(OD-2t)^2]$
β = empirical constant determined from tests
ξ = slenderness ratio

Newman, et al[1], conducted numerous tests with new and used CT in a hydraulic press and used CT in three different injector heads to determine appropriate value(s) for β. Figure 16.2 is a single frame from a video recording of one of the injector tests.

1. Newman, K and Aasen, J., “Catastrophic Buckling of Coiled Tubing in the Injector”, SPE Paper 46007, 1998 SPE/ICoTA Coiled Tubing Round Table, Houston, TX, April 15-16, 1998.

FIGURE 16.2 *Injector Snubbing Test (Single Video Frame)*

The results of these tests supported the following conclusions about unsupported buckling of CT:

- The location of the upper support is impossible to determine accurately due to
    - **a.** Chain/stripper alignment
    - **b.** Chain wear
    - **c.** Skate pressure
    - **d.** Chain block location
- The buckling direction is random
- Internal pressure does not affect the buckling load
- Results show significant scatter. Therefore, a large safety factor is necessary.

Based on these tests, Newman, et al, recommends using the following with the Gordon-Rankine equation to determine the maximum allowable snubbing force for unsupported CT.

- L_e, the vertical distance from the top of the stripper to the center of the lower sprocket axle, for L in the slenderness ratio
- $\beta = 0.03$
- 50% safety factor (SF)

Equation 16.4 is the result of applying these recommendations to Equation 16.3 with .

EQUATION 16.4 *Gordon-Rankine equation for CT between the injector and stripper*

where SF is 50%

Pressure Control Equipment

1. The pressure control equipment stack must include the following components, from the top down:
   - Primary
   - Ancillary, if so equipped
   - Secondary
   - Tertiary
2. All pressure control equipment must have a maximum allowable working pressure of at least 10,000 psi.
3. All connections must be flanged. No quick-connects or threaded connections are acceptable for HPCT operations.
4. Post a detailed schematic of the pressure control equipment stack at the following locations:
   - CT unit control cab
   - Remote BOP control panel for the tertiary equipment

NOTE: All components should be fully rated for H_2S service.

Primary Components

1. The primary pressure control equipment must consist of the following components, from the top down:

   a. Upper side-door stripper

   b. Lower stripper – either a radial or tandem side-door
2. Stripper packing elements and anti-extrusion rings

- Rated for high pressure and H_2S service at 250 ºF
- Replace stripper packing elements prior to each HPCT job
- Inspect anti-extrusion rings prior to each HPCT job and replace them as necessary

3. Inspect stripper wear bushings prior to each HPCT job and replace them as necessary

4. Strippers should be equipped with a high-pressure fluid injection port located below the packing element assembly.

5. Determine the maximum ID of lubricator to prevent buckling inside.

6. Inject lubricant or H_2S scavenger either before or into the active stripper when the CT is moving.

Secondary Components

1. BOP elastomers and seals must be rated for high pressure and H_2S service at 250 ºF.

2. The hydraulic accumulator system for operating the BOP rams must have the capability of performing all required operations at max WHP. This includes cutting pipe. If e-line or umbilical line is used inside the tubing, ensure the BOP will cut these items.

Tertiary Components

The tertiary pressure control equipment must consist of two independently controlled single ram BOPs, from the top down:

- Shear/seal BOP
- Pipe/slip BOP

The accumulator on the remote system must have sufficient capacity to open and close the BOP rams twice against a WHP of 10000 psi. Confirm this criteria meets or exceeds the operators minimum safety standards.

Injector Head Support and Work Platform

1. A combination injector head support and work platform should be used to minimize axial forces and bending moments transmitted to the wellhead from the injector head.

2. The minimum load rating of the structure should be the sum of the weight of the injector head and the maximum rated pulling force for the injector head.

Data Acquisition System (DAS)

The DAS for standard CT operations must be capable of recording and displaying

- Time
- Depth
- CTWI
- Reel Inlet Pressure
- Wellhead Pressure
- Pump Flow Rate

The DAS for HPCT operations should be capable of recording the following data in addition to that required for standard CT operations.

- Stripper pressure
- CT reel back tension (reel motor hydraulic pressure)

Stripper drag and reel back tension affect the weight indicator reading. These values are necessary for comparing predicted and measured performance. Both values can be calculated from a pull test. Measuring the stripper pressure and reel motor hydraulic pressure allows a continuous estimate of stripper drag and reel back tension, respectively.

CT Diameter Measurement Tool

1. Real-time monitoring of the CT external geometry (OD) on at least two (2) perpendicular (orthogonal) radials is important for HPCT operations.

2. The measurement tool should be capable of warning the operator about OD and ovality that exceed preset limits. These limits should include:
    - The minimum ID of the stripper

- OD that would cause $\sigma_{VME} > 0.8\sigma_y$
- OD or ovality that would cause Pc < 1.25 x WHP

3. The tool shall have an accuracy of ±5% of the reading.

4. The tool should be capable of creating a data file for each job in a format that can be read with commonly available software such as MS Excel or MS Word.

NOTE: The reliability of the OD and ovality measurements increases as the number of measured radials increases.

A CT string can become unsuitable for continued use if its geometry exceeds certain limits. Aside from the practical reason for determining whether CT can safely pass through the surface equipment and be gripped properly by the injector, real-time measurements of tubing geometry are crucial for avoiding disastrous failures. Tubing geometry has a direct effect on the:

- Stresses in the wall of the tubing caused by pressure and axial forces, see Chapter 8 "The von Mises Yield Condition", page 8-11
- Tubing's collapse resistance, see Chapter 8 "CT Collapse", page 8-18.
- Accumulated fatigue in any segment of the string, see Chapter 9 "CT Fatigue", page 9-5

CT becomes oval during normal use due to plastic deformation on the reel. Also, poorly fitting gripper blocks and worn components in the injector head can damage and deform the CT. Dents and ovality significantly decrease the collapse resistance of the CT. During pumping operations, the internal pressure can cause the CT to balloon as it plastically deforms on the reel and guide arch. This causes a corresponding decrease in the wall thickness. Both dimensional changes substantially weaken the CT's collapse resistance and decrease its working life. Moreover, extreme ballooning and ovality can restrict the passage of the CT through the injector and stripper.

CT working life cannot be measured with a non-destructive test or visual assessment. Even though ballooning coincides with fatigue damage, it is not a direct indication of accumulated fatigue. Ballooning only occurs with internal pressure, and fatigue occurs with every plastic deformation, regardless of pressure.

Safety Issues and Minimizing Risk for HPCT Operations

Completing all HPCT operations safely is one of the primary goals for this chapter. Ensure that both the Customer and the service company comply with the minimum requirements for personnel training, safety equipment, and procedures, before starting the job.

The guidelines provided in Chapter 17 “Minimizing Risk For CT Operations” and Chapter 18 “General CT Operations Guidelines” apply to HPCT operations with a few exceptions. This section highlights the safety issues and considerations for minimizing risk that are unique to high pressure operating conditions.

Operating with Tandem Strippers

Use the upper stripper during normal operations and leave the lower one relaxed (not contacting the CT) until it is needed.

1. If the upper stripper begins to leak, engage the lower stripper, and stop moving the CT (when it is safe to do so).

2. Lower stripper is sealing

- **a.** With the lower stripper sealing the wellbore, close and manually lock the secondary slip and pipe rams. Record the string weight prior to closing the rams.
- **b.** Replace the elements in the upper stripper.
- **c.** Ensure the new stripping elements are sealing.
- **d.** Retract the lower stripper and equalize the pressure across the pipe rams.
- **e.** Equalize the string weight to the recorded value prior to closing the rams.
- **f.** Unlock and open the pipe rams.

3. Lower stripper is leaking:

- **a.** If the lower stripper is leaking also, close and manually lock the secondary slip and pipe ram, then close and lock the tertiary pipe/slip ram. Record the string weight prior to closing any rams.
- **b.** Bleed any trapped pressure above the tertiary pipe/slip ram.
- **c.** Replace the sealing elements in both strippers.
- **d.** Ensure both the lower and upper strippers are sealing.
- **e.** Energize the upper stripper and retract the lower stripper.
- **f.** Equalize the pressure across the tertiary pipe/slip ram.
- **g.** Equalize the string weight to the recorded value prior to closing the rams.
- **h.** Unlock and open the pipe/slip ram.

4. Before resuming normal operations, pick up the CT far enough to inspect the surface of the tubing engaged by the pipe rams. POOH if the CT exhibits any mechanical gouging or increase in ovality that reduces the collapse rating of the tubing by more than 5% compared to undamaged tubing as calculated by the method of Timoshenko or API RP 5C7.

> *WARNING:* Never use a damaged CT string for HPCT operations. Replace the CT string before continuing.

Preventing CT Collapse

A major concern for HPCT operations is collapsing the CT. The CT operator must constantly monitor the stress condition of the CT with the DAS to insure that it is safely within the limits set in the Job Program. As a backup to the DAS, provide the CT operator with plots or tables of collapse pressure versus tension for each wall thickness section in the CT string. Stop the operation and determine how to reverse or halt any trend towards an unsafe condition.

Maintain as much pressure as possible inside the CT at all times. However, high internal pressure accelerates fatigue damage (see Chapter 9 "CT Fatigue", page 9-5). This means reducing the collapse potential must be balanced against prolonging the working life of the CT string. A real-time working life monitor such as Reel-Trak™ can provide ample warning of a developing fatigue problem and allow the CT operator time to determine corrective action.

Pressure Testing

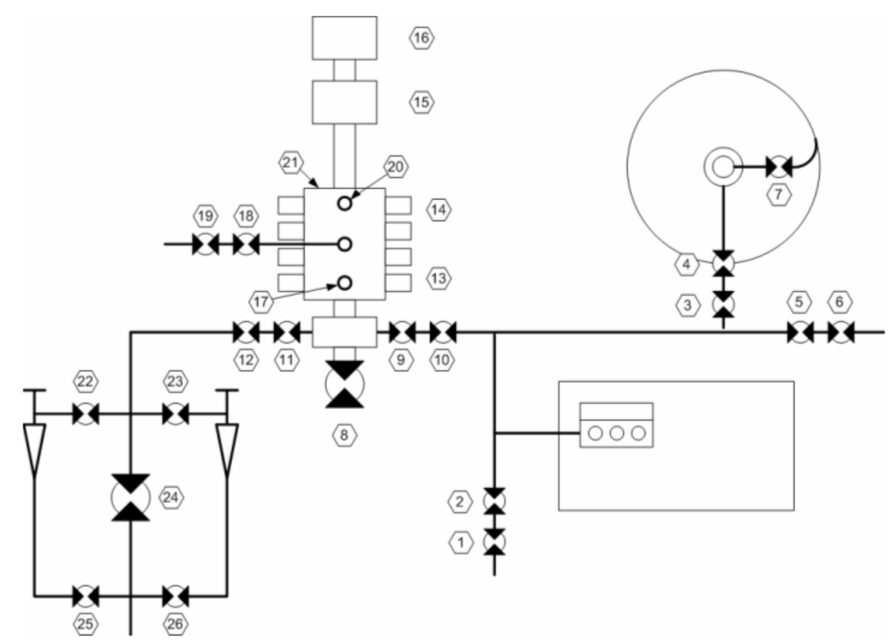
Follow the guidelines of Chapter 17 "Pressure Testing for Standard CT Operations", page 17-36 but use a test pressure of 10000 psi (±250 psi) or 120% of the maximum possible WHP for the planned HPCT operation, whichever is less.

When testing a complicated rig up, typically used in HPCT, the best way to ensure all components are properly tested and not forgotten is to use a Test Matrix, see Table 16.1. The matrix labels each component in the rig up and outlines the order they are tested. Each test is performed in a logical order, to minimize the time required to pressure test. Pressure tests are usually performed at a low (250 psi) and a high (10,000 psi) pressure.

NOTE: The BOP body and sealing rams must also be tested on a test stand in the service company’s yard prior to mobilizing the equipment to the job location.

TABLE 16.1 *Pressure Test Matrix*

Test	Valve Numbers to Close																										Results	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	LP Test	HP Test
1	X					X	X							X					X	X				X	X	X	P/F	P/F
2		X		X	X									X				X		X		X	X	X			P/F	P/F
3		X	X		X							X		X				X		X							P/F	P/F
4		X	X		X						X			X				X		X							P/F	P/F
5		X			X			X	X	X	X		X				X										P/F	P/F
6		X			X			X	X	X						X					X						P/F	P/F
7		X			X			X	X	X					X						X						P/F	P/F



CT String Management

The goal for CT string management is to remove the CT string from further consideration for HPCT operations if any section of the string off the reel during the job no longer has adequate mechanical strength for the expected operating conditions or adequate remaining working life. Removing damaged sections and splicing the string with butt welds is not acceptable for HPCT operations. The only acceptable methods for managing the distribution of fatigue damage in the string are:

1. Swapping ends on the reel (inverting the string)

2. Cutting a length of CT from the free end of the string at regular intervals

3. Using the CT string for a variety of jobs in different wells

Quantifying the effects of dents, scratches, and corrosion pits on the performance of CT is a difficult task at best. Even though these flaws can be measured, (e.g. length, width, depth) their effects can be more significant than their physical size suggests. Every cut or sharp-edged flaw creates a local stress concentration or stress riser that can magnify fatigue damage in the surrounding material. Moreover, such flaws can accelerate corrosion by providing fresh material for attack by corrosive fluids and gases. Measure the penetration of any flaw or damage into the CT wall and use the reduced wall thickness for calculating mechanical limits and fatigue life.

CAUTION: Dimple and slip tubing connectors introduce severe local stress concentrations to the surface of the CT. These stresses exacerbate the effects of corrosive environments, particularly H_2S and CO_2. For CT operations in corrosive environments, a prudent practice is to remove the tubing connector and re-install it on undamaged tubing after each trip into a well.

17

Minimizing Risk For CT Operations

Minimizing risk for CT operations is a process involving every aspect of planning and executing a CT job. Therefore, every participant in this process contributes to the outcome. This section describes a method for planning and preparing for a CT operation that will improve its chance for success. The next chapter (General CT Operations Guidelines) provides general guidelines for CT operations. Most of the concepts presented in these two sections are condensed in Sample Specifications for Coiled Tubing (CT) Operations. This document provides an example of minimum acceptable specifications for equipping, planning, and conducting CT operations in an imaginary development project.

Job Planning

Planning is one of the most critical phases of any CT operation. This section outlines a general method for planning CT operations. This method is designed to help the user anticipate potential problems and develop contingencies. The following list summarizes the planning process.

1. Gather information about the proposed job and well (Customer).
2. Run CT simulator(s) to model the proposed job (Customer and service company).
   - CT string selection
   - Parametric sensitivity
   - Predict operating conditions
3. Prepare a detailed job proposal (service company).
4. Convert the job proposal into a Job Program (Customer).
5. Revise or amend the Job Program (repeat steps 2-4) for any change in equipment specifications and expected operating conditions.

NOTE: Share the Job Program with all participants on the operation.

NOTE: Do not start the actual CT operation until the Job Program reflects the current equipment specifications and expected operating conditions.

Customer Planning Information

The Customer must provide the following information before the planning process can begin:

1. Job description and objective of CT operation
2. Description of well path (survey)
3. Wellbore geometry - well completion diagram
4. Expected wellbore conditions

- Fluids (density, viscosity, composition, and hazards)
- Pressures
- Flow rates (gas, liquid hydrocarbon, reservoir water)
- Temperatures – bottom hole and wellhead (flowing)

5. Bottom hole assembly (BHA) requirements (as determined by Customer)

6. Required flow rate(s) for treatment fluids (as determined by Customer)

7. Treatment fluid(s) – type and volume

8. Potential problems

- Measured depth (MD) for high drag or debris
- Pressure abnormalities
- Logistics (transportation, location constraints, fluid disposal, etc.)

9. Data acquisition requirements

10. Reporting requirements

11. CT test run requirements

Selection of the CT String

Conspicuously absent from this list is any mention of CT attributes. Even if a reel of CT is tentatively selected for a proposed operation, one cannot determine its suitability for the job until defining what that job is. At this point, the only information available on the CT is whether it will carry a wireline or need a smooth ID (no weld flash).

The next step in the planning process is to determine what sort of CT string could perform the proposed operations. That is, what OD, wall thickness, and material are necessary. This iterative process may involve modifying aspects of the preliminary job plan to accommodate the capabilities of available CT and surface equipment. The division of responsibility for planning CT operations naturally depends on local conditions, but the approach should be to model the operation with a CT simulator (see “CT Simulators”). If the well is nearly vertical, spreadsheet calculations may suffice. Either way, the planner should investigate a reasonable range of input parameters to evaluate risks for the proposed operation.

If the planning question is “What CT string do I need?”, the modeling output should be a description of a CT string that can successfully complete the operation with minimum risk. The output may also include suggestions for operating procedures that might further reduce risk to the operation. A likely outcome of this process is the discovery that the preferred CT string is unavailable. Now the planner asks the question “I must use a certain CT string for my job; can it be successful?” Consequently, the planner must concentrate on devising operating procedures and contingencies to improve the chances of success for the available CT string.

NOTE: A very important component of the planning process is to determine effects of a proposed operation on the fatigue life for the CT.

Can the selected reel of CT successfully perform the proposed job without failing due to fatigue? For a specific reel of CT the answer comes from estimating its remaining fatigue life (based on its fatigue history). For generic CT with certain attributes, the answer lies with estimating the amount of fatigue accumulated during an operation. The outcome of such an evaluation will determine the need for additional planning iterations.

Service Company Proposals

As part of the planning process for each CT operation, the service company should submit a job proposal for the Customer's approval that includes the following elements:

1. CT simulator input and results
2. Surface equipment proposed for the job
    - **a.** CT string
    - **b.** CT reel
    - **c.** Injector head and guide arch
    - **d.** CT weight sensor(s)
    - **e.** CT depth counter(s)
    - **f.** Pressure control equipment

g. Injector head support and work platform (if required)

h. Data acquisition system (DAS)

i. CT diameter measurement tool (if required)

j. Power pack

k. Auxiliary equipment

- pumps
- compressors
- tanks
- special tools

3. Bottom hole assembly (BHA) specifications (include a drawing)

a. Function

b. Components

c. Dimensions

d. Weight

e. Operating characteristics

- mechanical
- hydraulic

f. Forces generated by the BHA

- lateral - arms, centralizers, or pads

- axial – jars, setting tools
- torque – motor, indexing tool, orientor

g. Required axial forces – set down weight (SDW) and overpull

4. Treatment fluid(s)

a. Density

b. Viscosity

c. Composition

d. Hazards to personnel and equipment

5. Chronological list of major events (a detailed procedure)

6. Data acquisition and real-time monitoring

7. Safety issues and precautions

a. Well control

b. Treatment fluid(s)

c. Equipment hazards

8. Risk analysis for their operations

a. Potential problems and risk (based on previous experience and the CT simulator results)

b. Contingency plans

c. Emergency procedures

9. Environmental safeguards

10. QA plan for the job

11. Manpower requirements

12. Cost estimate

> *NOTE:* For corrosive operating environments, the proposal should include additive schedules for using corrosion inhibitor(s) and scavenger(s) plus an estimate of the expected corrosion rate for the CT string during the job.

Job Program

The Customer should convert the service company job proposal into a Job Program that includes the following elements:

1. Job description and objective of CT operation

2. Description of well path (survey)

3. Wellbore geometry - well completion diagram

4. Expected wellbore conditions

   a. Fluid(s)

   - density
   - viscosity
   - composition
   - hazards

   b. Pressures

   c. Flow rates

   - gas
   - liquid hydrocarbon

- reservoir water
- treatment fluid(s)

d. Temperatures – bottom hole and wellhead (flowing)

5. Well site (location) preparation for CT operations

6. Production facilities preparation for CT operations

7. Communications and logistics

8. Treatment fluid(s) and pumping schedule

9. Service company proposal

10. A detailed job procedure for each operation.

11. A list of all equipment and materials required and the provider of each—Customer or a service company.

12. Risk analysis for affects of CT operations on well site and surrounding infrastructure

a. Potential problems and risk

b. Contingency plans

c. Emergency procedures

13. Sampling requirements and procedures

a. CT string

b. Treatment fluids

c. Produced or return fluids

14. Reporting requirements

NOTE: The Customer must revise or amend the Job Program for a change in service company, equipment specifications, or expected operating conditions.

CT SIMULATORS

The purpose of CT simulators is to predict the performance of the entire CT string based on a given set of input conditions. Mechanical simulators, such as Orpheus™ calculate the forces, stresses, and buckling condition for each segment in a CT string (Chapter 6 "Tubing Forces", Chapter 7 "Buckling and Lock-up", and Chapter 8 "CT Mechanical Limits"). Other mechanical simulators, such as Hercules™, calculate safe operating limits for the CT (Chapter 8 "CT Mechanical Limits"). Hydraulic simulators, such as Hydra™, calculate the pressure distribution around the fluid flow path for a given flow rate or estimate the flow rate for given pump pressure (Chapter 10 "CT Hydraulic Performance"). Fatigue simulators, such as Reel-Trak™, predict the accumulated fatigue damage in each segment of the CT string for a combination of operating conditions (Chapter 9 "CT Working Life").

A CT simulator that properly models the physics of CT operations can help answer the following questions about a CT operation.

1. How far can the CT RIH prior to lock up or without exceeding a mechanical limit?

2. Where is the CT buckled?

3. At a given depth, how hard can the bottom of the BHA push on something prior to lockup? In other words, what is the maximum SDW or WOB?

4. What is the maximum Cf that will allow the CT to reach a given depth?

5. Can the CT POOH from TD without exceeding any mechanical limits?

6. During POOH, how much overpull (additional tension) can the CT withstand before exceeding any mechanical limits?

7. Does the CT have adequate working life remaining to complete the job?

8. At a given depth, can the CT deliver enough flow rate or pressure?

The CT service companies use several different CT simulators. Some of these CT simulators give good results in the hands of qualified operators, but operator experience and training vary widely. Consequently, the Customer should scrutinize each simulation to insure the results are reliable and useful. The purpose of this section is to outline the requirements for proper use of CT simulators.

Available CT Simulators

A detailed description of all available CT simulators is beyond the scope of this manual. However, the following list summarizes the major CT software in use in 2000.

- Cerberus™ (integrated software package for tubing forces, hydraulics, fatigue tracking, and job management)—developed by CTES, L.P. and used by numerous CT service companies and E & P companies.
- CIRCA™ (tubing forces and hydraulics) and CYCLE™ (fatigue)—developed by Nowsco and used exclusively by BJ Services
- CoilCADE™ (tubing forces and hydraulics), CoilLIFE™ (fatigue), and CoilCAT™ (tubing management)—developed and used exclusively by Schlumberger Dowell
- Tubing Analysis System (tubing forces, hydraulics, and fatigue)—developed jointly by MEDCO and BJ Services and used by some independents
- Maurer Engineering—developed by funding from DEA projects 44 and 67, distribution and user list are unknown

Each of these simulators has a unique user interface, set of proprietary calculation “engines”, and organization. However, all require a minimum set of input parameters to define the CT string, wellbore, operating environment, and forces acting on the CT string. Moreover, all of this software provides certain generic output describing the predicted performance of the CT during the simulated operation. The following sections provide guidelines for modeling CT performance and how to evaluate the results.

CT Simulator Input

The minimum set of input parameters that defines the CT string, wellbore, operating environment, and the forces acting on the CT string includes:

1. CT dimensions and properties
   - OD
   - Wall thickness versus position along the string
   - Weight per unit length (for each wall thickness section)
   - Material properties, especially yield stress
   - Position of all welds
   - Dimensions and weight of internal wireline, if any

2. BHA (tools) dimensions and properties

- OD
- ID
- Weight
- Material properties, especially yield stress
- Sources of extra drag (arms, centralizers, pads)
- Nozzles (number and orifice size)

3. Wellbore dimensions - ID versus depth

4. Well path description (survey) - inclination and azimuth versus depth

5. Open hole (reservoir) properties (permeability, pore pressure, PI, etc.)

6. Fluid properties (density and rheological) inside the CT versus depth

7. Fluid properties (density and rheological) outside the CT versus depth

8. Cf versus depth

9. Pump pressure or flow rate

10. Force applied at the BHA

- Axial – SDW or overpull
- Torque

11. Stripper friction and reel tension

Any simulator used for monitoring the working life (fatigue) of the CT string will also need a description of the surface equipment layout and a complete history of the accumulated fatigue in the string prior to the current job.

The mechanical simulators listed above have different schemes for handling wireline in the CT. CIRCA™ treats the wireline as a separate tubing string subject to its own force balance and transmitting force to the CT via frictional drag. Cerberus™ and the others use a simpler scheme that considers wireline as additional weight per unit length. Neither method allows the wireline to affect the CT's bending stiffness.

The choice of Cf is a contentious subject because it has such a tremendous impact on simulator results (and CT performance). Cf is one of the most powerful “controls” at the software user’s command to change the outcome of a tubing forces simulation. A common misconception is that Cf for RIH should be higher than Cf for POOH. Although drag appears to be higher RIH than POOH during actual CT operations, this is not due to different Cf for each direction of motion. Cf for sliding friction is independent of direction unless one of the surfaces has an oriented structure. The higher drag for RIH may be due to additional normal force caused by residual curvature in the CT. Pushing on the CT increases this normal force (higher drag) while pulling on the CT relieves it (lower drag). Correctly modeling the physics of this behavior involves more than arbitrarily increasing Cf for RIH. Artificially high Cf for RIH can lead to under-estimating maximum reach and SDW because post-buckling drag will be abnormally high.

Table 17.1 lists typical values for Cf from small-scale and large-scale drag tests.

TABLE 17.1 *Typical Values for Cf*

Surface	Cf
Water-wet steel	0.30-0.35
Lubricated water-wet steel	0.20-0.25
Oil-wet steel	0.15-0.20
Steel on rock	0.40-0.50

Parametric Sensitivity

A reliable CT simulator is a powerful and economical tool for testing effects of various parameters on a given CT operation. Determining the sensitivity of an operation to the parameters listed in the preceding section is a good method of evaluating the risks for that operation. Depending on the circumstances, some of these parameters may be fixed or uncontrollable for a CT operation. Otherwise, a judicious choice of equipment, procedures, or boundary conditions can reduce risks for an operation.

Parametric studies to assess the risks for a proposed CT operation are very important for pre-job planning. A good place to start a sensitivity study for a directional well is with RIH, since this is often the limiting case for a CT operation. If the CT simulator predicts success for RIH, the next step is to investigate different POOH scenarios. Sometimes CT can RIH with adequate SDW remaining but cannot safely POOH without exceeding a mechanical limit. After determining that the CT should be able to trip into and out of the well safely, the job planner should run the hydraulic and fatigue simulators. If the simulator requires an unreasonable or unrealistic value for one or more of the input parameters described above, the risk of failure for the actual operation is small. The following examples show how parametric studies with a CT simulator can aid the planning process.

EXAMPLE 0.1

During simulated slackoff into a directional well, a proposed CT string of uniform wall thickness can RIH to TD without lockup. However, during POOH, the VME stress exceeds the maximum acceptable value below the stripper.

The simulator indicates a larger OD or higher strength CT material would solve this problem. The first is unacceptable, because a reel of larger OD tubing is too heavy to lift onto the offshore platform. CT with higher yield strength is not available.

A third option is a tapered CT string. The choice of tubing wall thickness and corresponding length for each section in the string will be a 3-way trade-off between reducing the VME stress and preventing collapse during POOH, minimizing buckling (preventing lockup) during RIH, and maintaining an acceptable weight for the reel.

The job planner will propose a tapered CT string then determine if it meets all three objectives. Usually, several iterations with the CT simulator are necessary to identify a tapered string design that properly balances these trade-offs.

EXAMPLE 0.2

During simulated slackoff into a cased directional well full of seawater (8.5 lbs/gal and Cf = 0.30), the only available CT string buckles and locks up before reaching TD. The simulation assumed seawater inside the CT.

New simulations using lower density fluid inside the CT indicate that nitrogen (2.0 lbs/gal) inside the CT would allow the BHA to successfully RIH despite some buckling in the CT string. Unfortunately, the well site is too small to accommodate a nitrogen unit or tanks.

Simulations with lower friction coefficient indicate that Cf = 0.23 would allow the BHA to reach TD with the CT full of seawater. This reduction in friction is obtainable with certain lubricants. Thus, an effective lubricant in the seawater would permit the proposed CT operation to go ahead.

Example 0.3

During simulated POOH in a live horizontal gas well producing a little water (Cf = 0.30), the VME stress exceeds the maximum acceptable value for one of the sections in a tapered CT string. These simulations assumed nitrogen (2.0 lbs/gal) in the CT for RIH and seawater (remaining from stimulation operations) inside the CT for POOH.

Simulations with lower friction coefficient indicate that Cf = 0.25 would provide the necessary safety margin for POOH. However, killing the well to conduct the CT operation in a lubricated fluid is not an option.

New simulations using lower density fluid inside the CT indicate that air or nitrogen (2.0 lbs/gal) inside the CT would allow it to POOH safely. Thus, one alternative is to blow the seawater out of the string before starting to POOH.

Other simulations show that a different taper in the CT string would permit POOH with the CT full of seawater. Therefore, a different CT string might be an alternative.

Example 0.4

Simulations show that certain CT operations in a proposed horizontal well would be marginally possible with an available CT string and Cf based on experience with existing wells in the area.

However, the simulated well path lacks the irregularities of an actual well path. Based on offset well data, a smooth well path is not likely. Introducing tortuosity (small doglegs) into the well path creates scenarios in which the proposed CT operations would fail.

New simulations with a moderately tortuous well path and a range of Cf identify the upper limit on Cf that would allow each CT operation to proceed. Unfortunately, none of the friction coefficients could be obtained with available fluids. Thus, the proposed CT operations will not be possible with the available CT string. The next step in the parametric study is to investigate other CT strings.

Example 0.5

Simulations for RIH inside 7 in. casing of a directional oil well (Cf = 0.20) show that the only available CT buckles and locks up before the BHA reaches TD. The job planner already assumed nitrogen inside the CT, so increasing the string's buoyancy is not an option.	New simulations with a range of wellbore ID indicate that using 4.5 in. tubing in the vertical portion of the wellbore would eliminate buckling entirely. Thus, hanging a temporary liner from the surface to the kick-off point could enable CT operations as planned.

Example 0.6

A simulated CT workover operation is inside production tubing of a horizontal well full of heavy brine (Cf = 0.30). RIH with the CT full of brine causes the string to buckle and lockup before the BHA reaches TD. Lubricating the brine is out of the question. Likewise, hanging a temporary liner inside the production tubing is not feasible.	New simulations using lower density fluid inside the CT indicate that lowering the fluid density inside the CT by about 50% would allow the BHA to reach TD. Therefore, purging the CT with air or nitrogen could solve this problem.

Example 0.7

A proposal is on the table for using a mud motor on CT to drill out a plug in a horizontal well. Drilling tests inside casing at a test facility determine the minimum WOB required to drill out the plug in an acceptable time.	The CT simulator indicates the CT can RIH to TD without buckling as long as WOB = 0. Increasing the WOB to the minimum required for drilling causes the CT to buckle, but it would continue to slide and transmit axial force until WOB increases by about 30%. Therefore, the proposed CT drilling operation can go ahead as planned.

EXAMPLE 0.8

A CT service company recommends a tapered CT string with a BHA consisting of a jetting nozzle for acidizing a dying gas well. Water production has been steadily increasing, so Cf is approximately 0.30. After spotting and squeezing the acid, the plan is to "kick-start" the well by displacing the wellbore to nitrogen. This could cause a rapid increase in WHP.	Simulations with a range of WHP identify the upper limit for avoiding CT collapse for each wall thickness of CT in the wellbore. For the recommended CT string and expected WHP, the CT section immediately below the stripper will survive during POOH from TD. However, the next CT section farther down would collapse during POOH. Reducing WHP is not a practical option. Therefore, this job requires CT with higher yield strength or a different string taper.

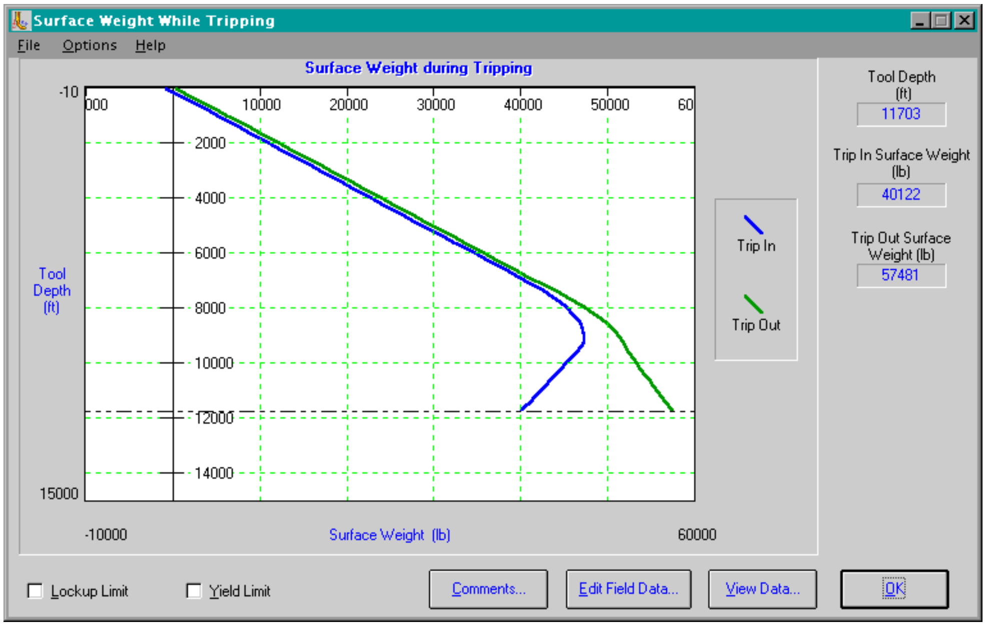
CT Simulator Output and Its Interpretation

Each CT simulator listed above has its own unique output format for tabular data and plots. Regardless of how the results are presented, only a few are essential for understanding the outcome of the simulated CT operation. These are:

- CTWI versus depth during RIH and POOH
- The distribution of axial forces acting on the CT string when it is static at a given depth
- The distribution of stresses in the CT string when it is static at a given depth
- The maximum SDW and overpull available at a given depth
- Working life remaining in each segment of the CT string after the proposed operation
- For hydraulic operations at a given depth, the maximum flow rate possible for a given pump pressure
- For hydraulic operations, the relationship between pump pressure and flow rate versus depth

Often the trend in CTWI versus depth is more revealing than the absolute values, because stripper friction, reel back tension, or WHP can bias the result. The trend or shape of the curve indicates how rapidly the drag between the CT and well bore is changing and where the effects of that drag manifest themselves. Figure 17.1 illustrates these effects for a well that starts vertical and builds angle to horizontal at about 9400 ft.

FIGURE 17.1 *CTWI Versus Depth During Simulated Tripping*



The parallel lines for RIH and POOH simply indicate a relatively straight part of the well without any obstructions, abnormal drag, or helical buckling. Since the wellbore is vertical over that interval, the slope of each line is the buoyed weight of the CT per unit length. The change in slope for the RIH curve from increasing (+) to decreasing (-) between 6800 ft and 9400 ft coincides with the build section of the well path and locally high drag due to curvature. The straight portion of each curve below 9600 ft indicates another relatively straight part of the well without any obstructions or helical buckling. Since the wellbore is horizontal below 9400 ft, the slope of the line is the drag on the CT per unit length (normal component of buoyed weight per unit length multiplied by Cf).

Some CT simulators also calculate the CTWI corresponding to lockup during RIH. Depending on the circumstances and location of the CT string in the well, the injector might have to apply quite high snubbing force (negative weight) to force the CT string into lockup. Figure 17.2 shows this lockup limit superimposed on the tripping curves from Figure 17.1. Such information can be a useful guideline for the CT operator. As long as the CTWI during RIH is higher than the lockup limit, the risk of lockup is small.

FIGURE 17.2 *Lockup Limit for RIH*

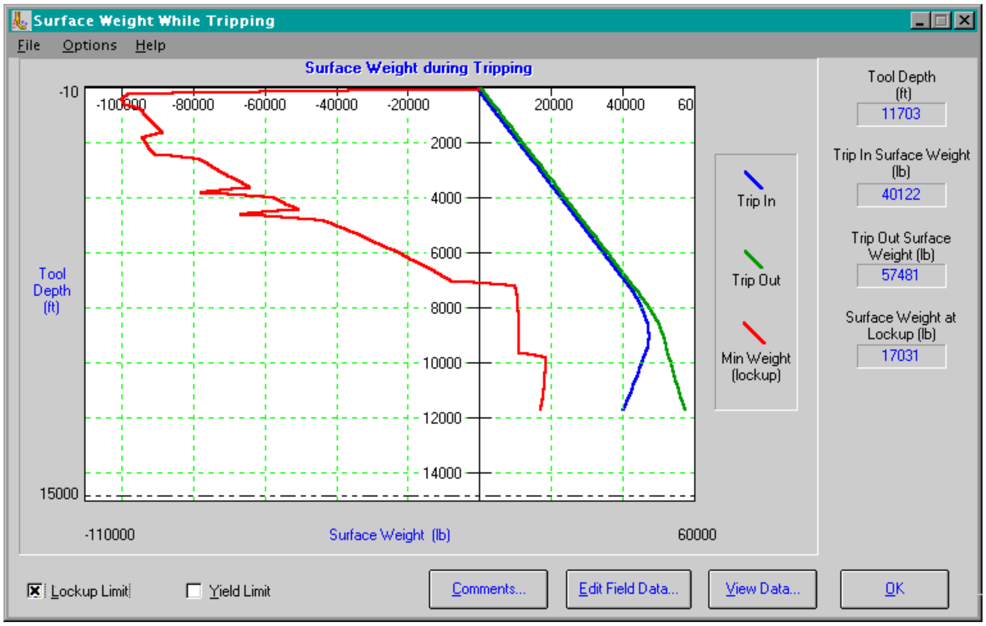


Figure 17.3 shows the axial force distribution in the CT string corresponding to the conditions of Figure 17.1. In this case, the bottom of the CT string is at TD (11,703 ft). The curves represent the local axial forces in the string just prior to stopping at TD while RIH and immediately before leaving TD when POOH. The straight-line portions of each curve have the same meaning as those described earlier for Figure 17.1. Only those sections of the string in compression are candidates for buckling. However, the local compressive force must exceed the critical buckling force before buckling can occur. (See Chapter 7 "Buckling and Lock-up".) The red line in Figure 17.3 is the critical force for helical buckling. The CT string will be helically buckled where the RIH curve lies to the left of the limit curve.

FIGURE 17.3 *Axial Force on the CT at Depth*

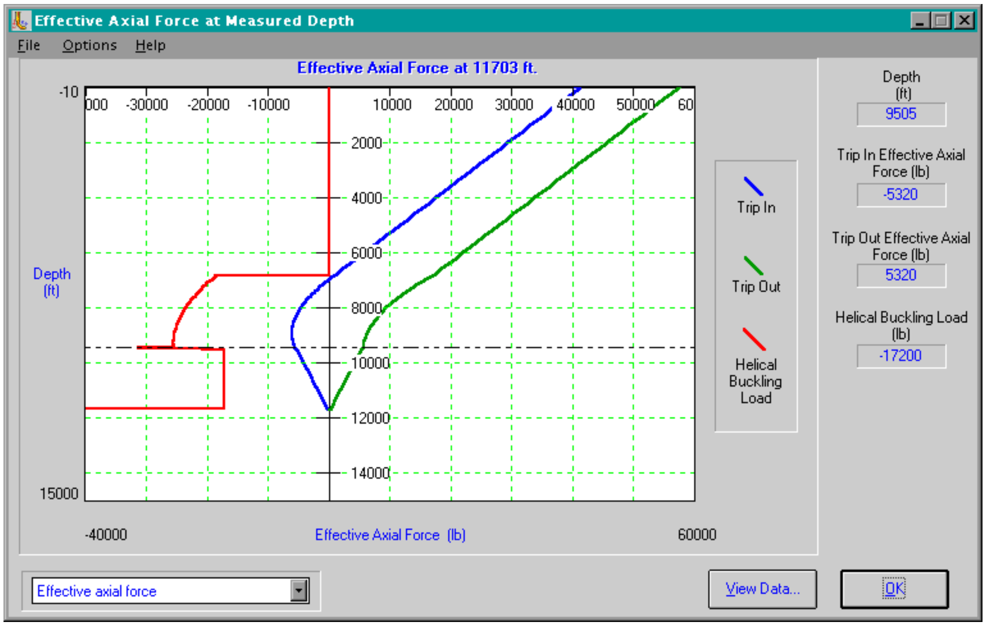


Figure 17.4 shows the distribution of VME stresses (see Chapter 8 "CT Mechanical Limits") along the CT string corresponding to the conditions of Figure 17.2. Any stress value less than the predetermined limit (perhaps 80% of yield) should be an acceptable operating condition.

FIGURE 17.4 *VME Stresses for the CT at Depth*

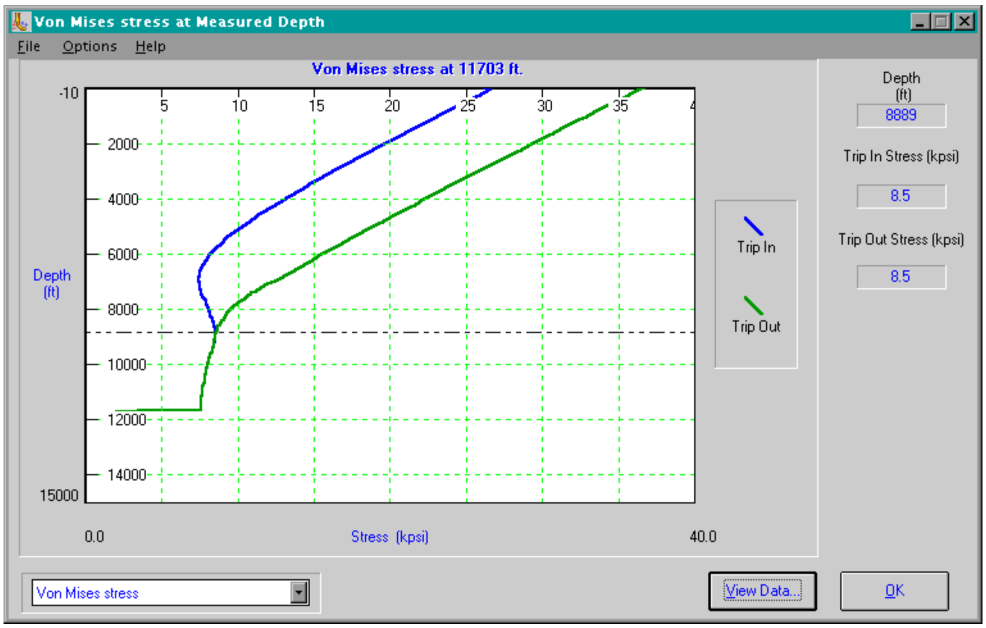


Figure 17.5 is one way to present information about the accumulated fatigue in a CT string. The gray area was the accumulated fatigue in the string prior to the current entry, the blue area. The latter represents the fatigue damage due to the latest CT operation. This figure indicates that a section of the string around 5700 ft is accumulating fatigue at a faster rate than the rest of the CT.

FIGURE 17.5 *CT String Accumulated Fatigue*

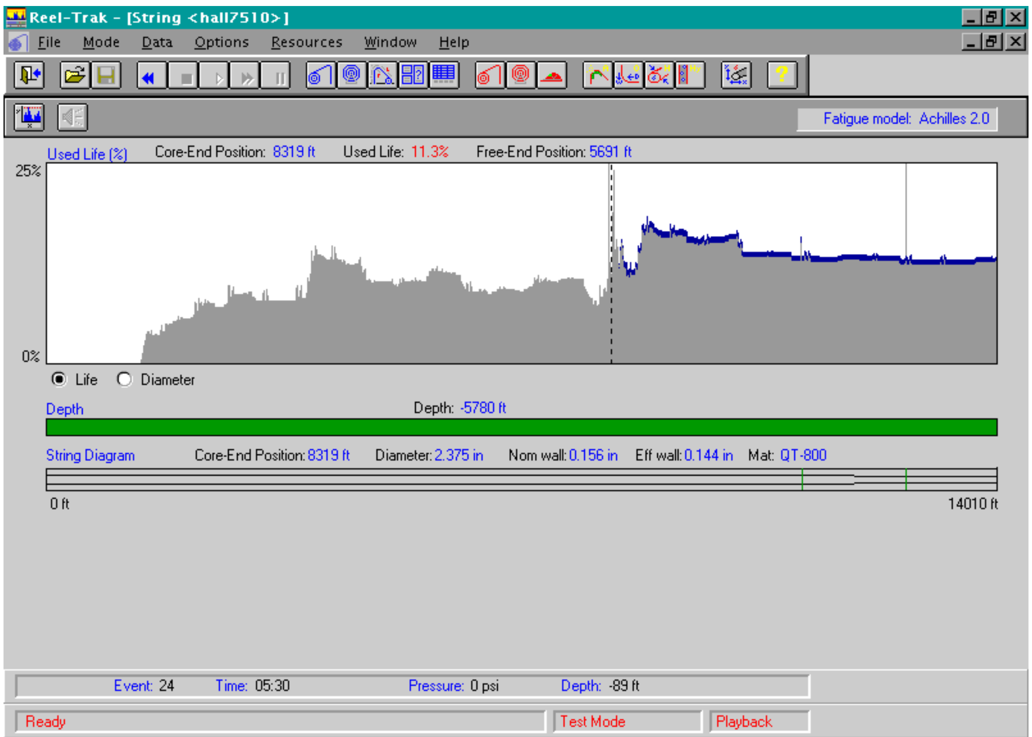
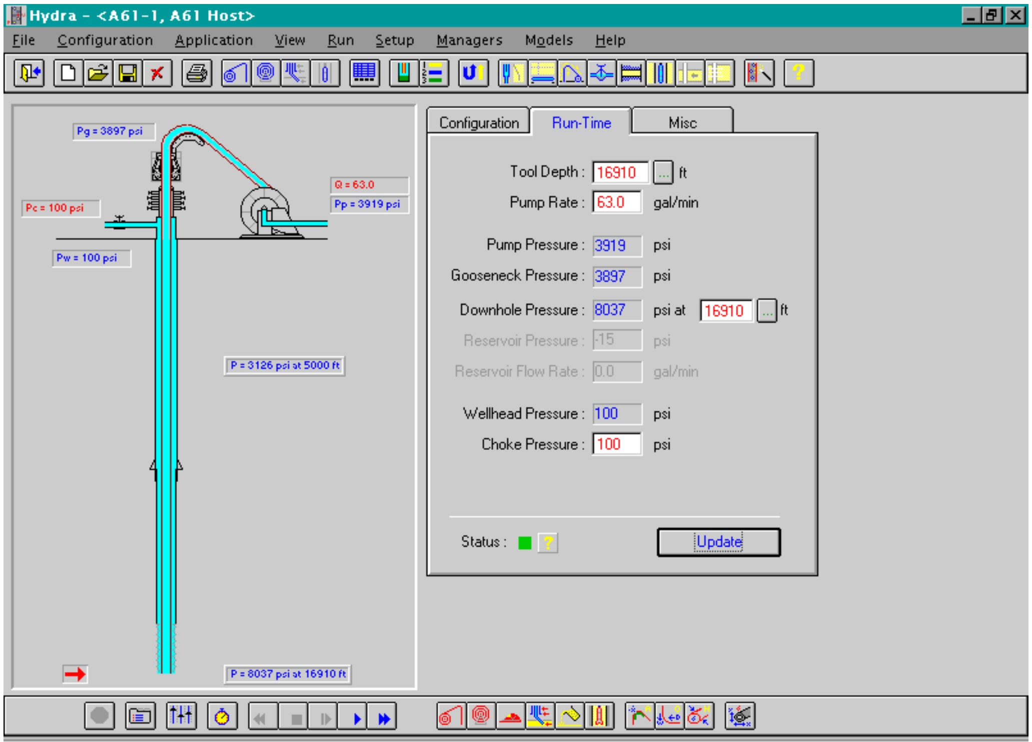


Figure 17.6 is a sample presentation of hydraulics calculations for a particular CT pumping operation. It shows the pressure at various locations along the flow path for a given tool depth, flow rate, and choke pressure.

FIGURE 17.6 *Hydraulics Calculations*



CT Simulator Guidelines

Certain behavior or indications in these simulator results are more revealing than others about the potential risk for a CT operation. These indicators and guidelines for their use include the following:

- Maximum SDW prior to lockup—the greater of (i) 500 lbs (or metric equivalent) or (ii) the compressive force required for the job. Even if the purpose of the CT job does not include pushing on anything, having extra push available is good insurance.
- Maximum overpull at the BHA—the greatest of (i) 5000 lbs (or metric equivalent), (ii) the tensile force required for the job, or (iii) the tension required to separate the mechanical disconnect. Even if the purpose of the CT job does not include pulling on anything, having extra pull to disengage the BHA or work through tight spots is good insurance.
- Maximum Cf prior to lockup in a directional well—any Cf value higher than is reasonable to expect for the prevailing conditions bodes well for the operation. This result indicates how sensitive RIH will be to drag. Without previous experience in a well under similar circumstances, quantifying Cf is extremely difficult.
- Rate of change in CTWI while RIH and POOH—abrupt changes in slope (curvature)at a given depth indicate rapidly changing drag at the depth. These effects are due to wellbore curvature, buckling of the CT, or both.
- Maximum reach prior to lockup in a directional well—at least 100 ft (or metric equivalent) beyond the target depth (TD) or the well maximum depth, whichever is less.

- Helical buckling location and length of helically-buckled segment in a directional well—This indicates the section of the CT string that might need stiffening, or the section of wellbore that might need a smaller ID or some lubrication.
- Maximum Cf prior to exceeding the VME stress limit for POOH—any Cf value higher than is reasonable to expect for the prevailing conditions bodes well for the operation. This indicates how sensitive POOH will be to drag.
- Maximum WHP prior to collapsing the CT—at least 25% higher than the expected maximum WHP during the CT operation is a reasonable margin.

EQUIPMENT SPECIFICATIONS

Equipment used for CT operations at WHP < 3500 psi must meet the minimum requirements specified in the following section. For equipment requirements for WHP > 3500 psi, see "Equipment Selection for HPCT Operations".

CT String

1. Use a CT simulator to determine what CT string(s) will have adequate mechanical strength and fatigue life to perform the proposed operation(s). Model the operation(s) with a CT simulator to determine suitable outside diameter (OD), wall thickness, and material strength for the CT string.

> NOTE: Adequate mechanical strength satisfies both of the following criteria:
>
> - Maximum von Mises equivalent stress in the CT string is less than 80% of the material yield strength ($\sigma_{VME} < 0.8\sigma_y$). See Chapter 8 "CT Mechanical Limits" for details.
> - Calculated collapse pressure (Pc) at the maximum expected tension is greater than 125% of the maximum possible wellhead pressure ($Pc > 1.25 \times WHP_{max}$). See Chapter 8 "CT Mechanical Limits" for details.

> NOTE: Adequate fatigue life means that the maximum accumulated fatigue in the CT string at the end of the operation will be less than 80% of its predicted working life. See Chapter 9 "CT Working Life" for details.

2. When the CT string could be exposed to H_2S or CO_2 during the job, use the lowest nominal yield strength material that meets the mechanical performance requirements. Generally, resistance to sulfide stress cracking and corrosion both increase with decreasing material yield strength.

3. The length of the CT string should be at least 1000 ft greater than the maximum target depth (TD) planned for the job.

4. The tubing connection to the CT reel plumbing should be a welded fitting. The weld must conform to the CT manufacturer's weld procedure specification and successfully pass magnetic particle and dye penetrate inspections.

5. Advanced CT life monitoring software is the only acceptable method for tracking the working life of CT strings.

6. Strings must be retired from CT operations upon reaching 80% of their predicted working life.

7. Remove a CT string from further consideration for CT operations if any section of the string no longer has adequate mechanical strength for the expected operating conditions due to any of the following:

- OD – excessive ballooning or necking down
- Excessive ovality – reduced collapse resistance
- Reduced wall thickness caused by the penetration of any flaw or damage into the CT wall

CT Reel

1. The CT reel should have a minimum core diameter to CT OD ratio of 40:1 (e.g., the minimum core diameter for 1.75 in. CT is 70 in.).

2. All plumbing (piping) components installed on the reel should be the integral type and rated to a maximum allowable working pressure of 5,000 psi.

3. The spare parts kit on location for reel assemblies should include the following items:

- Packing kit for the high pressure swivel
- Depth counter head assembly, if so equipped
- Drive pawl for the level wind assembly
- 2 rollers for the level wind head, sized for the CT string being run

Injector Head

1. Minimum performance capability of 25% more pull and push than required by the job program

2. Bi-directional (tension and compression) weight sensor(s)

3. Minimum guide arch radius of 48 times the CT OD (e.g., the minimum radius for 1.75 in. CT is 84 in.)

4. The system for gripping the CT must not slip on the CT nor damage the CT at the maximum rated pull and push.

NOTE: Damage to the CT is any mechanical gouging or deformation of the tubing geometry that increases the local σ_{VME} of the tubing by more than 5% compared to undamaged tubing.

5. The spare parts kit on location for the injector head should include the following items:

- 1 weight sensor
- 1 depth counter, if so equipped
- 1 set of guide arch rollers or wear shoes for the CT size used for the job
- 1 hydraulic skate ram

CT Weight Sensor(s)

1. The sensor(s) must be capable of measuring the full range of snubbing (compressive) and pulling (tensile) forces applied by the injector head to the CT.

2. The sensor(s) should provide an electronic signal proportional to the CT weight that can be recorded by the DAS and displayed in the CT unit control cab.

3. The sensor(s) should have an accuracy of ±5% of the reading.

CT Depth Counter(s)

1. The depth counter(s) must be capable of measuring the full length of the CT string.

2. At least one counter must provide an electronic signal proportional to the length of CT passing through the counter that can be recorded by DAS and displayed in the CT unit control cab.

3. At least one counter must be a mechanical type.

4. The counter(s) should have a display resolution of ±1 ft.

5. At least one spare mechanical counter and a spare electronic encoder should be on location during the job.

Pressure Control Equipment

1. The pressure control equipment stack must consist of the following sections, from the top down:

   a. Primary

   b. Ancillary, if so equipped

   c. Secondary

2. All pressure control equipment must have a maximum allowable working pressure of at least 5,000 psi.

3. All components must be fully rated for H_2S service.

4. Minimum bore diameter should be 3.06 in.

5. All pipe and pipe/slip combination rams must have equalization capabilities.

Primary Components

1. The primary pressure control equipment must consist of an upper side-door stripper (sometimes called the packoff or stuffing box).

2. Stripper packing elements and anti-extrusion rings

   - Should be OEM supplied
   - Products from non-OEM suppliers are acceptable only if physical test data demonstrates that their performance meets or exceeds the performance of the corresponding OEM product.
   - Must be rated for the expected service

Ancillary Well Control Equipment

Riser sections for accommodating long BHA assemblies should be installed between the primary and secondary pressure control components. Ancillary equipment must have the same materials requirements and pressure ratings as the other pressure control equipment.

Secondary Components

1. The secondary pressure control equipment must consist of a quad blowout preventer (BOP) with the following configuration, from the top down:

- **a.** Blind rams
- **b.** Shear rams
- **c.** Side outlet port
- **d.** Slip rams
- **e.** Pipe rams

2. BOP elastomers and seals

- Should be OEM supplied
- Products from non-OEM suppliers are acceptable only if physical test data demonstrates that their performance meets or exceeds the performance of the corresponding OEM product.
- Must be rated for the expected service

3. The BOP rams must operate from accumulators. The hydraulic accumulator system must have sufficient volume, with the hydraulic charge pump inoperative, to perform the following BOP operations:

- **a.** Close the slip rams
- **b.** Close the pipe rams
- **c.** Close the shear rams and shear the CT
- **d.** Close the blind rams
- **e.** Open all well control stack rams
- **f.** Close all well control stack rams

4. The accumulator system must have the capability of performing the operations described in item 3 immediately above at a WHP of 3500 psi.

5. Shear rams must be capable of efficiently severing the thickest wall section of the CT string used for the job. If wireline is installed in the tubing, the shear rams must be capable of efficiently severing both the CT and the wireline.

Spare Parts

The spare parts kit on location for the pressure control equipment should include the following items:

1. Primary equipment

- 5 stripper/energizer elements for each stripper
- 2 sets of anti-extrusion rings for each stripper
- 1 complete set of wear bushings for each stripper packoff assembly

2. Secondary equipment

- 2 sets of blind ram inserts
- 2 sets of pipe ram inserts
- 1 set of shear rams
- 1 set of slip rams
- 1 set of bonnet seals and o-ring redress kit for each ram
- 2 redress kits for the equalizing valves

3. Connections - 1 full set of replacement seals for each connection

Data Acquisition System (DAS)

1. The DAS should be a computer-based system capable of recording and displaying the following data:

- Time
- Depth
- CTWI
- Reel inlet pressure
- Wellhead pressure
- Pump flow rate

2. Pressure, flow rate, and volume measurements should have an accuracy of at least ±5% of the reading.

3. The DAS should provide real-time digital displays, trend (historical) records of the data, and alarms for operating data outside preset limits.

4. The DAS should provide the CT operator with a real-time indication of VME stress in the wall of the CT (at a specific location) relative to the yield strength of the material and/or safe operating limit.

5. The DAS should be capable of comparing the current CTWI with planned values at any point in the operation.

6. The DAS should present a real-time display of fatigue accumulation in the CT string and provide the operator with a means to rapidly determine the status of the remaining working life for the string.

7. The DAS should be capable of creating a data file for each job in a format that can be read with commonly available software such as MS Excel or MS Word.

8. The spare parts kit on location for the DAS should include the following items:

- 1 spare pressure sensor for the wellhead
- 1 spare pressure sensor for the reel inlet
- 1 spare pressure sensor or electronic load cell for CT weight

Bottom Hole Assembly (BHA)

1. All BHAs for CT operations must include dual flapper-type check valves. The seals (elastomer or metallic) used in the check valves must be rated for H_2S service and the bottom hole temperature.

2. All metals used in the fabrication of BHA components should meet the requirement of NACE MR-01-75.

3. The tubing connector used to attach the BHA to the CT must be able to withstand a tensile force equivalent to the greater of:

- the product of the cross sectional area of the CT times the lesser of 3500 psi or 125% of the maximum WHP expected for the job
- the maximum expected overpull for the job

4. Disconnect (release tool)

- Any BHA required to apply an axial force during operation must include a means of disconnecting the tool from the BHA.
- The BHA must include a hydraulic or electrical disconnect whenever the predicted maximum overpull available at the maximum expected TD is less than the force required to operate a mechanical disconnect.
- The disconnect must allow pressure testing of the BHA during rig up without separating the tool.

Power pack

The CT unit power pack must have the following capabilities:

- Continuous operation at full power
- Supply hydraulic fluid simultaneously to the attached equipment
- Emergency shut-down from inside the CT unit control cab

Cranes

- All cranes and crane operators must be certified to approved standards.
- All cranes used for hoisting and supporting CT equipment should be equipped with load cells accurate to ±5% of reading.
- All slings and other lifting equipment must comply with local requirements.

Fluid/Nitrogen Pumping Unit(s)

- Each pumping unit designated for the job must conform to the requirements of the Job Program.
- All pumping units must have a properly certified pressure relief device installed.

Chicksan Connections

All chicksan connections must be rated for the expected service.

Chemical/Nitrogen Tanks

- Each chemical and nitrogen tank designated for the job must conform to the requirements of the Job Program.
- All chemical and nitrogen tanks must meet local requirements for the following tests:

a. Vacuum

b. Pressure relief valve opening pressure

c. Piping and valves pressure integrity

Mixing Tanks

Each mixing tank designated for the job must conform to the requirements of the Job Program.

Downhole Motors

Each downhole motor designated for the job must conform to the requirements of the Job Program.

PRE-JOB PREPARATION AND TESTING OF CT EQUIPMENT

Minimizing risk for CT operations means minimizing surprises and maximizing reliability of the equipment. Both can be accomplished by strict adherence to a QA plan that includes requirements for testing equipment and verifying the accuracy of sensors, measuring equipment, and recording devices.

This section presents guidelines for preparation and testing of CT equipment in the service company yard, prior to mobilizing the equipment to the job location.

NOTE: These guidelines apply only to standard CT operations with WHP < 3500 psi.

Responsibilities

Both the Customer and the service companies should comply with these specifications. Also, each has unique responsibilities under these specifications.

Customer's Responsibilities

- Revise these specifications as necessary to meet the Customer's needs and to comply with regulatory requirements.
- Ensure that the service company has a copy of these specifications
- Audit service company records, inspect service company equipment, and observe service company operations to ensure compliance with these specifications.

Service Company's Responsibilities

- Obtain in writing from the Customer any waivers or concessions to these specifications.
- Ensure that all equipment supplied for CT operations complies with these specifications.
- Prepare and test all equipment in accordance with these specifications prior to mobilization of equipment for CT operations.
- Develop and maintain the following written documentation:

1. Quality assurance (QA) plan
2. Maintenance program plan
3. Log for each CT string that includes:
    - The mill quality control (QC) report
    - Pressure test data
    - Operational history
    - Record of accumulated fatigue
4. Log for each item of CT equipment that includes:
    - Functional and pressure test data (where applicable)
    - Calibration data (where applicable)
    - Maintenance and repair records.
5. Calibration records for reference standards
6. Certification of statutory compliance where applicable
7. Material safety data sheet (MSDS) for each hazardous chemical

- Verify on a regular schedule that the accuracy of each sensor and recording device meets the OEM specification for that equipment.
- Ensure that all documentation is correct and presented in a manner acceptable to the Customer.
- Ensure that all of its personnel are thoroughly trained to:

1. Perform their job functions
2. Operate all safety devices
3. Respond properly to emergency situations.

Pressure Testing for Standard CT Operations

The service company must conduct pressure tests for standard CT operations according to the following criteria. See Chapter 16 “High Pressure Operations” for specifications for pressure testing for HPCT operations.

1. Conduct all pressure tests with water to the lesser of 3500 psi (±250 psi) or 120% of the maximum possible WHP for the planned CT operation.

2. Test pressure must remain stable for at least 15 minutes.

3. A successful pressure test meets both of the following criteria:

- No visible leaks
- Pressure decrease less than 5% after 15 minutes at the test pressure

4. When pressure testing BOP rams, always equalize the pressure across the rams before opening them.

5. Record all pressure tests with at least one of the following:

- Chart recorder scaled so that the test pressure is between 25% and 75% of full scale on the chart. Use a separate chart for each pressure test.
- DAS

6. Measure pressure with a pressure sensor accurate to at least ±1% of reading.

7. Record test results in the logbook for the equipment being tested.

- Date, time, and location of test
- Serial number of pressure sensor and chart recorder
- Signature of person conducting test
- Stable test pressure and duration
- Tracking number or filing code for the test data

8. Keep each pressure test record on file for at least 12 months from the date of the pressure test.

Equipment Preparation

This section presents minimum requirements for preparing equipment proposed for CT operations. The service company should prepare and test all equipment in accordance with these specifications prior to mobilizing the equipment to the job location.

CT String

Refer to "Equipment Specifications" for the requirements for the CT string. Verify the following before mobilizing the equipment to the job location:

- The CT string is as specified in the Job Program.
- The CT string's fatigue history is current. If it cannot be made current, then reject the CT string for the planned operation.

CT Reel

The CT reel consists of the following components:

- Reel
- Reel support structure or cradle
- Level-wind
- Depth counter(s) - electronic and/or mechanical

Refer to "Equipment Specifications" for the requirements for the CT reel. Verify the following before mobilizing the equipment to the job location:

1. The CT reel and depth counter(s) are as specified in the Job Program.

2. These items have been inspected and maintained per the manufacturer's specifications.

3. The logbook for each of these items is up-to-date with the information specified in "Service Company's Responsibilities".

4. The CT reel level-wind and brake are functioning properly

5. If possible, that the depth counter(s) operate in both RIH and POOH modes.

6. The spare parts kit is stocked as required.

Injector Head

The injector head consists of the following components:

- Injector
- Guide arch
- Weight sensor(s) - double acting (bi-directional)
- Depth counter(s) - electronic and mechanical

Refer to "Equipment Specifications" for the required injector head, guide arch, weight sensor(s), and depth counter(s). Verify the following before mobilizing the equipment to the job location:

1. The injector head, guide arch, weight sensor(s), and depth counter(s) are as specified in the Job Program
2. Each of these items has been inspected and maintained per the manufacturer's specifications.
3. The logbook for each of these items is up-to-date with the information specified in "Service Company's Responsibilities".
4. The injector head is fully operational.
5. Proper operation of the weight indicators in both pipe light and pipe heavy modes with the DAS operating.
6. The spare parts kit is stocked as required.

Pressure Control Equipment

The pressure control equipment stack for CT operations consists of the following sections, from the top down:

1. Primary
2. Ancillary, if so equipped
3. Secondary

Refer to “Equipment Specifications” for the required pressure control equipment and to “Pressure Testing for Standard CT Operations” for the requirements for its pressure testing. Verify the following before mobilizing the equipment to the job location:

1. The pressure control equipment is as specified in the Job Program.

2. The pressure control equipment has been inspected and maintained per the following schedule:

a. After each job

- Inspect all ram elastomer seals. Normal wear will be a moderate amount of extrusion downstream of the pressure side. Replace seals if any elastomer is missing or the bond between the elastomer and the plates is separating.
- Wash and clean the rams, bonnets and body. Remove the ram and clean the bonnet.
- Check all flange and union seals and sealing surfaces for damage that might impair sealing. Repair or replace items as necessary.

b. Once a month

- Remove the actuators from the BOP.
- Remove the equalizing valve and clean.
- Remove ram from piston rod.
- Clean bonnets, ram, BOP body, out-lets, unions and any other parts exposed to well fluids
- Apply a generous amount of grease to the areas exposed to wellbore fluids.
- Inspect the shear blades and slip inserts.
- Check the BOP accumulator system components, precharge pressure, and liquid level.

3. The logbook for each item of pressure control equipment is up-to-date with the information specified in "Service Company's Responsibilities".

4. Each item of pressure control equipment functions properly per the following:

   - Each ram achieves full travel in both directions under hydraulic control.
   - Each ram position indicator shows the correct ram position.
   - Each ram can be manually locked.
   - Shear rams are capable of shearing the thickest wall section of the CT string selected for the job, including an internal electric cable (if so equipped).

5. The BOP bodies and rams have passed their pressure tests per the following requirements:

   a. The BOP body per "Pressure Testing for Standard CT Operations" above and record the results in the equipment log.

   b. Close and manually lock the blind rams and pressure test them from below. Record the results in the equipment log.

   c. Insert a test bar through the pipe and slip rams, close and manually lock both sets of rams, and pressure test the pipe rams from below. Record the results in the equipment log.

6. The spare parts kit is stocked as required.

NOTE: Use only OEM replacement parts or their equivalent approved by the Customer for servicing the pressure control equipment.

NOTE: The best approach for determining the capability of the shear rams is to actually shear a sample of the CT. High yield strength CT, heavy wall CT, and CT containing electric cable require special blades and/or booster cylinders on the rams. A shear test is mandatory for CT containing an electric cable. After each shear test, inspect the blades for damage and replace them as necessary.

WARNING: The shear blades can be installed upside down, so make sure the cutting edges of the blades face each other.

WARNING: Do not open the pipe rams or blind rams with a pressure differential across them. Opening these rams with a differential pressure will damage the rubber goods and the BOP will no longer function properly. Always equalize the pressure across the rams before opening them.

DAS

Refer to "Equipment Specifications" for the requirements for recording and displaying data from CT operations. Verify the following before mobilizing the equipment to the job location:

1. The DAS is configured to provide the required information
2. The operating limits, as specified in the Job Program, are properly set for each parameter
3. The annunciations (alarms) for abnormal conditions are functioning
4. The DAS is communicating with all of the sensors and recording the data
5. The data storage medium has adequate space to record the data for the planned job
6. The spare parts kit is stocked as required

Bottom Hole Assemblies (BHA)

Refer to "Equipment Specifications" for the requirements for the BHA. Verify the following before mobilizing the equipment to the job location:

1. The BHA is as specified in the Job Program.
2. The BHA has been inspected and maintained per the manufacturer's specifications.
3. The BHA components perform all required functions.
4. All connectors and crossovers are compatible with mating components.
5. All flow paths and nozzles are open.
6. The mechanical disconnect, if so equipped, will separate upon application of the specified tensile force.
7. The hydraulic or electrical disconnect, if so equipped, will separate with the application of the specified activation signal (pressure or electrical).

8. The two check valves operate freely.

Power Packs

Refer to "Equipment Specifications" for the requirements for the power packs. Verify the following before mobilizing the equipment to the job location:

1. The equipment is as specified in the Job Program.

2. The equipment has been inspected and maintained per the manufacturer's specifications.

3. The logbook for each power pack is up-to-date with the information specified in "Service Company's Responsibilities".

4. That it performs all required functions.

5. The shutdown systems operate properly.

Lifting Equipment

Refer to "Equipment Specifications" for the requirements for the cranes. Verify the following before mobilizing the equipment to the job location:

1. The equipment is as specified in the Job Program.

2. The equipment has been inspected and maintained per the manufacturer's specifications.

3. The logbook for each crane is up-to-date with the information specified in "Service Company's Responsibilities".

4. Each crane is fully operational.

5. All lifting equipment (if required) complies fully with local requirements.

6. The crane operator(s) is(are) fully qualified according to local standards.

Fluid/Nitrogen Pumping Unit(s)

Refer to "Equipment Specifications" for the requirements for the pumping units. Verify the following before mobilizing the equipment to the job location:

1. The equipment is as specified in the Job Program.

2. The equipment has been inspected and maintained per the manufacturer's specifications.

3. The logbook for each pumping unit is up-to-date with the information specified in "Service Company's Responsibilities".

4. Each pumping unit is fully operational.

5. Each pumping unit has a properly certified pressure relief device installed.

Chicksan Connections

Refer to "Equipment Specifications" for the requirements for the chicksan connections. Verify the following before mobilizing the equipment to the job location:

1. The equipment is as specified in the Job Program.

2. Chicksan components have been inspected and repaired as needed.

3. Tie-down equipment has been inspected and repaired as needed.

Chemical/Nitrogen Tanks

Refer to "Equipment Specifications" for the requirements for the chemical/nitrogen tanks. Verify the following before mobilizing the equipment to the job location:

1. The tanks are as specified in the Job Program.

2. The tanks have been inspected and maintained per the manufacturer's specifications.

3. The logbook for each tank is up-to-date with the information specified in "Service Company's Responsibilities".

Mixing Tanks

Refer to "Equipment Specifications" for the requirements for the mixing tanks. Verify the following before mobilizing the equipment to the job location:

1. The tanks are as specified in the Job Program.

2. The tanks have been inspected and maintained per the manufacturer's specifications.

3. The logbook for each tank is up-to-date with the information specified in "Service Company's Responsibilities".

4. The equipment is fully operational.

5. The equipment has passed the required pressure tests.

6. The tanks are clean and free of leaks.

Downhole Motors

Refer to "Equipment Specifications" for the requirements for the downhole motors. Verify the following before mobilizing the equipment to the job location:

1. The downhole motor is as specified in the Job Program.

2. The motor has been inspected and maintained per the manufacturer's specifications.

3. The downhole motor operates within the manufacturer's specifications.

> *NOTE:* The preferred method for testing the motor is with a dynamometer. If dynamometer testing is not possible, measure the free rotating and stall pressures for the motor.

CT String Management

CT string management is more than just tracking the accumulated fatigue damage along the string. It is a process of regular inspection, corrective action, and maintenance designed to ensure that each CT string can perform as planned. For the Customer, the benefit of good CT string management is reliable, low-risk performance from the service company. For the service company, the benefit of good CT string management is more revenue per string.

Fatigue (Working Life)

Early attempts to predict and combat CT fatigue were strictly based on experience, i.e., the number of round trips CT could make without breaking. Predictions based on such historical data are not very reliable since this method ignores the contribution of pressure to fatigue. Moreover, these data can not localize the CT segment(s) most likely to fail. With the advent of better data acquisition systems, service companies can track the number of trips for individual segments of a CT string.

The CT service industry has used three different methods for tracking the working life of CT strings. These methods, ranked in order from worst to best are:

- Running feet (worst)
- Trips
- Computer fatigue modeling (best)

The running feet method is the oldest and most primitive method for tracking CT working life. The user measures the total length of CT run into wells and discards the entire CT string when the total length exceeds a predetermined limit value. The basis for this limit is usually empirical or historical data on CT failures. However, the running feet method ignores the distribution of fatigue damage in the string and the effects of internal pressure. It misses the connection between cyclic stress, pressure, and fatigue damage.

The trip method is an improvement on the running feet method and is a reasonable approach if narrowly applied. It divides a CT string into sections and records the trips the sections make in both directions across the guide arch. The user weights the number of trips according to the prevailing pressure and/or corrosion conditions and retires the entire CT string when the cumulative trips (weighted) reaches a specified limit. This limit is derived from empirical data and full-scale testing. Unfortunately, the weighting factors will be different for every combination of CT geometry and properties. This is why the trip method is difficult to extrapolate to different operating conditions.

Advanced CT life monitoring software like Reel-Trak™ is less conservative than either the running feet or trip method of monitoring CT working life. It can provide a longer safe working life, greater earnings for each string, and identify highly fatigued sections in a string for remedial action. Such remedies include:

1. Removing damaged sections and splicing the string with butt welds (only acceptable for temporary repairs)

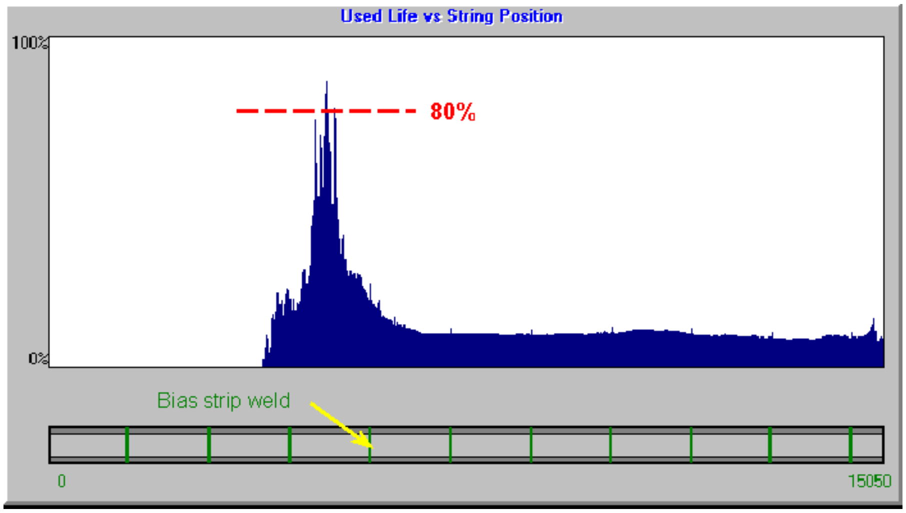
2. Position management

   - Swapping ends on the reel (inverting the string)
   - Cutting a length of CT from the free end of the string at regular intervals
   - Using the CT string for a variety of jobs in different wells

The following three figures give an example of string management during an actual CTD operation. Figure 17.7 shows the output from Reel-Trak™ at a time in the drilling operation when the driller had been reaming and making numerous short trips while trying to punch through a difficult hole section.

> *NOTE:* Advanced CT life monitoring software is the only acceptable method for tracking the working life of CT strings.

FIGURE 17.7 *Accumulated Fatigue After Extended CTD Operations Over a Narrow Depth Range*



The high fatigue peak approximately 5000 ft along the CT string corresponds to segments that have been cycling back and forth through the surface equipment at high pressure. The “virgin” segments to the left of the peak have never been off the reel. The “plateau” to the right of the peak corresponds to segments in the lower portion of the string that have only run through the surface equipment when tripping to TD or back to surface. The 80% limit was an arbitrary value chosen by the CT service company as the decision point for remedial action.

Figure 17.8 shows the portion of the CT string with unacceptable fatigue damage. The CT service company decided to remove this portion of the string and splice the two remaining sections together. After completing the repair operation, the fatigue distribution along the string looked like Figure 17.9.

FIGURE 17.8 *The Damaged Section of CT Identified for Remedial Action*

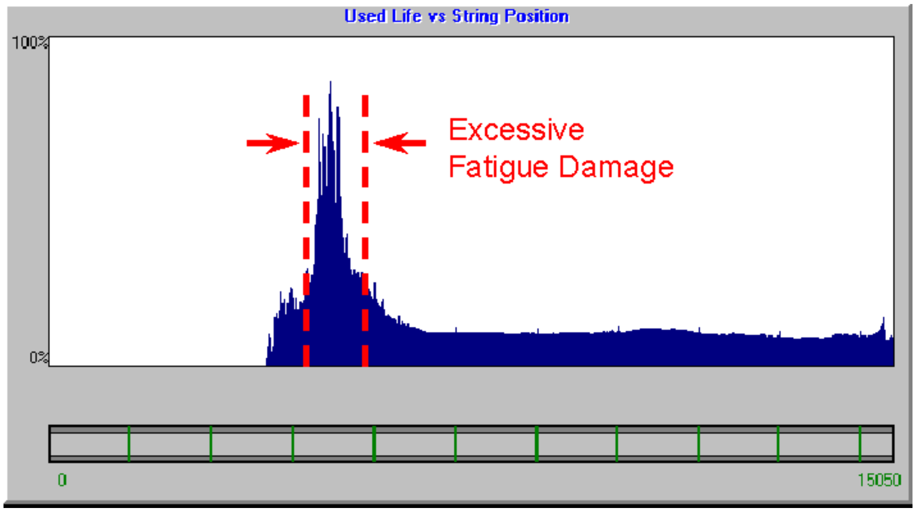
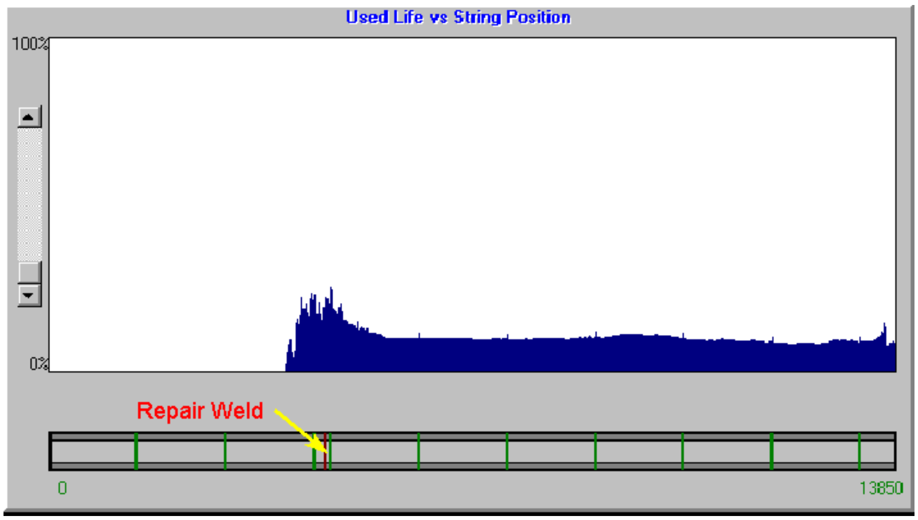


FIGURE 17.9 *Excessive Damage Removed and the String Repaired*



The CT service company successfully completed the CTD operation with the repaired string. The preceding example shows the value of using an advanced CT life monitoring system. Without such technology, the CT service company would probably not have identified the impending failure in time or would have wasted a salvageable CT string.

Dimensional Problems

A CT string can become unsuitable for continued use for reasons other than fatigue damage. Another problem that can limit the useful life of a string or its suitability for a given application is its geometry. CT becomes oval during normal use due to plastic bending on the reel.

Also, poorly fitting gripper blocks and worn components in the injector head can damage and deform the CT. Dents and ovality significantly decrease the collapse resistance of the CT (see CT Mechanical Limits). During pumping operations, the internal pressure can cause the CT to balloon as it plastically deforms on the reel and guide arch. This causes a corresponding decrease in the wall thickness. Both dimensional changes substantially weaken the CT's collapse resistance and decrease its working life. Moreover, extreme ballooning and ovality can restrict the passage of the CT through the injector and stripper.

Some CT software, such as Reel-Trak™, can estimate the ballooning and its effects on collapse resistance and working life. However, no models exist for predicting the ever-changing ovality of CT. The only option is to measure the ovality during CT operations. Several tools capable of measuring CT external geometry have emerged in recent years.

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

- the stresses in the wall of the tubing caused by pressure and axial forces will exceed the yield stress of the material. (See "The von Mises Yield Condition".)
- the accumulated fatigue in any segment of the string will exceed a predetermined limit during the operation. (See "CT Fatigue".)

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

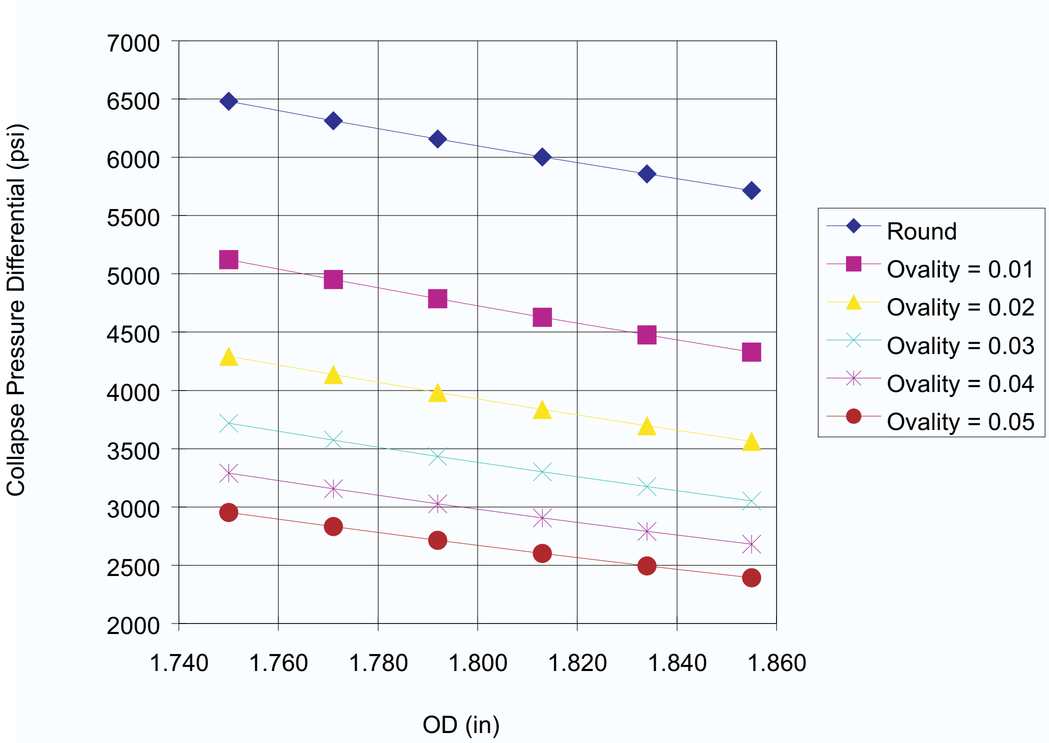
As the OD increases due to ballooning, the wall thickness decreases proportionally. However, ballooning has a relatively small effect on σ_{VME}.

EXAMPLE 0.9

σ_{VME} = 61,520 psi for CT with OD = 1.75 in. and t = 0.125 in. subjected to 30,000 lbs tension and 3000 psi collapse pressure.	If this CT ballooned 6% with use, the tubing dimensions would be OD = 1.855 in. and t = 0.117 in. For the same tension and collapse pressure, σ_{VME} = 63,640 psi.

Figure 17.10 illustrates the combined effects of ballooning and ovality on collapse pressure calculated from Equation 8.12 for 1.75 in. OD x 0.125 in. wall CT with 80 Kpsi yield strength subjected to 30,000 lbf tension. Note the significant decrease in collapse resistance with increasing OD and ovality. This example assumes wall thinning is due entirely to expansion of the OD and ignores effects of permanent elongation caused by combined tension and plastic bending. However, even modest ballooning (3%) decreases the collapse resistance by 5%.

FIGURE 17.10 *Effects of Ballooning on CT Collapse Resistance*



The working life (resistance to fatigue) of a CT string is just as important as its ability to resist axial and pressure forces. CT working life increases with increasing yield strength, decreasing OD, and increasing wall thickness (see "CT Fatigue"). Thus, ballooning due to high internal pressure decreases CT working life by increasing OD and decreasing wall thickness.

CT working life cannot be measured with a non-destructive test or visual assessment. Even though ballooning coincides with fatigue damage, it is not a direct indication of accumulated fatigue. Ballooning only occurs with internal pressure, and fatigue occurs with every plastic deformation, regardless of pressure. Certain CT fatigue models can accurately predict the working life of a CT segment if its dimensions and properties are known (see "CT Fatigue").

Table 17.2 summarizes the effects of ballooning and internal pressure on the fatigue life (trips to failure) predicted by Achilles™ for a segment of new 1.75 in. CT with 80 Kpsi yield strength. The reel diameter is 82 in. and the guide arch radius is 90 in. The increasing OD is an arbitrary choice based on ballooning, not a prediction from the CT fatigue model. However, the wall thickness shown corresponds to the thinning that would occur at the given OD. Clearly, ballooning shortens the useful life of a CT segment. This simple example highlights the importance of real-time measurements of tubing geometry.

TABLE 17.2 *Trips to Fatigue Failure, 80 Kpsi, 82 in. Reel and 90 in. Guide Arch*

OD (in.)	Wall (in.)	Internal Pressure (psi) 0	1000	2000	3000
1.750	0.1250	326	242	129	71
1.771	0.1233	318	234	124	68
1.792	0.1216	308	223	116	63
1.813	0.1200	300	213	108	58
1.834	0.1184	291	204	101	54
1.855	0.1169	283	195	95	50

Flaws and Damage

Quantifying the effects of dents, scratches, and corrosion pits on the performance of CT is a difficult task at best. Even though these flaws can be measured, (e.g. length, width, depth) their effects can be more significant than their physical size suggests. Every cut or sharp-edged flaw creates a local stress concentration or stress riser that can magnify fatigue damage in the surrounding material. Moreover, such flaws can accelerate corrosion by providing fresh material for attack by corrosive fluids and gases. Many CT inspection tools can "see" flaws and damage that are nearly invisible to the naked eye. They can even measure those flaws larger than a certain threshold. Unfortunately, no industry group, such as API, has proposed standards or guidelines for derating the performance of CT strings due to dents, scratches, or corrosion pits.

A prudent approach is to measure the penetration of the flaw or damage into the CT wall and use the reduced wall thickness for calculating mechanical limits (Chapter 8 "CT Mechanical Limits") and fatigue life ("CT Fatigue").

Any section of the CT string not capable of satisfactory performance should be cut out of the string, or at least positioned so that it remains on the reel.

NOTE: Butt welds are acceptable only on non-critical jobs and derate the fatigue life by at least 50%.

CAUTION: Dimple and slip tubing connectors introduce severe local stress concentrations to the surface of the CT. These stresses exacerbate the effects of corrosive environments, particularly H_2S and CO_2. For CT operations in corrosive environments, a prudent practice is to remove the tubing connector and re-install it on undamaged tubing after each trip into a well.

DATA ACQUISITION AND REAL-TIME MONITORING

Data acquisition has three important functions.

- First, it provides the CT operator with high quality, real-time information that he can use to properly perform his job. Operating data must be readily available in a format permitting rapid evaluation and judgments. However, real-time data are only a snapshot, a brief window, into a continuing operation. An instantaneous change in a parameter may only be a random, singular event, or it may herald the start of a trend. Historical data correlated against time or depth are necessary to describe the progress of an operation and warn of potential problems.
- The second function of data acquisition is to record trends in physical parameters. Based on these trends, the CT operator can minimize problems such as CT fatigue and deteriorating wellbore conditions.
- The third function of data acquisition is to provide permanent records of CT operations. These records have a myriad of uses including post-job analyses, research and development, training, and planning future operations.

The only acceptable data acquisition system (DAS) for CT operations is a computer-based system. All major CT service companies can meet this requirement. Chart records and analog gauges are fine for the CT unit operator, but neither provides a permanent record suitable for control, analyses, and planning as described in this manual. The data listed in the first two columns of Table 17.3 are readily available. All eight parameters are measured and displayed in the CT unit control cab. However, CT service companies seldom record stripper pressure and CT reel tension on their DAS. The former gives some indication of how stripper friction changes with time. Reel tension affects CTWI. Both data are necessary when comparing simulator results to measured data.

TABLE 17.3 *Real-time CT Operations Data*

Required	Important	Useful
Time	Pump flow rate	Fluids properties
Depth	Stripper pressure	BHA axial force
CTWI	CT reel back tension	
Reel inlet pressure		
Wellhead pressure		

Scanning rate is adjustable for computer-based systems, but CPU speed and/or data storage media may set upper limits on scanning rate and volume of data. Relatively slow scanning rate, 1-2 scans per minute, should be adequate while RIH and POOH or in vertical hole intervals. A higher scanning rate, 6-12 scans per minute, is important in highly deviated wells, near TD, and during critical operations. Data should also be available in a format for processing by commercially available spreadsheet and plotting software.

If the BHA contains a sensor package to measure tension between the CT and BHA, this data should be recorded on the DAS. During logging runs, CTWI and as many of the other variables as possible should be recorded on the logging computer for accurate correlation with the logs.

Monitoring Operations Data

Figure 17.11 shows one of the two digital display screens available from the Orion™ DAS. The user can configure each screen with up to eight (8) digital displays, customize the labeling and colors, and set alarm monitoring conditions.

FIGURE 17.11 *Orion™ Digital Display Screen*

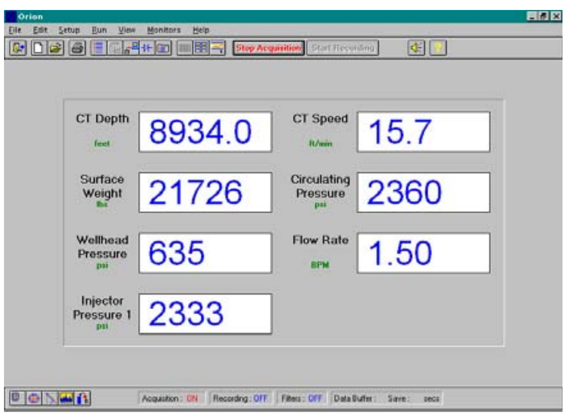
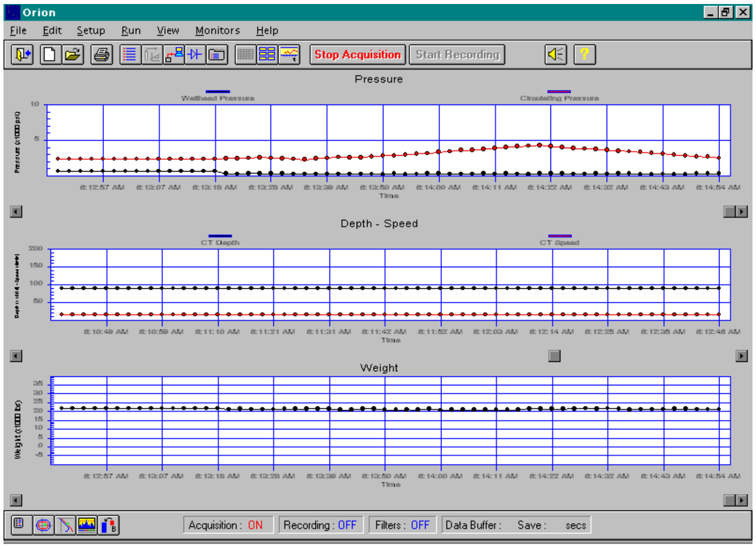


Figure 17.12 shows a different Orion™ display format for real-time CT operations data that provides a chart record or historical log of measurements over a specified time interval. The operator can choose which parameters to plot on which charts and customize the appearance of each one. This format is especially good for monitoring trends.

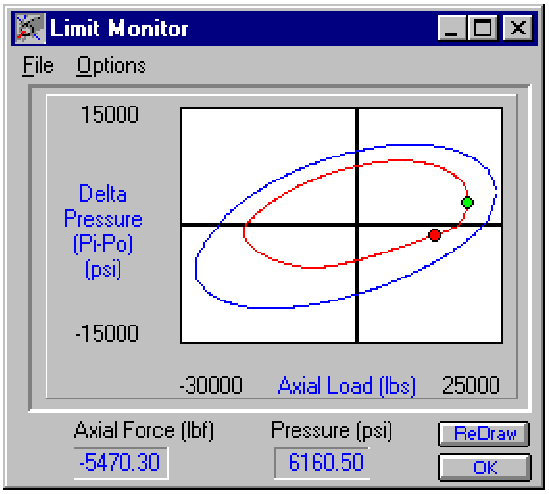
FIGURE 17.12 *Orion™ Chart Display Screen*



CT Working Limits Monitor

Chapter 8 "The von Mises Yield Condition", page 8-11 describes the use of Von Mises equivalent stress (σ_{VME}) for defining the safe operating limits for CT. This concept can be applied in real-time to provide the CT operator with a clear indication of σ_{VME} in the wall of the CT (at a specific location) relative to the yield strength of the material or safe operating limit. Figure 17.13 is an example of such a display from the Orion™ DAS. The blue ellipse corresponds to the yield stress for the CT material. The red ellipse represents the “safe” operating limit for σ_{VME}, here 80% of the yield stress. The green dot indicates the combination of differential pressure and axial force above the stripper, and the red dot indicates the corresponding condition below the stripper. As long as the dots are inside the red ellipse, the CT should not fail due to excessive stress.

FIGURE 17.13 *Orion™ CT Working Limits Display*

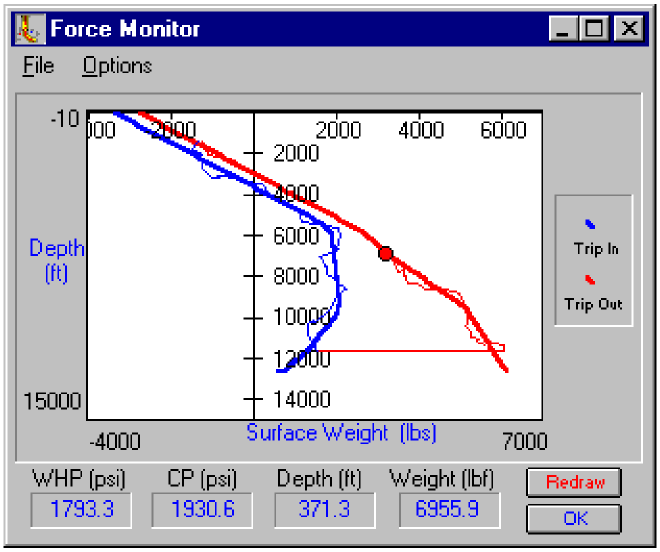


CT Forces Monitor

Section "CT Simulators" page 17-11 describes different ways of presenting CT simulator results from a general force balance on a CT string. The concept of general force balance can be applied in real-time to provide the CT operator with a clear indication of how the current CTWI compares with planned values at any point in the operation. Figure 17.14 is an example of such a display from the Orion™ DAS. The bold blue curve is the predicted CTWI for RIH. The fine blue curve is the actual CTWI for RIH. The bold red curve is the predicted CTWI for POOH. The fine red curve is the actual CTWI for POOH. The dot, here red because this snap-shot of the display occurred during POOH, indicates the current depth and CTWI.

This presentation of the data provides a powerful tool for forecasting the outcome of the operation. Due to all of the assumptions necessary to run a CT simulator, the absolute values can differ from reality for many reasons. The relationship between the actual measurements and the predicted absolute values is not as important as the comparison between the trends. As long as the trends are similar, the actual operation is going as planned. If the trends between actual and predicted values differ too much, then two results are possible. One, the job planner did not properly model the operation. Two, the CT simulation was accurate, but conditions have changed in the wellbore and caused the job to deviate from the expected results. Running the CT simulator again using current information from the operation can identify which of these results is more likely. The CT operator can then decide whether the operation is becoming risky or is safe to proceed on its present course.

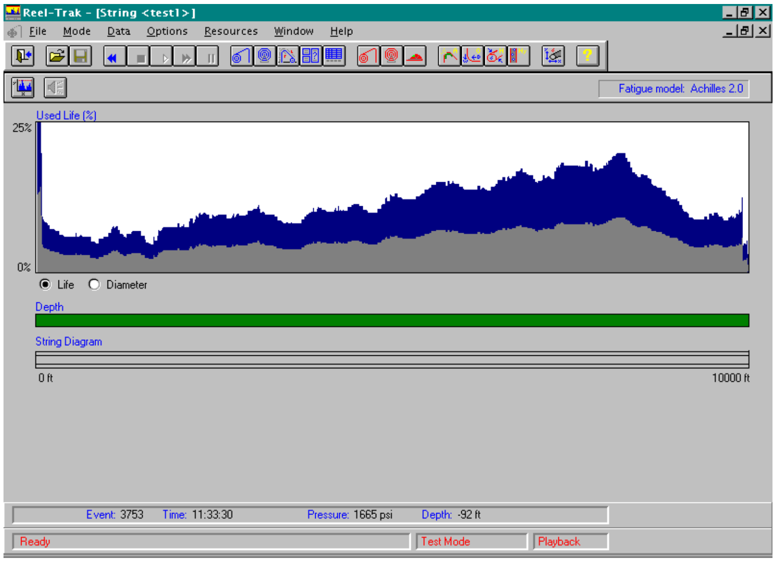
FIGURE 17.14 *Orion™ CT Forces Display*



Remaining Working Life (Fatigue) Monitor

Chapter 9 "CT Fatigue", page 9-5 discusses CT fatigue, and Section “Fatigue (Working Life)” page 17-45 describes how to use fatigue data to manage a CT string. A real-time display of fatigue accumulation in a CT string is a powerful tool for minimizing risk, especially for CT operations like drilling, milling, and hydraulic scale removal. The example shown in Section “Fatigue (Working Life)” page 17-45 is for a drilling operation. The Orion™ DAS can display fatigue calculations in real-time to provide the CT operator a timely indication of highly-fatigue portions of the CT string. Figure 17.15 is an example of such a display for Reel-Trak™ calculations.

FIGURE 17.15 *Orion™ Fatigue Monitor Display*



Monitoring CT Dimensions

As Section “CT String Management” page 17-45 describes, comprehensive string management includes accurate measurements of the CT string geometry (OD and wall thickness) and inspection of the CT for flaws and damage. Whether these measurements occur during a job or during spooling operations in the service company yard, the data should become part of the permanent record for the CT string.

This section shows examples of some of the electronic diameter measurements recorded by a DAS during a spooling operation on a 16,700 ft CT string with nominal OD = 1.75 in. The operational history and properties of this string are unknown. The average running speed during the spooling operation was approximately 150 ft/min. The operator stopped spooling every 1000 ft to measure the OD with a micrometer on two orthogonal diameters. The average OD from the electronic diameter tool varied ± 0.003 in. relative to the manual measurements.

Figure 17.16 is a plot of the average OD for the first 9000 ft of tubing. These data suggest a diameter enlargement at approximately 1600 ft and a diameter reduction at approximately 7000 ft. The increases in ovality at these locations (see Figure 17.17) indicate these diameter variations are not uniform along each 30º radial. Figure 17.18 and Figure 17.19 show the maximum and minimum diameters respectively for the first 9000 ft.

Figure 17.20 is a zoom view of the six individual diameter measurements (30º radials) around 1622 ft. The measurements are approximately 6 ft apart. These data clearly indicate a 0.020 in. bulge approximately 3 ft long. Figure 17.21 is a zoom view of the six individual diameter measurements around 7042 ft. All six diameters suddenly decrease below their preceding average at least 0.015 in. This suggests the CT string may be necked-down at this location. OD 1 and OD 6 (two adjacent radials) are approximately 0.030 in below their average values for approximately 3 ft. Thus, the diameter reduction is not symmetrical.

FIGURE 17.16 *Average OD for CT String B, 0-9000 ft*

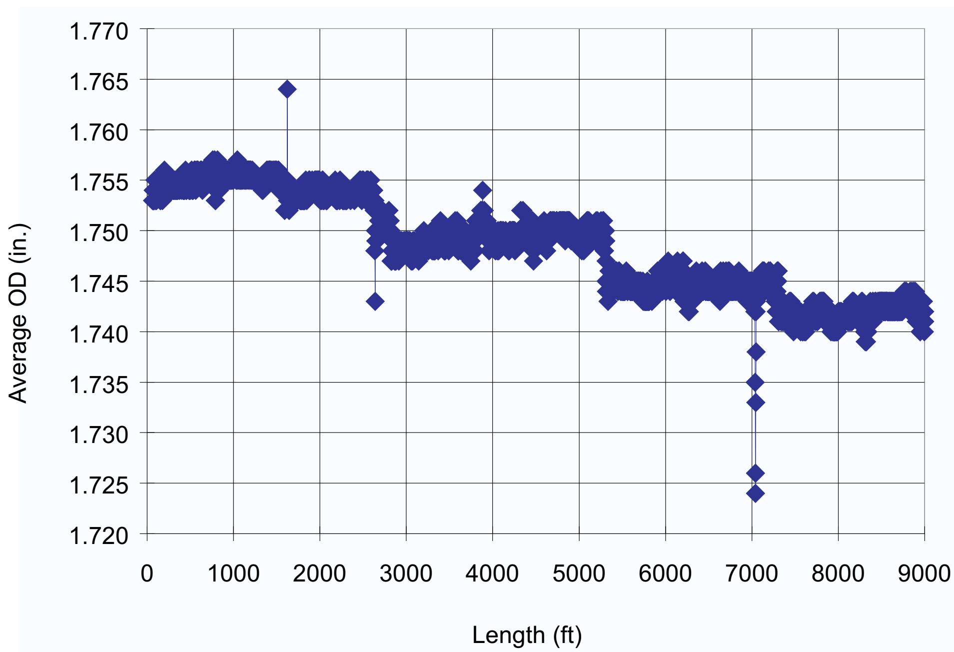


FIGURE 17.17 *Ovality for CT String B, 0-9000 ft*

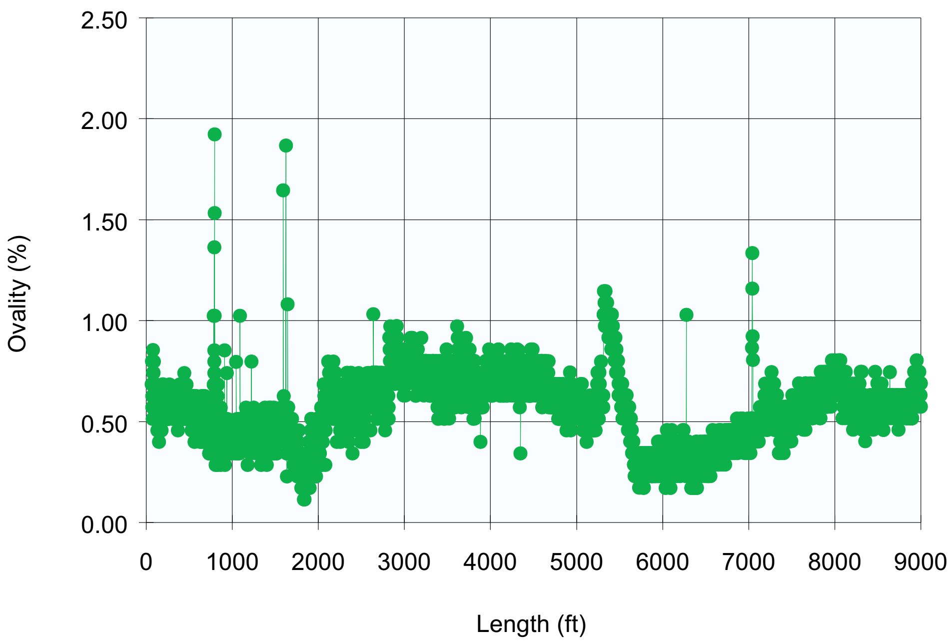


FIGURE 17.18 *Maximum OD for CT String B, 0-9000 ft*

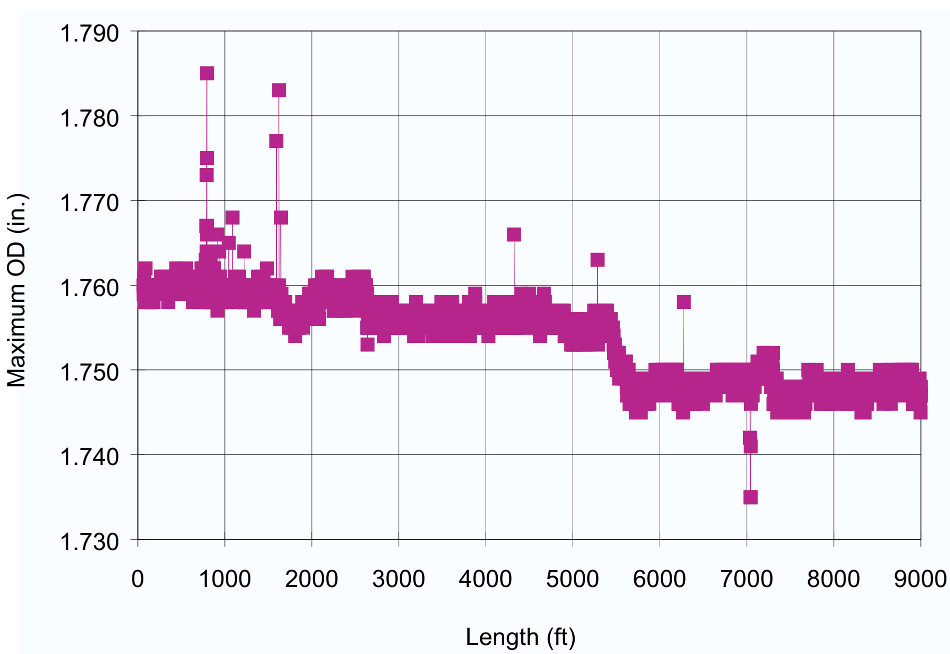


FIGURE 17.19 *Minimum OD for CT String B, 0-9000 ft*

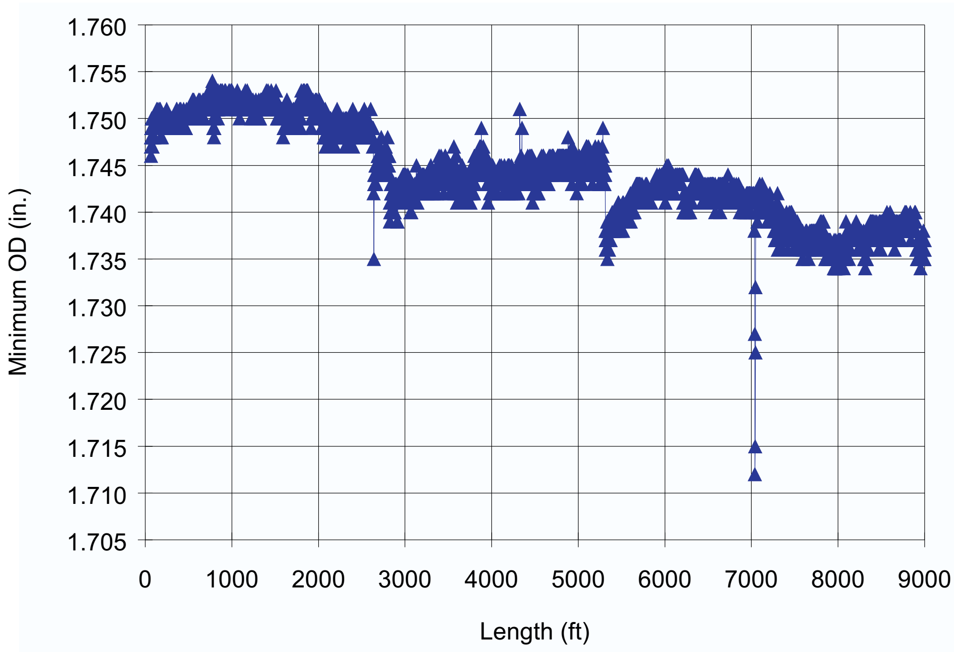


FIGURE 17.20 *Individual Diameters for CT String B, 1622 ft*

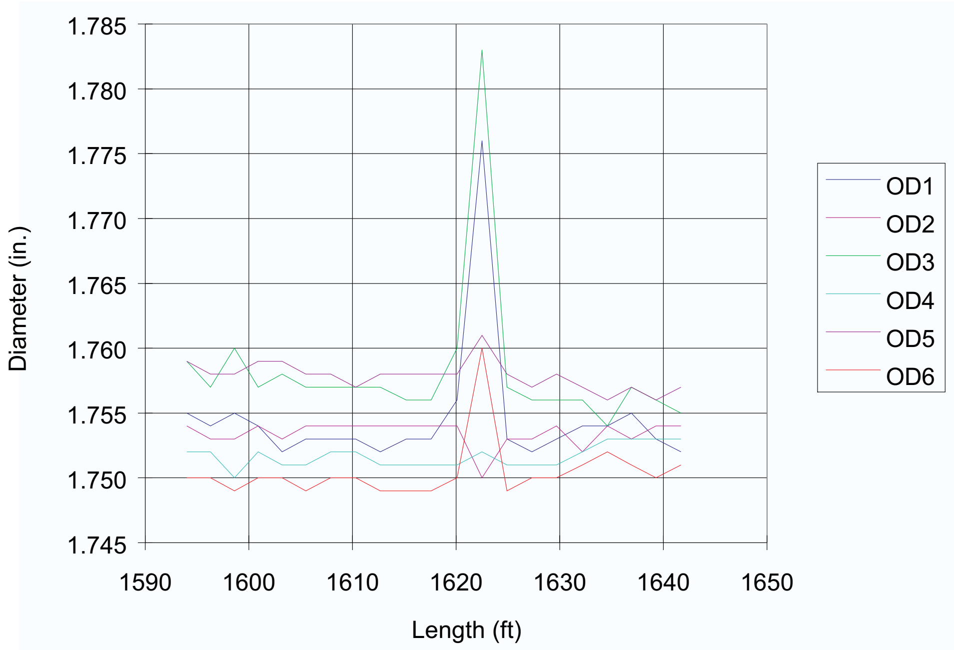
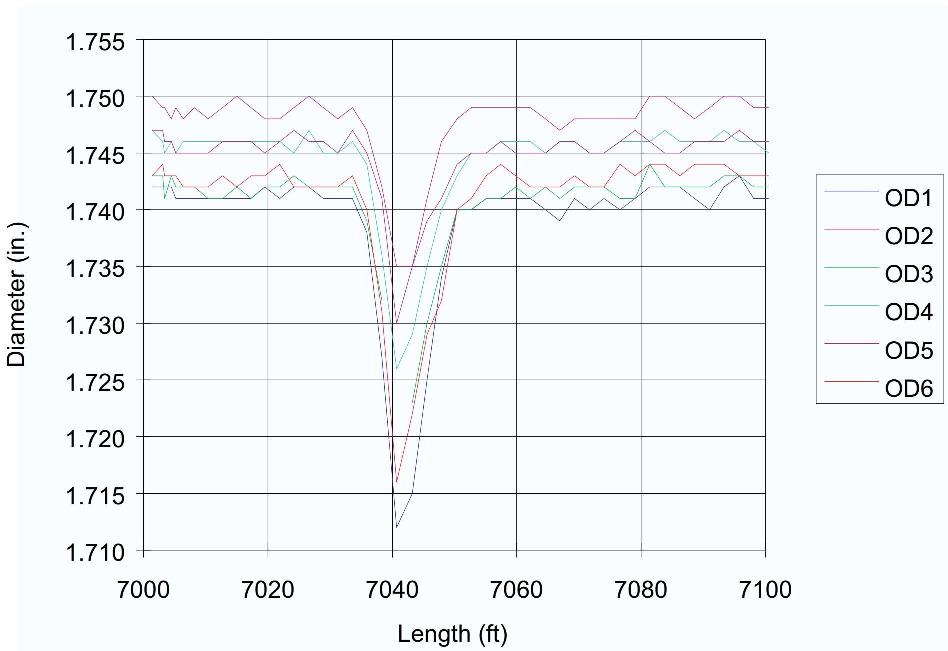


FIGURE 17.21 *Individual Diameters for CT String B, 7042 ft*



Post-job Reports

Requirements for post-job reporting on CT operations should be specified during the planning phase (see Section “Job Planning” page 17-4). However, the motivation to produce the planned reports will vary with the complexity and outcome of the job. Regardless of whether the job succeeded or failed, a certain amount of data, analyses, and related information are necessary to properly describe the outcome and provide a reference for planning future CT operations. The purpose of this section is to outline minimum requirements for effective post-job reporting.

Share the post-job report with all participants on the operation. For successful jobs, this can foster a sense of accomplishment and provide positive feedback. For unsuccessful jobs or those plagued with problems, the post-job report can teach valuable lessons and provide a mechanism for improving future jobs. In both cases, the additional scrutiny can serve as a useful quality control tool.

Service Company Responsibility

The service company should submit to the Customer a comprehensive and detailed report on each CT operation. **The report should contain the following information as a minimum:**

1. Chronology of major events
2. Comparison between the planned and actual operations
3. Conclusions and recommendations
4. Data from the DAS
    - Processed data - plots, tables, etc.
    - Raw data in electronic form
    - Interpretation of the data
    - Comparison of the data with CT simulator results
5. Description of problems
6. Description of the equipment used

a. CT description

- OD
- wall thickness (taper)
- material properties – yield stress and modulus of elasticity
- accumulated fatigue after the job

b. CT weight sensor(s)

c. Depth counter(s)

d. DAS

e. Injector head

f. Pressure control equipment

g. Injector head support and work platform (if used)

h. Guide arch radius

i. CT diameter measurement tool (if used)

j. CT reel diameter

k. CT disconnect(s)

l. BHA description (include a drawing)

- components
- dimensions
- weight

m. Pressure sensors – wellhead and reel inlet

n. Power pack

o. Auxiliary equipment

- pumps
- compressors
- tanks

p. Special tools

Customer's Responsibility

Customer personnel should contribute the following to the post-job report:

1. An overview of the CT operation and a comparison between the planned objectives and actual results
2. Discussion of any problems
3. Conclusions and recommendations
4. Actual operating conditions—pressures, flow rates, temperatures
5. Description of well path (survey)
6. Wellbore geometry—well completion diagram
7. Nominal properties of fluids inside and outside the CT

18

GENERAL CT OPERATIONS GUIDELINES

The primary objective of contingency planning is to minimize response time, or down-time, in the event unplanned conditions are encountered. In many cases, delays in response to unusual conditions result in a worsening of the circumstances or problem. This can quickly compound the potential risk to well security and personnel safety. Therefore, contingency planning must be part of every CT operation.

The level of contingency planning will generally reflect the conditions, potential hazards and/or complexity of the intended operation. Operations conducted in high potential hazard conditions require a higher level of contingency planning. In some circumstances, detailed procedures may be included in contingency plans to ensure the safety of personnel and equipment.

This section provides general guidelines for CT operations. Local regulations, policies, and working conditions may take precedence over the guidelines provided herein. However, these guidelines can reduce the risk of failure for any CT operation.

GENERAL SAFETY GUIDELINES

Completing all CT operations safely is one of the primary goals for these guidelines. The following sections describe minimum requirements for personnel training, safety equipment, and procedures for CT operations.

Personnel Training

1. Service company personnel on location should be properly trained to:

- Perform their required duties
- Operate the well control equipment (supervisors)
- Safely handle all treatment fluids planned for the job
- Operate any safety equipment required for their job
- Speak and read English fluently enough to understand the job procedures and safety procedures

2. Well control training for workover operations from a source accredited by the IADC should be required for:

- Customer well site supervisor
- Service company supervisor on location
- Any service company personnel authorized by their company to operate well control equipment

3. Basic first aid training from an approved source should be required for:

- Customer well site supervisor
- Service company supervisor on location

4. For any job where H_2S or other substance is a potential breathing hazard, all personnel on location directly participating in the CT operation should be certified from an approved source to operate a self-contained breathing apparatus (SCBA), commonly called a “Scott” air pack.

Safety Equipment

1. For any job where H_2S or other substance is a potential breathing hazard, install a windsock that will be easily visible from anywhere on the well site.

2. Supply appropriate personal safety gear to everyone who may need it

3. Create an emergency response and first aid site located at least 200 ft upwind from the wellhead. This site should be equipped with the following items, as a minimum:
   - 3 SCBA (when H_2S or other breathing hazard might be present)
   - Fire extinguishers suitable for flammable liquids
   - First aid kit
   - Eye wash kit
   - Stretcher
   - Radio or cellular phone capable of summoning off-site help

4. Emergency kill equipment should consist of the following components, as a minimum:
   - Kill line
   - Remotely controlled, hydraulically activated fail closed valve installed in the kill line between the TKV and the pump.
   - Pumping unit
   - Kill fluid storage tanks
   - Appropriate kill fluid

5. For any job where H_2S is a potential hazard, install H_2S detectors with audible alarms at strategic locations around the job site
   - Close to the wellhead at ground level
   - Downwind of the wellhead approximately 100 ft
   - In the wellhead cellar

6. Designate a vehicle for emergency use and equip it with the following equipment, as a minimum:
   - First aid kit
   - Eye wash kit
   - Fire extinguishers suitable for flammable liquids
   - Radio capable of summoning off-site help

7. For any job where H_2S or other substance is a potential breathing hazard, SCBA are required at the following locations:

- Emergency response and first aid site
- CT unit control cab
- Remote BOP operating station
- Fluid pump unit

8. In each work area involving acid or other hazardous chemicals provide the means to:

- Rapidly wash (flush) the hazardous substance off affected surfaces
- Neutralize the hazardous substance or minimize its effects.

9. Portable communicators (radios) that operate on a common channel (frequency) should be available on location to the following personnel:

- Customer well site supervisor
- Service company supervisor on location
- Equipment operators

Safety Procedures

1. Prominently display a detailed equipment layout drawing around the location noting the locations of hazards and escape routes.

2. Only Customer personnel should operate wellhead valves and associated equipment belonging to the Customer.

3. Control access to the job location by a sign in/sign out log. The Customer's well site supervisor, or his designate should maintain this log.

4. Prominently display large, weather-proof safety signs around the location whenever hazardous materials are in use. As a minimum, these signs should proclaim the following information:

- Types of chemicals in use and their constituents
- Relevant safety precautions for each chemical
- Emergency actions in event of chemical spill
- First aid treatment in case a person comes in contact with nitrogen or a hazardous chemical
- Emergency telephone number(s) for additional information.

5. Support the injector head on a work platform or from overhead with a crane whenever personnel are working on or near the injector head.

6. Before any person climbs onto or works on the injector head:

- **a.** Stop the drive chains
- **b.** Shut down the power pack
- **c.** Attach a warning tag to each injector head control

7. Before any person enters the wellhead cellar without an SCBA, confirm that LEL, oxygen, and H_2S are at safe levels.

8. Hold a safety meeting with all personnel on location prior to RIH.

- **a.** Summarize the planned operations
- **b.** Discuss the results of the risk analyses
- **c.** Describe contingency plans and emergency procedures
- **d.** Demonstrate special safety equipment
- **e.** Assign responsibilities
- **f.** Identify communications procedures

TRANSPORTATION OF EQUIPMENT AND MATERIALS

1. Properly secure and protect all equipment for safe transportation.

2. Transport hazardous chemicals in accordance with local requirements and with warning signs prominently displayed.

3. Verify that all equipment and loads being transported comply with local limits for weight and dimensions.

Rig Up

1. All equipment delivered to the location should meet the guidelines presented in Chapter 17 “Minimizing Risk For CT Operations” and the requirements of the Job Program.
2. Verify that the logbook for each piece of equipment is current.
3. Prior to each job, cut a 3 ft length of CT from the free end of the string and store it for future analysis, if required.
4. Whenever possible, run a drift larger than the maximum OD of the BHA through the well-bore to the depth required by the Job Program prior to commencing the job. If this requires the use of the CT equipment, perform the drift run after the well-site pressure tests.
5. Install the secondary pressure control equipment onto the crown valve according to Chapter 17 “Minimizing Risk For CT Operations”. (Install the remaining well control components per Section “Well-Site Pressure Testing” page 18-13.)
   a. Connect the hydraulic lines.
   b. Test the operation of the rams by hydraulically opening and closing each actuator.
6. Position vent lines from pressure relief valves to discharge safely away from any personnel.
7. Injector head
   a. Stabilize and secure the injector support platform (if provided) before installing the injector head.
   b. Verify proper operation of the injector head before installing it on the BOPs.
   c. Remove the transport clamps from the injector head and verify that the weight indicators are functioning.
   d. Ensure that the centerline (longitudinal axis) of the CT is aligned with the vertical centerline of the BOP stack.
   e. Post in the CT unit control cab a plot of applied tension and applied compression force vs. skate ram pressure for the injector used for the job.

8. Post a detailed schematic of the pressure control equipment stack in the CT unit control cab.

9. Verify that the DAS, all sensors, and all displays are fully operational. **Do not start the job until this requirement is met.**

10. If the BHA contains any ball-operated components, drift the CT and end connector with a wiper plug at least as large as the ball or plug that will be used during the operation. This should be done before the well-site pressure tests.

11. Prepare a detailed fishing diagram of the BHA prior to running it into the wellbore.

12. Operate crane engines continuously while any load is suspended from the crane.

13. For nitrogen operations over steel decking, support all tanks and cryogenic hoses with wooden planks covered with tarps or rubber mats

BOP OPERATION

BOP Operation

A BOP operates with 1500 psi hydraulic pressure. Two hoses must be connected to each cylinder for proper operation of a BOP. One hose is used to close the ram. The other hose is used to open it.

Closing and Locking the Rams

After fully closing the rams, close and lock the manual locks. If hydraulic pressure fails, the locks on the pipe rams and blind rams hold the well bore pressure, while slip rams hold the tubing. Operating the manual locks is critical for the slip ram if there is no backup. The following is the procedure for closing and locking the rams:

1. Close the rams with hydraulic pressure. If the hydraulic system has failed, release the hydraulic fluid in front of the piston, then close the rams manually. To release the fluid, either switch the valve over to the closed position, or remove the hydraulic fittings from the front of the piston. Then allow the fluid to drain.

2. Run the manual locks in and rotate the hand wheel clockwise to lock the rams. Tighten the hand wheel down with a pipe wrench and torque it down to make sure it is locked.

Unlocking and Opening the Rams

The rams must be fully opened to avoid contact with the tool string. The procedure to unlock and open the rams is:

1. Equalize the pressure above and below the rams.

> *WARNING:* Do not open the pipe rams or blind rams with a pressure differential across them. Opening these rams with a differential pressure will damage the rubber goods and the BOP will no longer function properly.

2. Unlock the manual locks by rotating the hand wheel counter-clockwise. Note that rotating the hand wheel clockwise will lock the rams.

3. Open the rams with hydraulic pressure. One cannot open the rams manually.

CAUTION: Do not use the slip rams during normal operations. If they are used, inspect the surface of the CT contacted by the rams for signs of damage. Do not run damaged CT below the BOPs.

WELL-SITE PRESSURE TESTING

The purpose of well-site pressure testing is to confirm the pressure integrity of the CT string, stripper, flanged connections, and other plumbing components after they have been made up on location. The BOP body and sealing rams must also be tested on a test stand in the service company yard per Chapter 17 "Minimizing Risk For CT Operations" prior to mobilizing the equipment to the job location. The following section describes procedures that correspond to the pressure control equipment listed in Chapter 17 "Equipment Specifications", page 17-25. Other equipment and rig-ups may require modifications to these procedures. However, the Customer's well-site supervisor must approve any such modifications.

1. Conduct all well-site pressure tests according to Chapter 17 "Pressure Testing for Standard CT Operations", page 17-36, unless instructed otherwise in the Customer Job Program.
2. Use a clean fluid pump for pressure testing all components connected to the CT.
3. **Replace or repair any component that fails its pressure test.**

WARNING: Do not pressure test CT strings with nitrogen or any other gas on location.

Surface Lines

1. Connect hard lines from the pump to the CT reel manifold and the TKV.
2. Pressure test the lines against the CT reel inlet valve and the TKV.

BOP Bodies and Sealing Rams

1. Fill the BOP stack with water through the TKV.
2. Close the BOP blind rams and open the equalizing port.
3. Slowly pump water through this port until fluid is observed above the blind rams.
4. Close the equalizing port and pressure test the blind rams.
5. At the conclusion of the test, reduce the pressure to zero through the pump.

6. Open the blind rams.

7. Close the TKV.

CT String, BOP Stack Connections, Stripper, and BHA Check Valves

1. Fully retract all of the BOP rams.

2. Insert the CT into the injector head and stripper. (This assumes the stripper has been installed on the injector head.)

3. Install the appropriate tubing connector on the end of the CT, then install the BHA as specified in the Job Program.

> *NOTE:* The tubing connector must meet the specifications in Chapter 17 "Bottom Hole Assembly (BHA)", page 17-31.

4. Lower the BHA into the riser and BOPs and make up the remaining connection(s).

5. Slowly raise the BHA until the tubing connector contacts the lower wear bushing in the stripper.

> *CAUTION:* Ensure that the gripping force applied to the CT by the injector head is adequate to hold the CT against the pressure force.

6. Energize the stripper.

7. Apply test pressure through the CT and increase the hydraulic pressure to the stripper until it stops leaking.

8. Reduce the pressure to zero through the BOPs and repair any leaks. **Always reduce pressure to the CT reel last to prevent collapsing the CT.**

    a. Tighten leaking connections.

    b. Replace the stripper element.

    c. Replace any faulty components in the BOPs.

9. Repeat steps 6-8 until the requirements of Chapter 17 "Pressure Testing for Standard CT Operations", page 17-36 are satisfied.

10. Test the BHA check valves by reducing pressure on the CT reel at least 1500 psi and monitoring the CT pressure for 15 minutes per the requirements of Chapter 17 "Pressure Testing for Standard CT Operations", page 17-36.

11. On completion of the test, reduce pressure through the BOPs to zero. **Always reduce pressure to the CT reel last to prevent collapsing the CT.**

12. Relax the stripper.

BOP Pipe Rams

1. With the stripper fully retracted, lower the BHA until the tubing connector is at least 12 in. below the pipe rams.

2. Adjust the gripping force the injector head applies to the CT so that the injector head can safely hold the CT against the pressure (snubbing) force per Chapter 17 "Injector Head", page 17-26.

3. Open the TKV and slowly pump water until the stripper leaks.

4. Close the TKV and equalizing valve.

5. Close and lock the BOP pipe rams and slowly pump through the CT to the required test pressure.

6. At the conclusion of the test, energize the stripper and equalize across the pipe rams.

7. Open the TKV and reduce pressure to zero through the pump.

8. Relax the stripper and open the pipe rams.

GENERAL OPERATING GUIDELINES

1. Operate crane engines continuously while any load is suspended from the crane.
2. Whenever possible, lubricate the CT while RIH to protect the stripper elements.
3. Zero the depth counters and weight indicator(s) prior to opening the well.
4. Maintain the lowest possible hydraulic pressure on the stripper that creates an effective seal around the CT in order to minimize wear on the stripper elements.
5. Maintain positive pressure in the CT reel at all times. With the CT in tension, do not exceed 500 psi collapse pressure differential without prior approval from the Customer supervisor.
6. Do not use the slip rams during normal operations. If they are used, inspect the surface of the CT contacted by the rams for signs of damage before continuing operations. Do not run damaged CT below the BOPs.
7. Whenever possible, run a tubing end locator (TEL) on the BHA for depth correlation purposes. Mark the CT with paint at known depths for visual reference. Do not scratch, dent, or otherwise mar the surface of the CT.
8. Maximum allowable SDW, without prior approval from the Customer supervisor, is the lessor of 2000 lbs or the value specified in the Customer Job Program.
9. Do not alter any operating limit without expressed permission of the Customer supervisor.
10. Operate the DAS at all times that the BHA is below the BOPs and monitor the real-time operations data.
    - Relatively slow DAS scanning rate, 1-2 scans per minute, should be adequate while RIH and POOH or in vertical hole intervals. Use a higher scanning rate, 6-12 scans per minute, in highly deviated wells, near TD, and during critical operations.
    - Monitor the VME stress in the CT wall relative to the working limit prescribed by the job program.

    WARNING: Do not exceed the CT working limit without prior approval from the Customer supervisor.

    - Monitor the trend in the CTWI compared to the predicted values.

WARNING: Advise the Customer supervisor if the comparison becomes unfavorable.

- Monitor the remaining working life in the CT string.

WARNING: Do not exceed 80% of CT working life without prior approval from the Customer supervisor.

11. Operate the data acquisition system at all times the CT is below the BOPs.

12. Upon completion of CT operations and prior to rigging down, vent all pressure from the CT through the kill line and release the stripper.

13. Clean the CT string after each operation involving pumping solids-laden slurries.

CT Running Speeds

If the Job Program does not specify running speeds, use the values in Table 18.1.

TABLE 18.1 *Maximum CT Running Speeds*

Situation		Maximum Speed
RIH	through any restrictions in the wellbore ID	15 ft/min
	when the BHA is passing through the wellhead	15 ft/min
	within 100 ft of tagging a designated target	15 ft/min
	within 500 ft of bottom or known obstruction	25 ft/min
	below the wellhead	75 ft/min
POOH	actual depth unknown, estimated depth about 500 ft	15 ft/min
	through any restrictions in the wellbore ID	15 ft/min
	when the BHA is passing through the wellhead	15 ft/min
	below the wellhead	100 ft/min

NOTE: Some BHAs, such as logging tools and completions, require slower running speeds than those in Table 18.1. Always heed the slowest maximum allowable running speed.

PULL TESTS

If the Job Program does not specify the location for pull tests, perform pull tests at the locations listed below while RIH. Do not adjust the weight indicator to conform to predicted values without the expressed consent of the Customer supervisor. Record any weight anomalies. Operate the DAS while performing pull tests.

- After RIH about 500 ft to verify that all equipment is operating correctly
- Every 1000 ft for wellbore inclination < 60°
- Every 500 ft for wellbore inclination ≥ 60°
- After passing through any downhole restriction or tight spot
- Any time the rate of change in CTWI increases significantly compared to the predicted values

Manually record the following parameters for each pull test

- Time
- Depth
- RIH, POOH, and hanging weights
- Stripper pressure
- Pump rate and pressure
- WHP

CT TEST RUNS

A valuable means of minimizing risk for an operation with a large or expensive BHA like perforating or logging is to conduct CT test runs prior to the actual job. These consist of substituting a “dummy” BHA for the real one, then running the CT operation as planned, including pull tests. The dummy BHA must resemble the real BHA as much as possible in weight and dimensions, but need not perform the planned functions of the real BHA. CT test runs are more than pass/fail tests because they provide a full dress rehearsal for the actual CT operation and data for validating the planning simulations. Updating simulations with better estimates of Cf is particularly important if the CT test run deviates from the predicted results.

CT OR BHA BECOMING STUCK

Working the tubing string in and out of the wellbore in an attempt to pass a hang-up point is often effective. However, this induces localized fatigue as the tubing is cycled around the gooseneck and reel. This can rapidly lead to failure of the work string.

Use the weight indicator response to help determine whether sticking is due to a downhole or near wellhead condition. For example, a rapid loss of weight over a short interval can indicate a hang-up point at or near the wellhead or pressure control equipment. Deeper, downhole hang-up points will cause a slower reaction which is dampened by the effect of tubing stretch or buckling.

Use the interval over which the weight loss is observed to help identify the hang-up mechanism. For example, a single-point mechanical hang-up can effect a more rapid weight indicator reaction than the build up of fill material around the BHA.

The following sections offer suggestions for reducing or solving sticking problems.

High Frictional Drag

1. Increase the CT buoyancy by displacing the CT to lower density fluid.

2. Pump lubricants into the CT/wellbore annulus.

3. Attempt to reciprocate the CT.

Tight Spot Due to an Obstruction

Able to Circulate

1. Increase the CT buoyancy by displacing the CT to lower density fluid.

2. Pump lubricants into the CT/wellbore annulus.

3. Reciprocate the CT at regular intervals.

4. Release the BHA.

Unable to Circulate

1. Reciprocate the CT at regular intervals (if possible).
2. Activate the circulating sub or flow bypass (if so equipped) in the BHA, or release the BHA and regain circulation.
3. Increase CT buoyancy by displacing the CT to lower density fluid.
4. Pump lubricants into the CT/wellbore annulus.

CT is Stuck

1. Determine the free point (see Section “Determining the Free Point” page 18-22).
2. Close and manually lock the BOP slip rams and the pipe rams.
3. Stop pumping and shut in the well if it is flowing.
4. Slowly depressurize the CT to check the integrity of the downhole check valves.

> *WARNING:* Be careful to avoid collapsing the CT.

5. If the downhole check valves leak, proceed to Section “Downhole Check Valves Leaking” page 18-23.
6. If the downhole check valves hold, proceed to Section “Downhole Check Valves Holding” page 18-23.

Determining the Free Point

For a vertical well and CT with a uniform wall thickness to the free point:

1. Pull slowly, but steadily on the CT with a force of 0.7 x A x σ_y (force F_1).

   where

2. Measure the depth, L_1, corresponding to F_1.

3. Slack-off the CT to 10-20% of F_1 (force F_2) and measure the corresponding depth, L_2.

4. Calculate the distance from the injector to the free point from the following equation:

where

For a non-vertical well, a tapered CT string, or both, use a CT simulator such as Orpheus™ to determine the free point.

Downhole Check Valves Leaking

1. Shear the CT per Section “Shearing CT” page 18-32.

2. Remove the sheared CT from the surface stack.

3. Close and manually lock the BOP blind rams.

4. Rig down the injector head and rig up a wireline (or smaller diameter CT if necessary) with a tubing cutter onto the BOPs.

5. RIH through the CT and cut it at the free point.

6. Retrieve the tubing cutter and rig down the wireline or smaller CT unit.

7. Prepare to fish the CT left in well.

Downhole Check Valves Holding

1. Close and manually lock the BOP slip rams and then the pipe rams.

2. Cut the CT above the injector head.

3. Rig down the injector head and rig up a wireline (or smaller diameter CT if necessary) with a tubing cutter onto the BOPs.

4. RIH through the CT and cut it at the free point.

5. Retrieve the tubing cutter and rig down the wireline or smaller CT unit.

6. Reinstall the injector head.

7. Splice the CT with a temporary connector to the CT on the reel.

8. Resume pumping slowly.

9. Open the pipe and then the slip rams and pull the CT free end to the surface.

WARNING: Pay close attention to the maximum running speeds per Section "CT Running Speeds" page 18-18

10. Close the hydraulic master valve.

11. Prepare to fish the tubing left in the well.

CONTINGENCY OPERATIONS

General Actions for Contingency Operations

In the event of any potentially hazardous problem always:

1. Clear the affected area of non-essential personnel.

2. Inform the Customer Supervisor of the nature and status of the problem and request a public announcement to advise personnel to remain clear of the affected areas.

3. If acid or other hazardous chemicals are involved, displace the CT reel to water as soon as possible.

4. Begin contingency operations promptly to control and/or overcome the problem.

Broken CT

Break Above the BOPs (Downhole Check Valves Holding)

1. Stop pumping and determine if the well is flowing.

> WARNING: Do not let WHP exceed the CT collapse pressure. Allowing the well to flow during the recovery operation may be necessary to reduce the WHP to a safe level.

2. Close and manually lock the BOP slip rams and the pipe rams.

3. Splice the CT with a temporary tube-to-tube connector.

4. Resume pumping slowly.

5. Open the pipe rams and then the slip rams and pull the BHA back to the surface.

> WARNING: Pay close attention to the maximum running speeds per Section “CT Running Speeds” page 18-18

6. Close the hydraulic master valve.

7. Make permanent repairs to the CT or substitute a different reel.

Break Above the BOPs (Downhole Check Valves Leaking)

1. Stop pumping and determine if the well is flowing.

> *WARNING:* Do not let WHP exceed the CT collapse pressure. Allowing the well to flow during the recovery operation may be necessary to reduce the WHP to a safe level.

2. Close and manually lock the BOP pipe rams and slip rams.
3. Shear the CT per Section “Shearing CT” page 18-32
4. Remove the sheared CT from the surface stack.
5. Close and manually lock the BOP blind rams.
6. Prepare to fish the CT left in well.

Break below the BOPs

A sudden change in the weight indicator (weight loss) and/or a variation in circulating pressure will generally indicate a workstring that has parted in the wellbore. Attempting to tag a known restriction may confirm that the tubing has parted, if the apparent depth is greater than previously noted.

1. Continue pumping slowly.
2. Slowly pull the broken end of the CT back to surface.
3. Close the hydraulic master valve.
4. Prepare to fish the CT left in well.

In some cases the first indication that the workstring has parted will be the release of well fluids as the tubing stub is pulled through the stripper. In this event, closing the blind rams will regain control of the well.

Leak in the CT above the BOPs

A leak in the tubing string indicates a significantly weakened area which may fail completely following further cycling. Action taken to secure the well and recover the workstring should be made while attempting to minimize further damage or fatigue to the string at the leak point.

Downhole Check Valves Holding

1. Stop pumping and determine if the well is flowing.

> WARNING: Do not let WHP exceed the CT collapse pressure. Allowing the well to flow during the recovery operation may be necessary to reduce WHP to a safe level.

2. Close and manually lock the BOP slip rams and the pipe rams.

3. Assess the effect of the leak on the integrity of the tubing.

4. If it is safe to pull on the CT, resume pumping slowly.

5. If it is unsafe to pull the CT, splice the CT with a temporary connector, then resume pumping slowly.

6. Open the pipe and then the slip rams and pull the BHA back to the surface.

> WARNING: Pay close attention to the maximum running speeds per Section “CT Running Speeds” page 18-18

7. Close the hydraulic master valve.

8. Make permanent repairs to the CT or substitute a different reel.

Downhole Check Valves Leaking

1. Stop pumping and determine if the well is flowing.

> WARNING: Do not let WHP exceed the CT collapse pressure. Allowing the well to flow during the recovery operation may be necessary to reduce the WHP to a safe level.

2. Close and manually lock the BOP pipe rams and slip rams.

3. Shear the CT per Section “Shearing CT” page 18-32.

4. Remove the sheared CT from the surface stack.

5. Close and manually lock the BOP blind rams.

6. Prepare to fish the CT left in well.

Leaking Riser or Secondary BOP

1. Stop moving the CT.

2. Close and manually lock the BOP pipe rams and slip rams.

3. Reduce the pressure above the pipe rams to zero.

4. Attempt to stop the leak by tightening the offending connection, plug, or seal.

5. Equalize pressure across the pipe rams.

6. If the leak persists, shear the CT per Section “Shearing CT” page 18-32. Otherwise, skip to step 10.

7. Remove the sheared CT from the surface stack.

8. Repair the leak.

9. Prepare to fish the CT left in well.

10. If the leak has been stopped, open the pipe rams, then the slip rams. Pull the CT above the injector to inspect the surface of the CT gripped by the rams.
    - If the CT is undamaged, resume CT operations.
    - If the CT is damaged, POOH and make permanent repairs or substitute a different reel of tubing.

Leaking Downhole Check Valves

1. Pump treatment fluid, water, or brine at a sufficient rate to prevent back flow up the CT.

2. POOH while pumping treatment fluid, water, or brine.

> *CAUTION:* Do not pump kill fluid without approval from the Customer supervisor.

> *WARNING:* Pay close attention to the maximum running speeds per Section "CT Running Speeds" page 18-18

Leaking Stripper Element

1. If the stripper begins to leak, stop moving the CT (when it is safe to do so).

> *CAUTION:* If the CT operation at the time of the stripper leak is a fill removal, scale removal, drilling or milling, then continue pumping at the planned rate to minimize the risk of sticking the BHA or tubing.

   a. Close and manually lock the BOP pipe rams around the CT.

   b. Remove any pressure trapped above the pipe rams.

   c. Replace the sealing elements in the stripper.

   d. Energize the stripper.

   e. Equalize pressure across the BOP pipe rams.

   f. Unlock and open the pipe rams.

2. Inspect the surface of the CT contacted by the rams.

   - If the CT is undamaged, resume CT operations.
   - If the CT is damaged, POOH and make permanent repairs or substitute a different reel of tubing.

CT Slipping in the Injector Head

1. Attempt to increase the force squeezing the gripper blocks together.
2. If the CT still slips, shut down the injector head.
3. Close and manually lock the BOP slip rams.
4. If the stripper is not leaking, close and manually lock the pipe rams. If the stripper is leaking, see Section “Leaking Stripper Element” page 18-29.
5. Shut down the power pack and tag the control valves before any person climbs onto or works on the injector head.

> *CAUTION:* If the CT operation at the time of the injector head difficulty is a fill removal, scale removal, drilling or milling, then continue pumping at the planned rate to minimize the risk of sticking the BHA or tubing.

6. Open the injector chains and clean or repair the gripper blocks.
7. Ensure that all personnel are safely clear of the injector.
8. Close the injector chains, remove the tags from the injector controls, and reinstate hydraulic power to the injector head.
9. Adjust the chain gripper pressure.
10. Energize the stripper.
11. Equalize pressure across the pipe rams.
12. Open the pipe and then the slip rams and inspect the surface of the CT contacted by the rams for signs of damage.
    - If the CT is undamaged, continue CT operations.
    - If the CT is damaged, POOH and make permanent repairs or substitute a different reel of tubing.

Acid Spills

1. If an unprotected person comes in contact with acid, liberally rinse the affected areas with water.

2. Inform the Customer supervisor immediately.

3. Neutralize acid spills in all affected areas with soda ash and wash the remains to drain. Pay particular attention to crevices, cable trays etc. that may have been subject to acid splashing.

Nitrogen Spills

WARNING: Liquid nitrogen causes severe freeze burns on contact with the skin and can crack steel plates. Nitrogen gas is an asphixant.

1. For liquid nitrogen contact with the skin, flush the affected areas with tepid water and inform the medic and Customer supervisor immediately.

2. If a nitrogen leak occurs, clear the area of all non-essential personnel and notify the Customer supervisor.

3. Equip personnel that may have to work in the vicinity of a nitrogen leak with self-contained breathing apparatus.

4. Leave major liquid nitrogen spills to evaporate on their own.

WARNING: Do not use water on large spills.

5. Thoroughly inspect all affected steel plates and decks for cracks.

6. Use water to wash away minor liquid nitrogen leaks in open areas.

Shearing CT

1. Stop moving the CT.
2. Close and manually lock the BOP slip rams, then the pipe rams, to secure the CT in the BOP.
3. Depressurize the BOP above the pipe rams.
4. Close and manually lock the BOP shear rams and shear the CT.
5. Remove the sheared CT from the surface stack.
6. Close and manually lock the BOP blind rams.
7. Prepare to fish the CT left in well.

> *NOTE:* If the CT BOP is leaking, closing the wellhead master valve may be necessary to secure the well. In that case, start with step 3, then close the wellhead master valve. Continue with steps 4-7.

Power Pack Failure

1. If the injector head has stopped moving and the CT is stationary, then apply the injector brake (if it has not activated automatically with the reduction in hydraulic pressure). Otherwise, take action to prevent the tubing from running away (see Section "Tubing Run Away Into the Well" page 18-33 or Section "Tubing Run Away Out of the Well" page 18-34, whichever applies).
2. Close the BOP slip rams, then close the pipe rams. Engage the manual locks on the rams.
3. Set the reel brake.
4. Repair or replace the power pack.

> *CAUTION:* If the CT operation at the time of the power pack failure is a fill removal, scale removal, drilling or milling, then continue pumping at the planned rate to minimize the risk of sticking the BHA or tubing.

5. Equalize pressure across the BOP pipe rams.

6. Unlock both rams.

7. Open the pipe rams and then the slip rams.

8. Release the reel brake and the injector brake.

9. Inspect the surface of the CT contacted by the rams for signs of damage.
   - If the CT is undamaged, resume CT operations.
   - If the CT is damaged, POOH and make permanent repairs or substitute a different reel of tubing.

Tubing Run Away Into the Well

The CT string can fall into the well due to its own weight, if the WHP is low and either of the following occurs.

- The injector chains completely lose their grip on the CT (traction runaway).
- The injector motors spin freely (hydraulic runaway). This mode of runaway is extremely rare, because the counter balance valves on the injector motor hydraulic circuit are designed to prevent this from happening.

If the fall is not arrested quickly, the end of the CT or the BHA can slam into a restriction in the wellbore or the bottom of the well with catastrophic results.

1. Attempt to match the speed of the injector with the CT's rate of decent.

2. Increase the inside chain tension to increase friction on the CT.

3. Increase stripper pressure to increase friction on the CT.

4. If the run away is hydraulic, manually set the injector brake or reduce the injector hydraulic pressure to zero to set the injector brake.

5. If the preceding actions do not stop the tubing runaway, do one of the following:
   - Close the slip rams on the CT.

   > *WARNING:* This usually damages both the CT and the slip rams. Inspect both and make the necessary repairs before continuing operations with either the BOP or CT string.

NOTE: Closing the pipe rams on moving CT will damage the seals and render them ineffective for well control.

- Allow the CT to fall into the well until it stops on its own. This invariably damages the BHA and the CT. Depending on what arrested the CT's fall, this can seriously damage the completion. Depending on the damage to the CT, retrieving the CT string might be difficult.

Tubing Run Away Out of the Well

The CT string can be ejected out of the well, if the WHP is high enough to overcome the weight of the CT below the stripper and either of the following occurs.

- The injector chains completely lose their grip on the CT (traction runaway).
- The injector motors spin freely (hydraulic runaway). This mode of runaway is extremely rare because the counter balance valves on the injector motor hydraulic circuit are designed to prevent this from happening.

If this ejection is not arrested quickly, the CT connector or the BHA can slam into the bottom of the stripper, or the CT reel can birdnest with catastrophic results. The former usually breaks the CT below the stripper and causes the BHA to fall into the well. The latter usually breaks the CT above the injector.

1. Attempt to match the speed of the injector with the CT's rate of ascent.

2. Increase the inside chain tension to increase friction on the CT.

3. Increase stripper pressure to increase friction on the CT.

4. If the run away is hydraulic, manually set the injector brake or reduce the injector hydraulic pressure to zero to set the injector brake.

5. Increase the reel rotational speed to pace the CT coming out of the well.

6. Prepare to close the hydraulic master valve if the CT comes out of the stripper.

7. Reduce WHP as much as possible by flowing the well.

8. If the preceding actions do not stop the tubing runaway, close the slip rams on the CT.

WARNING: This usually damages both the CT and the slip rams. Inspect both and make the necessary repairs before continuing operations with either the BOP or CT string.

NOTE: Closing the pipe rams on moving CT will damage the seals and render them ineffective for well control.

9. If closing the slip rams stops the runaway, close and manually lock the pipe rams.

10. If closing the slips fails to stop the runaway, the tubing connector will slam into the slips.

- If the connector holds, then secure the well with the hydraulic master valve.
- If the connector parts from the tubing, the tubing will be completely ejected from the well.

Tubing Pulls Out of the Stripper

If the BHA is lost in the well or the CT breaks in the well, the CT operator may not know how much CT is left below the surface and might accidentally pull the free end of the tubing out of the stripper. If this happens:

1. Stop the injector to keep the CT in the chains.

2. Close and manually lock the blind rams.

3. Plan fishing operations for the BHA and/or lost CT.

CT Collapsed near the Stripper

CT collapsed near the stripper poses several problems, including:

- Wellbore fluids can escape from the stripper because the stripper elastomers cannot seal around the deformed CT.
- Collapsed tubing may not move through the stripper's backup bushings. This will cause a sudden increase in CTWI. Attempting to force the CT through the stripper could damage the stripper.
- The injector may not be able to grip deformed CT.
- Pump pressure may increase due to the restriction in flow area at the collapsed section.

If the Well is Live

1. Slackoff the CT until the stripper can seal around the CT. If using tandem strippers, slack-off the CT until the lower stripper can seal around the CT.

2. Reduce WHP as much as possible by flowing the well.

3. If the stripper cannot obtain a seal, shear the CT per Section “Shearing CT” page 18-32.

4. After securing the well, prepare to fish the CT left in the well.

If the Well is Dead

Slowly pickup on the CT. If the injector cannot effectively grip the deformed CT, grab the CT with the crane or traveling block. Relax the inside chain tension and use the crane or traveling block to pull the CT from the well.

CAUTION: Do not exceed the crane lifting capacity.

If the Deformed CT Can Pass Through the Stripper

1. Slowly POOH until undamaged CT clears the injector head.

2. Remove the damaged tubing and temporarily splice the CT, or affect a permanent repair to the CT string.

If the Deformed CT Cannot Pass Through the Stripper

1. Clamp the CT to the injector head and disconnect the stripper from the BOP.

2. Raise the injector with the crane or traveling block enough to clamp the CT above the BOP.

3. Cut the CT above the clamp and remove the injector head and stripper.

4. Use the crane or traveling block to slowly POOH until approximately 25 ft of undamaged CT clears the BOP.

5. Remove the damaged tubing.

6. Reinstall the injector head and stripper over the end of the CT protruding from the BOP.

7. Temporarily splice the CT and POOH.

8. Replace the CT string before continuing the job.

CT Reel Hydraulic Motor Fails

1. Stop the injector.

2. Slowly pick up a few feet to create some slack in the CT between the guide arch and the reel.

3. Close the BOP slip and then the pipe rams and apply the manual locks.

4. Apply the reel brake, if so equipped.

5. Repair the reel drive and inspect the CT for damage.

   - If the CT is damaged, make a temporary splice. Open the pipe and slip rams and POOH.
   - If the CT is undamaged, open the pipe and slip rams and RIH as far as necessary to correct the wraps on the reel.

> *CAUTION:* Always equalize the pressure across the pipe rams before opening them.

If the CT reel cannot be repaired:

1. Cut the CT above the guide arch and remove the damaged reel.

2. Replace the reel and connect the end of the CT protruding from the injector to the new reel (or to the end of the CT on the new reel).

3. Open the pipe and slip rams and POOH.

Failure of the Crane with CT in the Well

No Damage to Wellhead or BOP Stack

1. Close and manually lock the BOP slip rams and the pipe rams.

2. Repair or replace the crane.

> **CAUTION:** If the CT operation at the time of the crane failure is a fill removal, scale removal, drilling or milling, then continue pumping at the planned rate to minimize the risk of sticking the BHA or tubing.

3. After the injector head has been secured to the crane, equalize the pressure across the pipe rams, then unlock and open both sets of rams.

4. Inspect the surface of the CT contacted by the rams for signs of damage.

- If the CT is undamaged, resume CT operations.
- If the CT is damaged, POOH and make permanent repairs or substitute a different reel of tubing.

Damaged Wellhead

1. Shear the CT per Section “Shearing CT” page 18-32.

2. Close the hydraulic master valve and secure the well.

3. Prepare a recovery plan before continuing work.

Damaged BOP Stack

1. Perform the contingency operations detailed in Section “Leaking Riser or Secondary BOP” page 18-28.

2. Close the hydraulic master valve and secure the well.

3. Prepare a recovery plan before continuing work.

WELL CONTROL FOR CT OPERATIONS

Well control for CT operations is considerably easier than for jointed pipe operations (except when using a rotating BOP), because the stripper allows the operator to maintain constant pressure control over a live well. However, many CT operations take place in dead (non-producing) wells. If the well "kicks" or begins to flow during such an operation, the CT personnel must know how to safely regain pressure control of the well. That is, they must stop the influx of formation fluids, circulate the kick safely from the well, and reestablish a BHP that will prevent further influx of formation fluids.

The basic principle of CT well control is the same as for jointed pipe operations, i.e., maintaining constant BHP throughout the well control operation. Several methods are available for doing that, and the choice depends largely on operator preference. CT well control methods include:

- Drillers (probably the best option for CT)
- Wait and weight
- Volumetric
- Lubricate and bleed
- Combined stripping and volumetric
- Bullheading

Detailed discussions of each of these methods are beyond the scope of this manual but they are available from numerous well control manuals for drilling operations. In each case, the CT well control method is the same as for jointed pipe operations with four exceptions:

- Frictional pressure loss in CT is considerably higher than for drill pipe or typical jointed work strings. This means that an accurate hydraulics simulator such as Hydra™ is an essential tool for planning and executing a CT well control operation.
- For CT operations, the length of tubing the kill fluid flows through can be much greater than the depth to the end of the tubing because of CT remaining on the reel. This affects the time required to circulate a fluid to a certain point in the well. In a shallow well, the influx may migrate to the surface before kill weight fluid exits the end of the CT.
- The dual flapper-type check valves in the BHA effectively isolate the reel inlet pressure sensor from reading the shut-in BHP unless the CT operator takes steps to open the check valve(s) long enough to make a reading.
- Many CT operations do not have adequate fluid mixing capacity to rapidly mix large volumes of kill fluid.

NOTE: An adequate volume of kill weight fluid should be on location during HPCT operations.

Three methods of opening the check valves so that the CT operator can accurately measure the shut-in BHP are:

- Start pumping slowly while keeping the annulus choke close. Record the CT pressure (reel inlet) at the time when the CT pressure stabilizes or the WHP starts to rise. This will be the shut-in BHP.
- Ramp the pump rate up to the proposed kill rate while maintaining constant WHP. When the pump is up to the kill rate speed, record the CT pressure (reel inlet). This value is the initial circulating pressure (ICP). Subtract the slow kill rate pressure from the ICP to get the shut-in BHP.
- Slowly pump fluid with the annulus choke closed until the WHP increases approximately 100 psi. Shut off the pump and slowly bleed off the WHP through the CT reel. Record the CT pressure (reel inlet) at the time the WHP stabilizes or reaches the initial pressure. This will be the shut-in BHP.

CT STRING MAINTENANCE

Inadequate maintenance of a CT string can rapidly decrease its working life and significantly reduce its performance capabilities. The purpose of this section is to provide guidelines for routine maintenance of CT strings that should prolong their useful working life. The Customer supervisor should review the log book for each CT string proposed for a job to determine its suitability for the planned operation.

CT Inspection

Currently, the CT industry lacks standard criteria for:

- Inspecting CT strings
- Assessing the severity of damage or flaws in CT strings
- Derating the performance of damaged strings

Damage to CT strings can be broadly classified as:

- Cracks
- Pitting
- Abrasion
- Mechanical damage
- Dimensional Abnormalities
- Erosion

The following sections describe how to recognize these damage mechanisms and their potential effects on CT performance. However, these sections do not offer any guidelines for quantifying the damage or derating CT strings because of visible damage.

Cracks

Cracks are a serious form of defect because the stresses applied to a CT string in normal use make the defect worse. Once initiated, cracks can propagate relatively quickly, jeopardizing the safety and reliability of the string.

WARNING: Any string section identified with cracks should be removed from service and repaired.

The majority of cracks are caused by fatigue damage and are often wrongly identified as pinholes when the crack has penetrated the wall. Cracks appear in three different “modes”:

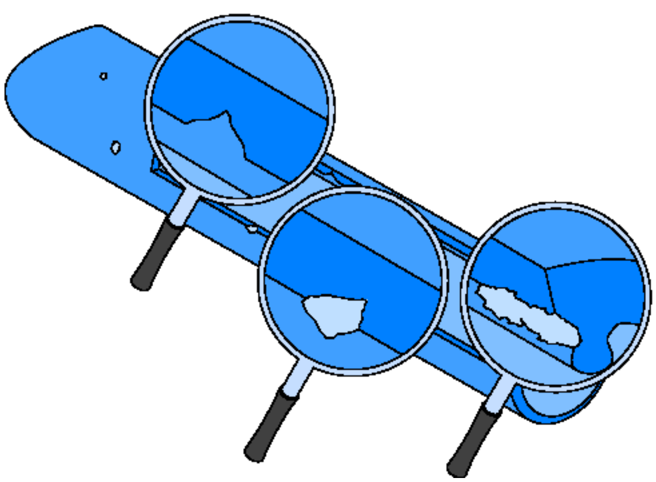
- Transverse cracks—Run around the circumference of the tube. Transverse cracks can grow very quickly due to the stress applied to the tube when bending. This form of crack is the most common defect identified on used CT strings.
- Longitudinal cracks—Run along the axis of the tube. These are less common but may propagate rapidly to form a split in the tube under severe stress.
- Angled cracks—Not a common configuration but typically associated with a bias weld.

Pitting

Pits are typically associated with localized corrosion that can occur on the internal and external surfaces of the tube.

- External—Resulting from contact with corrosive treatment fluid or wellbore fluids, atmospheric corrosion or a combination of each.
- Internal—Resulting from exposure to improperly inhibited corrosive treatment fluids, or (more commonly) failure to adequately flush or passivate the internal surface before storage. Figure 18.1 shows a variation of internal pitting associated with damage to the longitudinal weld.
- Weld bead—The weld bead can provide a site for the initialization and rapid progression of localized corrosion.

FIGURE 18.1 *Pitting*



Abrasion

Damage resulting from abrasion typically affects string performance as a result of reduced wall thickness, sites for enhanced corrosion, or stress concentrations for crack initiation:

- Abrasion—Localized wall loss can occur as a result of abrasion with wellbore tubulars, i.e. at contact points of the buckled (helical) tube.
- Longitudinal scratches—Can result from contact with sharp edges in the wellbore, pressure control equipment or CT equipment. If undetected, the scratch may extend for several thousand feet. Although the scratch may have little direct effect on string performance it may indirectly lead to accelerated localized corrosion or fatigue.

Mechanical Damage

Mechanical damage of CT strings can greatly affect the performance of a string. Such damage includes:

- Slip marks—Early slip designs were configured with slip teeth which formed semicircular indentations or marks. These resulted in localized stresses and significantly accelerated fatigue at that point. Current slip designs apply a “toothed” pattern over a longer interval to reduce these effects.
- Chain marks—May result from misaligned chains, incorrect tension or damaged chain blocks. A repeating pattern will probably result.
- Round dents—Have less effect on fatigue than sharp notches or cracks but can still significantly affect string performance.

Dimensional Abnormalities

Variations in string geometry cause problems with handling equipment (injector head chains) and pressure control equipment (stripper, slip rams, pipe rams, etc.). In addition, many string performance models (fatigue, pressure and tension, etc.) are based on algorithms which assume that the tube is circular and the wall thickness is constant (with allowance for tapered strings). If the actual geometry of the tube is different, the predictions may no longer be within an acceptable margin of error.

- Ovality—All tubing is out of round from the first time it is spooled. The maximum recommended ovality limits for any CT string is typically around 6%.
- Necking—generally caused by over stressing a section of tubing in tension.
- Ballooning—most frequently the result of cycling (bending) under high pressure. (See Chapter 16 “High Pressure Operations” for a discussion of ballooning.)

Erosion

Localized external erosion damage can occur when CT remains static across producing perforations or a reduced flow area such as a profile nipple.

Corrosion Control

Corrosion is one of the major factors affecting the useful life of coiled tubing. The effects of corrosion are often difficult to quantify, which complicates the assessment of a safe working life for a CT string. Corrosion can occur during an operation (from corrosive wellbore and treatment fluids) or during transportation and storage (due to incorrect maintenance and protection procedures).

The effects of workstring corrosion can be summarized as:

- Reduced tube strength/integrity—reduced tensile strength is caused by material loss, reduced pressure integrity is caused by localized pitting and material loss.
- Increased susceptibility to fatigue damage—pitting, material loss, and effects of hydrogen sulfide (H_2S).
- Reduced efficiency of pressure control equipment—elastomer seals are less efficient on a pitted surface. Severe corrosion can damage stripper elements and cause them to fail rapidly.
- Reduced efficiency of tubing monitoring equipment—rust and scale can cause problems for tubing inspection tools and depth measuring equipment.

The nature and degree of corrosion protection required depends on:

- The operation to be performed
- Wellbore conditions
- Local climatic conditions

The design phase of every CT operation must include the consideration of corrosive hazards which may be encountered. Since the total prevention of corrosion is often impractical, the objective is to reduce corrosion to an acceptable level.

The effects of the anticipated level of corrosion must be recorded and incorporated into the workstring life assessment.

Sources of Corrosion

Potential sources of work string corrosion include:

- Corrosive treating fluids (internal and external)
- Corrosive wellbore fluids (external)
- Hydrogen sulfide (external)
- Residual fluid (internal)
- Atmospheric corrosion (internal and external)

A typical workstring will be exposed to several (if not all) of these sources over its useful life.

Treating Fluids

Treating fluids can cause severe corrosion. However, their chemical composition is known and their effects can generally be controlled by the use of additives (corrosion inhibitors).

Factors affecting the corrosion of materials in a treating fluid environment include:

- Temperature—Higher temperatures generally increase corrosion rates and reduce the efficiency of additives.
- Exposure time—Should be minimized. Most corrosion inhibitors are time restricted, especially at higher temperatures.
- Fluid type and strength—Acid strength affects the corrosion rate and the quantity of inhibitor required.
- Additive types and concentrations—Inhibitor efficiency can be affected by surfactants, demulsifiers and mutual solvents.
- Fluid velocity—Increased fluid velocity can reduce the efficiency of any protective inhibitor layer.

Sufficient inhibitor must be mixed with the treating fluid to ensure adequate protection. Some depletion of the inhibitor in the treating fluid will occur during the job.

Thorough mixing of the selected corrosion inhibitor with the treating fluid is essential. In some cases, continued agitation of the fluid may be required to achieve the necessary dispersion of the inhibitor.

NOTE: All treatment fluids must be thoroughly mixed immediately prior to pumping.

Wellbore Fluids

Corrosive wellbore fluids may be present for a number of reasons:

- Spent (or depleted) treatment fluids
- Heavy brines or workover fluids
- Produced CO_2
- Produced corrosive fluids
- Hydrogen sulfide

The concentration of corrosive material, the temperature and the exposure time are the principal factors affecting corrosion rate.

The nature of corrosive wellbore fluids is dependent on their source. For example, corrosive brines and workover fluids will generally be inhibited to protect the wellbore tubulars. Such inhibitor treatments will generally provide sufficient protection for the CT string.

Inhibitor may be applied in one of two ways:

- Directly to the external surface of the CT, preferably below the stripper.
- By running the CT into the wellbore while circulating the inhibitor fluid, relying on turbulence at the nozzle to disperse the inhibitor.

The direct application method is preferred. However, if suitable equipment is unavailable or adequate protection can be assured by mixing, injection may be a viable alternative.

Hydrogen Sulfide

Hydrogen sulfide can significantly reduce the useful life of a workstring by degrading its material strength. This can occur as a combination of sulfide stress cracking (SSC), hydrogen-induced cracking (HIC) and weight-loss corrosion.

Hydrogen sulfide is non-corrosive in the absence of moisture. In the presence of moisture, a corrosive environment will result. If CO_2 or O_2 is also present, severely corrosive conditions may occur.

The presence or threat of H_2S affects a CT operation in several ways:

- The well condition must be considered sour following stimulation treatments and during cleanup. Personnel and equipment safety requirements must be met during those periods.

- Downhole tools and equipment must be positively identified as suitable for H_2S service.
- The efficiency of additives, particularly corrosion inhibitors, can be significantly reduced in the presence of H_2S.

Protection against the effects of H_2S can be achieved using a hydrogen sulfide scavenger. In most cases, H_2S protection should be applied to the external surface of the CT, as well as being included in the treatment fluid.

Residual Fluid

Residual fluid corrosion occurs when a workstring is stored for a prolonged period with fluid inside. Adequate flushing and purging should minimize the accumulation of fluid. However, it is difficult to achieve complete removal.

Internal protection of a CT reel begins by flushing and neutralizing the reel contents. Subsequent purging with nitrogen is frequently required to allow safe loading and transportation of the reel.

NOTE: Whenever possible, reels should be blown dry with nitrogen to minimize residual fluid.

Atmospheric Corrosion

Atmospheric corrosion (surface rust) can have the following detrimental effects on a workstring:

- Weakening of the tubing structure, due to chemical deterioration of the tubing surface.
- The resulting roughened surface provides localized sites for further corrosion.
- The rough surface reduces the efficiency/useful life of elastomers in the pressure control equipment.
- The snubbing force required to run tubing through the stripper can increase significantly if the surface is rough.
- Surface rust can interfere with depth measurement and tubing monitoring equipment.

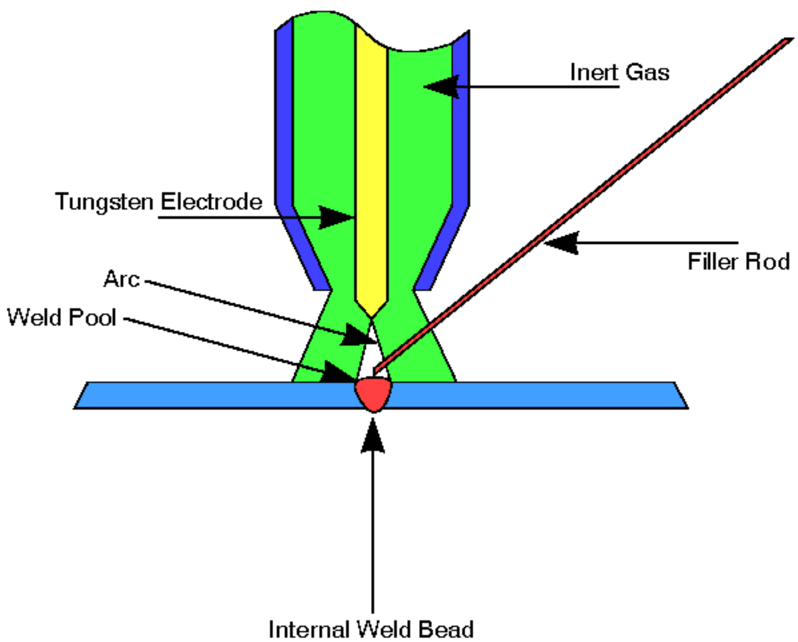
To provide external protection, apply a coating to the tubing's external surface as it is being spooled onto the reel, either during an operation or as part of routine maintenance. As a minimum, always apply an anti-rust coating to the CT string at the end of each job.

Repairs and Splicing

The Tungsten Inert Gas (TIG) welding technique is used in the repair and construction of CT work strings. It floods the weld location with an inert gas, which excludes contaminants from the weld site.

The TIG welding process uses the heat generated by an arc formed between a tungsten electrode and the work-piece (Figure 18.2) to form the joint.

FIGURE 18.2 *TIG Welding Technique*



The TIG technique is generally restricted to materials less than 0.280 in. (7.1 mm) thick. The low heat input and the slow deposition rate of this technique make it ideal for use with CT. The welds produced are clean and of high quality because they are performed in an inert atmosphere and without the use of chemical fluxes which can themselves contaminate the weld.

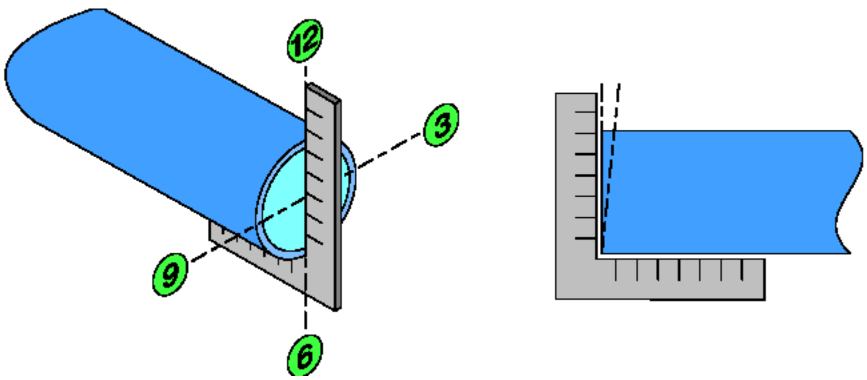
A weld may be performed manually or using a semi-automatic welding machine. In both cases, the preparation and handling of the tubing prior to welding are the same. The following key issues are associated with the preparation of the tubing for the butt weld.

- If the tubing is to be joined following the removal of a damaged or overcycled section, a close inspection of the tubing end should be made to ensure the damaged portion has been fully removed and that the remaining tubing is within recommended size specifications.

- Check and record the wall thickness of any tubing to be added to an existing reel.
- Prior to preparing the tubing ends, cut a 12 in. representative sample of tubing from each section to be joined. This sample should be properly identified and stored in a safe place. Should any problem occur with the completed weld in future operations, the tubing sample can be regarded as part of the tubing reel/weld record.
- Straighten both ends to be joined 8 to 10 ft from the weld-site.
- The tubing end must be cut square. Check the cut surface in at least four areas at approximately 90° apart (Figure 18.3). Any surface which is 1/32 in. or greater, out of true must be re-cut.

CAUTION: Do not use a roller type pipe cutter because some distortion of the tubing is unavoidable.

FIGURE 18.3 *Check Cut Tubing End*



- The seam weld internal bead should be removed approximately one-half inch from the ends to be joined.
- Any internal burrs which result from cutting the tubing should be removed using a round file.
- The inside of the tubing must be dry; if required lower the tubing height on either side of the join to prevent moisture from settling around the joint.
- Profile (chamfer) the outside edge as specified by the welding procedure to aid in achieving the desired weld penetration.
- The outer and inner surfaces of the tubing should be thoroughly cleaned and made free of any scale or rust. Sand paper or emery cloth should be used to obtain a smooth clean surface.
- De-grease the inner and outer surfaces using denatured alcohol or equivalent.
- Place tubing in chill blocks/clamp tubes and secure in approximate alignment. The chill blocks should be positioned as near as possible to the weld site, while allowing adequate access for the welding head.
- Adjust the alignment fixtures until the tubing ends are separated the distance specified by the welding procedure and in perfect alignment. The alignment should be checked using a suitable straight-edge at four points around the circumference of the tubing.

- Position protective wind curtain around the welding jig.

CAUTION: Protection of the gas shield against wind is mandatory. Welding should not be attempted without suitable wind protection in place.

The completed butt weld must be allowed to air-cool before being visually checked for any abnormalities and/or surface defects. The weld should be carefully dressed and ground to reduce bead height. The finished bead height should not be more than 0.005 in. above the tubing surface.

A butt weld must meet pre-defined standards in the following areas before the repaired CT can be placed in service:

- Parent material samples
- Visual inspection
- Hardness testing
- Radiographic inspection
- Pressure testing

CAUTION: Splicing a CT string with a butt weld is acceptable only for temporary repair.

Post-job Cleaning

CT strings may be used in a wide variety of applications, and be exposed to fluids with vastly different chemical properties. To assist in determining the action to be taken, recommendations for post-job maintenance are grouped as follows:

- Non-corrosive fluids
- Cement and particulate materials
- Acid or corrosive fluids

Non-corrosive Fluids

On completion of an operation, flush fluids that are potentially corrosive from the CT string. The flushing fluid should be clean, fresh water or the best available alternative. The minimum volume of fluid that should be flushed through the string is 1.5 times the string volume.

If possible, blow nitrogen through the string. In addition to removing potentially corrosive fluids, displacing the string with nitrogen substantially reduces the weight of the reel. This will aid in the handling of skid-mounted reels and reduce the effect of impact loads on the reel bearings and structure.

Use a foam plug to increase the efficiency of the nitrogen displacement. This is especially effective where nitrogen gas bottles are used, because the initial displacement rate is very low and a considerable slippage of fluid will take place around the reel. Confirm that the plug has passed from the tubing before rigging down the nitrogen supply.

Cement and Particulate Materials

The removal of cement and particulate materials is important for two principal reasons:

- To avoid a restriction on the low side of the reel, formed by settling material.
- To prevent solid materials that have settled from interfering with the operation of downhole equipment on subsequent operations.

Flushing the string as described above should ensure that the reel is free from internal buildup or restriction. Conduct the flushing with the highest flow rate practical. Inspect the water leaving the reel for continued contamination. As above, the minimum volume should be 1.5 times the volume of the string. Finally, displace the flushing fluid with nitrogen.

Acid and Corrosive Fluids

Following an operation involving acid or corrosive fluids, pump a pill of neutralizing solution through the string. Typically, the pill will be a solution of soda ash or caustic (depending on availability) at least one half the volume of the string. A commonly used formulation is 50 lb soda ash in 10 BBL clean water. Follow this by the flushing and displacement procedures described above.

CAUTION: Neutralizing or passivating solution can pose a disposal problem. Be sure to provide an appropriate disposal method for waste fluid.

CT Storage

When CT is to be stored, even for a relatively short period of time, take steps to ensure that the work string and associated documentation package are kept in a satisfactory condition.

Regular carbon steel CT can quickly corrode when exposed to marine environments. Such corrosion can occur on the inner surface of the tubing (internal corrosion), as well as on the outer surface (external corrosion).

Internal

Internal corrosion has an obvious detrimental effect on the working life of a CT string. Small amounts of moisture condensing inside the tubing can cause localized corrosion, leading to thinning of the tubing wall and stress risers.

Apply an internal corrosion inhibitor to ensure that the CT is delivered in as close to as-manufactured condition as possible. This inhibitor protects the CT under various transportation and storage conditions, but does not adversely affect tubing performance.

Once the string has been used, the protection of internal surfaces begins with the flushing and neutralizing of the reel contents. Subsequent purging with nitrogen is frequently required to allow safe loading and transportation of the reel. Whenever possible and practical, reels should be blown dry with nitrogen to minimize the residual fluid which collects at the bottom of the tubing wraps.

External

Inhibitors are also used to keep corrosion to a minimum on the external surface of a CT string. To prevent the occurrence of surface rust, the following conditions must be met:

- The tubing surface must be clean and free from corrosive fluids or moisture.
- A suitable protective coating must be applied to the entire tubing surface.
- The coating must not interfere with the operational use of tubing, measurement or well control equipment.
- The coating and its means of application must not cause a hazard to personnel or environment.
- The best external protection can only be applied to the tubing's external surface as it is being spooled onto the reel (either during operation or during maintenance procedures).

Stored reels or spools must be stored under cover. As a minimum, the spool/reel should be covered with a weatherproof tarpaulin or sheet. This must be adequately secured, yet must not trap fluids at the bottom of the spool.

During the storage period, check the CT string regularly to ensure that the protective coating has not degraded. If required, a further coating may be added using a sprayer to maintain adequate protection.

DEPLOYING A LONG TOOL STRING IN A LIVE WELL

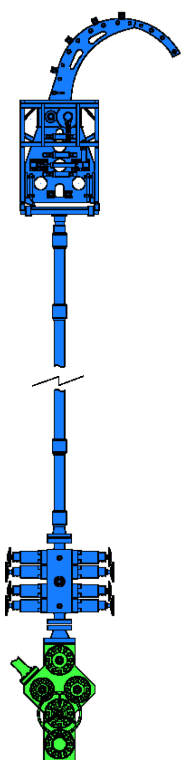
A major benefit of CT is its inherent safety in live well intervention. An important consideration for working in live wells is deployment of long tool strings. Three deployment methods are available:

- Lubricator deployment—the original method developed from wireline techniques
- Tool deployment—developed from lubricator deployment methods
- Safe deployment—the safest method, developed from lubricator deployment and tool deployment methods

Lubricator Deployment

The lubricator deployment method treats the CT equipment and tool string like wireline. The riser or lubricator must be tall enough to "swallow" the tool string. The entire assembly is supported by a crane and guy wires (Figure 18.4).

FIGURE 18.4 *Lubricator Deployment - Equipment Configuration*



Although this configuration works in a variety of operations, it involves a heavy suspended load (the injector head) and provides few contingency options. The principal disadvantages of this system include the following:

- A tall, large capacity crane is required to support the injector head.
- The operator has only limited visibility of CT and pressure control components.
- Access to the injector head is restricted to a small work basket, often perched high above the ground or deck
- Personnel are exposed to suspended loads during the rig up and rig down procedures.

Tool Deployment

The tool deployment system is an alternative to lubricator deployment. It reduces the working height of the injector head and allows performing pressure tests at all stages. This system relies on a deployment bar in the BHA to hold and seal the BHA inside the BOP.

Although this system is a considerable improvement on the lubricator deployment method, it still has the following disadvantages:

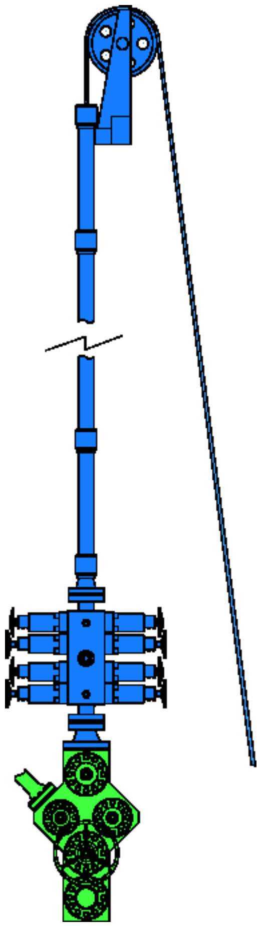
- Crucial stages of the operation depend on the skill of the crane operator.
- Personnel are exposed to suspended loads during rig up and rig down.

The tool deployment system involves the following steps:

1. Rig the tool string and lubricator assembly as for wireline operations.

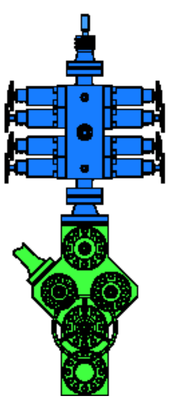
2. Run in the tool string until the deployment bar is opposite the BOP slip and pipe rams (Figure 18.5).

FIGURE 18.5 *Installing the Tool String*



3. Close the pipe and slip rams to secure wellbore pressure and hold the bar in place. (Figure 18.6)

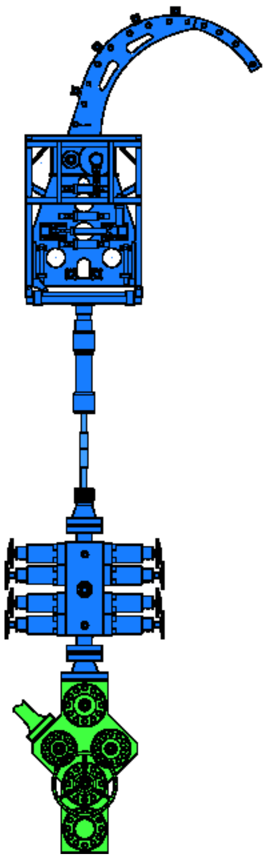
FIGURE 18.6 *Hanging off the Tool String*



4. Vent pressure from the lubricator. Break the bottom connection and gain access to the deployment bar top connection. Break this connection and lay down the lubricator assembly and running tool.

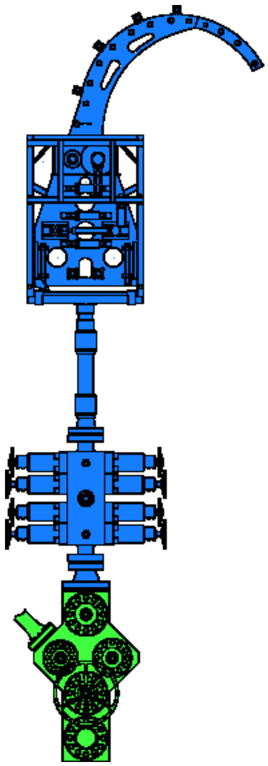
5. Slowly lower the injector head until the tool string connection reaches the deployment bar. Make up the tool string connection. Then lower the injector head to the riser. Make up the riser connection. (Figure 18.7)

FIGURE 18.7 *Connecting the Tool String and Running String*



6. After making all connections, pressure test the system. Then equalize the pressure, open the BOP rams, and run in the tool string. (Figure 18.8)

FIGURE 18.8 *Running the Tool String*

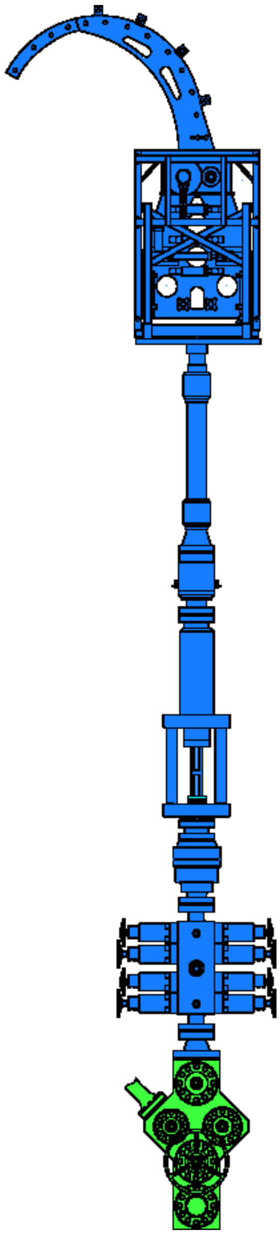


Safe Deployment System

Equipment for Safe Tool Deployment

The safe deployment system requires several items of surface equipment (Figure 18.9), as well as a deployment bar in the BHA.

FIGURE 18.9 *System Components*



Hydraulic Connector

The hydraulic connector or quick latch provides a quick and safe means of connecting the lubricator or injector head assembly to the wellhead equipment.

The hydraulic connector is remotely operated, so personnel do not have to work below suspended loads.

Side Door Riser

This side door riser (SDR) allows one to connect and secure the injector head assembly to the BOP stack before connecting the tool string. A guide tool in the SDR ensures that the deployment tool will be properly positioned across the BOP rams.

The SDR provides the following operational and safety benefits:

- The CTU operator controls the tool string connection process.
- The injector head is electrically grounded before tool string connections are made up.

Annular BOP

The annular BOP provides contingency pressure containment. It seals the annular gap around the tool sting or CT string as required (double barrier).

Control Panel

The CT operator controls the safe deployment system from a hydraulic control panel.

Downhole Tools

The downhole tools include a deployment bar and a quick-connect union system. These items enable easy and safe make-up of the tool string.

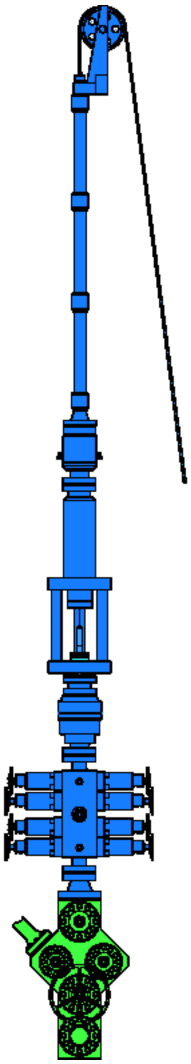
Generic Procedure for Safe Deployment

The safe deployment system for live well deployment includes the following basic steps:

> CAUTION: These instructions provide an overview only. They are not detailed enough to safely conduct a live well tool deployment.

1. Rig up the surface equipment.
2. Assemble the tool string and install it in the wireline lubricator. Make up the hydraulic connector to the lubricator.
3. Lift the lubricator onto the wellhead assembly and latch the hydraulic connector.
4. Equalize the pressure to the lubricator. Then open the wellhead valves and lower the tool string into the wellbore until the tool reaches the SDR guide (Figure 18.10).

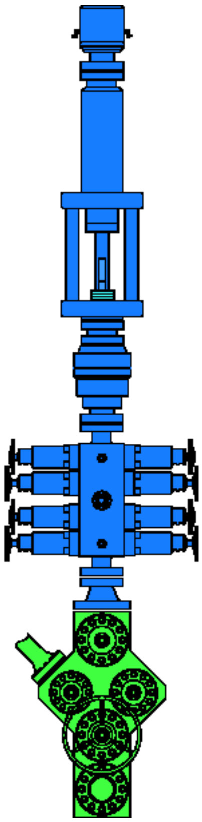
FIGURE 18.10 *Installing the Tool String*



5. Close the BOP slip and pipe rams, and the annular BOP. Vent the lubricator pressure.

6. Open the SDR and disconnect the running tool. Remove the lubricator assembly (Figure 18.11).

FIGURE 18.11 *Hanging off the Tool String*

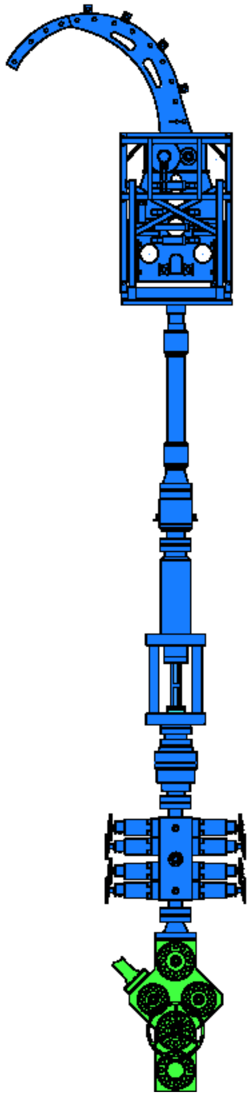


7. Fit the upper hydraulic connection to the injector head assembly. Make up the upper tool string.

8. Lift the injector head assembly. Latch the connector and secure the guy wires or chains.

9. Run in the CT until the tool string connection can be made up. Make up the tool string connection. (Figure 18.12 and Figure 18.13).

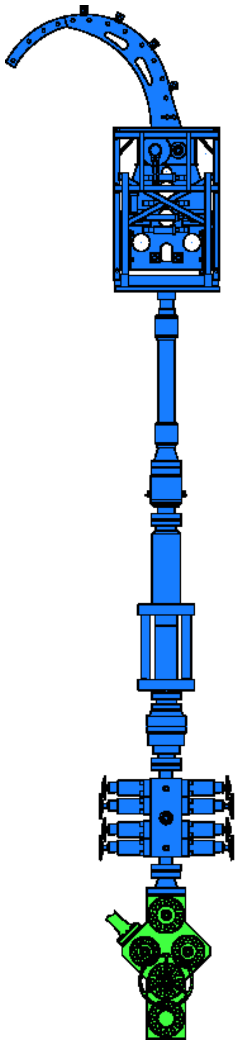
FIGURE 18.12 *Connecting the Running String and Tool String*



10. Close the SDR. Pressure test the completed rig up (constrained by WHP below pipe rams and/or annular BOP).

11. Equalize pressures and release the pipe and slip rams. Tag the stripper to verify depth settings and proceed RIH (Figure 18.13).

FIGURE 18.13 *Running the Tool String*



Safety Issues for Live Well Deployment

Inspect wellhead equipment to ensure that it can safely support and secure the additional weight and loading.

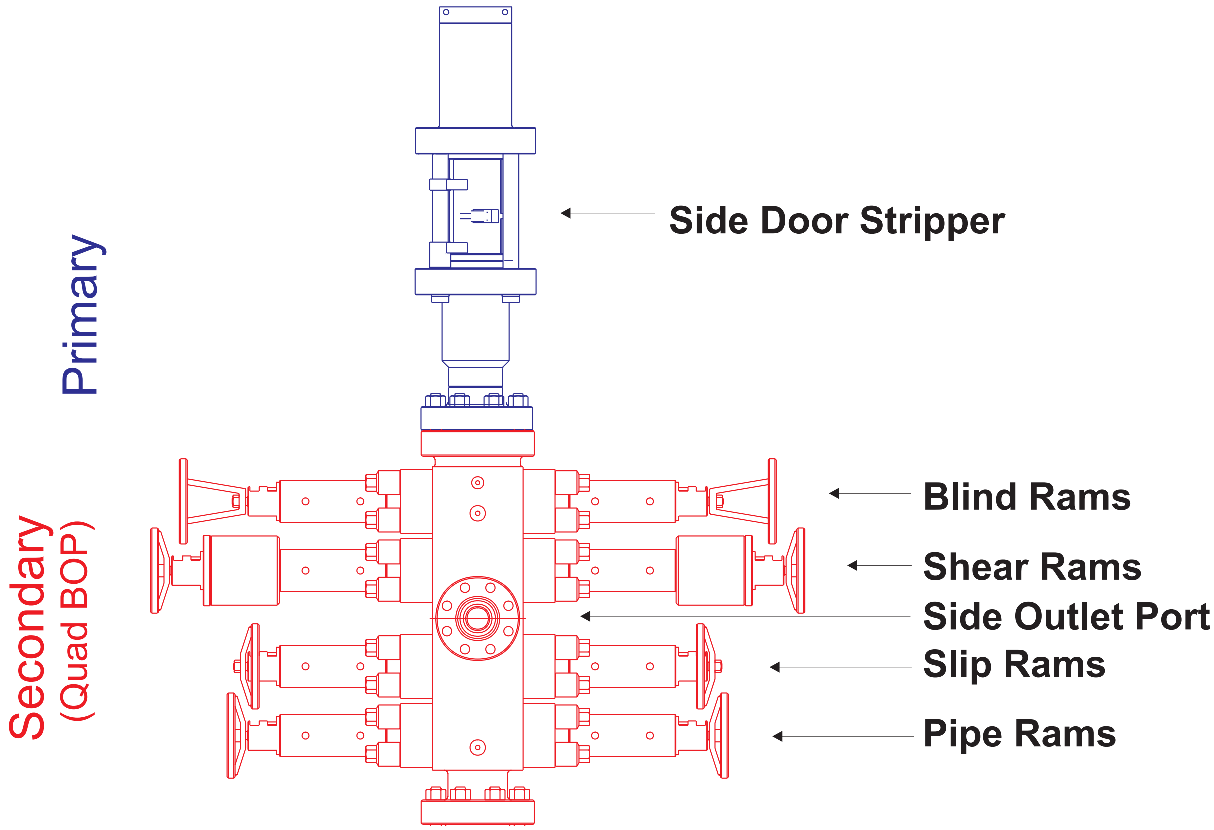
- Adequately secure the lubricator and injector head against lateral loads.
- Erect a work platform to aid access to the SDR.

CT EQUIPMENT DRAWINGS

PRESSURE CONTROL EQUIPMENT STACK

Stack for Standard Operations

FIGURE A.1 *Stack for Standard CT Operations (Texas Oil Tools)*



Stacks for High Pressure Operations

FIGURE A.2 *High Pressure Stack with Tandem Radial Stripper (Texas Oil Tools)*

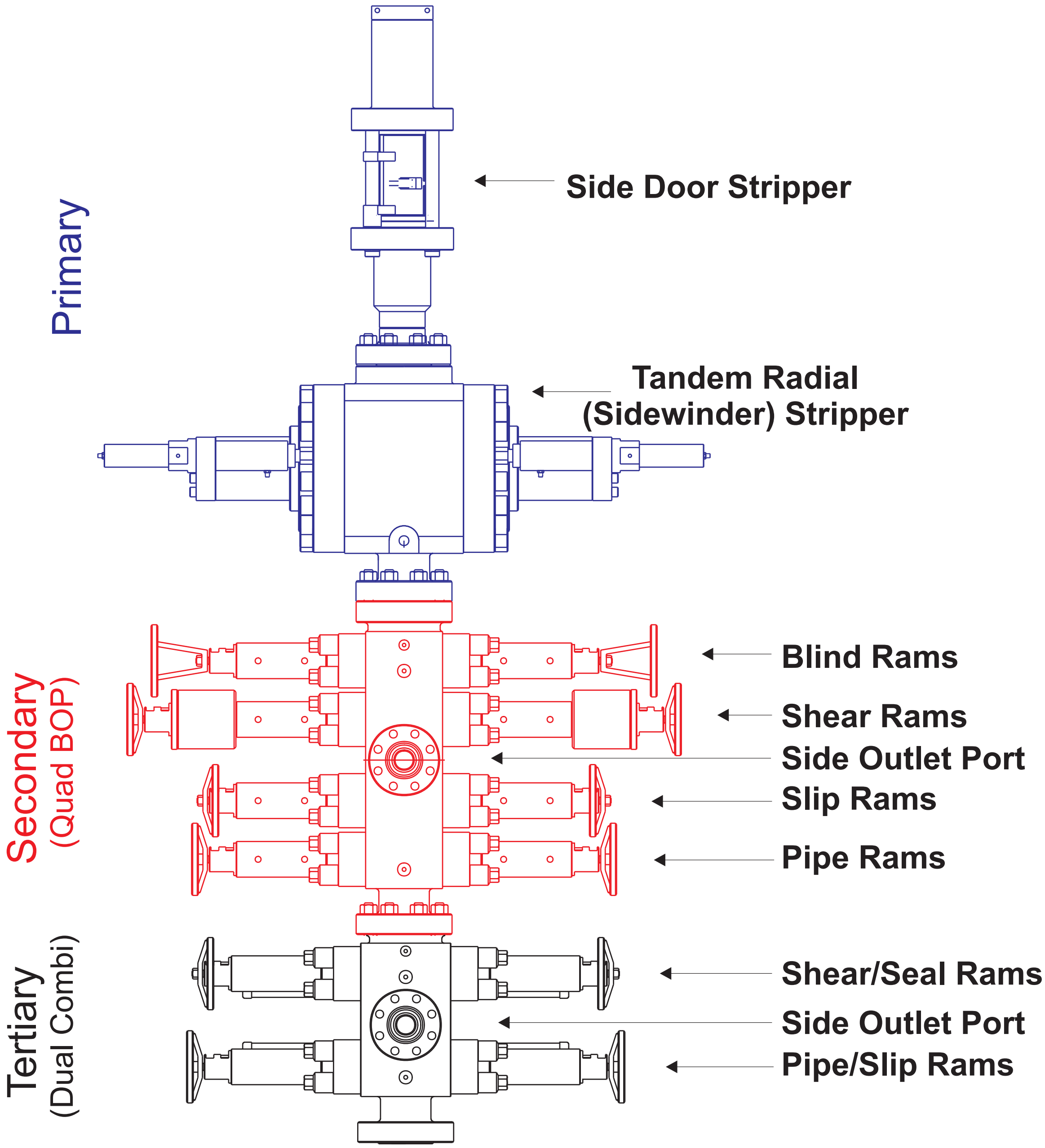
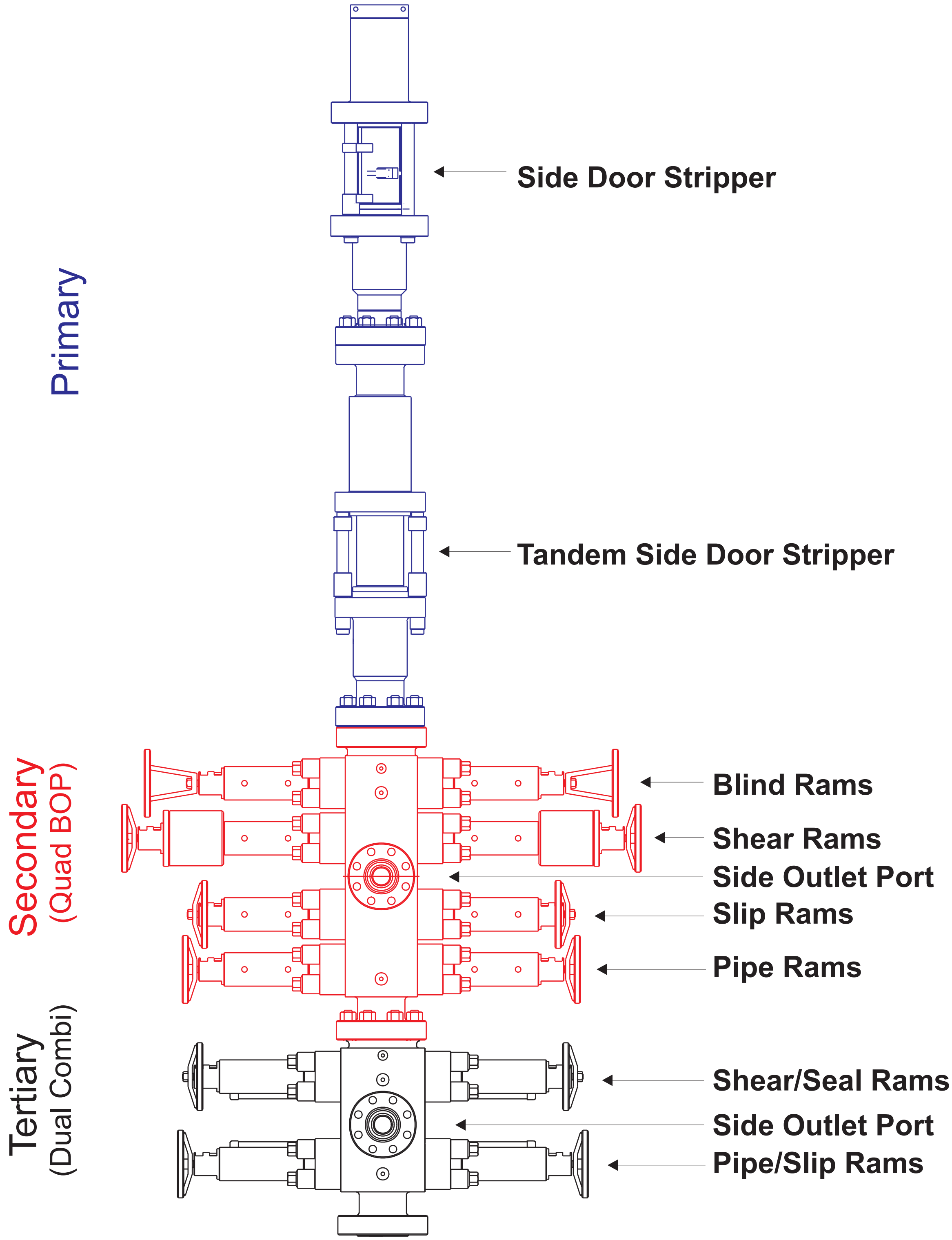


FIGURE A.3 *High Pressure Stack with Tandem Side Door Stripper (Texas Oil Tools)*



PRESSURE CONTROL COMPONENTS

FIGURE A.4 *Side Door Stripper (Texas Oil Tools)*

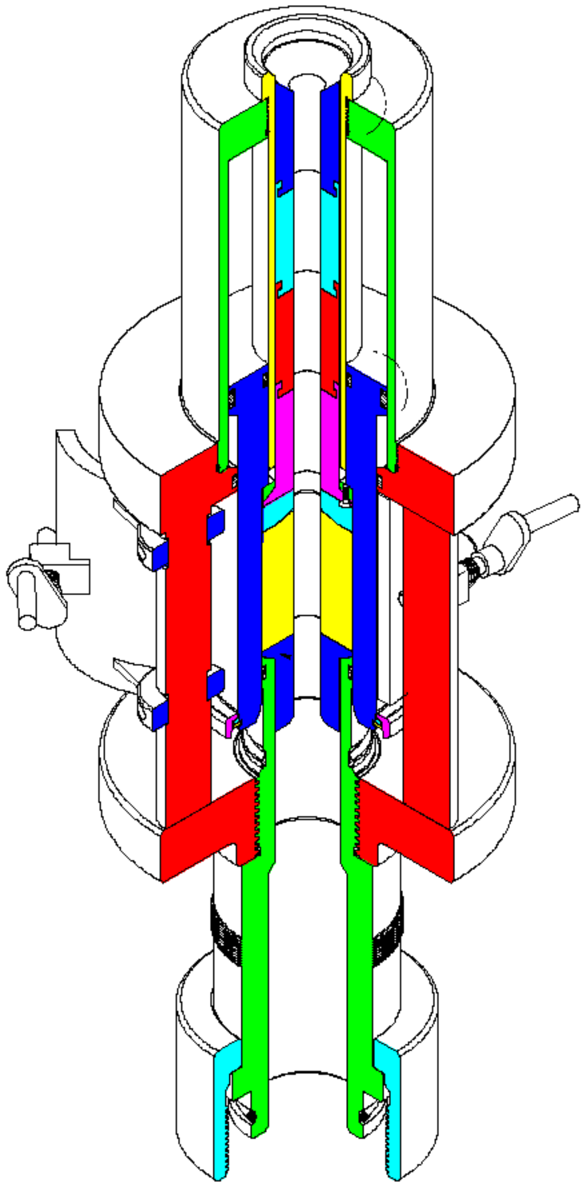


FIGURE A.5 *Tandem Side Door Stripper (Texas Oil Tools)*

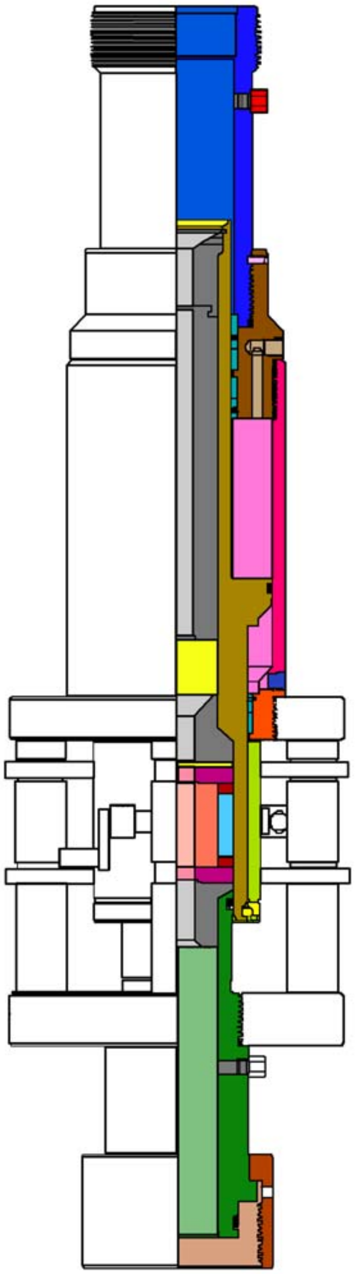


FIGURE A.6 *Sidewinder (Radial) Stripper (Texas Oil Tools)*

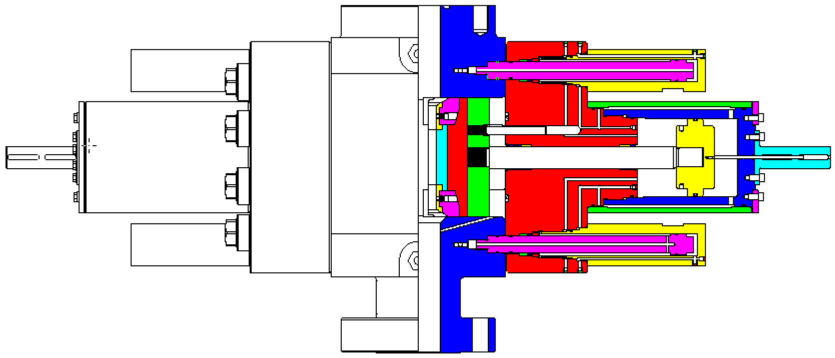


FIGURE A.7 *Quad CT Blowout Preventer (Texas Oil Tools)*

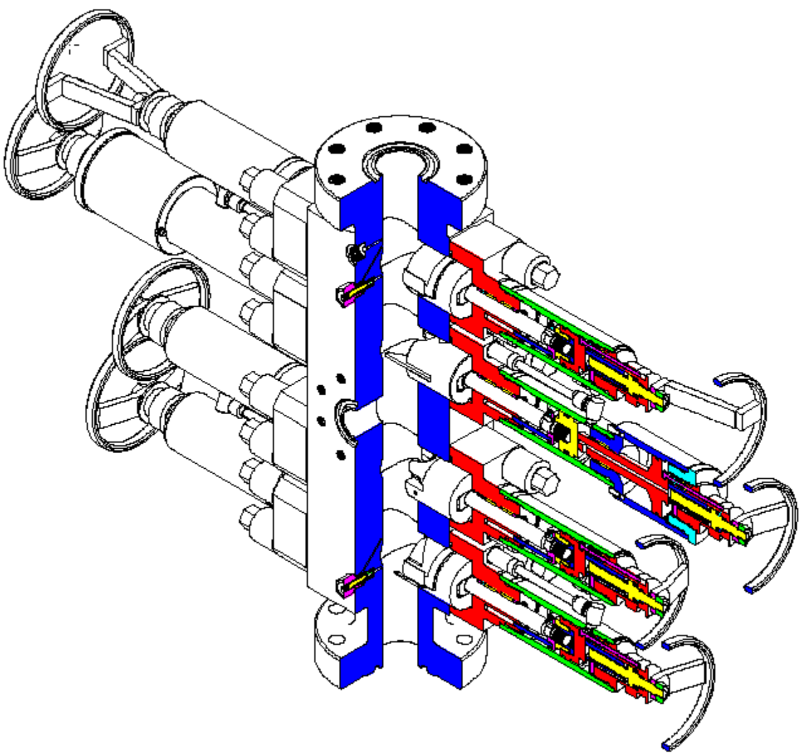
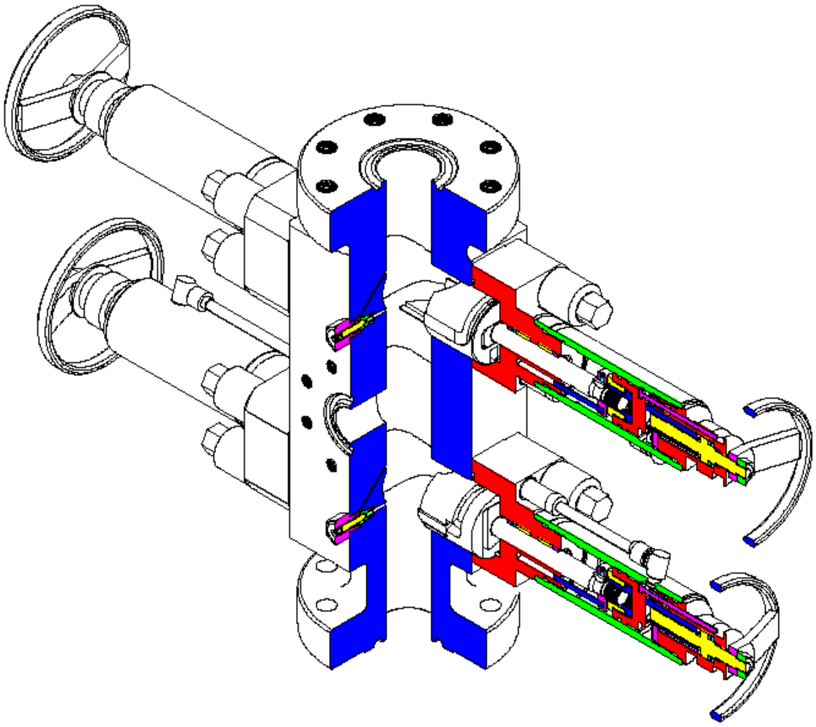
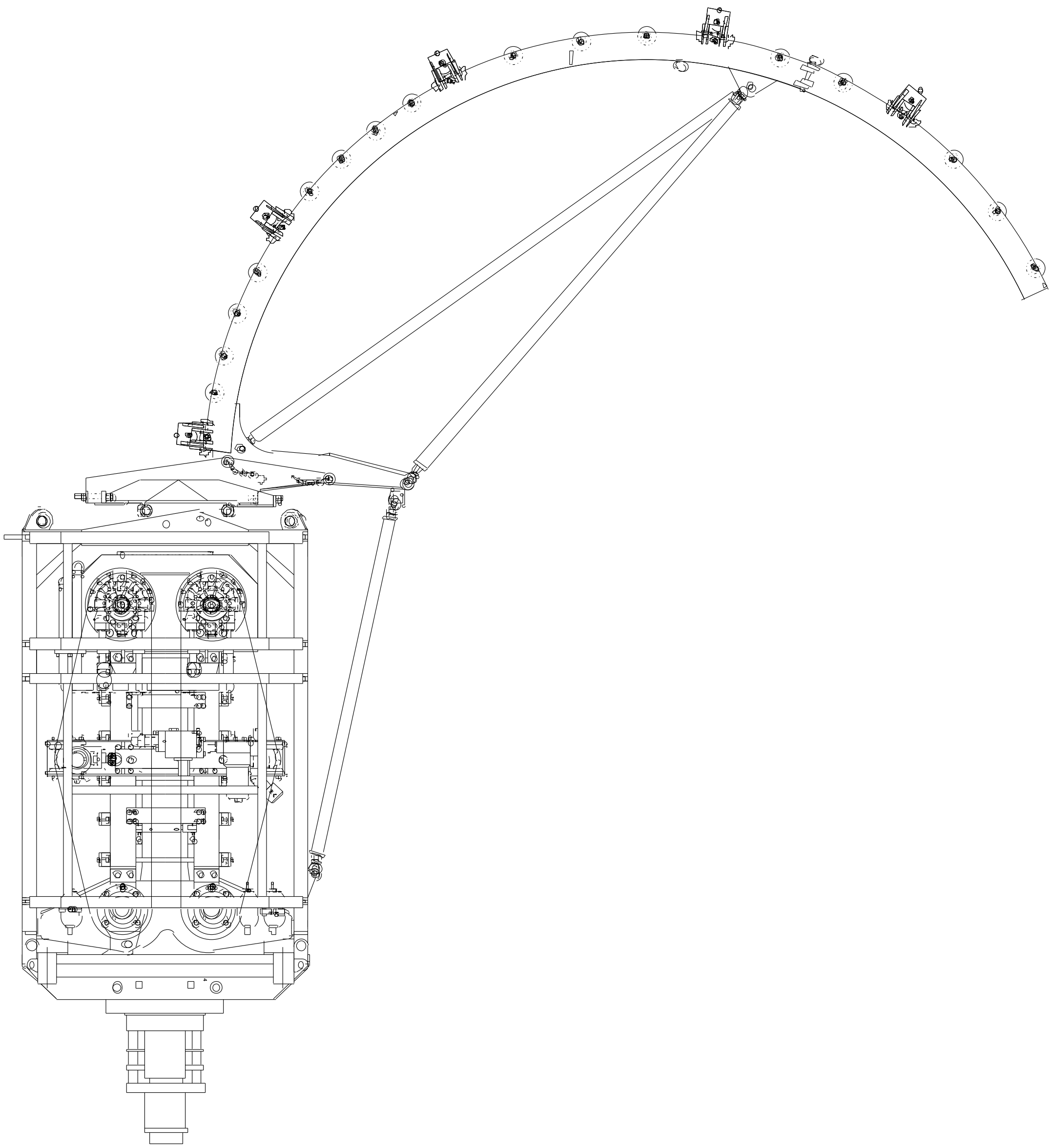


FIGURE A.8 *Dual Combi Blowout Preventer (Texas Oil Tools)*



INJECTOR HEAD

FIGURE A.9 *Hydra Rig 480 Injector Head with Large-Radius Guide Arch*



B

COILED TUBING PERFORMANCE DATA

The columns in the following tables are defined as:

- Outside Diameter—Nominal OD of the CT
- Wall Thickness Nominal—Nominal wall thickness
- Wall Thickness Minimum—Minimum wall thickness
- Weight—Weight of the CT per unit length
- Yield Load—Axial load at which new straight CT will yield with no internal or external pressure. See the “Stress Limits” description for pressure correction. Axial load is not the same as “weight” read on a weight indicator. See the “Stress Limits” description for clarification.
- Yield Pressure—Internal pressure at which yielding begins in new straight pipe with no axial load applied
- Yield Torque—Torque at which new straight CT will yield with no internal or external pressure, and no axial load applied
- Elastic Stretch—The amount of elastic stretch for new straight CT of a certain length (1,000 ft or 1,000 meters) when a certain axial load is applied (1,000 lb or 1,000 kg.)
- Collapse Pressure Fa = 0—External pressure at which new straight CT of with 0%, 2% and 4% ovality will collapse with no internal pressure and no axial load
- Collapse Pressure Fa = Fy/2—External pressure at which new straight CT of with 0%, 2% and 4% ovality will collapse with no internal pressure and a tensile axial load of half the yield load

EQUATION B.1 *Cross sectional area of the steel*

EQUATION B.2 *Yield load*

EQUATION B.3 *Yield pressure assuming the minimum wall thickness*

EQUATION B.4 *Yield torque for steel*

EQUATION B.5 *Elastic stretch for CT that has never been bent*

EQUATION B.6 *Ovality*

The collapse calculation is based on the equations in the following reference. Due to their length these equations are not reproduced in this manual.

API Recommended Practice 5C7, First Edition: "Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services", December 1996

Nomenclature

A = cross sectional area of the CT wall = A_o - A_I
A_I = internal cross sectional area of CT = π_i^2
A_o = external cross sectional area of CT = π_o^2
E = modulus of elasticity - 27 x 10^6 psi used for tables
F_y = axial yield load of the CT
L = length of the CT section
P_y = internal pressure required to yield the CT
r_I = internal radius of the CT
r_o = nominal external radius of the CT
$r_{o\text{-}max}$ = the largest radius for oval tubing
$r_{o\text{-}min}$ = the smallest radius for oval tubing
t = nominal wall thickness of the CT = r_o-r_I
t_{min} = minimum wall thickness of the CT
T_y = yield torque
δ_{af} = stretch due to axial force
ϕ = ovality of the CT

70,000 PSI YIELD STRENGTH

OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	Collapse Pressures per API RP 5C7: Ovality = 0% F_a=0 psi	Ovality = 0% Fa=Fy/2 psi	Ovality = 2% F_a=0 psi	Ovality = 2% Fa=Fy/2 psi	Ovality = 4% F_a=0 psi	Ovality = 4% Fa=Fy/2 psi
1.000	0.075	0.070	0.74	14,316	9,800	300	0.1699	8,910	6,098	5,196	3,556	4,082	2,793
1.000	0.080	0.075	0.79	15,256	10,500	316	0.1602	9,713	6,647	5,739	3,928	4,538	3,106
1.000	0.087	0.082	0.85	16,554	11,480	338	0.1484	10,539	7,213	6,442	4,409	5,146	3,522
1.000	0.095	0.090	0.92	18,011	12,600	362	0.1371	11,466	7,847	7,257	4,967	5,859	4,010
1.000	0.102	0.097	0.98	19,262	13,580	382	0.1287	12,263	8,393	7,978	5,460	6,496	4,446
1.000	0.109	0.104	1.04	20,492	14,560	401	0.1214	13,046	8,929	8,705	5,957	7,143	4,889
1.000	0.125	0.117	1.17	22,719	16,380	434	0.1078	14,464	9,899	10,065	6,888	8,368	5,727
1.250	0.075	0.070	0.94	18,165	7,840	488	0.1338	5,933	4,061	3,555	2,433	2,763	1,891
1.250	0.080	0.075	1.00	19,380	8,400	517	0.1260	6,784	4,643	4,016	2,748	3,129	2,141
1.250	0.087	0.082	1.08	21,062	9,184	556	0.1165	7,974	5,458	4,671	3,197	3,655	2,502
1.250	0.095	0.090	1.17	22,959	10,080	598	0.1074	9,335	6,389	5,437	3,721	4,279	2,928
1.250	0.102	0.097	1.25	24,595	10,864	634	0.1007	10,021	6,858	5,999	4,106	4,762	3,259
1.250	0.109	0.104	1.33	26,210	11,648	668	0.0948	10,679	7,309	6,564	4,492	5,252	3,595
1.250	0.125	0.117	1.50	29,152	13,104	728	0.0838	11,877	8,129	7,627	5,220	6,185	4,233
1.250	0.134	0.126	1.60	31,145	14,112	767	0.0788	12,690	8,685	8,372	5,730	6,846	4,685
1.250	0.156	0.148	1.82	35,867	16,576	853	0.0691	14,613	10,002	10,212	6,989	8,501	5,819
1.250	0.175	0.167	2.01	39,773	18,704	919	0.0627	16,205	11,091	11,810	8,083	9,965	6,820
1.500	0.095	0.090	1.42	27,907	8,400	893	0.0883	6,784	4,643	4,016	2,748	3,129	2,141
1.500	0.102	0.097	1.52	29,928	9,053	949	0.0827	7,776	5,322	4,561	3,122	3,566	2,441
1.500	0.109	0.104	1.62	31,928	9,707	1,003	0.0778	8,768	6,001	5,116	3,501	4,016	2,749
1.500	0.125	0.117	1.83	35,584	10,920	1,099	0.0686	10,068	6,891	6,039	4,133	4,797	3,283
1.500	0.134	0.126	1.95	38,072	11,760	1,162	0.0644	10,772	7,373	6,645	4,548	5,323	3,643
1.500	0.156	0.148	2.24	44,003	13,813	1,305	0.0562	12,450	8,521	8,150	5,578	6,649	4,551
1.500	0.175	0.167	2.47	48,955	15,587	1,417	0.0508	13,851	9,480	9,471	6,482	7,831	5,359
1.750	0.109	0.104	1.91	37,645	8,320	1,408	0.0659	6,662	4,560	3,949	2,703	3,076	2,105
1.750	0.125	0.117	2.17	42,017	9,360	1,548	0.0580	8,241	5,641	4,820	3,299	3,776	2,584
1.750	0.134	0.126	2.31	44,999	10,080	1,641	0.0544	9,335	6,389	5,437	3,721	4,279	2,928
1.750	0.156	0.148	2.65	52,140	11,840	1,855	0.0474	10,839	7,418	6,703	4,587	5,373	3,678
1.750	0.175	0.167	2.94	58,136	13,360	2,025	0.0428	12,085	8,271	7,815	5,349	6,352	4,347
1.750	0.188	0.180	3.13	62,147	14,400	2,133	0.0401	12,919	8,842	8,586	5,876	7,036	4,816
2.000	0.109	0.104	2.20	43,363	7,280	1,880	0.0572	5,083	3,479	3,099	2,121	2,406	1,647
2.000	0.125	0.117	2.50	48,449	8,190	2,074	0.0503	6,465	4,425	3,842	2,630	2,991	2,047
2.000	0.134	0.126	2.67	51,926	8,820	2,203	0.0471	7,421	5,079	4,365	2,988	3,409	2,333
2.000	0.156	0.148	3.07	60,277	10,360	2,502	0.0410	9,593	6,566	5,640	3,860	4,452	3,047
2.000	0.175	0.167	3.41	67,317	11,690	2,743	0.0369	10,714	7,333	6,594	4,513	5,279	3,613
2.000	0.188	0.180	3.63	72,043	12,600	2,898	0.0346	11,466	7,847	7,257	4,967	5,859	4,010
2.375	0.109	0.104	2.64	51,940	6,131	2,719	0.0477	3,337	2,284	2,169	1,484	1,695	1,160
2.375	0.125	0.117	3.00	58,098	6,897	3,008	0.0419	4,501	3,081	2,789	1,909	2,167	1,483
2.375	0.134	0.126	3.20	62,317	7,427	3,202	0.0393	5,307	3,632	3,218	2,203	2,500	1,711
2.375	0.156	0.148	3.69	72,482	8,724	3,657	0.0341	7,276	4,980	4,285	2,933	3,344	2,289
2.375	0.175	0.167	4.11	81,089	9,844	4,027	0.0306	8,977	6,144	5,234	3,582	4,113	2,815
2.375	0.188	0.180	4.39	86,887	10,611	4,268	0.0287	9,806	6,712	5,818	3,982	4,606	3,152
2.875	0.125	0.117	3.67	70,962	5,697	4,524	0.0343	5,836	3,994	2,565	1,756	1,873	1,282
2.875	0.134	0.126	3.92	76,172	6,136	4,826	0.0321	3,345	2,289	2,173	1,487	1,698	1,162
2.875	0.156	0.148	4.53	88,755	7,207	5,539	0.0278	4,972	3,403	3,040	2,080	2,360	1,615
2.875	0.175	0.167	5.04	99,452	8,132	6,125	0.0250	6,377	4,364	3,794	2,597	2,953	2,021
2.875	0.188	0.180	5.39	106,679	8,765	6,512	0.0233	7,338	5,022	4,319	2,956	3,372	2,308
2.875	0.203	0.195	5.79	114,926	9,496	6,943	0.0217	8,447	5,782	4,936	3,378	3,870	2,648
3.500	0.134	0.126	4.81	93,490	5,040	7,325	0.0261	5,249	3,592	2,163	1,480	1,553	1,063
3.500	0.156	0.148	5.57	109,097	5,920	8,441	0.0226	5,877	4,022	2,682	1,835	1,972	1,349
3.500	0.175	0.167	6.21	122,405	6,680	9,369	0.0203	4,172	2,855	2,614	1,789	2,032	1,391
3.500	0.188	0.180	6.64	131,419	7,200	9,985	0.0189	4,961	3,396	3,034	2,077	2,356	1,612
3.500	0.203	0.195	7.14	141,727	7,800	10,676	0.0176	5,872	4,019	3,522	2,411	2,738	1,874
4.500	0.204	0.195	9.35	184,610	6,067	18,326	0.0135	3,240	2,218	2,117	1,449	1,655	1,133
4.500	0.224	0.214	10.22	201,704	6,658	19,855	0.0123	4,138	2,832	2,596	1,777	2,018	1,381
4.500	0.250	0.240	11.34	224,838	7,467	21,880	0.0111	5,366	3,673	3,250	2,225	2,524	1,728

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

80,000 PSI YIELD STRENGTH

OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	Collapse Pressures per API RP 5C7: Ovality = 0%		Ovality = 2%		Ovality = 4%	
								F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi
1.000	0.075	0.070	0.74	16,361	11,200	342	0.1699	9,903	6,778	5,869	4,017	4,620	3,162
1.000	0.080	0.075	0.79	17,436	12,000	361	0.1602	11,100	7,597	6,559	4,489	5,186	3,549
1.000	0.087	0.082	0.85	18,919	13,120	387	0.1484	12,044	8,243	7,362	5,039	5,881	4,025
1.000	0.095	0.090	0.92	20,584	14,400	414	0.1371	13,104	8,969	8,294	5,676	6,696	4,583
1.000	0.102	0.097	0.98	22,014	15,520	437	0.1287	14,015	9,592	9,117	6,240	7,423	5,081
1.000	0.109	0.104	1.04	23,420	16,640	458	0.1214	14,909	10,204	9,948	6,809	8,163	5,587
1.000	0.125	0.117	1.17	25,965	18,720	496	0.1078	16,530	11,313	11,503	7,873	9,563	6,545
1.250	0.075	0.070	0.94	20,760	8,960	558	0.1338	6,464	4,424	3,972	2,719	3,102	2,123
1.250	0.080	0.075	1.00	22,148	9,600	591	0.1260	7,447	5,097	4,506	3,084	3,524	2,412
1.250	0.087	0.082	1.08	24,071	10,496	635	0.1165	8,822	6,038	5,264	3,603	4,130	2,827
1.250	0.095	0.090	1.17	26,239	11,520	684	0.1074	10,395	7,114	6,147	4,207	4,847	3,317
1.250	0.102	0.097	1.25	28,109	12,416	724	0.1007	11,453	7,838	6,856	4,692	5,442	3,725
1.250	0.109	0.104	1.33	29,954	13,312	763	0.0948	12,204	8,353	7,501	5,134	6,002	4,108
1.250	0.125	0.117	1.50	33,316	14,976	832	0.0838	13,574	9,290	8,716	5,966	7,068	4,838
1.250	0.134	0.126	1.60	35,594	16,128	876	0.0788	14,502	9,926	9,568	6,548	7,824	5,355
1.250	0.156	0.148	1.82	40,990	18,944	975	0.0691	16,701	11,430	11,671	7,988	9,716	6,650
1.250	0.175	0.167	2.01	45,455	21,376	1,050	0.0627	18,520	12,675	13,497	9,238	11,389	7,795
1.500	0.095	0.090	1.42	31,893	9,600	1,021	0.0883	7,447	5,097	4,506	3,084	3,524	2,412
1.500	0.102	0.097	1.52	34,203	10,347	1,085	0.0827	8,593	5,881	5,137	3,516	4,028	2,757
1.500	0.109	0.104	1.62	36,489	11,093	1,147	0.0778	9,740	6,666	5,777	3,954	4,545	3,111
1.500	0.125	0.117	1.83	40,668	12,480	1,256	0.0686	11,507	7,875	6,902	4,724	5,482	3,752
1.500	0.134	0.126	1.95	43,511	13,440	1,328	0.0644	12,311	8,426	7,594	5,197	6,083	4,163
1.500	0.156	0.148	2.24	50,290	15,787	1,492	0.0562	14,229	9,739	9,315	6,375	7,599	5,201
1.500	0.175	0.167	2.47	55,948	17,813	1,619	0.0508	15,830	10,834	10,823	7,408	8,949	6,125
1.750	0.109	0.104	1.91	43,023	9,509	1,609	0.0659	7,306	5,001	4,430	3,032	3,463	2,370
1.750	0.125	0.117	2.17	48,019	10,697	1,769	0.0580	9,131	6,250	5,436	3,720	4,269	2,922
1.750	0.134	0.126	2.31	51,428	11,520	1,876	0.0544	10,395	7,114	6,147	4,207	4,847	3,317
1.750	0.156	0.148	2.65	59,589	13,531	2,120	0.0474	12,387	8,478	7,660	5,243	6,141	4,203
1.750	0.175	0.167	2.94	66,441	15,269	2,314	0.0428	13,812	9,453	8,932	6,113	7,259	4,968
1.750	0.188	0.180	3.13	71,025	16,457	2,438	0.0401	14,764	10,105	9,812	6,715	8,042	5,504
2.000	0.109	0.104	2.20	49,558	8,320	2,149	0.0572	5,481	3,752	3,441	2,355	2,688	1,840
2.000	0.125	0.117	2.50	55,370	9,360	2,370	0.0503	7,078	4,844	4,305	2,947	3,365	2,303
2.000	0.134	0.126	2.67	59,344	10,080	2,518	0.0471	8,184	5,601	4,911	3,361	3,846	2,632
2.000	0.156	0.148	3.07	68,888	11,840	2,860	0.0410	10,886	7,451	6,426	4,398	5,076	3,474
2.000	0.175	0.167	3.41	76,934	13,360	3,135	0.0369	12,244	8,380	7,536	5,158	6,033	4,129
2.000	0.188	0.180	3.63	82,335	14,400	3,312	0.0346	13,104	8,969	8,294	5,676	6,696	4,583
2.375	0.109	0.104	2.64	59,360	7,006	3,107	0.0477	6,595	4,514	3,163	2,165	2,344	1,604
2.375	0.125	0.117	3.00	66,397	7,882	3,438	0.0419	4,809	3,291	3,079	2,107	2,409	1,649
2.375	0.134	0.126	3.20	71,220	8,488	3,660	0.0393	5,740	3,929	3,581	2,451	2,797	1,914
2.375	0.156	0.148	3.69	82,837	9,971	4,179	0.0341	8,016	5,486	4,818	3,298	3,772	2,582
2.375	0.175	0.167	4.11	92,673	11,251	4,602	0.0306	9,981	6,831	5,913	4,047	4,656	3,186
2.375	0.188	0.180	4.39	99,299	12,126	4,878	0.0287	11,207	7,670	6,649	4,551	5,264	3,602
2.875	0.125	0.117	3.67	81,100	6,511	5,171	0.0343	6,486	4,439	2,906	1,989	2,126	1,455
2.875	0.134	0.126	3.92	87,053	7,012	5,516	0.0321	7,765	5,314	3,334	2,282	2,446	1,674
2.875	0.156	0.148	4.53	101,435	8,237	6,330	0.0278	5,353	3,664	3,372	2,308	2,635	1,803
2.875	0.175	0.167	5.04	113,659	9,294	7,000	0.0250	6,977	4,775	4,250	2,909	3,321	2,273
2.875	0.188	0.180	5.39	121,919	10,017	7,442	0.0233	8,088	5,535	4,858	3,325	3,804	2,603
2.875	0.203	0.195	5.79	131,344	10,852	7,935	0.0217	9,369	6,412	5,569	3,811	4,377	2,995
3.500	0.134	0.126	4.81	106,845	5,760	8,371	0.0261	5,810	3,977	2,449	1,676	1,762	1,206
3.500	0.156	0.148	5.57	124,683	6,766	9,647	0.0226	6,533	4,471	3,037	2,079	2,237	1,531
3.500	0.175	0.167	6.21	139,892	7,634	10,707	0.0203	4,429	3,031	2,873	1,966	2,252	1,542
3.500	0.188	0.180	6.64	150,193	8,229	11,411	0.0189	5,341	3,656	3,366	2,304	2,630	1,800
3.500	0.203	0.195	7.14	161,974	8,914	12,202	0.0176	6,394	4,376	3,934	2,693	3,072	2,103
4.500	0.204	0.195	9.35	210,983	6,933	20,944	0.0135	4,153	2,842	2,572	1,760	1,985	1,358
4.500	0.224	0.214	10.22	230,519	7,609	22,692	0.0123	4,390	3,004	2,852	1,952	2,236	1,531
4.500	0.250	0.240	11.34	256,957	8,533	25,005	0.0111	5,809	3,976	3,618	2,476	2,825	1,934

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

90,000 PSI YIELD STRENGTH

								Collapse Pressures per API RP 5C7					
								Ovality = 0%		Ovality = 2%		Ovality = 4%	
OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi
1.000	0.075	0.070	0.74	18,407	12,600	385	0.1699	10,854	7,429	6,528	4,468	5,150	3,524
1.000	0.080	0.075	0.79	19,615	13,500	406	0.1602	12,252	8,385	7,320	5,010	5,796	3,967
1.000	0.087	0.082	0.85	21,284	14,760	435	0.1484	13,550	9,274	8,283	5,669	6,617	4,528
1.000	0.095	0.090	0.92	23,157	16,200	466	0.1371	14,742	10,090	9,330	6,386	7,533	5,156
1.000	0.102	0.097	0.98	24,766	17,460	491	0.1287	15,766	10,791	10,257	7,020	8,351	5,716
1.000	0.109	0.104	1.04	26,347	18,720	516	0.1214	16,773	11,480	11,192	7,660	9,184	6,285
1.000	0.125	0.117	1.17	29,210	21,060	557	0.1078	18,596	12,727	12,940	8,857	10,759	7,364
1.250	0.075	0.070	0.94	23,355	10,080	628	0.1338	6,940	4,750	4,367	2,989	3,427	2,345
1.250	0.080	0.075	1.00	24,917	10,800	665	0.1260	8,059	5,515	4,978	3,407	3,907	2,674
1.250	0.087	0.082	1.08	27,080	11,808	714	0.1165	9,624	6,587	5,841	3,998	4,595	3,145
1.250	0.095	0.090	1.17	29,518	12,960	769	0.1074	11,413	7,811	6,844	4,684	5,406	3,700
1.250	0.102	0.097	1.25	31,622	13,968	815	0.1007	12,884	8,818	7,713	5,279	6,123	4,190
1.250	0.109	0.104	1.33	33,698	14,976	859	0.0948	13,730	9,397	8,439	5,776	6,753	4,622
1.250	0.125	0.117	1.50	37,481	16,848	936	0.0838	15,271	10,452	9,806	6,711	7,952	5,442
1.250	0.134	0.126	1.60	40,043	18,144	986	0.0788	16,315	11,166	10,764	7,367	8,802	6,024
1.250	0.156	0.148	1.82	46,114	21,312	1,097	0.0691	18,789	12,859	13,129	8,986	10,930	7,481
1.250	0.175	0.167	2.01	51,137	24,048	1,182	0.0627	20,835	14,260	15,184	10,392	12,813	8,769
1.500	0.095	0.090	1.42	35,880	10,800	1,149	0.0883	8,059	5,515	4,978	3,407	3,907	2,674
1.500	0.102	0.097	1.52	38,479	11,640	1,220	0.0827	9,363	6,408	5,696	3,899	4,479	3,065
1.500	0.109	0.104	1.62	41,050	12,480	1,290	0.0778	10,668	7,301	6,424	4,396	5,065	3,466
1.500	0.125	0.117	1.83	45,751	14,040	1,413	0.0686	12,945	8,860	7,765	5,314	6,167	4,221
1.500	0.134	0.126	1.95	48,950	15,120	1,494	0.0644	13,850	9,479	8,543	5,847	6,844	4,684
1.500	0.156	0.148	2.24	56,576	17,760	1,678	0.0562	16,008	10,956	10,479	7,172	8,548	5,851
1.500	0.175	0.167	2.47	62,942	20,040	1,822	0.0508	17,809	12,189	12,176	8,334	10,068	6,891
1.750	0.109	0.104	1.91	48,401	10,697	1,810	0.0659	7,899	5,406	4,891	3,347	3,838	2,626
1.750	0.125	0.117	2.17	54,021	12,034	1,990	0.0580	9,975	6,827	6,037	4,132	4,752	3,252
1.750	0.134	0.126	2.31	57,856	12,960	2,110	0.0544	11,413	7,811	6,844	4,684	5,406	3,700
1.750	0.156	0.148	2.65	67,037	15,223	2,385	0.0474	13,935	9,538	8,618	5,898	6,909	4,728
1.750	0.175	0.167	2.94	74,746	17,177	2,603	0.0428	15,538	10,634	10,048	6,877	8,166	5,589
1.750	0.188	0.180	3.13	79,903	18,514	2,743	0.0401	16,610	11,368	11,039	7,555	9,047	6,192
2.000	0.109	0.104	2.20	55,752	9,360	2,418	0.0572	5,822	3,985	3,758	2,572	2,954	2,022
2.000	0.125	0.117	2.50	62,291	10,530	2,667	0.0503	7,639	5,228	4,749	3,250	3,726	2,550
2.000	0.134	0.126	2.67	66,762	11,340	2,833	0.0471	8,897	6,089	5,439	3,723	4,273	2,924
2.000	0.156	0.148	3.07	77,499	13,320	3,217	0.0410	11,972	8,194	7,161	4,901	5,665	3,877
2.000	0.175	0.167	3.41	86,551	15,030	3,527	0.0369	13,775	9,428	8,478	5,802	6,787	4,645
2.000	0.188	0.180	3.63	92,627	16,200	3,726	0.0346	14,742	10,090	9,330	6,386	7,533	5,156
2.375	0.109	0.104	2.64	66,779	7,882	3,496	0.0477	7,242	4,956	3,529	2,415	2,620	1,793
2.375	0.125	0.117	3.00	74,697	8,867	3,868	0.0419	5,057	3,461	3,339	2,286	2,634	1,802
2.375	0.134	0.126	3.20	80,122	9,549	4,117	0.0393	6,116	4,186	3,918	2,682	3,078	2,107
2.375	0.156	0.148	3.69	93,191	11,217	4,702	0.0341	8,706	5,958	5,334	3,650	4,189	2,867
2.375	0.175	0.167	4.11	104,258	12,657	5,177	0.0306	10,942	7,489	6,578	4,502	5,190	3,552
2.375	0.188	0.180	4.39	111,712	13,642	5,488	0.0287	12,473	8,536	7,446	5,096	5,899	4,038
2.875	0.125	0.117	3.67	91,237	7,325	5,817	0.0343	7,118	4,871	3,243	2,220	2,376	1,626
2.875	0.134	0.126	3.92	97,935	7,889	6,205	0.0321	8,570	5,865	3,730	2,553	2,739	1,875
2.875	0.156	0.148	4.53	114,114	9,266	7,121	0.0278	5,676	3,885	3,678	2,518	2,893	1,980
2.875	0.175	0.167	5.04	127,867	10,456	7,875	0.0250	7,524	5,149	4,686	3,207	3,676	2,516
2.875	0.188	0.180	5.39	137,159	11,270	8,372	0.0233	8,788	6,015	5,379	3,681	4,225	2,892
2.875	0.203	0.195	5.79	147,762	12,209	8,926	0.0217	10,246	7,013	6,188	4,235	4,874	3,336
3.500	0.134	0.126	4.81	120,201	6,480	9,417	0.0261	6,350	4,346	2,730	1,869	1,968	1,347
3.500	0.156	0.148	5.57	140,268	7,611	10,853	0.0226	7,171	4,908	3,389	2,319	2,500	1,711
3.500	0.175	0.167	6.21	157,378	8,589	12,046	0.0203	4,624	3,165	3,101	2,122	2,452	1,678
3.500	0.188	0.180	6.64	168,967	9,257	12,837	0.0189	5,662	3,875	3,671	2,512	2,887	1,976
3.500	0.203	0.195	7.14	182,221	10,029	13,727	0.0176	6,861	4,695	4,324	2,959	3,393	2,322
4.500	0.204	0.195	9.35	237,356	7,800	23,562	0.0135	4,467	3,057	2,826	1,934	2,192	1,500
4.500	0.224	0.214	10.22	259,333	8,560	25,528	0.0123	4,580	3,134	3,076	2,105	2,434	1,666
4.500	0.250	0.240	11.34	289,077	9,600	28,131	0.0111	6,195	4,240	3,961	2,711	3,111	2,129

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

100,000 PSI YIELD STRENGTH

OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	Collapse Pressures per API RP 5C7 Ovality = 0% F_a=0 psi	Ovality = 0% Fa=Fy/2 psi	Ovality = 2% F_a=0 psi	Ovality = 2% Fa=Fy/2 psi	Ovality = 4% F_a=0 psi	Ovality = 4% Fa=Fy/2 psi
1.000	0.075	0.070	0.74	20,452	14,000	428	0.1699	11,763	8,051	7,174	4,910	5,670	3,881
1.000	0.080	0.075	0.79	21,795	15,000	452	0.1602	13,334	9,126	8,062	5,517	6,393	4,375
1.000	0.087	0.082	0.85	23,649	16,400	483	0.1484	15,055	10,304	9,203	6,299	7,352	5,032
1.000	0.095	0.090	0.92	25,730	18,000	518	0.1371	16,380	11,211	10,367	7,095	8,370	5,728
1.000	0.102	0.097	0.98	27,518	19,400	546	0.1287	17,518	11,990	11,397	7,800	9,279	6,351
1.000	0.109	0.104	1.04	29,275	20,800	573	0.1214	18,637	12,755	12,435	8,511	10,204	6,984
1.000	0.125	0.117	1.17	32,456	23,400	619	0.1078	20,662	14,141	14,378	9,841	11,954	8,182
1.250	0.075	0.070	0.94	25,950	11,200	698	0.1338	7,363	5,039	4,739	3,244	3,736	2,557
1.250	0.080	0.075	1.00	27,685	12,000	739	0.1260	8,620	5,900	5,430	3,716	4,277	2,927
1.250	0.087	0.082	1.08	30,089	13,120	794	0.1165	10,380	7,104	6,402	4,382	5,049	3,456
1.250	0.095	0.090	1.17	32,798	14,400	854	0.1074	12,392	8,481	7,527	5,152	5,957	4,077
1.250	0.102	0.097	1.25	35,136	15,520	905	0.1007	14,152	9,686	8,528	5,837	6,775	4,637
1.250	0.109	0.104	1.33	37,443	16,640	954	0.0948	15,256	10,441	9,377	6,417	7,503	5,135
1.250	0.125	0.117	1.50	41,645	18,720	1,040	0.0838	16,968	11,613	10,895	7,457	8,836	6,047
1.250	0.134	0.126	1.60	44,492	20,160	1,095	0.0788	18,128	12,407	11,959	8,185	9,780	6,693
1.250	0.156	0.148	1.82	51,238	23,680	1,219	0.0691	20,876	14,288	14,588	9,984	12,145	8,312
1.250	0.175	0.167	2.01	56,819	26,720	1,313	0.0627	23,150	15,844	16,872	11,547	14,236	9,743
1.500	0.095	0.090	1.42	39,867	12,000	1,276	0.0883	8,620	5,900	5,430	3,716	4,277	2,927
1.500	0.102	0.097	1.52	42,754	12,933	1,356	0.0827	10,087	6,904	6,239	4,270	4,919	3,367
1.500	0.109	0.104	1.62	45,611	13,867	1,433	0.0778	11,553	7,907	7,056	4,829	5,575	3,816
1.500	0.125	0.117	1.83	50,834	15,600	1,570	0.0686	14,277	9,772	8,600	5,886	6,835	4,678
1.500	0.134	0.126	1.95	54,389	16,800	1,660	0.0644	15,389	10,532	9,493	6,497	7,604	5,204
1.500	0.156	0.148	2.24	62,862	19,733	1,865	0.0562	17,786	12,173	11,643	7,969	9,498	6,501
1.500	0.175	0.167	2.47	69,935	22,267	2,024	0.0508	19,788	13,543	13,529	9,260	11,187	7,656
1.750	0.109	0.104	1.91	53,779	11,886	2,011	0.0659	8,440	5,777	5,331	3,649	4,199	2,874
1.750	0.125	0.117	2.17	60,024	13,371	2,211	0.0580	10,775	7,375	6,622	4,532	5,225	3,576
1.750	0.134	0.126	2.31	64,285	14,400	2,344	0.0544	12,392	8,481	7,527	5,152	5,957	4,077
1.750	0.156	0.148	2.65	74,486	16,914	2,650	0.0474	15,484	10,597	9,575	6,554	7,676	5,254
1.750	0.175	0.167	2.94	83,051	19,086	2,892	0.0428	17,264	11,816	11,165	7,641	9,074	6,210
1.750	0.188	0.180	3.13	88,781	20,571	3,048	0.0401	18,456	12,631	12,265	8,394	10,052	6,880
2.000	0.109	0.104	2.20	61,947	10,400	2,686	0.0572	6,106	4,179	4,047	2,770	3,202	2,191
2.000	0.125	0.117	2.50	69,213	11,700	2,963	0.0503	8,149	5,577	5,171	3,539	4,073	2,788
2.000	0.134	0.126	2.67	74,181	12,600	3,147	0.0471	9,563	6,545	5,949	4,072	4,688	3,209
2.000	0.156	0.148	3.07	86,110	14,800	3,575	0.0410	13,020	8,911	7,883	5,395	6,247	4,275
2.000	0.175	0.167	3.41	96,168	16,700	3,918	0.0369	15,306	10,475	9,420	6,447	7,541	5,161
2.000	0.188	0.180	3.63	102,919	18,000	4,140	0.0346	16,380	11,211	10,367	7,095	8,370	5,728
2.375	0.109	0.104	2.64	74,199	8,758	3,884	0.0477	7,866	5,384	3,889	2,662	2,892	1,979
2.375	0.125	0.117	3.00	82,996	9,853	4,297	0.0419	5,246	3,590	3,568	2,442	2,837	1,942
2.375	0.134	0.126	3.20	89,025	10,611	4,575	0.0393	6,437	4,405	4,230	2,895	3,342	2,287
2.375	0.156	0.148	3.69	103,546	12,463	5,224	0.0341	9,348	6,398	5,831	3,991	4,594	3,144
2.375	0.175	0.167	4.11	115,842	14,063	5,753	0.0306	11,862	8,119	7,229	4,948	5,715	3,912
2.375	0.188	0.180	4.39	124,124	15,158	6,098	0.0287	13,583	9,296	8,203	5,614	6,508	4,454
2.875	0.125	0.117	3.67	101,375	8,139	6,463	0.0343	7,727	5,288	3,576	2,448	2,625	1,796
2.875	0.134	0.126	3.92	108,817	8,765	6,895	0.0321	9,359	6,405	4,123	2,822	3,031	2,074
2.875	0.156	0.148	4.53	126,793	10,296	7,912	0.0278	5,942	4,067	3,956	2,708	3,132	2,144
2.875	0.175	0.167	5.04	142,074	11,617	8,750	0.0250	8,019	5,488	5,100	3,490	4,017	2,750
2.875	0.188	0.180	5.39	152,399	12,522	9,302	0.0233	9,440	6,461	5,882	4,025	4,634	3,172
2.875	0.203	0.195	5.79	164,180	13,565	9,918	0.0217	11,080	7,583	6,791	4,648	5,362	3,670
3.500	0.134	0.126	4.81	133,557	7,200	10,464	0.0261	2,357	1,613	1,754	1,201	1,428	978
3.500	0.156	0.148	5.57	155,853	8,457	12,058	0.0226	7,786	5,329	3,736	2,557	2,761	1,890
3.500	0.175	0.167	6.21	174,865	9,543	13,384	0.0203	4,759	3,257	3,294	2,254	2,630	1,800
3.500	0.188	0.180	6.64	187,742	10,286	14,264	0.0189	5,926	4,056	3,947	2,702	3,126	2,139
3.500	0.203	0.195	7.14	202,468	11,143	15,252	0.0176	7,273	4,978	4,690	3,210	3,698	2,531
4.500	0.204	0.195	9.35	263,729	8,667	26,180	0.0135	4,747	3,249	3,066	2,098	2,391	1,636
4.500	0.224	0.214	10.22	288,148	9,511	28,365	0.0123	5,505	3,768	3,571	2,444	2,799	1,916
4.500	0.250	0.240	11.34	321,196	10,667	31,257	0.0111	6,525	4,466	4,278	2,928	3,380	2,313

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

110,000 PSI YIELD STRENGTH

								Collapse Pressures per API RP 5C7					
								Ovality = 0%		Ovality = 2%		Ovality = 4%	
OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi	F_a=0 psi	Fa=Fy/2 psi
1.000	0.075	0.070	0.74	22,497	15,400	471	0.1699	12,630	8,644	7,805	5,342	6,182	4,231
1.000	0.080	0.075	0.79	23,974	16,500	497	0.1602	14,380	9,842	8,791	6,016	6,982	4,778
1.000	0.087	0.082	0.85	26,014	18,040	532	0.1484	16,561	11,334	10,123	6,929	8,087	5,535
1.000	0.095	0.090	0.92	28,303	19,800	569	0.1371	18,018	12,332	11,404	7,805	9,207	6,301
1.000	0.102	0.097	0.98	30,269	21,340	601	0.1287	19,270	13,189	12,536	8,580	10,207	6,986
1.000	0.109	0.104	1.04	32,202	22,880	630	0.1214	20,500	14,031	13,679	9,362	11,224	7,682
1.000	0.125	0.117	1.17	35,702	25,740	681	0.1078	22,728	15,556	15,816	10,825	13,150	9,000
1.250	0.075	0.070	0.94	28,545	12,320	768	0.1338	7,732	5,292	5,087	3,481	4,030	2,758
1.250	0.080	0.075	1.00	30,454	13,200	812	0.1260	9,131	6,250	5,861	4,011	4,634	3,172
1.250	0.087	0.082	1.08	33,098	14,432	873	0.1165	11,091	7,591	6,946	4,754	5,493	3,759
1.250	0.095	0.090	1.17	36,078	15,840	940	0.1074	13,330	9,123	8,198	5,611	6,499	4,448
1.250	0.102	0.097	1.25	38,649	17,072	996	0.1007	15,289	10,464	9,309	6,371	7,405	5,068
1.250	0.109	0.104	1.33	41,187	18,304	1,049	0.0948	16,781	11,485	10,314	7,059	8,253	5,649
1.250	0.125	0.117	1.50	45,810	20,592	1,144	0.0838	18,665	12,774	11,985	8,203	9,719	6,652
1.250	0.134	0.126	1.60	48,942	22,176	1,205	0.0788	19,941	13,648	13,155	9,004	10,758	7,363
1.250	0.156	0.148	1.82	56,362	26,048	1,341	0.0691	22,964	15,717	16,047	10,983	13,359	9,143
1.250	0.175	0.167	2.01	62,501	29,392	1,444	0.0627	25,465	17,429	18,559	12,702	15,660	10,718
1.500	0.095	0.090	1.42	43,853	13,200	1,404	0.0883	9,131	6,250	5,861	4,011	4,634	3,172
1.500	0.102	0.097	1.52	47,030	14,227	1,492	0.0827	10,764	7,367	6,765	4,630	5,348	3,660
1.500	0.109	0.104	1.62	50,172	15,253	1,577	0.0778	12,397	8,485	7,674	5,252	6,076	4,159
1.500	0.125	0.117	1.83	55,918	17,160	1,727	0.0686	15,429	10,560	9,389	6,426	7,471	5,113
1.500	0.134	0.126	1.95	59,827	18,480	1,826	0.0644	16,928	11,586	10,442	7,146	8,364	5,725
1.500	0.156	0.148	2.24	69,148	21,707	2,051	0.0562	19,565	13,391	12,808	8,766	10,448	7,151
1.500	0.175	0.167	2.47	76,929	24,493	2,226	0.0508	21,766	14,897	14,882	10,186	12,305	8,422
1.750	0.109	0.104	1.91	59,157	13,074	2,212	0.0659	8,931	6,113	5,750	3,936	4,547	3,112
1.750	0.125	0.117	2.17	66,026	14,709	2,433	0.0580	11,531	7,892	7,190	4,921	5,688	3,893
1.750	0.134	0.126	2.31	70,713	15,840	2,579	0.0544	13,330	9,123	8,198	5,611	6,499	4,448
1.750	0.156	0.148	2.65	81,934	18,606	2,915	0.0474	17,032	11,657	10,533	7,209	8,444	5,779
1.750	0.175	0.167	2.94	91,357	20,994	3,182	0.0428	18,991	12,998	12,281	8,405	9,981	6,831
1.750	0.188	0.180	3.13	97,660	22,629	3,352	0.0401	20,301	13,894	13,492	9,234	11,057	7,568
2.000	0.109	0.104	2.20	68,142	11,440	2,955	0.0572	6,332	4,334	4,306	2,947	3,430	2,348
2.000	0.125	0.117	2.50	76,134	12,870	3,259	0.0503	8,607	5,890	5,571	3,813	4,407	3,016
2.000	0.134	0.126	2.67	81,599	13,860	3,462	0.0471	10,181	6,968	6,441	4,409	5,092	3,485
2.000	0.156	0.148	3.07	94,721	16,280	3,932	0.0410	14,030	9,602	8,593	5,881	6,820	4,668
2.000	0.175	0.167	3.41	105,784	18,370	4,310	0.0369	16,836	11,523	10,362	7,092	8,295	5,677
2.000	0.188	0.180	3.63	113,210	19,800	4,554	0.0346	18,018	12,332	11,404	7,805	9,207	6,301
2.375	0.109	0.104	2.64	81,619	9,634	4,272	0.0477	8,465	5,793	4,244	2,905	3,161	2,164
2.375	0.125	0.117	3.00	91,296	10,838	4,727	0.0419	5,375	3,679	3,762	2,575	3,018	2,065
2.375	0.134	0.126	3.20	97,927	11,672	5,032	0.0393	6,701	4,586	4,512	3,088	3,588	2,456
2.375	0.156	0.148	3.69	113,900	13,709	5,747	0.0341	9,942	6,804	6,309	4,318	4,987	3,413
2.375	0.175	0.167	4.11	127,426	15,469	6,328	0.0306	12,741	8,720	7,867	5,384	6,232	4,265
2.375	0.188	0.180	4.39	136,537	16,674	6,707	0.0287	14,656	10,031	8,948	6,124	7,110	4,866
2.875	0.125	0.117	3.67	111,512	8,953	7,110	0.0343	8,309	5,687	3,904	2,672	2,870	1,964
2.875	0.134	0.126	3.92	119,698	9,642	7,584	0.0321	10,127	6,931	4,512	3,088	3,320	2,273
2.875	0.156	0.148	4.53	139,473	11,325	8,703	0.0278	6,150	4,209	4,203	2,877	3,352	2,294
2.875	0.175	0.167	5.04	156,282	12,779	9,625	0.0250	8,462	5,792	5,491	3,758	4,345	2,973
2.875	0.188	0.180	5.39	167,639	13,774	10,232	0.0233	10,044	6,874	6,366	4,357	5,032	3,444
2.875	0.203	0.195	5.79	180,598	14,922	10,910	0.0217	11,870	8,124	7,379	5,051	5,839	3,997
3.500	0.134	0.126	4.81	146,912	7,920	11,510	0.0261	2,357	1,613	1,804	1,235	1,488	1,019
3.500	0.156	0.148	5.57	171,438	9,303	13,264	0.0226	8,376	5,732	4,077	2,791	3,018	2,066
3.500	0.175	0.167	6.21	192,351	10,497	14,722	0.0203	9,561	6,544	4,846	3,316	3,638	2,490
3.500	0.188	0.180	6.64	206,516	11,314	15,690	0.0189	6,132	4,197	4,193	2,870	3,345	2,289
3.500	0.203	0.195	7.14	222,715	12,257	16,777	0.0176	7,632	5,223	5,031	3,443	3,988	2,729
4.500	0.204	0.195	9.35	290,102	9,533	28,798	0.0135	4,991	3,416	3,289	2,251	2,579	1,765
4.500	0.224	0.214	10.22	316,963	10,462	31,201	0.0123	5,835	3,994	3,849	2,635	3,030	2,074
4.500	0.250	0.240	11.34	353,316	11,733	34,382	0.0111	6,799	4,653	4,567	3,126	3,630	2,485

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

120,000 PSI YIELD STRENGTH

OD in.	Nom. Wall in.	Min. Wall in.	Wt. lb/ft	Yield Load lb	Yield Press. psi	Yield Torque ft-lb	Elastic Stretch ft *	Collapse Pressures per API RP 5C7: Ovality = 0%: F_a=0 psi	Ovality = 0%: Fa=Fy/2 psi	Ovality = 2%: F_a=0 psi	Ovality = 2%: Fa=Fy/2 psi	Ovality = 4%: F_a=0 psi	Ovality = 4%: Fa=Fy/2 psi
1.250	0.134	0.126	1.60	53,391	24,192	1,314	0.0788	21,753	14,888	14,351	9,822	11,735	8,032
1.250	0.156	0.148	1.82	61,486	28,416	1,463	0.0691	25,052	17,146	17,506	11,981	14,574	9,975
1.250	0.175	0.167	2.01	68,183	32,064	1,576	0.0627	27,780	19,013	20,246	13,857	17,083	11,692
1.500	0.134	0.126	1.95	65,266	20,160	1,992	0.0644	18,467	12,639	11,391	7,796	9,125	6,245
1.500	0.156	0.148	2.24	75,434	23,680	2,238	0.0562	21,344	14,608	13,972	9,563	11,398	7,801
1.500	0.175	0.167	2.47	83,922	26,720	2,429	0.0508	23,745	16,252	16,235	11,112	13,424	9,188
1.500	0.188	0.180	2.63	89,573	28,800	2,549	0.0478	25,344	17,346	17,794	12,179	14,836	10,154
1.750	0.134	0.126	2.31	77,141	17,280	2,813	0.0544	14,228	9,738	8,854	6,060	7,032	4,813
1.750	0.156	0.148	2.65	89,383	20,297	3,180	0.0474	18,581	12,717	11,490	7,864	9,212	6,305
1.750	0.175	0.167	2.94	99,662	22,903	3,471	0.0428	20,717	14,179	13,398	9,170	10,889	7,452
1.750	0.188	0.180	3.13	106,538	24,686	3,657	0.0401	22,147	15,157	14,718	10,073	12,063	8,256
2.000	0.134	0.126	2.67	89,017	15,120	3,777	0.0471	10,751	7,358	6,913	4,732	5,482	3,752
2.000	0.156	0.148	3.07	103,332	17,760	4,290	0.0410	15,000	10,266	9,289	6,357	7,385	5,054
2.000	0.175	0.167	3.41	115,401	20,040	4,702	0.0369	18,367	12,570	11,304	7,737	9,049	6,193
2.000	0.188	0.180	3.63	123,502	21,600	4,968	0.0346	19,656	13,453	12,440	8,514	10,044	6,874
2.000	0.203	0.195	3.89	132,691	23,400	5,260	0.0323	21,119	14,454	13,765	9,421	11,214	7,675
2.375	0.134	0.126	3.20	106,829	12,733	5,490	0.0393	6,908	4,728	4,764	3,261	3,814	2,611
2.375	0.156	0.148	3.69	124,255	14,956	6,269	0.0341	10,487	7,177	6,767	4,631	5,367	3,673
2.375	0.175	0.167	4.11	139,010	16,876	6,903	0.0306	13,577	9,292	8,489	5,810	6,738	4,612
2.375	0.188	0.180	4.39	148,949	18,189	7,317	0.0287	15,692	10,740	9,680	6,625	7,703	5,272
2.375	0.203	0.195	4.70	160,259	19,705	7,775	0.0267	18,087	12,379	11,062	7,571	8,838	6,049
2.875	0.134	0.126	3.92	130,580	10,518	8,274	0.0321	10,872	7,441	4,898	3,352	3,608	2,469
2.875	0.156	0.148	4.53	152,152	12,355	9,495	0.0278	6,300	4,312	4,416	3,023	3,549	2,429
2.875	0.175	0.167	5.04	170,489	13,941	10,500	0.0250	8,853	6,059	5,858	4,009	4,656	3,187
2.875	0.188	0.180	5.39	182,878	15,026	11,163	0.0233	10,600	7,255	6,829	4,674	5,416	3,707
2.875	0.203	0.195	5.79	197,016	16,278	11,902	0.0217	12,615	8,634	7,951	5,442	6,307	4,316
3.500	0.134	0.126	4.81	160,268	8,640	12,556	0.0261	2,357	1,613	1,847	1,264	1,541	1,055
3.500	0.156	0.148	5.57	187,024	10,149	14,470	0.0226	8,937	6,116	4,413	3,020	3,272	2,239
3.500	0.175	0.167	6.21	209,837	11,451	16,061	0.0203	10,246	7,013	5,252	3,594	3,948	2,702
3.500	0.188	0.180	6.64	225,290	12,343	17,116	0.0189	6,281	4,299	4,405	3,015	3,541	2,424
3.500	0.203	0.195	7.14	242,961	13,371	18,303	0.0176	7,936	5,432	5,345	3,658	4,259	2,915
4.500	0.204	0.195	9.35	316,475	10,400	31,416	0.0135	5,197	3,557	3,493	2,391	2,755	1,885
4.500	0.224	0.214	10.22	345,778	11,413	34,038	0.0123	6,130	4,195	4,111	2,813	3,251	2,225
4.500	0.250	0.240	11.34	385,436	12,800	37,508	0.0111	7,017	4,802	4,826	3,303	3,861	2,643
6.625	0.280	0.270	18.95	646,860	9,781	95,023	0.0066	4,097	2,804	2,899	1,984	2,320	1,588
6.625	0.300	0.288	20.24	688,030	10,433	100,525	0.0062	5,157	3,530	3,486	2,386	2,754	1,885

*. Feet of stretch when 1,000 lbs of force is applied to a section 1,000 ft. long.

BIBLIOGRAPHY OF CT REFERENCES

SPE Papers about Coiled Tubing; 2000-1972

SPE On-Line Library (OIL) at www.spe.org/oil/index.html

1. 65532 - Development of a Single-Trip Coiled Tubing Sidetracking System

2. 65138 - Optimising Performance of Mature Reservoir: An Innovative Use of Coiled Tubing Drilling Technology to Tap Unswept Reserves, Alwyn North UKCS

3. 64661 - An Integrated Approach to Marginal Field Development: Case History from the Gulf of Suez

4. 64501 - Intervention in Wells with Buckled Production Tubing

5. 64412 - Emerging Techniques in Gravel Packing Open-Hole Horizontal Completions in High-Performance Wells

6. 63269 - A Three-Layer Modeling for Cuttings Transport with Coiled Tubing Horizontal Drilling

7. 63251 - A General String Design Method for Extended-Reach and High-Pressure Applications

8. 63231 - Gravel-Pack Isolation Squeeze for Plug-Down Recompletion

9. 63113 - A Successful Completion/Perforation by Use of a Downhole Lubricator Valve: A Case Study from the Siri Field, Danish Sector, North Sea

10. 63042 - Artificial Lift for Slim Holes

11. 62892 - Gas Shutoff Evaluation and Implementation, North Slope, Alaska

12. 62790 - New Bio-Polymers for Drilling, Drill-in, Completions, Spacer Fluids and Coiled Tubing Applications

13. 62748 - Zonal Isolation in Stimulation Treatments and Gas/Water Shutoff Using Thermally Compensated Inflatable Packers and Plugs

14. 62744 - Reducing the Risk, Complexity and Cost of Coiled Tubing Drilling

15. 62742 - Modelling of Transient Cuttings Transport in Underbalanced Drilling

16. 62741 - The Development of a Coiled-Tubing Deployed Slow-Rotating Jet Cleaning Tool that Enhances Cleaning and Allows Jet Cutting of Tubulars

17. 62738 - Rotational Toolface Orientation to Facilitate Coiled Tubing Target Acquisition

18. 60756 - Controlling Small Positive-Displacement Motors when used with Coiled Tubing and Compressible Fluids

19. 60755 - The Effects of Particle Size, Fluid Rheology, and Pipe Eccentricity on Cutting-sTransport

20. 60752 - A Concept of a New Steerable Drilling System for Coiled Tubing

21. 60751 - Vibration Analysis for Coil Tubing Drilling in Prudhoe Bay

22. 60750 - Anaconda: Joint Development Project Leads to Digitally Controlled Composite Coiled Tubing Drilling System

23. 60748 - Coiled Tubing Inspection and Tubing Management: A Case Study

24. 60747 - Optimizing and Managing Coiled Tubing Frac Strings

25. 60744 - The Effect of Corrosion in Coiled Tubing and Its Prevention

26. 60740 - Running Coiled Tubing in Colombia Living on the Edge

27. 60738 - A New Approach to Monitor Tubing Limits

28. 60737 - Rotation of Coiled-Tubing

29. 60734 - Composite Coiled Tubing Solution

30. 60733 - Pumping with Coiled Tubing - A New Coiled Tubing Application

31. 60732 - Cable Internal, Coiled Tubing Deployed Submersible Pump Installation

32. 60730 - Development of a Power and Data Transmission Thermoplastic Composite Coiled Tubing for Electric Drilling

33. 60729 - The Development of a Light Well Intervention Ship

34. 60728 - Pipeline Intervention From a Dynamically Positioned Mono-Hull Vessel via a Flexible Riser

35. 60727 - Big Loop: On-Site Welded Continuous Pipe

36. 60725 - Bridge-Plug Millout With Coiled Tubing Case Histories

37. 60722 - Coiled Tubing: Extending the Reach of Slickline Operations

38. 60721 - Advances in Coiled Tubing Jetting Technology

39. 60720 - Friction Pressure Correlations of Newtonian and Non-Newtonian Fluids through Concentric and Eccentric Annuli

40. 60719 - Friction Pressures of Newtonian and Non-Newtonian Fluids in Straight and Reeled Coiled Tubing

41. 60718 - Advantages to Remedial Operations of Coiled-Tubing-Enables Under-balanced Removal of Latest-Generation Composite Bridge Plugs

42. 60717 - Selective Chemical Water Shutoffs Utilizing Through-Tubing Inflatable Packer Technology

43. 60711 - Current and Future Successes in Coiled Tubing Automation

44. 60710 - Theoretical Analysis and Design Modification of PDM for Air Drilling

45. 60709 - Integration of Conventional Fracturing, Coiled Tubing, and Retrievable Tool Technology

46. 60708 - Integration of Coiled-Tubing Underbalanced-Drilling Services To Improve Efficiency and Value

47. 60707 - Managing Differential Pressures During Coiled Tubing Operations

48. 60706 - Coiled Tubing Drilling Expanding Application Key to Future

49. 60705 - Coiled Tubing-Deployed Jetting Tool Enhances Cleaning and Jet Cutting

50. 60702 - Multilateral Well Leg Re-Entry Made Possible With a Unique Coiled Tubing Downhole Tool

51. 60701 - New Downhole Tool for Coiled Tubing Extended Reach

52. 60700 - A Hybrid Milling/Jetting Tool The Safe Solution to Scale Milling

53. 60699 - Full-Scale High-Pressure Stripper/Packer Testing with Wellhead Pressure to 15,000 psi

54. 60698 - High-Pressure/High-Temperature Coiled Tubing Casing Collar Locator Provides Accurate Depth Control for Single-Trip Perforating

55. 60696 - Concentric Coiled Tubing Well Vacuuming Technology for Complex Horizontal Wells in Eastern Venezuela

56. 60695 - Coiled Tubing Scale Removal of Iron Sulfide A Case Study of the Kaybob field in Central Alberta

57. 60694 - Good Coiled Tubing Welds, Properly Managed, Do Not Break

58. 60693 - Coiled Tubing for SlimHole Cementing and Completing

59. 60691 - Case Studies Demonstrate That Effective Soluble Scale Removal Treatment Outperforms Bull Heading

60. 60319 - A New Approach for Predicting Frictional Pressure Losses of Non-Newtonian Fluids in Coiled Tubing

61. 60313 - Economic Fracturing of Bypassed Pay: A Direct Comparison of Conventional and Coiled Tubing Placement Techniques

62. 59534 - A Coiled Tubing-Deployed Slow-Rotating Jet Cleaning Tool Enhances Cleaning and Allows Jet Cutting of Tubulars

63. 59164 - Research and Development of Advanced Coiled Tubing

64. 59161 - Wired BHA Applications in Underbalanced Coiled Tubing Drilling

65. 59139 - Zonal Isolation in Stimulation Treatments and Gas/Water Shutoff Using Thermally Compensated Inflatable Packers and Plugs

66. 59131 - Improved Zonal Isolation Through the Use of Sealants Before Primary Cementing Operations

67. 59021 - TEST OF HYDRAULIC JET PUMP IN THE BALAM 91 WELL

68. 58782 - Application Of Inflatable Packers For Production Testing And Conformance Problems In Algeria

69. 58710 - An Experimental Study of Acid Placement in Variable Inclination Laterals

70. 57571 - Underbalanced Drilling With Coiled Tubing in Oman

71. 57570 - The Galileo Experience

72. 57459 - Coiled Tubing Ultrashort-Radius Horizontal Drilling in a Gas Storage Reservoir: A Case Study

73. 57447 - An Update On Use of Coiled Tubing for Completion and Recompletion Strings

74. 57435 - Enhancing Production in Multizone Wells Utilizing Fracturing Through Coiled Tubing

75. 57432 - Coiled Tubing Conveyed Fracture Treatments: Evolution, Methodology and Field Application

76. 57013 - Static Buckling of Rod and Pipe String in Oil and Gas Wells

77. 56940 - Coiled Tubing NDT Inspection: Implementation, Experience and Results

78. 56865 - An Overview of Air/Gas/Foam Drilling in Brazil

79. 56864 - Designing Under- and Near-Balanced Coiled-Tubing Drilling by Use of Computer Simulations

80. 56671 - Coiled Tubing Used as a Continuous Sucker-Rod System in Slim Holes: Successful Field Experience

81. 56533 - Acid Stimulation of Power Water Injectors and Saltwater Disposal Wells in a Carbonate Reservoir in Saudi Arabia: Laboratory Testing and Field Results

82. 56528 - An Experience in Acidizing Sandstone Reservoirs: A Scientific Approach

83. 56500 - Expandable Tubular Solutions

84. 56044 - Fundamental Equations for Dynamical Analysis of Rod and Pipe String in Oil and Gas Wells

85. 55682 - Effect of Coiled-Tubing Initial Configuration on Buckling Behavior in a Constant-Curvature Hole

86. 55681 - Improved Model for Collapse Pressure of Oval Coiled Tubing

87. 55624 - Development of a Coiled Tubing Diametral Growth Model

88. 55618 - Selective Production of Horizontal Openhole Completions Using ECP and Sliding Sleeve Technology

89. 55044 - Sand Jet Perforating Revisited

90. 55036 - Horizontal Underbalanced Drilling of Gas Wells with Coiled Tubing

91. 54738 - Acidizing Deep Open-Hole Horizontal Wells: A case History on Selective Stimulation and Coil Tubing Deployed Jetting System

92. 54596 - Gel-Cement Combination Squeezes For Gas Shutoff

93. 54509 - First Underbalanced Coiled-Tubing-Conveyed Perforating Operation Performed in an HP/HT Highly Deviated Well in East Venezuela

94. 54508 - The Reeled Monodiameter Well

95. 54504 - High Pressure Coiled Tubing Instrumental in Deep Water Well Work

96. 54502 - Application of C.T.D. Offshore, Indonesia Phase One Pilot Project

97. 54496 - Dynamically Overbalanced Coiled Tubing Drilling on the North Slope of Alaska

98. 54494 - Laying Large-Diameter Coiled Tubing Offshore in the Arabian Gulf: A Case History

99. 54492 - SLIMWELL CONCEPT - INNOVATIVE COILED TUBING COMPLETION TECHNOLOGY

100.54485 - Coiled Tubing String Longitudinal Properties

101.54484 - Results of Recent Inspections Performed on Coiled Tubing

102.54483 - Industry Guidelines for Underbalanced Coiled-Tubing Drilling of Critical Sour Wells

103.54482 - Full-Scale Coiled Tubing Fatigue Tests With Tubing Pressures to 15,000 psi

104.54481 - Development of Welding Procedure Specification for Girth Welds in Coiled Tubing

105.54480 - High-Pressure Coiled-Tubing-String Design

106.54478 - Coiled Tubing Failure Statistics Used to Develop Tubing Performance Indicators

107.54477 - Scale Removal From the Recesses of Side-Pocket Mandrels

108.54476 - Through-Tubing Inflatables: Isolation and Guidelines for Coiled-Tubing Applications

109.54475 - Utilizing 4 ½-in. Monobores and Rigless Completions to Develop Marginal Reserves

110.54473 - A Unique Solution to Zonal Isolation Utilizing Foam-Cement and Coiled-Tubing Technologies

111.54472 - Coiled Tubing Milling and Temporary Plug and Abandonment Operations

112.54469 - The ALL Electric BHA: Recent Developments toward an Intelligent Coiled - Tubing Drilling System

113.54467 - New Downhole Gas Separator Enhances Coiled Tubing Jetting and Stimulation Procedures

114.54462 - ICoTA's CT Drilling Training and Competence Guidelines - How to use them.

115.54461 - The Varying Modulus of Elasticity for Coiled Tubing Material

116.54341 - Plug-and-Abandonment Technique for Geothermal Wells Reduces Operators' Costs

117.54327 - Development of a Wireless Coiled Tubing Collar Locator

118.54326 - Advanced Horizontal Well Production Logging - An Australian Offshore Example

119.53345 - Scale Removal in Khuff Gas Wells

120.53320 - Design, Execution and Evaluation of a Novel Coiled Tubing Acid Stimulation Operation - A Case History

121.53244 - Cementing Through High Pressure Coiled Tubing on HPHT Khuff Gas Well Offshore Abu Dhabi

122.52840 - The Buckling Behavior of Pipes and Its Influence on the Axial Force Transfer in Directional Wells

123.52791 - Electric Coiled Tubing Drilling: A Smarter CT Drilling System

124.52189 - Effect of Drill Pipe/Coiled Tubing Initial Configuration on Contact Force

125.52121 - Coiled Tubing Hangoffs: A Simple, Yet Effective Tool for the Future

126.51792 - Coiled-Tubing Drilling In Perspective

127.51287 - Understanding Factors Affecting Coiled-Tubing Engineering Limits

128.51095 - Environment and Coiled Tubing: Both Can Be Protected

129.51092 - Prediction of Contact Force for Drill Pipe/Coiled Tubing

130.51083 - Prediction of Frictional Drag and Transmission of Slack-off Force in Horizontal Wells Using Neural Networks

131.51066 - Liquid Carbon Dioxide Fracturing for Increasing Gas Storage Deliverability

132.51054 - Novel Application of Nondamaging Polymer Plugs with Coiled Tubing Improves Efficiency of Temporary Well Isolation Projects

133.50968 - World's First 4.5-in. Coiled-Tubing Pipeline

134.50966 - Coiled-Tubing Deformation Mechanics: Diametral Growth and Elongation

135.50964 - The Use of Coiled Tubing During Matrix Acidizing of Carbonate Reservoirs Completed in Horizontal, Deviated, and Vertical Wells

136.50678 - Breakthrough Well Suspension Operations in West of Shetland Horizontal Wells

137.50655 - History of and Applications for a Coil-Tubing-Conveyed, Inflatable, Selective Injection Straddle Packer

138.50654 - Coiled-Tubing Technology: An Application of High-Pressure Jet Cleaning in a Deep, High-Temperature, Sour Marine Environment

139.50619 - Water Shut-Off: Simulation and Laboratory Evaluation

140.50613 - Development and Trends in Hydraulic Fracture Stimulation of German Rotliegend Gas Wells

141.50591 - A Static Slickline-Retrievable Wellhead Plug System for Use with Horizontal Trees in Offshore Systems

142.50578 - Slim-Hole Sidetrack Cuts Costs by 50%

143.50178 - Application of New Generation Technology to Horizontal Well Production Logging - Examples from the North West Shelf of Australia

144.49196 - The Application of Novel Wax Divertor Technology to Allow Successful Scale Inhibitor Squeeze Treatment into a Sub Sea Horizontal Well, North Sea Basin

145.49152 - Microbial Water Treatment: An Alternative Treatment to Manage Sulfate Reducing Bacteria SRB - Activity, Corrosion, Scale, Oxygen, and Oil Carry-Over at Wilmington Oil Field - Wilmington, CA

146.49103 - Fluid Placement Model for Stimulation of Horizontal or Variable Inclination Wells

147.49040 - Proppant Transport Characterization of Hydraulic Fracturing Fluids using a High Pressure Simulator Integrated with a Fiber Optic/LED Vision System

148.48941 - Drilling and Completing a High-Angle Well With Coiled Tubing Technology

149.48935 - Significant Production Enhancement of Extended Reach, Prolific Gas Lift Oil Wells -- Case History of Systematic Problem Resolution

150.48861 - Fluid Placement Model for Horizontal Well Stimulation

151.47847 - Slickline Power Unit on Coiled Tubing Provides Innovative Solution for Setting a Nippleless Lock in a Multilateral Completion

152.47845 - Case History - Hydraulic Rig Assist Utilized in Workover Program in Dayung Gas Field, Indonesia

153.47840 - Turbo Drilling Through Coiled Tubing Using Foam In Sub-hydrostatic Well : A Case History For Jotana Field In Cambay Basin, India

154.47791 - Optimization of Drilling Parameters with the Performance of Multilobe Positive Displacement Motor PDM -

155.46252 - Coiled Tubing Fatigue Damage on Floating Vessels

156.46053 - Applications Update - Advanced Composite Coiled Tubing

157.46052 - High Strength Coiled Tubing

158.46046 - Coiled Tubing Drilling on the North Cormorant Platform

159.46042 - Planning For Underbalanced Drilling With Coiled Tubing? The feasibility study and computer modeling.

160.46040 - The Benefits of Real-Time Coiled Tubing Diameter Measurements

161.46039 - Corrosion Issues with Underbalanced Drilling In H2S Reservoirs

162.46038 - Remote Coiled Tubing Operation Monitoring

163.46037 - Coiled Tubing as an Alternative to Service-Rig Completions for Multifractured Horizontal Wells in the Westerorse Gas Fields in Alberta

164.46036 - Development of an Internal Coiled Tubing Connector Utilizing Permanent Packer Technology

165.46034 - Effective Management of Coiled Tubing Workstrings

166.46032 - Job Tracking Using Local Friction Profile to Minimize Risk in CT Operations

167.46030 - Coiled Tubing Velocity Strings - Expanding the Cases

168.46026 - An Abrasive Jetting Scale Removal System

169.46023 - Results From NDE Inspections of Coiled Tubing

170.46016 - Development Update of an MWD Directional Drilling Package for 2-3/4" Open-hole: Tiny Tools

171.46014 - Estimation of QT-800 Fatigue Lifetime through the Use of Magnetics

172.46013 - Electric Coiled Tubing Drilling - The First Steps Toward a Smart CT Drilling System

173.46009 - Effect of Coiled Tubing Initial Configuration on Buckling Behavior in a Hole of Constant Curvature

174.46004 - Collapse Data Analysis and Coiled Tubing Limits

175.46003 - An Improved Model for Collapse Pressure of Oval Coiled Tubing

176.40031 - Composite Coiled Tubing in Harsh Completion/Workover Environments

177.39795 - Drill Pipe/Coiled Tubing Buckling Analysis in a Hole of Constant Curvature

178.39784 - Cost Effective Method for Improving Permeability in Damaged Wells

179.39699 - Optimization of Borate-Based Gels Used for Wellbore Diversion During Well

180.39636 - Effect of Relative-Permeability Modifier Treatments in a Sandstone-Layered System and

181.39597 - Sand Jet Perforating Revisited

182.39487 - Water Quality Requirements and Restoring the Injectivity of Waste Water Disposal Wells

183.39422 - Field Validation of a Foam Diversion Model: A Matrix Stimulation Case Study

184.39419 - A Systematic Study of Iron Control Chemicals Used During Well Stimulation

185.39418 - Stimulation of Tight Carbonate Reservoirs Using Acid-in-Diesel Emulsions: Field Application

186.39374 - Hybrid Coiled Tubing System for Offshore Re-entry Drilling and Workover

187.39358 - Through Tubing Infill Drilling as a Method for Increased Oil Recovery on the Gullfaks Field

188.39353 - Multi-Lateral Well Construction: A Multi-Benefit Drilling Technology

189.39352 - An Analysis of Failures in Coiled Tubing

190.39348 - Selective Isolation of Perforated Liners Using Casing Patches: Case Studies from North Sea Operations

191.39346 - Development of a novel Silicone Rubber/Cement Plugging Agent for Cost Effective Through Tubing Well Abandonment

192.39305 - The First Coiled Tubing Sidetrack in Norway, Gullfaks Field

193.39300 - Cuttings Transport Problems and Solutions in Coiled Tubing Drilling

194.39261 - Cementing Through Coiled Tubing Decreases Well Completion And Testing Costs

195.39260 - One Year Experience With Coiled Tubing Drilling

196. 39226 - Slimhole Lateral Well Drilling Across Faults from 4-1/2" Cased Producers in the Denver-Julesburg Basin, Colorado

197.39208 - Deliverability Enhancement and Well Testing of Two Gas Storage Fields in Mt. Simon

198.39026 - Analytical Study of the Performance of Positive Displacement Motor PDM - : Modeling for Incompressible Fluid

199.38836 - Coiled Tubing Resin Squeeze to Mitigate Water Production in Offshore Gravel-pack Wells

200.38833 - Successful Water Shutoff in a High-Temperature, High-Volume Producer - A Case History from the Ula Field, Offshore Norway

201.38832 - Novel Approaches to Profile Modification in Horizontal Slotted Liners at Prudhoe Bay, Alaska

202.38791 - Measurement and Interpretation of Fluid Levels Obtained by Venting Casing Gas

203.38770 - Design and Implementation of a 22,600 ft Underbalanced Coiled Tubing Scale Cleanout in the Gomez Field, Pecos County, Texas

204.38757 - The Application of New Wireline Well Tractor Technology to Horizontal Well Logging and Intervention: A review of Field Experience in the North Sea

205.38624 - Electrodrilling: Past Experience and Present Opportunities

206.38618 - A Comparative Study of Borate-Crosslinked Gel Rheology Using Laboratory and Field Scale Fracturing Simulations

207.38613 - Development and Case Histories of an MWD Directional Drilling Package for 2-3/4" Openhole

208.38558 - Using 4000 ft Long Induced Fractures to Water Flood the Dan Field

209.38549 - Spinners Run While Perforating

210.38536 - Deployment of a Coiled Tubing Gas Lift Completion and Subsequent Recovery of Reserves From a Marginal BP Forties Well

211.38523 - Deepwater Remotely Actuated Completions for the 21st Century

212.38479 - Brent Well Completion and Intervention Developments towards 2000

213.38428 - Casing Exit Techniques Using Coiled Tubing: Worldwide Case Histories

214.38427 - An Advanced Coiled Tubing Control System

215.38426 - A Case Study of Downhole Obstruction Avoidance for CT-Conveyed TCP Operations

216.38425 - Positive Displacement Motor Test with Two-phase Flow

217.38424 - Development & Application of Inline Connectors for Weight Restricted Offshore Operations

218.38423 - Utilizing Coiled Tubing in Mobile Bay's 22,000 TVD Gas Wells Yields Economical and Technical Advancements

219.38422 - Accuracy and Reliability of Coiled Tubing Depth Measurement

220.38421 - Effects of Coiled Tubing Shear History on the Rheological and Hydraulic Properties of Fracturing Fluids

221.38420 - Coiled Tubing Injection-Well Cleanouts with Tapered-OD Strings

222.38419 - High Pressure Coiled Tubing Job Prepares Gulf Coast Well

223.38418 - An Operational Overview of the Use of High Pressure Coiled Tubing in the Gulf of Mexico

224.38417 - Using Coiled Tubing to Remove Silicate Scale from Geothermal Wells

225.38416 - Titanium as an Alternative to Conventional Coiled Tubing: A North Sea Case Study

226.38415 - Full-Scale, Low-Cycle Fatigue Tests with 2-in. Coiled Tubing and an Automatic Coiled Tubing Inspection and Monitoring System

227.38414 - Update on Advance Composite Spoolable Pipe Developments

228.38412 - Determining the Mechanical Properties of Coiled Tubing

229.38411 - Surface Characteristics of Coiled Tubing and Effects on Fatigue Behavior

230.38410 - Serviceability of Coiled Tubing for Sour Oil and Gas Wells

231.38409 - Development and Use of an Analytical Model to Predict Coiled Tubing Diameter Growth

232.38408 - Elongation of Coiled Tubing During its Life

233.38407 - Large Coiled Tubing Fatigue Life

234.38406 - Coiled Tubing Deployed ESPs Utilizing Internally Installed Power Cable - A Project Update

235.38404 - Field Installed Coiled Tubing Gas Lift Completions

236.38403 - Advances in Sliding Sleeve Technology and Coiled Tubing Performance Enhance Multizone Completion of Abnormally Pressured Gulf of Mexico Horizontal Well

237.38401 - Advancements in SPOOLABLE™ Completions to Accommodate Wireline Operations

238.38400 - Coiled Tubing Operations From a Floating Vessel

239.38399 - Coiled Tubing Horizontal Underbalanced Drilling Project; Costs and Operational Analyses

240.38397 - Application of Coiled Tubing Drilling Technology on a Deep Underpressured Gas Reservoir

241.38396 - Coiled Tubing Applications in the Sultanate of Oman

242.38395 - Coiled Tubing Drilling Case History, Offshore The Netherlands

243.38199 - Gel Plugs for Temporary Isolation in Horizontal Wells Completed with Slotted Liners

244.38194 - A Novel Dual Injection System for Water Shut-Off Treatments

245.38183 - Andrew/Cyrus Horizontal Well Completions

246.38147 - Method for Deploying Tubing Conveyed Perforating Guns in Live Well Conditions

247.37832 - Environmental Excellence and Profitability in Asset-based Upstream Organizations

248.37769 - World's First 4.5" Coiled Tubing Pipeline

249. 37734 - An Effective Matrix Diversion Technique for Carbonate Formations

250. 37673 - Implementation of an Advanced Multi-Lateral System With Coiled Tubing Accessibility

251. 37656 - Extending the Reach of Coiled Tubing Drilling Thrusters, Equalizers and Tractors -

252. 37655 - Planning, execution and Review of Brent's First Coil Tubing Drilled Well

253. 37654 - A New, Integrated, Wireline-Steerable, Bottom Hole Assembly Brings Rotary Drilling-Like Capabilities to Coiled Tubing Drilling

254. 37645 - Amorphous Diffusion Bonding: New Technology Towards a Seamless Reeled Tubing System

255. 37635 - Introduction of Game-changing Drilling Technology

256. 37624 - Hydrate Plug Remediation: Options and Applications for Deep Water Drilling Operations

257. 37618 - Pushing the ERD Envelope at Wytch Farm

258. 37616 - New Well Architectures Increase Gas Recovery and Reduce Drilling Costs

259. 37601 - Pro-Star 2000: Investing in State-of-the-Art Drilling Technology in Order to Reduce the Overall Well Cost Without Compromising on Quality and HSE Issues

260. 37534 - Thermal Performance of Insulated Concentric Coiled Tubing ICCT - for Continuous Steam Injection in Heavy Oil Production

261. 37508 - Real-time Well-site Monitoring and Evaluation of Coiled Tubing Cleanouts

262. 37483 - Design and Testing of a High-Performance Inflatable Packer

263. 37470 - The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO2 WAG Horizontal Injection Wells

264. 37466 - A SUCCESSFUL WATER SHUT OFF. A CASE STUDY FROM THE STATFJORD FIELD

265.37408 - A New Approach for Accurate Prediction of Loading in Gas Wells Under Different Flowing Conditions

266. 37357 - Nonelastomeric Sliding Sleeve Maintains Long Term Integrity in HP/HT Application: Case Histories

267. 37328 - Experimental Investigation of Frictional Pressure Losses in Coiled Tubing

268. 37127 - Characterizing Horizontal Well Performance in a Tight Gas Sand Using Pressure Transient, Production Logging and Geological Data

269. 37119 - Correction Routines for Production Logs in High Productivity Wells with Open Hole Completions and Screens

270. 37110 - Slotted-Liner Completions Used in the First Horizontal Wells in Mexico

271. 37093 - The Selective Evaluation and Stimulation of Horizontal Wells Using Concentric Coiled Tubing

272. 37076 - A Simplified Well Control Model for Horizontal Slimholes and Coiled Tubing Drilling

273. 37075 - Horizontal Underbalanced Drilling in a Sour Gas Carbonate Using Coiled Tubing: A Case Study

274. 37074 - High Penetration Rate Drilling with Coiled Tubing

275. 37062 - Underbalanced-Directional Drilling with Coiled Tubing - Challenges and Solutions

276. 37056 - An Improved Analysis of Axial Force Along Coiled Tubing in Inclined/Horizontal Wellbores

277. 37054 - An Approach for the Selection and Design of Slim Downhole Motors for Coiled Tubing Drilling

278. 37053 - Large Diameter Coiled Tubing Drilling

279. 36995 - Electronically Enhanced Remote Actuation Systems Improve Deepwater Completions Capabilities, Economics

280. 36965 - Wandoo Field Horizontal Completions - Phased Development of a Shallow, Highly Permeable Reservoir, with a Thin Oil Column

281. 36963 - Production Optimizing With Coiled Tubing and Other Rigless Techniques

282. 36947 - Gravel Packed Wells in the Statfjord Field: Completion, Workover and Production History

283. 36942 - Coiled Pipeline Technology: A Gulf of Suez Case History

284. 36909 - Well Plugging Operations in West of Shetland Horizontal Wells Using Coiled Tubing Techniques

285. 36908 - Repair of a Failed Gas Lift Completion Using a 1500 Ft. Long 3 1/2 in. Coiled Tubing Insert Straddle

286. 36753 - Horizontal Well IPR Calculations

287. 36582 - Intelligent Completion for Oil and Gas Production Control in Subsea Multi-lateral Well Applications

288. 36473 - Novel Fracture Technology Proves Marginal Viking Prospect Economic, Part II: Well Clean-Up, Flowback and Testing

289. 36464 - The Effect of Fluid Flow on Coiled Tubing Reach

290.36463 - Shallow Gas Well Drilling with Coiled Tubing in the San Juan Basin

291. 36461 - Hydraulic Fracturing for Control of Sand Production and Asphaltene Deposition in Deep Hot Wells

292. 36433 - Acoustic Telemetry: The New MWD System

293. 36138 - Well Completions in the Middle East Using 3 1/2-inch OD Coiled Tubing: Case Study Evaluation

294. 36137 - Coiled Tubing Conveyed Perforating

295. 36111 - Design, Execution and Evaluation of Matrix Acid Stimulation Jobs using Chemical Diversion and Bullheading

296. 36002 - The Architecture of a Plug-and-Play Kernel for Oilfield Software Applications

297. 36001 - The Migration of CADE Software for Oilfield Application to Laptop Computers

298. 35966 - The Challenge of Performing Safer Coiled Tubing Operations

299. 35712 - Optimal Configurations of Multiple-Lateral Horizontal Wells

300. 35669 - Horizontal Well Production Optimization Using Production Logs Run on Coiled Tubing in the 26R Sand Reservoir, Stevens Zone, Elk Hills Field, California

301. 35665 - Designing Under and Near Balanced Coiled Tubing Drilling Using Computer Simulations

302. 35613 - Rigless Multi-zone Recompletion Using a Cement Packer Placed with Coiled Tubing: A Case History

303. 35590 - Lessons Learned on Coiled Tubing Completions

304. 35587 - Recent Applications of Coiled Tubing in Remedial Wellwork at Prudhoe Bay

305. 35586 - Case History of Successful Coiled Tubing Conveyed Jet Pump Recompletions Through Existing Completions

306. 35566 - The Economics of Coiled Tubing Deployed ESP Completions in the North Sea. A Field Life Cycle Perspective

307. 35561 - Development of HP-HT Coiled Tubing Unit

308. 35550 - Perforation Optimisation of a Layered Reservoir

309. 35546 - Coiled Tubing Drilling of Horizontal Re-entry Wells, UK Land

310. 35544 - Underbalanced Coiled Tubing Drilling Experience on the Ula Field

311. 35537 - Risked Production Forecast for Horizontal Well Development at Albuskjell

312. 35130 - Newly Applied BHA Elements Contribute Towards Mainstreaming of Coiled tubing Drilling Applications

313. 35128 - Coiled Tubing Drilling Practices at Prudhoe Bay

314. 35127 - Coiled Tubing Drilling of Horizontal Sidetrack in House Mountain Field, Alberta

315. 35126 - Coiled Tubing Window Milling

316. 35079 - Troll West Oil Province - Subsea Horizontal Completion Experience

317.35069 - Approach to Underbalanced Well Operations in Petroleum Development Oman

318. 35047 - The RamRig Concept For Drilling and Workover Rigs

319. 35043 - Slim Hole Drilling and Well Intervention from a Light Vessel

320. 30792 - An Algorithm to Predict Pressure and Temperature Profiles Through a Coiled Tubing

321. 30716 - Optimizing Recovery From A Strong Water-Drive West Texas Gas Reservoir Through Integrated Reservoir Simulation Studies

322. 30681 - Coiled Tubing Stimulations Eliminate Hole Failures & Condensate Losses In Arun Field

323. 30679 - Development of a Coiled Tubing Cable Installation System

324. 30649 - The Management and Optimization of a Major Wellwork Program at Prudhoe Bay

325. 30648 - UNDERBALANCED COMPLETIONS

326. 30521 - Interactions between Torque and Helical Buckling in Drilling

327. 30490 - Technical and Economical Feasibility of Coiled Tubing Drilling

328. 30486 - Sidetracking Technology for Coiled Tubing Drilling

329. 30453 - Casing Window Milling With Abrasive Fluid Jet

330. 30440 - The Forties Field - 20 Years Young

331. 30427 - Coiled Tubing Stimulation Treatment in an Offshore Injection Well: A Case History

332. 30426 - Water Shut Off in the North Sea: Testing a New Polymer Gel System in the Heather Field, UKCS Block 2/5

333. 30424 - Subsea Well Intervention from a Monohull Vessel

334. 30421 - Downhole Swab Valve Aids in Underbalanced Completion of North Sea Well

335. 30417 - Well Completion Design and Operations for a Deep Horizontal Well with Multiple Fractures

336. 30408 - Snubbing Units: A Viable Alternative to Conventional Drilling Rig and Coiled Tubing Technology

337. 30405 - Reduction of Cost with New Well Intervention Technology, Well Tractors

338. 30404 - Coiled Tubing Extended Reach Technology

339. 30397 - The Emerald Field Operating Experience

340. 30372 - Preparing for Decommissioning of the Heather Field

341. 30199 - CriTi-CAL: A Computer Program for Critical Coiled Tubing Calculations

342. 30197 - Modeling Coiled Tubing Velocity Strings For Gas Wells

343. 30154 - HORIZONTAL WELLS - ARE THEY WORTH THE COST?

344. 30143 - Brief: J-Block Template Drilling: Innovation and Teamwork Break World Records

345.30123 - Utilization of Biologically Generated Acid for Drilling Fluid Damage Removal and Uniform Acid Placement Across Long Formation Intervals

346. 29981 - Zonal Isolation and Evaluation for Cemented Horizontal Liners

347. 29786 - REELED PIPELAY COST REDUCTION USING WORKBOAT-BASED INSTALLATION

348.29781 - Coiled Tubing Completions: An Economic Discussion of Procedures

349. 29736 - Environmental Impact of a Flocculant Used to Enhance Solids Transport During Well Bore Clean-Up Operations

350. 29707 - Impacts of Environmental Regulations on Future Resource Development in Louisiana Wetlands

351. 29679 - A Unique Method of Evaluating Stimulation Effectiveness in Production Damaged Slotted Liners

352. 29635 - Coiled Tubing Deployment of 3.5 " Tubing To Be Used As Offshore Gas Pipeline

353. 29629 - Project Design for Slimhole Steam Injectors in Thermal Recovery Projects as Compared to Conventional Steam Injectors

354. 29541 - Transient Aspects of Unloading Oil and Gas Wells With Coiled Tubing

355. 29496 - Slack-off Load Transmission in Horizontal and Inclined Wells

356. 29491 - Computer Simulator of Coiled Tubing Wellbore Cleanouts in Deviated Wells Recommends Optimum Pump Rate and Fluid Viscosity

357. 29475 - Water Shutoff Through Fullbore Placement of Polymer Gel in Faulted and in Hydraulically Fractured Producers of the Prudhoe Bay Field

358. 29474 - Shut-Off of a Geopressured Water Channel Behind Casing via Coiled Tubing Utilizing a Dual Slurry Cement System: A Case History

359. 29461 - Coiled Tubing Working Life Prediction

360. 29456 - An Evaluation of Large Diameter Coiled Tubing for Subsurface Production Tubulars

361.29409 - Use of a Novel Drill-In/Completion Fluid Based on Potassium Formate Brine on the First Open Hole Completion in the Gullfaks Field

362. 29363 - A Dynamic Model for Underbalanced Drilling With Coiled Tubing

363. 29361 - Re-Defining the Exploration Drilling Technique in the North Sea: The First Step

364. 29359 - Underbalanced Coiled Tubing Drilled Horizontal Well in the North Sea

365. 29358 - Steps Towards a Comprehensive Reeled Tube Drilling System

366. 29267 - Two New Design Tools Maximize Safety and Efficiency for Coiled Tubing Pumping Treatments

367. 29266 - THE USE OF COILED TUBING DURING MATRIX ACIDIZING OF CAR-BONATE RESERVOIRS

368. 29249 - Coiled Tubing Applications for Blowout Control Operations

369. 29188 - Coiled Tubing as Initial Production Tubing: An Overview of Case Histories

370.29185 - The Friction Measuring Tool: Real-Time Estimates of Sandface Pressure During Fracture Treatments

371. 29162 - Coiled Tubing Applications for Underground Gas Storage

372. 28866 - Further Advances in Coiled-Tubing Drilling

373. 28698 - Use of the Dual-Screen Thru-Tubing Sand Control Method

374.28559 - Experience With Completion and Workover of Horizontal and Extended Reach Wells in the Statfjord Field, North Sea

375. 28558 - THE USE OF COILED TUBING DURING THE WYTCH FARM EXTENDED REACH DRILLING PROJECT

376. 28519 - Hydrocarbon Blowdown From Vessels and Pipelines

377. 28502 - Successful Gas Shutoff With Polymer Gel Using Temperature Modeling and Selective Placement in the Prudhoe Bay Field

378. 28487 - Database Analysis of Thru-Tubing Inflatable Packer Systems

379. 28309 - CRITICAL PARAMETERS IN MODELLING THE CHEMICAL ASPECTS OF BOREHOLE STABILITY IN SHALES AND IN DESIGNING IMPROVED WATER-BASED SHALE DRILLING FLUIDS

380. 28304 - Practical Pressure Loss Predictions in Realistic Annular Geometries

381. 28303 - Implementing Residual Bend in a Tubing Forces Model

382. 28300 - Hybrid Coiled Tubing/Snubbing Drilling and Completion System

383. 28286 - The Challenge for the Coiled-Tubing Industry

384. 28222 - Development of a Computer Wellbore Simulator for Coiled-Tubing Operations

385. 27990 - New and Expected Developments in Artificial Lift

386. 27922 - Air Foam Improves Efficiency of Completion and Workover Operations in Low Pressure Gas Wells

387. 27895 - An Operator's Perspective On Through-Tubing Recompletion Technology

388. 27892 - Coiled-Tubing Completion Procedure Reduces Cost and Time for Hydraulically Fractured Wells

389. 27879 - Coiled-Tubing Drilling in Kern County, California: A Case Study

390. 27864 - Cost-Effective Solutions to Well Plugging and Abandonment

391. 27851 - New Pressure Tool Development Yields Critical Bottomhole Data

392. 27809 - Horizontal Well Acidizing of a Carbonate Formation: A Case History of Lisburne Treatments, Prudhoe Bay, Alaska

393. 27737 - Improved Well Design Maximises Oil-Rim Profitability

394. 27603 - Experience of Coiled Tubing Operations at North Brae, in Deep, High Pressure Corrosive Wells

395. 27602 - Logging and Perforating Operations Utilizing Coiled Tubing in a 25,000-ft MD, High-Angle Well

396. 27598 - Integration of Production Log and Oxygen Activation Techniques For Diagnosing Water Production Problems

397. 27595 - Jet Pump Testing in Italian Heavy Oils

398. 27503 - Recent Advances in Subsea Completion Workover Blowout Preventers

399. 27435 - Balanced Drilling With Coiled Tubing

400. 27434 - Coiled-Tubing Drilling: A Directional Service Company Point of View

401. 27432 - 3 1/2-in. Coiled Tubing: A First Run

402. 27297 - Design Verification and Inspection Maintenance Establish Greater Reliability and Safety

403. 27156 - Coiled Tubing Drilling: A Means To Minimize Environmental Impact

404. 26864 - Installation of 2 7/8-in. Coiled-Tubing Tailpipes in Live Gas Wells

405. 26781 - Permanent Downhole Gauges Used in Reservoir Management of Complex North Sea Oil Fields

406. 26736 - Optimising Shale Drilling in the Northern North Sea: Borehole Stability Considerations

407. 26735 - Optimisation of the Return Gas Distribution During Kicks in Oil- and Water-Based Muds: Results From Full-Scale Kick Experiment

408. 26718 - Continuous Semirigid Electric Line for Downhole Measurements in Highly Deviated Wells

409. 26716 - Results of Feasibility Study of Running Coiled Tubing to Depths of 30,000 ft in Deviated Wells

410. 26715 - Horizontal Drilling With Coiled Tubing: A Look at Potential Application to North Sea Mature Fields in Light of Experience Onshore The Netherlands

411. 26713 - A Joint Industry Research Project To Investigate Coiled-Tubing Buckling

412. 26596 - An Evaluation of Prudhoe Bay Horizontal and High-Angle Wells After 5 Years of Production

413. 26584 - Propellant Gas Fracture Stimulation of a Horizontal Austin Chalk Wellbore

414. 26573 - A Study of the Effects of Mixing Energy Imparted on Cement Slurries by Field Equipment and Coiled Tubing

415. 26571 - Acid-Resistant Microfine Squeeze Cement: From Conception to Viable Technology

416. 26565 - Single-Phase or Multiphase Blowdown of Vessels or Pipelines

417. 26540 - Low-Cost Alternative for Remedial Sand Control Application

418. 26539 - Development of a Standard Coiled-Tubing Fatigue Test

419. 26538 - A Spoolable Coiled-Tubing Gas-Lift Completion System

420. 26536 - Development of Composite Coiled Tubing for Oilfield Services

421. 26520 - Quantitative Three-Phase Profiling and Flow Regime Characterization in a Horizontal Well

422. 26512 - Development of Coiled-Tubing-Conveyed Thru-Tubing Inflatable Selective Stimulation Tool

423. 26511 - Analysis of Slack-Off Force Transmitted Downhole in Coiled-Tubing Operations

424. 26348 - Coiled-Tubing Radials Placed by Water-Jet Drilling: Field Results, Theory, and Practice

425. 26336 - Drilling and Completing Horizontal Wells With Coiled Tubing

426. 26335 - Coiled-Tubing Sidetrack: Slaughter Field Case History

427. 26090 - Planning a Coiled-Tubing-Conveyed Production Logging Job in a Horizontal Well

428. 26089 - Cement Slurry Qualification, Field Mixing, and Quality Assurance Procedures for Coiled-Tubing Squeeze Operations in Prudhoe Bay, Alaska

429. 26087 - Use of Coiled Tubing for Abandoning Shallow Thermal Wells, South Belridge Field, Kern County, California

430. 26086 - Emerging Coiled-Tubing Applications at Prudhoe Bay, Alaska

431. 26030 - Waste Minimizing Processing Technique for Solids Laden Biopolymer Gels

432. 25767 - A Clarified Xanthan Drill-in Fluid for Prudhoe Bay Horizontal Wells

433. 25723 - Strategic Background and Economic Analysis in the Development of a Project for Coiled Tubing Drilling

434. 25691 - Fully Retrievable, Slimhole Gamma Ray MWD System Minimizes the Risk of Horizontal Drilling

435. 25593 - Application of Short-Radius Horizontal Hole Drilling

436. 25571 - An Alternative Method of Installing ESP's

437. 25565 - Prediction and Evaluation of Horizontal Well Performance

438. 25499 - Fishing With Coiled Tubing

439. 25496 - Laying Sand Plugs With Coiled Tubing

440. 25412 - Field Evaluation of Acid Simulation Diverter Materials and Placement Methods in Arab-D Injection Wells With Openhole Completions

441. 25386 - Overview of Acid Stimulation Practices in Malaysian Oil Fields

442. 25370 - Helical Buckling and Lock-Up Conditions for Coiled Tubing in Curved Wells

443. 25369 - High-Strength Coiled Tubing Assists High-Pressure Well Servicing in the Gulf of Mexico

444. 25147 - Effect of Mixing Energy Levels During Batch Mixing of Cement Slurries

445. 25141 - Scale Control in the South Brae Field

446. 25085 - A Simple New Tool for Solving Some Complex Production Problems

447. 25083 - Stimulation and Production Logging of Horizontal Wells AGIP Bouri Field, Offshore Libya

448. 24993 - An Effective Matrix Stimulation Technique for Horizontal Wells

449. 24988 - Collapse Pressure of Oval Coiled Tubing

450. 24986 - Through-Tubing Remedial Treatments Using a Novel Epoxy Resin System

451. 24975 - Borehole Stability in Shales

452. 24794 - A Coiled-Tubing-Deployed Downhole Video System

453. 24793 - Coiled Tubing in High-Pressure Wells

454. 24792 - Design and Installation of a 20,500-ft Coiled Tubing Velocity String in the Gomez Field, Pecos County, Texas

455. 24765 - Validation of Coiled-Tubing Penetration Predictions in Horizontal Wells

456. 24621 - Safe Deployment of Specialized Coiled-Tubing Tools in Live Wells

457. 24594 - Coiled-Tubing Drilling

458. 24580 - Analysis of Gas-Rise Velocities From Full-Scale Kick Experiments

459. 24497 - Logging and Stimulating Horizontal Wells Offshore Abu Dhabi

460. 24052 - New Coiled-Tubing Cementing Techniques at Prudhoe Developed To Withstand Higher Differential Pressure

461. 23951 - New Horizontal Drilling Techniques Using Coiled Tubing

462. 23876 - First Field Trial of a Coiled Tubing for Exploration Drilling

463. 23875 - Horizontal Slim-Hole Drilling With Coiled Tubing: An Operator's Experience

464. 23806 - A Case Study for the Matrix Stimulation of a Horizontal Well

465. 23749 - Use of Reeled Tubing in Gas Lift Completion Systems

466. 23639 - Slim Hole Multiple Radials Drilled with Coiled Tubing

467. 23541 - Horizontal Well Evaluation in a Giant Oil-Rim in Unconsolidated Sand

468. 23266 - Safe Coiled-Tubing Operations

469. 23144 - Offshore Coiled-Tubing Cement Squeezes, Forties Field

470. 23131 - Coiled-Tubing Pressure and Tension Limits

471. 23110 - A Platform Abandonment Program in the North Sea Using Coiled Tubing

472. 23106 - Coil-Tubing Milling/Underreaming of Barium Sulphate Scale and Scale Control in the Forties Field

473. 22961 - Workover Techniques in Bass Strait

474. 22959 - The Role of Coiled Tubing in the Western Operating Area of the Prudhoe Bay Unit

475. 22825 - Thru-Tubing Inflatable Workover Systems

476. 22823 - A New Technique for Servicing Horizontal Wells

477. 22822 - The Development and Use of a Coiled-Tubing Simulation for Horizontal Applications

478. 22821 - Recompletions Using Large-Diameter Coiled Tubing: Prudhoe Bay Case History and Discussion

479. 22820 - Coiled-Tubing-Life Modeling

480. 22404 - Production Logging in a Rod-Pumped Well Using Coiled-Tubing-Conveyed Tools and Nitrogen Gas Lift

481. 22316 - An Integrated Three-Dimensional Wellstring Analysis Program

482. 22283 - The Use of Low-Density Particles for Gravel Packing a Highly Deviated Well

483. 22227 - Monitoring Coiled Tubing Life During Service

484. 22068 - Thixotropic, Crosslinking Polymer/Borate/Salt Plug: Development and Application

485. 22067 - Lost Circulation Material Usage in Coiled Tubing Remedial Cementing at Prudhoe Bay

486. 21991 - Re-Entry and Relief Well Drilling To Kill an Underground Blowout in a Subsea Well: A Case History of Well 2/4-14

487. 21978 - Installation of STAR Satellite Platform

488. 21795 - Horizontal Well Damage Characterization and Removal

489. 21727 - Methods of Detecting and Locating Tubing and Packer Leaks in the Western Operating Area of the Prudhoe Bay Field

490. 21702 - Performing Workover Drilling Operations Through Small-Diameter Restrictions

491. 21602 - Data Acquisition, Analysis, and Control While Drilling With Horizontal Water Jet Drilling Systems

492. 21332 - Mothballing and Demothballing of an Onshore Oil Field

493. 21314 - Logging on Coiled Tubing: A Proven Technique for Highly Deviated Wells and Other Applications

494. 21311 - Horizontal Drilling Success Offshore Abu Dhabi

495. 20993 - The Leman F and G Development: Obtaining Commercial Production Rates From a Tight Gas Reservoir

496. 20984 - The Use of Low-Density Particles for Packing a Highly Deviated Well

497. 20963 - Planning, Implementation, and Analysis of the First Troll Horizontal Well Test

498. 20959 - Cementing Through Coiled Tubing and Its Influence on Slurry Properties

499. 20956 - SPT: Tool for Improved Placement of Chemicals In a Live Well

500. 20906 - Thixotropic Cementing With Coiled Tubing at Prudhoe Bay

501. 20679 - Fishing With 1.5- and 1.75-in. Coiled Tubing at Western Prudhoe Bay, Alaska

502. 20534 - Practical Transient Multilayer Test Design, Implementation, and Analysis of Gas Wells in the North Sea Southern Basin

503. 20459 - Openhole Drilling Using coiled Tubing and a Positive Displacement Mud Motor

504. 20433 - Use of a Dynamic Two-Phase Pipe Flow simulator in Blowout Kill Planning

505. 20427 - Coiled Tubing Workovers in Deep, Hot Wells

506. 20426 - New Technologies Address the Problem Areas of Coiled-Tubing Cementing

507. 20420 - Relief-Well Planning and Drilling for a North Sea Underground Blowout

508. 20355 - CASE Technology Is Used in the Development of a General Completion Simulator

509. 20312 - EXACT SOLUTIONS FOR ECCENTRIC ANNULAR BOREHOLE FLOW WITH CUTTINGS BEDS AND GENERAL WALL DEFORMATION

510. 20311 - ANALYTICAL SOLUTIONS FOR INCLINED ANNULAR BOREHOLE FLOW WITH DRILLSTRING ROTATION

511. 20024 - Artificial Lift With Coiled Tubing for Flow Testing the Monterey Formation, Offshore California

512. 19888 - Perforating the Horizontal Well

513. 19543 - Improved Coiled-Tubing Squeeze-Cementing Techniques at Prudhoe Bay

514. 19541 - HCl/HF Acid-Resistant Cement Blend: Model Study and Field Application

515. 19401 - Evolution of a Hybrid Fracture/Gravel-Pack Completion: Monopod Platform, Trading Bay Field, Cook Inlet, Alaska

516.19229 - SAFELY EXCEEDING THE "CRITICAL BUCKLING LOAD" IN HIGHLY DEVIATED HOLES

517. 18884 - Granular Diverting Agents Selection, Design, and Performance

518. 18350 - Coiled-Tubing-Conveyed Logging Systems

519. 18256 - Innovative Technology in Producing Operations

520. 17950 - Appraisal of Techniques Applied To Stimulate the Deep Khuff Gas Wells

521. 17592 - Coiled Tubing Non-Rig Workovers at Prudhoe Bay

522. 17581 - Coiled Tubing in Horizontal Wells

523. 17443 - Inflatable Packers: Production Application

524. 17296 - Novel Workover Treatment Proves Effective in Permian Basin: Laboratory and Field Results

525. 17165 - Geothermal Well Damage in the Paris Basin: A Review of Existing and Suggested Workover Inhibition Procedures

526. 17154 - Key Factors for Enhanced Results of Matrix Stimulation Treatments

527. 16565 - Logging Horizontal Wells: Field Practice for Various Techniques

528. 15489 - Coiled-Tubing Logging System

529. 15468 - Production Operations Forum

530. 15104 - Coiled Tubing Cement Squeeze Technique at Prudhoe Bay, Alaska

531. 14827 - Matrix Acidizing Design and Quality- Control Techniques Prove Successful in Main Pass Area Sandstone

532. 14804 - The Ultrashort-Radius Radial System

533. 13682 - Design and Techniques of Testing and Evaluation of Deep Khuff Wells

534. 13649 - Resin-Coated Sand Slurries for Repair of Damaged Liners

535. 12590 - Dewatering a Deep Gas Well With a Gas Lift System-A Case History

536. 12473 - Selective Gas Shut-Off Using Sodium Silicate in the Prudhoe Bay Field, AK

537. 12413 - A DEDICATED PRODUCTION SUPPORT VESSEL FOR OFFSHORE OPERATIONS

538. 12091 - 1982: A Precipitous Decline, The Service Company, Bidding and Integrity

539. 11723 - Volumetric Requirements for Foam and Mist Drilling Operations

540. 9423 - "Silicalock" - A Novel Sand-Control Process for Gas Wells

541. 4115 - Gas Well Stimulation Using Coiled Tubing and Acid with a Mutual Solvent

OTC PAPERS ABOUT COILED TUBING

1. OTC 7032 – “High-Strength Coiled Tubing Expands Service Capabilities,” Chitwood, G.B. et al., presented at the 24th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1992)

2. OTC 7033 – “Bonded Three-Layered Epoxy Coating to Continuous Steel Coiled Tubing,” Reuser, H.C., Plummer, R.A. and Lanan, G.A., presented at the 24th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1992)

3. OTC 7034 – “New Muscle for Coiled Tubing,” Kilgore, M.D., presented at the 24th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1992)

4. OTC 7035 – “Alternate Methods for Installing ESPs (Electrical Submersible Pumps),” Robinson, C.E. and Cox, D. C., presented at the 24th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1992)

5. OTC 7046 – “A Real-Time Fiber Optic Downhole Video System,” Cobb, C.C. and Schultz, P.K., presented at the 24th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1992)

6. OTC 7230 – “An Operator-Oriented Data Acquisition System for Coiled-Tubing Units,” Eriken, V.I. and Foster, J.C., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

7. OTC 7321 – “Rigless Completions: A Spoolable Coiled-Tubing Gas-Lift System,” Moore, B.K., Laflin, W.J., and Walker, E.J., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

8. OTC 7322 – “Coiled-Tubing-Deployed Electric Submersible Pumping System,” Lidisky, D.J. et al., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

9. OTC 7323 – “Buckling of Pipe and Tubing Constrained Inside Inclined Wells,” Yu-Che Chen, U. and Adnan, S., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

10. OTC 7324 – "Installation of 2-7/8- in. Coiled-Tubing in Live Gas Wells," Campbell, J.A. and Bayes, K., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

11. OTC 7325 – "Coiled Tubing Life Prediction," Avakov, V. A., Foster, J.C., and Smith, E.J., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

12. OTC 7330 – "Nippleless Completion System for Slimhole/Monobore Wells," Hopmann, M.E., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

13. OTC 7331 – "Rigless Slimhole Drilling," Courville, P.W. and Maddox, S.D., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

14. OTC 7354 – "Zone Isolation of Horizontal Wells by Coiled-Tubing-Actuated Tools," Robison, C.E., Mashaw, H.R., and Welch, W.R., presented at the 25th Annual SPE Offshore Technology Conference, Houston, TX, U.S.A. (May 1993)

MISCELLANEOUS REFERENCES ABOUT COILED TUBING

1. "Operation Pluto", Hartley, Arthur Clifford, Institution of Civil Engineers, *The Civil Engineer in War,* Vol. 3 (1948).

2. "Operation Pluto", Moore, Rufus J., U.S. Naval Institute Proceedings, June, 1954, pp. 647-653.

3. "Coiled tubing … operations and services, Part 1 – The evolution of coiled tubing equipment", Sas-Jaworsky II, A., *World Oil*, pp. 41-47 (November 1991).

4. "Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services", American Petroleum Institute, API RP 5C7, First Edition, 1996.

5. "Workover Well Control, Part 4: Coiled-Tubing Rigs Speed Workover Operations", Adams, N., *Oil and Gas Journal,* Volume 79, No. 37, September 14, 1981, pp. 87-92.

6. "Coiled tubing … operations and services, Part 3 – Tube technology and capabilities", Sas-Jaworsky II, A., *World Oil*, pp. 95-101 (January 1992).

7. "High Pressure Applications Enabled by CT Advances", Sas-Jaworsky II, A., *American Oil and Gas Reporter,* January, 1996.

8. "Plasticity and Fatigue Damage Modeling of Severely Loaded Tubing", Tipton, Steven M. and Newburn, Dale A., presented at The First Symposium on Advances in Fatigue Lifetime Predictive Techniques, American Society for Testing and Materials, San Francisco, CA, April 1990.

9. "Multiaxial Plasticity and Fatigue Life Prediction in Coiled Tubing", Tipton, Steven M., *Fatigue Lifetime Predictive Techniques: 3rd Volume*, ASTM STP 1292, M.R. Mitchell and R.W. Landgraf, Eds., American Society for Testing and Materials, Philadelphia, 1995.

10. "Collapse Tests Expand Coiled-Tubing Uses", Walker, E.J. and Mason C.M., *Oil and Gas Journal,* Volume 88, No. 10, March 5, 1990, pp. 56-60.

11. "More Collapse Tests Add to Coiled Tubing Applications", Walker, E.J. and Costall, D., *Oil and Gas Journal,* Volume 89, No. 24, June 17, 1991, pp. 43-46.

12. "How Loads Affect Coiled Tubing Life", Walker, E.J., *World Oil Magazine,* Vol. 213, No. 1, January 1992, pp. 47-49.

13. "Coiled tubing … operations and services, Part 4 – Sand and solids washing", Sas-Jaworsky II, A., *World Oil*, pp. 71-79 and 97 (March 1992).

14. "Coiled tubing … operations and services, Part 5 – Unloading wells with lighter fluids", Sas-Jaworsky II, A., *World Oil*, pp. 59-66 (April 1992).

15. "Coiled tubing … operations and services, Part 2 – Workover Safety", Sas-Jaworsky II, A., *World Oil*, pp. 71-72 and 77-78 (December 1991).

16. "Improved Coiled Tubing Squeeze Cementing Techniques at Prudhoe Bay", Hornbrook, P.R., and Mason, C.M., JPT (April 1991, pp. 455-459).

17. "Designing Slurries for Coiled Tubing Cement Squeezes", Pavlich, J.P., Greaves C., and Edwards, T.M., *World Oil Magazine*, Volume 213, No. 6, June 1992, pp. 61-65.

18. "Artificial Lift with Coiled Tubing for Flow Testing the Monterey Formation, Offshore California", Peavy, M.A. and Fahel, R.A. *SPE Production Engineering*, May 1991, pp. 142-146.

19. "Coiled tubing … operations and services, Part 12 – Stimulation", Sas-Jaworsky II, A., *World Oil*, pp. 39-43 (January 1992).

20. "Coiled Tubing … operations and services, Part 7 – Cementing", Walker , E.J., and Gantt, L. and Crow, C., *World Oil*, June 1992.

21. "Logging with a Coiled Tubing System", Latos, J.S. and Chenery, D., *Journal of Canadian Petroleum Technology*, March-April 1988.

22. "Horizontal Slim-Hole Drilling with Coiled Tubing: An Operator's Experience", Ramos, A.B., Fahel, R.A., Chaffin, M. and Pullis, K.H., Paper 23875, IADC/SPE Drilling Conference, New Orleans, Louisiana, February 1992.

23. "First Field Trial of a Coiled Tubing for Exploration Drilling', Traonmilln, E.M.; Courteille, J.M.; Bergerot, J.L.; Reysset, J.L. and Laffiche, J.M.Y., Paper 23876 IADC/SPE Drilling Conference, New Orleans, Louisiana, February 1992.

24. "Coiled Tubing Velocity String Set at Record 20,500 ft.", Adams, L.S., *Oil and Gas Journal* (OGJ), April 13, 1992.

D

NOMENCLATURE AND ABBREVIATIONS

NOMENCLATURE, ABBREVIATIONS, AND ACRONYMS

TABLE D.1

A	area
a	coefficient for hydraulic friction factor calculation
b	coefficient for hydraulic friction factor calculation
BHA	bottom hole assembly
BHCT	bottom hole circulating temperature
BHI	Baker Hughes INTEQ
BHP	bottom hole pressure
BHST	bottom hole static pressure
BHT	bottom hole temperature
B_n	normal force due to helical buckling
BOP	blowout preventer
CCL	casing collar locator
CCT	concentric coiled tubing
C_d	drag coefficient
Cf	coefficient of kinetic friction
C_n	normal force due to curvature
CTL	CT logging
CTTM	CT test machine
CTU	CT unit
CTWI	CT weight indicator reading
D	depth
DAS	data acquisition system
D_e	equivalent hydraulic diameter
DP	dynamically positioned
D_{reel}	CT reel core diameter
E	Young’s modulus (modulus of elasticity)
ECD	equivalent circulating density
ESP	electric submersible pump
F	force

TABLE D.1

f	term in API 5C7 collapse calculation
f_H	hydraulic friction factor
FTM	fatigue test machine
g	local acceleration due to gravity, term in API 5C7 collapse calculation
g_c	universal gravitational constant
h	height
H	liquid holdup
HAZ	heat affected zone
He	Hedstrom number
HPCT	high pressure coiled tubing
I	moment of inertia
ID	inside diameer
J	polar moment of inertia
JIP	joint industry project
K	consistency index
k	segment number
L	length
LSA	low specific activity
MD	measured depth
M_R	bending moment
MW	mud weight
n	flow behavior index, segment number
N_{Re}	Reynolds Number
OD	outside diameter
P	pressure, rigid tool contact force
Pe	stability collapse term
POOH	pull out of the hole
Py	yield collapse term
q	foam quality
R	bending radius, gas constant
r	radius
r_c	radial clearance

TABLE D.1

RIH	run into the hole
ROP	rate of penetration
SCBA	self contained breathing apparatus
SDW	set down weight
SSSV	subsurface safety valve
T	temperature, torque
t	wall thickness
TD	total depth, target depth
TEL	tubing end locator
TIG	tungsten inert gas
TKV	tubing kill valve
TNL	tubing nipple locator
TVD	true vertical depth
V	velocity
VME	von Mises equivalent
W	CT segment buoyed weight per unit length
WHP	wellhead pressure
WOB	weight on bit
Z	gas compressibility factor

GREEK SYMBOLS

TABLE D.2

ΔL	change in length, CT segment length
ΔP	differential pressure
Φ	porosity of a deposit of solid particles
Γ	axial stress correction factor
ε	strain
γ	shear rate
φ	ovality
λ	helix period
μ	viscosity, Poisson’s ratio
θ	angle of inclination from vertical
ρ	density
σ	stress
τ	shear stress

SUBSCRIPTS

TABLE D.3

a	axial
b	bottom
CH	critical helical
CS	critical sinusoidal
i	inside
n	normal
o	outside
s	surface
w	wall
Y	yield

INDEX

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z

-A-

-B-

-C-

-F-

-M-

-N-

-O-

-R-

-S-

-T-