Table of Contents

This manual has been prepared to complement the information provided through the presentations and discussions held during a Schlumberger Dowell Coiled Tubing Client School. The technical information within this manual is intended to provide a basic understanding of the equipment, tools, processes and design requirements associated with modern coiled tubing operations. Comprehensive and detailed information, such as that required to safely and successfully complete the design and execution of coiled tubing operations, may not be included. Consequently, it is recommended that the local Dowell representative be consulted during the feasibility or design preparation phase of any coiled tubing operation.

CTCSM Rev A – March 1995/November 1996

COILED TUBING AND PRESSURE CONTROL EQUIPMENT

Contents Page

INTRODUCTION

This manual section contains a brief description of the principal items of equipment required to perform basic coiled tubing (CT) operations. The major components of each item are identified and a short explanation of its function given.

A basic CT equipment package consists of the following items.

- Injector head
- Coiled tubing reel
- Power pack
- Control cabin
- Pressure control equipment

1.1 INJECTOR HEAD

The tractive components of the injector head are generally configured to drive two opposing, endless chains on which are mounted a series of short gripper blocks. The gripper blocks are shaped to the size of the tubing being used, and the chains are pressed together with the tubing held between. The total load of the CT in the well is held by the friction of these blocks on the tubing surface. Hydraulic motors drive the chains, thereby allowing the tubing to be run in or out of the wellbore.

Three makes of injector head may be encountered in Dowell CT operations: Hydra-Rig, Stewart and Stevenson, and Uniflex (found on earlier CT units, now supported by Rebound Rig International).

Most injector heads incorporate the same major components, although the method of operation and design may be slightly different (Fig. 1).

Major injector-head components include the following.

• Hydraulic motors

• Drive chains

• Chain tensioners

• Gooseneck or guide-arch

• Weight indicator

1.1.1 Hydraulic Motors

The hydraulic motors provide the traction required to move the tubing in or out of the well. By controlling the pressure and flow rate of the hydraulic fluid delivered to the motors, the speed and, more importantly, potential force exerted by the injector head can be controlled. Two motors, generally synchronized through a gearbox, are used to drive the injector head.

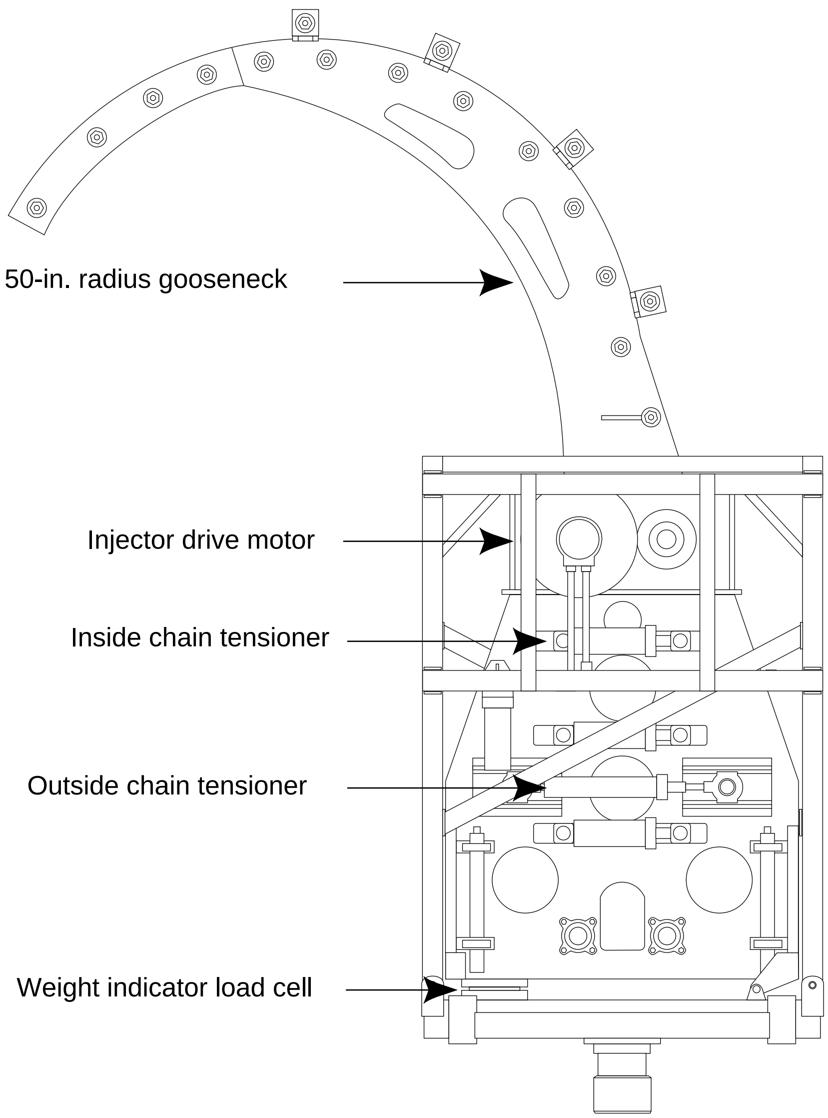

Figure 1. Hydra-Rig HR 240 injector head, side view.

1.1.2 Drive Chains

The chains consist of links, gripper blocks and roller bearings (conventional chain). Since the load of the tubing string is held by friction, the face material of the block and its condition are very important to the efficient operation of the injector head and the prevention of mechanical damage to the tubing (Fig 2).

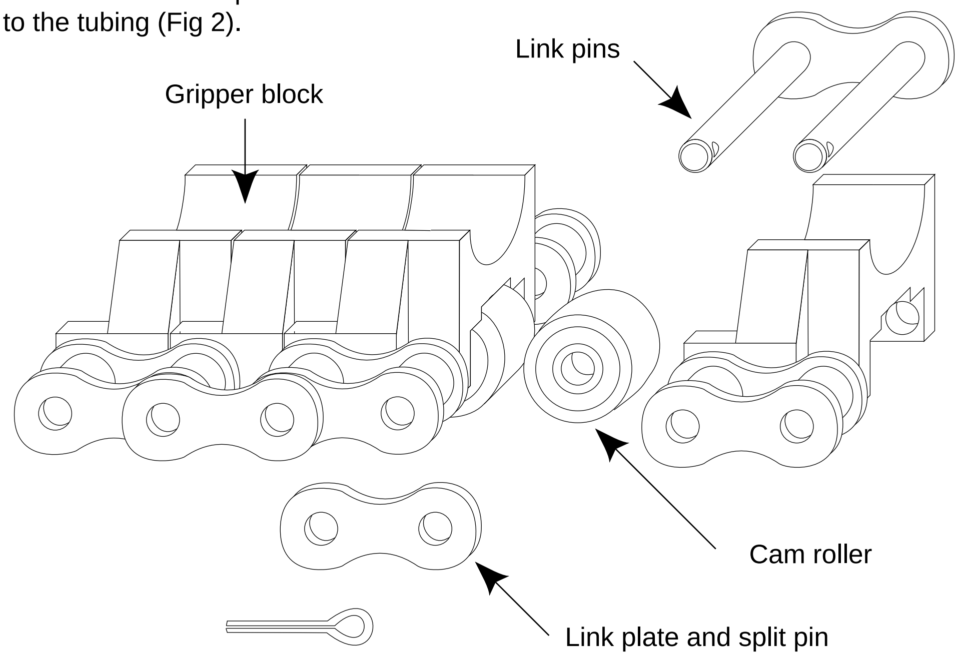

Figure 2. Injector-head chain components, Hydra-Rig "S" type chain.

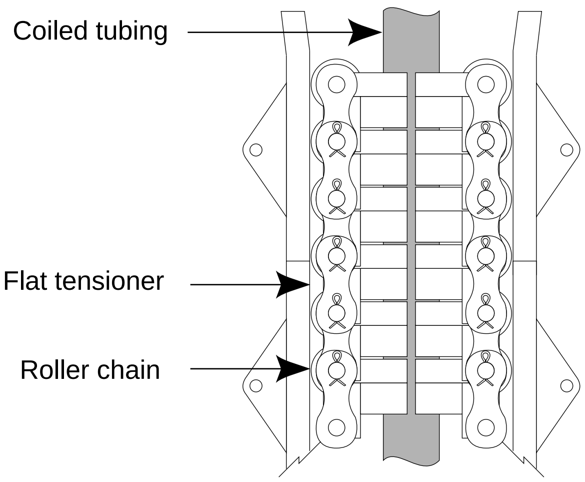

Figure 3. "S" type injector-head chain.

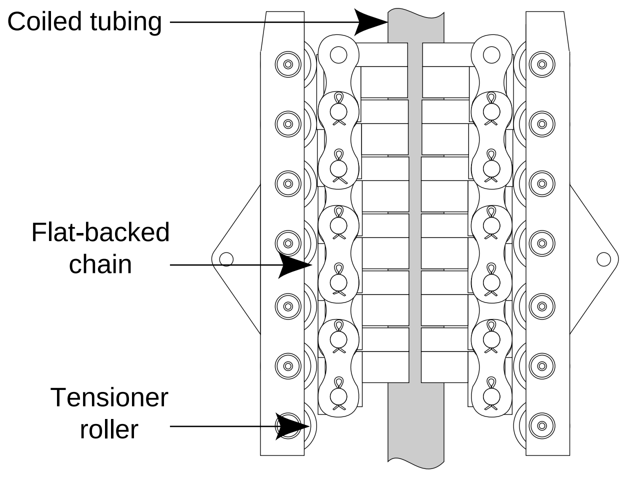

Figure 4. "R" type injector-head chain.

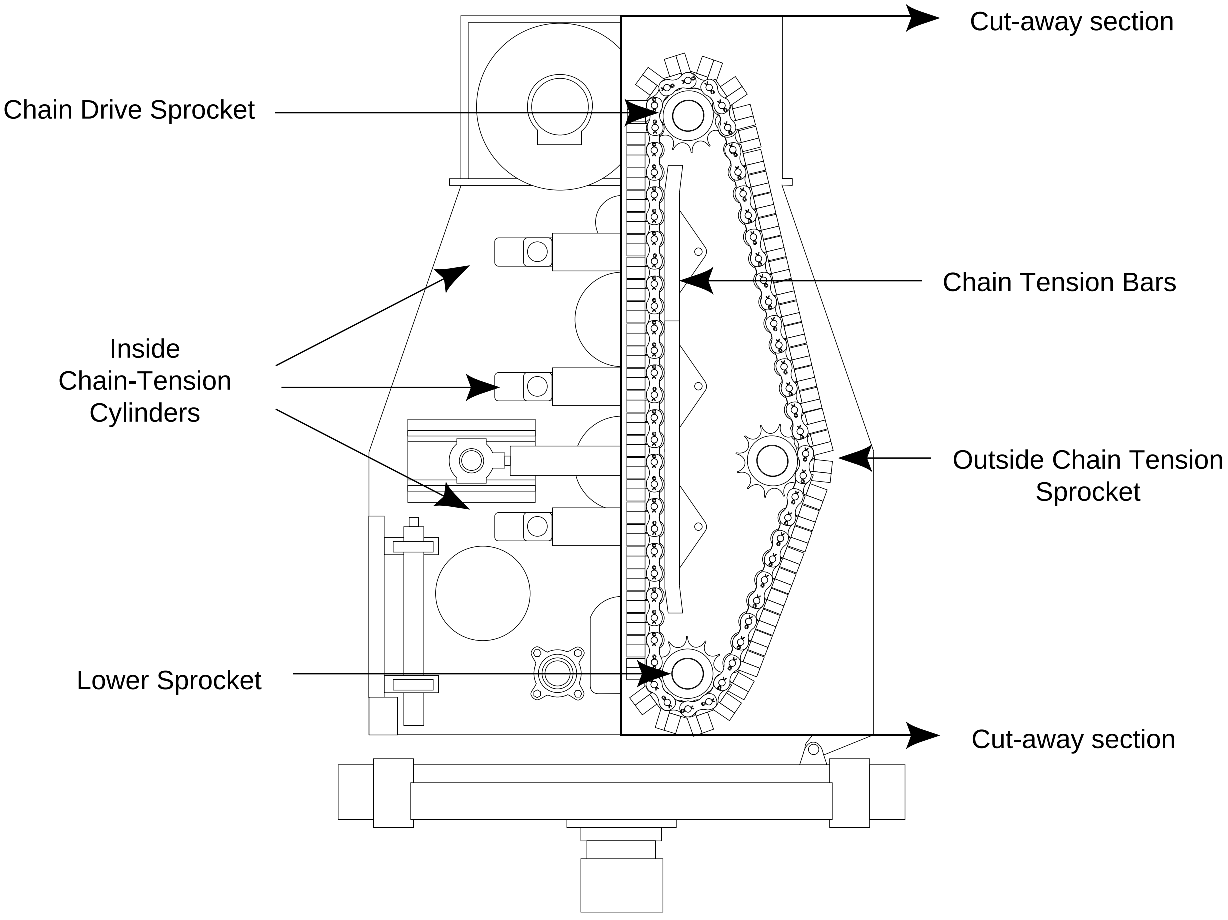

Figure 5. Inside and outside chain tensioner configuration ("S" system).

1.1.3 Chain Tensioners

As the tubing is run deeper into a well, the load on the injector chains increases, requiring an increased force to the gripper blocks to maintain efficient traction. This is achieved by using the applied hydraulic pressure in the inside chain tensioner system (Fig. 5).

Hydra-Rig offers a choice of chain and tensioner systems (Fig. 3 and 4). The traditional design of gripper block has integral rollers and solid bar skates (denoted as the "S" type), an alternative configuration has solid back gripper blocks and a roller system on the skate (denoted as the "R" type).

1.1.4 Gooseneck

The gooseneck, or guide arch, acts as a guide for the tubing, taking it through the angle as the tubing leaves the reel, to the vertical position as it enters the top of the injector-head chains. Profiled rollers support the tubing as it is bent over the gooseneck arc.

1.1.5 Weight Indicator

The weight indicator indicates the tension exerted on the tubing hanging from the injector head chains. The tensile load measured is a function of the weight of the tubing hanging in the well, and includes the effect of the wellhead pressure and buoyancy. The weight indicator will also let the operator see when the tubing tags or hangs up on an obstruction. Weight indicators may operate hydraulically, electronically or as a combination of both. A recording device must always be incorporated into the weight indicator system

1.2 COILED TUBING REEL

The CT reel is used to store and transport the tubing. All of the effort required to run, and retrieve the CT from the well is provided by the injector head. The tension between the reel and injector is necessary to ensure the smooth feeding of the injector and proper spooling onto the tubing reel. The major components of the CT reel include the following.

- Reel drum
- Reel drive system
- Levelwind assembly
- Reel swivel and manifold

1.2.1 Reel Drum

The capacity of any reel drum for a given size of tubing may be calculated using the procedure and formula given below. The results are approximate, and the formula assumes ideal spooling of the tubing.

L = (A + C) (A) (B) (K),

where
L = tubing capacity (ft),
A = tubing stack height (in.),
B = width between flanges (in.),
C = reel drum core diameter (in.), and
K = K value for different tubing sizes.

K Values for Different Tubing Sizes

Tubing OD (in.)	K Value
1	0.262
1-1/4	0.168
1-1/2	0.116
1-3/4	0.086
2	0.066
2-3/8	0.046
2-7/8	0.032
3-1/2	0.021

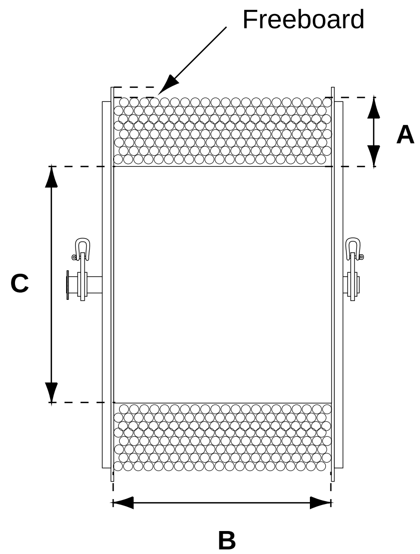

Figure 6. Reel drum capacity.

The freeboard is the amount of clearance between the OD of the reel flanges and the OD of the wrapped tubing at maximum capacity (L). The minimum recommended freeboard varies with the tubing size.

Minimum Recommended Freeboard

Tubing OD (in.)	Freeboard (in.)
1 and 1-1/4	1.5
1-1/2 and 1-3/4	2.0
2 and 2-3/8	3.0
2-7/8 and 3-1/2	4.0

Example of Calculating Reel Capacity

Tubing OD = 1.50 in.; therefore, the freeboard is 2.0 in.

A = 22 in. (24-in. drum rim height minus 2-in. freeboard)
B = 72 in.
C = 72 in.
K = 0.116

L = (22 + 72) (22) (72) (0.116)

L = 17,272 ft of 1.5-in. tubing.

1.2.2 Reel Drive System

The reel is driven by a hydraulic motor which incorporates a safety device to protect the reel and the hydraulic system should there be a mechanical failure or operator error. The motor drives the reel shaft via a drive chain and shaft sprocket. On some of the latest designs of reel, the motor and gearbox is mounted directly on the reel shaft. Backpressure on the reel motor is maintained throughout all operations to ensure that the tubing is kept at an appropriate tension between the reel and injector-head gooseneck. The braking system is engaged to secure the reel and prevent rotation during transportation or when the injector–head control valve is in the neutral position. The design and location of the brake vary between manufacturers and the reel models. The latest designs incorporate a hydraulically operated brake within the reel motor housing. Earlier models apply the braking force to the rim of the reel flange, and are hydraulically or pneumatically operated (Fig. 7).

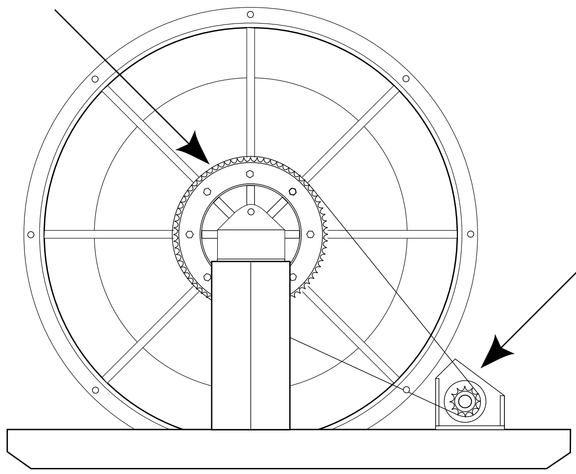

Figure 7. Typical Hydra-Rig reel drum configuration.

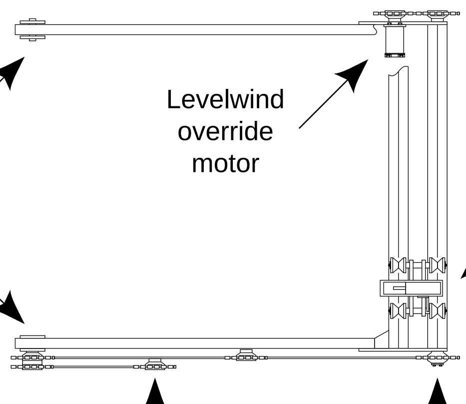

Figure 8. Hydra-Rig reel levelwind assembly.

1.2.3 Levelwind Assembly

To minimize the strain and possibility of mechanical damage to the tubing, it is important to ensure that the tubing is spooled evenly onto the reel. The levelwind assembly is designed to automatically spool the tubing on and off the reel, though it incorporates a manual override facility allowing the operator to correct or prevent improper spooling. The height of the levelwind is adjustable, hydraulically or manually, to match the angle of the tubing between the reel and gooseneck (Fig. 8).

The levelwind also provides a convenient mounting position for a depth counter or encoder and tubing monitoring equipment. In addition, equipment required to apply CT lubrication or corrosion inhibitor is also mounted on the levelwind assembly.

1.2.4 Reel Swivel and Manifold

The reel swivel provides a pressure-tight rotating seal to enable fluids to be pumped through the tubing while running in and out of the well. Reel manifold designs vary, but as a minimum will include a valve within the reel core to isolate the tubing. Most designs incorporate a pressure debooster/transducer to enable the operator to read the fluid pressure as it enters the reel (Fig. 9).

If a cable is installed in the tubing, additional facilities will be located within the reel core and on the axle to allow the cable to enter the tubing. A rotating electrical collector is located on the shaft to provide electrical continuity between the surface equipment and the cable on the reel.

1.3 POWER PACK AND CONTROL CABIN

The power pack provides the hydraulic energy to operate the CT unit (CTU) functions and controls. Generally, it consists of a diesel engine driving an array of hydraulic pumps supplying each system or circuit with the required pressure and flow rate. The major components of the power pack include the following (Fig. 10).

- Engine
- Pumps
- Pressure control valves
- Hydraulic reservoir
- Filters and strainers
- Heat exchanger
- Hydraulic fluid

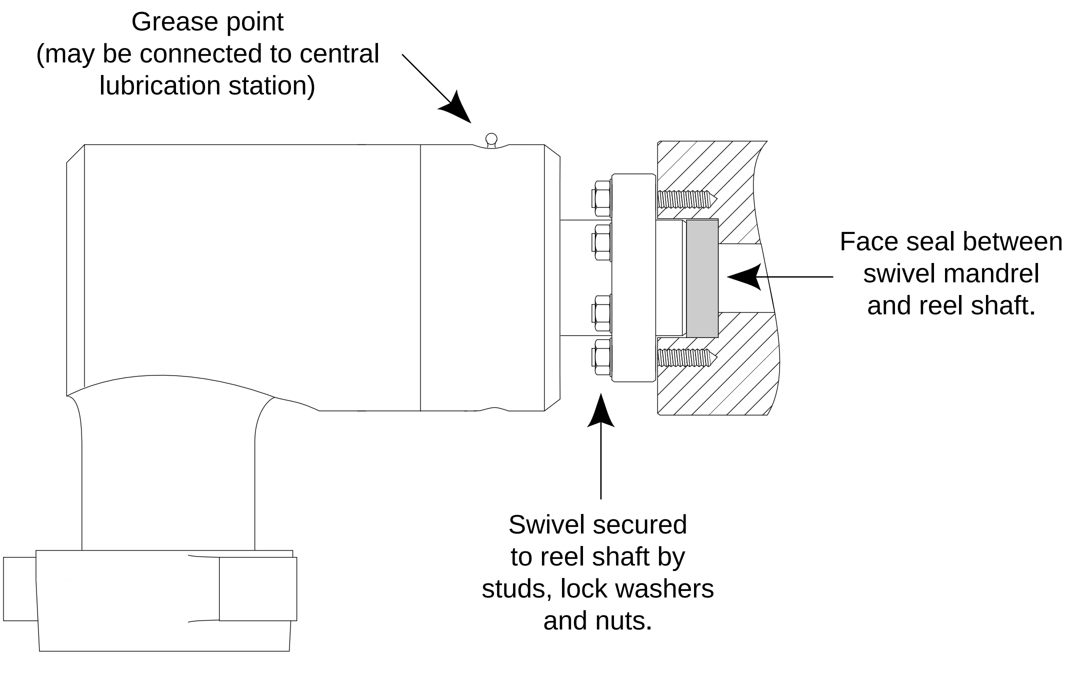

Figure 9. Hydra-Rig 1-1/4-in. bore, 10,000-psi reel swivel.

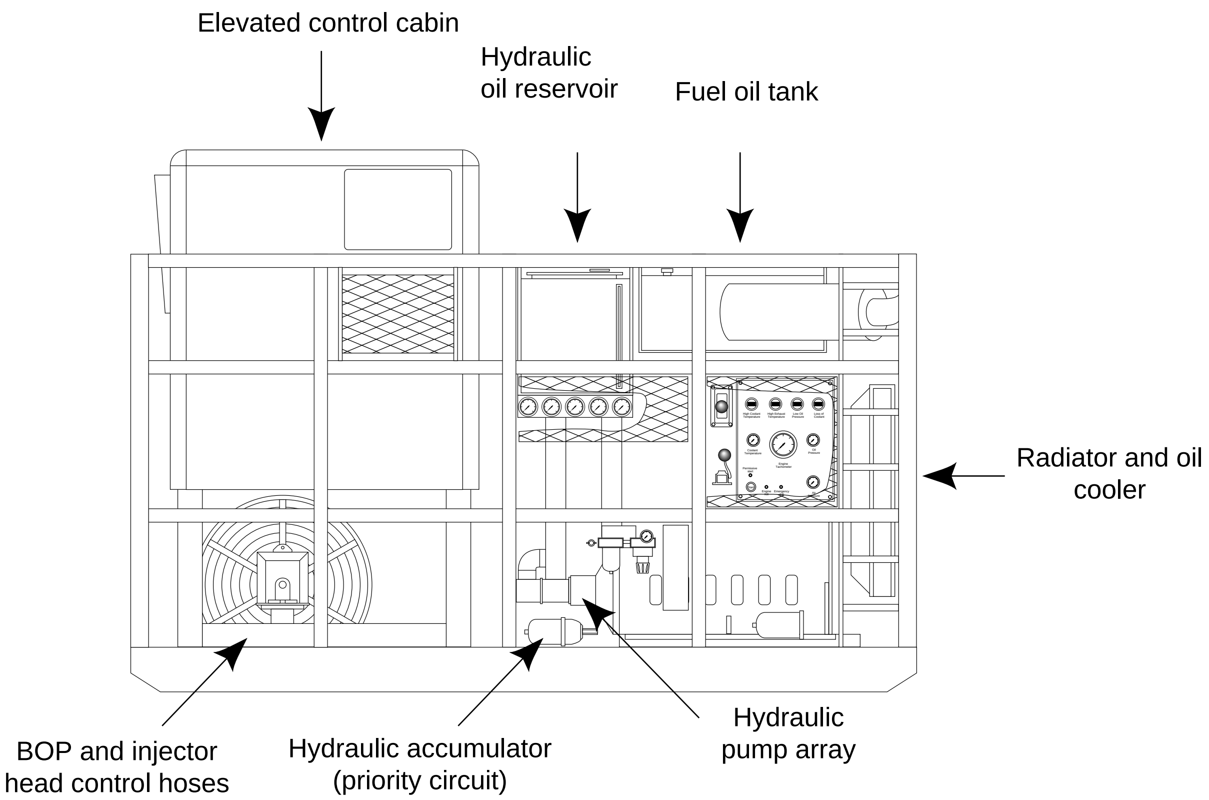

Figure 10. Power pack principal components (3 piece CTU)

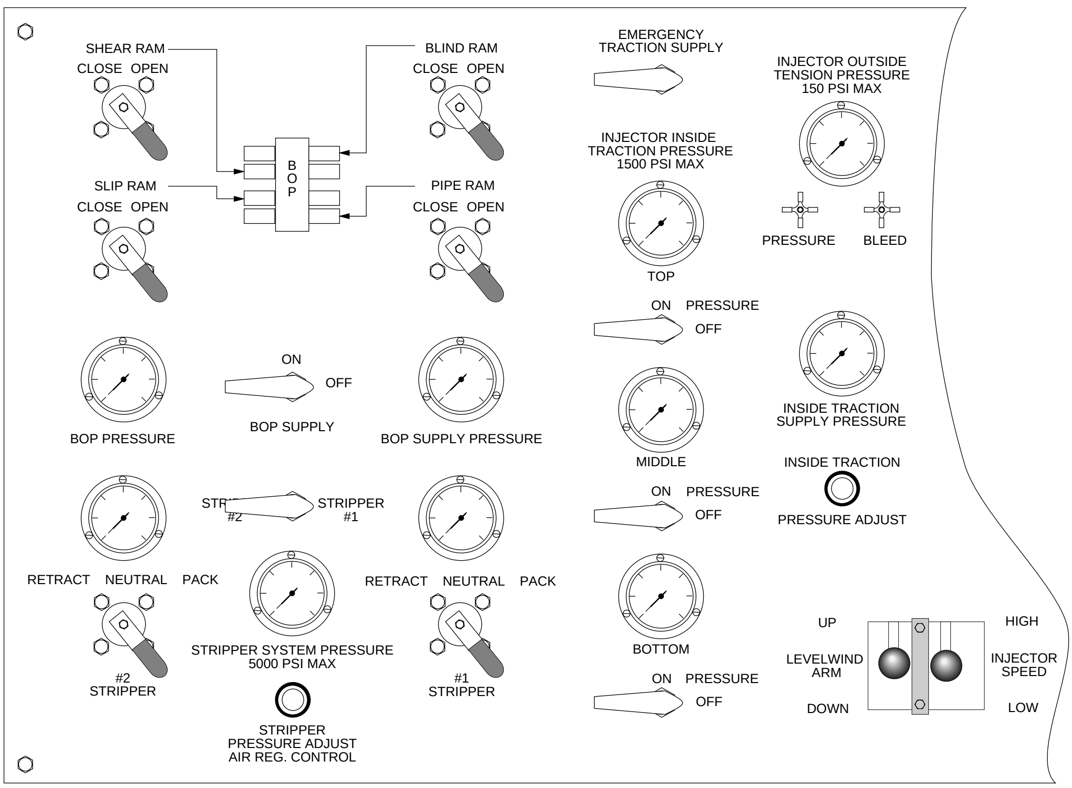

Figure 11. Control console (left)

1.3.1 Engine

The engine of the power pack is generally a dedicated unit, although on some truck-mounted units the truck engine is used. A variety of engine protection systems and, if necessary, a complete Zone II protection package may be fitted to allow the unit to operate in the environment in which it is required.

1.3.2 Hydraulic Pumps

There are many types and models of hydraulic pumps. The type of pump generally fitted to CTU power packs is the balanced vane type of either single-, or two-stage construction.

1.3.3 Pressure Control Valves

Pressure control valves perform functions such as limiting the maximum system pressure or regulating the reduced pressure in certain portions of a circuit. A relief valve is found in every circuit. Its purpose is to limit the pressure in a system to a preset maximum by diverting some or all of the flow to the hydraulic fluid reservoir.

1.3.4 Hydraulic Reservoir

The hydraulic reservoir stores the fluid, allows it to cool, allows any entrained air to be released and permits dirt to settle out of the fluid.

1.3.5 Filters and Strainers

The fluid in the hydraulic system is kept clean principally through the use of filters and strainers.Generally, strainers are fitted to the suction side of the system, e.g., on the bottom of the reservoir on the suction line. However, filters may be fitted anywhere in the system, provided the filter and its housing are rated at the appropriate pressure.

1.3.6 Heat Exchangers

The generation of excess heat is a common problem in hydraulic systems. The heat exchangers are principally designed to cool the fluid; however, in some environments, it may be necessary to heat the fluid, e.g., where high-viscosity oils have to be warmed to reduce the viscosity in cold climates. The exchanger may use forced air as a coolant or, more commonly, water will be circulated through the exchanger to cool (or heat) the fluid.

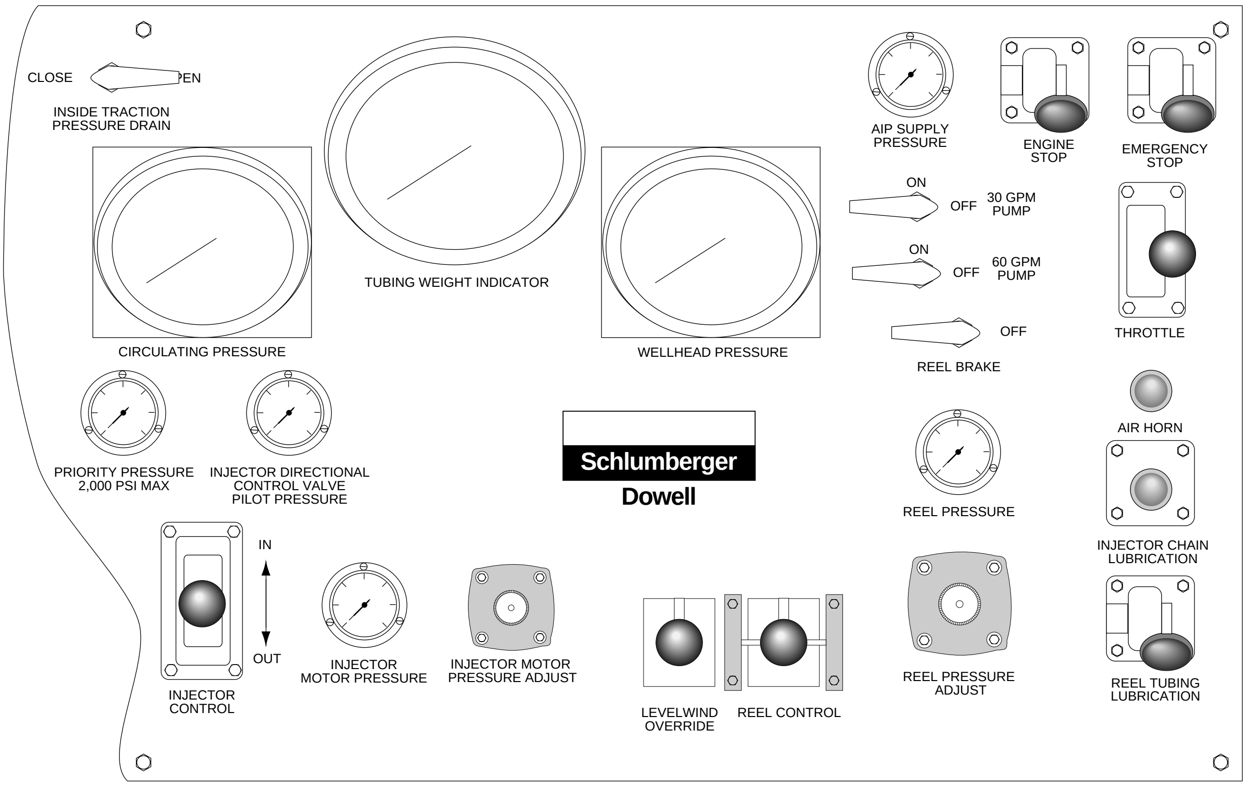

Figure 12. Control console (right)

1.3.7 Hydraulic Fluid

The hydraulic fluid has four primary functions: transmit power, lubricate moving parts, seal clearances between parts, cool components and dissipate heat.

The exact type of hydraulic fluid used in Dowell equipment may be determined by local availability and environmental conditions. The quality requirements of fluids are well defined; as a result, a list of recommended fluids has been compiled for use in Dowell equipment, and should be followed wherever possible.

1.3.8 Control Cabin

Depending on the configuration of the CTU, the control cab may be contained on a separate skid, be incorporated with the power-pack skid or be permanently truck mounted.

The control cab will contain all necessary controls and instruments to allow the CT operation to be run from one control station (Fig. 11 and 12). In some instances, controls and instruments for associated services (e.g., pumping) are also located in the CTU control cab. Manual pumps for standby or emergency use on essential hydraulic functions are also located in the control cab. These will include manual or air-driven pumps to energize the BOP, stripper and skate tension circuits so that well security can be maintained in the event of a major equipment failure.

Only qualified personnel are authorized to operate and perform maintenance on the CTU and ancillary equipment.

2.0 PRESSURE CONTROL EQUIPMENT

2.1 Stripper

The stripper is designed to provide a pressure-tight seal or packoff around the coiled tubing as it is being run (or stripped) in and out of a well with surface pressure. The seal is achieved by energizing the stripper packer which forces the inserts to seal against the tubing. The energized force is applied hydraulically and is controlled from the operator control cab. Since the packer inserts are consumable and may need to be changed during an operation, the design of the stripper components allows the replacement of inserts while the equipment is rigged up and the tubing is in place. The stripper is flange-mounted to the injector head and when rigged up supports most of the injector head weight.

The side-door stripper is designed to permit easier access to the stripper packing arrangement. Conventional stripper systems require the packing to be removed from the top of the stripper assembly within the injector-head frame (Fig. 14). Side-door strippers allow the packing arrangement to be removed below the injector head. This simplifies the removal and replacement of the packing arrangement while the tubing is in place (Fig. 15).

The side-door stripper has several operational advantages over conventional stripper systems:

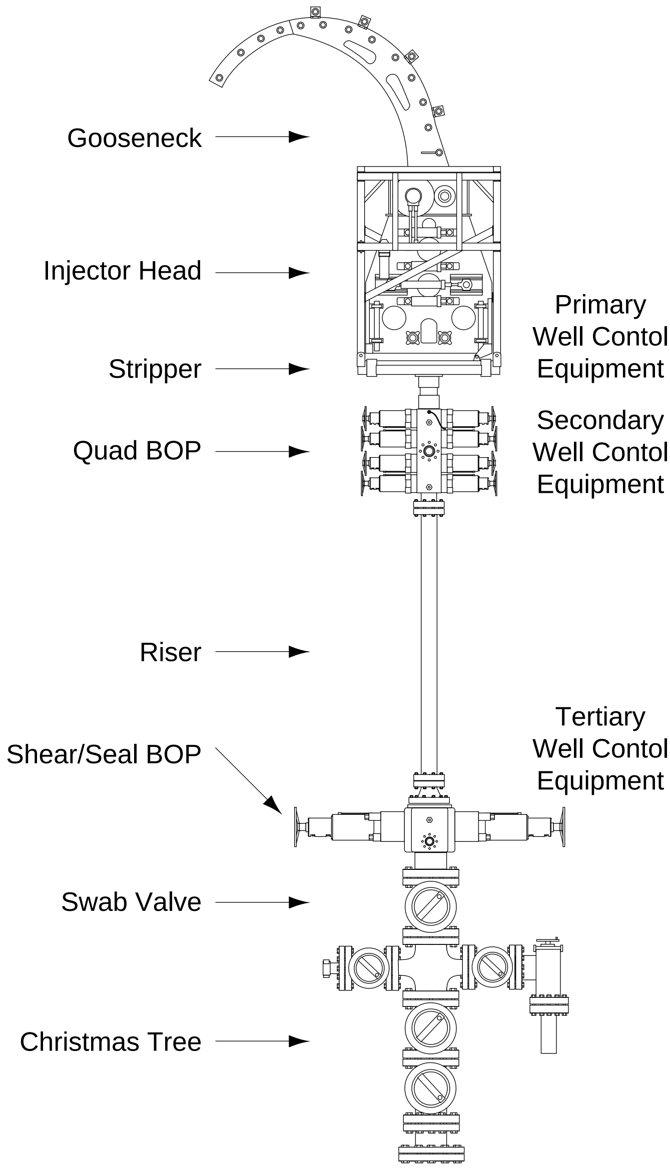

Figure 13. Well control equipment rig-up.

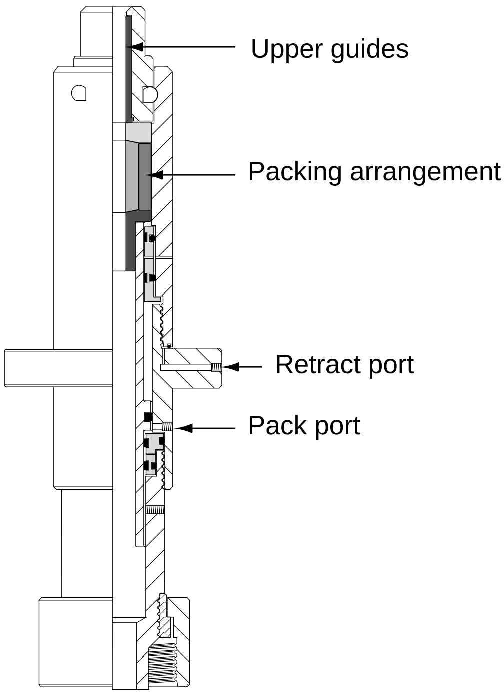

Figure 14. Conventional stripper assembly.

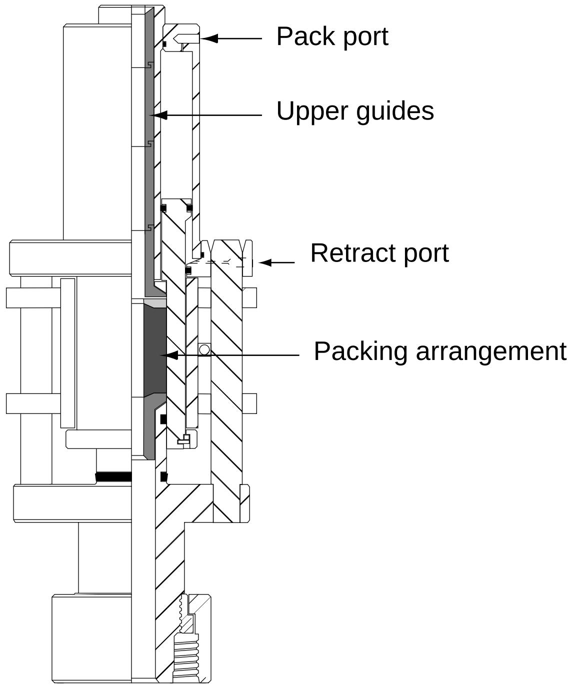

Figure 15. Side-door stripper assembly.

- The stripper assembly can be mounted closer to the injector-head chains since there is no longer a requirement to access the stripper from above.
- The packing arrangement is more accessible, therefore inspection and replacement are easier and safer.
- The extended guides and bushings improve centralization of the CT, thereby reducing packer wear.

In some instances of extreme well conditions, or if required by the operating company, a dual or tandem stripper assembly can be used.

2.2 Quad and Combi BOPs

The BOPs most commonly used within Dowell are Texas Oil Tools 10,000-psi Working Pressure, H_2S Resistant Quad or Combi BOPs. They are hydraulically operated from the control cabin using the BOP hydraulic circuit and accumulator. The accumulator provides a reserve of hydraulic energy to enable the BOP to be operated (for a limited number of functions) following an engine shutdown or circuit failure.

A variety of special BOPs are also used as tertiary pressure barriers, generally providing shear/seal capabilitties for added safety during offshore operations.

Quad BOPs comprise the following components (Fig. 16).

- Blind rams
- Shear rams
- Slip rams
- Pipe rams
- Equalizing valves
- Top and bottom connections
- Side port and pressure port

2.2.1 Blind Rams

Blind rams are designed to isolate pressure from below when there are no obstructions (such as tubing or tools) in the bore of the BOP. The design incorporates a seal arrangement which uses the well pressure to help keep the rams closed and sealed once they have been activated. Since the rams provide total isolation, a pressure equalization system is required to enable the pressure above and below to be equalized before attempting to open the rams.

2.2.2 Shear Rams

Shear rams are only operated when it is absolutely necessary to cut the tubing or tool string in the well. This may occur under a variety of conditions, and the priority in shearing the tubing is usually to maintain the security of the well. Once the tubing is cut, the upper tubing is withdrawn to allow the blind rams to be closed.

In combi BOP configurations, the blind ram and shear ram functions are combined in one ram set.

2.2.3 Slip Rams

Slip rams are fitted with hardened steel inserts which are shaped to the profile of the tubing. When closed, they grip the CT and are capable of supporting the weight of the tubing in the well, or force acting to push the tubing from the wellbore. Slip rams are generally closed in conjunction with the pipe or shear rams

2.2.4 Pipe Rams

Pipe rams incorporate seals which are profiled to the size of the tubing in use, and when closed will isolate pressure from below while there is tubing or a suitably sized tool string in the bore of the BOP. Similar to the blind rams, the pipe rams are also assisted in operation by the well pressure and, consequently, require the pressure to be equalized before attempting to open the rams.

In combi BOP configurations, the slip ram and pipe ram functions are combined in one set of rams (Fig. 17).

Equalizing valves are fitted integral to the body of the BOP and are located by the blind rams and pipe rams.The valves are operated manually using an Allen-type key. The pressure across sealing rams (pipe rams and blind rams) must be equalized before they can be opened.

The type and size of connections on the BOP may vary, although they generally will be pin and collar, or flange connections.

The side port or kill port provides access for kill fluid to be pumped down the tubing after the tubing has been sheared, with the blind, pipe and slip rams closed. The pressure port allows access for a pressure transducer or de-booster which is used to read the well pressure inside the BOP. This value is displayed as wellhead pressure on the control panel console.

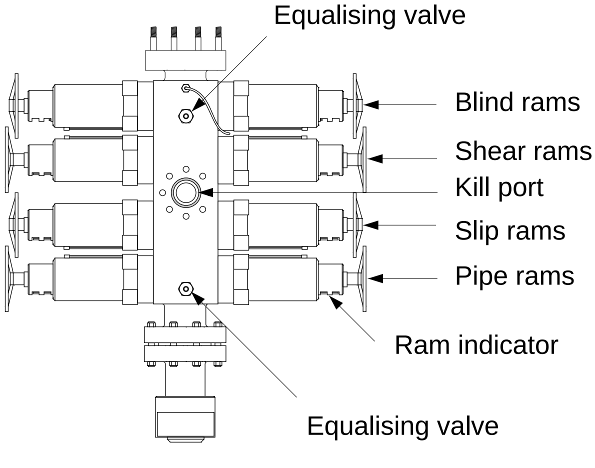

Figure 16. Quad BOP

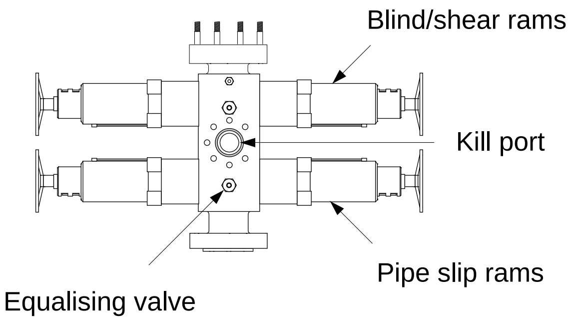

Figure 17. Combi BOP

DOWNHOLE TOOLS AND EQUIPMENT

Introduction

Downhole tools of some description are used on almost all coiled tubing operations. Most tools currently used can be categorized as follows.

- Primary tools – Coiled tubing connectors and check valves are included in this category, i.e., tools which may be considered essential for all operations.
- Support tools – This category includes tools such as a release joint and jar, i.e., tools which enhance or support the toolstring function, or provide a contingency release function.
- Functional tools – These are tools selected on the basis of their ability to to perform the intended operation.

The designation STIFFLINE* Services is given to CT services conducted by Dowell that are generally conducted using nonelectric wireline tool strings. Such services may be categorized as follows.

- Conveying retrievable flow control tools - A wide variety of plugs and flow control devices are commonly used to selectively control production. The plugs, or locks, may be located in specific landing nipples, tubing joints or on the tubing wall.
- Operating fixed completion equipment - This principally involves the operation (opening and closing) of sliding sleeves, or circulation devices located in the production tubing or uncemented production liner.
- Conveying gauges or monitoring equipment - Gauges and sampling or monitoring equipment can be conveyed by wireline or CT, and if necessary secured in a tubing nipple or similar locating device.
- Wellbore servicing - A variety of well service operations are commonly performed, generally as preparatory work before performing other services e.g., tubing drifting, depth (fill) check, paraffin removal.
- Fishing - Coiled tubing fishing operations can provide a rapid and economic solution to a variety of light- to medium-weight fishing problems.

The operational features of CT conveyed tools and techniques offers several advantages over conventional wireline methods.

- Coiled tubing is considerably stronger than slickline or braided line allowing the application of greater forces and lifting capacity.
- The rigidity of CT allows access to highly deviated or horizontal wellbores.
- Fluids circulated through the CT can be used to improve access to the fish or wellbore equipment to be engaged.
- Fluids pumped through the CT can also be used to power specialized tools.

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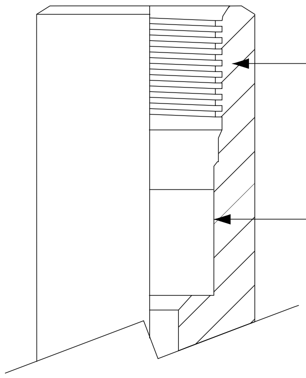
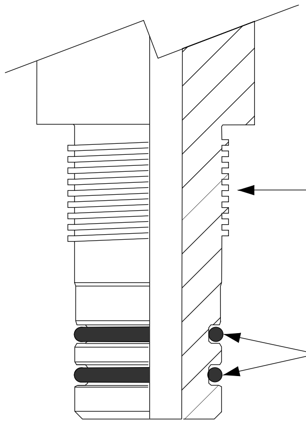
2.1 STANDARD THREADS

Schlumberger Dowell has designed three standard thread specifications for use in coiled tubing applications. The purpose of these thread specifications is to provide a uniform worldwide standard so all downhole tools successfully make up on location. The standard threaded connections are available in the following sizes:

- 1-1/4-in. CT standard thread, designated as a nominal 1.500-in.-10 Stub Acme 2G
- 1-1/2 in. CT standard thread, designated as a nominal 1.812-in.-10 Stub Acme 2G
- 1-3/4 in. CT standard thread, designated as a nominal 2.000 in. -10 Stub Acme 2G



The standard thread connections are also available in a non-rotating configuration. This connection is designed for use when there is difficulty making up the connection or where the tools cannot be rotated.



The material selected for tool and thread construction should be chosen to meet the requirements of the tools application. However, a material with a yield stress of less than 75,000 psi should not be used for the standard thread connections. The benefits of the Dowell standard thread design include the following:

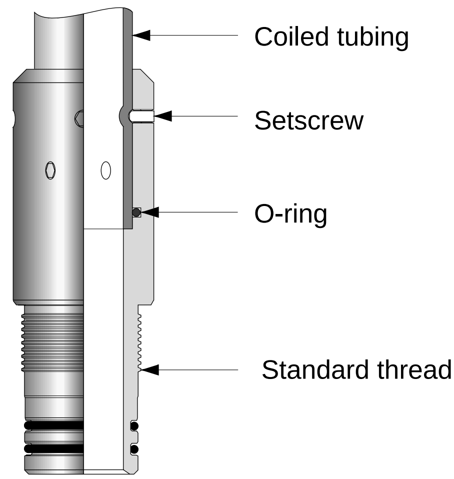
- The threads are protected from treatment fluids by dual O-ring seals.
- During make-up, the threads engage before the O-rings, reducing the likelihood of damaging the seal during assembly.

Specifications

CT Size (in.)	Make-Up Length (in.)	Minimum OD (in.)	Maximum ID (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Static Torque (ft-lbf)	Max Tensile Load (lbf)
1-1/4 1-1/2 1-3/4	2.850	1.690 2.125 2.563	0.937 1.250	5000	350	1500 2500	Exceeds tubing value

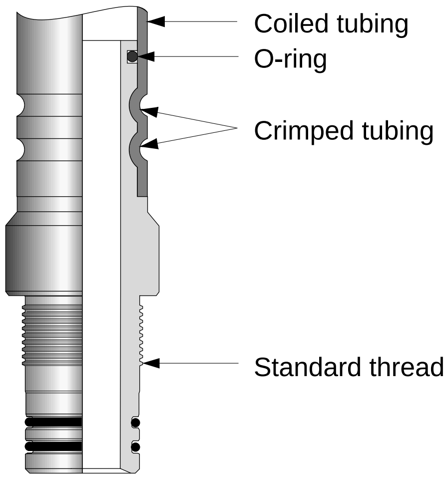
2.2 COILED TUBING CONNECTORS

Coiled tubing connectors connect various downhole tools to the end of the CT. Connectors are commercially available in a wide range of designs and sizes. However, three types of connectors are recommended for use within Schlumberger Dowell, the Dowell Grapple Connector, the Setscrew/Dimple Connector and the Roll-On Connector. Selecting the appropriate connector is generally dependent on the application and operator preference.



Setscrew/dimple connector

The Setscrew Connector is attached to the CT by set-screws engaging in preformed dimples. A dimpling tool is used to place the dimples in the same pattern as formed by the screws on the connector. The setscrew connector attaches to the outside diameter of the CT, and therefore, interferes less with the internal flow path of the tubing.



Roll-on connector

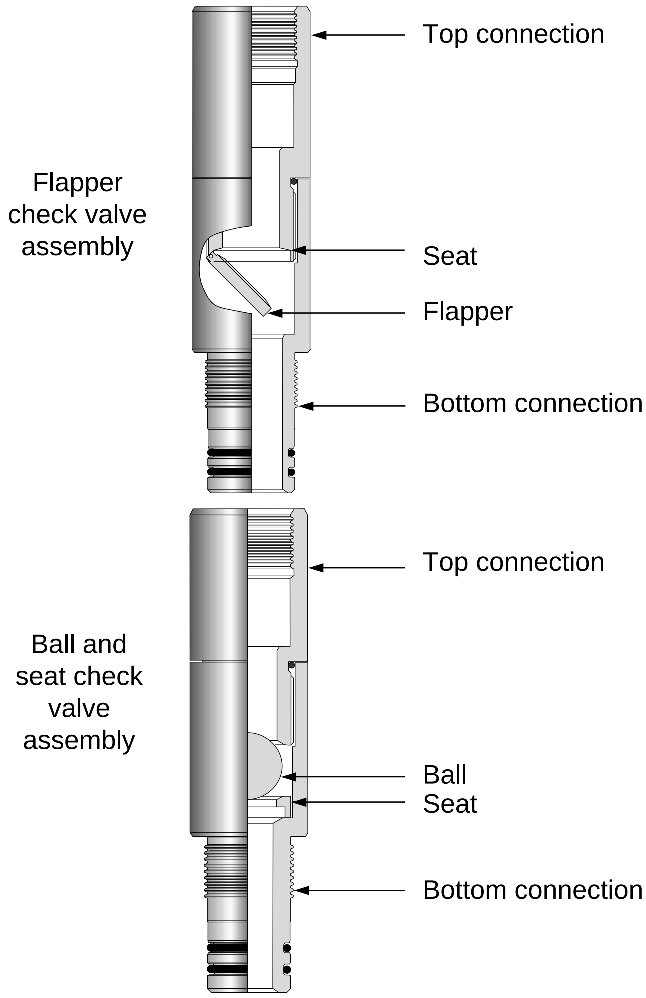
The roll-on connector attaches to the internal diameter of the CT and is held in place by crimping the CT around a connector profile with a special crimping tool. However, the roll-on connector poses a significant obstruction to fluids, darts or balls pumped through the CT. In special applications where an extremely slim bottomhole assembly is required, and where low torque and tensile strength values are required, the roll-on connector may be considered a practical alternative to the grapple and setscrew connector.

Specifications

Connector Type	CT Size (in.)	Typical OD (in.)	Typical ID (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Tensile Load (lbf)	Torque Tolerence (ft-lbf)
Setscrew	1-1/4 1-1/2 1-3/4	1.750 2.000 2.250	0.750 1.060 1.125	5000	300	25,000	Exceeds tubing value
Roll-On	1-1/4 1-1/2 1-3/4	1.250 1.500 1.750	0.625 0.625 1.000	5000	300	21,000	50

2.3 COILED TUBING CHECK VALVES

The check valve is generally attached to the coiled tubing connector at the end of the CT string. By preventing the flow of well fluids into the CT, well security is maintained in the event of failure or damage to the tubing at surface. Check valves should be part of every CT bottomhole assembly and should only be omitted when the application precludes its use (e.g., where it is desired to reverse circulate through the CT). In most cases it is recommended that tandem check valves be fitted to provide some redundancy of operation.



Flapper check valves

Flapper check valves are, by necessity, becoming more commonly used. The fullbore (or near fullbore) opening permits the use of more complex CT tools, fluids and operating techniques by allowing balls, darts and plugs to pass through to the toolstring from the CT without restriction. Most flapper check valves are of similar design, although some may incorporate a cartridge valve assembly for ease of maintenance.

Ball and seat check valves

The ball and seat check valve has been predominantly used on conventional CT applications because of its simple construction and ease of maintenance. However, this design has several limitations including restricted flow area and bore obstruction. These limitations require using an alternative when fullbore opening or unrestricted flow area is required.

Specifications

Check ValveType	Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Tensile Load (lbf)
Ball and Seat	6 to 12	1.688 2.125 2.563	N/A	5000	300	Exceeds tubing value
Flapper	6 to 12	1.688 2.125 2.563	0.625 1.000 1.300	5000	300	Exceeds tubing value

2.4 NOZZLES AND JETTING SUBS

Nozzles and jetting subs for use on coiled tubing form the downhole “end” of the CT bottomhole assembly. These nozzles and subs are generally of simple design and construction and are often locally manufactured. The required jetting action generally determines the position and size of the nozzle ports. In general, these tools will fall into two categories.

Circulating subs

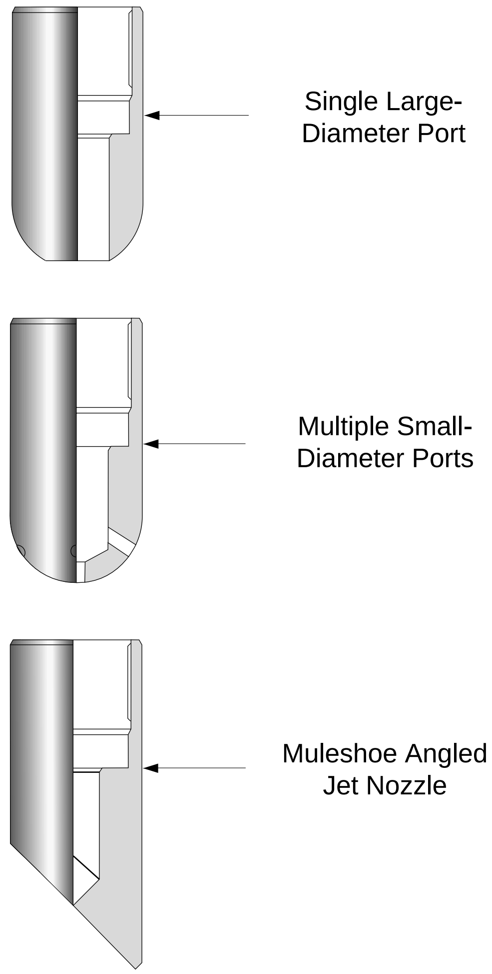
Nozzles used on operations where fluids are to be circulated without a jetting action require a large port area. This port area may be composed of several small ports to increase turblence, or a few large ports; the criteria being that there is relatively little pressure drop across the nozzle.

Jetting subs

Nozzles used on operations that require jetting action will have a relatively small port area, usually composed of several small ports. The efficiency of a jetting nozzle is largely dependent on the fluid velocity through the port. The largest constraints on the jetting nozzle design are the limits of the flow rate and pressure available at the nozzle. These limits are a result of the relatively large friction pressure induced within the CT string.

The position, shape and direction of the jet ports affect the jetting action of the nozzle, and in most cases, are determined by the intended application.

Combination nozzles are often used to perform special operations. The various functions of combination nozzles can be accomplished with a ball or sleeve mechanism within the nozzle assembly, which is activated to block certain ports. Simple versions are activated by dropping a ball through the CT work string.



2.5 RELEASE JOINTS

The coiled tubing release joint releases the coiled tubing work string from the CT tool string in a controlled manner should the need arise. The resulting fishing neck on the tool string in the well allows easy reconnection with an appropriate fishing tool. Release joints are available with the following methods of operation:

- tension-activated release
- pressure-activated release
- combination

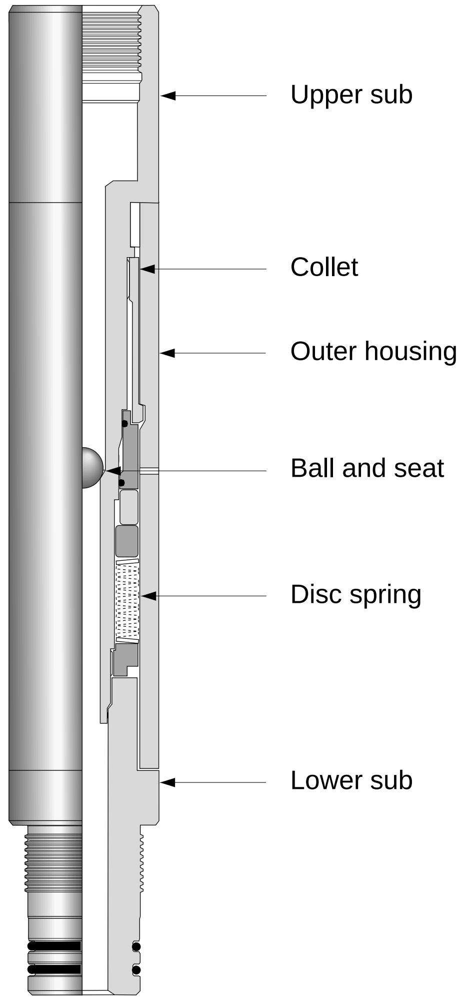
Tension-activated release joints

The tension-activated release joint may be regarded as a weak point in the tool string which will part before any damage is inflicted on the retrieved tool string or the CT. Most designs use shear pins or screws which, when sheared, allow the top and bottom assemblies of the release joint to separate.

Pressure-activated release joints

Pressure-activated release joints are generally activated by applying pressure through the CT which in turn exerts a pressure differential between the inside and outside of the tool sufficient to activate the mechanism. In many cases, a ball is circulated through the CT work string to land in a seat located in the release tool.

This type of release joint is desirable when fishing or jarring, because of its ability to withstand high-impact loads.



Specifications

Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	Ball Diameter (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Torque (ft-lbf)	Max Tensile Load (lbf)
15	2.12	0.50	5/8	5000	350	500	35,000

2.6 ACCELERATORS

A coiled tubing accelerator is used in conjunction with CT jars in fishing or STIFFLINE operations. Accelerators generally consist of a sliding mandrel which compresses a spring when forced in its operating direction (i.e., up, down, or in some cases, either up or down).

Placed in the tool string above the jar assembly, the primary function of the accelerator is to store the energy to be released when the jar fires. Accelerator action also helps protect both the tools located above the accelerator, and the CT work string from the shock load caused by the jar impact.

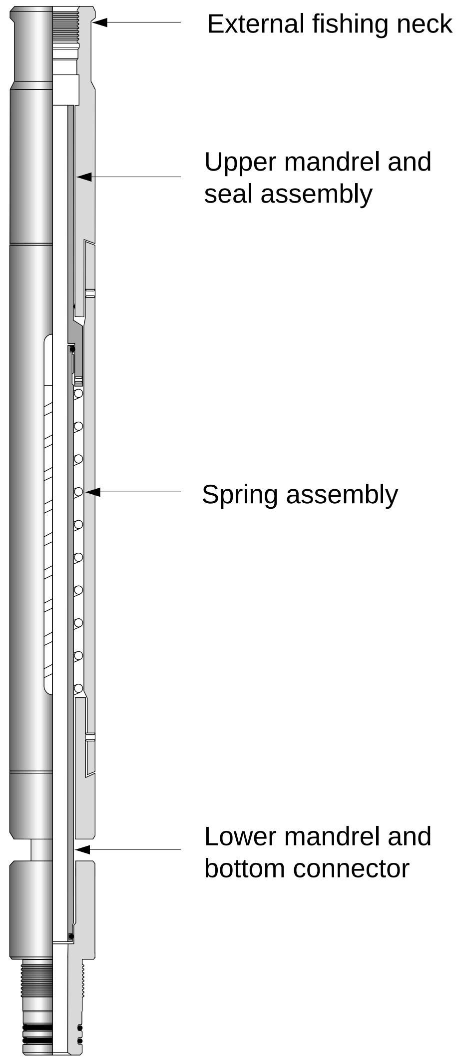
Accelerators used in CT operations operate on one of the following principles:

- spring (mechanical)

- compressed fluid (hydraulic)

Compressed fluid tools are generally called intensifiers and are less common than spring-operated accelerators in CT operations.

Most jar manufacturers offer accelerators or intensifiers to match the jars. Jars and accelerators should be used as a matched set, alleviating any problems associated with the compatibility of the tools. The accelerator must have an available stroke which is greater than that of the jar at the time of firing.



Specifications

Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	Firing Stroke (in.)	Max Working Torque (ft-lbf)	Max Operating Temperature (°F)	Max Tension (after firing) (lbf)	Typical Trip Setting (lbf)
70	2.25	0.50	8	1200	500	80,000	5000

2.7 JARS

A jar may be described as a device which delivers a sudden shock (up or down) to the tool string. In coiled tubing applications, jar assemblies generally include a sliding mandrel arrangement which allows the brief and sudden acceleration of the tool string above the jar. Travel of the mandrel is limited by a stop (hammer) which strikes a corresponding stop on the outer mandrel (anvil).

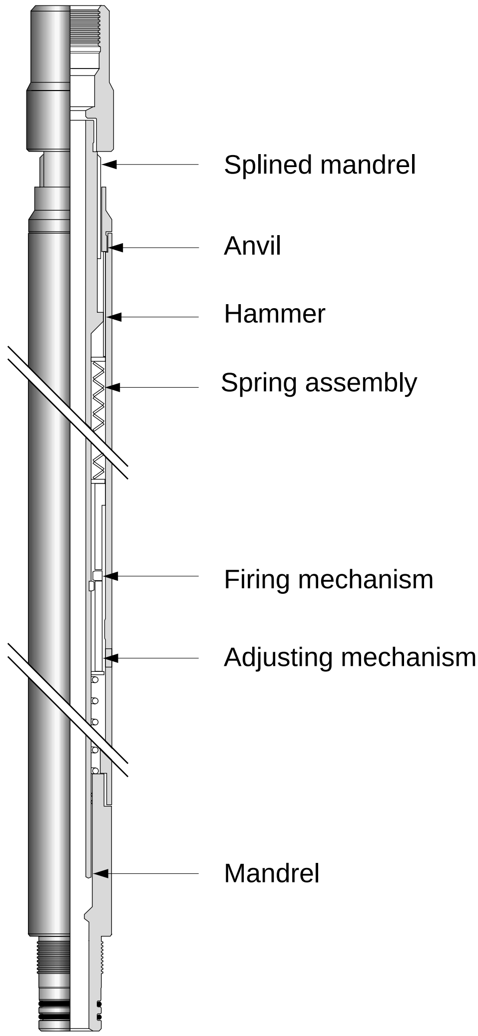
Most jars release (also called a trip, fire, hit or lick) in one direction only. However, some designs feature the ability to jar up and down without resetting the tool.

An accelerator (detailed elsewhere) must be included in any CT bottomhole assembly in which a jar is fitted. The accelerator is placed in the tool string above the jar assembly in order to store the energy that will be released when the jar fires.

Jars commonly used in CT operations operate on one of the following principles:

- mechanical
- hydraulic
- fluid powered (e.g., impact drill).

All three jar types operate on the upstroke; however, only jars operating on the mechanical and fluid-powered principles are capable of downstroke or dual operation. The ability to jar down is an important feature which may be required on many fishing and STIFFLINE* operations. The release of many overshots, spears and pulling tools often requires a downward blow at the tool.



Specifications

Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	Firing Stroke (in.)	Max Working Torque (ft-lbf)	Max Operating Temperature (°F)	Max Tension (after firing) (lbf)	Typical Trip Setting (lbf)
70	2.25	0.50	8	1200	500	80,000	5000

2.8 OVERSHOTS

Overshots are commonly used on a wide variety of coiled tubing fishing operations. Overshots are designed to engage over the fish to be retrieved, gripping on the OD surface of the fishing neck.

Once latched on the fish, the grip exerted by the overshot grapple increases as the tool string tension is increased. In the event the fish or tool to be retrieved is immovable, a release mechanism can be activated to retrieve the CT and tool string. This release may be incorporated into the design of the overshot (releasable overshot) or may require the operation of a separate CT release joint (non-releasable overshot).

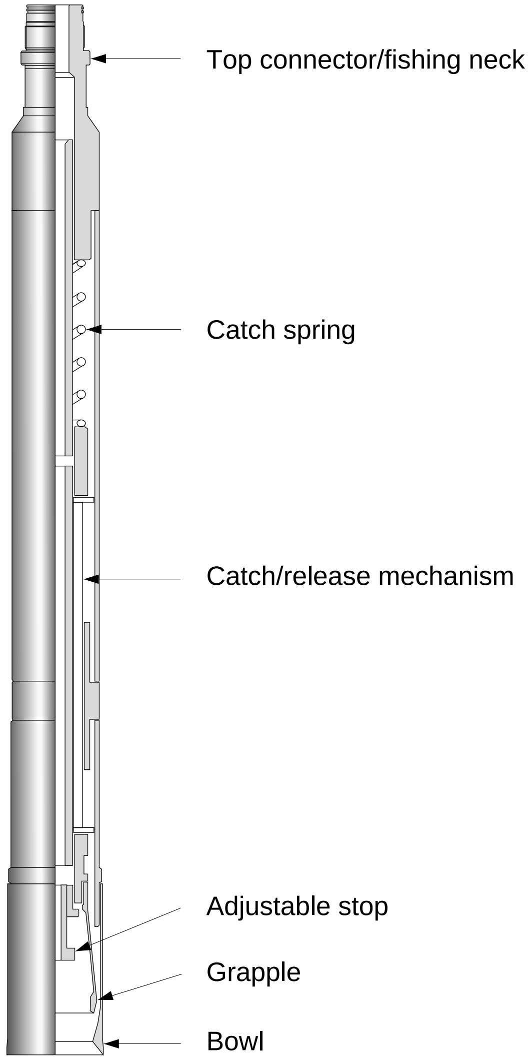
It is recommended that only releasable overshots be used in CT applications. Non-releasable overshots should be avoided and only run where the implication of their use is fully understood.

The design and operation of releasable overshots used by Dowell, vary slightly among manufacturers. However, the principal features and components are similar and include the following:

- A catch/release mechanism, usually controlled by a ratchet mechanism, which cycles each time weight is set on the tool.

- A bowl/grapple assembly which should be selected only after consideration of the fishing neck profile, overshot reach and completion restrictions.

- A circulation facility which enables the circulation of fluid and offers significant advantage over alternative fishing methods.



Specifications

Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	GrappleRange (fishing neck) (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Tensile Load (lbf)
30	2.25	0.50	0.88 to 4.50	5000	350	40,000

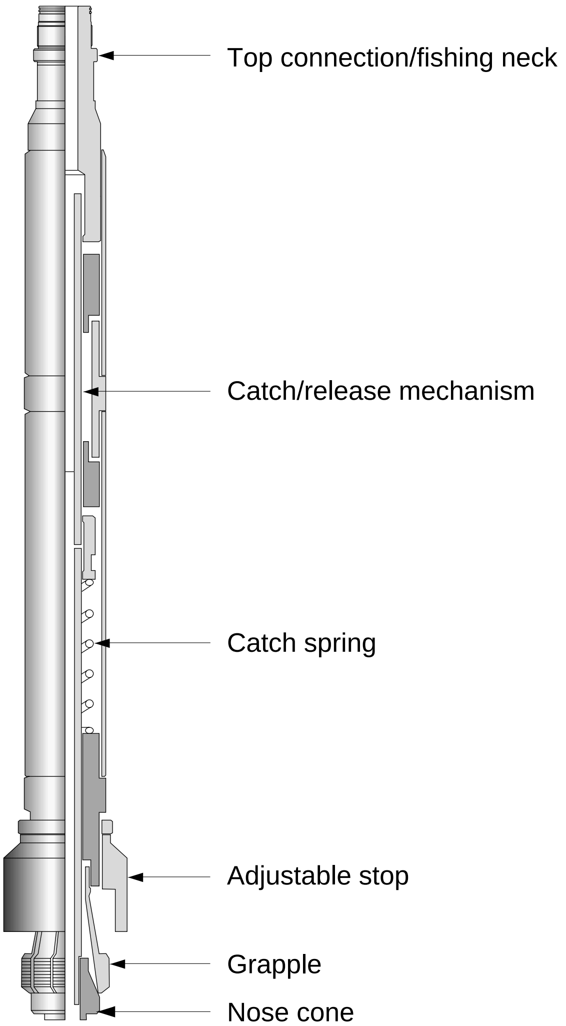
2.9 SPEARS

Spears of various designs are commonly used on fishing operations. Spears are designed to engage the fish by gripping on the ID surface. Although the preferred method of engaging a fish is by overshot, the spear provides a useful alternative when retrieving a fish with a suitable bore.

In the event that the fish or tool to be retrieved is immovable, a release mechanism can be activated to retrieve the coiled tubing and tool string. This release mechanism may be incorporated into the design of the spear (releasable spear) or, in some cases, may require the operation of a separate CT release joint (nonreleasable spear). It is recommended that only releasable spears be used in CT applications.

The design and operation of releasable spears, used by DS, varies slightly among manufacturers. However, the principal features and components are similar and include the following:

- A catch/release mechanism, usually controlled by a ratchet mechanismand which cycles each time weight is set down on the tool (e.g., set down on the fish to catch, set down again to release).
- A cone grapple assembly which should be made after considering the fishing neck profile and the completion restrictions.
- A circulating facility which enables fluid circulation and offers a significant advantage over alternative fishing methods.



Specifications

Typical Length (in.)	Typical OD (in.)	Typical ID (in.)	Grapple Range (in.)	Max Working Pressure (psi)	Max Operating Temperature (°F)	Max Tensile Load (lbf)
35	2.25	0.50	1.75 to 4.50	5000	350	40,000

COILED TUBING STRING

Contents	Page	Contents	Page

1 OPERATING LIMITS

The experience associated with Dowell research and development efforts has helped create well-defined, recommended operating limits and procedures for coiled tubing (CT) operations.

This manual section will identify the current Dowell recommended operating limits, and outline the factors that contribute toward them. Most of these factors are dependent on the physical and metallurgical characteristics of the tubing, and on the history of the CT string. However, some of the operating limits given apply to operating techniques and conditions.

Several of the limits are defined by the use of CoilCADE* computer models and modules. Therefore, an understanding of the input requirements of these models is essential in the design process of any Dowell CT operation. In addition, correct interpretation of the CoilCADE output plots and tables is required to ensure the operation is designed and safely executed within the prescribed limits.

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The limits discussed in this section apply to the following aspects of CT and CT operations.

- Pressure and tension
- Diameter and ovality
- Fatigue and corrosion
- Pumped or produced fluids
- H_2S considerations

Tubing fatigue and reel history data are factors which may influence the limitations and applications of particular tubing strings. These effects are cumulative and require a recording system to accurately monitor the progress of the tubing life.

1.1 Pressure and Tension

The factors which affect the operational limits of a CT string in any application are often interactive,e.g., the pressure capacity of a CT string can be greatly affected by the tension to which it is subjected. Therefore, it is essential that all relevant factors are taken into account when determining any operational limits.

The CoilLIMIT* module of the CoilCADE program determines the pressure and tension limits that apply to a CT work string in given wellbore conditions. Using the Von Mises incipient yield criteria, the model determines the pressure and tension limits at which the CT begins to yield.

The effect of ovality is considered in the model collapse pressure calculation. In addition, the effect of helical buckling within the wellbore tubular is also considered. The limits calculated for a previous job will apply unless one of the following points apply:

- Acid or corrosive fluids have been pumped since previous limits were calculated.
- Significant corrosion has occurred to the CT.
- The wellbore or tubulars on the intended operation are larger than those for which the previous limits were calculated.
- The wellbore conditions of the intended operation are greater than these for which the previous limits were calculated.

The CoilLIMIT output includes a plot describing the pressure and tension limits which will apply during the intended operation. In addition, maximum allowable pressure and tension values are given. These values are used to define the test pressure and tension applied to the CT while function testing the BOP and pressure control equipment.

An example CoilLIMIT output plot is shown in Fig. 1.

The principal curve shown is the working limit curve. This curve and the P_{max} and T_{max} lines define the Dowell pressure and tension operating limits for a specific CT string under the stated conditions.

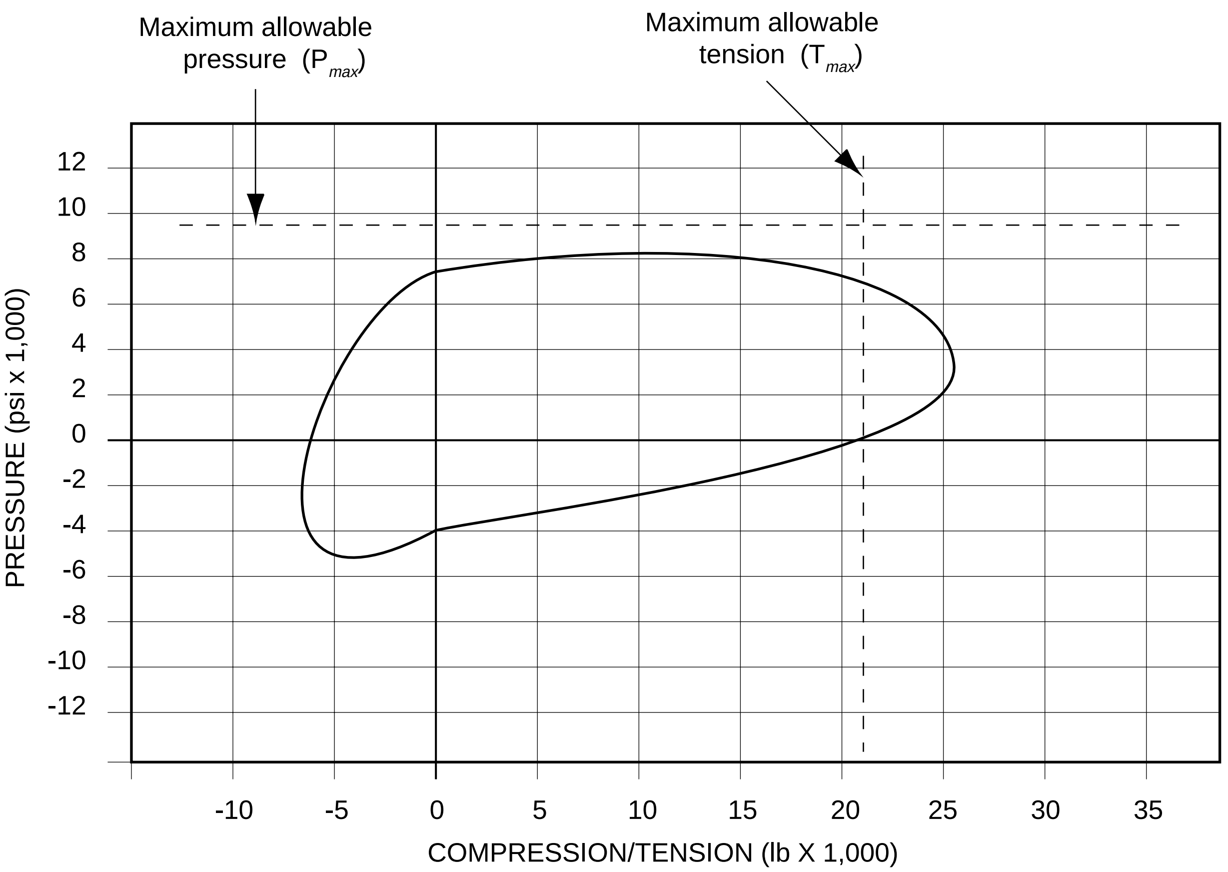

Fig. 1. CoilLIMIT output plot.

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In the event that CoilLIMIT output data are not available, the following longstanding recommended limits will apply.

1.1.1 Internal Burst Pressure

This is the internal pressure required to stress the OD of the nominal wall thickness tubing to the minimum material yield. This varies greatly with the tensile load applied to the tubing. An extract of tubing data supplied by a tubing manufacturer (Fig. 2) details specifications and capacities of CT manufactured from 70,000 psi grade material. It should be noted that the effect of axial tension on pressure rating has not been applied and the data are for new tubing at minimum strength.

Due to the relatively high friction pressures encountered when pumping through CT, the highest internal pressure will generally be found at the reel core. However, the effects of hydrostatic pressure should not be ignored.

The internal pressure limitations currently recommended where no CoilLIMIT output data are available are as follows.

- Maximum pump pressure while running tubing 4000 psi

- Maximum pump pressure with tubing stationary 5000 psi.

1.1.2 External Collapse Pressure

This is the external pressure required to stress the tubing to its minimum yield strength. This varies greatly depending on the tensile load applied to the tubing. Ovality and irregularities in the tubing surface profile can lower the tubing resistance to collapse even more.

The maximum outside to inside pressure differential currently recommended where no CoilLIMIT output data are available is as follows.

- Maximum Collapse Differential 1,500 psi.

1.1.3 Wellhead Pressure

Wellhead pressure acts on the CT by creating an upward force which (if high enough) will tend to force the tubing out of the well. This force is equal to the cross-sectional area of the tubing times the pressure acting on that area. As the pressure increases, then so does the force of the sealing area on the tubing. At higher wellhead pressures, the friction between the tubing and stripper inserts plays a major role in limiting the maximum wellhead pressure in which tubing can be safely run.

The maximum wellhead pressure into which CT can be safely run is not a limitation of well control or safety equipment. It is set by the ability of the injector head to overcome the forces created by the friction andwellhead pressure while injecting CT into the well, e.g.,

- Maximum recommended running wellhead pressure 3500 psi

1.1.4 Tension

The tubing tensile operating limit is dependent on the type of alloy used in its manufacture, OD of the tubing and wall thickness. The manufacturers data such as that shown in Fig. 2 show the minimum yield strength values for a range of tubing sizes and wall thicknesses.

When tapered strings are used, it is important that the operator is aware of the weld locations, because the tensile limit will vary with the wall thickness of the tubing.

The tensile strength of a tubing string can be reduced for several reasons, not least by the events during the history of the tubing string. A safety factor to take account of these unknown events is included when determining the tensile limit of a specific string.

- The recommended maximum CT tension limit is 80% of the manufacturer's published yield strength.

1.2 Diameter and Ovality

The Dowell recommended diameter and ovality limits are based on the ability of the currently used pressure control equipment to operate efficiently with oversized or distorted tubing. In addition, the reduced collapse resistance which is associated with oval tubing requires that the CT be closely monitored.

A TIM* device (tubing integrety monitor) should be used to monitor tubing diameter and ovality.

Alarm limits on the TIM should warn the operator if tubing diameter varies by more than plus 5% or minus 3% of the nominal diameter. In addition, a tubing ovality warning sounds when the ovality of the CT reaches 105%.

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COILED TUBING WORK STRING DATA – 70,000 PSI YIELD STRENGTH MATERIAL

Tubing Dimensions (in.)				x Sec Area (in²)		Wt (lb/ft)	Load Capacity (lb)		Pressure Capacity (psi)			Internal Capacity per 1000ft		External displacement per 1000ft	
O.D. NOM	Wall NOM	Wall MIN	I.D. NOM	Wall NOM	Inside NOM	NOM	Yield MIN	Ultimate MIN	Tested	Burst MIN	Collapse MIN	(gal)	(bbl)	(gal)	(bbl)
0.75	0.067	0.063	0.616	0.143	0.298	0.489	10,031	10,748	9,400	12,600	10,722	5.48	0.369	22.95	0.547
1.00	0.067	0.063	0.866	0.196	0.598	0.668	13,720	15,040	6,980	11,440	8,260	30.60	0.729	40.78	0.971
1.00	0.075	0.071	0.850	0.218	0.568	0.741	15,260	17,440	7,860	12,900	9,970	29.51	0.703	40.78	0.971
1.00	0.087	0.083	0.826	0.250	0.536	0.848	17,500	20,000	9,200	15,100	11,120	27.84	0.663	40.78	0.971
1.00	0.095	0.091	0.810	0.270	0.515	0.918	18,900	21,600	10,080	16,500	12,030	26.54	0.637	40.78	0.971
1.00	0.109	0.104	0.782	0.305	0.480	1.037	21,350	24,400	11,530	19,210	13,600	24.94	0.594	40.78	0.971
1.25	0.067	0.063	1.116	0.247	0.980	0.840	17,290	19,760	5,580	9,020	5,410	50.21	1.212	63.75	1.518
1.25	0.075	0.071	1.100	0.277	0.950	0.941	19,390	22,160	6,290	10,130	6,770	49.35	1.175	63.75	1.518
1.25	0.087	0.083	1.076	0.318	0.909	1.081	22,260	25,440	7,360	11,900	8,810	47.22	1.124	63.75	1.518
1.25	0.095	0.091	1.060	0.345	0.882	1.172	24,150	27,600	8,070	13,050	9,830	45.82	1.094	63.75	1.518
1.25	0.102	0.097	1.046	0.368	0.859	1.251	27,340	31,250	9,100	11,400	10,450	44.64	1.063	63.75	1.518
1.25	0.109	0.104	1.032	0.391	0.837	1.328	27,370	31,280	9,220	15,180	11,140	43.48	1.035	63.75	1.518
1.25	0.125	0.118	1.000	0.442	0.785	1.502	31,000	33,225	10,000	13,200	12,500	40.80	0.971	63.75	1.518
1.25	0.134	0.128	0.982	0.470	0.757	1.597	32,886	35,235	10,000	15,000	13,300	39.34	0.936	63.75	1.518
1.25	0.156	0.148	0.938	0.536	0.691	1.840	37,100	39,750	10,000	17,400	15,200	35.89	0.855	63.75	1.518
1.50	0.095	0.091	1.310	0.419	1.348	1.425	29,350	33,540	6,720	10,750	7,490	70.03	1.667	91.806	2.186
1.50	0.109	0.104	1.282	0.476	1.291	1.619	33,340	38,100	7,680	12,430	9,430	67.06	1.597	91.806	2.186
1.50	0.125	0.119	1.250	0.540	1.227	1.836	37,800	43,200	8,790	14,390	10,690	63.74	1.518	91.806	2.186
1.50	0.134	0.128	1.232	0.575	1.192	1.955	40,250	46,000	9,460	15,500	11,390	61.92	1.474	91.806	2.186
1.50	0.156	0.148	1.188	0.658	1.108	2.239	46,106	49,410	10,000	13,800	13,000	57.58	1.370	91.806	2.186
1.75	0.109	0.104	1.532	0.5619	1.843	1.910	39,335	44,955	6,100	7,630	3,600	95.78	2.28	120.68	2.870
1.75	0.125	0.118	1.500	0.6381	1.767	2.190	44,670	51,051	7,000	8,750	4,100	91.82	2.19	120.68	2.870
1.75	0.134	0.128	1.482	0.6803	1.725	2.313	47,621	54,424	7,500	9,380	4,400	89.63	2.13	120.68	2.870
1.75	0.156	0.148	1.438	0.7812	1.624	2.660	54,684	62,496	8,700	10,920	5,000	84.39	2.01	120.68	2.870
2.00	0.109	0.104	1.782	0.6475	2.494	2.200	45,328	51,803	5,300	6,670	3,100	129.59	3.09	157.63	3.750
2.00	0.125	0.118	1.750	0.7363	2.405	2.670	51,540	58,905	6,100	7,650	3,400	124.98	2.98	157.63	3.750
2.00	0.134	0.128	1.732	0.7855	2.356	3.070	54,988	62,843	6,500	8,200	3,800	122.42	2.91	157.63	3.750
2.00	0.156	0.148	1.688	0.9037	2.238	4.400	63,261	72,298	7,600	9,550	4,500	116.28	2.77	157.63	3.750

Fig. 2. Manufacturers tubing data for 70,000 psi coiled tubing work string material.

NOTE: The ovality percentage value is obtained by dividing the major axis diameter by the minor axis diameter.

- The recomended operating limits applied to CT diameter and ovality are as follows:

  Maximum OD – 106% of the nominal CT diameter.

  Minimum OD – 96% of the nominal CT diameter.

1.3 Fatigue and Corrosion

Fatigue damage in CT as a result of combined pressure and bending cycles is the primary consideration when attempting to define the useful life of a CT string. It is an unusual material characteristic which must be predicted because it cannot be measured.

The CoilLIFE* computer model features a complex mathematical model which was derived from an extensive CT fatigue testing program. This model calculates the damage that occurs to the tubing due to the sequence of pressure and bending cycles. By analyzing the cumulative data of a CT string, the model can predict when the first cracks in the tubing will be initiated. By applying a safety factor to this prediction, the CT string may be withdrawn from service before a fatigue-induced major operating failure (MOF) occurs.

To enable the CoilLIFE model to function effectively, the following parameters must be accurately recorded over the length of the CT string.

- Bending cycles
- Pressure cycles
- Major and minor diameters
- Chemical environment

With these parameters input to the model, a plot can be made to display the percentage tubing life against the length of the string. An example plot is shown in Fig. 3.

As a CT operation is being designed, the proposed pumping and tubing movement schedules may be input to the model. The resulting plot may then be analyzed to verify the ability of the CT string to safely complete the intended operation.

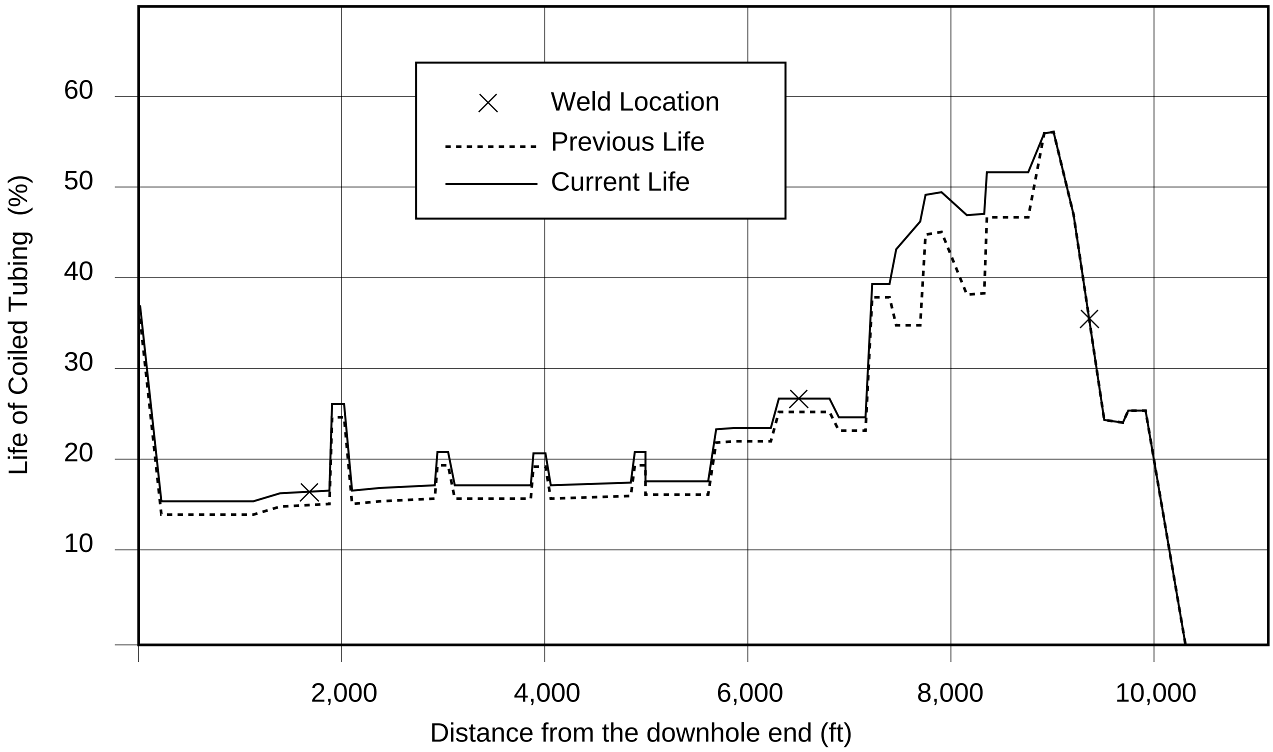

Fig. 3. CoilLIFE output plot.

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CT work strings containing tubing elements which have been used in excess of 95% should be removed from service to allow the appropriate action to be taken.

1.4 Pumping and Flowing

The pumping or flowing of highly flammable and explosive fluids during any operation will inevitably expose personnel and equipment to some risk. To reduce that risk to an acceptable minimum the precautions identified in Safety and Loss Prevention (S&LP) Standards 5 and 22 must be followed.

1.4.1 Pumped Fluids

Since there is no definitive method of predicting the development of a tubing pinhole, the pumping of hydrocarbon gas or condensates through CT is STRICTLY PROHIBITED.

The pumping of crude oil through CT is allowed CONDITIONAL that it has been degassed. It should be confirmed prior to pumping that the crude has been effectively degassed and that all personnel, including the client representative, are aware of Dowell policy concerning the pumping of flammable fluids.

Adequate fire protection service must be provided on location for the duration of the operation.

The pumping of "live crude" through CT is not permitted.

1.4.2 Reverse Circulation

Reverse circulation through CT is allowed if the following conditions are met.

- CT size is 1-1/2 in. or greater.

  The high friction pressure encountered while pumping through small-sized tubing, together with the relatively low resistance to collapse, will exceed practical working limitations. Therefore, reverse circulation through 1-in. and 1-1/4-in. CT is not permitted. A tandem check valve must always be run with these tubing sizes.

- The well is dead and is full of kill-weight fluid.

  The CT/well tubular annulus must be filled with kill-weight fluid, and the fluid which is being circulated should be of a sufficient density to maintain control of the well conditions.

- After considering the anticipated combination of tensile and differential pressure loads, the FSM has given his/her approval.

  The tubing may be subjected to extreme loads and forces during this type of operation, Therefore,it is important that the parameters on which the job was designed and approved are maintained as closely as practical.

1.4.3 Flowing Through CT

The production of reservoir fluids through CT above the well pressure control equipment is STRICTLY PROHIBITED.

The absence of a suitable master valve and kill facility, located at or on the wellhead, renders temporary CT a totally unsuitable and dangerous means of production.

Reservoir fluids can be safely produced through CT completions which have been installed and secured following approved procedures and using equipment designed for this application.

1.5 Hydrogen Sulfide

Equipment which is designed and built for use in H_2S environments can safely tolerate exposure to relatively high levels of H_2S for an extended time period. However, the presence of H_2S (even in minute concentrations) can be sufficient to initiate corrosion or cracking in equipment that is not intended for use in such an environment.

The hazards associated with use of the incorrect equipment in an H_2S environment are severe, both in terms of personnel safety and well control.

Where a total system pressure is greater than 265 psia and the H_2S partial pressure exceeds 0.05 psia the system is considered sour. This is based on the National Association of Corrosion Engineers (NACE) Standard MR-01-75-88 definition of a sour environment.

In practice CT operations will almost always be performed in systems with a total pressure exceeding 265 psia. Therefore, the critical limit in terms of H_2S corrosion in any system will be 0.05 psia. This is applicable in single- and multiphase fluids.

1.5.1 Determining Sour Status

To simplify the procedure in determining whether a well is to be considered a “sour well” and initiate the corresponding requirements of equipment and personnel safety, the following recommendations are made.

It should be noted that these are minimum recommendations; application of more stringent limits may be justified by local requirements or client preference.

- Any well on which an acid treatment is to be performed, and which has or has had any history of H_2S, will be regarded as an H_2S well.

- Any well on which the CT will be exposed to a total system pressure less than 5000 psi, and an H_2S level in excess of 10 ppm, will be regarded as an H_2S well.

- Any well on which the CT will be exposed to a total system pressure greater than 5000 psi containing any level of H_2S will be regarded as an H_2S well.

- Only equipment that can be positively identified as suitable for use in an H_2S environment (as specified by NACE Standard MR -01-75-88 and API R49) should be used when working on a well that is known or suspected to contain H_2S.

2 COILED TUBING FORCES

When CT is run into or pulled out of a vertical well, it is relatively easy to predict what will be the indicated weight of the tubing string.The tubing weight per foot, or meter, is known so the weight of the string will correspond to the length hanging in the well, with some correction being made for the effects of buoyancy. Thus, the weight of the string as shown on the weight indicator display on the surface gives a primary indication of the forces being applied to the CT downhole.

In highly deviated wellbores, the forces required to push the CT along the wellbore cannot be accurately determined by the weight indicator display alone. A number of forces which act on the CT must be taken into account to predict the loads that the tubing will be subjected to in the wellbore.

The CoilCADE computer program has been developed by Dowell to model the forces acting on the CT under given conditions. It is thereby possible to determine the loads on the CT string, enabling efficient job design prior to the operation.

The CoilCADE Tubing Forces Model (TFM) outputs are used to assist in the design of CT operations which are safe and reliable, and also predict the maximum depth which a tool string may be run in horizontal and highly deviated wellbores. A plot of the anticipated weight indicator load against the measured depth is used during the job as a means of checking and interpreting any anomalous conditions.

Most models or calculations used to determine forces acting on the CT divide the well and tubing string into sections or elements. The resultant load is then calculated for each component in each element. In this way it is possible to examine the effects over the length of the tubing and not only at the top or bottom of the tubing string.

The forces identified below have varying effects on the CT string (Fig. 4). Each may vary individually during an operation and all will change from well to well.

It is important that account be taken of each force as accurately as possible to help ensure that the operation may be completed as designed.

- Buoyancy
- Well profile
- Tubing residual bend
- Helical buckling
- Tubing friction
- Stripper friction
- Wellhead pressure
- Fluid flow
- Reel back tension

2.1 Buoyant Weight

This is the weight of the CT, taking into account the effect of internal and external fluids, their density and corresponding buoyancy effect.

The buoyant weight of each element in the string has a tensile effect on the other elements in the tubing string.

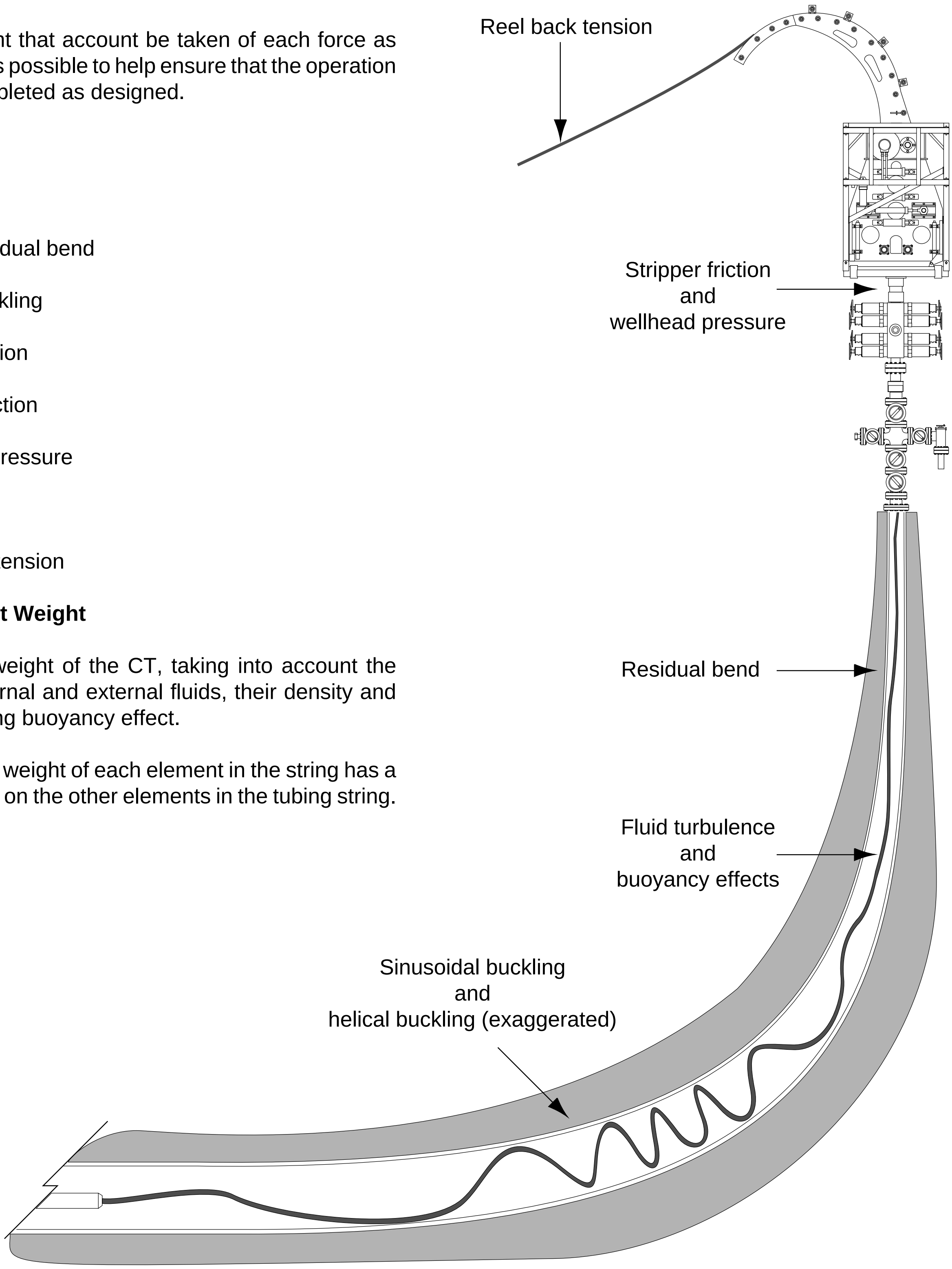


Fig. 4. Coiled tubing forces.

2.2 Well Profile

The profile of a well or completion can affect the load or force applied to the tubing string in two ways.

• Low Side Drag

The buoyant weight of a tubing string, which is lying against the low side of the well, will vary with the deviation of the well. As the deviation changes, the amount of friction due to buoyant weight will also change.

• Belt Effect

When tubing is placed in tension around a curve, the tubing is forced against the inside surface of the well tubular (Fig. 5). This causes a corresponding increase in friction. The belt effect may be induced by changes in deviation and azimuth.

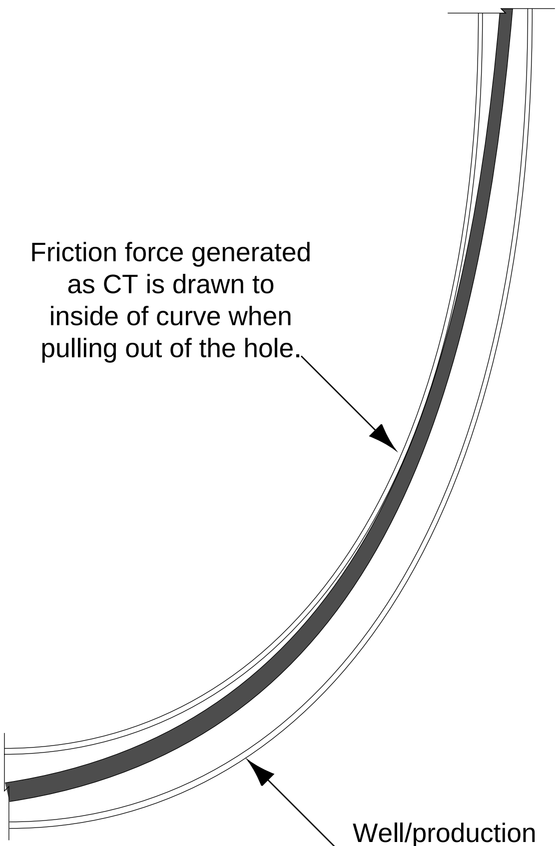


Fig. 5. Belt effect on wellbore curvature.

2.3 Residual Bend

When the CT is injected through the stripper, the tubing will be bent with a radius of curvature of about 24 ft. This bend is referred to as the residual bend and originates from storing the CT in a plastically deformed state on the reel.

As the tension on the CT string is increased, as a result of string weight or applied tension, the tubing will straighten. When the tension is decreased, the tubing will again form a residual bend.

The principal effect of the CT residual bend occurs as compressive force is applied to the string and buckling is initiated.

2.4 Buckling

Compressive force exerted on the CT string during normal operations in deviated wells may result in buckling of the string in two distinct modes.

• Sinusoidal buckling

• Helical buckling

The force required to push CT into a horizontal or deviated well increases as the tubing is pushed further along the wellbore. When the force reaches a certain level, the CT will snap into a sinusoidal wave pattern (Fig. 6). The load at this point is referred to as the sinusoidal buckling load or critical buckling load.

The period and amplitude of this sinusoidal waveform is dependent on the dimensions of the CT and well tubular in which it is contained. However, since the period will be very long in comparison with the amplitude, any bending of the CT will be within the elastic range and no plastic deformation or damage will be caused to the tubing.

The orientation of each sine wave varies, giving the appearance of helically buckled tubing. However, the important difference between sinusoidal and helical buckling is that helically buckled tubing will contact the wall of the well tubular throughout the period, whereas sinusoidally buckled tubing does not.

When downward force is applied to a sinusoidally buckled work string, the tubing will continue to move further into the well. As the force required continues to increase, a point will be reached where the tubing snaps from being sinusoidally buckled to being helically buckled (Fig. 7).

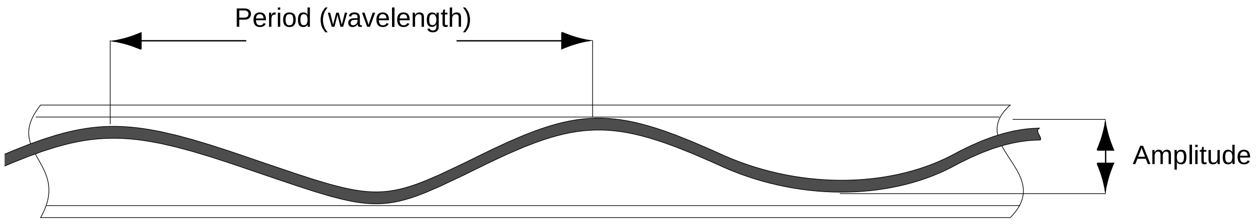


Fig. 6. Sinusoidal buckling.

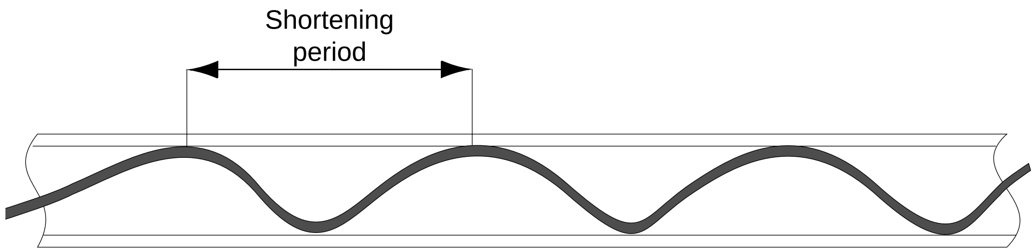


Fig. 7. Helical buckling.

As with sinusoidal buckling, the wave pattern is dependent on the CT and well tubular dimensions and is within the elastic range of the CT. The direction of the helix will change over the length of the buckled section of tubing, thus the number of rotations and induced torque over the total length of the buckled section remains zero.

When the tubing is helically buckled, the resulting helix applies force against the side of the well tubular. However, the tubing can still be moved further into the wellbore. The increased friction caused by forcing the tubing further into the wellbore causes the period of helix to shorten, which in turn further increases the friction. At a certain point, the friction forces become greater than the force pushing the tubing. When this point is reached, it is impossible to push the tubing further into the wellbore. This condition is referred to as helical lockup.

Following helical lockup, it will still be possible to inject tubing into the well; however, this will only result in increasing the amount of buckled tubing in the well. The BHA cannot be pushed further into the well following helical lockup. Determining the point at which lockup occurs is a major element of CT job design work in horizontal and deviated well applications.

Where the wellbore contains a curvature, either as a result of deviation or azimuth change, the sinusoidal and helical buckling loads will be increased. This is due to the increased support the well tubulars afford to the CT. Increasing the compressive force tends to stabilize the CT by forcing it into the trough of the curve. A larger force is required to move the CT out of the trough into a sine or helical waveform.

2.5 Fluid Turbulence

When fluid is flowing at high rates through the CT or through the surrounding annulus, the CT will tend to vibrate. This vibration will effectively decrease the friction between the CT and the well tubular in which it is contained.

2.6 Stripper Friction

The seal provided by the stripper to secure well pressure causes a friction force to be applied to the tubing. When the stripper operating pressure or wellhead pressure is increased, the friction caused by the stripper seal area will also increase.

When operating at high wellhead pressures, this friction becomes a significant factor. In extreme cases the friction imposed by the stripper seal area may make it difficult to inject the CT through the stripper assembly.

2.7 Wellhead Pressure

Wellhead pressure acts on the CT by creating an upward force which tends to force the tubing out of the well. The chart in Fig. 8 shows a plot of force against wellhead pressure for various CT sizes.

NOTE: This chart shows the calculated effect of wellhead pressure only.

2.8 Tubing Reel Back Tension

The amount of back tension applied to the CT between the reel and injector head will affect the value shown on the weight indicator display. This is due to the design of the injector head frame pivot and location of the weight indicator load cell.

Although the CT reel back tension does not affect the actual stress in the tubing below the drive chains, it must be taken into consideration in to accurately predict the weight indicator reading which will be displayed and recorded.

3 COILED TUBING FATIGUE

The working life of a piece of metal (e.g., coiled tubing) is governed by the loads and resulting stresses to which it is exposed. Since the introduction of CT services, the industry standard unit of measure for CT life was “running feet.” This unit of measurement is a reflection of what happens to the CT in the well and, consequently, implies that the stresses applied to the CT in the wellbore determine its life.

Extensive studies made into the behavior and fatigue of CT have conclusively shown that the useful life of a CT work string is almost entirely determined by fatigue imposed by tubing handling methods outside the wellbore.

Damage is caused by the repeated bending and straightening of the CT at the gooseneck and reel. The resulting failure mechanism is referred to as low cycle fatigue. Tubing damage is dramatically increased if internal pressure is applied while simultaneously bending the CT.

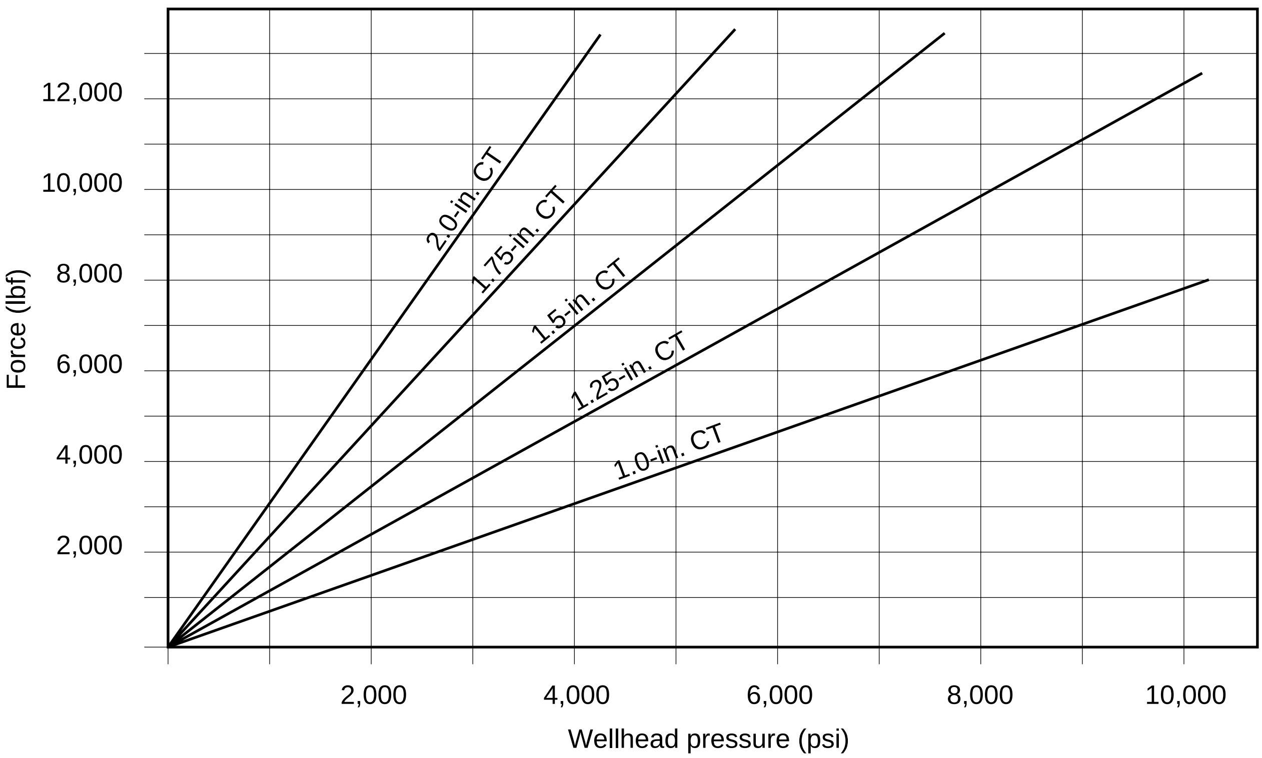


Fig. 8. Force exerted on various sizes of CT by wellhead pressure.

As a result of the research and development efforts, a CoilCADE CT fatigue tracking system has been implemented. This system takes account of the factors that are now known to have a major influence over the useful life of a CT string.

The physical and metallurgical properties of CT have significantly improved in recent years. This combined with improved manufacturing techniques and quality control procedures has resulted in the production of a consistent product with a predictable performance.

Early manufacturing processes required that the CT string be assembled using butt welds to join several short lengths of tubing. This introduced a relative weakness into the CT material adjacent to the weld site (Fig. 9). Tubing failures in this type of work string almost always occur within this heat-affected zone (HAZ).

Most CT strings are now being formed from a continuous length of strip material. The short lengths of flat strip material, which are used to assemble the final string length, are welded and heat treated in a closely controlled process which effectively removes any HAZ from the strip material.

3.1 Stress and Strain

A stress is the internal reaction of a body to an external force. It is generally described as the internal force acting across a unit area in a solid material in resisting the separation, compacting or sliding that tends to be induced by external forces. Stress analysis is the determination of the stresses produced in a solid body when subjected to various external forces.
Since stress is a function of the area of an element, stress values are expressed in force/area (e.g., psi).

Whenever a stress is applied to an element, the element reacts by changing its dimensions, i.e., it is deformed. Strain is a measure of this deformation and is defined as the change in the dimension of the element divided by its original dimension.

The units of strain are consequently expressed as in./in., mm/mm, etc.... or sometimes as a percentage.

Any stress applied to an element will always have an associated strain; a bending stress causes a bending strain.

In any operation CT is exposed to several stresses, some of which apply at specific points while others apply throughout the entire system. The primary stresses that are applied to a CT string are shown in Fig. 10.

The types of stress identified in Fig. 11 have been found to be the principal stresses that affect a CT work string.

• Hoop stress (circumferential)

  Internal pressure applied to a CT string produces a hoop stress which is applied to the full length of the string.

• Bending stress

  A bending stress is produced when the CT is being bent over the gooseneck or onto the reel.

• Radial stress

  The radial stress and associated radial strain only become a significant factor when the wall thickness of the CT is reduced as a result of the combined effects of the hoop strain and bending strain.

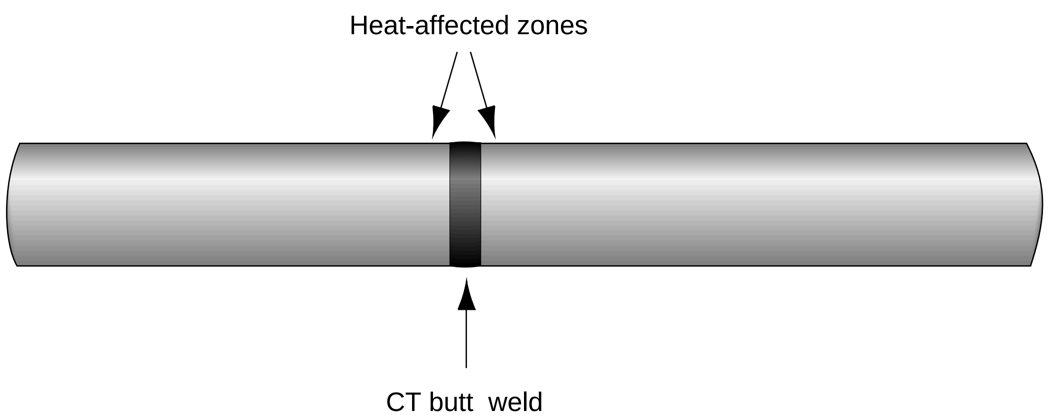


Fig. 9. Heat-affected zones adjacent to a CT butt weld.

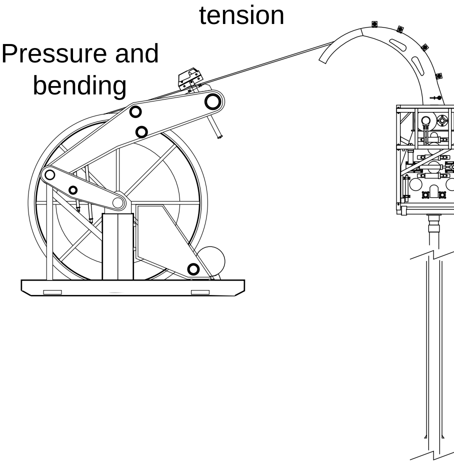


Fig. 10. Primary Stress effecting the CT string.

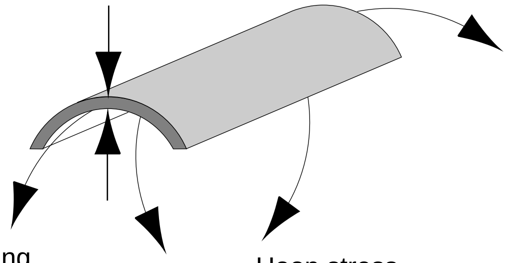


Fig.11. Principal CT stresses.

The tension applied to the CT downhole is the result of tensile stresses which terminate at the injector-head chains. The tension to which the CT is subjected at surface is negligible under normal operating conditions.

3.2 Stress-Strain Theory

For most metals, there is a well-established relationship between the stresses applied to an element and the resulting strains. This general relationship is graphically shown in Fig 12.

There are two distinct parts to the relationship as shown by the lines OA and AB . In the line OA, the strain is directly proportional to the applied stress, i.e., if a small amount of pull is applied,the material stretches a little. If twice as much pull is applied, it stretches twice as much (however, the material will always return to its original dimension). This applies up to a limit corresponding to Point A, which is known as the yield point .
The stress (C) applied at Point A is known as the yield strength.

Beyond Point A, the behavior of the material changes. A small change in stress will result in a large strain. If it is pulled beyond its yield point, the material stretches significantly until it breaks. The breaking point corresponds to Point B.

The applied stress (D) at Point B is known as the ultimate strength of the material. The strain (E) at Point B is known as the ultimate strain.

The plastic and elastic regions shown in Fig. 13 identify important differences in material behavior.

If the applied stress is kept within the range OA, e.g., point Y, and then released, the strain will also return to zero. The material is said to behave elastically in this interval and is the reason for referring to Point A as the elastic limit.

Elastic deformation represents an actual change in the distance between atoms of a material when a load is applied. When the load is released, the atomic structure returns to its original position.

A stress/strain plot of the release will follow the same line OY. There is no permanent damage or deformation to the material when the stresses are in this range.

If the applied stress is in the range AB, e.g., Point X, and is then released, a stress/strain plot of the release will not follow a line XO.
Although the stress returns to zero, a strain (Z) will remain, i.e., there is some permanent change to the material.

The line XZ, which is parallel to line OA, shows how the stress will be removed.

This is called plastic deformation and is the reason why the interval AB is referred to as the plastic region. A plastic deformation represents a permanent change in the atomic structure of a material when the stress is removed.

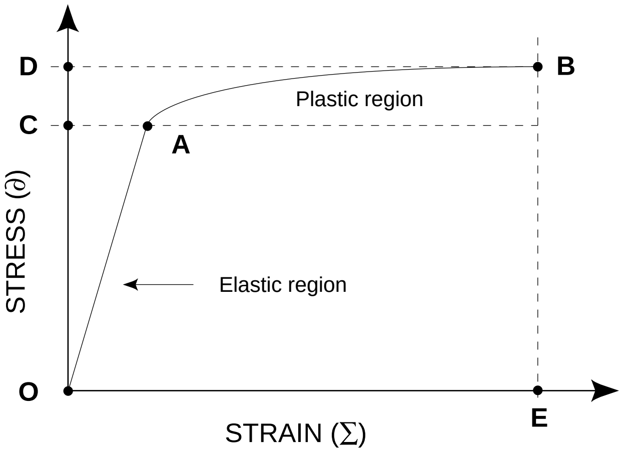


Fig. 12. General stress/strain plot.

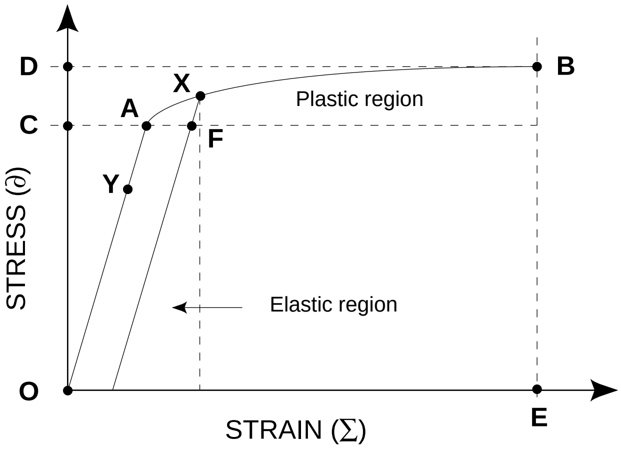


Fig. 13. Plastic deformation plot.

The new elastic limit for the material is now somewhere between points F and X, but its exact position depends on the type of material and the stresses involved. The next time a stress is applied, it will go up the line ZX and not OA.

It is important to understand that every time a material is stressed beyond the yield point, some permanent damage occurs.

3.3 Stress/Strain Theory Applied to Coiled Tubing

The plot and chart in Fig. 14 identify some of the specifications generally used by manufacturers to describe the CT.

By quoting minimum values, the manufacturer is guaranteeing that this is the worst case. In fact, most batches of 70,000-psi CT material have actual yield strengths of about 75,000 psi and ultimate strengths of around 80,000 psi.

These values are a function of the alloy only, and are not related to the pipe size or wall thickness.

All manufacturers provide data similar to those shown in Fig. 2 (Coiled Tubing Data). The yield and ultimate values of load capacity are obtained by multiplying the relevant material properties of the alloy (i.e., 70,000 psi and 75,000 psi) by the wall cross-sectional area to give the load capacity (lb).

Two important points should be noted when considering stresses applied to the CT:

- The stress/strain theory applies to each of the different stresses applied to the CT, e.g., bending stress, hoop stress, radial stress or the tensile stress acting on the CT while in the well.

- The stresses can be simplified into two groups– those acting on the CT when it is in the well and those acting on the CT at the surface.

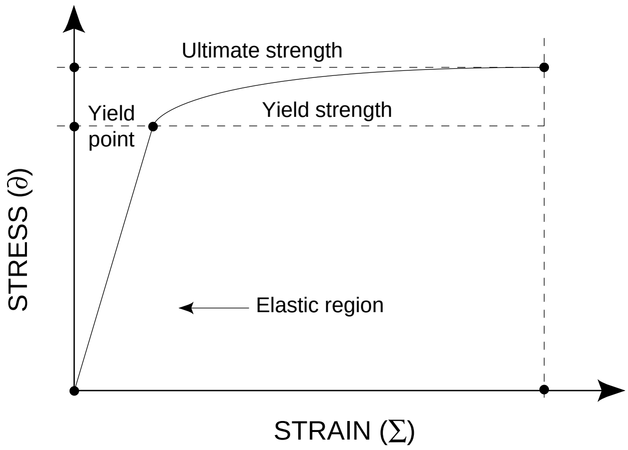
3.3.1 Stress Applied in the Well

The CT is straightened by the injector-head chains, and the string weight is then held by the chains. Below the chains the CT is usually hanging freely in the well (except in deviated/horizontal holes). The CT stresses are always within the elastic region except in very extreme cases.

Although other stresses are present, the primary stress acting on the CT in the well is tension.

Factors that can affect CT tension are buoyancy, well geometry (frictional drag), obstructions and stuck pipe. If the tubing becomes stuck in the hole and the operator continues to pull on the CT, the tension in the tubing would increase until the yield stress is reached and the CT would then begin to plastically deform.
Once the ultimate stress of the material is reached, a failure will occur. Normally, the CT would break just below the injector head if this were allowed to happen. Consider an example of the tension in a CT string in a well (Fig. 15).

Assume the minimum yield strength of the CT is 70,000 psi. The area of 1-1/4-in. OD x 0.087-in. wall thickness



Property	Value
Minimum yield strength	70,000 psi
Minimum tensile strength	75,000 psi
Minimum elongation (ultimate strain)	30%

Fig. 14. General stress/strain plot.

CT is 0.318 in.[2] The minimum yield load capacity of 1-1/4-in. OD x 0.087-in. CT is 22,260 lb. The minimum ultimate load capacity is 25,440 lb, and the weight is 1.081 lb/ft.

If the CT is run to a depth of 15,000 ft, the string weight will be 16,215 lb (without any buoyancy effect or support from a deviated wellbore). This load is well within the elastic region.

Torque can be applied to the tubing in several ways. The tubing will follow a helical path down the wellbore and effectively produce a minimal torque stress value. However, the most severe case of torque stress arises when downhole motors are run on the CT. A typical downhole motor for use on 1-1/4-in. CT can generate about 100 ft/lb of torque which is well below the torque yield limit (504 ft/lb for 0.087-in. wall thickness) of the CT. However, as larger and more efficient motors are developed, consideration should be given to this factor.

3.3.2 Stress Applied at the Surface

A characteristic of bending strain is that the bottom portion of the tubing decreases in length, resulting in a negative bending stress and strain (compression). The top portion increases in length, resulting in a positive bending stress and strain (tension).

The hoop strain which is considered relevant may be simply stated as the diametral growth of the CT due to high internal pressure.

The radial strain becomes a significant factor once the wall thickness is reduced, because of the combination of the hoop and bending strains.

One strain acting independently will cause less severe results than a combination of strains simultaneously produced. In fact, the CT is subjected to a combination of strains a majority of the time. As a result a multiaxial stress/strain analysis is required to determine the combined stress to which the CT is being subjected. Multiaxial forces act in the directions of the three

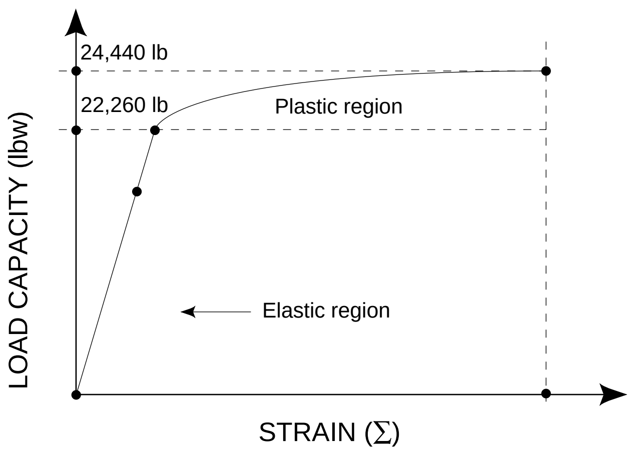


Fig. 15. An example of CT tension in the well.

coordinate axes (x,y and z) and produce stresses not equivalent to zero. There are many mathematical models which predict the life of a given alloy under certain test conditions. However, an exact cumulative stress/strain diagram for CT does not yet exist, although it is believed that the curve resembles that shown in Fig. 16 for the “top” portion of a piece of CT.

This graph depicts the combined effect of the three primary strains due to continuous reciprocation of the CT at the surface.

Point 0 on the graph represents the tubing after being stress relieved at the factory but before it has been spooled onto a reel for the first time (it has never been bent).

Tubing which has never been bent behaves elastically. As CT is spooled onto a reel, the material is subjected to combined postyield strains equivalent to Point 1.

Once it is spooled, it is then called CT and practically the entire cross section is plastically deformed. This can be observed by cutting a section of tubing from the reel and laying it on the ground. The CT is no longer straight but is curved due to the residual stress in the CT which is induced by plastic deformation.

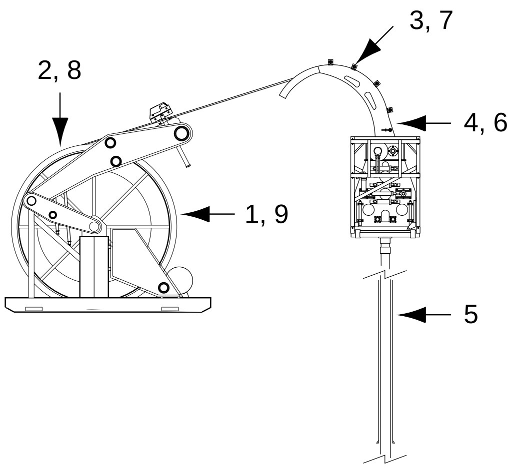
However, tubing that has been plastically deformed will still behave elastically, e.g., if a 3-ft length of 1-1/4-in. CT is bent 2 in. and the force is then removed, the CT will return to its original shape.

Point 2 of the plot corresponds to residual strains which remain after the tubing has been rolled off of the reel and straightened as it approaches the gooseneck.

As the tubing is again bent over the gooseneck, combined strains increase to those at Point 3. Restraightening the tubing within the injector head creates a strain reversal to Point 4. A subsurface tensile load lower than the yield point of the CT material is represented at Point 5.

On pulling out of the hole, the pipe returns through the chains and travels over the gooseneck (point 6).

As the cycles accumulate, the combined strain increases until the ultimate strain is exceeded and the pipe fails (fatigue). At the point of failure, the final stress will have been produced, which has in turn caused the tubing to reach its ultimate strain.



The numbers on the illustration above correspond to the numbered points on the stress strain diagram.

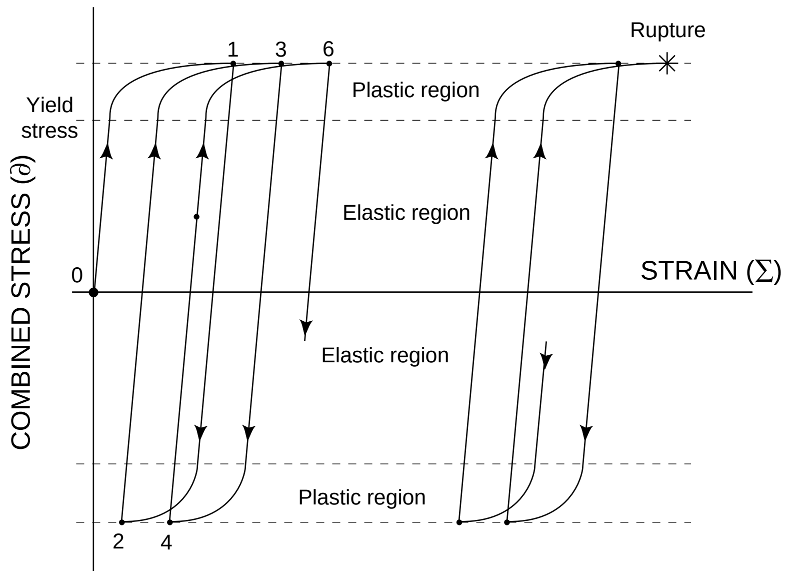


Fig. 16. Stress/strain diagram for CT during spooling and operation.

3.4 Fatigue Testing

The first documented Dowell CT fatigue tests were performed in Holland in 1988. At that time a piece of CT was positioned over the gooseneck with a 7500-kg weight added to the tubing below the injector-head chains and a 50-kg weight positioned on the opposite end to ensure the CT remained wrapped around the gooseneck. The reel was not used.

The injector head was elevated, and the tests were conducted using a cycling stroke of approximately 26 ft (8 m) and an internal pressure of 5000 psi. With the test parameters fixed, the number of "cycles," the OD of the CT and the skate pressures were recorded.

These tests were not truly representative of an actual job as all of the strain reversals associated with the CT coming on and off the reel were not simulated. However, they were the first documented tests which gave a qualitative idea of the factors that are important to the fatigue life, and therefore safe working life of the tubing.

An important factor identified during the tests is that varying skate pressures affect the life of the CT. The less the skate pressure applied, the longer the tubing life.

Full-scale fatigue tests conducted by the Dowell Coiled Tubing R&E Group (TCT) began in 1989. Various CT geometries and internal working pressures have been tested to destruction, and testing continues as new CT products are commercialized by manufacturers.

The above tests fully reproduced actual job conditions and, by using the T.I.M. and strain gages, produced data not obtained in previous testing.

The eventual failure of CT due to fatigue was confirmed to be a result of cumulative deformation occurring every time the pipe is bent. To determine the evolution of the damage, cumulative strains were monitored. The strain data were then input to several local strain-based fatigue life prediction theories.

3.4.1 Fatigue Test Results

The tests revealed two physical, easily measurable phenomena which can be exploited in the field. Field systems track the condition of the pipe with respect to these phenomena and correlate them to the fatigue life of a CT work string.

- Bending Under Pressure

  There is a distinct relationship between the number of trips to failure and the simultaneous internal pressure. The higher the internal pressure, the less the number of trips to failure (e.g., 199 trips at 300 psi versus 41 trips at 5000 psi). If there is a butt weld within the section, the number of trips to failure will be dramatically reduced due to the changed metallic structure in the HAZ.

- Diametric Growth

  The CT grows in diameter as trips are made with an internal pressure applied. This growth is significant and in some cases is severe, e.g., during one of the tests at 5000 psi with 1-1/4-in. CT, the pipe ballooned from its original 1.25 in. out to 1.47 in.

Under static conditions, the levels of pressure that are typically applied will not result in any permanent deformation, because the associated stresses are well within the elastic limit. However, when the tubing is being bent sufficiently to make the bending stress plastic, any other stress that is applied at the same time will also have plastic strains associated with it. This applies even if these additional stresses applied individually would be elastic. Therefore, bending the CT with a high internal pressure, i.e.,greater than 3000 psi, will cause some diametric growth.

If the CT is bent with no internal pressure, there will be no significant growth in diameter.

Approximately 60% of the CT jobs performed worldwide have an applied internal pressure greater than 3000 psi. Therefore, the majority of CT workstrings will be subject to ballooning in the sections that have been cycled at a higher pressure.

From the results of these fatigue tests, field quality systems have been developed:

- A fatigue tracking system comprising on-site data acquisition supplying data for the CoilCADE reel database. The CoilLIFE computer model can then be used to predict the remaining life of the CT work string.

- A T.I.M. real-time inspection system will accurately measure the diameter of the CT to alert operating personnel if the predefined dimensional limits of the CT are exceeded.

Other significant findings from the test results are listed below:

- The CT always failed at the portion that had made complete trips (from the reel through the injector-head chains and back onto the reel).
- The CT fails at the maximum diameter of the ballooned portion and generally on the underside. In the vast majority of the tests, this occurred while passing over the gooseneck coming out of the hole.
- At the beginning of the tests, the CT assumes an elliptical shape such as that shown in Fig. 17. At higher pressures, the minor axis grows to become the major axis and is also dependent on the number of trips performed.
- The top portion of the CT often conforms to the shape of a wave just before failure as shown in Fig. 18. The wave shape is more pronounced at higher internal pressures and barely visible at lower internal pressures.
- The initial cracking (which initiates failure) begins on the inside suface of the tubing.
- The sequence of pressure and bending cycles must be considered to determine CT life.
- The CT behaves elastically when subjected to an internal pressure alone. However, when the CT is bent at the same time, the CT then behaves plastically.
- Bending strains remain essentially constant to failure at all pressure levels; however, hoop strains increase with increasing internal pressure.
- Test measurements showed that CT will either not lengthen or only lengthen slightly with an applied internal pressure, and that most of the damage is caused by diametric growth (ballooning).
- The longitudinal weld does not seem to have an effect on the longevity of the CT.
- Thicker walled pipe gives a longer cycle life.
- The smaller the OD of the CT, the more cycles that can be made before failure.
- The less skate tension, the longer the tubing life.
- The tests with the butt weld revealed the regions of localized plastic deformation were located approximately 0.2 in. on either side of the weld, in the HAZ.
- Reversing the direction of curvature also reduces the life of the CT. Reversal of the CT is commonly caused by positioning the levelwind too low. Theoretical predictions suggest that as much as a 25% reduction in the life of the CT may result if a reversal is present on every trip throughout the life of the CT.
- Although a section of CT fails, the remainder of the string is not affected in the same manner as the failed section unless subjected to exactly the same conditions. Therefore, the entire string should be evaluated to determine whether it should be repaired or discarded.

Prior to the conclusion of the tests outlined above, there

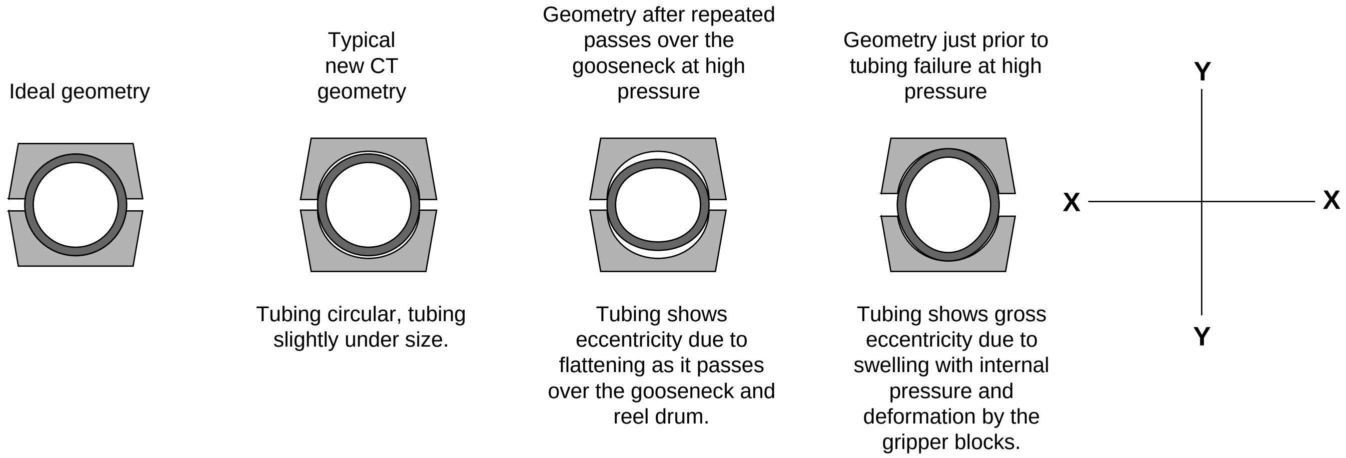


Fig. 17. Ovality changes in CT.

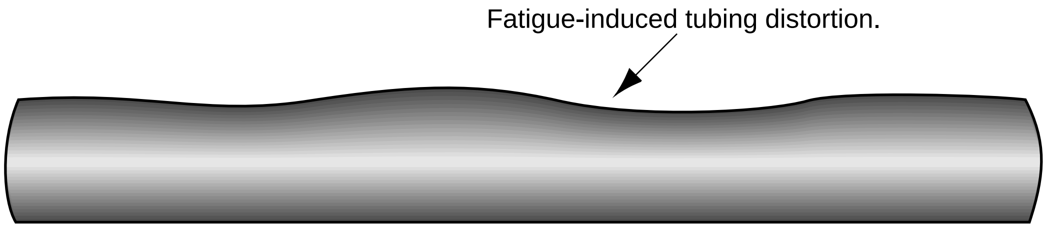


Fig. 18. Fatigue-induced deformation.

were a number of misconceptions regarding CT fatigue prevalent in the industry. As a result of the tests and subsequent action, these are now disproved.

4 REFERENCES

The following references are recommended to assist with job design information or for further reading.

Technical Papers

Adrichem, W.V., and Newman K.R.: “Validation of Coiled Tubing Penetration Predictions in Horizontal Wells," paper SPE 24765, presented at the SPE Annual Technical Conference and Exhibition, Washington D.C. U.S.A. (October 1992).

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Newman, K.R.: “Coiled Tubing Pressure and Tension Limits," paperSPE 23131, presented at the SPE Offshore Europe Conference, Aberdeen, Scotland, (September 1991).

Newman, K.R., Corrigan M. and Cheatham J.B.: “Safely Exceeding the ‘Critical Buckling Load’ in Highly Deviated Wells," paper SPE 19229, presented at the Offshore Europe Conference, Aberdeen, Scotland, (September 1989).

COILED TUBING JOB DESIGN

Contents

1 INTRODUCTION

As the features and benefits of modern coiled tubing operations, equipment and downhole tools become more complex, the initiation of a thorough and methodical job design process becomes essential. Although the majority of the job design process is performed away from the wellsite, many potential execution problems or hazards can be identified. With timely identification, operational problems or hazards may be resolved without jeopardizing the safety of personnel or well security. Therefore, the job design process must be regarded as an investigation and preparation procedure for all aspects of the intended operation – not simply the selection of an appropriate treatment, toolstring or equipment configuration.

Fundamental to any job design process is a full understanding of the overall objectives. The ultimate success of the operation will be gauged against these objectives, therefore, a clear understanding is essential. In some instances, the objectives may be economically or operationally misguided. A joint review of influencing factors, conducted by operator and contractor personnel, can allow such conditions to be identified. As a consequence, alternatives can be investigated and selected to provide improved return on investment or greater operational success.

In almost all CT applications, the workstring functions as a conveyance method for treatment fluids or toolstrings. Therefore, to complete a treatment design some knowledge and understanding of the associated service is required (e.g., matrix stimulation or squeeze cementing). In many cases a number of alternative treatments, or means of application may be identified. While some may be quickly dismissed due to economic or availability reasons, it is prudent to assess all options to ensure that the selected treatment is optimal in terms of efficiency and economics.

A major component in the design of Dowell CT operations is the use of CoilCADE* software. CoilCADE software provides design support for a wide range of CT applications through validated models which are used to simulate conditions anticipated during the operation. The resulting outputs are used to confirm the operation can be safely completed under the given conditions.

Databases within CoilCADE are used to track the history, and more importantly the fatigue to which CT workstrings may be subjected.

The illustration in *Fig. 1* shows a generalized CT job design sequence. In complex or sensitive applications, several iterations of each stage may be required to ensure the desired results. Conversely, the design of routine treatments is often driven and tuned by experience.

The evaluation phase is a necessary, though often overlooked requirement to complete the CT operation and assess the design efficiency.

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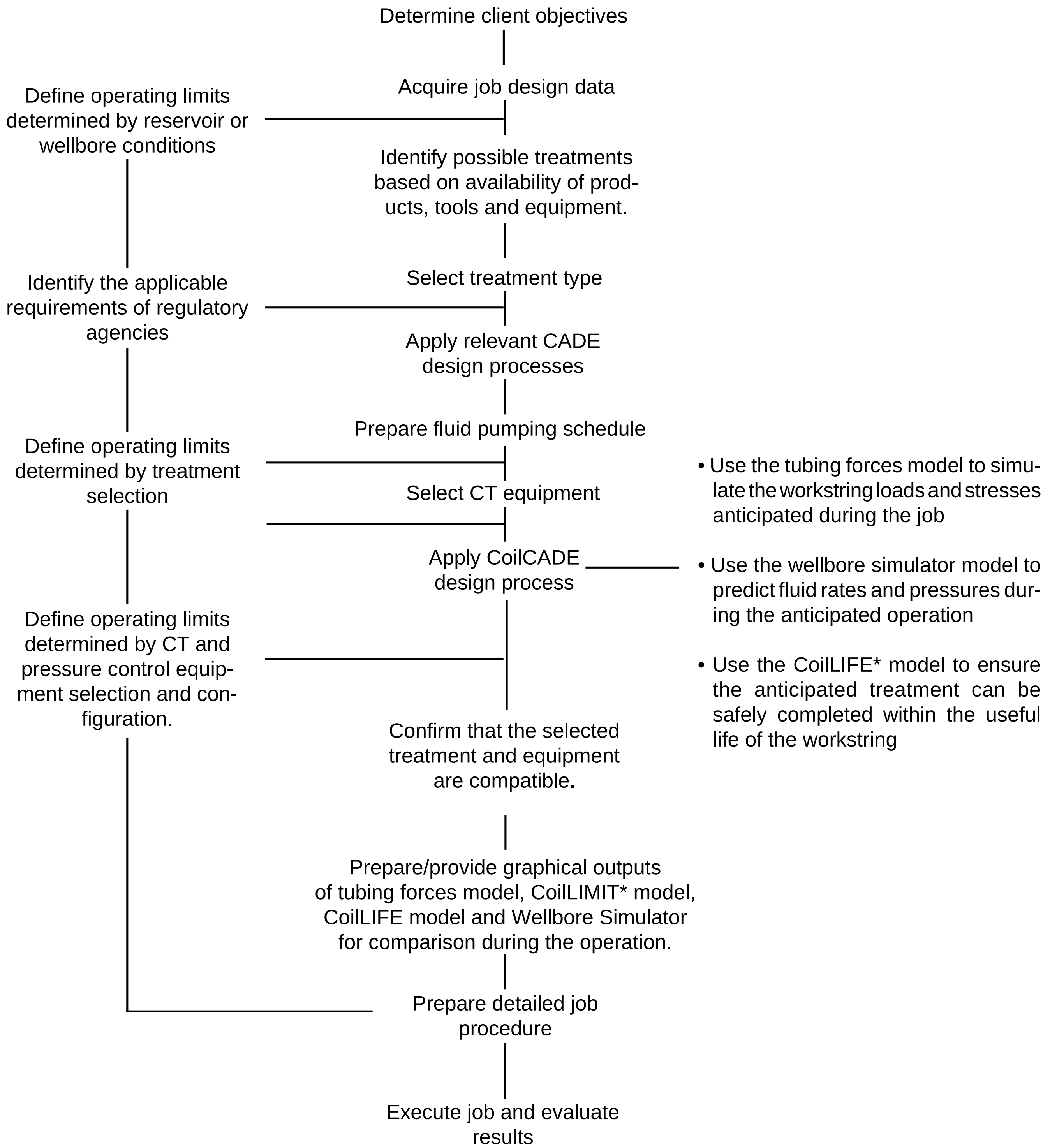

Fig. 1 Generalized coiled tubing job design methodology.

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2 JOB DESIGN DATA

The data required to enable the job design process to be completed varies with the type of application and its complexity. The principal areas of investigation are shown below and are grouped in three categories: data obtained from well records, information relating to product and service availability, and the requirements of regulatory agencies.

Well file sourced

- Reservoir parameters
- Wellbore conditions
- Surface or location limitations

Dowell sourced

- Product availability/compatibility
- Equipment and tool availability

Regulatory requirements

- Operational requirements or limitations

The output of representative plots and values from computer models is greatly dependent on the input of accurate data. Consequently, some effort should be made to ensure the accuracy of job design data. While acquiring this data, the overall objectives should be confirmed by investigating the desired changes in wellbore or reservoir conditions.

The design methodology adopted for each job is dependent on the application or operation to be completed, and in many cases prior experience is the best guide. However, there are several factors which apply to all Dowell CT operations and consequently must be considered during all phases of the job design and execution.

- Well security - it is essential that adequate well security is maintained to guard against the exposure of personnel, equipment and the environment to wellbore pressure and fluids.

- Personnel safety - performing the necessary tasks using the required safety equipment, or with equipment on standby for immediate use as required.

- Operating limits - the operating and safety limits of all equipment and tools must be known by relevant operators. The operation must be designed and executed within stated or calculated limits.

- Operating standards - the operation must be executed, as designed, by trained and competent personnel in accordance with applicable operating practices, regulations and safety standards.

2.1 Associated Services

The factors and constraints associated with the design and selection of associated services are contained in the relevant service line manuals. In this manual, summaries or guidelines are occasionally given for associated services conveyed by CT. However, in all cases it is recommended that the local Dowell CT representative is consulted during the job design process.

Published articles and technical papers are often useful reference sources for many aspects of CT and associated operations.

3 CoilCADE SOFTWARE

CoilCADE software is an assembled package of modular design which allows modifications and additions to be easily made. The package includes calculation and data base modules as well as the capability of several graphic and report format outputs. Being modular also allows selective, or reiterative use of models during the job design process.

The CoilCADE software comprises the following principal job design modules.

- Tubing forces
- CoilLIFE
- CoilLIMIT
- Wellbore simulator
- Friction pressure
- Foam cleanout

The following brief descriptions of CoilCADE modules and their functionality is provided for general information purposes only.

3.1 Tubing Forces

This module employs a Tubing Forces Model (TFM) which was specifically developed for CT. The model enables analysis of the loads applied to the CT by simulating the behaviour of the workstring under given wellbore and operating conditions. The forces which are modelled include buoyancy, frictional drag, stripper friction, reel back tension, workstring and toolstring weight and the effect of wellhead pressure. By determining these forces the model can predict weight indicator readings, the point of helical buckling and the point of lock-up.

The principal functions and outputs of the TFM are shown below.

- Confirm that the selected workstring and tool assembly can be run to the desired position in the wellbore.

- Verify that the selected toolstring will pass any doglegs or wellbore anomolies.

- Provide a predicted weight indicator reading vs. depth plot for running in and pulling out of the wellbore. This plot enables the CT unit operator to compare predicted and actual values, allowing anomalies to be detected *(Fig. 2)*.

3.2 CoilLIFE

The CoilLIFE module operates in conjunction with a database, which is maintained for each CT reel, to predict the remaining useful life of the workstring. The reel length (including changes), pressure cycle history and acid exposure history is updated for each operation. In addition, the CoilLIFE model calculates the fatigue damage imposed on the tubing due to the sequence of pressure and bending cycles.

The principal functions and outputs of the CoilLIFE module include the following.

- Based on extensive CT fatigue studies and testing, the CoilLIFE module predicts the life remaining in each workstring element. This information is presented in a plot of workstring-life remaining (%) vs. distance from the downhole end of the string (ft) *(Section 3, Fig.3)*.

- Details of the anticipated operation can be input to the CoilLIFE model to ensure that the selected workstring has sufficient life remaining to allow the operation to be completed safely.

- Minimizes the risk of tubing failure during an operation.

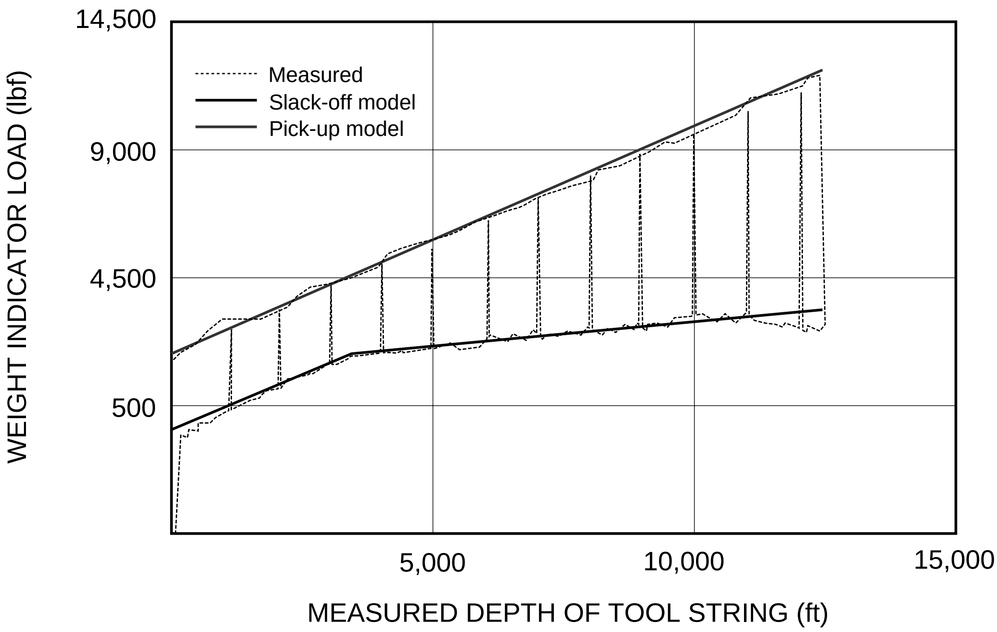

Fig. 2 Tubing forces model graphical output.

3.3 CoilLIMIT

The CoilLIMIT module is used to determine the pressure and tension limits for a given workstring under the anticipated wellbore conditions. The model uses Von Mises incipient yield criteria to determine the pressure and tension conditions under which the CT will begin to yield. The effect of workstring ovality is also considered when calculating the collapse pressure limit.

The principal functions and outputs of the CoilLIMIT module include the following.

- The CoilLIMIT output plot graphically depicts the safe pressure and tension limits for the workstring in a given wellbore *(Section 3, Fig. 1)*

3.4 Wellbore Simulator

The wellbore simulator uses equations for the conservation of mass and momentum to model transient, multi-phase fluid flow and particle transport in a wellbore environment. The circulation of fluids (compressible and incompressible) is modeled with the pick-up and transport of solids to determine circulation rates and pressures. Possible formation leakoff or inflow is also calculated to allow the Wellbore Simulator to model the mixing and flow of all solids, liquids and gasses in the annular flow stream (Fig. 3).

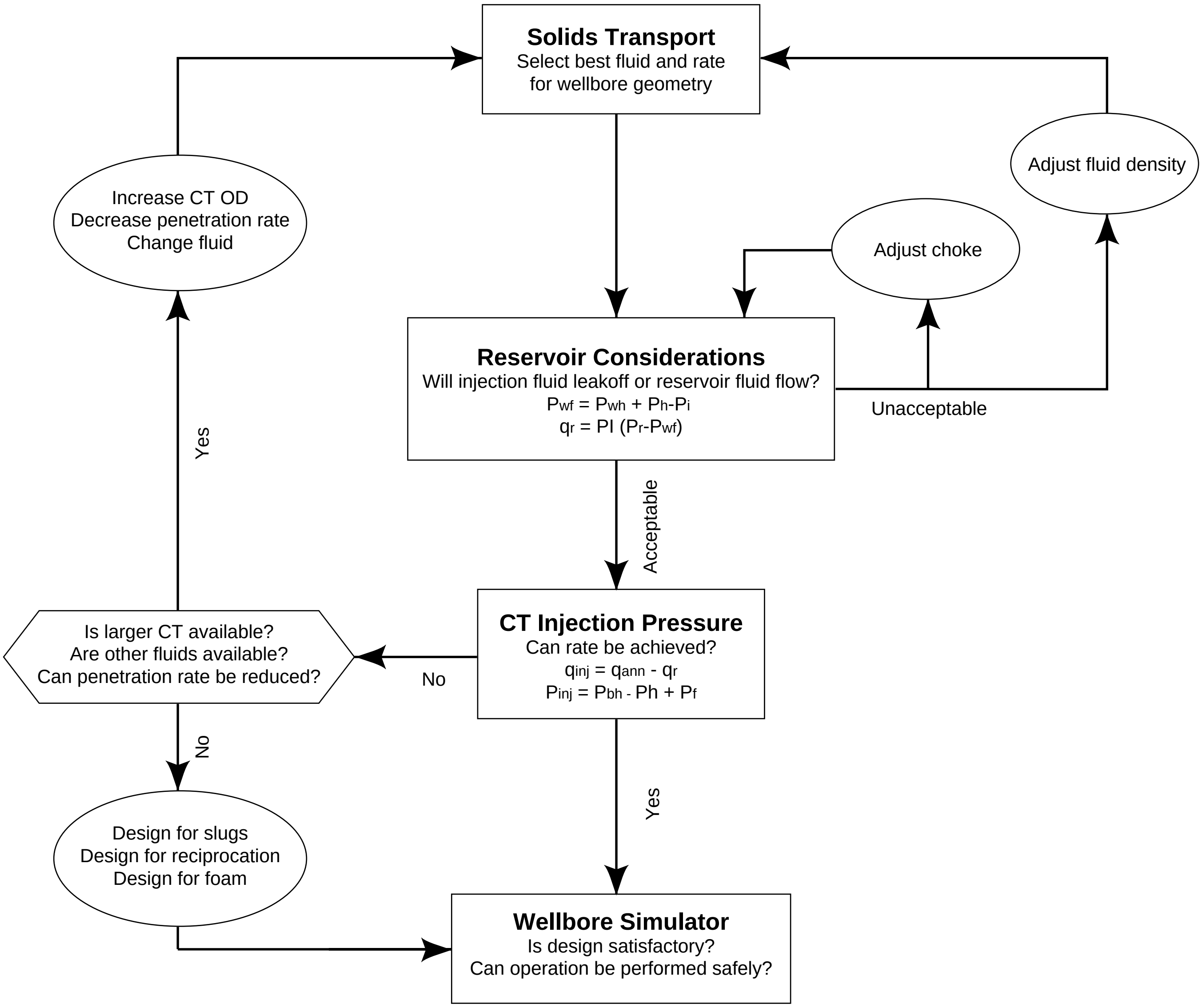

Fig. 3 Wellbore simultaor – wellbore fill removal flowchart.

The principal functions and outputs of the Wellbore Simulator include the following.

- Used to determine treatment feasibility, and enable equipment and product selection (including quantity) for a treatment.

- Predicts the rate of gas, liquid and solid returns, allowing efficient operations to be conducted at the wellsite.

- Quantifies return fluid composition to allow appropriate disposal arrangements to be made.

3.5 Friction Pressure

Based on fluid friction correlations, the fluid friction model determines friction pressure gradients for Power Law, Newtonian, Bingham Plastic and foam rheological models. The friction pressure module is also used to select fluids, rate and pressures for input to the Wellbore simulator.

The principal functions and outputs of the Friction Pressure module include the following.

- Provides fluid friction, pressure and rate data for use in other CoilCADE modules.

- Provides graphical output of friction pressures for various fluids in a given CT workstring and annular configuration.

3.6 Foam Cleanout

The foam cleanout module calculates the rates and volumes of liquid and gas required to achieve a desired bottomhole pressure and foam quality.

The principal functions and outputs of the CoilLIFE module include the following.

- A calculated output details the pump rates and volumes of liquid and gas required to maintain the specified bottomhole foam quality.

- Surface choke pressures required to maintain desired wellbore conditions.

4 OPERATING LIMITS AND PROCEDURES

Operating procedures should be prepared to ensure correct execution of the intended operation, as designed and in a safe manner. These job procedures or guidelines must be prepared for every CT operation, and will generally comprise a sequence of actions, checks or controls.

The operating limits of the CT workstring and applicable components of the toolstring should be considered during the preparation of the job procedure. In addition, workstring and toolstring operating limits should be documented - either within the job procedure or as an appendix.

Additional plans and procedures to be considered include contingency plans and emergency procedures.

Contingency Plans — Contingency plans should be prepared as a reference source to be used as a guide in the event unplanned conditions are encountered during an operation. By necessity, some plans may include emergency procedures required to maintain control of well pressure or surface equipment. However, CTU operators must be fully familiar with such emergency procedures, and be capable of conducting them without reference to prepared plans or procedures.

Emergency Procedures — Emergency procedures may be defined as an immediate responses to conditions which threaten well security, or personnel safety. Such responses are enacted as a result of detailed training, familiarity with equipment and executed with the knowledge and awareness of the wellbore and operational conditions.

5 REFERENCES

The following references are recommended for job design information or for further reading.

Technical Papers

Newman, K.R.: “Collapse Pressure of Oval Coiled Tubing”, SPE Paper 24988 European Petroleum Conference, Cannes, France. November 1992.

Newman, K.R., M.G. Allcorn: “Coiled Tubing in High Pressure Wells”, SPE Paper 24793, SPE Fall Meeting, Washington, D.C. October 1992.

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CONVENTIONAL COILED TUBING APPLICATIONS

Contents — Page

1 WELLBORE FILL REMOVAL

The removal of fill material from producing wells is historically the most common application of coiled tubing (CT) services. The process is commonly known by several names, including, sand washing, sand jetting and wellbore or fill cleanouts. The primary reason for fill removal is generally to restore the production capability of the well. However, fill removal may be necessary for several reasons, some of which are of greater importance in deviated or horizontal well completions. Typical fill removal operations are designed to

- restore the production capability of the well
- permit the free passage of wireline or service tools
- ensure the proper operation of downhole flow control devices
- maintain a sump (space) below the perforated interval to allow complete passage of tools or as a contingency tool drop area
- remove material which may interfere with subsequent well service or completion operations.

When designing a fill removal treatment, the source of the fill material should be thoroughly investigated. In addition to helping determine the most appropriate removal technique, investigations may indicate that a secondary treatment at the source will prevent further production of fill material.

Common types of fill material include

- formation sand or fines

- produced proppant or fracturing operation screenout
- gravel-pack failure
- workover debris (e.g., scale particles).

For the purpose of fill removal operations, fill materials can be broadly divided into three categories:

- sludge or very fine particulates
- unconsolidated particulates
- consolidated particulates

These general descriptions reflect the type of circulating fluid and possible mechanical assistance which will be required for efficient removal.

Removing fill and conditioning the wellbore should be considered before every operation that involves injection of fluid into the producing (or injection) formation. Also, CT operations which are conducted using tools that will be affected by the presence of particulates or fill should be preceded by a precautionary wellbore cleaning treatment.

In most cases, CT provides the only viable means of removing fill material from a wellbore. The ability to continuously circulate through CT while maintaining a high level of well control enables fill removal operations to be completed efficiently with minimum disruption to completion equipment or production.

In the majority of cases, fill is removed by circulating a fluid through the CT while slowly penetrating the fill with an appropriate jetting nozzle. The fill material is entrained in the fluid flow and is circulated out of the wellbore through the CT/production tubing annulus. Crucial to the success of the operation is the basic requirement that the annular fluid velocity is greater than the settling velocity of the fill material in the fluid.

The fill particles which are easiest to transport and remove in a carrier fluid have a low settling velocity. Such particles are of low density and/or small dimensions. Chemical or mechanical techniques can be used to assist removal. However, chemical removal of fill is generally not 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 drill motor or impact drill and bit may be required.

In highly deviated and horizontal wellbores, settling of the fill material from the carrier fluid is a major concern. In such cases, the fill particles have to fall through the fluid only a short distance before settling occurs on the low side of the wellbore.

In addition to the factors to be considered which ensure efficient removal of the fill material, some consideration must be given to the separation and disposal of fill and carrier fluid.

It will become apparent from the following guidelines and references that there are many factors associated with the successful design and execution of fill removal operations. Several of these factors are interrelated. Understanding the factors and their relationships is essential and serves to emphasize that each fill removal job design must be based on the characteristics of the well to be treated.

1.1 Design

The initial steps for the design of an appropriate fill removal technique require thorough investigation of the following points:

- wellbore and completion geometry
- reservoir parameters
- surface equipment/logistical constraints
- fill characteristics.

A summary of data required is shown in Fig. 1. This should be used as a checklist when preparing a fill removal operation design.

Selection of an appropriate fluid and possible mechanical assistance which may be necessary should be based on these data.

1.1.1 Design Data

Obtaining accurate data for use in treatment designs is crucial to the selection of optimum techniques, treatment fluids and ultimately success of the operation.

Reservoir Parameters

Reservoir Pressure

Reservoir pressure is the most important consideration

FILL REMOVAL DESIGN DATA

Completion

- Production casing/liner and tubing details, e.g., size, weight, grade, depths, deviation, nipples or restrictions, material/alloy, etc.
- Perforation details, depth, interval, shot density, etc.
- Completion or wellbore fluid details, e.g., type, density, losses, etc.

Reservoir

- Reservoir temperature and pressure
- Porosity and permeability
- Formation sensitivity
- Gas/oil contact, water/oil contact

Production and Surface Equipment

- Production logs/history
- Configuration of production and surface equipment
- Storage and disposal facilities/limitations

Fill Characteristics

- Particle size and geometry
- Material density
- Solubility
- Consolidation
- Estimated volume of fill material
- Presence of viscous material

Fig. 1.

when determining and designing an appropriate fill removal technique. Accurate bottomhole pressure (BHP) data are required to enable the design of a pumping schedule which will maintain a circulation system capable of carrying the fill material to the surface without incurring losses. Under ideal conditions, the annular fluid column hydrostatic pressure plus friction pressure should balance the BHP.

Additional system pressure can be applied by adjusting a surface choke located on the fluid returns line. If the reservoir pressure is insufficient to support a full liquid column, fluids such as foam, nitrified fluids or nitrogen and liquid slugs should be considered. Some fill removal techniques can use the flow potential of the well to assist in removing the material.

Reservoir Temperature

Due to the relatively low circulation rates associated with CT, the bottomhole static temperature (BHST) should be used when designing treatments.

Accurate reservoir temperature data are essential for the design of treatments containing foam or nitrogen slugs. In addition, the rheology and density of many fluids are affected by temperature.

Formation Sensitivity

The potential to damage the producing formation must be minimized during any treatment. The sensitivity of the formation may preclude the use of some fluids, requiring the use of compatible fluids or fluids with a low fluid loss.

Wellbore and Completion Geometry

Tubular Size

The tubular, or minimum restriction size, will determine the maximum OD of CT string that can be safely used. Using a CT work string with the largest possible OD can provide the combined benefits of reducing the annular space, thereby increasing the annular velocity and available treatment fluid pump rate.

Fill removal in larger tubulars is complicated by two factors — the pump rates required to achieve efficient fill removal are increased, and larger tubing can potentially contain higher volumes of fill material.

Restrictions

Nipples and other internal restrictions in the completion tubulars should be regarded as possible bridging points and areas of possible localized erosion.

In completions where fill is to be circulated through a small annulus or restriction, it may not be possible to maintain adequate annular velocities without overpressuring the reservoir.

Deviation

The ability of fluids to successfully carry and remove fill from the wellbore decreases as the deviation increases. Highly deviated and horizontal applications require special design and execution considerations.

Completion Packer

Wells with an uphole completion packer can contain large volumes of oil in the production tubing/casing annulus (Fig. 2). Because hydrocarbons destabilize foams, design and execution techniques must take account of such completions.

Logistical Constraints

Logistical constraints affecting the design or execution of fill removal operations can be summarized as those applied to the use or placement of equipment, and constraints applied to the disposal of the fill or carrier fluid.

Equipment

In general terms, complex job designs will require more equipment. If space at the wellsite is a constraint (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.

Disposal

Disposal of the resulting fill material/carrier fluid must be considered. Straightforward circulation treatments using inert fluids can be designed to separate and recirculate

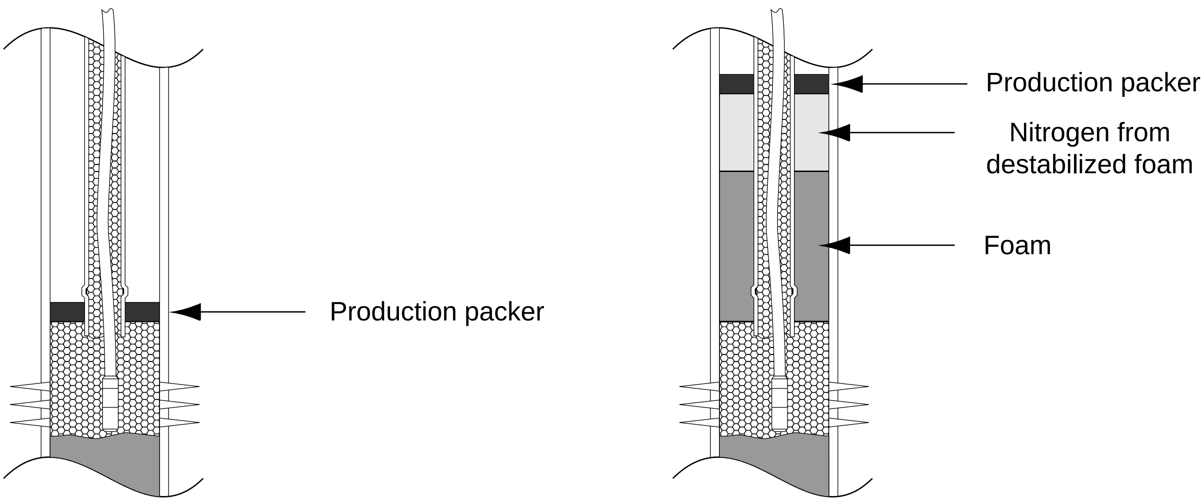

Fig. 2. Conventional and uphole packer completions.

the carrier fluid to reduce the volumes required and minimize subsequent disposal. However, more complex job designs including gelled fluids, foams and nitrogen/gel slugs can result in large volumes of fluid for disposal.

Certain types of fill or scale are classed as low specific activity (LSA) radiation sources (e.g., strontium and barium sulfates). Appropriate monitoring and protection measures must be taken to ensure safe operations. The local or national requirements or regulations associated with the processing and disposal of LSA solids must be known to personnel designing and executing the operation.

1.1.2 Fill Characteristics

To ensure the greatest efficiency of any fill removal operation, the physical properties of the fill material must be known. A sample of material should be obtained for physical and chemical analyses. Samples of fill produced from the reservoir formation can be obtained from produced fluids or wireline sampling tools. If possible, fill samples should be obtained from the wellbore for analyses. Samples obtained from produced fluids will contain particles which are more easily transported (i.e., less dense and smaller particles) than the remaining wellbore fill. Samples of fill material resulting from workover or stimulation activity should be easily obtained from surface samples.

The conveying properties of most fill materials can be severely affected by the presence of mud or other fluids which can cause a viscous mass.

Obtaining a sample of consolidated fill material may not be possible. In such cases, the reservoir details and well history should be closely studied to enable an accurate estimation of the fill properties. The fill characteristics required for the job design include the particle size and density, solubility, and compressive strength.

STANDARD MESH/PARTICLE SIZE

U.S. Standard Mesh Size	Particle Diameter (in.)
3	0.2500
4	0.1870
6	0.1320
8	0.0937
10	0.0787
12	0.0661
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

Fig. 3. U.S. Standard mesh/particle sizes.

TYPICAL WELLBORE FILL MATERIAL PARTICLE SIZE AND DENSITY

Fill Material	U.S. Standard Mesh Size Range	Density (SG)
Proppants		
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
Drilling/Workover Fluid Solids		
Barite	-	4.33
Bentonite	-	2.65
Calcium Chloride	-	1.75
Sodium Chloride	-	2.16
Calcium Carbonate	-	2.71
Wellbore Debris		
Steel	-	7.90
Brass	-	8.50
Common Elastomers	-	1.20
Formation Materials		
Sand and Fines	100 to 350	2.65

Fig.4. Typical wellbore fill material particle size and density.

Particle Size and Density

To enable a fluid to carry fill particles in a vertical wellbore, the velocity of the fluid must exceed the settling rate of a particle in the carrying fluid. The particle settling rate can be estimated using particle size and density data, fluid properties and completion and work-string geometry (Fig. 3 through Fig. 5). By comparing the settling rate with the minimum annular velocity anticipated during the operation, the design feasibility can be checked.

Particle size and density are generally determined by laboratory analyses or estimated from well/field historical data. The size range of particles in a recovered sample can be extensive. To design for total removal of all fill material, the particle settling velocity of the largest particles should be used for annular fluid velocity design calculations.

Particle Solubility

Fill removal operations can be simplified if the fill can be chemically dissolved by acid or solvents. However, totally soluble fills are uncommon and are generally the result of plugs or pills placed during previous workover operations.

Nonetheless, some chemical action can be beneficial in the removal of compacted fills by jetting special fluids. Since obtaining samples of such compacted fill materials is often impractical, the formulation of treatment fluids is commonly based on local experience and well history.

Compressive Strength

Heavily compacted or consolidated fill often requires some mechanical means of breaking or loosening of the material. Since obtaining samples of such compacted fill material is often impractical, determining the level of mechanical assistance required is generally based on experience or availability of tools.

1.1.3 Fluid Performance

In considering and comparing various fluids for removal of a specified fill material, several mathematical models may be used depending on the fluid type. The fluid types commonly encountered are Newtonian, non-Newtonian and foam. An additional type of fluid system is described where nitrogen and a liquid (Newtonian or non-Newtonian) are pumped in alternate slugs.

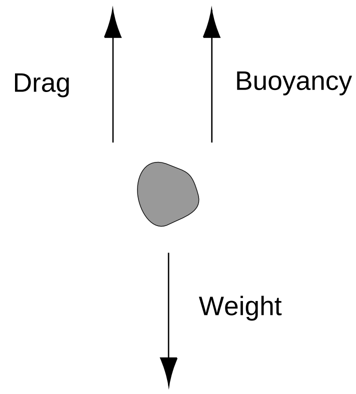

Fig. 5. Forces acting on particles during removal.

The following models and equations, if used correctly, can provide an approximation of the fluid (or particle) performance. They are provided to enable an understanding of the factors which affect fluid or particle performance in fill removal operations.

Factors which are known to affect the performance, but are not considered in the model, include the unknown nature of the fill material and the effect of particle loading on the carrier fluid in the annulus.

Newtonian/Non-Newtonian Fluids

The rate at which particles settle in a fluid can be determined by reference to modified versions of the Stokes and Newton law of free settling (Swanson). This combined and modified model can be applied to a wider range of fluids and particle sizes.

Fill removal operations should be conducted with an annular fluid velocity at least twice (x2) the settling velocity of the particles.

A single particle settling equation is used to illustrate the factors which affect the particle settling rate.

$$v = \frac{9.28\ ß\ g\ (8.34\ SGp - p1)\ d^2}{18 \mu a} \qquad (1)$$

where

v = particle settling rate (in./sec)
ß = 0.22 for Power law fluids
g = gravitational acceleration (32.2 ft/sec/sec)
p1 = density of the carrier fluid
SGp = specific gravity of particles
d = fill particle diameter
μ_a = apparent viscosity of the carrier fluid (cp)

The apparent viscosity (μ_a) of the carrier fluid is a key factor in the equation, and should be calculated for the rates anticipated during the operation. The shear rate for a Newtonian fluid is determined by

$$\gamma' = \frac{1647.18\,(Q)}{(D_1 - D_2)\,(D_1^2 - D_2^2)} \qquad (2)$$

where

Q = flow rate (bbl/min)
D_1 = inside diameter of outer tubular (in.)
D_2 = outside diameter of CT (in.).

A correction must be made for Power law fluids in a laminar flow regime;

$$\gamma'_{PC} = \frac{(3n' + 1)\ \gamma'}{4n'} \qquad (3)$$

where
γ'_{PC} = shear rate for Power law fluids.
n' = flow behavior index

Using the result from Eq. 3 it is possible to calculate the apparent viscosity (μ_a) from the equation

$$\mu_a = \frac{47880\ K'}{\gamma\ (1-n')} \qquad (4)$$

The resulting apparent viscosity (μ_a) value is used in Eq. 1 to determine the settling rate.

Newtonian fluids have a constant viscosity and a shear rate that is linearly proportional to the shear stress. Water, brines and light oils are Newtonian fluids. Such fluids have a low viscosity and are relatively easy to place in turbulent flow.

Non-Newtonian fluids have a nonlinear shear rate-shear stress relationship. Gelled water- and oil-base fluids are commonly used non-Newtonian fluids which exhibit Power Law rheological properties.

Foam

Foams are formed by combining nitrogen gas with a base fluid and a foaming agent. In fill removal operations, the base fluid can have a water or oil base. Higher viscosity foams can be generated by foaming a gelled base fluid.

Two factors influence the properties of the foam— the base fluid composition and the proportion of gas added to the liquid.

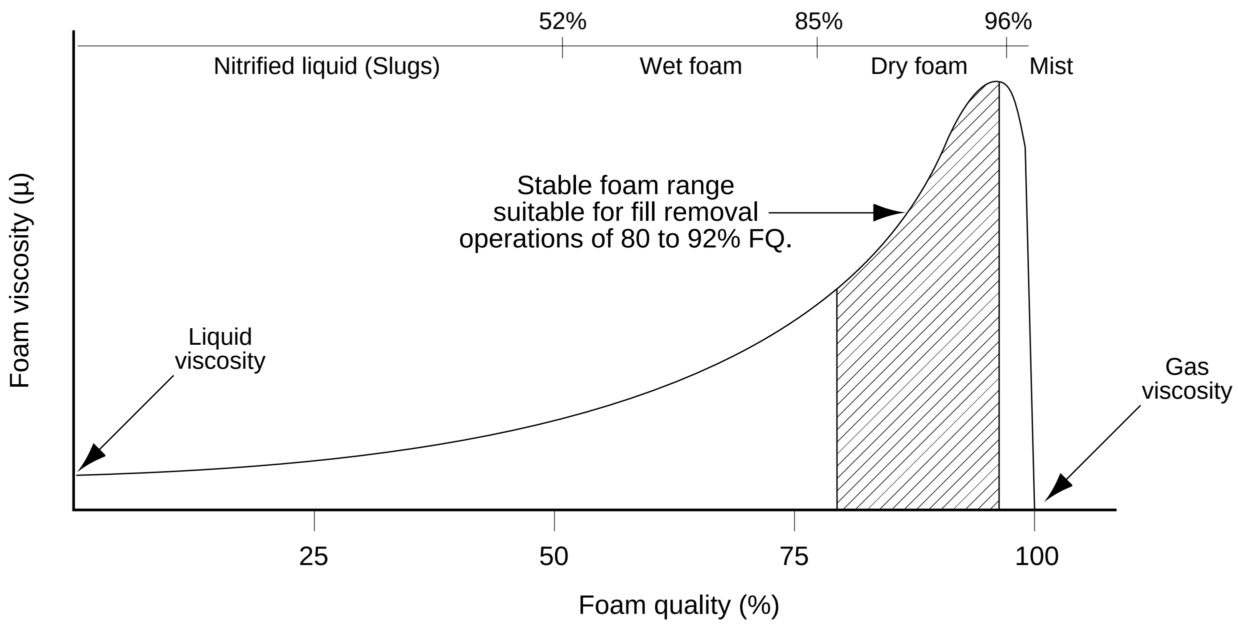

Fig. 6. Foam quality verses. foam viscosity.

The volumetric measurement of gas content in a foam is expressed as a percentage, known as foam quality, and is defined as

$$\text{Foam Quality (FQ)} = \frac{\text{Volume of Nitrogen}}{\text{Volume of Nitrogen + Liquid}} \ \%$$

The types of fluid/foam generated in various foam quality ranges are shown in Fig. 6. At low FQ, the small amount of nitrogen added tends to form gas slugs. There is no overall increase in fluid viscosity, so the particle carrying properties are similar to those of the base fluid.

As the FQ is increased, smaller bubbles of nitrogen form a self-supporting system in which there is little migration of gas or liquid. This is the principle of a stable foam. The fluid viscosity is increased such that the foam now exhibits excellent particle carrying ability.

By further increasing the FQ, the bubbles begin to break down into a mist. As the foam begins to break down, the particle carrying ability is rapidly reduced to zero.

The maximum solids carrying ability of a foam occurs at around 96% FQ. Fluctuations into higher foam quality can result in a potentially catastrophic reduction in carrying ability. Therefore, fill removal operations should be designed with foam in the 80 to 92% FQ range.

Foam quality is highly dependent on pressure and temperature because both factors change the gaseous volume. For this reason the foam returns to the surface must be choked to maintain the annular fluid below 92% FQ. Foams of less than 52% FQ behave as Newtonian or Power law fluids according to the type of base fluid. Foams with 52 to 96% FQ are Power law fluids.

Liquid and Nitrogen Stages

A common fill removal technique involves pumping liquid and nitrogen in alternating stages, rather than simultaneously when generating foam. The principal advantage of this pumping regime is increased annular velocities caused by the expansion of the gaseous nitrogen. In addition the hydrostatic pressure of the fluid column is significantly reduced.

The particle carrying ability of the fluid system is based solely on the carrying ability of the base fluid.

1.1.4 Deviated Wells

Fill removal techniques in highly deviated and horizontal wellbores require several special design and execution considerations.

During production or attempted fill removal operations, material can rapidly accumulate on the low side of the wellbore. Once the fill has settled, it is difficult to re-establish particle transport.

In some cases, the fluid velocity may be sufficient to carry the fill along the horizontal section, but is insufficient to lift it through the build angle into the vertical wellbore (Fig. 7). This is due to the gravitational effects which cause the particles to accumulate and slide down the low side of the tubular. Such effects are most evident at inclinations of 30 to 60°. In wellbores of greater than 60° deviation, the fill or cuttings tend not to slide down the tubular wall.

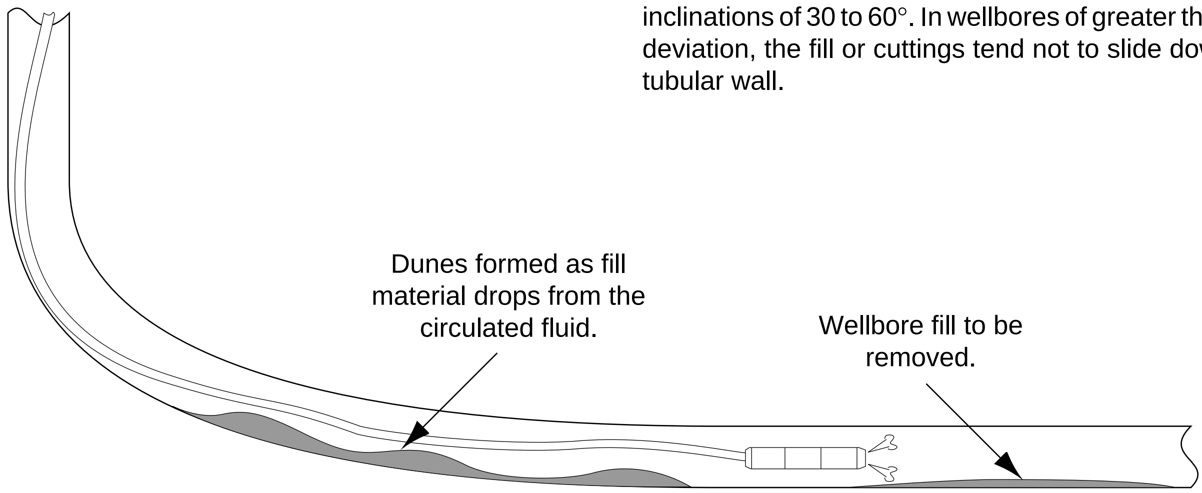

Fig. 7. Particle behaviour in horizontal wellbores.

Studies have shown that hole cleaning in a horizontal wellbore is optimized when the fluid is in turbulent flow. 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. In addition, turbulent flow is difficult to achieve over the length of a horizontal section where the CT is non-centralized.

To compensate for the resulting laminar flow regime and low annular velocity, the rheology of the fluid must be modified. Alternatively, in some cases, 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.

1.1.5 Fluid Selection

Fluids used in the removal of wellbore fill material are selected following consideration of the following criteria:

- bottomhole pressure
- particle carrying ability
- friction pressure
- logistical constraints
- disposal
- compatibility
- cost.

Water/Brine

The general availability, low cost and generally straightforward handling requirements of water and light brines ensures their popularity as a basic fluid used in most workover operations.

Water and light brines are commonly used as fill removal fluids in applications where the BHP and configuration of wellbore tubulars are suitable. In these cases 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.

Newtonian fluids can be easily placed in turbulent flow which provides a useful scouring action. In addition, Newtonian fluids generally provide the best jetting action if compacted fill is to be removed.

Formation sensitivity and compatibility with wellbore fluids should be checked prior to introducing aqueous-base fluid into the wellbore. Compatibility problems can generally be overcome by the use of stimulation fluid additives.

Under static conditions these fluids exhibit no particle suspension capabilities. Therefore, it is vital that an adequate annular fluid velocity is maintained throughout the operation.

Oil/Diesel

Light oils used in fill removal operations possess Newtonian fluid characteristics similar to those discussed for water/brine. The most significant advantages of light oil are improved compatibility and the reduction in fluid density, extending its suitability for operations in wells with a lower BHP.

Operations associated with the handling and pumping of flammable fluids require several safety, logistical and environmental concerns to be addressed. Personnel involved with the design or execution of flammable fluid operations must be familiar with the requirements of the applicable S&LP Standards.

Compatibility problems with oil-base fluid systems are likely to be less restrictive than those of water-base systems. However, compatibility should never be assumed, and basic laboratory compatibility tests should be performed when possible.

Disposal of the carrier fluid is generally handled by normal production facilities. However, separation of the fill material may require that fluids are rerouted to temporary separation/production facilities.

Separation and recirculation of flammable fluids are generally impractical for safety reasons. Consequently, larger volumes of fluid than would be necessary on recirculated water-base systems are required.

Similar to water/brine, light oils exhibit no particle suspension properties under static conditions. Therefore, it is vital that an adequate annular fluid velocity is maintained for the duration of the operation.

Gelled Fluids

Water-base gels are the most common fill removal fluid used in applications which require improved particle carrying and suspension ability.

The viscosity of gelled fluids is dependent on formulation and temperature. Therefore, it is important that the fluid design accurately reflects the anticipated wellbore temperatures, and the field mixing procedures closely follow the designed formulation. Variations in either of these factors from the designed system can result in gels with severely diminished particle carrying ability.

The additional fluid viscosity results in increased friction pressures in the CT work string and annulus which can further restrict the pump rate. However, the improved particle carrying ability of gelled fluids adequately compensates for the reduction in annular velocity.

Several types of water-base gelling agents are commonly used in fill removal operations, most of which are derived from stimulation/fracturing fluids. Formulations and rheology data for most gel types are shown in the Stimulation Manuals. However, laboratory tests should be run to obtain rheology data for the designed gel at the applicable temperature.

Oil-base gel fill removal fluids provide an improved particle carrying ability on application where oil-base fluids are preferred.

Liquid and Nitrogen Stages

Staged treatments are effective in several applications where conventional fluid treatments are at the limit of their effectiveness.

- The CT/tubular annulus size is at the extreme range of the fluid's capability.
- The length of the CT work string limits the desired pump rate due to friction pressure.
- The hydrostatic pressure exerted by a conventional fluid column is too great.
- Foam is not a practical alternative.

The job design must result in a pumping schedule which ensures that the fill is penetrated only when liquids are at the nozzle. When N_2 is at the nozzle , the CT should be stationary or withdrawn.

Foam

A good quality stable foam provides the best particle carrying capability of any fluid. However, foam treatments are subject to more logistical and operational constraints than most other fill removal techniques. Provided a high degree of backpressure control is exercised on annular returns, foam may be used on a wide range of BHP conditions. Although foam treatments are closely associated with low and very low BHP treatments, the technique can be successfully applied to fill removal in very large tubulars.

The low fluid-loss properties of foam are of benefit in removing fill from completions in high-permeability formations. Similarly, applications in water-sensitive reservoirs can be treated using special water-base foams or oil-base foam. The operational cost associated with foam treatments, i.e., the additional nitrogen pumping equipment, is a disadvantage in applications where the BHP and tubular sizes allow alternative techniques to be used.

Foam is a poor jetting fluid and is unsuitable for many applications where the fill is compacted and requires some jetting action to ensure complete removal.

Water-base foams are destroyed by hydrocarbons, consequently, treatments must be performed without reservoir fluids entering the wellbore. Hydrocarbons contaminating the foam, even is small quantities, will result in an unpredictable reduction in the carrying ability of the foam.

The practical and environmental problems associated with breaking and disposing of the foam fluid depend on the capability of the production or testing equipment available at the wellsite.

To ensure that foam treatments are designed and executed efficiently relatively complex procedures must be carefully followed. In addition, treatment parameters must be closely monitored to enable the treatment to be modified to suit changing well conditions.

Stable foams can only exist in the foam qualities shown in Fig. 6. Stable foams are generated by creating a uniform bubble size at the desired gas/liquid ratio. If the bubble size is nonuniform, liquid slugs can be easily formed which tend to prematurely break the foam. The configuration and geometry of a CT string on the reel will usually facilitate the generation of a good quality stable foam. However, foam generating equipment may be required for use with larger size tubing strings (1-3/4 in. and greater).

An approximate measure of foam stability is foam half-life. The foam half-life of a foam is defined as 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 stability of a foam, it is necessary to increase the strength of the bubble walls. This is achieved by increasing the viscosity of the base liquid.

Nitrogen Gas

Fill removal operations using only gas as a transport medium are applicable in low BHP or liquid-sensitive gas wells. Such applications generally use the production capability of the gas well to assist the nitrogen achieve the critical annular velocity required to initiate solids transport. In such applications, erosion of the CT or completion equipment is a concern due to the high annular velocities required. An additional concern exists in that pumping operations must be uninterrupted. Interruption of the pump rate or even reducing the annular velocity below the critical level, will cause the solids to immediately fall back. In this event, re-establishing solids transport is difficult and sticking of the CT string is likely.

1.1.6 Downhole Tools

The downhole tools referenced in this section are those which may be required over and above the primary CT downhole tools normally required (e.g., check valve/ connector).

Small fill particles that are not compacted can usually be successfully removed by fluid action alone; therefore, mechanical assistance is generally not required. However, the exact nature of the fill material is often not known before commencing the operation. Therefore, in some cases, it is desirable to use a tool string equipped to provide some mechanical assistance as a contingency measure.

Mechanical assistance during fill removal operations can be provided by jetting tools, drill motors or impact drills. Additional tools may also be required to support the operation (or provide contingency release) of the tool string.

Removal of very large particles or workover debris contained within the fill may require the use of specialized fishing tools.

The following are some basic requirements of tools to be used in association with fill removal operations:

- The flow rate through the tool string should not be restricted below that required to provide the desired annular velocity.
- Tools must be capable of operating in the high-solids-content annular 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.

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.

All forms of jetting have two main disadvantages - full bore cleaning cannot be assured, and large cuttings can be produced which cannot be transported by the annular fluid.

Drill Motor

Motors, bits and underreamers can be effective in the complete removal of compacted fill materials. However, the use of motors can be constrained by temperature, fluid type and cost.

Impact Drill

Impact drills are suited to a wide variety of fill removal operations, which include the following advantages:

- The impact drill does not operate until resistance is met by the bit, allowing full circulation while running in the hole.
- A wide range of fluids may be used to power impact drills.
- Impact drill assemblies are relatively short, facilitating rig up and deployment.
- Impact drills are capable of operation at higher temperatures than conventional motors.

A significant disadvantage of impact drills is their inability to underream below a restriction.

Junk Removal

Wellbore fill that contains workover debris or large solids (e.g., cement lumps) can require special fishing equipment. A variety of magnetic tools, junk baskets and custom- designed tools are used in such applications. If a wellbore is known or suspected of containing junk or particles which cannot be removed by circulation, the BHA must be carefully chosen to reduce the risk of sticking. In addition, an appropriate release tool must be included in the tool string. The risk of sticking the CT in such applications can be high.

1.1.7 Tubing Movement

The rate of penetration during any fill removal operation is determined by the ability of the annular fluid to safely remove the fill material. Loading of the annular fluid with fill material increases the hydrostatic pressure exerted by the annular column. In low BHP applications, this may result in fluid being lost to the formation. Excessive loading of the annular fluid can ultimately result in sticking of the CT or tool string.

Estimates of penetration rates, tubing movement and circulation times are required to enable fluid quantity, preparation and disposal needs to be planned, i.e., fluid requirements are dependent on time in the wellbore, and time in the wellbore is determined by tubing movement. To avoid the problems associated with excessive penetration rates yet optimize the fill removal operation, tubing movement must be closely aligned to the pumping schedule. This is particularly important while performing staged treatments, when only certain stage fluids are designed to carry the fill material.

The following guidelines on tubing movement and penetration rates should be considered when designing fill removal operations.

Tagging Fill

In many cases the top of the fill will be known as a result of a wireline survey. In such known conditions, the CT progress to the fill and commencement of washing can quickly and efficiently be completed.

The fluid type and circulation rate will be determined by the existing wellbore fluid, e.g., it may be desirable to displace wellbore fluids as the CT is being run.

When the top of the fill is not known, several precautions should be taken to ensure that the CT is not run into a potential sticking situation. In many cases, loose fill material can easily be penetrated with little or no indication on the tubing weight indicator display. Slow circulation through the CT could be sufficient to penetrate the fill, yet be insufficient to transport the fill particles.

When performing fill removal operations in wellbores where the top and extent of fill are unknown, an assumed top of fill point must be identified. When the CT reaches this point, the CT penetration rate and pumping schedule must be designed to be capable of safely removing the fill.

Penetrating Fill

The rate of fill penetration must never exceed the rate at which the maximum fluid loading occurs (Fig. 8). The values shown are based on field experience in vertical wellbores and are conservative when compared with theoretical examples. However, increased friction pressure resulting from the fluid rheology changes will be minimal below these levels.

During staged treatments (i.e., nitrogen/gelled fluid), penetration should only be attempted when the fluids designed to carry the fill material are exiting the CT nozzle or tool. This requires that a detailed and accurate pumping schedule be prepared. To simplify the design and execution of such treatments, it is recommended that the stage volumes be related to the CT reel volume.

RECOMMENDED MAXIMUM FLUID LOADING	
Fluid Type	**Maximum weight of fill material per gallon of fluid (lbm)**
Water	1
Gelled Fluid	3
Foam	5

Fig. 8.

1.1.8 Computer Modeling

The Wellbore Simulator (WBS) in the CoilCADE* software package is a computerized mathematical simulator which models the flow of fluids in a wellbore environment. Although it has been developed to design, execute and evaluate fluid circulation procedures performed via CT, it may be applicable to a general set of pumping conditions.

With a given set of conditions, the WBS uses the equations for conservation of mass and momentum to determine the distribution of the fluids, continuous and dispersed fluid velocities, and pressures encountered when those conditions are met in the field.

The user inputs information about the well, tubulars, reservoir and fluids as well as a pump schedule, and allows the simulator to determine the effectiveness of that schedule.

Initially designed for fill removal treatments, the simulator mathematically describes the physical processes that may occur in the wellbore or how the physical properties of the fluids may vary with downhole conditions. These processes include

• flow into or out of the wellbore through perforations

• flow out of the wellbore through a choke

• solids pickup by the cleanout fluid

• gas dissolution from the production fluids

• U-tubing due to heavier fluids falling in the tubing

• transport of heat between the wellbore and formation.

As with all of the Dowell CADE products, it is essential that the user understand the process that is being modeled in the simulator. Several assumptions have been made which will limit its use in the first release. These assumptions can be found in the user documentation as well as the engineer's report for each simulation. This information should be thoroughly read when evaluating the results of the model.

1.2 Fill Removal Operations

In removing fill from the wellbore, it is necessary to ensure that materials are transported to an appropriate point for separation/disposal. Within this process, it is important to ensure that fill materials are not displaced into areas which may interfere with the operation of the wellhead, production or pressure control equipment. In addition, it is important to ensure that wellbore conditions are maintained in conditions which avoid formation damage by the introduction of the fill material. To enable this to be safely and efficiently achieved, accurate monitoring and recording of key parameters are essential during all phases of the operation.

1.2.1 Execution Precautions

Execution precautions to be observed during wellbore fill removal operations principally relate to the correct handling of fluids (including nitrogen), control of surface choke facilities, and disposal of the returned fill material and fluids. The potentially toxic, corrosive and LSA nature of the fluid or fill requires that special monitoring and protection methods be used to ensure the safety of the personnel, equipment and environment.

Personnel

All personnel involved in the design or execution of CT well kill operations must be familiar with requirements

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detailed in the relevant S&LP Standards. In addition, the requirements for the handling and disposal of LSA materials must be known. Monitoring and protection criteria should be defined in association with the operating company or designated third party.

Well Security

The control of well pressure and fluids must meet the requirements of relevant S&LP Standards. In addition the requirements of the operating company and applicable regulatory authorities must be known.

Equipment

All Dowell treating and monitoring equipment must be spotted and operated in accordance with the requirements of the relevant S&LP Standards. In addition, equipment certified for use in hazardous area must be operated and maintained in accordance with the operating zone requirements (e.g., Zone II equipment).

1.2.2 Equipment Requirements

Operations that involve the circulation of particulate material from the wellbore must be carefully planned and executed. The consequences of stopping or losing circulation while the annular fluid is laden with solids can be severe. Therefore, adequate precautions must be taken to ensure that the operation proceeds as planned. A typical equipment schematic for fill removal operations is shown in Fig. 9.

Coiled Tubing Equipment

Fill removal operations frequently require the tool string to be repeatedly cycled over a localized area. In this event, consideration must be given to the effects of inducing fatigue in the corresponding localized area of the work string as it passes the reel and gooseneck. In addition, the effect of fatigue while conducting high-pressure jetting operations must be accurately predicted. Cycling the work string under high internal pressures drastically reduces the useful life of the work string.

Pressure Control Equipment

The configuration of CT pressure control equipment allows fill removal operations to be completed safely and efficiently under live well conditions. The equipment must be configured to avoid circulating corrosive or solids-laden annular return fluid through the BOP. However, in certain cases, it may be necessary to return fluids through a shear/seal BOP installed above the tree. Returns should then be taken through a pump-in tee installed in the riser.

Downhole Tools and Equipment

Jetting Assemblies

Jetting tools should be configured 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.

Drill Motor Assemblies

Drill motor assemblies should be function tested before running in the hole. Typically, this is achieved after the assembly has been made up to the work string and is hanging inside the lubricator/riser. This should be considered a basic operational check. More comprehensive checks, including the motor torque, must be completed prior to rigging up.

Impact Drill Assemblies

Impact drill assemblies should be function tested before running in the hole. Impact drills do not operate until the tool is pushed into the collapsed position; therefore, the toolstring has to be manipulated during the test procedure.

Typically, the function test is performed after the tool string has been assembled and attached to the work string, and circulation has been established. The tool is collapsed and tested by placing the bit on a firm wooden surface by carefully controlling injector head.

Auxiliary Equipment

The fluid mixing, handling and pumping equipment must be of adequate capacity and be configured to minimize cross contamination of the fluid stages.

Live well operations may require the use of a choke manifold to control annular returns. In this event, a clear line of communication must exist between the CTU, pump and choke manifold operators.

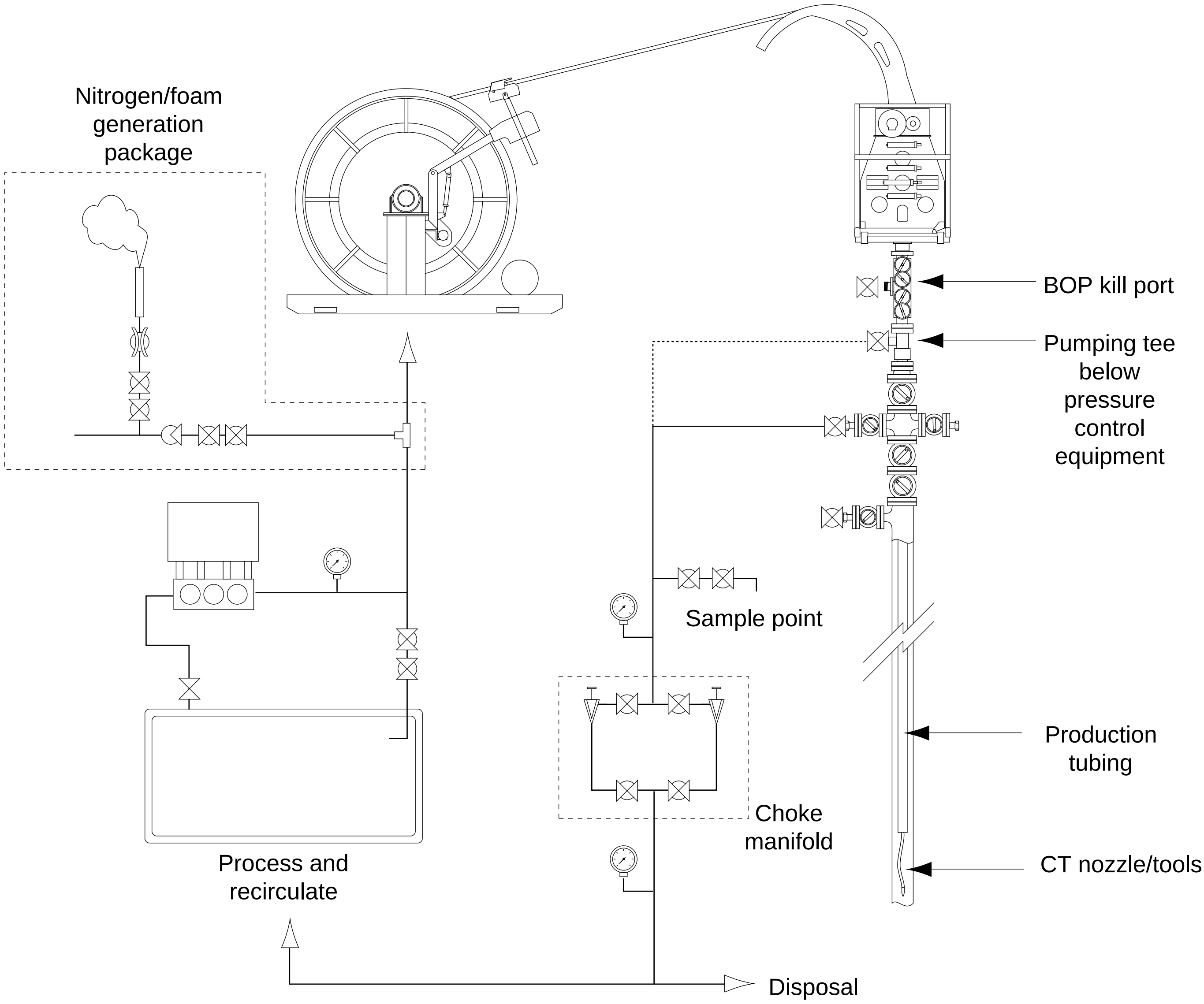

Fig. 9. Typical foam equipment configuration for fill removal.

1.2.3 Treatment Execution

The steps required to successfully complete a fill removal operation will depend on the particular conditions encountered in each case. In the following section, the key points in each phase of the operation are outlined. When preparing and documenting a treatment procedure, it is recommended that the key points be reviewed (with the applicable points being incorporated into the job procedure as required).

Wellbore fill removal treatments are frequently designed and conducted on a regular basis within a field or area. Consequently, procedures are often tuned to meet local conditions by application of the DESIGN EXECUTE EVALUATE* cycle. Whenever possible, previous case histories for similar applications should be referenced.

Execution of wellbore fill and scale removal treatments are accomplished in two basic steps:

- wellbore preparation

- treatment and tool operation

Wellbore Preparation

- The recovery of wellbore samples for analysis can be completed by CT conveyed tools in conjunction with preparatory work. Typically, slick-line methods are used; however, in deviated or logistically difficult conditions, CT may be used.

- If it is desired to remove completion equipment components such as gas-lift valves or safety valves, the use of CT conveyed methods should be considered. In some cases, the fill or scale condition to be treated will hamper retrieval of downhole devices. Tools and techniques used in CT conveyed methods will allow the circulation of treatment fluids to facilitate removal. In addition, the forces which may be exerted by CT are greater than commonly used wireline equipment.

- It may be necessary to kill the well for safety, fluid compatibility or production reasons. In such wellbores with known fill or deposits, it is clearly undesirable to risk damaging the near wellbore area by bullheading the wellbore fluid. Coiled tubing well kill techniques can be used to minimize the potential of damage during the well kill process.

Treatment and Tool Operation

- The volume and density of all fluids pumped into the wellbore must be monitored and recorded.

- Since full bore cleaning cannot be assured, a number of passes should be made over any consolidated fill area. The procedure will be determined by experience in similar conditions and fill material characteristics.

- Use the largest feasible size of work string to allow higher circulation rates and higher annular velocity.

- The operational efficiency of impact drills is greatly dependent on applying the appropriate weight at the tool. The use of a suitable accelerator can simplify the process; however, a high degree of injector-head control is necessary. This control is based on weight indicator readings; therefore, the weight indicator system must be properly operated and maintained.

1.3 Fill Removal Evaluation

The requirements of the operator will ultimately determine the extent to which the fill material must be removed and what means are to be used to evaluate the success of the operation.

Solids removal operations are generally evaluated by performing a drift run. Typically, a slick-line gauge-cutter tool will be run, although CT conveyed methods may also be used.

2 MATRIX STIMULATION

When a well does not, or can no longer, produce at the rates expected, the formation may be "damaged." By carefully evaluating the wellbore and reservoir parameters, the type and degree of damage can be identified. If the reservoir permeability is low, the well may be a candidate for hydraulic fracturing. However, if near-wellbore damage is found to be reducing well productivity, matrix stimulation may be appropriate. In addition to offering economic advantages over hydraulic fracturing, matrix treatments are preferred when fracturing may result in the undesirable production of gas or water.

Various types of damage exist, several of which may coexist, because almost every operation performed on a well (drilling, completion, production, workover and stimulation) is a potential source of damage. The most common form of damage is plugging of the formation around the wellbore.

Stimulation treatments must 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.

Coiled tubing is commonly used to perform matrix treatments, and in many cases will offer several advantages over conventional treatment techniques.

- The CT pressure control equipment configuration allows the treatment to be performed on a live well. The potential formation damage associated with well killing operations and the corresponding loss of production time are thereby avoided.

- 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. This in conjunction with 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., FoamMAT* foam diversion or a selective treatment system using straddle-pack isolation tools. This 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.

2.1 DESIGN

The following general guidelines outline the principal considerations when designing and executing matrix treatments. While most of the points listed will apply to any matrix treatment, some emphasis is made on considerations which apply to operations performed through CT.

- Ensure that the well is a candidate for matrix stimulation by confirming the presence of damage.

- Identify the location, composition and origin of the damage.

- Gather and compile the wellbore and completion information required for job design and evaluation of treatment options.

- Select an appropriate treatment fluid, including additives and associated treatments. Conduct compatibility tests to ensure there are no adverse reactions between fluids.

- Determine the maximum injection rate and pressure.

- Determine the treatment volume.

- Consider the use of diverting agents to help ensure complete coverage.

- Consider the use of selective treatment tools.

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MATRIX TREATMENT DESIGN DATA	
Drilling	- Drilling mud details over zone of interest, e.g., type, density, losses, unusual conditions, etc. - Casing/liner cementing details for zone of interest, e.g., type, density, losses, evaluation, unusual conditions, etc.
Completion	- Production casing/liner and tubing details, e.g., size, weight, grade, depths, deviation, nipples or restrictions, material/alloy, etc. - Perforation details, depth, interval, shot density, etc. - Completion fluid details, e.g., type, density, losses, etc.
Reservoir	- Formation analysis. - Reservoir temperature and pressure. - Porosity and permeability. - Gas/oil contact, water/oil contact.
Production	- Production test results, e.g., skin, effective permeability, production rates, etc. - Production logs/history. - Results of NODAL* analysis
Workover	- Details of previous stimulation or remedial treatments.
Laboratory Analyses	
	- Acid solubility - Formation water analysis - Emulsion and sludge testing - Iron content testing - Permeability and porosity - Flow test (ARC) - SEM/ Edax studies - Petrographic studies - Determine paraffin/asphaltine content.

Fig. 10.

- Prepare a complete pumping schedule, including shut-in and flowback requirements.

- Forecast the economic viability of the treatment.

The importance of obtaining adequate, and accurate, wellbore and reservoir data prior to designing stimulation treatments cannot be understated. This is necessary for several reasons:

- By confirming the composition, location and degree of damage, the selection of an appropriate treatment fluid is possible.

- The maximum cost effectiveness of the treatment can only be ensured if all aspects of the treatment are optimized.

- By conducting pre- and posttreatment tests and comparisons, the efficiency of the treatment may be quantified.

In addition to reservoir and wellbore parameters, the selection of an appropriate treatment may be dependent on the well or field production objectives and economics.

2.1.1 Candidate Selection

When a well has been identified as a possible candidate for matrix treatment, it is necessary to gather and compile data for analyses and design purposes. Fig. 10 summarizes the typical fields of data required for matrix treatment design. This should be regarded as a basic guide list which may require additional input for complex job designs or procedures.

Formation Damage

The objective of a matrix treatment is to remove the damage which impairs the productivity of the well, i.e., decrease skin. Therefore, it is essential to know the type, amount, location and origin of the damage.

The presence and amount of damage are calculated from data obtained by conducting a pressure transient analysis, i.e., by pressure buildup or drawdown tests. Such tests provide invaluable information to optimize the treatment and evaluate the results.

The type, location and origin of the damage are determined by reviewing the results of the pressure transient analyses in conjunction with the information outlined in Fig. 10.

Damage can be characterized by two important parameters - its composition and location. The locations of various damage types are summarized in Fig. 11.

Wellbore and Completion Characteristics

A key factor in determining the suitability of CT in any operation is the ability to safely run and retrieve the CT into and out of the wellbore. The size of completion tubulars and placement of restrictions will initially determine if CT can be used to convey the treatment fluid or tools.

In highly deviated and horizontal wellbores, deviation survey data are required, in addition to completion geometry, as input for the CoilCADE* Tubing Forces Model (TFM). The TFM may then be used to determine how far the CT may be pushed into the wellbore. In addition, the anticipated forces are calculated for running and retrieving the CT.

Well Preparation

There are several options available when selecting a treatment technique. For example, the entire treatment may be performed through CT, or the CT may be used to prepare the wellbore and spot the treatment fluid

TYPE AND LOCATION OF COMMON FORMATION DAMAGE

	Damage Location			
Type of Damage	Tubing	Gravel Pack	Perforations	Formation
Scales	**x**	**x**	**x**	**x**
Organic Deposits	**x**	**x**	**x**	**x**
Silicates, Aluminosilicates		**x**	**x**	**x**
Emulsion		**x**	**x**	**x**
Water Block				**x**
Wettability Change				**x**
Bacteria	**x**	**x**	**x**	**x**

Fig. 11.

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inside the production tubing. Regardless of the technique employed, it is undesirable to inject damaging fluids, scales or other wellbore solids into the formation. Design consideration must be given to the removal of the following potential damage sources before conducting the main treatment:

- wellbore fill material near the treatment zone (see Wellbore Fill Removal)
- scale, asphalt or solids in the production tubing/liner
- rust and scale deposits inside the CT work string.

The Dowell Tubeclean Service uses a fluid containing inhibited acid, solvents, iron reducing agents and solids suspending agents to clean tubulars before stimulation and sand control treatments. In addition to removing damaging solids, the Tubeclean treatment prevents the main treating fluid from carrying high concentrations of dissolved iron into the formation.

2.1.2 Treatment Fluid

Selection of an appropriate treatment fluid is determined by the type of damage and its location. The location of the damage is a significant consideration because the treatment fluid may contact several other substrates before contacting the damaged zone, e.g., rust or scale on well tubulars or carbonate cementing materials. The fluid must then provide an effective treatment on contact with the damaged zone.

In most cases, the exact type of damage cannot be identified with absolute certainty. In addition, there is often more than one type of damage present. Therefore, many stimulation treatments incorporate fluids to remove more than one type of damage.

Selection of the most appropriate treatment fluid and additives for given wellbore and reservoir conditions should be made by following guidelines given in the reference documents listed in Section 5.

The following list summarizes the criteria considered when selecting treatment fluids for use with CT:

- Physical characteristics of the damage. These characteristics will often determine the nature of the base treatment fluid, e.g., acid- or solvent-base treatment.
- Reaction of the treatment fluid with the formation. Adverse reactions between the formation and treating fluid can create new damage and compound existing productivity problems. Such potential reactions are controlled by additives in the treatment fluid and by preflush and overflush treatments.
- Prevention of excessive corrosion, both to CT and completion equipment (see subsection 2.5.1 Corrosion Inhibitor).
- Use of friction reducers to optimize the treatment rate (seesubsection 2.4.2 Friction Reducer).
- Compatibility of treatment fluid with wellbore and reservoir fluids. Fluid additives are used to prevent sludge or emulsions, disperse paraffins and prevent precipitation of reaction products.
- Compatibility of treatment fluid with diverting agent (see subsection 2.5 Diversion).
- 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. As an alternative, energizing the treatment fluid may be appropriate.

Preflush/Overflush

Some treatments, especially in sandstone reservoirs, require preflush and overflush fluids to prevent adverse secondary reactions and the creation of precipitates from the treatment fluid.

The preflush provides separation between the connate water and treatment fluid and, in sandstone treatments, reacts with carbonate minerals in the formation to prevent their reaction with the hydrofloric acid (HF). Brine, solvent or hydrochloric acid (HCl) can be use as preflush fluids.

The primary purpose of an overflush is to displace potentially damaging precipitates deep into the reservoir, away from the wellbore. Special overflushes can be formulated to facilitate diverter cleanup. Ammonium chloride brine, HCl (3 to 10%) and light hydrocarbons (e.g., diesel) are commonly used as overflush fluids.

The volume of preflush or overflush required is calculated on the basis of the radial displacement required.

2.1.3 Fluid Additives

While the base treatment fluid is designed to remove the damage, most treatments require the use of additives to improve reactions and control potential damage to the formation, completion tubulars or CT work string. The following types of additive are commonly used on matrix stimulation treatments:

- Acid corrosion inhibitors are required on all jobs to reduce the rate of corrosion on treating and completion equipment to an acceptable level.
- Alcohol is often used in gas wells to lower surface/ interfacial tension, increase vapor pressure and improve cleanup.
- Antifoam agents prevent excess foam from being formed when mixing fluids on the surface.
- Clay stabilizers are used to prevent damage from the dispersion, migration or swelling of clay particles.
- Diverting agents help ensure complete coverage of the zone to be treated.
- Formation cleaner will kill and remove bacteria and polymer residues.
- Iron stabilizers are used to prevent the precipitation of gelatinous ferric iron in the formation.
- Mutual solvents serve as a wetting agent, demulsifiers and surface/interfacial tension reducer.
- Organic dispersants and inhibitors are used to remove and inhibit the deposition of organic materials.
- Surfactants have several functions and uses which may be summarized as aiding the penetration of fluids through the formation during treatment and flowback.

Many of the additives commonly used in stimulation treatments will present a hazard to personnel and the environment if handled incorrectly. Consideration must be given to the safe handling, mixing, cleanup and disposal of treatment fluids and additives.

A more detailed description and explanation of fluid additives crucial to CT operations follows. Further details on range and selection of other fluid additives may be found in the references listed in Section 5.

Corrosion Inhibitors

The useful life and reliability of a CT work string are governed by the effects of fatigue and corrosion. Therefore, ensuring adequate corrosion control is an obvious requirement when designing stimulation treatments performed through CT.

In common with all stimulation fluid additives, corrosion inhibitors must perform their principal function without affecting the injectivity or productivity of the treated formation. Several compounds provide excellent corrosion protection but can cause significant formation damage.The range of corrosion inhibitors and inhibitor aids developed by Dowell is formulated to provide optimum inhibition performance without damaging the formation.

The addition of certain materials to the acid system (such as surfactants, mutual solvents, demulsifiers and non-emulsifiers) can alter the temperature range in which an inhibitor may be considered effective. In severe cases, the inhibitor may be rendered ineffective at the desired treatment temperature.

The stresses to which a CT work string is subjected as it is plasticly deformed require some consideration when selecting corrosion inhibitor schedules for CT conveyed treatments. In addition, the extremely high fluid velocities encountered inside the CT means a higher concentration of corrosion inhibitor is required to provide the necessary protection.

The efficiency of pumping a small high-concentration corrosion inhibitor slug ahead of the treatment fluid is inconclusive and cannot substitute for a well-designed and prepared inhibitor schedule. However, it is generally accepted that an inhibitor slug ensures good initial protection for the work string. The efficiency of such a treatment is improved when all rust or scale inside the CT is removed by pickling the work string prior to the treatment.

The performance of most corrosion inhibitors is significantly reduced in the presence of H_2S. To overcome these effects, an H_2S scavenger (e.g., M187) should be used. Increasing the concentration of corrosion inhibitor is ineffective.

CORROSION INHIBITOR AND INHIBITOR AID SELECTION	
Corrosion Inhibitors	**Remarks**
A166	Low-temperature inhibitor up to 310°F. Not recommended if acid systems incorporate large additive packages. Use appropriate inhibitor aid at suggested temperature ranges.
A186	Organic acid inhibitor. Does not require inhibitor aids.
A250	General use inhibitor up to 300°F. Use Inhibitor Aid A201 above 220°F.
A252	High-temperature inhibitor (<350°F) requires A201 above 250°F.
A260	Temperature range up to 300°F. Effective with large additive packages. Requires Inhibitor Aid A153 if temperature is under 240°F. If temperature is over 240°F, use A201.
A270	High-temperature inhibitor designed for temperatures above 275°F although it is effective at lower temperatures. Use with A201.
Inhibitor Aids	
A153	Enhances efficiency of inhibitor. Minimizes pitting tendencies below 240°F.
A179	Preferred inhibitor aid when acid system contains Methanol K46.
A201	General use inhibitor aid. Ineffective at temperatures below 220°F.

Fig. 12.

The selection of an appropriate corrosion inhibitor (type and concentration) can be done only after specification of the following treating and well 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.

The effective range of corrosion inhibitors can be extended and improved by using inhibitor aids. A list of corrosion inhibitors and inhibitor aids commonly used with CT conveyed treatments is shown in Fig 12.

H_2S Protection

The presence of H_2S affects the design and execution of matrix stimulation jobs in several ways:

- Because H_2S is frequently liberated as an acid reaction product, the well condition must be considered sour following treatment and during cleanup. Personnel and equipment safety requirements must be observed during these periods.
- Wells with a sour status must be treated using CT downhole tools and equipment that can be positively identified as suitable for H_2S service.
- The efficiency of some additives, especially corrosion inhibitors, can be significantly reduced in the presence of H_2S.

Protection against the effects of H_2S can be achieved by using a scavenger (e.g., M187or A255). In most cases, H_2S protection should be applied to the exterior surface of the CT as well as included in the treatment fluid.

Friction Reducers

The efficiency of many treatments can be significantly improved by increasing the rate at which the treatment fluid enters the formation. The pump rate of treatments performed through CT is limited by the restricted internal diameter and length of the work string, i.e., fluids must be pumped through the total string length, regardless of the depth of the treatment. Using a friction reducing agent can significantly increase the rate at which fluids may be pumped. In addition to improving the treatment efficiency, the job time will be reduced. Such a reduction in job time may be an important consideration in large volume treatments.

2.1.4 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.

Downhole Sensor Package

The downhole sensor package (DSP*) is a real-time downhole data acquisition system which can be used to monitor temperature, pressure and casing collar data. Real-time bottomhole pressure (BHP) and temperature (BHT) data acquired during a matrix treatment can be used to determine the efficiency of the stimulation as it progresses. This capability provides several benefits contributing to the optimization of the treatment:

- Accurate BHP and BHT data for any well profile. The DSP package has potential for virtually every oilfield CT application anytime it is desirable to have accurate real-time knowledge of the BHP and BHT during a CT operation. This includes vertical, inclined and horizontal wellbores, cased and open hole.

- Evaluate-Treat-Evaluate– Conventional static pressure build up and pressure drawdown flow testing is easily done using the DSP package. Well test data collected by the system and sent to the laptop can be processed on location to allow for last minute changes in a treatment design if necessary. Pressure buildup tests run before and after an acid or other formation damage removal treatment can be used to evaluate changes in effective permeability, skin damage and well productivity. The BHP during matrix treatments can be used by MatTIME* software to calculate skin.

- Optimized diversion–Use of the DSP package allows for real-time knowledge of the actual BHP, regardless of fluctuations in the circulating rate, foam quality, hydrostatic head or friction pressure. If necessary, it allows for changes to be made to the treatment schedule as the job is being pumped. For example, while a foam diversion stage is being pumped, the BHP continues to decrease instead of increase; the foam stage can be continued until the BHP sufficiently increases to indicate that diversion is taking place.

2.1.5 Treatment Volume

The treatment volume (gal/ft of perforated interval) is most commonly determined by field experience, although laboratory tests can be conducted if no history exists. The amount of acid required to remove formation damage is dependent on many factors relating to the characteristics of the damage, formation and treatment fluid.

The objective of establishing the treatment volume is to achieve an acceptable permeability increase. Increasing the treatment fluid volume in an attempt to remove all damage is costly and carries the risk of further formation damage. For example, in sandstone formations, excessive removal of the cementing material can result in the deconsolidation and collapse of the formation.

2.1.6 Diversion

Successful matrix treatments depend on the uniform distribution of the treating fluid over the entire production (or injection) interval. When fluids are pumped into a well, they naturally tend to flow into the zones with the highest permeability and least damage. By diverting the flow of treatment fluid to the areas of lesser permeability, a more effective treatment will be achieved. Production log data can be used to identify high-permeability zones or thief zones, enabling the design of an efficient placement/diversion technique.

The criteria for selection of a diversion technique or agent include the following:

- The diverting agent must provide uniform distribution of treating fluid into zones of widely different permeability.

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- The diverter 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 treating fluid, additives and overflush or displacement fluids.

- The diverter must be effective at the applicable treatment temperature.

Diverting techniques can be classified as mechanical, chemical or foam. In addition, although not a true diversion technique, reciprocating the CT nozzle over the treatment zone during the treatment can be beneficial in some operations. Reciprocating the CT can assist in treatments intended to remove possible damage in or around the perforation tunnels. An appropriate jetting nozzle reciprocated over the interval while pumping the fluid will help clean the perforation tunnels and improve the treatment.

One of the greatest advantages of performing treatments through CT is the ability to continuously pump fluids while moving the tubing and nozzle. However, a consequence of reciprocating the string under high internal pressure is the increased fatigue that can be induced in a relatively short interval of the work string. The benefits of such techniques must be weighed against the reduced life of the CT string and localized fatigue.

In almost all cases, the ability to spot the treatment fluid over the entire treatment zone before injection will be beneficial.

Mechanical Diversion

Mechanical diversion methods applicable to CT matrix treatments are limited to techniques incorporating bridge plugs, packers and straddle packers. Conventional methods of diversion using ball sealers are not compatible with CT conveyed treatments because of the restricted internal diameter and low pump rates associated with CT.

The use of packers and plugs to isolate and selectively treat zones can be desirable because the treatment is effectively conducted on a shorter zone. Within this short zone, the need for diversion during the treatment is less critical and successful treatments can be performed using conventional fluids.

A straddle packer configuration is preferred because the forces created by the injection pressure are balanced, enabling a secure and efficient packer seal. The distance between the two packers is adjustable, using a range of spacers, when the tool is assembled (Fig 13).

The following points must be considered when designing a matrix treatment in conjunction with a packer tool string.

- The maximum spacer length (i.e., treatment interval) is limited by the maximum tool length that can be safely deployed into and out of the well.

- The maximum injection pressure is determined by the specifications and expansion of the packers.

- All fluids must be free of particulate solid which could block restricted passages within the tool string.

- Circulation through the work string while the toolstring is being run and retrieved is not possible. Pumped fluids will cause the packer elements to inflate, thereby increasing the risk of damaging the packer or surging or swabbing the wellbore.

Chemical Diversion

Many chemical compounds have been used as diverting agents. However, because cleanup problems were encountered in numerous cases, only a few are now commonly used. Most chemical diverters function by forming a bridge or cake of lower permeability on the formation face to create an artificial skin. This soluble cake is dissolved and removed during cleanup and subsequent production (or injection).

High-viscosity fluids can also be used as diverting agents but are more commonly used to plug water zones when acidizing adjacent oil zones or in horizontal wellbores. The use of self diverting acid (SDA) systems is increasingly effective in carbonate formations. In such acid systems the fluid crosslinks to provide a high viscosity as it spends. When completely spent it uncrosslinks and can be easily flowed back.

The efficiency of chemical diversion techniques is improved with higher injection or treating rates. Because a limitation of CT conveyed treatments is the relatively low circulation rate, certain chemical diverting agents may be unsuitable in low pump-rate applications. In addition, large particulate solids can plug or interfere with the operation of downhole tools (e.g., check valves) required on CT operations.

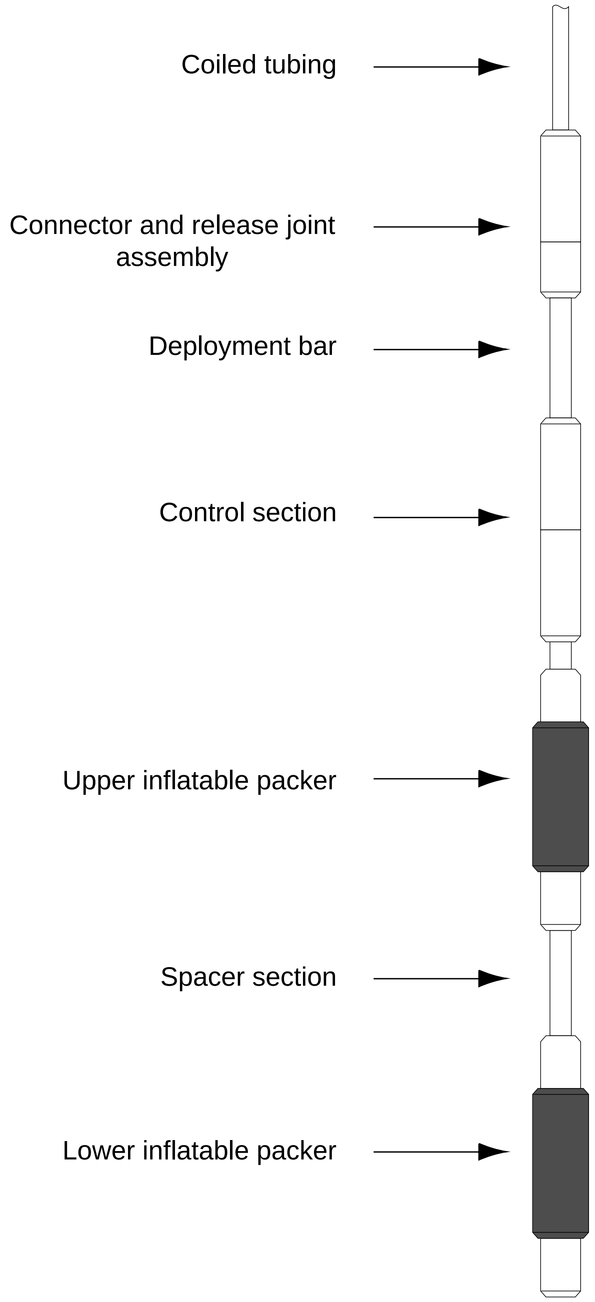

Fig. 13. Dual inflatable packers.

An appropriate chemical diverting agent must meet several physical and chemical requirements:

- Permeability – The bridge or cake formed on the formation face should be as impermeable as possible to achieve maximum diversion. If the permeability of the cake is greater than that of the tightest zone, little or no diversion will occur.

- Invasion – Deep invasion of diverter into a producing formation is undesirable. The efficiency of diversion and subsequent cleanup is increased by reducing invasion.

- Dispersion – To ensure a satisfactory buildup of diverter, the particles of diverting agent must be properly dispersed in the carrier fluid.

- Compatibility – Diverting agents must be compatible with the base treating fluid, additives and overflush/ displacement 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 to enable a rapid and complete cleanup.

Diverting agents with a large particle size, i.e., the particle size is 10/20 U.S. mesh size to 100 U.S. mesh size (2mm to 150µm), are often referred to as bridging or plugging agents. Diversion materials with a particle size less than 100µm are commonly known as matrix diverting agents.

Insoluble bridging agents (such as silica) are sometimes used. However, soluble materials reduce the risk of causing permanent damage to the formation cause by incomplete removal. Common water-soluble agents (Fig. 16) include rock salt and benzoic acid. The most common oil-soluble diverters include graded oil-soluble resins, naphthalene flakes and wax polymer beads that are soluble in oil. These wax polymer beads are deformable to increase diversion efficiency and temperature degradable to improve cleanup.

The particle size of the diverting agent must correspond to the petrophysical properties (such as pore size and permeability) of the treated zone.

Chemical diverting agents can be applied in a staged pumping schedule, i.e., specially prepared diverter stages are pumped alternately with stages of treatment fluid, or the agent is included in the treatment fluid and continuously applied.

Foam Diversion

Foam can be an effective diverter in many matrix stimulation treatments, particularly those performed in horizontal wellbores. Unlike a particulate diverter that requires fluid contact to assist cleanup, foam will break or be produced to allow a rapid and efficient cleanup.

Conventional foam diversion techniques divert treatment fluids in the casing, tubing or perforation tunnels. While this is fairly effective, laboratory tests and experience have shown that the diversion effect is slow to form and has a relatively short life before rapidly losing efficiency. The FoamMAT Diversion Service from Dowell generates and maintains a stable foam in the formation (thief zone) during the treatment. By diverting the treatment fluid from the thief zone to the damaged zone, a complete and effective treatment is achieved.

A FoamMAT pumping schedule is computer designed based on the specific reservoir and wellbore conditions. As a result, a rapid-building and long-lasting foam diversion will be created within the formation. Treatments are generally designed to include several foam stages to ensure complete coverage of the treatment zone.

Zones that have water/oil (WOC) contact can be efficiently treated because the special preflush and subsequent injection of 65 to 70% quality nitrified fluid form a very stable foam in the water zone. With the water zone blocked with foam, the oil zone can then be treated as desired.

The high friction pressures associated with pumping foamed fluids through CT impose practical limitations. In most cases, only 1-1/2-in. CT or larger should be used to convey FoamMAT fluids.

CHEMICAL DIVERTERS	
Material	**Nature**
J227	Benzoic Acid Flakes
J363	Water and Oil Soluble Salt
J237/J238	Oil Soluble Resin
U62/U63	Emulsifier

Fig. 14.

Effective in any type of well, the FoamMAT Diversion Service typically follows a pumping schedule such as outlined in Fig 6.

2.1.7 Downhole Tools

A number of tool strings and bottomhole assemblies (BHAs)are used in conjunction with matrix stimulation treatments. The string composition and configuration will depend on the tool-string function; however, the following criteria will apply to all tool strings used on matrix treatments:

- The material from which the tool is manufactured must be resistant to inhibited treatment fluid.
- The tool seals and components must be compatible with the treatment fluid and additives.
- The tool seals or O-rings should be located to protect threaded connections or components from corrosive treatment fluids.

2.1.8 Pumping Schedule

A pumping schedule detailing each fluid stage of the treatment should be prepared. The schedule should include anticipated pump rates and times, and can be regarded as a summary of the total operation. The volume and density of each fluid stage should be noted. Each fluid should be listed, including

- fluids circulated while running in the hole (RIH) with the CT
- fluids used to circulate out wellbore fluids or fill material that could be damaging to the formation
- fluids used to clean the completion tubulars
- preflush and injectivity test fluids
- main treatment fluid (including diverter stages)
- overflush fluids.

Cleanup and Flowback

In most cases, flowback of spent fluids should be accomplished as soon as possible. Detrimental reaction products and precipitates can be formed within the formation if some spent-acid products remain for an extended time. Therefore, a rapid flowback is generally

FoamMAT DIVERSION PRINCIPALS

The FoamMAT process principle generally consists of five distinct and orderly steps.

1. Clean the near-wellbore region (exept dry gas wells).

Brine with mutual solvent or CLEAN SWEEP* I, CLEAN SWEEP II or CLEAN SWEEP III fluid 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 (e.g., EZEFLO* F78 Surfactant, Foaming Agent F52.1 or EZEFLO F75N) to displace the mutual solvent (solvents are detremental to foam), to minimize the adsorption 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 bottomhole treating pressure.

4. Shut-in (recommended).

A 10-min 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.

Fig. 15.

desirable. However, in some cases (notably following clay damage treatments), the production rate should be gradually increased to minimize the migration of fines.

The treatment fluid reaction product flowed back immediately following an acidizing treatment can be significantly corrosive. This is particularly true of poorly designed or executed operations where the treatment fluids were incompatible with the formation or type of damage, or the fluids were incorrectly placed.

Corrosive flowback fluids are of concern because any corrosion inhibitors used in the original treatment fluid will be exhausted and largely ineffective at protecting the completion tubulars and the outside surface of the CT.

The pH of wellbore fluids should be monitored during the cleanup period.

2.1.9 Horizontal Wellbores

Attempts to bullhead acid treatments into horizontal wellbores have generally proved ineffective. Techniques that improve fluid placement and treatment efficiency have been developed using CT (see references Economides et al.). The work string is placed at the end of the wellbore and is slowly retrieved toward the vertical section. The rate of retrieval (ft/min) is dependent on the fluid injection rate and the desired volumetric coverage (which depends on the damage radius of the wellbore section to be treated). Reactive fluids are pumped through the CT while an inert fluid is pumped down the CT annulus. This technique assumes that the acid will react laterly with the formation exactly where the CT nozzle is located. Obviously this is not always possible, especially in carbonate reservoirs where thief zones (either natural or created by wormholes) can prevent the desired fluid placement. Thus, horizontal wellbores are

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generally treated in discrete intervals with stages of chemical diverters used to separate the treatment intervals.

2.2 Matrix Stimulation Operations

2.2.1 Execution Precautions

Execution precautions to be observed during matrix stimulation treatments are generally based on the corrosive and toxic nature of the chemical products used. However, there are several other important considerations which must be understood and accounted for in the execution procedure. In addition, personnel involved in service activity or flowback operations following the treatment, should be informed of the treatment and potentially hazardous conditions which may exist on completion of the treatment.

Personnel and Environment

All personnel involved in the design or execution of matrix stimulation or CT services must be familiar with requirements detailed in the relevant Dowell Safety and Loss Prevention (S&LP) Standards.

The corrosive and toxic nature of most stimulation fluids and additives demands that care and attention are required during all phases of the operation. The handling, mixing application, cleanup and disposal of stimulation fluids must be completed with due consideration for personnel and and environmental safety.

Well Security

The control of well pressure and fluids must meet the requirements of the relevant S&LP Standards. In addition, the requirements of the operating company and applicable regulatory authorities must be known.

Equipment

All Dowell treating and monitoring equipment must be spotted and operated in accordance with the requirements of the relevant S&LP Standards. In addition, equipment certified for use in hazardous areas must be operated and maintained in accordance with the operating zone requirements.

Posttreatment

Following any acid treatment, it is possible that H_2S may be liberated. Therefore, appropriate precautions should be taken during posttreatment work. Additionally, corrosive treatment fluids may be produced to surface.

2.2.2 Equipment Requirements

Treatments, such as matrix stimulation, which require the preparation and pumping of corrosive fluids must be carefully planned and executed. The treatment fluid and spent-fluid returns should be routed to minimize exposure to personnel and equipment.

Coiled Tubing Equipment

It is recommended that the CT work-string internal surface be pickled with a low-concentration inhibited acid before performing the matrix treatment. Such a treatment provides the following benefits:

- Rust and scale deposits that can be damaging to the formation if injected are removed.

- Inhibition from the main treatment fluid is more effective if the inhibitor is adsorbed onto a clean surface.

The pickling process can be performed before or after the equipment arrives at the job site. A significant consideration in determining the place of treatment is the disposal of the fluids following the pickling treatment. In many cases the most convenient disposal method is to use the wellsite production or disposal facility.

Pickling is typically performed using 7-1/2 to15% inhibited HCl. A treatment volume of 250 to 400 gal is generally sufficient. Displacement of the pickling fluid will often depend on how and where the treatment is performed. Clean freshwater or ammonium chloride brine (2 to 3 %) should be pumped after the pickling solution. Further displacement with nitrogen can be conducted before transportation if required.

If the main treatment is not to be performed within 24 hrs, a neutralizing solution should be used to prevent corrosion by any remaining pickling solution. Typical neutralizing solutions are mixed using 50 lbm of soda ash in 5 bbl of clean fresh water displaced with freash water or nitrogen.Some operating companies require that the work-string volume be checked by inserting and displacing a plug or foam pig. Such checks can be combined with the displacement of pickling treatments.

To ensure adequate protection against corrosion, it is a common practice to pump a small-volume/high-concentration inhibitor slug ahead of the main treatment.

While this maximizes corrosion protection, it is generally undesirable to inject such a fluid into a producing formation. Therefore, provision should be made in the treatment design and pumping schedule for circulation of the inhibitor slug to the CT annulus.

The volume and type of displacement fluid used during the treatment will determine the amount of postjob flushing and neutralizing that is required. However, a neutralizing solution should be circulated through the work string on the completion of every acid job, or series of treatments. Typically, 50 lbm of soda ash mixed with 4 to 5 bbl of clean fresh water should be used.

As with the prejob pickling procedure, flushing and neutralizing the work string must be conducted with due regard for the safe disposal of fluids.

Pressure Control Equipment

Because significant quantities of H_2S may be liberated during an acid treatment, only H_2S service pressure control equipment should be used.

In treatments when acid is to be pumped through the production tubing as well as the CT work string, the acid injection point must be below the CT pressure control equipment. Similarly, when flowing spent treating fluids, avoid flowing through the CT pressure control equipment (Fig 16). The extent of postjob flushing and neutralizing of fluids in the CT pressure control equipment will depend on the likelihood of corrosive fluid contact. However, due to the nature of the equipment, acid contact should be assumed and equipment internally cleaned and inspected following every operation.

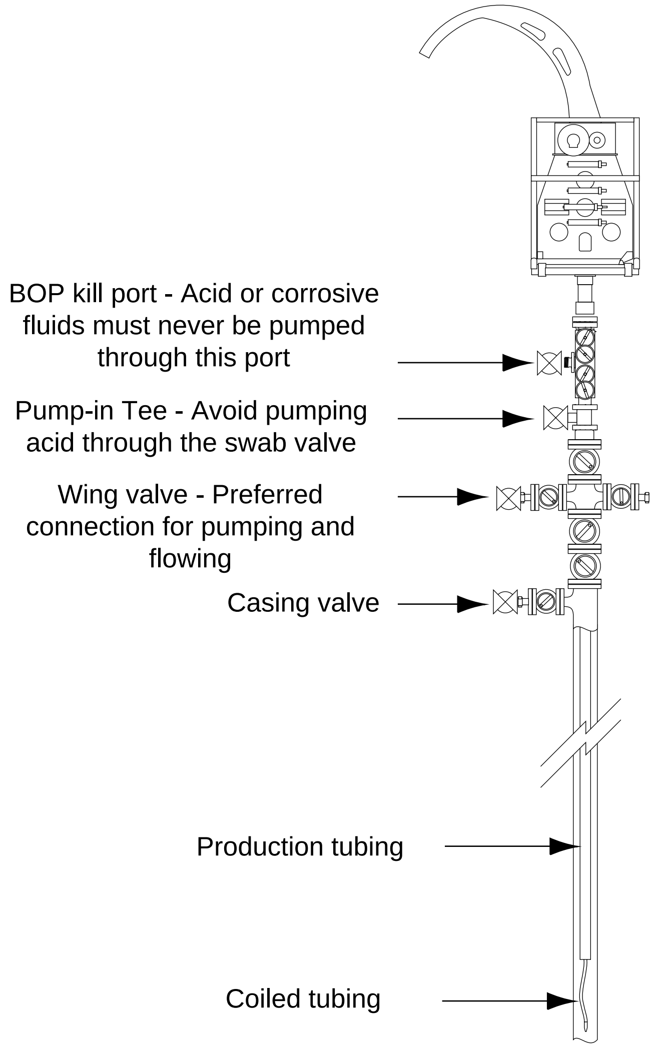

Fig. 16. Pressure control equipment configuration.

Pumping Equipment

All fluid mixing pumping and storage equipment must be clean and free from solids. If cementing equipment is to be used, a pickling/acid treatment must be performed on the equipment and lines to ensure no solid particles are released during the treatment. All tanks should have accurate volume markers or strap charts to ensure correct treatment volumes.

As in all treatments which involve the injection of fluids into a producing formation, all surface mixing, storage and pumping equipment must be clean and free from damaging solids. The equipment and lines should be flushed with clean water to remove potentially damaging solids or liquids.

Pressure and rate limits (governed by the CT equipment or reservoir conditions) for every stage of the operation must be defined and noted on the pumping schedule.

Operations that require the manipulation or movement of the CT string during the treatment must be conducted with a good line of communication between the fluid pump operator and the CTU operator. In most cases radio headsets will be required.

The maximum pump rate achievable under the given pressure limitations should be used to reduce the exposure time of equipment to corrosive fluids and also to achieve the maximum diversion effect.

The volume and type of displacement fluid used during the treatment will determine the amount of postjob flushing and neutralizing that is required.

Monitoring and Recording Equipment

Monitoring and recording equipment must be capable of operating with all treating and displacement fluids at the rates anticipated during the treatment.

Wellbore, fluid and reservoir parameters required by recording and process software for real-time analyses should be accurately input.

Departures from the planned pumping schedule must be noted for postjob reporting purposes.

Downhole Equipment

Prior to the installation of any tool in a CT tool string, several dimensional and operational checks must be made.

A note of the tool dimensions and profile must be made for use in the BHA fishing diagram. Minimum requirements are length, OD, ID and connection size and type.

Operating specifications for the tool must be noted to help ensure that the operating conditions for which the tool is designed are not exceeded. The following information should typically be included — tension, compression and pressure limitations, temperature ranges, H_2S service and fluid compatibility.

All downhole tools which have been exposed to corrosive fluids should be serviced as soon as possible following retrieval. As a minimum requirement, the tools should be broken at all service breaks and flushed clean.

2.2.3 Fluid Preparation

Fluids should be prepared to the design specification following the standards set in the S&LP Manual.

Samples of all raw and mixed fluids should be taken and kept until the job is completed and has been fully evaluated. In addition, the pH and specific gravity (SG) of all fluids should be checked and noted.

2.3 Evaluation of Matrix Stimulation

The evaluation of matrix acidizing treatments is based on the analyses of the reservoir response to the injection of the stimulation fluid. In particular, the change (improvement) in reservoir flow characteristics is of interest.

By modeling and comparing the response of an ideal reservoir with that of the actual reservoir, the degree of damage is assessed. Injection pressures measured and recorded during the stimulation treatment can be interpreted to provide an indication of the efficiency of the damage removal.

3 SQUEEZE CEMENTING

Squeeze cementing may be defined as the process of forcing cement slurry, under pressure, through perforations or holes in the casing or liner. When the slurry is forced against a permeable formation, some of the fluid enters the formation matrix filtering out the slurry solids on the formation face. In performing a CT squeeze, the pressure is gradually increased in predefined increments (hesitation squeeze). With a properly designed slurry and squeeze procedure, a firm filter cake will fill the opening(s) allowing the final squeeze pressure to exceed the formation fracture pressure.

The firm filter cake, in the form of nodes, allows cleaning of the wellbore by circulation immediately after completing the squeeze procedure. Therefore, subsequent drilling or underreaming operations to clean the wellbore are avoided.

With the development of efficient squeeze cementing techniques conducted through CT, significant cost savings can benefit operators performing through-tubing workovers. Conventional methods of cement placement required the use of a workover rig. However, most of the time and expense associated with mobilization of equipment, well killing and completion handling can be avoided when using CT conveyed services. In addition, the operational features of CT and associated pressure control equipment provide several technical and economic benefits.

Squeeze cementing operations conducted through CT have been developed and improved by evolving operating procedures to suit well/production conditions, and by refining the slurry design. For example, a key operational factor is the removal of excess cement slurry from the wellbore. Current techniques can allow rapid and efficient removal of excess slurry, thereby permitting production to be resumed with minimum delay. In addition, extensive laboratory testing and analyses have increased the understanding of the cement slurry performance and characteristics as it is mixed in small volumes and pumped through the CT string.

Squeeze cementing operations are applied to permanently block the intrusion of undesirable fluids to the wellbore. In oil wells, this is frequently required to reduce excessive water or gas production which limits downstream separation or process capacity. The cement providing the block to production must remain effective under the highest differential pressure anticipated when production is resumed.

The following conditions are treated with a high degree of reliability using CT squeeze cementing techniques:

- 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.

In treating these conditions, CT squeeze cementing techniques offer several advantages over conventional workover rig practices.

- The CT pressure control equipment configuration allows the treatment to be performed through the completion tubulars without the need for a rig. In addition, the well can be safely killed with relatively low volumes of fluid.
- Associated operations can be performed as part of a packaged service, e.g., wellbore fill can be removed or artificial lift services may be applied to restore production following the treatment.
- Placing the slurries and fluids through CT avoids contamination from wellbore and displacement fluids. The mobile injection point improves the placement efficiency and accuracy.
- Low treatment volumes are required and wellbore cleaning of excess slurry is easily performed.
- Experience has shown that significant time, product and cost savings can be realized.

Early experiences of CT cementing showed that compared with conventional primary cementing operations, CT cementing requires more stringent design and control considerations. Only by exercising a high degree of control and verification on all aspects of the operation can the desired result be reliably achieved.

Since the consequences of an improperly applied squeeze cement treatment may be severely damaging to the reservoir, wellbore or completion, correct assessment of the well and reservoir conditions must be confirmed before the treatment design is finalized.

3.1 Laboratory Testing

A variety of additives, used in varying concentrations, are commonly used to control the characteristics of a squeeze slurry. The efficiency of the additives is dependent on their proper use in the correct concentration. Therefore, the proportions used in laboratory testing of cement slurries must be clearly communicated to allow field operations to replicate the slurry and desired characteristics.

Batch mixing and pumping a cement slurry through a CT string may significantly affect the principal slurry properties—the fluid loss and thickening time. Thickening time for a slurry mixed according to API mixing procedures (API Spec. 10, Section 5) may be reduced as much as 75%. The reasons for such significant changes in slurry properties are related to the mixing procedures and energy imparted to the slurry as it is mixed and pumped.

As a result of extensive laboratory and yard tests, it is known that the mixing energy and manner in which it is applied affect slurry properties. This causes a higher consumption, and therefore requirement of additives by the cement slurry.

As a consequence of these effects, slurries designed for use with CT must undergo special laboratory test procedures which more accurately simulate actual conditions.

The principal characteristics of a squeeze cement slurry can be categorized as follows:

• thickening time

• filter-cake properties/fluid loss

• rheology.

The stability and reproducibility of these characteristics are directly related to the shear energy imparted to the slurry during mixing and pumping through the CT. Only by adequately shearing the slurry are characteristics stabilized. Therefore, the mixing energy/shear imparted during mixing in the laboratory, or during field mixing, must be sufficient to achieve stable slurry characteristics.

3.1.1 Thickening Time

As with primary cementing, API testing schedules have been developed to test the thickening time of squeeze cementing slurries. However, conducting the placement through CT subjects the slurry to significantly different conditions (and rates of change) than is represented by conventional API squeeze schedules. Such API squeeze schedules have been developed for use with drillpipe or tubing placement. To more accurately reflect the actual conditions encountered during a CT cement squeeze, modified versions of the API schedules are used. A typical modified test schedule for CT operations is shown in Fig 17.

The relatively small flow areas and rates associated with CT permit a rapid temperature increase in circulated fluids. Therefore, bottomhole static temperature (BHST) should be used when conducting test procedures. Conventional API test schedules use bottomhole circulating temperature (BHCT).

Because the mixing energy imparted to the slurry also influences the thickening time, the test procedure should closely simulate the anticipated mixing and pumping procedure.

The recommended thickening time is typically based on the predicted job time plus a safety factor of 40-50%.

3.1.2 Fluid Loss

Fluid-loss-control additives are required to ensure the creation of good quality filter cake on permeable surfaces in and around the perforation tunnel. Ultimately, this filter cake should cure to provide an impermeable cement node with sufficient compressive strength to remain secure at the anticipated differential pressure.

Excessive fluid loss can result in bridging of the well bore tubulars with dehydrated cement (Fig. 18). Slurries with too little fluid loss can result in an insufficient buildup of filter cake on the formation surface. To avoid these conditions, the filter cake for CT squeeze cement slurries should be designed within a range of 0.5 to 1.0 in. (design criteria for operators in Prudhoe Bay, Alaska). This will generally correspond to a fluid loss within the range of 40 to 100 mL/30 min (API). A more exact value should then be determined after considering the characteristics of the formation. A good starting point for the design of gas- or water-shutoff slurries is 0.75in. High-pressure, fluid-loss cells are used to study the

TYPICAL COILED TUBING CEMENT SLURRY TEST SEQUENCES

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.

- Postsqueeze

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.

Fig. 17.

filter-cake performance for possible slurry formulations Three tests are commonly run on the resulting filtercake to allow comparison or appraisal of the slurry— filter-cake thickness, quality and temperature sensitivity.

The thickness of the test sample filtercake is representative of the amount which will be deposited downhole during a squeeze. Therefore, the minimum required filtercake produced under downhole conditions should be sufficient to fill the anticipated, or ideal, perforation profile. Slurries that develop little filtercake may be considered unsuitable for squeeze applications because most of the slurry in the perforations will be in a slurry form. This increases the likelihood that the cement will be accidentally removed when the excess slurry is removed from the wellbore on completion of the squeeze procedure.

Filter-cake quality is assessed by penetrating the filter-cake with a steel rod that has a one-pound force applied. Firm filtercake is more resistant to washing or jetting during the removal of excess cement from the wellbore. The condition of the slurry remaining in the test cell is also of interest, because it indicates the likely condition of the excess slurry which will be removed from the wellbore. The slurry above the firm filter cake should be in a liquid state without gelation tendencies.

The temperature sensitivity of the slurry influences the production of good quality filtercake. Some slurries exhibit significantly different filter-cake characteristics when tested over a range of temperature. Generally, the slurries that perform consistently over a range of temperatures possess the characteristics desired for use with CT.

3.1.3 Rheology

Fluid friction is always a concern when pumping through CT strings. However, cement slurries have a higher viscosity than most types of workover fluid which significantly reduces the maximum pump rate achievable within operating pressure limits. Due to the relatively small volumes of slurry to be placed and the design incorporating extended thickening times, placement time is generally not a concern. Typical squeeze slurry composition and characteristics are shown in Fig. 19.

Most cement slurries behave as Bingham plastic fluids, i.e., the viscosity of the fluid is dependent on the yield point (τ_y) and plastic viscosity (μ_p). In simple terms, the plastic viscosity is primarily a function of the amount of solids in the slurry and cannot be significantly influenced

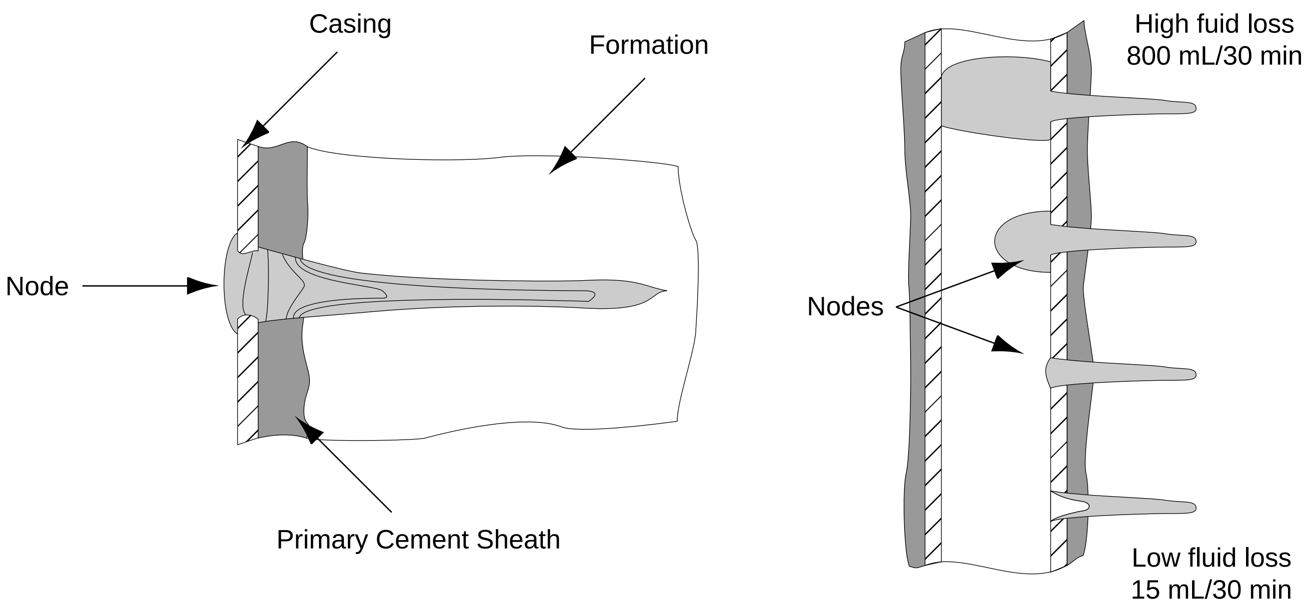

Figure 18. Cement node buildup.

TYPICAL SQUEEZE CEMENTING SLURRY COMPOSITION AND CHARACTERISTICS

Conventional Squeeze Slurry

Class G Cement

+ 0.1 gal/sk	D47	Antifoam
+ 0.4% BWOC	D156	Fluid-Loss Additive
+ 0.5% BWOC	D65	Dispersant
+ 0.2% BWOC	D800	Retarder
+ 0.1 gal/sk	D135	Surfactant (shear bond/fluid-loss enhancer)
+ 0.5% BWOC	D20	Slurry Stabilizer
+ 5.05 gal/sk		Fresh Water

Density	15.6 lb/gal
Yield	1.19 ft^3/sk
Filter Cake	0.8 in. — firm
Fluid Loss	67 mL/30 min (170°F BHCT)
Thickening Time	7 hr 20 min to reach 70 Bc (180°F BHST)
Bingham Yield	9.5 lb/100 ft^2 (95°F), 9.2 lb/100 ft^2 (170°F)
Plastic Viscosity	39.2 cp (95°F), 37.3 cp (170°F)

No free water/sedimentation. D20 is prehydrated in water, all additives are mixed in water, and cement is added in 15 sec at 12,000 rpm for 180 sec.

Latex Cement Squeeze Slurry

Class G Cement

+ 0.1 gal/sk	D47	Antifoam
+ 1.3 gal/sk	D134	Latex Fluid-Loss Additive
+ 0.4% BWOC	D65	Dispersant
+ 0.5% BWOC	D800	Retarder
+ 0.10 gal/sk	D135	Surfactant (shear bond/fluid-loss enhancer)
+ 1.0% BWOC	D20	Slurry Stabilizer
+ 3.82 gal/sk		Fresh Water

Density	15.6 lb/gal
Yield	1.21 ft^3/sk
Filter Cake	0.7 in. — firm
Fluid Loss	58 mL/30 min (170°F BHCT)
Thickening Time	7 hr 29 min to reach 70 Bc (180°F BHST)
Bingham Yield	17 lb/100 ft^2 (95°F), 12 lb/100 ft^2 (170°F)
Plastic Viscosity	34 cp (95°F), 34 cp (170°F)

No free water/sedimentation. D20 is prehydrated in water, all additives are mixed in water, and cement is added in 15 sec at 12,000 rpm for 180 sec.

Fig. 19.

by additives. The yield point is a measure of the distribution of the particles in the slurry. The yield point, and therefore the viscosity, of a slurry can be altered by adding dispersants. However, care must be exercised in the use of dispersants because it is possible to overdisperse a slurry, in which case settling of the cement solids will occur. A prerequisite for CT squeeze slurries is no settled solids and no free water.

The apparent viscosity (μ_a) is commonly used in specifying the characteristics of a cement slurry since it is relatively easily measured using a FANN 35 Viscometer.

Optimum rheological values for CT squeeze cement slurries are

Minimum possible τ_y (5 to 10 lbf/100 ft^2)

Minimum possible μ_p (less than 50cP)

Since cementing operations may require the CT to remain inside a column of cement for an extended period, no gel- strength buildup should be evident within two hours at BHST.

Rheology and stability tests are commonly performed at surface mixing temperatures and at BHST. In general stable slurries provide good rheology characteristics which are are easily reproducible.

3.2 Design

3.2 .1 Slurry Volume

The appropriate volume of slurry prepared for a CT cement squeeze is dependent on several factors. In most cases, previous squeeze experience in the same or similar reservoirs will provide the best guidelines. Although it is desirable to achieve a successful squeeze in one operation, some hazards exist if the slurry volume is excessive. Conversely, the minimum practical slurry volume is that which will ensure correct placement of the necessary volume of uncontaminated cement.

The following factors influence the slurry volume:

- 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 force applied to the tubing, i.e., in deep applications, the additional tension resulting from the cement inside the CT may exceed operating limits.

- The configuration of surface mixing and pumping equipment i.e., reducing the volume of surface lines (especially large-diameter 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 account for contamination. In addition, the plugs can provide a positive indication of slurry location.

When using CT to place a fluid column in a wellbore, the ultimate position of the fluid column is primarily dictated by the location of the CT nozzle and by the volume of fluid pumped. Consequently, fluid volumes must be carefully designed, measured and confirmed when performing operations requiring critical depth control.

3.2.2 Slurry Placement

The success of any cement squeeze is dependent on the accurate placement of an uncontaminated slurry which has the desired characteristics. The following factors are of importance during slurry placement:

- Depth control

- Contamination protection

- Cement column stability

- Isolation of adjacent zones

- Tubing movement

3.2.3 Depth Correlation

Depth-sensitive applications, such as cement squeezing, generally require the CT nozzle to be positioned and controlled using a higher degree of accuracy than can be achieved using surface measuring equipment. The effects of stretch, buckling and residual bend can be variable and considerable. For this reason a downhole reference point is generally required to achieve the necessary accuracy of placement.

There are three methods of acquiring a depth reference: log correlation, tagging bottom or tagging completion

restrictions.
Log correlation tools require an electrical connection, and therefore are limited to applications conducted with CTL reels. Squeeze cementing operations are not compatible with downhole tools or the CTL reel.

Tagging bottom can be significantly inaccurate in wells containing fill. In addition, buckling of the CT occurs in deviated wells or large completions, thereby inducing an error. However, in certain conditions it is a viable method which is often used.

Locating restrictions in the completion tubulars using a tubing end (TEL) or tubing nipple locators (TNL) is the most practical method of depth control in critical squeeze cementing operations.

3.2.4 Protection Against Contamination

The relatively small volumes associated with squeeze cementing through CT require that care must be taken to avoid contamination. Contamination will result in unpredictable slurry characteristics, a reduction in the compressive strength of the set cement and incorrect placement due to the change in slurry volume.

As in all cementing operations, it is recommended that spacer fluids are pumped ahead and behind the cement slurry. The most commonly used and, in most cases, most appropriate spacer fluid is fresh water.

A great potential for contamination exists in the surface lines and pumping equipment. However, some simple precautions should be taken to ensure clean fluid interfaces and eliminate contamination. A reel manifold sampling point and flush line can be rigged to allow the surface lines to be flushed each time a new fluid is pumped (Fig. 20).

After isolating the CT reel (close the reel inlet valve), and opening the flush line at a sample point, the new fluid is pumped until uncontaminated fluid is observed at the sample point. Pumping recommences downhole after the manifold valves have been realigned and a fluid volume reference is taken.

Mechanical separation, and protection, of the cement slurry can be achieved 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, thereby providing a positive indication of plug location.

Plug launching equipment fitted to the reel allows several plugs to be preloaded and then launched in sequence without affecting the pressure integrity of the reel or manifold.

3.2.5 Cement Column Stability

Early in the history of CT cement squeezes, it was determined that successful placement of a stable cement column off-bottom, over a less dense fluid was impossible (Fig. 21). Experiments conducted with fluids of varying viscosity and density concluded that to ensure correct cement placement, a retaining platform must be used. A number of fluid and mechanical platforms have since been successfully used to support squeeze or plugback

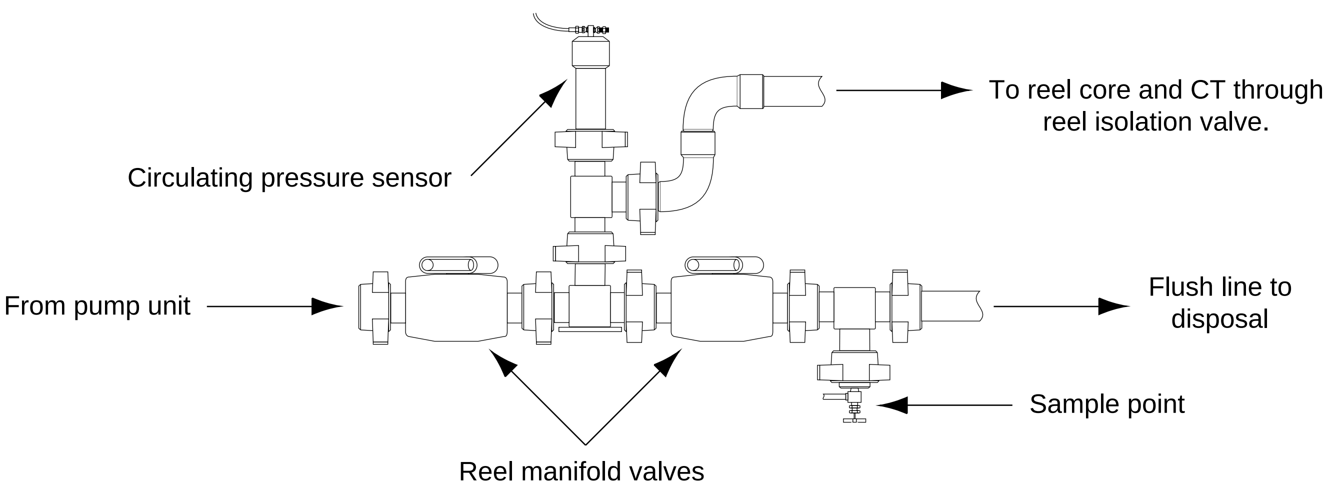

Fig. 20. Reel manifold sampling point and flush line.

cement slurries:

• excess cement slurry

• weighted gel

• sand

• PROTECTOZONE* Fluid

• calcium carbonate

• through-tubing bridge plug.

The nature and size of an appropriate platform should be determined for each case. Under some conditions it may be appropriate to place the cement column from the bottom of the rat hole.

Isolation of adjacent perforations below the zone to be squeezed can be achieved by similar methods to those shown above for providing a platform. However, it is common for all perforations around the squeeze zone to be cemented. Selective reperforation of the interval has achieved better results with the benefit of less complex job design.

Placement techniques for fluids or plugs conveyed by CT differ from conventional drillpipe or tubing conveyed methods.Capillary forces associated with the relatively small ID tube restrict the ability of viscous fluids to fall from the tubing while pulling up. Attempting to pull up through a placed plug will result in cement stringers being pulled uphole.

The technique commonly used to place plugs takes advantage of a basic feature of coiled tubing operations, i.e., the ability to pump fluids while moving the tubing. Once the cement/spacer interface starts rising in the annulus, the CT nozzle is withdrawn at a rate which maintains the nozzle within the rising slurry column. The CT nozzle should be kept at least 50 to 100 ft below the top interface while the column is being placed. As the last of the cement is pumped from the CT, the nozzle should be withdrawn above the theoretical top of the cement (TOC).

This technique will result in a clean cement interface. Further tubing movement, circulation or reverse circulation will be determined by operational requirements.

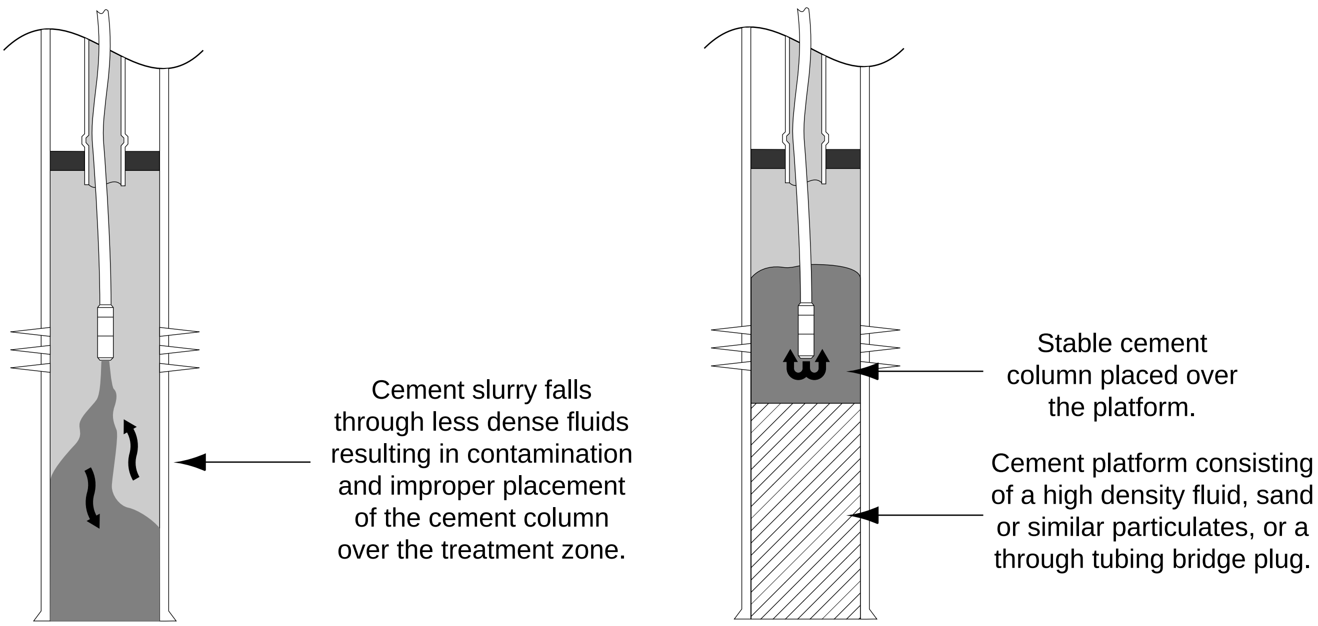

Fig. 21. Cement placement with and without a retaining platform.

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3.2.6 Tool Selection

Tool strings used in conjunction with cement squeezes should generally be kept to a minimum. However, there are a number of functions which may be required depending on the application.

• Connector

Required on all jobs. The simple connectors are less sensitive to accidental cement invasion than the Dowell grapple.

When using cement plugs, pigs or balls, connectors that deform the internal surface of the CT (e.g., dimple/setscrew and roll-on connectors) should be checked for adequate clearance.

• Check Valves

Cannot be used when procedures call for reverse circulation of excess cement from the wellbore. When fitted, only full-bore flapper check valves should be used.

• Depth Correlation

Tubing end or nipple locators are commonly used to confirm depth; however, many treatments are performed using TD as a reference point.

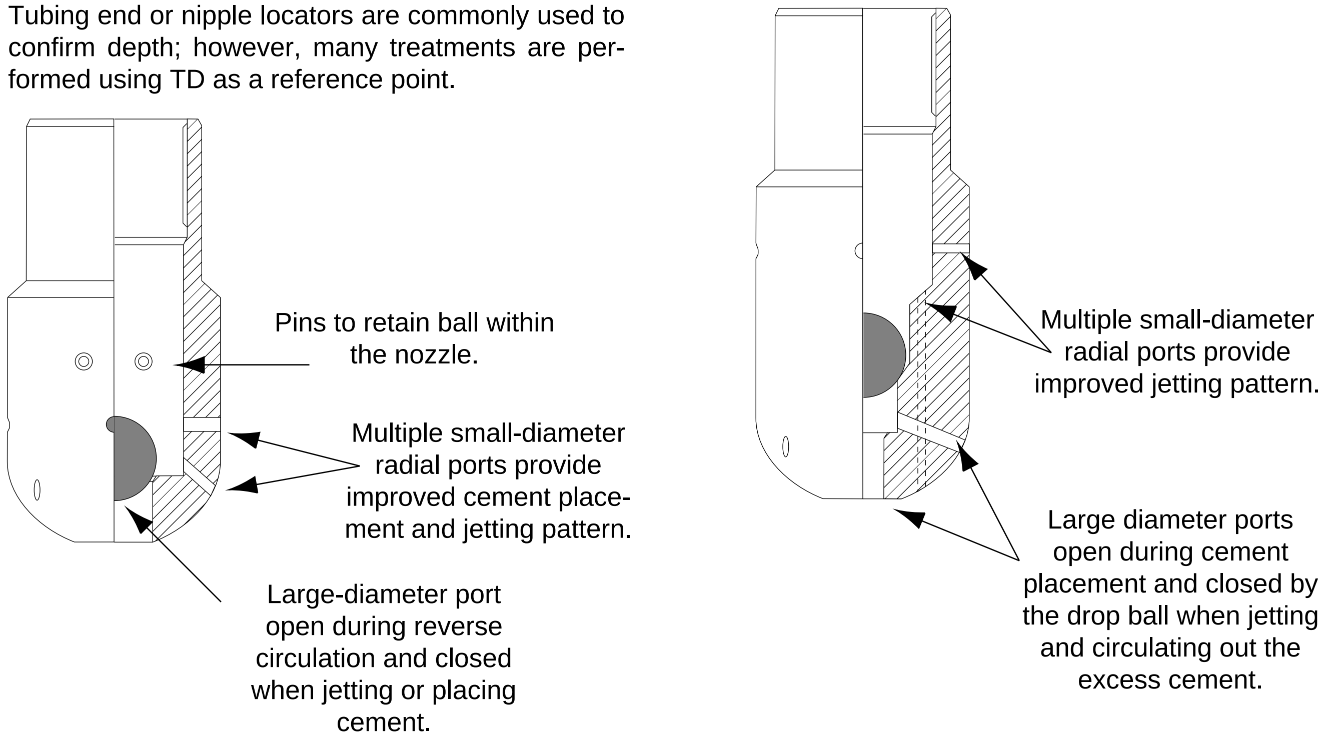
• Plug Catcher

For use with plugs ahead or behind the cement slurry. Essentially to catch and retrieve the plugs, some versions provide some indication that the plug has seated by causing a pressure increase visible at the surface.

• Nozzles

A variety of jetting nozzles have been developed to improve the slurry placement. In addition, some more complex designs are intended to ensure satisfactory removal of excess cement by reverse circulation.

While it is advantageous to perform all aspects of the operation without changing the nozzle or BHA, some functions ideally require different nozzle/jet configurations. For example, to clean and condition the wellbore and to place the cement slurry, a nozzle with multiple side-facing jets is preferred. However, if excess slurry is to be removed by reverse circulation, a single large-port nozzle (to avoid plugging) is preferable. Combination nozzles (Fig.22) are designed to provide improved reverse circulating and jetting capabilities.



reverse circulating nozzle

improved jetting/circulation nozzle

Fig. 22. Cementing nozzle features.

3.3 Squeeze Cementing Operations

In many cementing operations, the cement setting process provokes a sense of urgency which can affect the normal decision-making ability of personnel. The risk of premature setting and the corresponding operational difficulties can impose a sense of urgency that results in misguided actions which are neither methodical or necessary. Principally for this reason, it is essential that clear and precise procedures be prepared for the entire cementing operation. This should include details of normal, contingency and emergency operating procedures.

3.3.1 Execution Precautions

Execution precautions to be observed during squeeze cement treatments relate to the safety in handling of cement and chemicals, ensuring the correct placement of a slurry with the desired characteristics and ensuring that cement deposits do not remain in the CT or pressure control equipment on completion of the operation.

Personnel

All personnel involved in the design or execution of squeeze cementing or CT services must be familiar with requirements detailed in the relevant Safety and Loss Prevention (S&LP) Standards.

Well Security

The control of well pressure and fluids must meet the requirements of the relevant S&LP Standards. In addition, the requirements of the operating company and applicable regulatory authorities must be known.

Equipment

All Dowell treating and monitoring equipment must be spotted and operated in accordance with the requirements of the relevant S&LP Standards. In addition, equipment certified for use in hazardous areas must be operated and maintained in accordance with the operating zone requirements.

3.3.2 Equipment Requirements

A schematic diagram of typical equipment layout is shown in Fig. 23.

Coiled Tubing Equipment

Some operating companies require that the work-string volume be checked by inserting and displacing a plug or foam pig. Such checks can be combined with the displacement of pickling treatments where required.

To minimize contamination, a flushing/sampling manifold should be rigged up on the CT reel.

When pumping high-density fluids through the CT work string, there may be significant changes in the string tension forces.

All manifolds and valves should be flushed to ensure that all traces of cement are removed.

Pressure Control Equipment

All manifolds and valves should be flushed to ensure that all traces of cement are removed.

Pumping Equipment

All fluid mixing, pumping and storage equipment must be clean and configured to avoid contamination or dilution of the cement slurry.

Pressure and rate limits (governed by the CT equipment or reservoir conditions) for every stage of the operation must be defined and noted on the pumping schedule.

All manifolds and valves should be flushed to ensure that all traces of cement are removed.

Monitoring and Recording

Accurate monitoring and recording of the job parameters is essential to allow complete control of the job and preparation of postjob reporting and analyses. The schematic diagram in Fig.24 identifies typical job parameters and their point of measurement/recording.

Downhole Equipment

A complete fishing diagram must be prepared to include all downhole equipment. In addition, the operation of all tools must be fully understood.

3.3.3 Treatment Execution

The steps required to successfully complete a cement squeeze will depend on the particular conditions

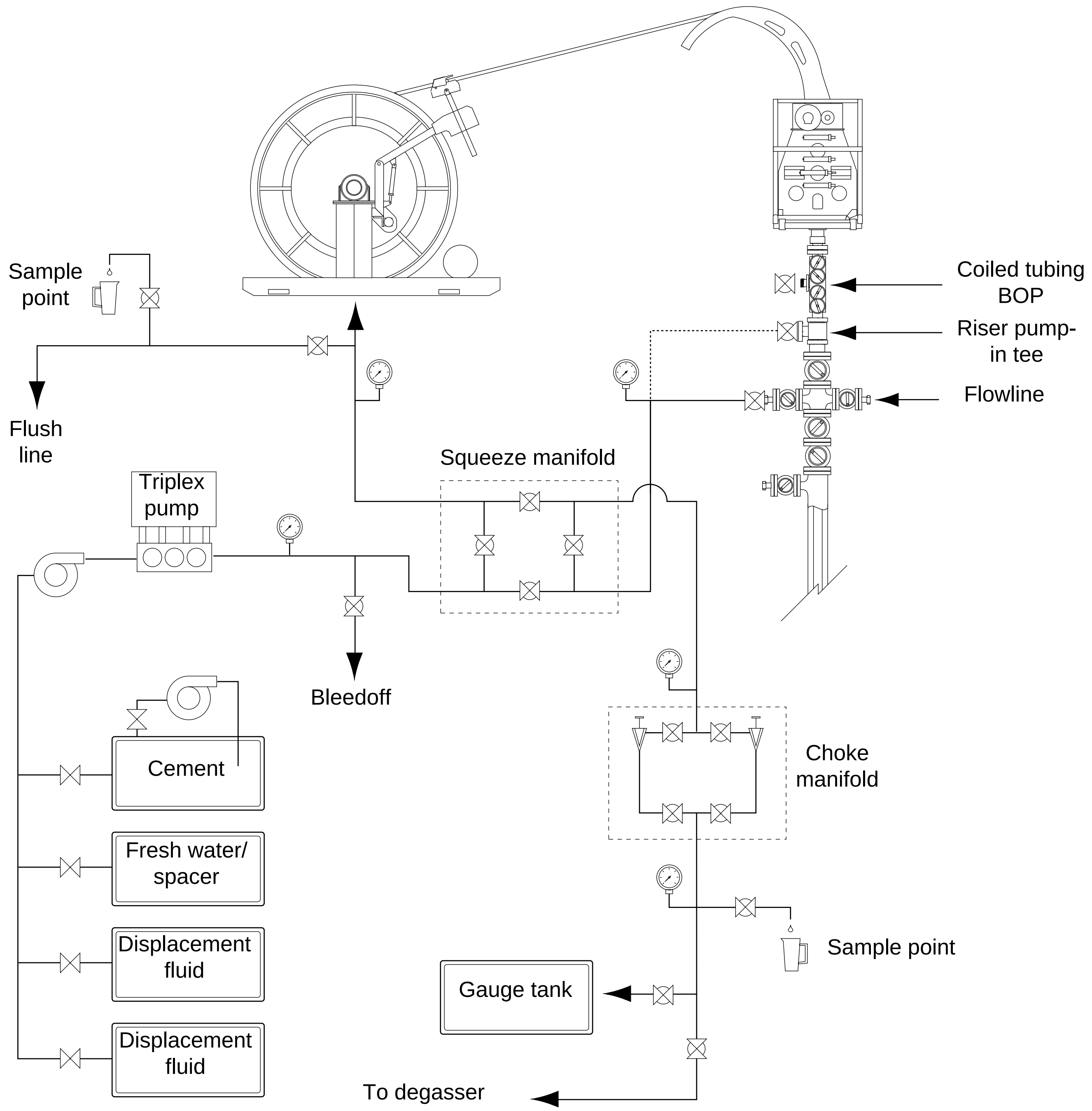


Fig. 23. Typical squeeze cementing equipment configuration.

encountered in each case. In the following section, the key points in each phase of the cementing operation are outlined. When preparing and documenting a treatment procedure, it is recommended that the key points are reviewed and the applicable points incorporated into the procedure as required.

Cementing operations are frequently conducted in multiple well campaigns within a field or area. Consequently, procedures are often tuned to meet local conditions by application of the DESIGN, EXECUTE and EVALUATE* cycle. Whenever possible, previous case histories for similar applications should be referenced.

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Execution of squeeze cementing operations is accomplished in four basic steps:

• wellbore preparation

• slurry mixing and pumping

• squeeze

• removal of excess cement.

See Fig 26 through Fig 33.

Welbore Preparation

In preparing the wellbore and completion for squeeze cementing operations, several operations are commonly completed. Slick-line conveyed tools and methods are generally used where possible; however, in deviated or unusual conditions, CT is capable of completing all preparatory work.

Wellbore preparation operations will generally include the following:

• Slick-line work, e.g., fitting dummy gas-lift mandrels.

• Pressure test the production tubing annulus.

• Establish hangup depth or TD using slick line.

• Confirm and correlate depths with CT and flag the tubing.

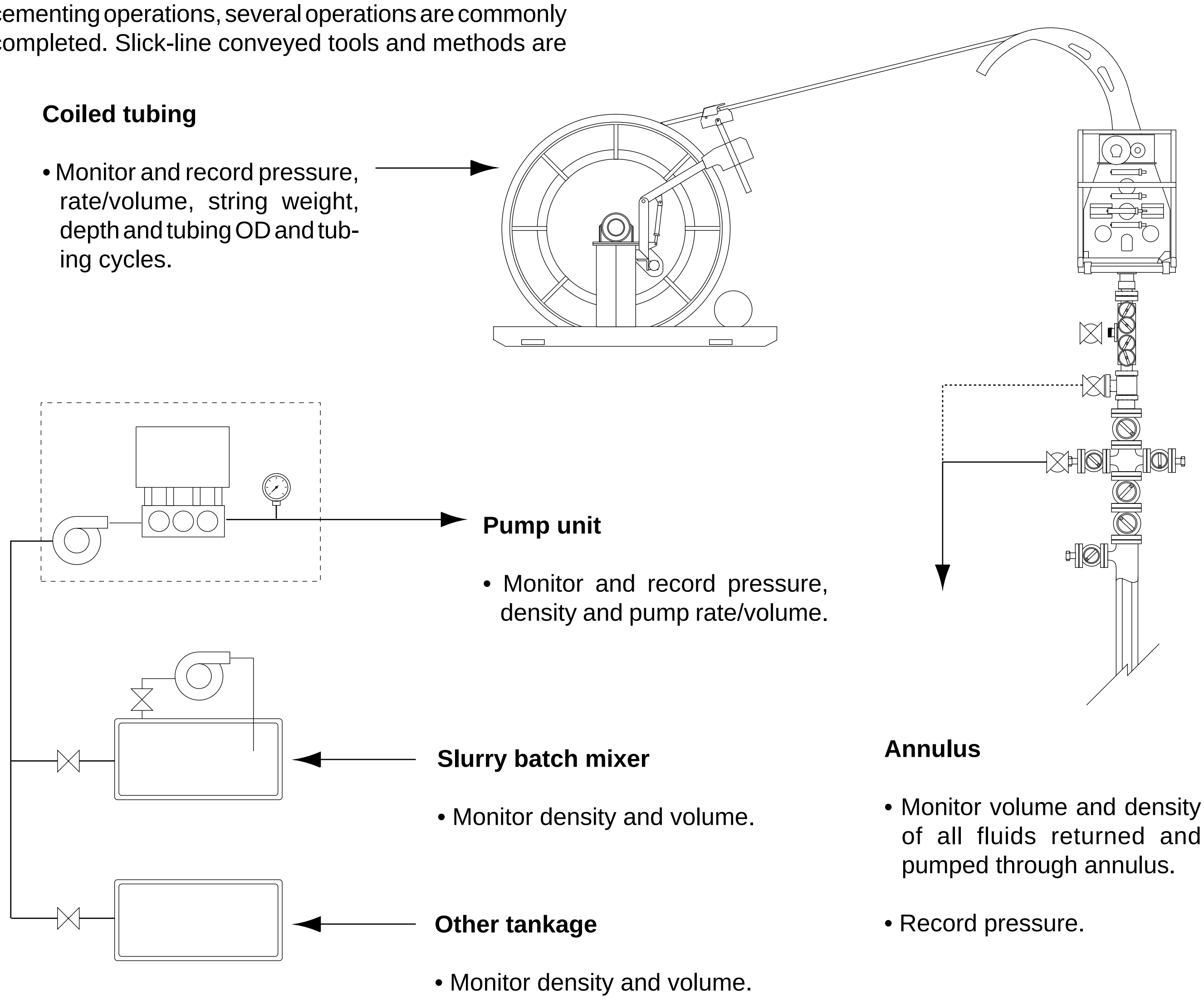

Fig. 24. Squeeze cementing parameters to be monitored and recorded.

• Remove fill from the rathole below perforated interval.

• Perform pretreatment perforation wash or acidizing.

• Place a stable platform for the cement slurry.

• Ensure that the wellbore is fully loaded with filtered water (or equivalent).

Slurry Mixing and Pumping

Before mixing and preparing the slurry, the wellbore should be fluid filled and a stable and adequate cementing platform should be in place. In addition, placement depths should be confirmed and the CT flagged at critical points, e.g., anticipated top and bottom of the placed cement column.

Key points in the slurry mixing and pumping process include the following:

• Batch mix and shear the slurry ensuring that additive proportions are accurately measured. Contingency plans should be made for dumping or disposal of slurry which fails to meet the required specifications.

• Conduct job-site quality control tests (filtercake, fluid loss, rheology).

• Prepare contaminant and spacer fluids as required. Equipment rig-up should be configured to avoid accidental contamination on the surface.

• Confirm CT depth and coordinate tubing movement with pumped volumes. The CT nozzle movement and location must be closely aligned to the fluid type and volume exiting the nozzle. Pump operators and CTU operators must have a mutual understanding of the operation to be completed. It is also essential that they have a clear line of communication.

• Lay in cement slurry following the prepared pumping schedule (Fig. 33) . While spotting the cement column, it is essential that the wellbore remain fully loaded with fluid to prevent gas migration in the CT production tubing annulus.

The following guidelines should be considered to reduce the risks of operational failure when using thixotropic cements.

• Do not stop pumping while thixotropic cement is inside the work string.

• Place the CT nozzle above the thief zone and pump down the production tubing/CT annulus while squeezing the cement.

• Overdisplace thixotropic cement slurries 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).

Squeeze

The effect of placing and squeezing cement slurry across the treatment zone is often unknown. Squeeze pressure may build quickly as the slurry contacts the formation face, or in formations with fractures or void spaces behind the liner or casing, squeeze pressure may not be achieved. Consequently, prepared procedures must detail actions to be taken for a number of events which may or may not occur.

The downhole generation of filter cake is aided by performing hesitation type squeezes (e.g., 10 min at 1000 psi, 15 min at 1500 psi, 20 min at 2000 psi....). As the fracture pressure is exceeded during this process, the filter cake prevents the formation from fracturing. A firm filter cake is formed which contributes greatly to the success of the squeeze operation.

• To reduce the risk of sticking, the CT nozzle should be constantly or at least frequently moved during the operation.

• When displacing the spacer and slurry, the CT should be at the lower flagged depth when the spacer exits the nozzle. When 50 ft of cement has been placed above the nozzle, the CT should be slowly withdrawn from the wellbore. To minimize the risk of dilution/ contamination, the nozzle should be kept at least 50 ft below the top cement interface. With a flowmeter placed in the annular return line, the volumes pumped and returned can be compared to determine the squeezed slurry volume.

• The annular/choke manifold pressure must be closely monitored and controlled during the cement placement and squeeze. A clear line of communication must exist between the choke manifold operator, pump unit operator and CTU operator.

• If squeeze pressure builds before all of the cement has left the CT, the cement should be laid in while balancing the returns with fluid pumped, i.e., fluid return rate should equal the fluid pump rate through the CT. The

CT nozzle should be at the top cement interface as the last of the slurry exits the nozzle.

- The nozzle should be located 50ft above the TOC before attempting to squeeze the cement. For safety, assume TOC as worst case, with no cement being placed behind the perforations.

- If squeeze pressure does not build when the interval is covered with cement, use a hesitation technique to attempt pressure buildup in stages. The hesitation periods are dependent on how much slurry the well "takes" and the volume of slurry available for the squeeze.

- If the squeeze "breaks back" during a pumping stage, the hesitation sequence should be resumed. This is often an indication that perforations previously plugged by debris have broken down and are now accepting fluid.

- Maintain slow circulation through the CT and control BHP by choking the returns. Closely monitor the return volume and rate.

- When final squeeze pressure is achieved, continue circulating and holding pressure on the annular choke for one hour.

- On completion of the squeeze sequence, stop circulation, close choke and monitor the wellhead pressure WHP.

- Slowly bleed off the pressure to approximately 500 to 1000 psi above the BHP and prepare for cleanout operations.

Removal of Excess Cement

An important feature of CT workovers is the ability to complete operations and restore the well to production in a relatively short time. In the case of 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, which may be summarized as follows.

- reverse circulation of live cement

- circulation of contaminated cement

- reverse circulation of contaminated cement.

The Dowell operational requirements for reverse circulation through CT workstrings, as detailed in S&LP Standard, No. 22, must be understood and fully implemented in any operation in which reverse circulation is to be performed.

During removal of the excess cement it is generally desirable to maintain a positive squeeze pressure over the treated zone. In effect, this is automatically applied in the case of reverse circulation techniques by the friction pressure created when lifting fluid through the work string. Cleanouts performed by conventional circulation should have the back pressure controlled by a surface choke.

Key points relating to the methods of removing excess cement are detailed below.

Reverse Circulating of Live Cement

Reverse circulation of live cement slurry (uncontaminated slurry) can be safely performed if the following conditions are met:

- The designed slurry thickening time (including safety factor) should allow 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.

Typical procedures for reversing live cement include the following steps:

- With the CT nozzle positioned above the spacer fluid, establish circulation down the CT production tubing annulus. Maintain a stable pump rate which does not exceed the maximum allowable differential on the CT at the wellhead (1500 psi).

- Penetrate the spacer and cement column with the nozzle at a rate which ensures 50% dilution of the excess slurry. This serves to reduce the hydrostatic pressure acting inside the work string and aids removal.

- The CT should be run to the the lower flag mark with circulation maintained until clean returns are observed at the surface.

EXAMPLE SQUEEZE CEMENTING PUMPING SCHEDULE		
Pumping Schedule	**Tubing Movement**	**Annulus Choke**
Workstring capacity 16.23 bbl	Treatment zone 13,500 to 13420 ft (TD 13,580)	
Bullhead filtered seawater (200 bbl) 3 bbl/min <1200 psi 8.7 lb/gal 200 bbl	Swab valve closed	Closed
Filtered seawater while RIH with CT 0.5 bbl/min <1000 psi 8.7 lb/gal 90 bbl	RIH to tag TD 75 ft/min 13,580 ft	Closed
Gel/sand cement platform (20 bbl) 2.0 bbl/min <4000 psi 14.0 lb/gal 16 bbl 4 bbl	At TD 13,580 ft With 16 bbl pumped, start POOH 50 ft/min stop at 13,500 13,500 ft	Open Open
	Allow sand to settle (30 min) tag at 13,520 ft 13,520 ft	
Fresh water spacer (15 bbl) 2.0 bbl/min <4000 psi 8.7 lb/gal 15 bbl	Nozzle 10 ft above tagged sand 13,510 ft	Open
Cement slurry (20 bbl) 2.0 bbl/min <4000 psi 16.0 lb/gal 17 bbl 3 bbl	With 17 bbl of slurry pumped, start POOH 50 ft/min	Open
Fresh water spacer (5bbl) Displacement Fluid (25 bbl) 2.0 bbl/min <4000 psi 8.6 lb/gal 4 bbl If squeeze pressure builds, lay in remaining cement while gauging returns one for one.		After 4 bbl of displacement, choke and gauge returns. 1200 psi max.
16 bbl Continue displacement to obtain squeeze. 10 bbl	With 16 bbl displaced, nozzle should be at TOC 13,000 ft	Build to final squeeze pressure of 2000 psi.
Contaminant (50 bbl) Max. rate <4000 psi 8.5 lb/gal..................	RIH through excess slurry 25 ft/min.........................	

Fig. 25.

- After clean returns are observed, change to circulation through the CT with returns choked to maintain positive squeeze pressure. Make a jetting pass through the treated zone. The jetting fluid pump rate should generally be reduced when passing the treatment zone to avoid damaging the cement nodes. The interval above the treated zone can be jetted at an increased rate.
- Commence reverse circulation again at previous pump and penetration rates until clean returns are observed.
- If required, displace the annulus to nitrogen to achieve the necessary underbalance to test and evaluate the squeeze. Maintain sufficient WHP to apply positive squeeze pressure until the cement has achieved sufficient compressive strength to allow testing (generally after 24 hr).

Preparation

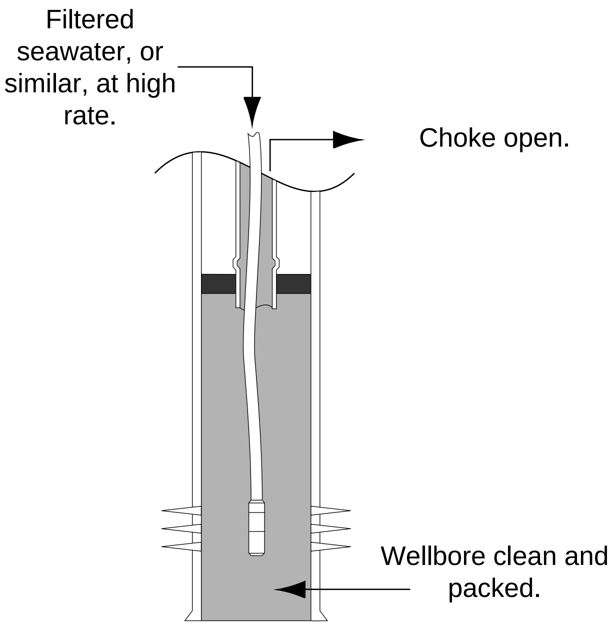

Fig. 26.. Wellbore preparation.

Placing the Slurry

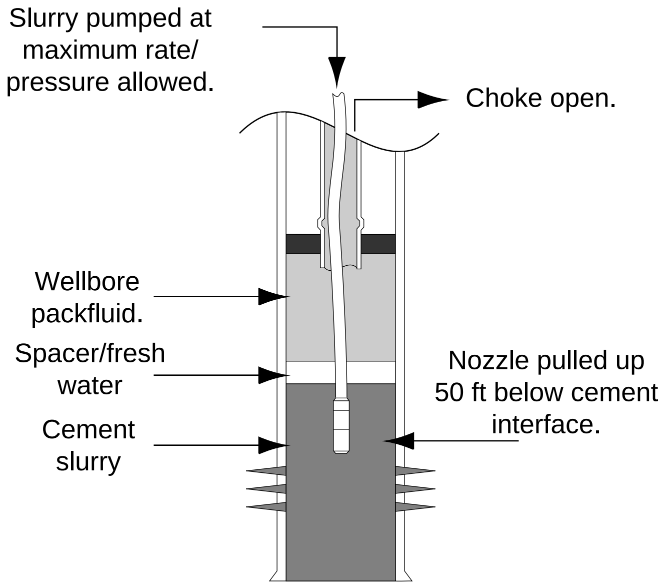

Fig. 27. Laying in cement slurry.

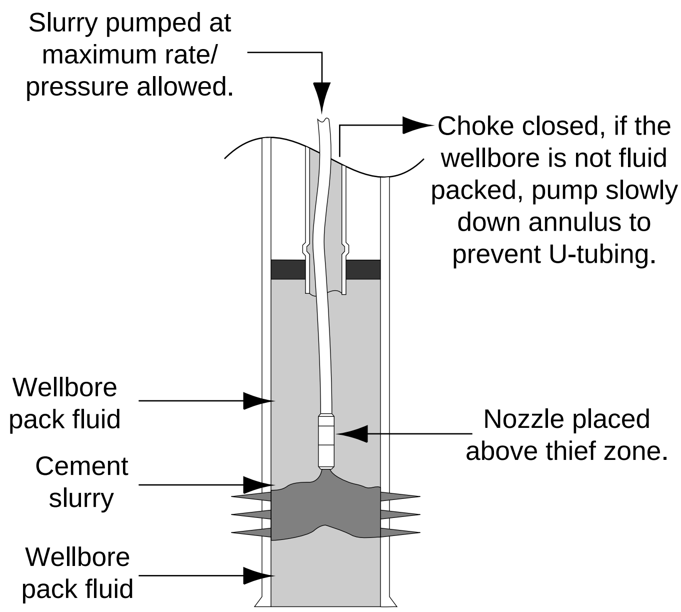

Fig. 28. Placing thixotropic slurries.

Squeezing the Slurry

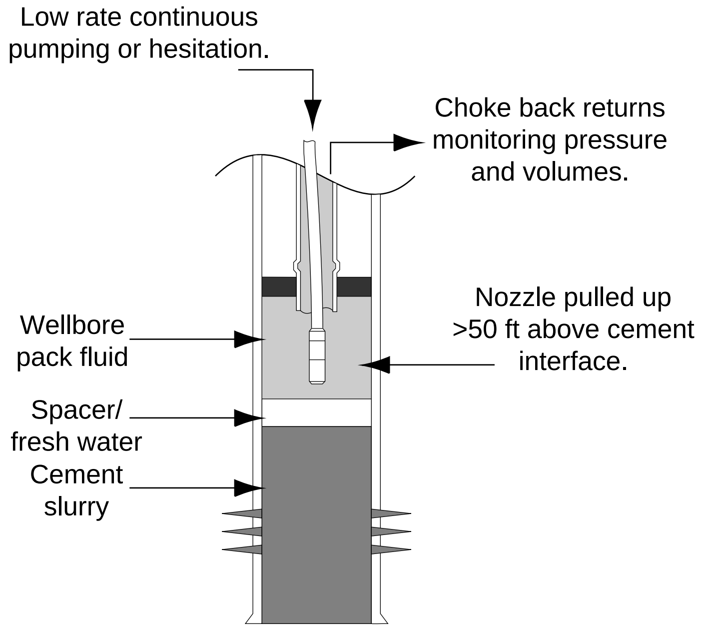

Fig. 29. Commencing squeeze.

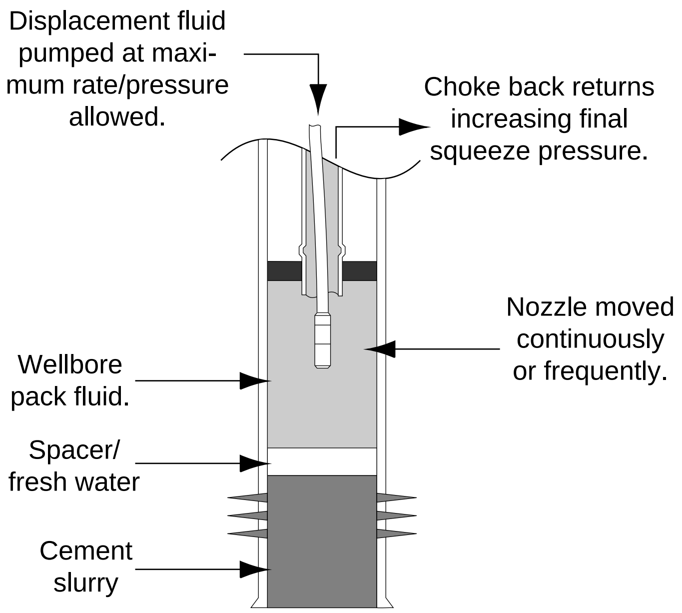

Fig. 30. Completing squeeze

Removing Excess Cement from the Wellbore

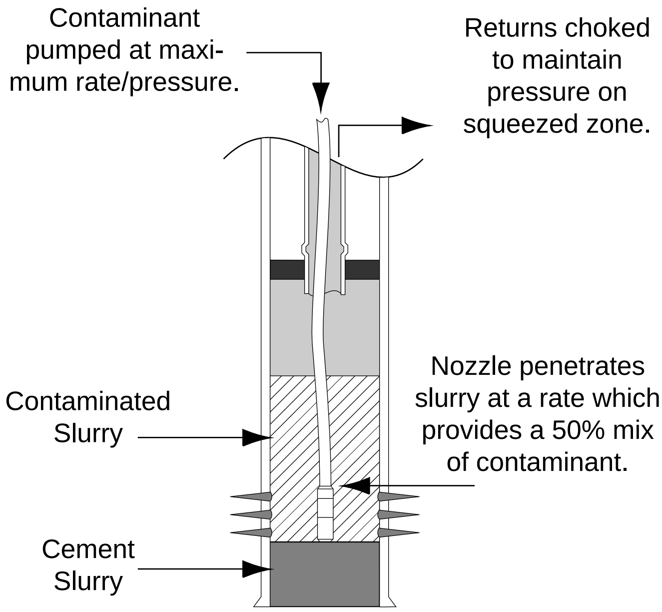

Fig. 31. Contaminating excess slurry.

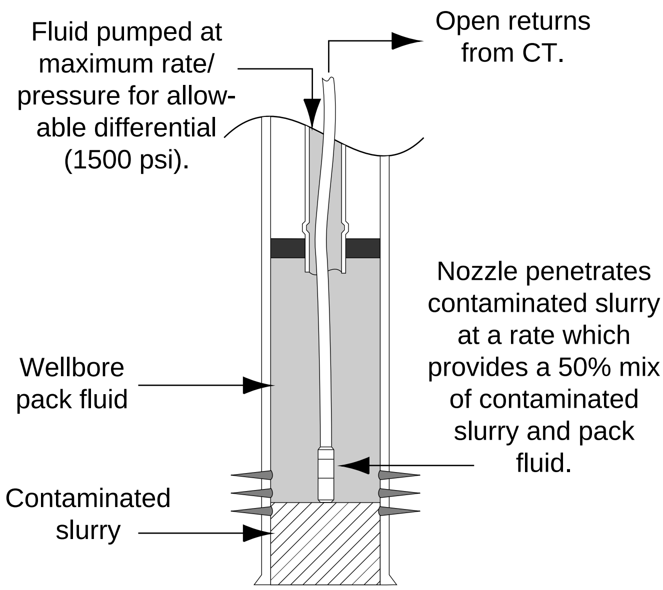

Fig. 32. Reverse circulating excess slurry.

Removing Excess Cement from the Wellbore

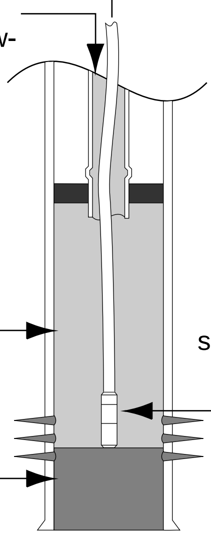

Fig. 33. Reverse circulating live slurry.

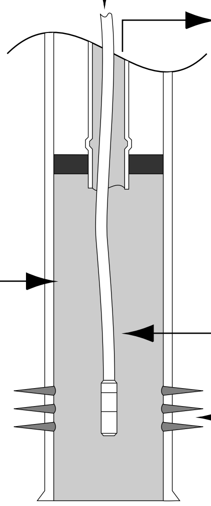

Fig. 34. Wellbore circulated clean.

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 the compressive strength. In this way the likelihood of damaging the treated zone is reduced. However, unless the contaminant is correctly and thoroughly applied, there is some risk of partially obstructing the wellbore with set cement. Typical borax/ bentonite and biopolymer contaminant formulations are shown in Fig. 35.

Typical procedures for contaminating excess cement include the following steps:

- With the CT nozzle positioned above the worst case cement top, establish circulation of the contaminant through the CT while maintaining the desired choke pressure at the surface.
- Penetrate the slurry at a rate which ensures a 50% mixture of contaminant and cement slurry.
- Reduce the pump rate and penetration rate across the treated zone to minimize the risk of damaging the cement nodes.
- Continue the contamination run to the lowest slurry level.
- POOH while continuing to pump the contaminant. Maintain a pump rate and withdrawal rate sufficient to ensure a final dilution/contamination ratio of 1.5:1 (1.5 parts contaminant to 1 part slurry).
- When the nozzle is at the top of the contaminated column begin reversing as detailed in *Reversing Circulating Live Cement*.

Circulation of Contaminated Cement

In the event that the operating conditions cannot safely support reverse circulation of the excess slurry, conventional circulation may be used. For example, operations performed through 1-1/4-in. work strings cannot employ reverse circulation techniques due to the excessive friction pressure encountered. Typical procedures for the circulation/contamination of excess cement slurry include the following steps:

- With the CT nozzle at the top of the spacer fluid, commence pumping contaminant while maintaining the necessary choke pressure to apply positive squeeze pressure on the treated zone.

- RIH while pumping at maximum rate/pressure at a penetration rate which ensures a 50% dilution/contamination of the slurry.

- Reduce pump rate and penetration rate across the treated zone to minimize the risk of damaging the cement nodes.

- Continue contamination run to the lowest slurry level.

- POOH while continuing to pump contaminant. Maintain a pump rate and withdrawal rate sufficient to ensure that the circulated fluids remain above the nozzle.

- On reaching the tubing tail/entry guide, run back into the lowest cleanout depth, and again reduce rates when passing the treated zone.

- POOH to top of the treated zone. Cement accelerator may be placed over the zone if desired.

- Continue to POOH circulating wellbore pack fluid at the maximum rate. The tubing withdrawal rate must be controlled to ensure that all fluids are circulated above the nozzle.

- Ensure that all nipples, mandrels or completion components are thoroughly jetted while pulling out of the wellbore.

3.4 Evaluation of Squeeze

The methods used to evaluate the efficiency of a cement squeeze are primarily dependent on the purpose and objectives of the treatment. For example, water and gas shutoff treatments are generally checked by performing an inflow test; whereas, thief zone squeezes and squeeze treatments performed prior to hydraulic fracturing are commonly checked by pressure testing the wellbore prior to reperforating.

However, the initial step in any evaluation process should be to confirm the condition of the wellbore in the treatment zone. In the event that the wellbore is obstructed by large cement nodes or buildup, some drilling/underreaming may be required. A wireline or CT conveyed drift run using tools of an appropriate size is commonly used to check wellbore condition.

In addition a check should be made to ensure the rathole is debris or cement free.

The duration and differential pressure to which any cement squeeze treatment is tested will be at the discretion of the client. However, the evaluation process should be discussed during the job design phase to ensure the risks of damaging the treated zone are minimized.

Inflow differential pressure applied during testing should be equal to or slightly greater than the anticipated drawdown when production has been restored. An acceptable/unacceptable inflow rate should be determined prior to testing.

Injection wells will typically be tested to the injection header maximum pressure. Wells to be reperforated and fractured should be pressure tested to the maximum BHP anticipated during the fracturing treatment.

TYPICAL CEMENT SLURRY CONTAMINANTCOMPOSITION		
Borax/Bentonite		
	10 to 20 lb/bbl	Bentonite
	20 lb/bbl	Borax
	3 gal	Cement Retarder D109 (case dependent)
Bio-Polymer Gel		
	1.5 lb/bbl	Biozan gel

Fig. 35.

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WIRED COILED TUBING APPLICATIONS

Contents Page

1 COILED TUBING LOGGING EQUIPMENT

In addition to the basic coiled tubing reel components, the following items are required to complete the surface equipment hook up during CTL* (coiled tubing logging) operations. These items are typically permanently installed or assigned to a CTL reel.

- Pressure bulkhead
- Reel Collector
- Logging cable

1.1 Pressure Bulkhead

The pressure bulkhead (PBH) is used to allow electrical connections to be made with the uphole end of the logging cable inside the CT while maintaining the pressure integrity of the reel (Fig. 1).

1.2 Reel Collector

The reel collector is used to allow an electrical connection to be made between the cable in the rotating reel core and the surface electrical equipment.The collector is typically mounted on the reel axle on the opposite end from the fluid swivel. The most recent design of collector are intended to be permanently afixed to the reel shaft. However, for earlier designs, such as that used on conventional wireline logging operations, the collector is typically removed during transportation (unless adequate protection can be provided).

Maintenance of the collector and bulkhead is generally restricted to ensuring the electrical integrity of the components and preventing the accumulation of dirt and corrosion on the external surfaces by regular and thorough cleaning.

1.3 Cable

The development of logging cables for the oil and gas industry has resulted in a selection of cable types, manufactured for a variety of applications.

* Mark of Schlumberger

Cables are constructed from various conductor, insulation, jacket and armour materials.

The factors influencing a cable's operating limit generally include the following.

• Tensile Strength

The ability of the cable to support its own weight in the well will limit the operating depth to which the cable may be reliably used.

• Temperature

The materials used as cable conductor insulators are effective only within a specified operating temperature range. Degradation of the material with temperature may result in the electrical failure of the cable.

• Hostile Environment

The materials used in certain cable types may be incompatible with the well or treatment fluids encountered in the intended application.

The factors described above are generally interactive. Therefore, selection of the appropriate cable materials and construction commonly involves a trade-off of the desired operating characteristics against the product cost. There are three basic types of armored logging cable commonly used.

• Monocable

The monocable has one conductor, and is primarily used in production service operations for perforating and production logging.

• Coaxial

Coaxial cables have a shield (known as a serve) composed of many small copper wires that are spiralled wound around the insulated central conductor. Coaxial cables are of similar dimensions to monocable, but have a higher data carrying capability.

• Heptacable

Heptacables have seven conductors and are primarily used in openhole logging.

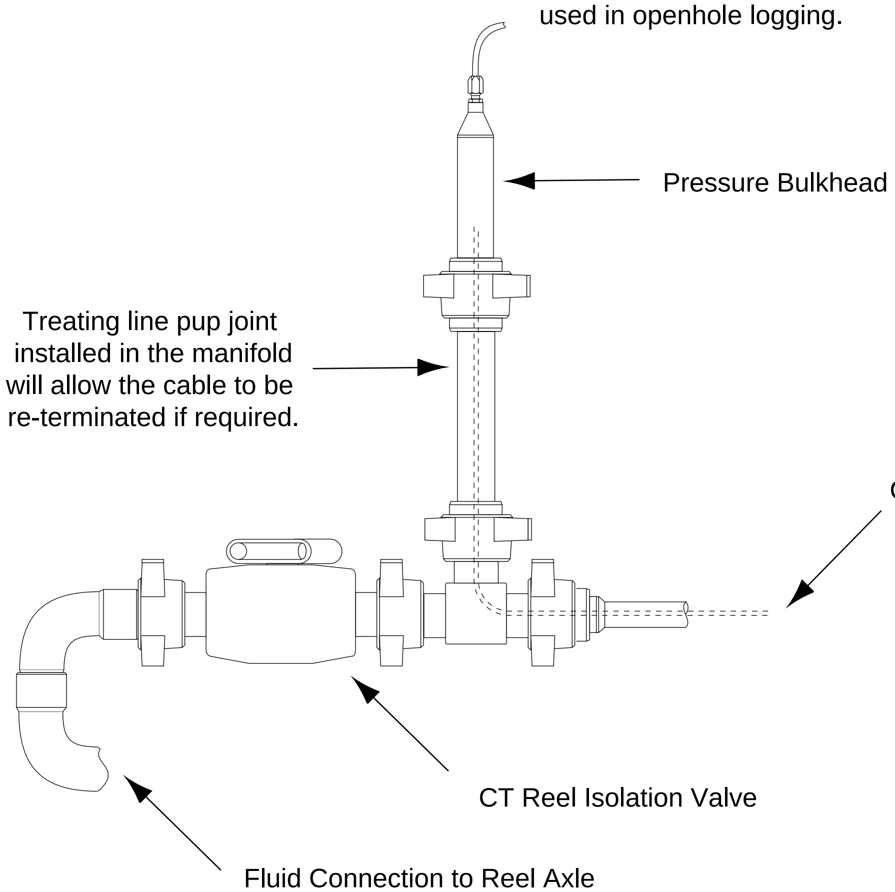

Figure 1. CTL reel manifold –– typical configuration.

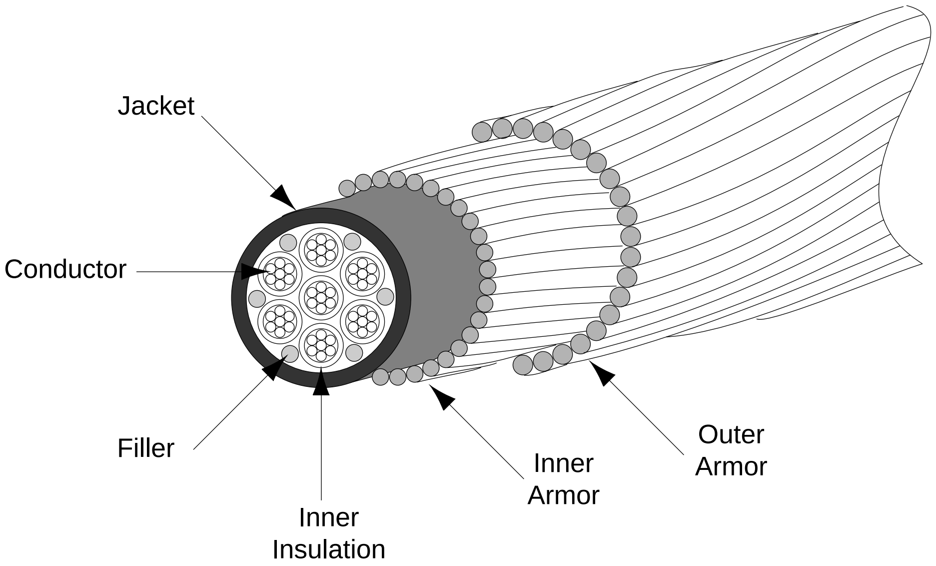

Figure 2. Heptacable components.

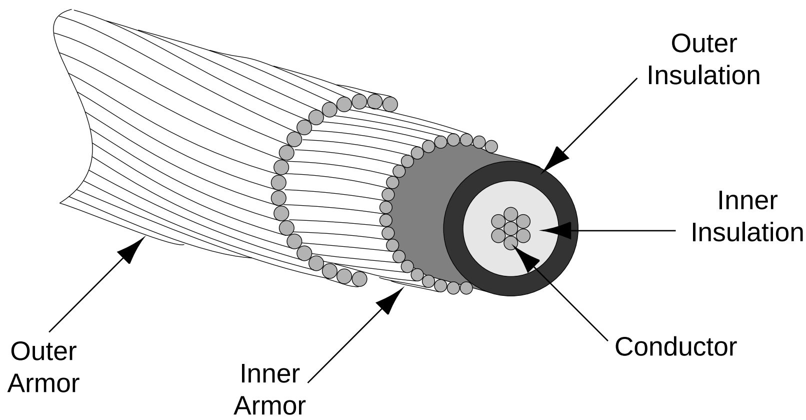

Figure 3. Monocable components.

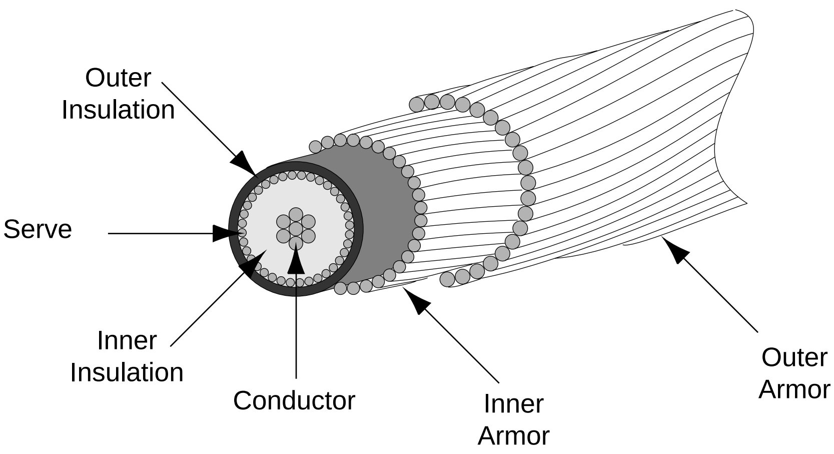

Figure 4. Coaxial cable components.

1.4 Cable Installation

A reel equipped for CTL operations represents a significant investment. This applies both to the cost of the components and to the processes required for assembly. In general terms, the installation of logging cable into a coiled tubing string is not a straightforward process. Consequently several techniques have been investigated during the search for the optimum cable installation method.

1.4.1 Tubing Mill Installation

Installing the logging cable at the time the CT string is formed is a relatively new technique which is applicable only to small diameter cables (mono- or coaxial cable). The in-line mill process requires specialized equipment to protect the cable from the extremely high temperatures associated with welding and heat treating the CT.

Using a similar technique, a pulling cable can be installed as the tubing is being manufactured. The string is subsequently layed out and the logging cable installed by winching through the pulling cable. The likelyhood of damage to the logging cable due to heat is thereby eliminated. However, there remains some risk of damage to the string or cable during the layout, installation and spooling process. This type of installation is generally undertaken by the tubing manufacturer, with the completed logging string being shipped from Houston,Texas.

1.4.2 Wellbore Installation

Wellbore installation of logging cable in the CT string is perhaps tehnically the most straightforward means of cable installation. However, there are several drawbacks, not the least of which is finding a deep enough well in a suitable location. In addition to the required depth, care must be exercised to ensure that the cable temperature limits are not exceeded.

1.4.3 Installation by Circulation (Off Reel)

Installing the logging cable by circulation while the tubing is the off reel is logistically difficult and in may locations impossible. It is necessary to spool the CT from the reel and lay it in as straight a position as is possible. Finding a suitable work site to allow approximately 18,000 ft (3-1/2 miles) of CT to be laid out straight can be extremely difficult.

Holland is one of the few European locations where the terrain allows such a facility. Consequently, most CTL of the early reels prepared in this way have been assembled in Holland.

To facilitate the passage of the towing pig and cable through the CT string it is recommended that only continuously milled tubing strings be used. The absence of butt welds on this type of CT string greatly increases the success rate of the pump through operation.

1.4.4 Installation by Circulation (On Reel)

The ability to install cable into a string which is spooled on a reel avoids the difficulties outlined above. Equipment and procedures are currently being developed by Dowell to enable the installation, and de-installation of cable to be safely and reliably undertaken on a routine basis.

1.5 Conductor Deployment System

One of main operational concerns associated with logging operations relate to the rig-up and handling procedures required for long toolstrings. The conductor deployment system has been developed to overcome such concerns when pressure deploying logging tools on CT. The system consists of surface and downhole sub systems.

Surface Pressure Deployment Equipment

• Quick latch (QL)

• Side door deployment tool (SDDT)

• Annular blow-out preventer (ABOP)

Downhole Deployment Equipment

• Deployment bar

The components and configuration of the conductor deployment system are shown in Figure 5. The surface deployment system significantly increases job safety and reliability by providing a dual barrier to wellhead pressure (WHP) and by securing the injector head to the wellhead riser before makeup of the CT tool string . During deployment, the QL is used to connect the injector to the SDDT which is located above the ABOP on the wellhead. After latching the injector, the CT and tools are connected via a hydraulically actuated window in the SDDT. The ABOP is a backup wellhead seal for the BOP and the stripper.

A dedicated hydraulic control panel is used to control and monitor the system operation.

1.5.1 Quick Latch

The QL provides a quick and safe means of connecting a lubricator or injector to the wellhead riser . The QL has mating conical surfaces to provide stabbing and self-alignment of the injector at angles up to eight degrees without operator assistance. The self-alignment feature means that the centerlines of the wellhead and the injector are coaxial after latching so that the injector is stable if the hoist line from the crane is accidentally lowered or breaks. The QL also has mechanical locking screws to prevent accidental operation.

1.5.2 Side Door Deployment Tool

The SDDT improves job safety and reliability by providing a means of grounding the injector to the wellhead before the CT is connected to the tool string. After the injector is latched to the SDDT via the QL, the tool string is madeup through a hydraulically actuated window in the SDDT. The window is then closed and the tools RIH. The SDDT eliminates the problem of lowering the injector thread by thread when the CT is connected to the tool string.

The SDDT window is designed such that WHP over 1,800 psi will prevent accidental opening of the window by hydraulic pressures up to 1,500 psi. Locking pins also prevent accidental opening of the SDDT window.

The SDDT has integral bleed and purge valves. The purge valve can be used to nitrogen purge the SDDT before opening the window when servicing sour wells.

1.5.3 Annular BOP

The ABOP provides a backup wellhead seal for the BOP pipe rams, blind rams and for the stripper. The ABOP is hydraulically actuated and has a replaceable rubber element with steel reinforcing segments. Special element compounds are available for low-temperature service, high H_2S service or for stripping.

1.5.4 Downhole Deployment Equipment

The downhole deployment system uses a deployment bar to land the tool string in the BOP and to seal wellbore pressure. The bar can be sheared using the BOP shear rams at any time during deployment to maintain well control.

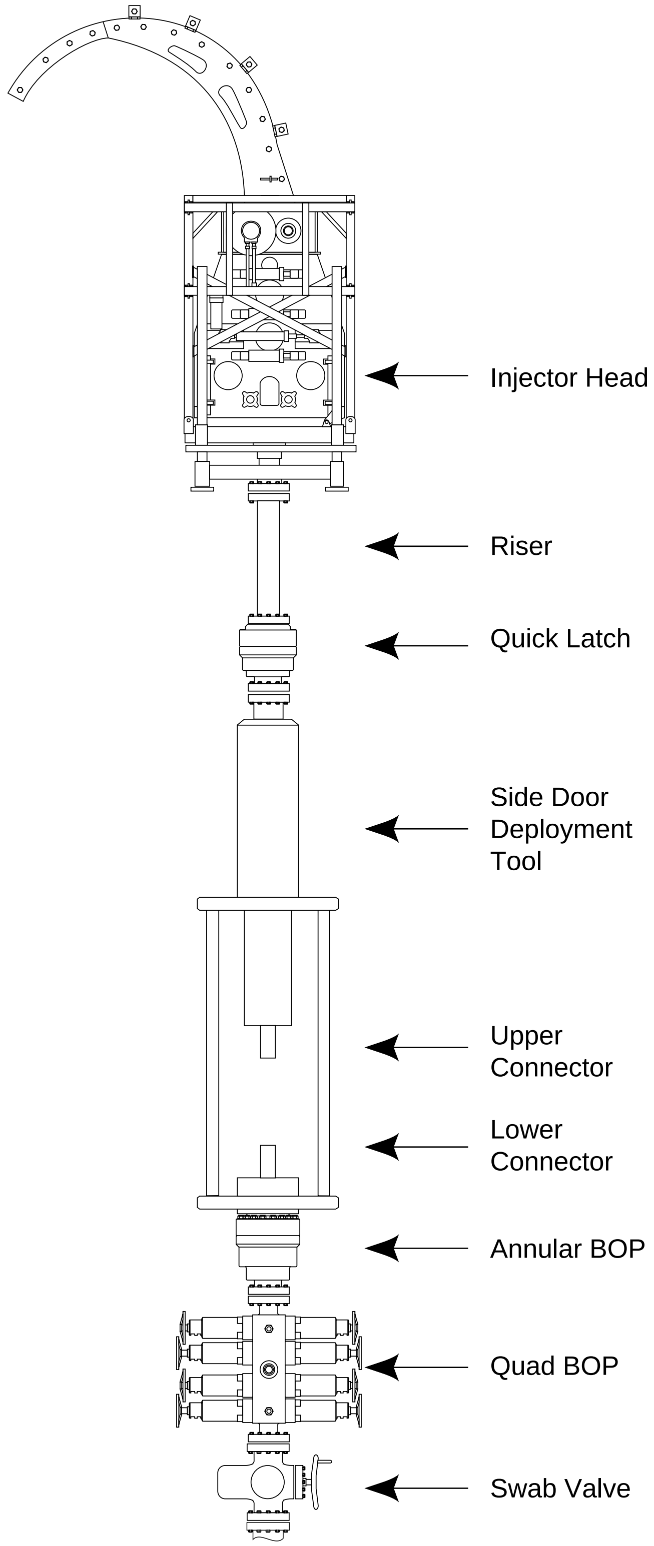

Figure 5. Conductor deployment system.

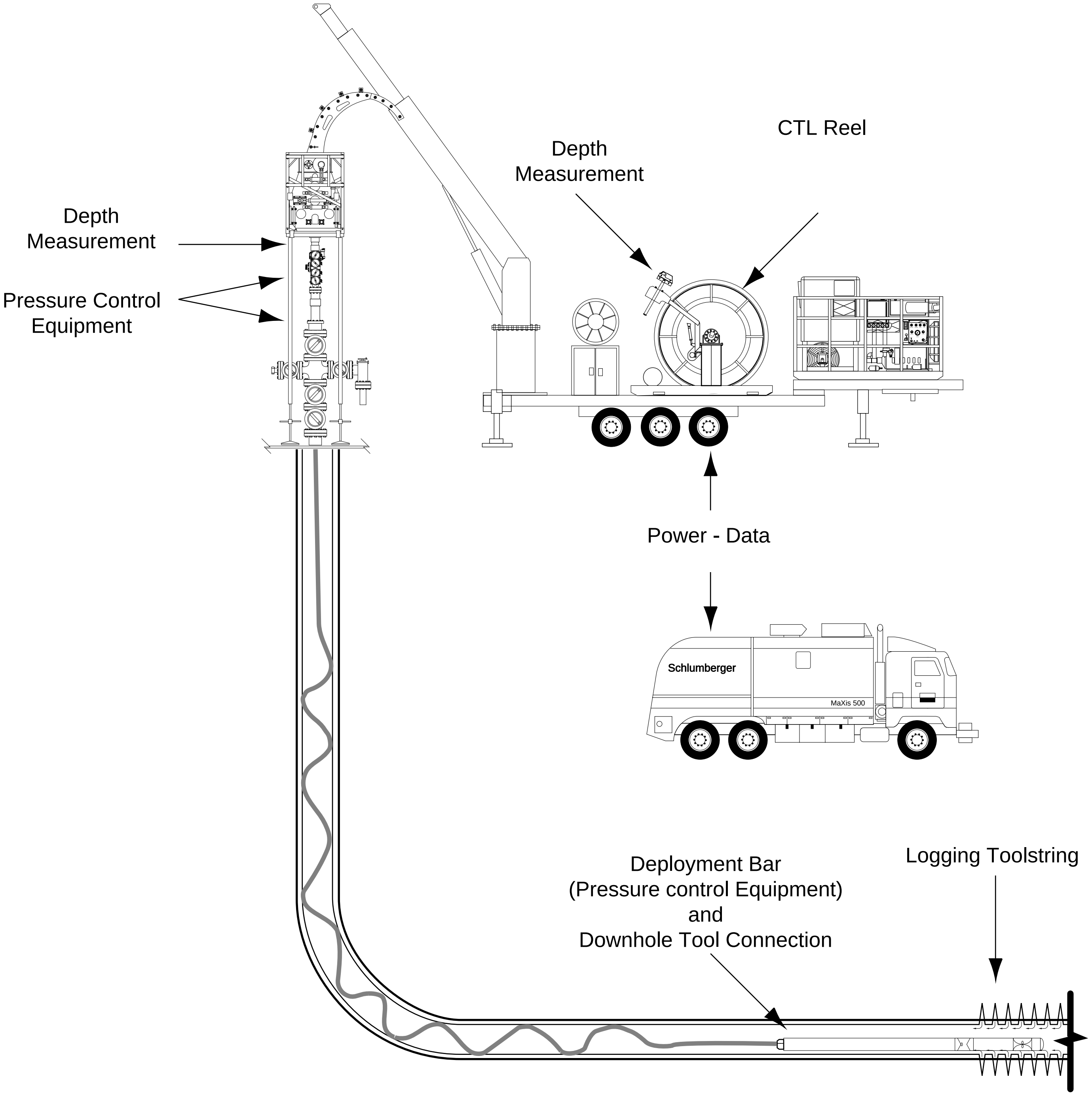

Figure 6. CTL system principal components

2 COILED TUBING LOGGING APPLICATIONS

The installation of logging cable in a CT string has extended logging capabilities in horizontal and deviated wells, and allowed real time measurements while pumping. The majority of CTL applications can be categorised as follows.

• Openhole logging

• Perforating

• Production logging

2.1 Openhole Logging

Openhole logging is principally a formation evaluation service performed before setting casing or liner over the interval of interest. In most cases, several tools are assembled and run simultaneously. The most common tools and their corresponding measurements are:

• Gamma ray - lithology identificationand 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.

There are two distinct types of application for openhole CTL:

• In highly deviated and horizontal wellbores where the tool string can no longer be lowered into the well by gravity

• Special applications in vertical wellbores.

2.1.1 Deviated and Horizontal Wellbores

In deviated wellbores, conventional openhole logging operations are performed by conveying the toolstring on drillpipe. CT offers several advantages over this technique:

• shorter trip times

• continuous logging can be performed (up and down) with better speed and depth control

• the logging cable is protected within the CT

• the toolstring is less likely to be damaged by excessive compressive forces which may be exerted when conveyed on drill pipe.

The distance that a toolstring may be pushed along a horizontal wellbore is dependent on several factors. A principal factor being the weight and corresponding friction of the toolstring in the wellbore.

Open tool suites are generally large (3-3/8-in. OD) and heavy. This combined with the relatively high friction encountered in the open hole section can limit the reach which may be expected during openhole CTL operations.

The CoilCADE tubing forces model calculates the forces and resulting stresses being applied to the CT as it is being run into and out of the well. This model is used in the design of every CTL job to predicted limits of operation.

• How far the tools can be pushed into the highly deviated or horizontal section of the well.

• What the weight indicator reading should display to the operator during these operations.

• What the maximum stress will be in the CT during these operations.

The maximum possible depth of penetration is reached when CT lock-up occurs. At this point, further injection of tubing will only result in increasing the buckling of CT in the wellbore. This may be observed on the CT weight indicator display as a rapid loss of weight

2.1.2 Vertical Wellbores

When logging on cable, the cable stretch and toolstring drag can, under certain conditions, combine to create a slight yo-yo effect at the toolstring while logging. While in normal operations this is generally considered minimal and insignificant, it can be an important consideration in applications which require a high degree of depth control.

Since the CT has a higher tensile strength than normal logging cables, CTL is often considered as viable in applications which carry a high risk of stuck toolstrings, e.g., when logging highly permeable formations where the risk of differential sticking is high. Similarly, the rigidity of the tubing can be used to push tools past minor wellbore restrictions. The ability to circulate fluid through the CT can be an advantage in applications that require clean operating conditions.

2.1.3 Equipment Configuration

Open hole logging tools generally require the use of heptacable to receive power and transmit data. At the downhole end, the cable and CT are attached to the coiled tubing head adaptor (CTHA). This adapter connects the cable electrically, and the CT mechanically, to the logging toolstring. A mechanical weak point and fishing neck incorporated within the CTHA allow for contingency release and retrieval of the toolstring in the event of an emergency.

The most important measurement made during any logging operation is depth. Encoders mounted on the CT injector head are connected to the CT unit control cabin and the logging unit.

2.2 Perforating

The use of coiled tubing to convey perforating guns is an extension of established coiled tubing logging services. The rigidity and strength of CT can be used when perforating highly deviated and horizontal intervals and when long and heavy gun assemblies are deployed. In addition, the configuration of CT pressure control equipment allows perforating to be easily and safely performed on live or underbalanced wells.

2.2.1 Gun selection

Several types of perforating guns are used in conventional perforating operations. These may be broadly categorized by type of application.

- Casing guns – These guns are larger (e.g., 3-3/8-in. to 7-in. OD) which are conventionally conveyed on wireline or tubing/drill pipe (TCP).

- Through-tubing guns – Because of the size restrictions associated with through-tubing work, such guns are generally 1-11/16-in. to 2-7/8-in. OD.

The most common perforating guns used with CT are of the through-tubing type as this is the application for which CT-conveyed perforating is commonly used.

An additional subdivision of through-tubing guns reflects the recoverability of the fired gun system.

- Expendable guns – Used in applications where debris of large size and volume can be tolerated.

- Semi-expendable guns – Semi-expendable guns, used in applications where moderate debris can be tolerated.

- Retrievable guns – Retrievable guns are contained within a rugged hollow carrier which confines the gun debris after firing. In addition to providing better retrieval, the carrier also allows the guns to be used at higher temperature and pressure.

  Hollow gun carriers tend to swell as a result of the extreme pressures encountered during perforating. Therefore, the anticipated OD of the gun system after firing must be compatible with the minimum restriction in the wellbore.

2.2.2 Perforation Charges

The productivity, and therefore effectiveness, of a perforated interval depends greatly on the geometry of the perforations. There are several factors that determine the efficiency of flow through a perforated completion.

- Perforations must extend beyond the zone surrounding the wellbore which has been damaged by drilling mud and cement filtrate.

- Perforations must be cleaned of charge and formation debris resulting from the perforating operation. This is best accomplished by perforating in underbalance conditions to enable all perforations clean up immediately after firing.

- The density of perforations, i.e. shots per foot (SPF), must be carefully selected to avoid excessive pressure drop at the perforation. This is largely determined by formation characteristics. For example, in layered formations with relatively poor vertical permeability, a higher shot density will be required.

Shot phasing is desirable to optimise productivity and maintain casing or liner strength.

- In most applications a perforation diameter of 3/8-in. is considered adequate to allow easy clean up and avoid premature plugging with asphalt or scale. Completions which are to be gravel packed require evenly spaced holes of around 3/4-in. to minimize the pressure drop across the packed perforation tunnel.

The relative importance of each factor is dependent on the type of completion, formation characteristics, and the extent of formation damage caused by drilling and cementing operations. A computer model (SPAN**) has been developed to predict the outcome of any perforation job, allowing the completion engineer to compare alternatives.

2.2.3 Firing Mechanism

Two means of firing the guns are applicable to CT-conveyed perforating. Electrical firing using a CTL string or pressure activated firing initiated by applied internal pressure in the CT string.

Pressure firing systems may be used without the need for a cable in the CT string, but suffer a distinct disadvantage in that correlation logging tools cannot be run to confirm the location of the guns.

The conventional electrical detonators used in wireline perforating operations are susceptible to detonation caused by induced currents from stray voltage sources. Stray voltage can originate from many sources, e.g., faulty electrical equipment, welding equipment, cathodic protection equipment and radio frequency (RF) transmission. Therefore, adequate safety precautions must be taken to eliminate such sources before perforating operations can commence.

The Slapper-Actuated Firing Equipment, or S.A.F.E.* firing system, has been developed as a firing system which is protected from the effect of stray voltage.

2.3 Cased Hole Logging

Cased hole logging is principally an evaluation service which confirms or identifies characteristics of the reservoir or completion. The most common activities include production logging, cement evaluation and corrosion logging.

- Production logging – measurement of temperature, pressure, density, flow velocity; may include fluid sampling, noise tool and gravel-pack tool
- Reservoir monitoring – gamma ray spectroscopy and thermal decay time logs
- Corrosion monitoring – multifinger caliper, borehole televiewer
- Cement evaluation – cement bond log, cement evaluation tool, ultrasonic imaging tool.
- Gyro compass
- Free point indicator
- Downhole seismic array

The majority of cased hole logging operations are conducted on completed wells which are producing. Therefore, the need exists for pressure control equipment and associated operating procedures. Standard CT equipment and procedures can fulfill these requirements and provide advantages and features exclusive to the CTL service.

CTL services are suited for several types of cased hole applications:

- highly deviated and horizontal wellbores where the tool string can no longer be lowered into the well by gravity
- vertical well applications where a high degree of depth and speed control is required
- applications that exploit the ability to pump through the CT while simultaneously logging

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2.3.1 Deviated and Horizontal Wellbores

The principal objective of production logging in horizontal wells is to determine the flow profile and productivity intervals along the wellbore (i.e., what intervals or fractures are producing, what fluids are being produced and how much is each interval producing). The resulting flow profile is correlated with lateral variations in permeability, saturation, etc., to detect production anomalies (e.g. crossflow). By performing simultaneous pressure and rate transient tests the well and reservoir parameters can be quantified.

The information obtained from such an operation can then be used to design the workover or remedial treatment required to obtain optimum production from the well.

The acquisition and interpretation of data from horizontal wells can be complex and difficult. This difficulty is due primarily to the behavior of wellbore fluids and the operation of logging tools in a horizontal wellbore profile. For example, multiphase fluids tend to segregate with heavier, slower moving fluids gravitating to the bottom of the wellbore. In such segregated flow regimes, advanced interpretation techniques are required to obtain accurate fluid velocity measurements. In addition, some conventional logging tools measure fluid density by comparing two pressure measurements made at a fixed vertical distance apart. In highly deviated or horizontal wellbores such measurements are no longer valid.

The challenge brought by such conditions has resulted in the development of sensors, tool string combinations, operating techniques and advanced interpretation skills specifically designed for horizontal applications.

Tools which measure the compression or tension applied to the tool string may be used on logging operations. These tools provide a means of monitoring the progress of the tool string along the wellbore.

2.3.2 Vertical applications

The strength and rigidity of the CT, together with the speed and depth control associated with CTL services offers several advantages over conventional techniques in vertical wellbores. The ability of CT equipment to be safely used on live and flowing wells is an additional advantage.

2.3.3 Simultaneous Pumping Applications

By conveying logging tools on a tube, simultaneous pumping and logging operations are possible. This technique provides the basis for LiftLOG* services which pump nitrogen to initiate and maintain production. This ability allows production logs to be made of non-eruptive wells.

Historically, production logs of such wells have not been possible because the pumping device must be removed to allow passage of the logging tools. With the pump removed, the well does not flow and production logging is not possible. By using LiftLOG services, the well is artificially lifted with nitrogen while the producing interval is logged.

3 REFERENCES

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COILED TUBING COMPLETIONS

Contents — Page

1 COILED TUBING COMPLETIONS

The development of larger OD (>2 in.) coiled tubing (CT) has increased the utility of CT as a completion conduit. This combined with the inherent advantages of live well operations permitted by CT equipment, has further increased interest and development efforts.

The economic advantages offered by completions which may be run and retrieved without the requirement for a rig led CAMCO to a three year development and testing program. The culmination of this program is a CT completion system which is not only a viable–but provides an attractive alternative to conventional jointed tubular completions.

The definition of coiled tubing completions may be stated as:

> Completions which utilize coiled tubing as a wellbore tubular, or as a means of conveying and installing completion equipment or tools.

1.1 CT Completions History/Evolution

In addition to innovative CT completion technology, there exists a significant role for CT in completions which are adapted from, and use, conventional technology. An overview of the histroy and evolution of coiled tubing completions is shown in Fig. 1

1.2 CT Completion Benefits

Time and economy are the principle benefits which are driving CT completion development. However, some CT completion applications offer the flexibility to increase, or sustain production (velocity strings). This combined with the elimination of the costs and potential reservoir damage associated with killing the well, ensures the attractiveness of many CT options.

- Time – Rapid mobilization, installation and retrieval– one day in and one day out are the goals of many CT completions.

History/Evolution of Coiled Tubing Completions	
1969	Coiled tubing used as a workstring
1970	1-in. CT introduced
1978	1-1/4-in. CT introduced
1982	CT production instalations (Canada)
1986	1-1/2-in. CT introduced
1986	CT hanger (Wellhead Spool) developed
1988	1-3/4-in. introduced, CT installed for gas and inhibitor injection, CT production packer introduced
Coiled Tubing Completions – The last 5 years	
1989	2-in. CT introduced, Continuous strings (bias weld)
1989	Camco patent filed
1990	2-in. CT installed as production string
1990	2-3/8 and 2-7/8-in. CT introduced
1992	3-1/2. CT introduced
1992	ESP installed on coiled tubing
1993	SPOOLABLE™ completions introduced
1994	ESP on CT with internal cable

Fig. 1. History and evolution of coiled tubing completions.

In addition to the rapid deployment of the initial completion string, the duration of future workovers will also be reduced.

• Economy – The cost of most completion activities is generally directly related to the time required. In difficult or hostile environments there are additional cost factors which must also be considered, e.g., equipment and rigs suitable for arctic operations is extremely expensive. The ability to run a completion string without the requirement for a specialized worover or service rig provides significant economic benefits.

In many wellsites, 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.

Live well intervention dispenses with the need for potentially significant well kill procedures. Similarly, well kick-off procedures and equipment are not required.

• Reduced risk of reservoir damage – Many reservoirs, particularly reservoirs which are depleted, are extremely intolerant of kill fluids. Severe formation damage may result from any attemt to workover or recomplete the well. In such applications, the ability to run a coiled tubing completion without killing the well may be an attractive option.

There is an increasing awareness of reservoir damage and its implications. It is generally accepted that prevention is easier and generally economically better than any attempt to cure.

1.3 Types of CT Completion

There are three main categories of coiled tubing completion.

- Velocity string installations
- Externally upset CT completion
- SPOOLABLE† CT completions

In the earliest completion applications, coiled tubing was installed in existing production tubing as siphon or velocity strings. This concept later expanded to include gas lift applications with, in its simplest from, the coiled tubing providing a single point gas injection system.

The efficiency of such gas lift applications is low which led to the development of a gas lift system which utilized existing gas lift technology and equipment adapted for coiled tubing completions. This has been refined to the reliable external upset coiled tubing completion detailed below.

A logical developement of this technology marraige was to design and build a completion string with components which could be passed through the coiled tubing and pressure control equipment. As a result SPOOLABLE coiled tubing completions and accessories have been designed.

Coiled tubing completions are best suited to applications which allow operators to take the maximum advantage of the inherent benefits CT can provide.

Note: Spoolable is a trademark of CAMCO

1.3.1 Velocity String Installations

- Predominantly gas well application
- Improve wellbore hydraulics
- Significant and sustained production increases from marginal wells
- Pump out plug or check allows live well installation (Fig. 2.)

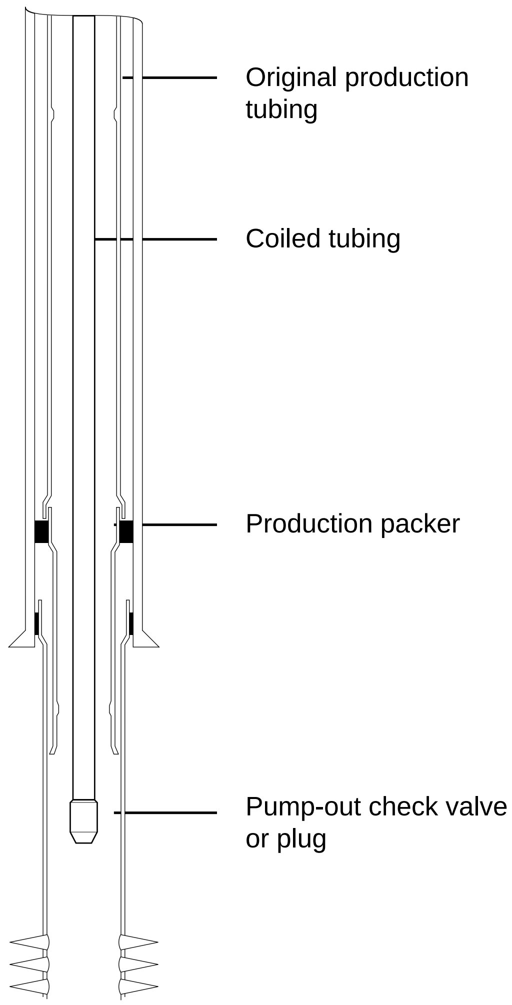


Fig. 2. Velocity string installation

†Mark of CAMCO

1.3.2 Externally Upset Completions

- Cannot be run through injector-head chains or conventional pressure control equipment (Fig. 3).
- Completion must be assembled on location.
- Standard completion components.
- Requires special installation equipment.
  – Access window
  – Annular BOP

1.3.3 SPOOLABLE™ Completions

- Can be run and retrieved through conventional CT pressure control equipment (Fig. 4).
- Can be assembled in controlled conditions away from the wellsite.
- Designed for live well installation using standard CT equipment.

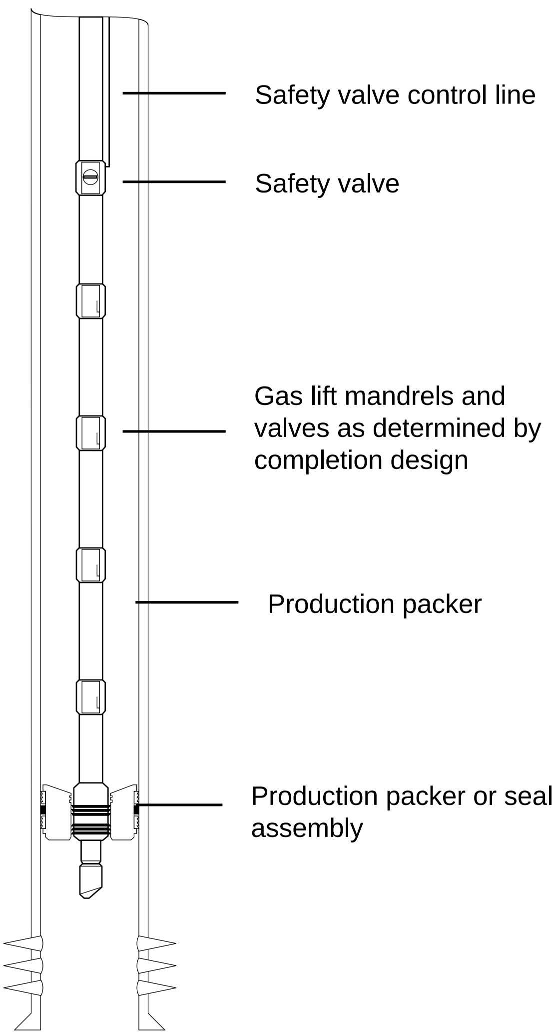


Fig. 3. Externally upset completion.

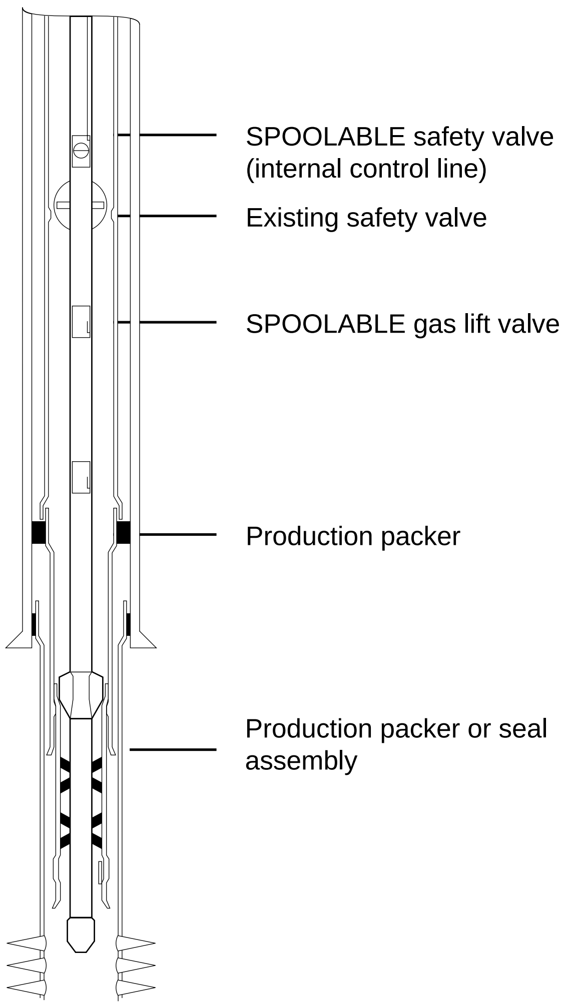


Fig. 4. SPOOLABLE completion.

2 COMPLETION APPLICATIONS

Types of Coiled Completion

• Primary completions

• Artificial lift completions

• Remedial completions

• Special service completions

• CTD completions

2.1 Artificial Lift Completions

• Gas lift
  – Externally upset
  – SPOOLABLE™

• Electric submersible pumps
  – External cable
  – Internal cable

2.2 Remedial Completions

• Velocity string

• Sand control

• Tubing/casing repair

• Concentric injection string

2.3 Completion of CTD Wellbores

• Well deepening

• Sidetrack

• Multiple drainholes

CTD Completion Characteristics

• Small-diameter wellbore

• Operations performed thru-tubing

• Live well operations

• Deviated wellbore

• Multiple wellbores

• Moderate to severe dog-legs

• Depleted reservoir

• Unstable formations

2.4 Candidate Wells

Completion/Recompletion Applications

• Initial installations
  – Slimhole completions
  – Under economic justification

• Improving production hydraulics
  – Velocity string
  – Reduce the required gas injection rate
  – Installing gas lift in depleted reservoirs

Remedial Applications

• Remedial installations
  – Thru-tubing gravel pack
  – Casing/tubing repair and zonal isolation
  – Re-instate safety valve function

• Difficult pulling jobs
  – Dual completions
  – Failed gravel packs
  –Collapsed casing

Reservoir and Economic

• Special kill fluid requirements
  – Heavy (and costly) kill fluid required
  – High risk of formation damage

• Economic
  – Marginal wells where rig costs cannot be justified
  – Applications or locations requiring special rig configuration

2.5 Constraints of Coiled Tubing Completions

- Increased Xmas tree height
- Weight and handling (especially offshore)
- Completion-bore obstructed by components
- Components not generally suitable for “sand” service
- Coiled tubing material equivalent to L-80 or N-80 API grade materials

3 COMPLETION COMPONENTS

- Production string(s)
- Connectors
- Gas lift valves
- Packers
- Nipples and landing profiles
- Flow control devices
- Circulation devices
- Pumps
- Installation equipment

3.1 Coiled Tubing Connectors

- External Connector
- Single O-ring
- Dual O-ring
- Packing element seal
- Internal Spoolable™ connector

3.1.1 Connector – Externally Upset

- Compact design
- Simple assembly
- High strength
- Utility applications
- O-ring seal suitable for applications with minimal tubing OD deformation (Fig. 5)

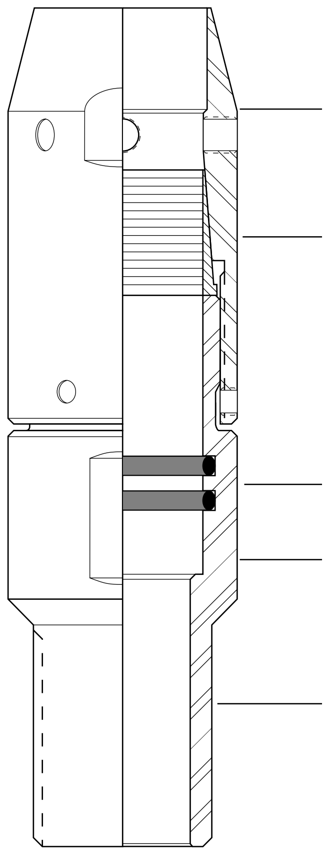


Fig. 5. External connector – dual O-ring.

3.1.2 External Connector – With Packing

- Energized seal separate from slip mechanism
- Sealing arrangement tolerant of ovality and deformation
- Mechanism compensates for thermal expansion and contraction (Fig. 6).

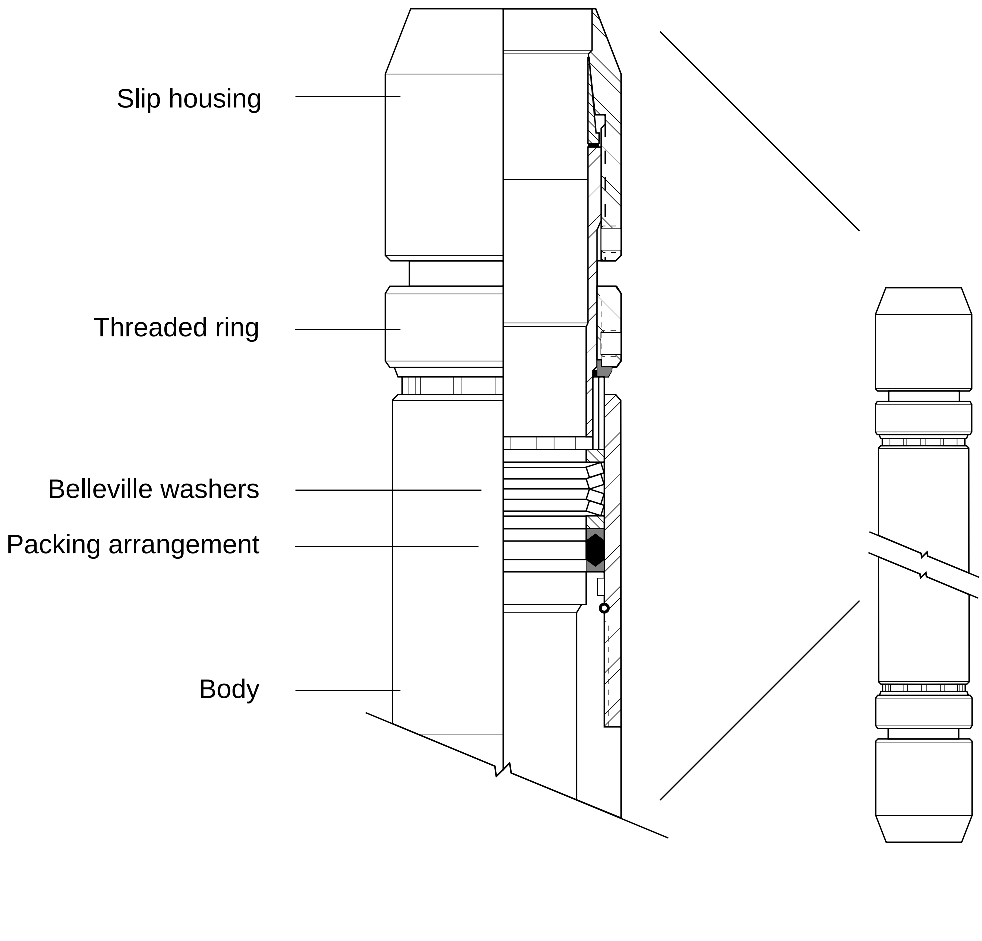


Fig. 6. External connector – packing element seal.

3.1.3 Internal Connector – Spoolable

- Alternative to welding when assembling completion strings (Fig. 7).
- Can be passed through pressure control equipment and spooled
- Slip grip increases with tension

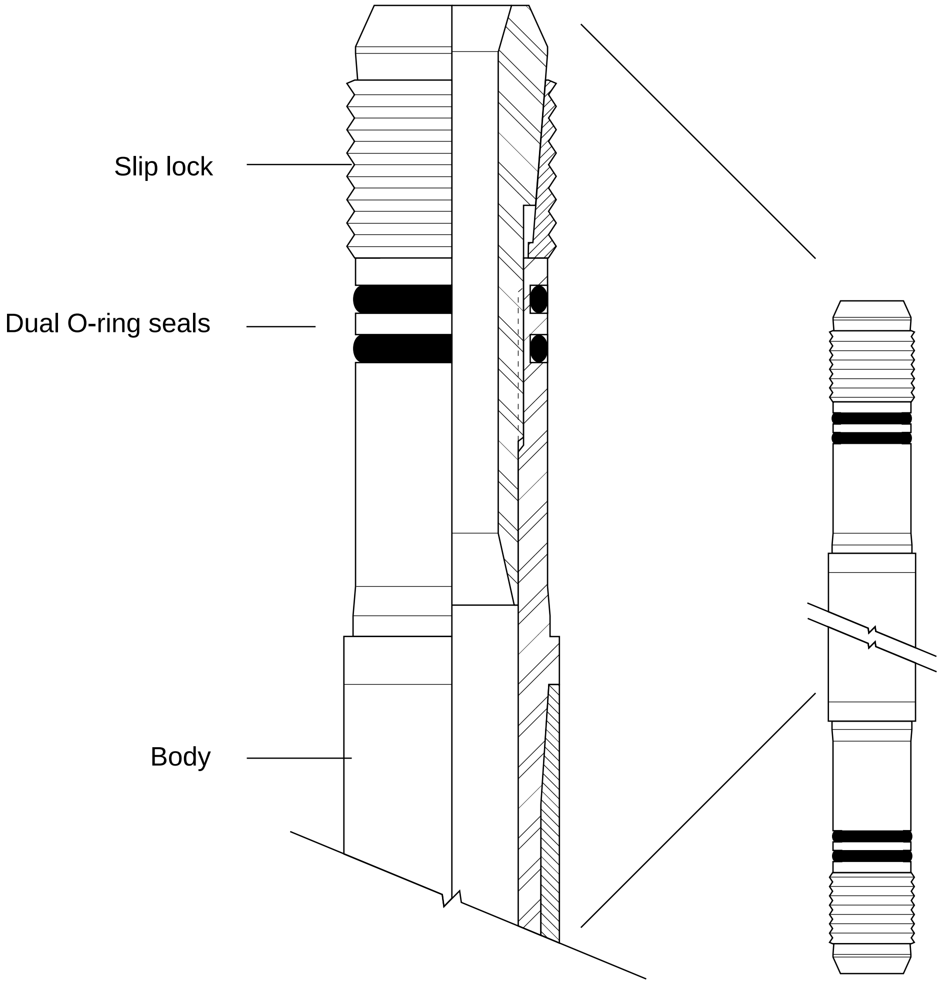


Fig. 7. SPOOLABLE connector.

3.2 Gas Lift Valves and Mandrels

• External upset mandrels

– Sidepocket
– KBMG or KBMM mandrels (4.50-in. min ID)

– Slimhole
–CT-40 or CT-50 mandrels (under 4.50 in. ID)

– Internal Spoolable™ mandrels and valves

3.2.1 Gas Lift Valve – Externally Upset

• Conventional gas lift equipment – proven design

• Serviced by conventional slickline tools and techniques

• Slimhole and sidepocket mandrels (Fig. 8).

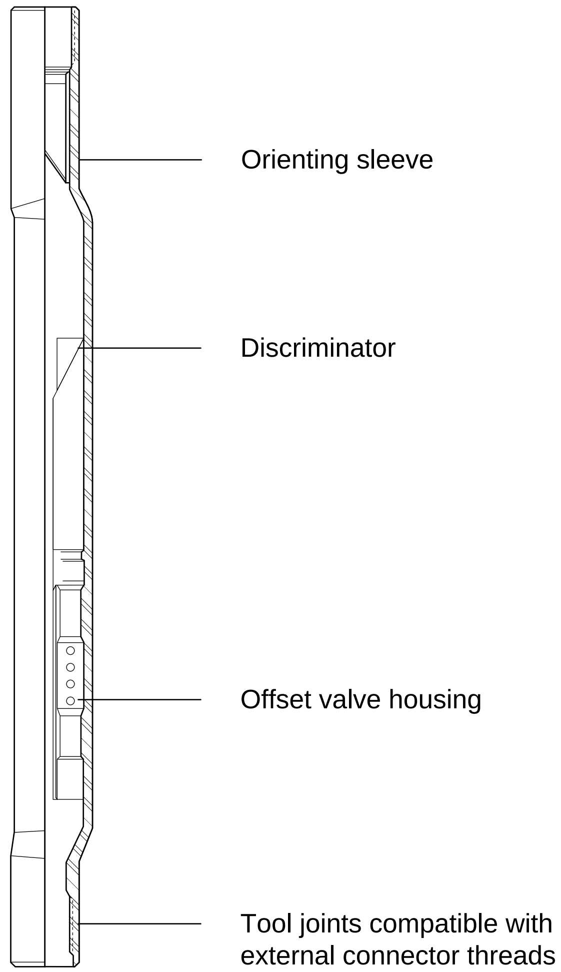


Fig. 8. External gas lift mandrel.

3.2.2 Gas Lift Valves – Spoolable

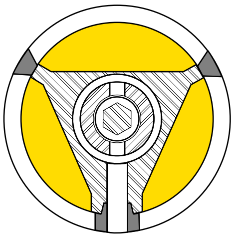
- Production through CT or annulus
- Mandrel welded or jointed by SPOOLABLE™ connectors
- Applicable for 1-1/2 to 3-1/2-in. CT (Fig. 9).
- Four production modes

  – CTS-I
  Injection pressure operated, tubing production

  – CTS-IA
  Injection pressure operated, annular production

  – CTS-F
  Fluid pressure operated, tubing production

  – CTS-FA
  Fluid pressure operated, annular production



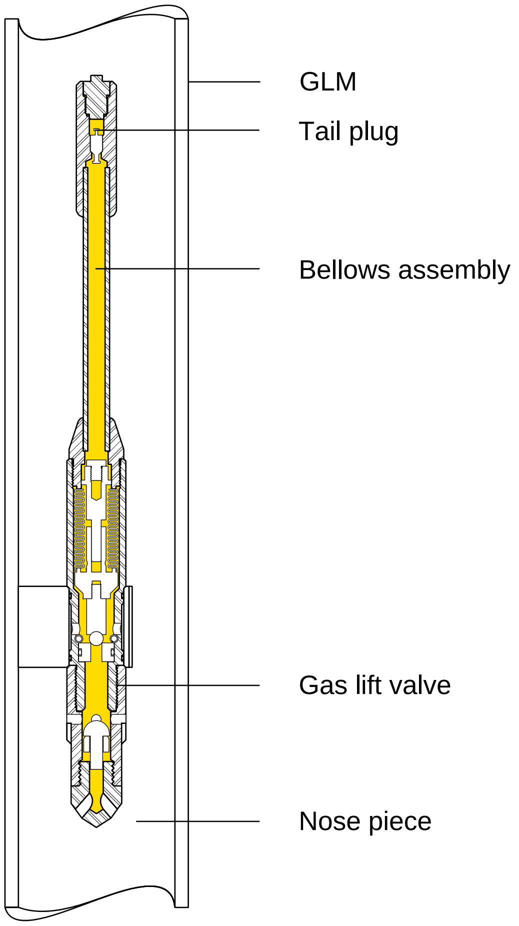


Fig. 9. SPOOLABLE™ gas lift mandrel.

3.3 CTS–TRSP Safety Valve

• 2-3/8-in. OD (3-1/2-in. tubing)

• 1.467 in2 flow area

• Control line inside CT

• 5000 psi working pressure

• Curved flapper

• Verification tested (Fig. 10).

– Class 1 API 14A

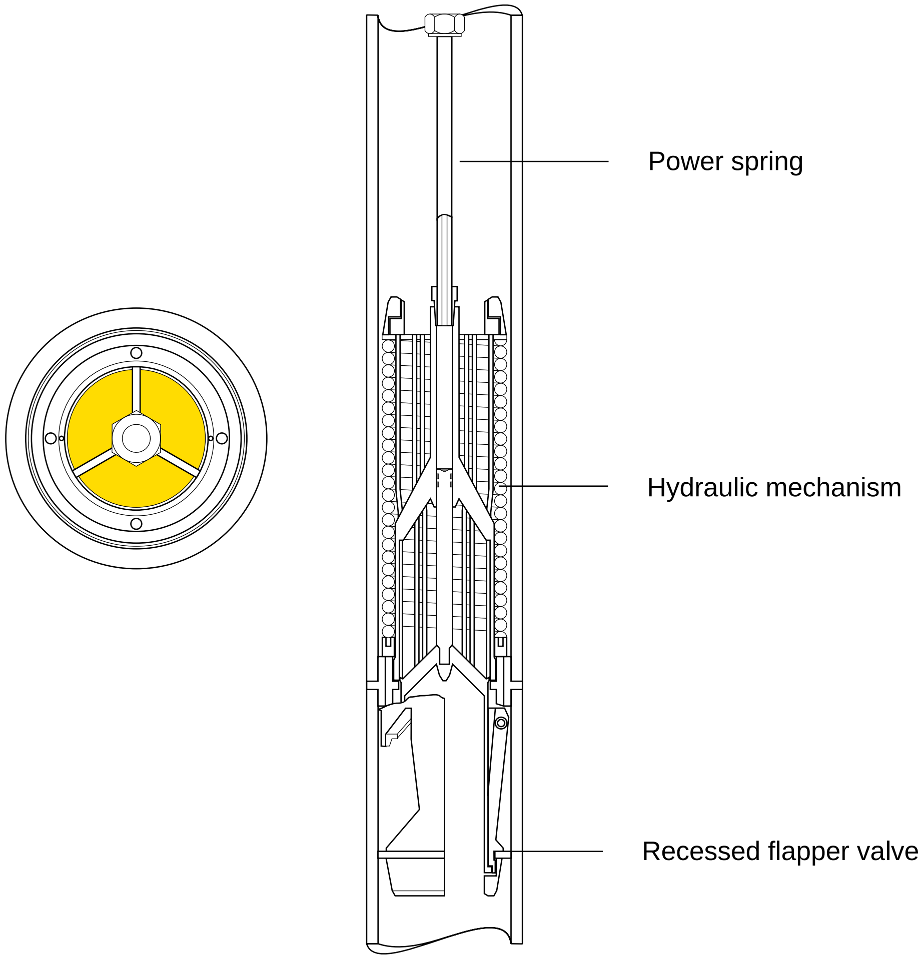


Fig. 10. SPOOLABLE safety valve.

3.4 Surface Equipment Rig-Up (External Upset)

- Access window provides a work area for coupling the completion components (Fig. 11).

- Annular preventer provides a well control barrier capable of sealing on varying diameter tubulars

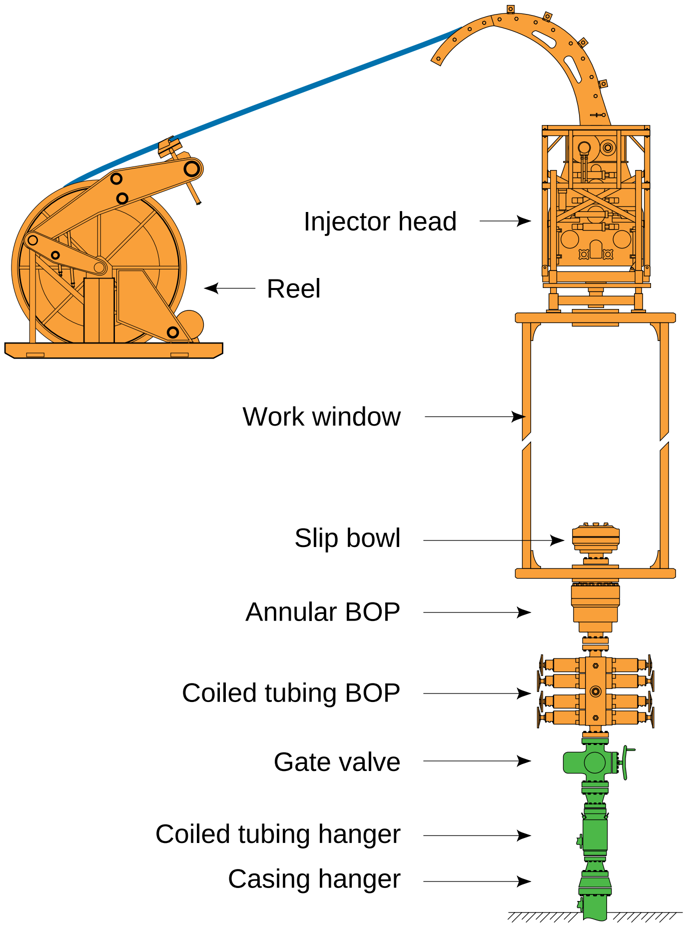


Fig. 11. Surface equipment rig-up.

3.5 Surface Equipment Rig-Up (Spoolable)

- Surface equipment rig-up comprises coiled tubing and pressure control equipment generally used for conventional coiled tubing service operations (Fig. 12).

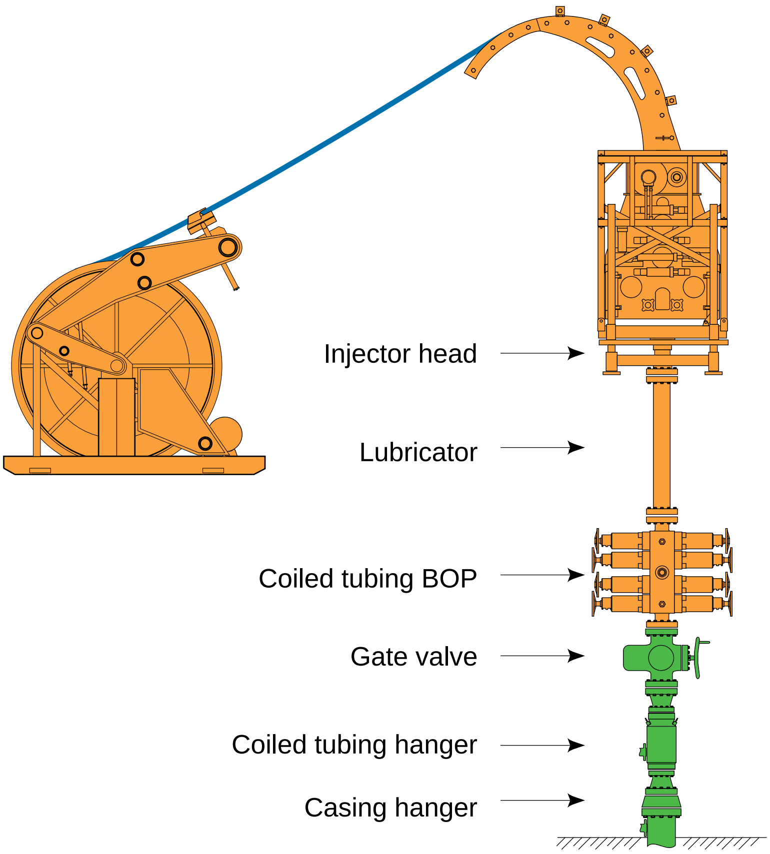


Fig. 12. Surface equipment rig-up.

4 COMPLETION DESIGN AND ENGINEERING

4.1 NODAL Analyses

- Selection of tubulars with appropriate ID
  – liquid loading, velocity string applications
- Confirm suitability of completion components
  – restrictions or limitations to production
- Confirm perforation shot density
  – important on gravel-packed completions
- Forecast production capability for downstream design and engineering

4.2 Dimensional Criteria

- Depth/length
  – Yield criteria for tubing and completion components
- Wall thickness
  –Taper configuration, completion weight, drift ID
- Well path–deviation
  – Installation force predictions and set-down weights
- Upsets and profiles
  – Installation, retrieval and service access
- Connections and tool joints
  – Compatibility and resulting restrictions

4.3 Tubing Forces and Movement

- Temperature
  – Changes in length and resulting stresses
- Pressure
  – Combined stresses for operating limits
- Weight
  – Set-down and hang-off weights
- Fluid gradients
  – Changes may effect pressure and weight factors
- Friction and applied force

4.4 Hardware Selection Process

- Optimize production
- Facilitate installation
- Simplify maintenance
- Enable stimulation and workover
- Provide for contingency

	Coiled Tubing Material ASTM A606 Type 4 (Mod.)	Jointed Tubing Material AISI 4130	API-5CT L-80 Type 1
Element	**% Content**	**% Content**	**% Content**
Carbon	0.100 to 0.150	0.280 to 0.330	0.430 Max
Manganese	0.600 to 0.900	0.400 to 0.600	1.900 Max
Phosphorus	0.025 Max	0.025 Max	0.030 Max
Sulphur	0.005 Max	0.025 Max	0.030 Max
Silicon	0.30 to 0.90	0.200 to 0.350	0.450 Max
Nickel	0.250 Max	–	0.250 Max
Chromium	0.500 to 0.750	0.800 to 1.100	–
Copper	0.150 to 0.400	–	0.350 Max
Molybdenum	–	0.150 to 0.250	–

Fig. 13 Material comparison – chemical composition.

4.5 Material Selection

• Comparison of common materials (Fig. 13 and 14)

• Material strength

• Corrosion

• H2S embrittlement

• Stress cracking

• Erosion

Comparison of Common Materials

• API tubulars
  – Standard grades J-55, C-75, C-95, N-80, P-110

• Completion equipment
  – 4130, 4140, MP35N, inconel, monel

• Coiled tubing
  – ASTM A-606 Type 4 modified

4.6 Corrosion, H2S Embrittlement and Stress Cracking

• Coiled tubing handling
  – External surface condition
  – Bending stresses

• Materials under development
  – Improved alloys
  – Titanium
  – Composite

4.7 Well Preparation

• Existing completion
  – Removal, complete or partial
  – Concentric recompletion

• Fill and junk removal

• Stimulation

• Packer or isolation device

• Barriers

• Plugs and installation devices

4.8 Perforating

• New completion
  – SPAN* design software
  – Technique

• Remedial completion reperforation
  – By-pass skin
  – Perforate under flowing conditions
  – Ensure adequate inflow area (gravel pack)

4.9 Safety and Environment

• Live well operation
  – Barrier provision for installation and retrieval

• Wellhead and safety equipment
  – Installation and testing standards

• Emergency response and contingency planning

• Environment
  – Requirement for kill fluids
  – Wellsite equipment requirements

	A-606	4130	L-8- Type
Tensile Strength (psi, min)	80,000	100,000	95,000
Yield Strength (psi, min.)	70,000	80,000	80,000
Elongation (%, min)	30	16	As spec
Reduction of Area (%, min)	–	35	–
Hardness (HRc)	22 (max)	18 to 22	23 (max)

Fig. 14. Material comparison – mechanical properties.

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COILED TUBING DRILLING

Contents — Page

1 EVOLUTION OF COILED TUBING DRILLING

The techniques and equipment associated with coiled tubing drilling (CTD) have undergone rapid development since the first operations attempted in 1991. A principal stimulus for this activity was the availability of reliable large diameter CT which enabled sufficient hydraulic horsepower to be delivered downhole. This energy is required to power the downhole motor and provide sufficient flow rate to ensure adequate hole cleaning through efficient cutting transport. In addition, larger and heavier wall tubing provides the necessary weight for efficient drilling and to safely withstand the torque and fatigue imposed by drilling operations.

In 1991 Dowell established a coiled tubing drilling task force to utilize the expertise of several organisations within the Schlumberger group. Engineers from Sedco-Forex (drilling), Anadrill (MWD) and Dowell (coiled tubing) formed a group dedicated to the engineering and development of CTD tools, equipment and practices required to form an integrated CTD service package. A step-by-step approach was adopted to ensure that operational capability was developed to support the new tools and equipment.

1.1 Advantages of CTD

The factors, or advantages, associated with CTD which have provided the impetus for the service development can be categorized as shown below.

- Safety
- Economic
- Operational
- Environmental

1.1.1 Safety

The configuration of the well control equipment used in CT operations provides a higher degree of control and safety than that associated with conventional drilling equipment. This level of control is maintained throughout drilling and tripping operations. A large proportion of accidents are associated with pipe handling and the making and breaking of tooljoints. With CTD, exposure to such hazards is much reduced.

1.1.2 Economic

Under the right conditions, CTD has the potential to provide a general reduction in drilling and well costs. While this was a significant objective for early CTD attempts, it was seldom achieved due to the difficulties which are typically associated with an emerging technology.

The principal areas of cost saving in CTD are related to the reduced hole size (slimhole) and wellsite area. In addition, CT units and equipment typically have lower mobilization and demobilization costs.

1.1.3 Operational

The safety advantage brought by CT well control equipment enables underbalanced drilling operations to be completed safely and efficiently. The principal advantage of underbalanced drilling being reduced reservoir damage caused by the invasion of drilling fluid and cuttings.

Since the majority of CT services are performed through the production tubing, specialized thru-tubing CTD can be undertaken with the completion tubulars in place. Well deepening and side-tracking of existing wells in depleted reservoirs is an area in which CTD offers significant operational and cost benefits compared with conventional drilling techniques.

Ultimately, it is intended that the techniques and equipment used in CTD will provide a level of control and response which will permit “joystick drilling”.

1.1.4 Environmental

In several locations, e.g., urban areas, minimizing the wellsite area, as well as the visual and noise impact, is a significant factor in the preparation and execution of drilling operations. The configuration of CT equipment enables operations to be completed from a smaller work site using equipment which is less visually intrusive. Additionally, operations using continuous tubing cause significantly less noise pollution than those using jointed pipe.

1.1.5 Limitations and Disadvantages

The limitations and disadvantages of CTD can be summarized in the following categories.

- Economic – in many areas, the abundance of low-cost conventional rigs render the use of CTD for some applications uneconomic. In such areas, only specialized CTD techniques which cannot be completed by conventional equipment will be viable.

- Hole size – the advantage of being able to drill slimhole is, in some applications, countered by the inability to drill larger hole sizes.

- Rotation – since the CT string cannot be rotated, steering adjustments in directional drilling applications must be initiated using downhole tools.

- CT fatigue and life – although the fatigue and useful life of CT strings are now well understood and monitored, it can be difficult to accurately predict the extent to which a strings life may be used during any CTD operation.

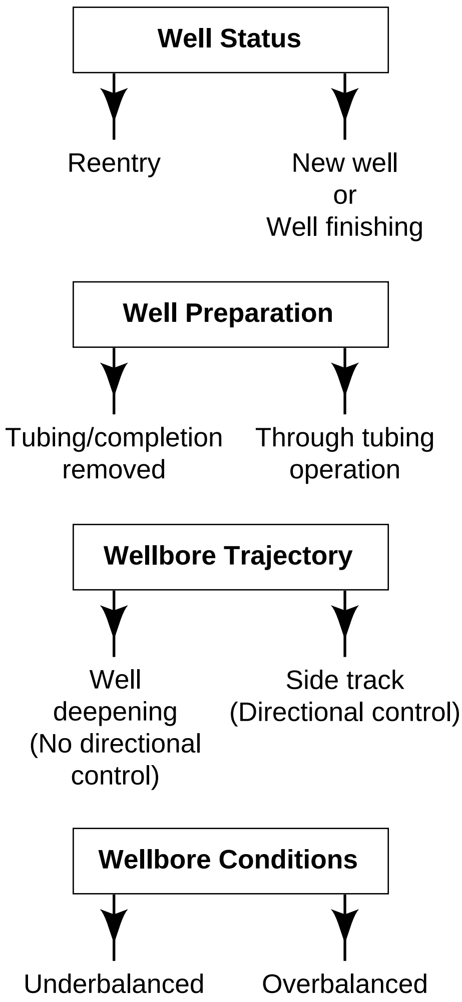

Fig. 1 Classification of CTD applications.

1.2 CTD Applications

There are several ways in which CTD applications have been classified. Most operations can be described using the following criteria (Fig. 1):

- Well status – new well or re-entry

- Well preparation – tubing/completion removed or thru-tubing

- Wellbore trajectory – well deepening or side track

- Wellbore conditions – underbalanced or overbalanced drilling

The illustration in Fig. 2 shows the world wide trend in CTD from 1991 through 1994. In this period, two distinct areas of CTD operation were identified; operations which utilize the unique capability of CT and operations which could have been completed by conventional drilling techniques and equipment. It is generally accepted, that the increasing trend toward specialized applications will continue as the reliability of the techniques improve and the resulting benefits become more apparent.

2 JOB DESIGN AND PREPARATION

The job design and preparation sequence for CTD operations comprises several distinct tasks or areas of investigation.

- Establish the client's objectives

- Review the technical feasibility

- Technical preparation

- Administrative preparation

2.1 Establishing Objectives

Unlike most CT service activities, the overall objective(s) of the client may not always be immediately apparent, e.g., is the well being drilled for production, appraisal, delineation or exploration purposes? It is beneficial to the overall process if all parties involved in the design and execution of the CTD operation are aware of the objectives and goals associated with them. In addition, the means and criteria by which the achievement of the objectives will be assessed should also be known.

There are several specific applications for CTD. The following information and guides are based on the four most common applications, i.e., the majority of CTD enquiries or feasibility studies requested by clients may be included in these categories.

• New exploration wells

• New development wells

• Existing well deepening

• Existing well sidetracking

The location and logistic concerns outlined in Fig. 3 apply to all CTD applications. To assist with the data acquisition process, an enquiry guide for each application is included in Fig. 4 through Fig. 6. A summary of the current technical capabilities is also included.

2.2 Technical Feasibility

When assessing the technical feasibility of any CTD operation a logical and methodical approach is essential (Fig. 7). The following areas should be investigated and the relevant criteria determined (depending on the specific application and conditions). A summary of the constraints which may limit the application or extent of CTD operations is shown in Figure 8.

• Weight on bit

• Annular velocity

• Pumping pressure and rate

• CT string tension

• CT life/fatigue

• Torque

• CT reel handling

• Directional requirements

2.2.1 Weight On Bit

The necessary force, or weight on bit (WOB), required to maintain penetration while drilling, can be obtained from two sources. When drilling vertical or slightly deviated wellbores, drill collars are used to provide weight on bit. In such cases the CT is kept in tension to ensure a stable trajectory. In highly deviated wellbores the CT string is used to provide the necessary weight on bit.

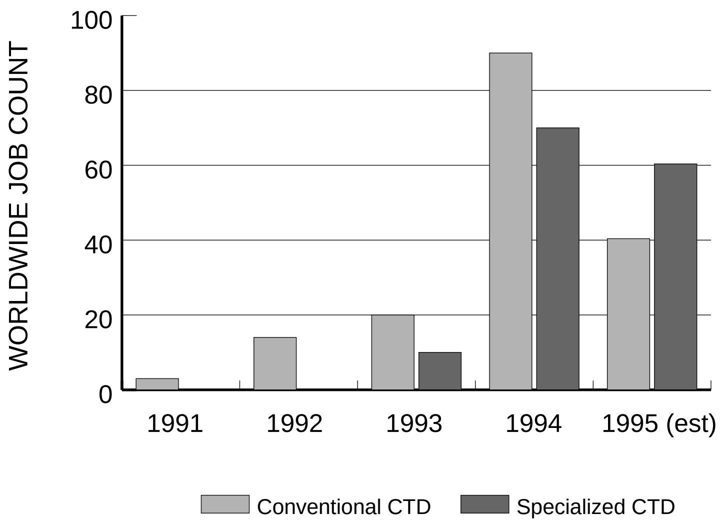

Fig. 2 CTD operations 1991 through 1995 (est).

CTD ENQUIRY GUIDE – LOCATION, LOGISTICS AND ENVIRONMENT

Onshore

Location
- In which type of environment is the wellsite, e.g., urban area, jungle or desert?
- What are the location constraints, e.g., size, obstructions and obstacles?

Logistics
- Are there any known logistical constraints, e.g., limits to access, operational windows etc.?

Environment
- What provisions may be necessary to enable adequate environmental protection, e.g., noise, spill protection or temporary chemical storage?

Offshore

Location
- What are the dimensional and deck load constraints for the operational, storage and fluid handling areas?

Logistics
- Is a crane of adequate capacity available? Is it located in position which allows unrestricted access to the well and operational areas? What are the load capacity and boom length?
- Where is the personnel accommodation?

Environment
- What provisions may be necessary to enable adequate environmental protection, e.g., noise, spill protection or temporary chemical storage?
- What local weather, sea, seasonal conditions may restrict operations?

Figure 3. CTD enquiry guide – location, logistic and environment.

CTD ENQUIRY GUIDE – NEW WELLS & VERTICAL WELL DEEPENING

Exploration and production objectives

• Is this an oil or gas well?

Data collection
• How extensive is the logging program to be?
• What are the mud logging requirements?
• What is the minimum acceptable size of the production casing or liner ?

Wellbore design

Wellbore geometry
• What is to be the TD and open-hole sizes?
• What is the casing program, i.e., casing size and shoe depths?

Deviation
• If the wellbore is deviated, what is the projected well profile, i.e, inclination and azimuth versus depth!
• What is the acceptable target tolerance fromprojected profile?
• If the wellbore is vertical, what is the maximum acceptable deviation?

Downhole conditions
• What are the formation pressures and temperature?
• What is the well lithology?
• Is there a risk of shallow gas?
• Are there any sloughing shales?
• What is the likelihood of H2S?

Operations

Bit and drilling performance
• What is known of the formation(s) drillability ?
• Are offset well bit records available?

Drilling fluid
• Is the reservoir to be drilled under or overbalanced?
• What drilling fluid(s) is to be used, i.e., mud, foam or air?
• What are the properties of the mud system to be used, i.e., type, density and characteristics?
• What is the likelihood of lost circulation?

Current Technical Capability

Hole size
Up to 12-1/4-in. hole – for hole sizes greater than 6-3/4-in. formations must be unconsolidated (motors OD:– 4-3/4-in. or modified 6-1/2-in.)

Depth
Achievable depth dependent on hole size and formation drillability (new well CTD generally limited to 5,000 to 6,000 ft with three or four casing strings.

Typical limitations
• Torque tolerance of the CT string limits the motor size.
• The CT pumping pressure limits the depth of the hole sizes larger than 4-3/4-in.

CT string size
• 2-3/8-in. CT is recommended for hole sizes greater than 6-3/4-in. or for 4-3/4-in. sections deeper than 5,000 ft.

Figure 4. CTD enquiry guide –new exploration well

CTD ENQUIRY GUIDE – EXISTING WELL SIDETRACK REENTRY

Production and completion objectives

Production
- Is this an oil, gas or injection well?

Completion
- What will be the liner size?
- What is the minimum acceptable liner size?
- Will the liner be cemented?
- How is the new completion to be configured?

Wellbore design

Wellbore geometry
- What is to be the TD and open-hole sizes?
- What are the existing casing sizes and shoe depths?

Deviation
- What is the existing well profile, i.e, inclination and azimuth versus depth?
- Which kick-off technique will be used, e.g., window or section milling?
- What is the re-entry well profile, i.e., kick-off depth, build up rate, inclination, azimuth and drain hole length?
- What is the acceptable target tolerance from projected profile?

Downhole conditions
- What are the formation pressures and temperature?
- What is the well lithology?
- Are there any sloughing shales?
- What is the likelihood of H_2S

Operations

Bit and drilling performance
- What is known of the formation(s) drillability?
- Are offset well bit records available?

Drilling fluid
- Is the reservoir to be drilled under or overbalanced?
- What drilling fluid(s) is to be used, i.e., mud, foam or air?
- What are the properties of the mud system to be used, i.e., type, density and characteristics?
- What is the likelihood of lost circulation or losses?

Current Technical Capability

Hole size
Through-tubing
- Minimum completion size of 4-1/2-in., allowing a 3-1/2- or 3-3/4-in. hole.

Conventional (completion removed)
- Up to 4-3/4-in. with a build-up radius of up to 60°/100ft.
- Up to 6-in. with a build-up radius of up to 15°/100ft.

Depth
- Horizontal drainhole can exceed 2,000ft, but is dependent on BUR, KOD, casing and CT sizes.

Total depth
- Through tubing: up to 15,000ft
- Conventional (completion removed): more than 10,000ft

Typical limitations
- Build-up radius (BUR) limited by bending friction force of the BHA which limits the available WOB.
- Downhole WOB provided by the CT limits the horizontal drainhole length (CoilCADE check)

CT string size
- 1-3/4- to 2-3/8-in. depending on the hole profile

Figure 6. CTD enquiry guide – existing well sidetrack reentry.

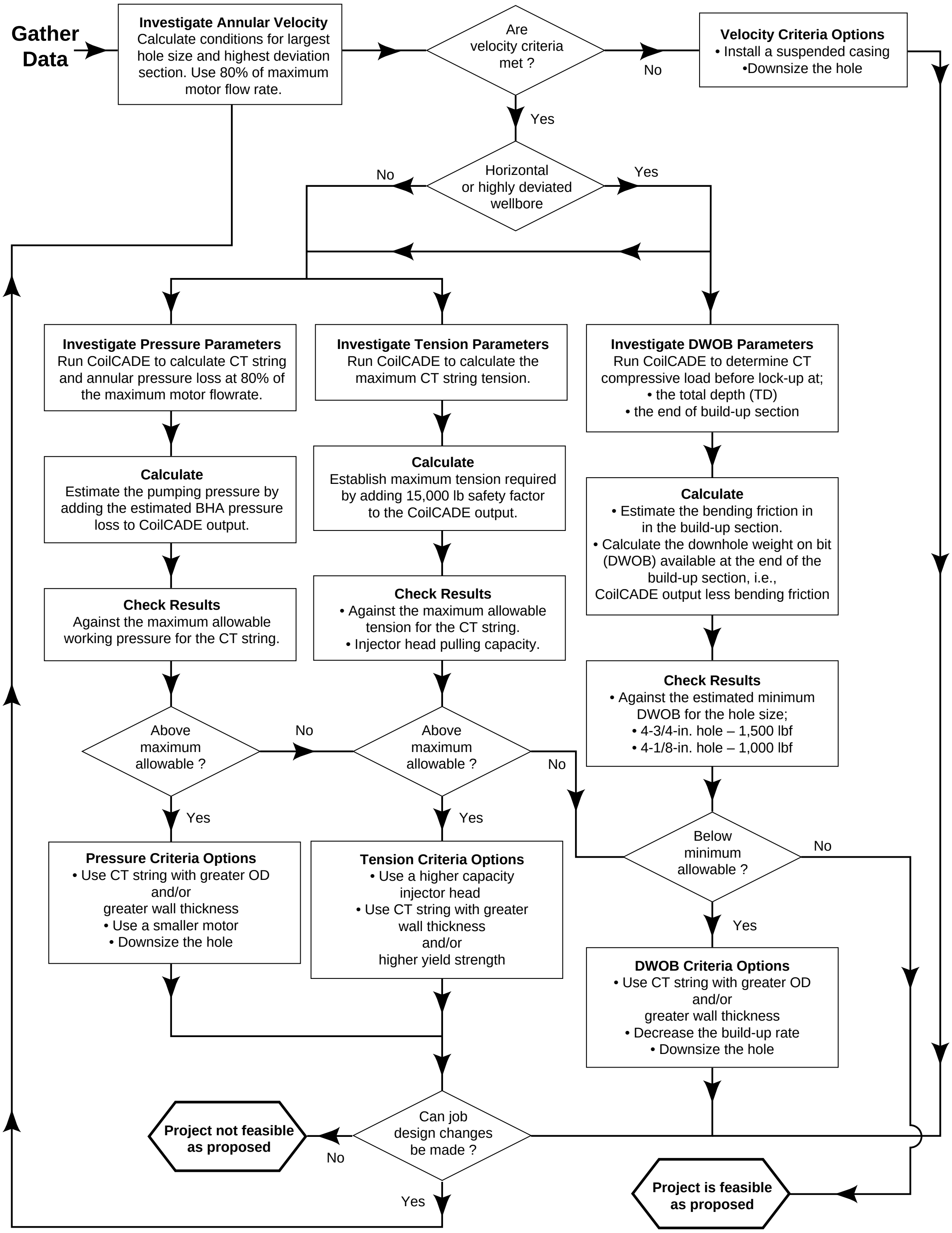

Figure 7. Step by step feasibility study flowchart.

COILED TUBING DRILLING – LIMITING PARAMETRS

Constraints	Limitation	Equipment Limitations	Design Limit	Remarks
Drilling Rate (ROP)				
Hydraulic power at the bit	Maximum flow rate	• CT Max allowable pressure • Motor maximum flow rate • CT length and diameter • Mud type, weight, yield	• Hole diameter • Hole depth	Use the largest fishable motor for the hole size for maximum flow rate (consider max allowable CT pressure). Use CT string length appropriate to the well TD. Use a shear thinning mud to minimize the pressure loss.
Mechanical power at the bit	Torque	• CT max allowable torque • Motor max torque	• Hole diameter	Use a motor with the maximum torque in its category. Make sure the CT and BHA max allowable torque is less than twice the motor stall torque.
	RPM	• Motor speed • Bit max operating speed	• Hole diameter	Two basic types of slim hole motors are available: high speed/low torque or low speed/high torque. A drill off test is necessary to optimize ROP and minimize vibrations for a given formation and motor/ bit combination.
	Weight on Bit (WOB)	• CT diameter, wall thickness and yield • BHA ID, OD, and length	• Hole diameter • Drain hole length • Build up rate	In the case of vertical or slightly deviated holes, drill collars are used to provide WOB, but for highly deviated or horizontal wells, the CT provides the WOB and the maximum compressive load at the CT end before lock up, is the limiting factor. "The maximum available compressive load at the end of the CT, must be estimated using coilCADE in two critical positions: in the build up section and at the total depth (TD). • In the build up section, the max CT compressive load before lock up must be sufficient to overcome the bending friction force of the BHA (not taken into account by coilCADE) while providing sufficient WOB to drill at an acceptable rate. • At TD in the horizontal or deviated section, the max CT compressive load before lock up given by coilCADE, is the maximum available WOB at TD.
Tripping and Hole Cleaning				
Pull capacity	Tension	• CT max allowable tension • Injector Pulling capability • BHA max allowable tension	•Hole depth	The maximum tension must at least be equal to the maximum hanging CT and BHA weight + the estimated maximum hole drag (CoilCADE) + a recommended safety margin for overpull (15,000 to 20,000 lbf).
Hole cleaning	Minimum annular velocity	• CT Max allowable pressure • CT length and diameter • Motor maximum flow rate	•Hole diameter	As a general rule, the minimum velocity in a vertical wellbore section is 40ft/min. In highly deviated wellbores 100 ft/min should be used as a guide. The Wellbore Simulator should be used in the assessment of critical cases. The annular velocity should be considered in the largest hole section that is generally the upper hole section where the casing is the largest and in the most deviated hole section.

Figure 8. CTD limiting parameters

In conventional drilling operations using jointed pipe, the actual weight on bit is relatively easy to calculate. However, due to the buckling which occurs in a CT string, such calculations are no longer valid for CTD. A tubing forces model (such as found in CoilCADE*) must be used to determine the available compressive load at the bit before the CT locks up. At the point of lock-up, no further weight can be applied to the bit, but surface indications (weight indicator) may not reflect this condition. The term downhole weight on bit (DWOB), refers to the actual force being transmitted to the bit, not the apparent force displayed by the weight indicator at surface.

While drilling the buildup section of a deviated wellbore, the CT must provide sufficient force to bend the BHA around the build up curve and still provide sufficient DWOB to ensure penetration at a reasonable rate. This bending friction force must be calculated then subtracted from the CoilCADE output value. The resulting force represents the available DWOB.

The proposed trajectory co-ordinates are required to enable CoilCADE analyses. This information is typically obtained from the directional drilling (DD) representative. Variations in azimuth and inclination effect the tubing forces and add to the complexity of the simulation (Fig. 9). If severe, the doglegs resulting from azimuth and inclination changes will significantly limit the extent of penetration–this applies both to the drilling process and subsequent well intervention.

The tables shown in Fig. 10 and 11 illustrate the force required for a range of hole and BHA sizes. Short radius BHAs containing knuckle joints (or similar) will require more detailed modelling.

Several CoilCADE simulations may be required to compile a table incorporating variables in BHA or hole size. In this way the design can be optimized to provide adequate DWOB throughout the build-up horizontal (or deviated) sections. For example, larger or heavier CT work strings provide more available DWOB while a higher build-up radius reduces the available DWOB.

A friction coefficient of 0.4 should be used in CoilCADE analyses of openhole sections.

The minimum recommended DWOB available for CTD in various hole size ranges is shown below.

Openhole Diameter (in.)	Recommended Minimum DWOB (lbf)
3-3/4 to 4	1000
4-1/8 to 4-3/4	1500
5 to 6-1/4	2500

2.2.2 Annular Velocity

It is necessary to determine if the available annular velocity will be sufficient to provide adequate hole cleaning. This is critical in two general areas.

• Horizontal and highly deviated sections

• Large diameter casings or top hole sections

Hole geometry, cuttings size and drilling fluid characteristics greatly influence the hole cleaning ability of any system. However, due to the high-speed motor and bit combinations typically used in CTD operations, the cutting size is generally very small (<50 microns). The small cutting size significantly assists with removal.

The following annular velocity rules of thumb can be used in preliminary feasibility and design work.

• Vertical hole sections – 30-40 ft/min annular velocity (new wells and shallow sections with coarser cuttings may require velocities as high as 50 ft/min).

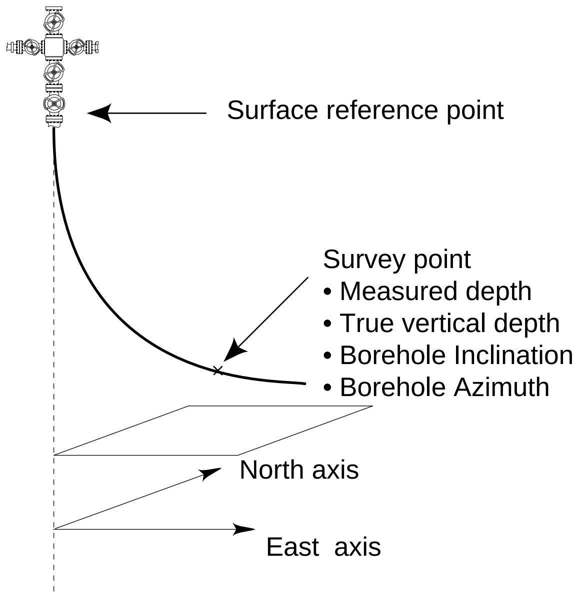

Figure 9. Azimuth/inclination.

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BHA BENDING FRICTION FORCE – 2-7/8-in. MOTORS					
Dog Leg Severity (°/100 ft)	**Hole Diameter (in.)**	**Friction Coefficient**	**BHA OD (in.)**	**BHA ID (in.)**	**Bending Friction Force (lbf)**
15	4.75	0.35	3	2.25	254
20	4.75	0.35	3	2.25	391
25	4.75	0.35	3	2.25	546
30	4.75	0.35	3	2.25	718
35	4.75	0.35	3	2.25	905
40	4.75	0.35	3	2.25	1106
45	4.75	0.35	3	2.25	1319
50	4.75	0.35	3	2.25	1545
55	4.75	0.35	3	2.25	1783
60	4.75	0.35	3	2.25	2031
15	4.125	0.35	3	2.25	317
20	4.125	0.35	3	2.25	488
25	4.125	0.35	3	2.25	681
30	4.125	0.35	3	2.25	896
35	4.125	0.35	3	2.25	1129
40	4.125	0.35	3	2.25	1379
45	4.125	0.35	3	2.25	1645
50	4.125	0.35	3	2.25	1927
55	4.125	0.35	3	2.25	2223
60	4.125	0.35	3	2.25	2533
15	3.75	0.35	3	2.25	388
20	3.75	0.35	3	2.25	597
25	3.75	0.35	3	2.25	834
30	3.75	0.35	3	2.25	1097
35	3.75	0.35	3	2.25	1382
40	3.75	0.35	3	2.25	1689
45	3.75	0.35	3	2.25	2015
50	3.75	0.35	3	2.25	2360
55	3.75	0.35	3	2.25	2723
60	3.75	0.35	3	2.25	3103

Figure 10. BHA bending friction forces

BHA BENDING FRICTION FORCE – 3-1/2-in. MOTORS

Dog Leg Severity (°/100 ft)	Hole Diameter (in.)	Friction Coefficient	BHA OD (in.)	BHA ID (in.)	Bending Friction Force (lbf)
5	6	0,35	3.5	2.5	82
10	6	0,35	3.5	2.5	232
15	6	0,35	3.5	2.5	426
20	6	0,35	3.5	2.5	656
25	6	0,35	3.5	2.5	916
30	6	0,35	3.5	2.5	1204
35	6	0,35	3.5	2.5	1518
40	6	0,35	3.5	2.5	1854
45	6	0,35	3.5	2.5	2213
5	4.75	0.35	3.5	2.5	116
10	4.75	0.35	3.5	2.5	328
15	4.75	0.35	3.5	2.5	602
20	4.75	0.35	3.5	2.5	927
25	4.75	0.35	3.5	2.5	1296
30	4.75	0.35	3.5	2.5	1703
35	4.75	0.35	3.5	2.5	2146
40	4.75	0.35	3.5	2.5	2622
45	4.75	0.35	3.5	2.5	3129

BHA BENDING FRICTION FORCE – 4-3/4 -in. MOTORS

Dog Leg Severity (°/100 ft)	Hole Diameter (in.)	Friction Coefficient	BHA OD (in.)	BHA ID (in.)	Bending Friction Force (lbf)
5	6	0.35	4.75	3	447
10	6	0.35	4.75	3	1264
15	6	0.35	4.75	3	2322
20	6	0.35	4.75	3	3576

Figure 11. BHA bending fricion forces.

• Horizontal hole sections – 100 ft/min (depends a great deal on the length of horizontal section and the drilling fluid characteristics).

A table of common hole, motor and CT sizes is shown in Fig.12.

There are several recently developed mud and drilling fluid systems which provide improved hole cleaning ability and fluid performance. Investigation and selection of CTD drilling fluids should be conducted in co-operation with DFS personnel.

Shear thinning fluids (e.g., some polymer muds) can decrease pressure losses by 30-40%. The CoilCADE hydraulic model cannot accurately simulate the performance of such fluids with yield point (YP) and plastic viscosity (PV) inputs alone–results are typically conservative.

High pressure wells requiring high mud weight can present a problem which limits the depth (length of CT string) which may be efficiently drilled.

2.2.3 Pump Pressure and Rate

The friction pressure induced by long or small diameter CT strings can be a limiting factor for some motor/bit/CT string combinations. Hydraulic models should be used to ensure the compatibility of the various components and pumping equipment. The CoilCADE model should be used to calculate pressure loss within the CT string and annulus. An estimate of the pressure loss within the BHA should be added to the resulting value. The total pressure loss is then compared with the allowable CT string pressure or pumping equipment limitation(s).

As a general guide, the following BHA pressure loss values can be used.

Type of BHA	Estimated pressure loss (psi)
4 3/4" OD vertical hole BHA	400
3' OD Directional BHA	1000

2.2.4 CT String Tension

A tubing forces model should be used to determine the maximum anticipated tension required to operate under the expected wellbore conditions. A safety margin for overpull (typically around 15,000 lb) should be added to the maximum anticipated tension. The resulting total must then still be below the Dowell maximum allowable tension as determined by the CoilLIMIT* module of CoilCADE.

2.2.5 Torque

Excessive torque is not generally a problem with the bit/motor/CT string combinations typically used in CTD operations. However, an awareness of the torque limits, and factors influencing such limits, is essential in hole/bit sizes larger than 4-3/4-in.

The torque generated by 6-in. motors can exceed the torque limits of 2-3/8-in. CT. Consequently, CTD of large hole sizes (e.g., 8-1/2 or 12-1/4-in.) should be completed using a 4-3/4-in. motor or 6-3/4in low torque motors (e.g. 1-2 or 2-3 lobes).

The maximum allowable CT torque should be less than twice the motor stall torque.

2.2.6 CT Life and Fatigue

There are two principal areas of importance regarding CT life and fatigue in CTD operations.

• A careful study of the anticipated cycles and operating conditions should be undertaken to assess the expected life usage of the specified string.

• Once the operation has commenced, a careful record must be kept and regularly reviewed to ensure that actual life usage is within that predicted.

Because of the variable and unknown factors associated with most drilling operations, it is extremely difficult to estimate the expected life usage. Nonetheless, the consequences of exceeding the fatigue and life limitations can be severe (in the case of a failure) and inconvenient (in the case of a reel change being required).

As a general guide, data gathered from completed CTD operations indicates the following life usage.

Vertical wells

Shallow wells, e.g., 2000 ft can be drilled with the CT being exposed to relatively few bending cycles (2 or 3 cycles being typical). Therefore the life expectancy of a string can reasonably extend to several wells.

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ANNULAR VELOCITY – MOTOR/HOLE SIZE vs. CT SIZE

	Flowrate (BPM)	Hole ID (in.)	Annular Velocity (ft/min) 1-3/4-in CT	2-in.CT	2-3/8-in. CT
2-7/8-in. motor	2.00	3.750	187	205	244
	2.00	4.125	148	158	181
	2.00	4.750	106	111	122
	2.00	6.125	60	61	65
	2.00	7.000	45	46	47
	2.00	8.000	34	34	35
	2.00	9.000	26	27	27
2-3/8-in motor	2.30	3.750	215	235	281
	2.30	4.125	170	182	208
	2.30	4.750	121	128	140
	2.30	6.125	69	71	74
	2.30	7.000	52	53	55
	2.30	8.000	39	39	41
	2.30	9.000	30	31	31
3-1/2-in. motor	2.30	4.125	170	182	208
	2.30	4.750	121	128	140
	2.30	6.125	69	71	74
	2.30	7.000	52	53	55
	2.30	8.000	39	39	41
	2.30	9.000	30	31	31
3-1/2-in. motor	2.60	4.125	192	206	235
	2.60	4.750	137	144	158
	2.60	6.125	78	80	84
	2.60	7.000	58	59	62
	2.60	8.000	44	45	46
	2.60	9.000	34	35	36
4-3/4-in. motor	4.75	6.125	-	146	153
	4.75	7.000	-	109	113
	4.75	8.000	-	81	84
	4.75	9.000	-	64	65
4-3/4-in. motor	6.00	6.125	-	-	194
	6.00	7.000	-	-	142
	6.00	8.000	-	-	106

Figure 12. Annular velocities for different hole size/motor/CT string combinations.

Deviated wells

Data from previous operations indicate that a 2-in. CT string can, on average, be used for three or four re-entry wells. Similarly, a 2-3/8-in. CT string is typically used on two to three wells.

In all cases, continuous monitoring (TIM* and CoilLIFE) is essential to ensure that prescribed limits are not exceeded.

2.2.7 CT Reel Handling

One of the main constraints on the size and length of CT strings are the limits imposed by road transport weight regulations and offshore crane capacity. While it may be undesirable to assemble (field weld) work strings, it may be the only option in the case of limited road weights. Offshore crane capacity restrictions can be overcome, in some circumstances, by spooling the tubing between a supply boat and platform. Using this technique, the empty reel is lifted to the platform and rigged up to spool the tubing string from a shipment spool on the boat deck.

2.2.8 Directional Requirements

Applications which require directional control and monitoring require special investigation and the involvement of directional engineers at an early stage. As a guide of current capability, the following limits apply.

- Downhole temperature – currently limited to 310°F maximum.

- Deviation build rates – A function of tool string length and stiffness with, in general, longer tool strings requiring lower build rates. Also, aggressive build rates can limit the efficiency of orienting tools. The current orienting tool is designed to operate within dog-legs of up to 30°/100 ft. The Slim 1 tool (with low-flow pulser) can operate in a dog leg severity of 55°/100 ft.

- Hole size – Currently, directional assemblies utilize a 2-7/8-in. monel housing. Consequently, the minimum hole size with directional control is 3-1/2-in.

2.3 CTD Project Preparation

The preparation for a CTD project typically involves co-ordinating the input of several specialist disciplines to compile an overall job plan or procedure. In most cases it is desirable to assign one engineer as the person in charge of the design and preparation of the CTD operation. Logically, this person will provide a focused point of contact between client and contractor(s), and be available for operation support duties during the execution of the CTD project.

The tasks required to be completed in this phase of CTD project preparation may be summarized as technical or administrative. Regardless of how the various elements are categorized, each should be regarded as a key component which is essential for completion of a safe and successful CTD project.

2.3.1 Technical Preparation

There are several tasks to be performed, each with associated deadlines, in the process of technical preparation. The tasks can be planned, and appropriate duties delegated, with the help of check lists in the following principal areas.

- Basic equipment and services

- Procedures and planning

- Drawings and schematic diagrams

- Personnel

To enable the efficient management and co-ordination of these individual areas, it is advisable to prepare a list of tasks required to complete technical preparation. Such a list should contain information on the task, designated person, deadline and additional information appropriate to the specific task.

2.3.2 Basic Equipment and Services

To help identify the source(s) of equipment, services and expertise necessary to complete the project, comprehensive check lists should be prepared under the headings shown below.

Each list should be formatted to include an accurate description of the item or service, the source and applicable deadlines or leadtimes.

• Surface equipment

• Consumables

• Spare parts and supplies

• Dowhhole tools

• Associated services

2.3.3 Procedures and Plans

Due to the complex nature of the overall operation, it is recommended that detailed procedures and plans be prepared for the principal project elements. These procedures should take account of the specific wellsite, wellbore and reservoir conditions (or anticipated conditions) under which they will be executed.

All procedures and plans should be carefully reviewed by the personnel, groups or organisations involved. In some cases it may be necessary to adopt a formal review and approval process to ensure all parties acknowledge acceptance.

Note: Ensure that each document is clearly identified with a date or version number. This will minimise confusion and error where several parties are provided with procedures or plans.

The following list includes typical elements of a CTD project. This list comprises the basic requirements of a number of CTD applications, consequently, some elements may not be applicable. Similarly, additional elements may be required for specific CTD project(s).

• Mob/demob organisation

• Rigging up/down

• Setting whipstock & milling window (if required)

• Well control

• Well control equipment testing

• BHA deployment even overbalance

• Running and setting liner or casing (if required)

• Running completion string

• Cementing job design

• Mud program

• Contingency plans

• Emergency responses (in the event of fire, etc)

2.3.4 Drawings and Schematic Diagrams

Much of the explanation required within procedures and plans can be simplified by the use of clear and suitably detailed drawings and schematic diagrams. The following list includes typical examples of drawings or schematic diagrams for CTD projects.

Note: Ensure that each document is clearly identified with a date or version number. This will minimise confusion and error where several parties are provided with procedures or plans.

• Wellbore schematic (at each stage of the operation)

• Trajectory plot if deviated

• Surface equipment lay out with dimensions (or scale) including indication of restrictive zoning where applicable, e.g., Zone II

• 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

2.3.5 Personnel

In addition to the availability and assignment of personnel, there may be several issues which should be addressed. The following examples may apply to the organisation of CTD personnel for various applications and locations.

• Training and certification of personnel

• Personnel job descriptions

• Operations and support organisation organograms

2.3.6 Administrative Preparation

Clarify and finalize arrangements between the client and third party contractor(s). The final agreement should include the following sections:

• Equipment list provided by contractor and operator

• Personnel list provided by contractor

• List of services provided by contractor and operator

• Liability clauses

• Day rates, lump sums, incentives and penalties including force majeure

3 EXECUTION

3.1 Well Control (Overbalanced Drilling)

This section addresses only well control in over balanced drilling applications. The issues concerning underbalanced drilling are addressed separately in Section 3.4.

Most conventional well control precautions and procedures used for conventional drilling apply to overbalanced CTD (with minor modifications). For example, in slim hole wells, it is vital that kicks are detected as soon as possible. Within the relatively small wellbore, even small influxes of reservoir fluid can displace a significant volume of drilling fluid–resulting in a rapid worsening of the situation. Dynamic kill is not a viable option for CTD due to the small annular pressure loss. The wait and weight method or the driller's method, such as used for kick control on conventional drilling operations is typically used.

The preferred kick detection system for CTD operations is to use a flowmeter installed on the return line. The equipment is described in the surface equipment section of this manual.

If foam or air is being used as a drilling fluid, the implication is that the reservoir pressure is very low. In the event of a kick, the well will generally kill itself, or worst case, pumping water will kill the well. Pressure deployment of the BHA is typically required if drilling with foam in a gas reservoir. This is necessary as the foam may break when tripping, resulting in unstable wellbore conditions.

CTD well control procedures and policies are described in the Dowell safety and loss prevention manual (SLP22) which also refers to the Sedco Forex Well Control handbook.

3.2 Conventional Sidetracking

The term conventional sidetracking or re-entry applies to CTD operations which are undertaken under the following conditions.

• The well is killed and all subsequent CTD activities are performed in overbalanced conditions.

• The original completion tubulars have been removed.

• A mechanical whipstock is used to initiate window milling operations in the casing or liner.

There are four distinct operational phases in completing a conventional side tracking operation. Each phase will require the involvement of different specialist skills which may require the participation of third party suppliers or service companies.

• Well preparation

• Preparing/setting the whipstock

• Milling the window

• Drilling the sidetrack

Conventional sidetracking is currently undertaken at depths in excess of 10,000 ft, with resulting drain hole diameter within a range of 3-1/2- to 6-in (Fig 13).

The application of conventional CTD sidetracking techniques have special significance on offshore platforms, where mobilization and logistic difficulties may render conventional rig-based re-entry techniques non-viable. The economic viability of onshore CTD re-entry operations is greatly dependent on the local availability, and suitability, of conventional rigs and equipment.

3.2.1 Well Preparation

The following list summarizes the operations typically required as well preparation for setting the whipstock then continuing with subsequent milling and drilling operations.

• Kill the well

• Nipple down christmas tree and nipple up well control equipment

• Test the well control equipment

• Pull the production tubing and retrieve packer (if required)

• Squeeze cement off perforated interval (if necessary) or set cement plug and/or set bridge plug• Run CCL (to check for casing collars at the KOD), CBL (to check cement/bond quality) and Gamma Ray (to correlate depth).

• Run a casing scrapper to the KOD

3.2.2 Setting the Whipstock

The procedures and equipment necessary to set the whipstock depends on the operation objectives. If azimuth control is required, then a whipstock anchor must be set. The whipstock anchor is necessary to ensure the whipstock is correctly orientated, to allow milling and drilling operations to be started along the correct trajectory.

The following list summarizes the activities which may be necessary to run and set a mechanical whipstock ready for milling operations.

• If azimuth control is required, set the whipstock anchor. This is typically run on wireline, but CT conveyance may be appropriate in some circumstances.

• Perform a gyro survey to determine the orientation of the whipstock anchor. The orientation must be known to allow the whipstock key to be set. Thereby ensuring the whipstock orientation is correct when set on the whipstock anchor.

• Prepare the whipstock – if run without an anchor, the whipstock is equipped with a set of slips which are set on the casing wall (similar to packer slips). A bridge plug or cement plug must be set at the kick off depth to enable the whipstock slips to be set with set-down weight. If the whipstock is to be used with an anchor, a mule shoe and orientation stinger will be made up to the bottom of the whipstock.

• Run and set the whipstock

Whipstock run with an anchor and stinger

The BHA is run in the hole, the anchor is tagged and stinger engaged into the anchor. A swivel assembly allows the stinger to rotate freely allowing correct alignment of the whipstock and anchor. Weight is then applied to set the slips in the anchor, overpull confirms that the stinger is anchored. A release stud between the whipstock and the running tool is then sheared with additional overpull, and the running assembly is retrieved or milling of the window starts if a starting mill is run with the running tool.

Whipstock run without an anchor

The BHA is run in the hole, the cement plug or bridge plug tagged and the whipstock slips set. A shear stud on the running tool is sheared by applying weight (or by pulling depending on the type of whipstock). The running assembly is then retrieved or milling of the window starts if a starting mill is run with the running tool.

In some applications a special mill/motor assembly is used as a running tool. The advantage being the ability to start milling immediately the whipstock is set, with no need to retrieve and change the BHA (see below).

3.2.3 Window Milling

It is generally recommended that window milling be performed using low speed motors (typically 3-1/2- or 4-3/4-in. motors, depending on hole size). The necessary weight-on-bit being provided by drill collars. The WOB required to mill a casing window does not generally exceed 1,000 to 2,000 lbf. A representative of the whipstock vendor or directional drilling company is generally required on location to supervise the preparation and execution of window milling operations.

There are two basic options for window milling using a mechanical whipstock.

• Using a conventional starting mill/whipstock lug combination.

• Using a diamond speed mill

Starting mill/whipstock lug combination

The following list summarizes the activities necessary to mill a casing window using a starting mill and whipstock lug.

• A conventional starting mill is first made up to a low speed motor and run in the hole to mill about 3 ft of casing and the whipstock lug.

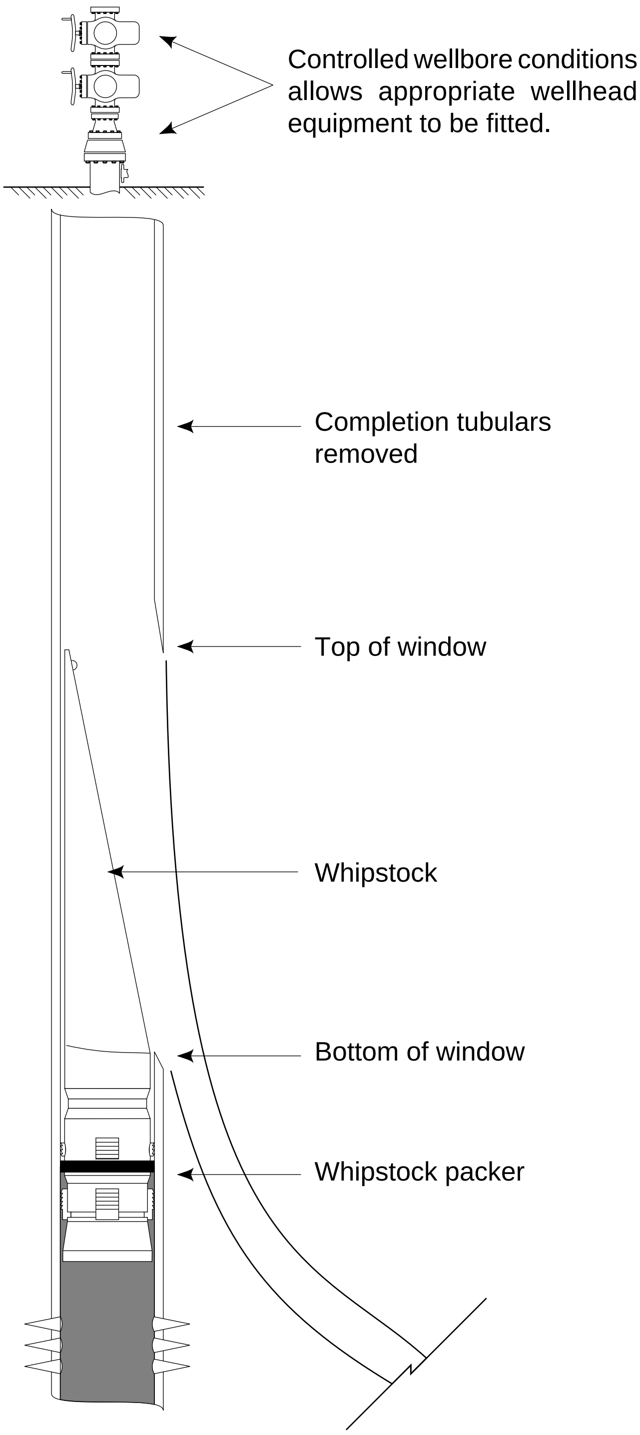

Figure 13. Typical conventional sidetrack configuration.

- The starting mill is replaced by a window mill and a water melon mill. The water melon mill being made up between the window mill and the motor. About 9 ft of window is milled, followed by approximately 5 ft of formation. Drilling the formation allows the next milling assembly to enter the open hole when dressing off the window.

- A string mill is made up on top of the water melon mill for reaming the window section.

As an alternative to the multiple runs and BHA changes outlined above, the low-speed motor can be used as a whipstock running assembly. This enables window milling to commence immediately after the whipstock shear stud has released, i.e., a BHA change is not necessary to start milling. A check must be made to ensure the motor can withstand the necessary pull or set down weights required to set the whipstock and shear the stud.

Diamond speed mill (no lug in the whipstock concave)

- A diamond speed mill and low speed motor assembly is used to mill approximately 5 ft of window.

- A water melon mill is then made up above the speed mill to complete the window and to drill approximately 5 ft of formation.

- A string mill is then made up above the water melon mill for reaming the window section.

3.3 Thru-Tubing Re-entry

The term thru-tubing reentry applies to CTD operations which are undertaken under the following conditions.

- Operations are conducted over (or through) the christmas tree.

- The original completion tubulars remain in place.

- Well control equipment is used to enable under- or over-balanced drilling to be conducted safely.

Thru-tubing reentries can only be undertaken using mill and bit assemblies which are compatible with the minimum ID (restriction) present in the tubing string or completion. In some cases, tubing restrictions may be milled out or cut to allow access for larger mills and bits. Nondirectional deepenings and sidetracks may generally be undertaken through completion strings of

3-1/2-in. or greater. Directional applications generally require tubing 4-1/2-in. or greater to allow passage of the 3-in. OD directional BHA. The resulting drainhole hole is generally 3-1/2 or 3-3/4-in. depending on the minimum restriction.

Thru-tubing reentry techniques have special significance on applications where completion removal is uneconomic or impossible. The constraints associated with working within the completion tubulars generally preclude conventional rigs and equipment from this type of operation.

Significant benefits can be gained from thru-tubing CTD in underbalanced conditions. Consequently thru-tubing CTD can offer great potential in the development of depleted reservoirs.

There are three basic techniques which can be used to kick-off and mill a casing or liner window below the tubing tail-pipe. The regional CTD specialist should be contacted during the design phase of any thru-tubing CTD application to ensure that the most recent design and executing techniques can be applied (Fig 14).

- Whipstock in production tubing
- Thru-tubing whipstock
- Cement kick-off techniques
  - Time drilling in a cement plug
  - Whipstock in cement plug pilot hole

3.3.1 Well Preparation

The following list summarizes the operations typically required as well preparation for thru-tubing CTD operations.

- Nipple up CT well control equipment.
- Plug and abandon existing perforated zones
- Run CCL (to check for casing collars at the KOD), CBL (to check cement/bond quality) and Gamma Ray (to correlate depth)
- Mill some nipples in the tubing or cut tail pipe if necessary because of restrictions.

3.3.2 Whipstock in Production Tubing

If the kick off is to be performed from the production

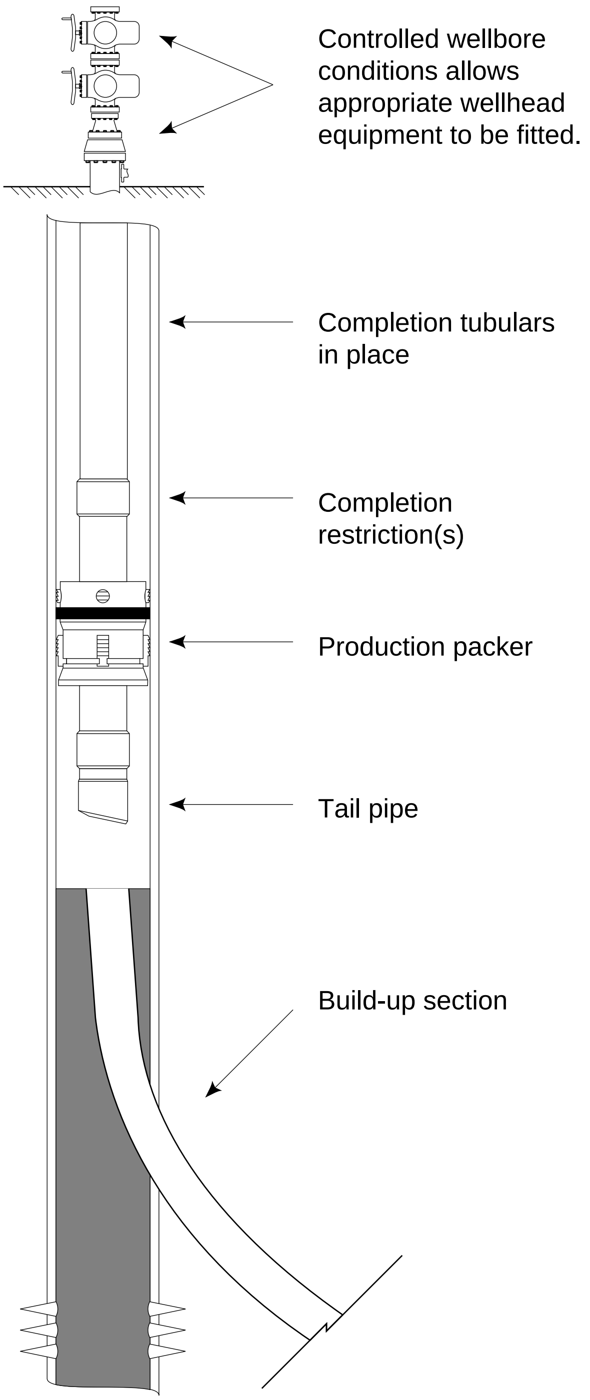

Figure 14. Typical thru-tubing sidetrack configuration.

tubing, a conventional whipstock and anchor can be set in the tubing and a window milled in tubing and the casing/liner. The hardware and techniques required are currently available and are relatively conventional. However, some modifications may be required.

It is generally not possible to set a whipstock in the production tubing tail pipe. Therefore, the whipstock will need to be set above the production packer. This is generally an unacceptable option, consequently this technique has limited application.

3.3.3 Thru-tubing Whipstock

Thru-tubing whipstocks are a relatively recent development which requires ongoing refinement to improve reliability. The size ranges available are currently restrictive (through 4-1/2-in. tubing to set inside 7-in, casing or liner). However this will undoubtedly increase as the tool reliability improves and the techniques become more common.

Current (1995) thru-tubing whipstocks can only be used to sidetrack on the high side of the hole. They are available from Baker Oil Tools, Weatherford and TIW. As of mid 95, only the BOT thru-tubing whipstock have been successfully field tested.

3.3.4 Cement Kick-off Techniques

Both of the cement kick-off techniques outlined below are recently developed and are undergoing continued testing and development.They both require the accurate placement of a high quality, high compressive-strength cement plug. Consequently, sufficient effort and resources should be allocated to ensure the successful design and execution of the cement plug placement (Fig 15).

Cement plug preparation

- A cement plug of high compressive-strength is placed in the interval 50 ft below the kick-off depth to the bottom of the tail pipe (subject to length and volumes). After the cement has adequately cured, the top of the cement is tagged and dressed if necessary.

- The cement in the tail pipe is then drilled out using a directional BHA comprising a diamond speed mill and a slightly bent motor (± 0.25°)

- Once out of the tubing the bend is oriented in the direction of the desired sidetrack. This is achieved using the gravity tool face and the hole gyro survey. Drilling is continued through the cement plug, keeping the tool face until it reaches the kick-off depth (KOD).

Time drilling from a cement plug

- The BHA is retrieved and the bend changed to a higher angle (± 2.5°).

- The window is milled using a time drilling technique, i.e. milling with low WOB (or low motor differential pressure), running the CT string in short intervals (1/4-in. or 1/2-in. only) with predetermined delay intervals. The delay time will vary throughout the milling operation as the quantity of steel to be cut varies through the window.

- When the window and approximately 5 ft of formation have been drilled, the BHA is retrieved.

- The window is then dressed using a water melon mill assembly similar to that outlined in the conventional sidetracking section. A bull nose (no bit) is made up at the bottom of the water melon mill to avoid drilling out the cement by accident while dressing the window.

Whipstock set in the cement plug pilot hole

- The pilot hole is drilled in the cement plug approximately 10 ft deeper than the KOD. This rat hole is used to set the bottom section of the whipstock.

- The BHA is retrieved and the appropriate whipstock is run to bottom.

- After carefully tagging bottom, the whipstock assembly is correctly oriented using an orienting tool. By applying weight, the slips of the whipstock are set against the casing/cement. Additional weight parts the shear-stud allowing retrieval of the running assembly.

- A straight milling BHA with a diamond speed mill is run to mill the window and approximately 5 ft of formation.

- The window is then dressed using a water melon mill assembly similar to that outlined in the conventional sidetracking section.

The regional CTD specialist should be consulted during the design phase of any thru-tubing CTD application on which either of the above cement kick-off techniques are to be used.

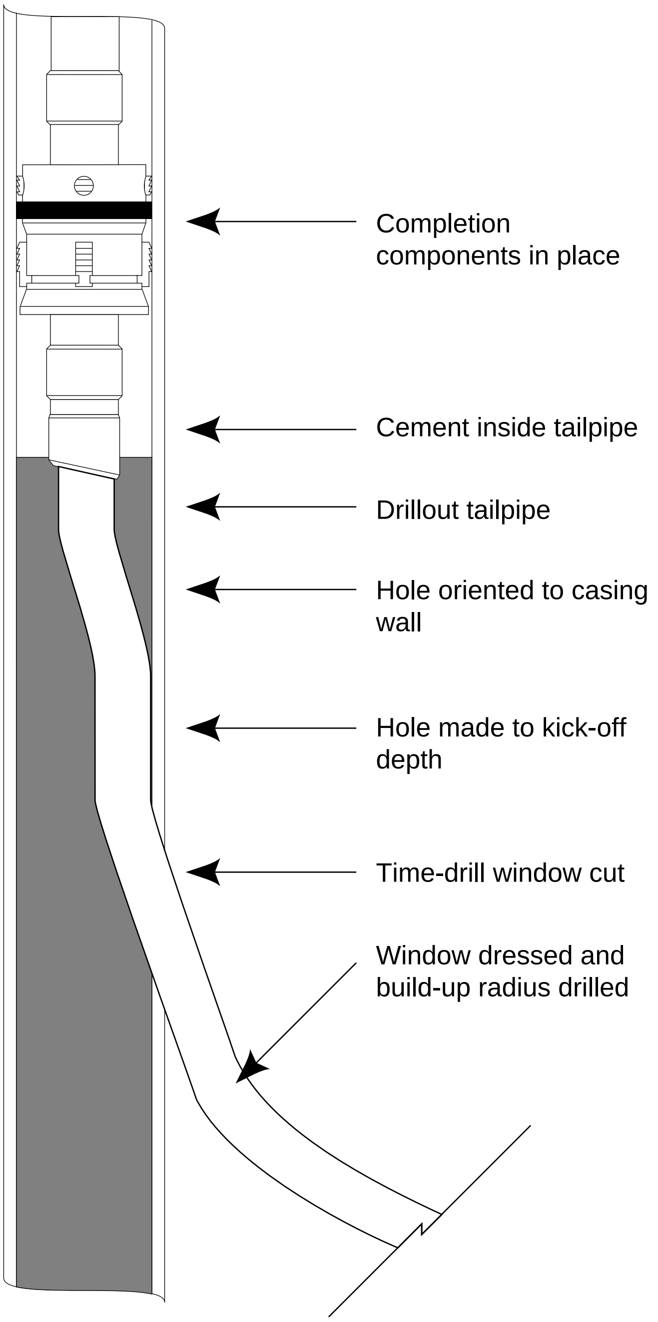

Figure 15a. Time-drilled cement kick-off (thru-tubing).

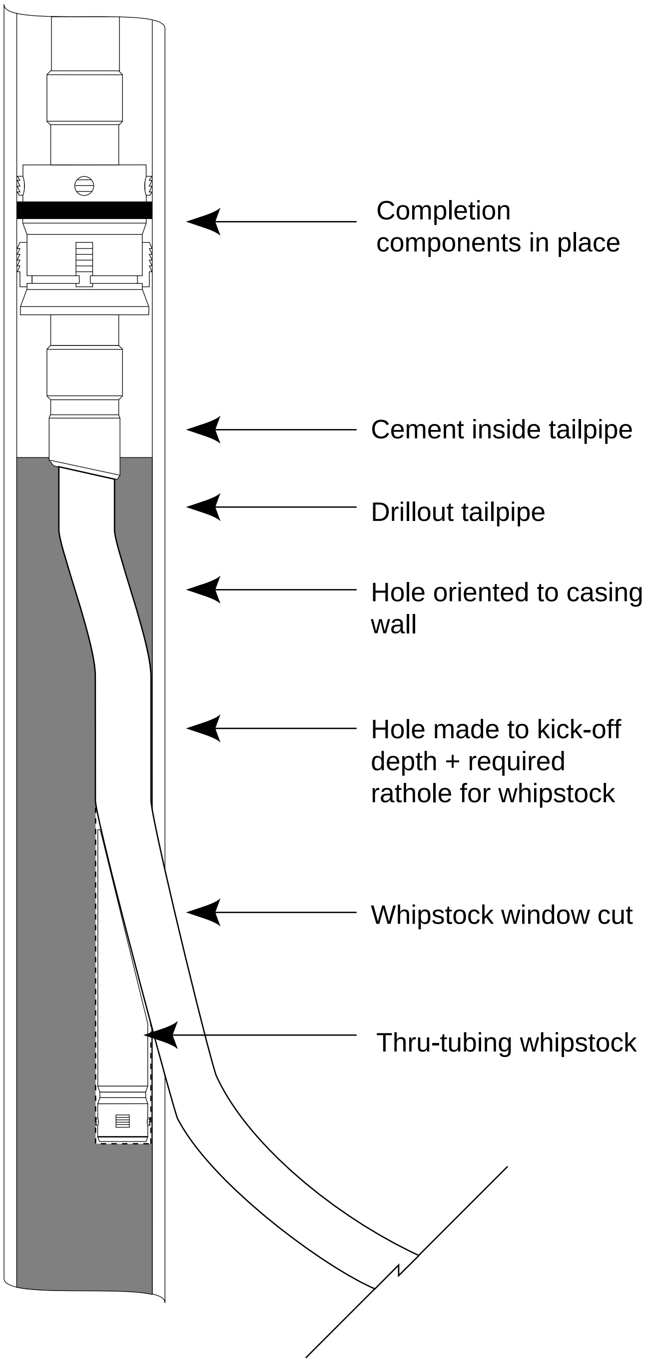

Figure 15b. Whipstock cement kick-off (thru-tubing).

3.4 Underbalanced Drilling

3.4.1 Definition and Objectives

There has been confusion regarding the definition of underbalance drilling. For example, foam/air drilling or drilling with a parasite string without the well flowing is called sometimes underbalanced drilling. However, this is in fact overbalanced drilling if the well does not flow. The term underbalanced drilling implies that the reservoir pressure is at all times higher than the equivalent circulating density of the fluid in the annulus. Under these conditions, the well will be capable of flowing reservoir fluid while drilling or tripping.

The principal objective of underbalanced drilling is to avoid formation impairment caused by the invasion of drilling fluid. Some of the horizontal wells drilled underbalanced by CTD have production rates approximately twice that of nearby wells which were drilled overbalanced. These nearby wells were drilled using conventional techniques and are completed with larger wellbore and completion tubulars.

Underbalanced drilling is not a damage free technique. However, the potential increase in well productivity outweighs most of the associated risks. Permeability reduction resulting from the imbibition of drilling fluid can occur. However, the relative effect is significantly less than overbalanced drilling damage. The absence of a protective sealing filter cake can also result in some formation damage when the well is shut in. Further investigation is necessary to assess the extent of these damages for the various types of drilling fluids in different formation types. An appropriate choice of deployment technique to avoid shutting the well, may be the key to limiting reservoir damage.

One of the main concerns while drilling underbalanced is maintaining borehole stability. Such concerns are heightened under the following conditions.

- If no liner or casing has been set over the cap rock interval above the pay zone

- In unconsolidated reservoirs

- In heterogeneous reservoirs with, for example, shale stringers.

Consequently, the reservoir stability and homogeneity need to be evaluated for all candidate wells. Precautions to contol or limit borehole instability include:

- Careful controlling the degree of underbalance.

- Selecting appropriate drilling fluids to minimize adverse reactions with sensitive formations.

- Setting a casing or liner at the top of the reservoir.

Underbalanced drilling may be likened to drilling while taking a kick. However, the equipment and techniques used are specifically designed to operate under these conditions, unlike conventional drilling. Also, since the completion tubular and christmas tree are still in place, a high level of control can be maintained. Safety issues are also affected by the reservoir pressure.

Thru-tubing underbalanced drilling is generally acceptable to regulatory agencies, largely as a result of long established CT workover procedures and experience in live wells.

3.4.2 Creating Underbalanced Conditions

Creating and controlling the correct degree of underbalance can be an extremely complex process. For example, computer models provide the only practical means of predicting the well head and bottom hole pressures in a two phase flow.

The means of creating suitable underbalanced conditions depends greatly on the anticipated reservoir pressure. Reservoir pressure can be characterised as being either above or below the hydrostatic pressure of a column of water in the wellbore.

Reservoir pressure above water column hydrostatic pressure

Under these conditions, underbalanced pressure can be created by using a fluid(s) which is less dense than water. In marginal cases, careful analysis of the equivalent fluid density while circulating solids in the annulus should be conducted to ensure underbalanced conditions exist.

Reservoir pressure below water column hydrostatic pressure

Underbalanced pressure conditions can be created in three basic ways.

- Use a low density drilling fluid

- Use annular gas-lift

- Use nitrogen to kick-off the well, then use appropriate fluids

Low density fluids

The following low- and ultra low-density fluids have been used for drilling. This method is applicable to most wells with low or high gas-oil-ratios (GOR).

- Oil based fluids – use is limited to reservoirs with pressure corresponding to an equivalent mud weight (EMW) of at least 7 ppg. Oil based fluids must be conditioned after the well returns have been passed through the separators and mud treatment equipment.

- Nitrified or aerated fluid or foam – in wells with a high GOR, nitrified foam or mud is the only solution to avoid downhole explosion or fire. In wells having a low GOR, the use of an aerated foam or mud instead of nitrified systems needs careful risk analyses. Foam is typically the best option since a number of computer models are available to predict foam performance, pressure losses and resulting EMW. Treatment and disposal of the wellbore returns are significant problems encountered with foam based fluid systems.

- Gas – natural gas, air or an inert gas like nitrogen have all, at some time, been used in drilling operations. Due to the risk, and consequences, of downhole fires and explosions, Dowell only recommend nitrogen. A careful risk analysis is required for all non-inert gas (or air) applications. Regardless of the gas used, this type of drilling is generally performed in very hard formation with very low permeability (such as found in the Rocky Mountain region). Such applications are quite distinct from "normal" underbalanced drilling with CTD.

Annular gas lift

Two methods are in relatively common use to assist with drilling operations. Both being applicable in wells with low GOR.

- Parasite string – the existing production tubing is pulled and a casing or tubing string with a parallel parasite string is set in place. The setting depth is dependent on the formation pressure, i.e., the more depleted the reservoir, the deeper the string injection point will be.

  On concluding the drilling operations, the parasite string is pulled and a production tubing string run. Ideally, retrieving the parasite string and running the production tubing should be performed under live well conditions to avoid potential damage during shut-in. From a cost and efficiency standpoint, a parasite string is generally not the best option.

- Gas lift system in the production tubing – if the well is or needs to be equipped with a gas-lift production string and the tubing is large enough to achieve the scope of work, then the gas lift assisted drilling can be an economic option. If the well is not suitably equipped, the production string can be pulled and replaced with larger tubing.

Well kick-off and appropriate fluids

Some marginal wells may quickly load-up and be capable of flowing only in ideal conditions. In such cases, nitrogen kick-off and careful fluid selection (and control) may be sufficient to support underbalanced drilling with CT. This method is only applicable in wells with high GOR.

3.4.3 Controlling Underbalance Pressure

A surface choke is the primary means of controlling the degree of underbalance created downhole. However, if gas lift mandrels or a parasite string is used, the gas or nitrogen injection rate will also provide a means of control. Experience has shown that the surface equipment commonly used to treat return fluid, creates a significant back pressure. Consequently, varying the gas lift system parameters to control the degree of underbalance is of limited value.

A downhole annulus-pressure sensor helps to accurately monitor the bottom hole pressure. This can ensure the underbalance is maintained over a horizontal wellbore section (assuming the reservoir pressure remains constant over the horizontal interval).

3.4.4 Well Pressure Control

Well control procedures used for conventional overbalanced drilling are no longer applicable for underbalanced drilling. A gas or oil kick does not require that the well be killed even when tripping.

For a thru-tubing underbalanced operation, with the christmas tree in place, the well control or safety procedures are the same as when performing live well service operations, and are well documented.

For non thru-tubing underbalanced operations, accepted procedures are not well documented and each application must be carefully reviewed on a case by case basis.

3.4.5 Drilling Fluid

The type of drilling fluid is largely determined by the means by which the underbalance conditions are created. The required functions of a drilling fluid used in underbalanced drilling are not the same as that required for overbalanced drilling. For example, a drilling fluid for underbalanced operations is not required to fulfill the following functions.

- Balance the formation pressure
- Minimize formation damage (filter cake and water loss).

However, the fluid must fulfill the following basic requirements.

- Efficiently transport cuttings from the wellbore (slip and annular velocity) – previous experience demonstrates that cuttings size in underbalanced conditions are such that slip velocity is very low. A circulating sub above the motor provides the first option to increase flow rates for improved hole cleaning (especially in 9-5/8-in. or larger casing). A mud system with the appropriate PV, YP, and gel characteristics is preferred, especially in non thru-tubing applications.
- Cool and lubricate the bit – generally not a major issue.
- Control corrosion – controlled by additives, not generally a major issue.
- Provide sufficient inhibition over shale – may be a concern if shale stringers are to be drilled, although can be addressed with OBM or mud with appropriate additives.

If a production tubing gas-lift system is used, and shale inhibition is not a concern, water is generally recommended as a drilling fluid. Water can generally achieve adequate hole cleaning in 4-1/2-in. tubing and even 7-in. liner below tail pipe. Disposal is simplified since water can generally be dumped or pumped into the production line.

3.4.6 Wellbore Returns

The simple solution for handling and disposal of wellbore returns, i.e., drilling fluid, oil, gas, formation water and cuttings, is to route the entire return flow to the production line. Concerns regarding the routing of solids to production facilities are minimal, since the volumes of cuttings for the small hole sizes drilled are generally tolerated–even at high penetration rates. However, the flow line may create enough back pressure to prevent the well from flowing. If the production facilities cannot treat the returned fluids, it may be necessary to treat the returns independently, i.e., using three phase separators (see Schlumberger Testing).

The schematic diagram in Fig 20b outlines a typical process for treatment of wellbore returns. Returns are controlled by the choke manifold, following which they are routed to the separator(s) where oil, gas, drilling solids, and water are separated. Sample catchers (e.g. a tee with valves and screens) can be installed downstream the choke manifold or returns fluid samples are recovered and centrifuged to recover cuttings.

The separated gas will be vented or flared depending on volume and local constraints. The separated oil is generally stored in an appropriate tank. The residual water and solids are routed to a settling tank system, from where the water is disposed or recirculated and the solids cleaned and dumped (either periodically or at the end of the project). If water or mud needs to be dumped or treated, the same procedures as for normal drilling operations can apply.

If some of the fine solids are allowed to recirculate, an increase in fluid density and pumping pressure can result. In this likelihood, a centrifuge can be used to treat the mud downstream the separator(s). Cuttings from the centrifuge will be collected in cutting bins and sent for treatment later.

On gas wells, when foam is used, the returns will require partial separation to allow the gas to be vented or flared and the broken foam disposed. On foam-drilled oil wells, the surface equipment may need to be adapted or modified to ensure efficient breaking of the returns prior to separation.

Recirculating foam fluid is an option but requires a specific separator built to break the foam (by lowering the pH). Following separation, the liquid pH is increased to allow recirculation of the foam liquid phase.

3.4.7 BHA Deployment

In underbalanced drilling, the BHA needs to be deployed, i.e., run and retrieved under pressure and live well conditions. There are two basic options, either use an external lunricator eg. wireline lubricator or an internal lubricator eg. deployment against the SSSV.

Lubricator/riser

The deployment procedures are similar to those used when deploying CT service tools. It will generally be necessary to deploy the BHA in more than one section when using a wire line lubricator. On some offshore locations, there is sufficient riser length to allow the BHA to be deployed in one section.

Techniques allowing the well to flow while tripping, will minimize formation damage which could result from shut-in.

SSSV deployment

Deploying against the SSSV results in the well being shut in and therefore balanced. As discussed in a previous section, the absence of filter cake can affect the formation during shut-in. However, further studies are required to determine the extent and nature of such damage.

3.4.8 Installing Completion Tubulars

Installing a liner

The deployment technique limits the type of liner to a predrilled liner (jointed or coiled) with the holes plugged with aluminium. The liner float shoe has an aluminium ball to allow the deployment under pressure. The aluminium plugs or ball are removed by spotting acid (with a CT work string) after running and/or setting the liner. Plugged liner can withstand a maximum differential pressure of only 2,000 psi.

If a jointed slick liner (without collars) is to be run underbalanced, the injector head can be used to snub the liner into the well. The length of liner being run will be limited by the CT and injector head maximum pull capacities.

If a conventional jointed liner with external collars is to be run, it will be deployed with a wireline lubricator and the capacity of the wire line will limit the weight and therefore the length of the liner.

Coiled tubing liners are run as normal CT using the appropriate size of coiled tubing and well control equipment.

Installing a production string

A production string will only be required on CTD operations not performed through the production tubing. Either a CT completion string is run and the CT unit used to run it under pressure or a conventional jointed tubing production string is run by a snubbing unit.

The maximum CT completion size is currently 3-1/2-in. Transportation and handling of 3-1/2-in. CT strings can be logistically difficult offshore and onshore. It is likely that the majority of CT completion strings will be limited to 2-7/8-in. or 2-3/8-in.

3.5 Running and Pulling Wellbore Tubulars

It may be necessary to pull the completion string on re-entry wells before sidetracking or deepening. In addition, the completion may be removed to allow access for a liner to cover and protect the build up section. On new wells, it may be necessary to run one or two strings of casing. Two options are available, crane or jacking substructure. Selection 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. However, if the string gets stuck, there is limited pulling capacity in reserve.

Conventional drilling slips, elevators, and safety clamps are used. Single joints are handled with the crane which also holds the entire tubing or casing string in much the same way as a rig does. A power tong is required to make up the connections.

The liner or casing string can be run and made up, floating i.e. partially empty to limit its hanging weight. To run a liner we need to consider the weight of the total weight of the string (comprising the liner string, liner hanger, running tool, and drill collars to provide weight to push the liner around the build up if it is a directional well).

A conventional CT logging deployment technique is used to make up the connection between the stripper and the well head after the CT connector has been connected to the liner string i.e. the liner string is hung off in the BOP rams and the CT connector is made up to the liner. The skate pressure is released to allow the injector head to be stripped over the CT until the BOP/ stripper connection can be made up. Once all connections are made up and tested, the string weight is picked up and the liner released from the BOP ready to RIH.

Substructure with jacking system

Dowell has designed and built three different types of jacking systems to run or pull wellbore tubulars without the requirement for a mast. Both systems include a substructure and a set of snubbing jacks. 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 pull capacity and an 11 ft stroke. The Hydra Rig system can only be used with 7-1/16-in. or smaller BOPs.

The third system built by Dreco has four jacks with a 200,000 lbs pull capacity and an 8 ft stroke. The system can be used with an 13 5/8-in. BOP stack and is the best suited system for drilling aplications.

These substructures accommodate a tubing power tong to make up or break the tubing connections. Single joints of tubing are handled by the CTU crane. Both systems also allow the injector head to be skidded off the well when running or retrieving the BHA.

4 SURFACE EQUIPMENT

The type of application, location and complexity of the operation will determine which items of surface equipment are specified and then selected. The principal components required to complete most CTD projects can be categorized as follows.

- CTD substructure or rig
- CT equipment
- Well control equipment
- Pumping equipment
- Mud storage and treatment equipment
- Pipe handling equipment
- Ancillary surface equipment
- Monitoring and recording equipment
- Safety and emergency equipment
- Rig camp and wellsite facilities

4.1 Rigs and Structures for CTD

Coiled tubing drilling is performed with the support of conventional rotary rig masts and substructures, and with specially designed substructures and jacking systems developed for CTD. For obvious reasons, substructures designed specifically for CTD offer the greatest potential for efficient CTD operations.

4.1.1 CTD Substructures and Jack Systems

On specialized CTD rigs, the functions of the draw-works, crown block, travelling block and drilling line are replaced by the injector head and jacking system . The rotary table function being replaced by a downhole motor.

4.1.2 Location Requirements

New wells

The location is typically required to be as small as possible, currently 25m x 32m (Fig. 16) is the minimum foot print of a CTD rig. A conductor pipe must be driven prior to the rig mobilization. A small cellar around the conductor will help collect mud and water spills when tripping.

The wellsite requires minimal preparation, basic grading and levelling generally being sufficient. Provision for guy cable anchor points may be required (depending on the configuration of the selected equipment).

Re-entry wells

The location has already been established and is generally larger than is required.

Offshore wells

The selection and placement of CTD equipment is constrained by the space and handling capability of the rig (semi) or platform. Tender assisted operations can simplify equipment placement. Basic considerations for offshore location planning include the following:

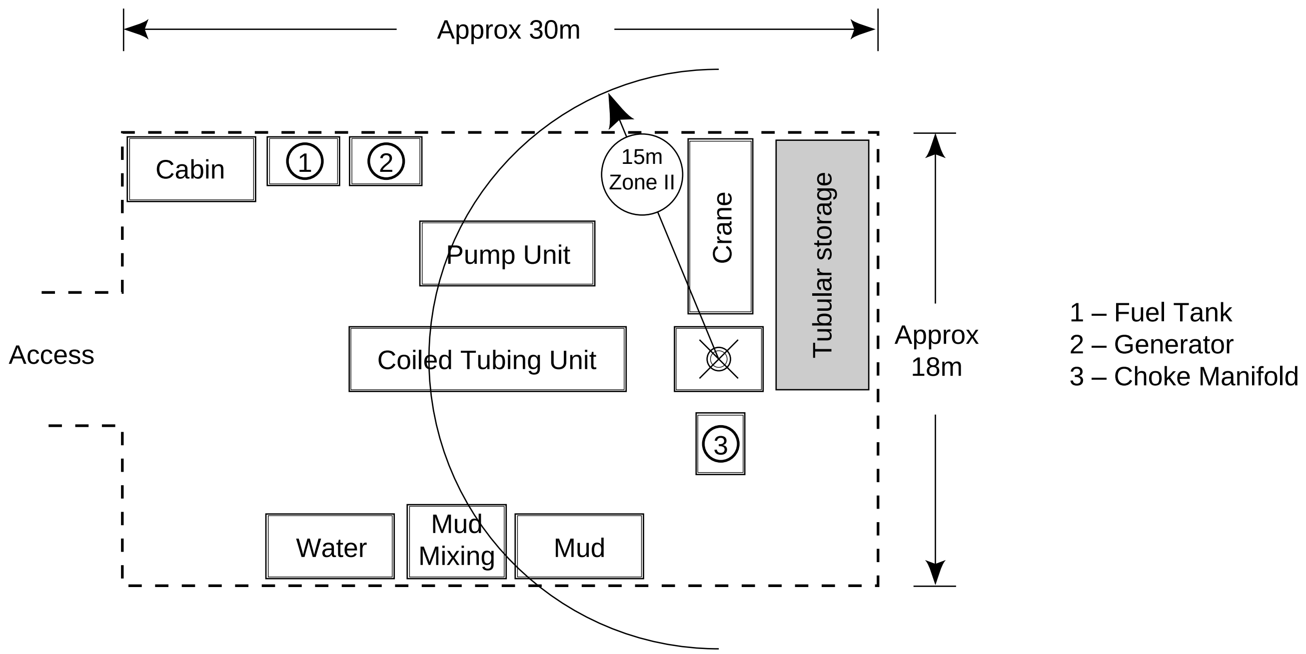

Figure 16a. Typical CTD equipment and location layout – minimum footprint

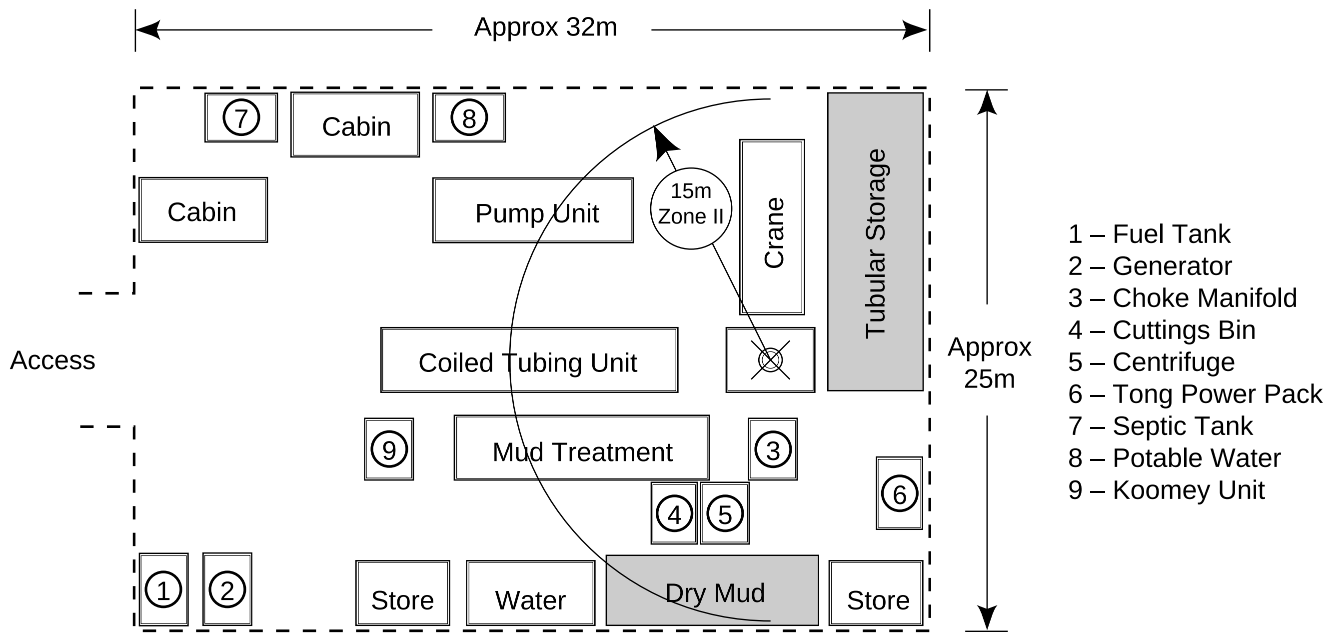

Figure 16b. Typical CTD equipment and location layout – heavy set up

- Exact dimensions of available space, including details of areas effected by zoning requirements (Zone I or II).

- Deck load capacities, including location of load bearing beams or restricted areas.

- Details of the crane capacity and boom extension capability.

4.2 CT Equipment Package

- Coiled Tubing – for new and directional wells, CT sizes of 1-3/4, 2 or 2-3/8-in. are required. A wall thickness of at least 0.156-in. manufactured from 70,000 or 80,000 psi yield strength material is recommended.

  For sidetracks, determine the optimum size, wall thickness and yield strength through CoilCADE simulation. For simple well deepenings 1-1/2-in. CT can be used in certain circumstances.

- Injector Head – for new and directional wells, a minimum of 60,000 lbf pull capacity is recommended. For well deepening a 40,000 lbf capacity injector head may be used if conditions allow. A 72-in. radius gooseneck is required for 1-3/4-in. and larger CT.

- Reel – the reel capacity (string length) and weight should be confirmed. A reel core expander may be required for 1-3/4-in. and larger CT.

- Powerpack – If nonstandard equipment (e.g., high capacity injector head) or auxilliary equipment is to be powered by the CTU powerpack, confirmation should be made that the output of the power pack is adequate and that the pressures and flowrates are compatible.

- Crane – for onshore operations, an independent crane truck is preferred to an integrated crane CTU trailer. Boom length must be sufficient to handle a 40 ft pipe/BHA over the substructure.

- Wireline (for directional drilling with wireline) –A mono cable is needed for the Baker Inteq or ENSCO or Drilex steering tool operation. A Hepta cable is required for the Anadrill Cobra wire line BHA.

The CTL* reel will be equipped with normal reel collector and pressure bulkhead equipment.

4.3 Well Pressure Control Equipment

- BOP size and pressure rating – the BOP size or bore depends on the hole or planned completion size. Two BOP sizes commonly used are 4-1/16-in. and 7-1/16-in. In special cases 11-in. BOPs are used. For most CTD applications, a 5,000 psi pressure rating is adequate but the operating pressure rating must exceed the expected bottom hole pressure.

- 4-1/16-in. 10,000 psi quad-ram BOP– standard for CTD operations (Fig. 18).

- 7-1/16-in. ram BOP – found in single or double, shear/seal or ram configurations. The shear rams can shear the 3-in OD BHA components.

- Annular BOP/CT stripper – for CTD, the only function of this BOP is to close on the BHA when tripping the BHA or on the liner if a double ram BOP is to be used. Alternatively, an accepted drilling practice is to drop the BHA in the hole in case of a kick while tripping the BHA. However, local regulatory agencies generally ask for one annular BOP. Annular BOPs are available in 4 -1/16 and 7-1/16-in. sizes.

- Kill line – used to kill the well by pumping through/down the annulus.

- Choke line – used to divert the flow to the choke manifold while controlling a kick and choking wellbore returns.

- Choke manifold – pressure rating must be consistent

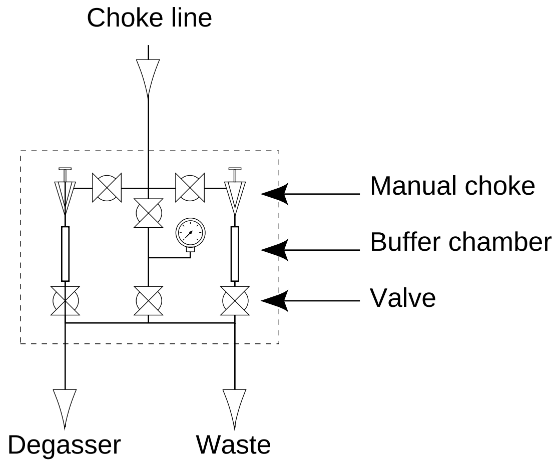

Figure 17. Choke manifold configuration.

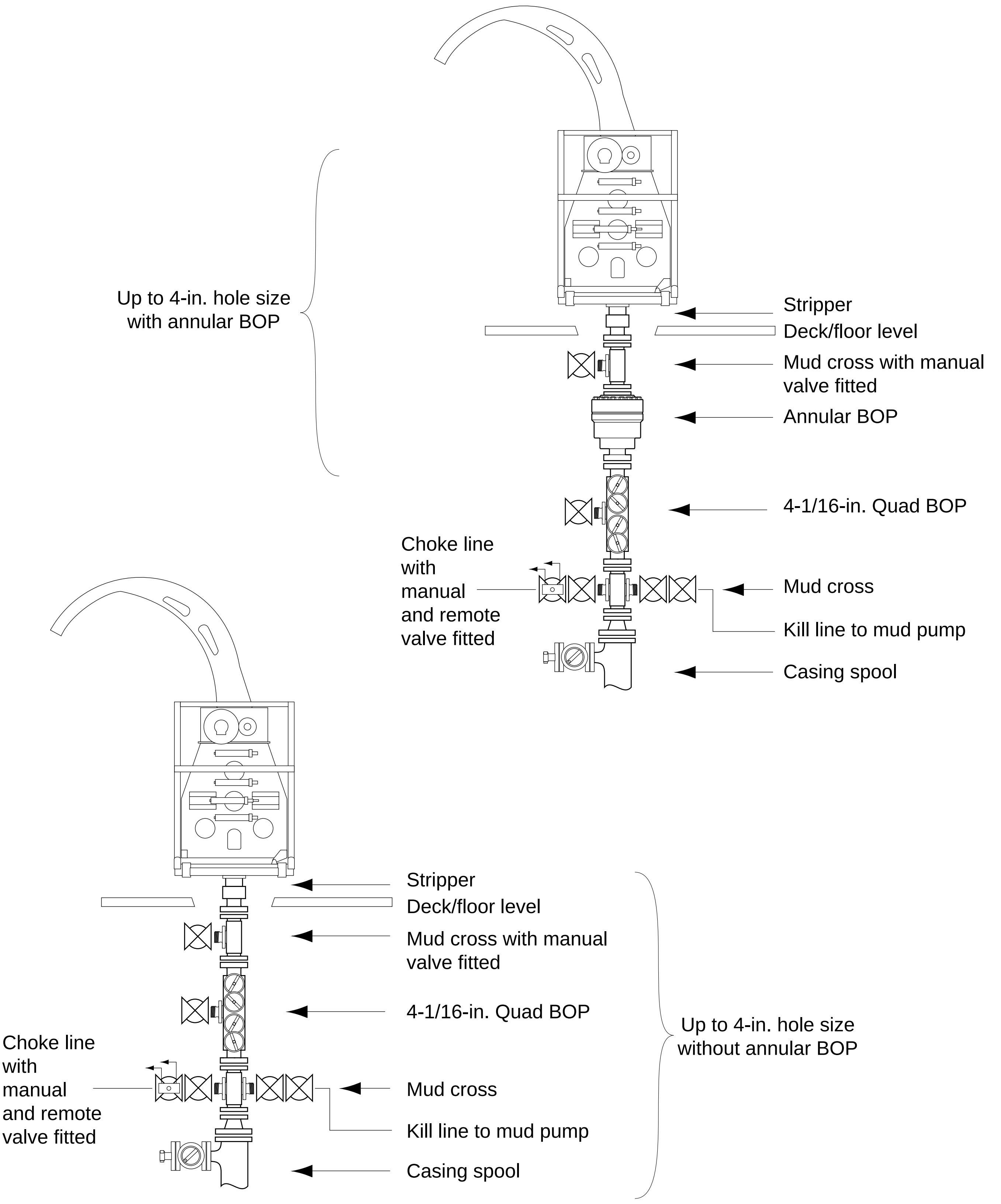

Figure 18a. Typical well control equipment configurations – for hole sizes up to 4-in.

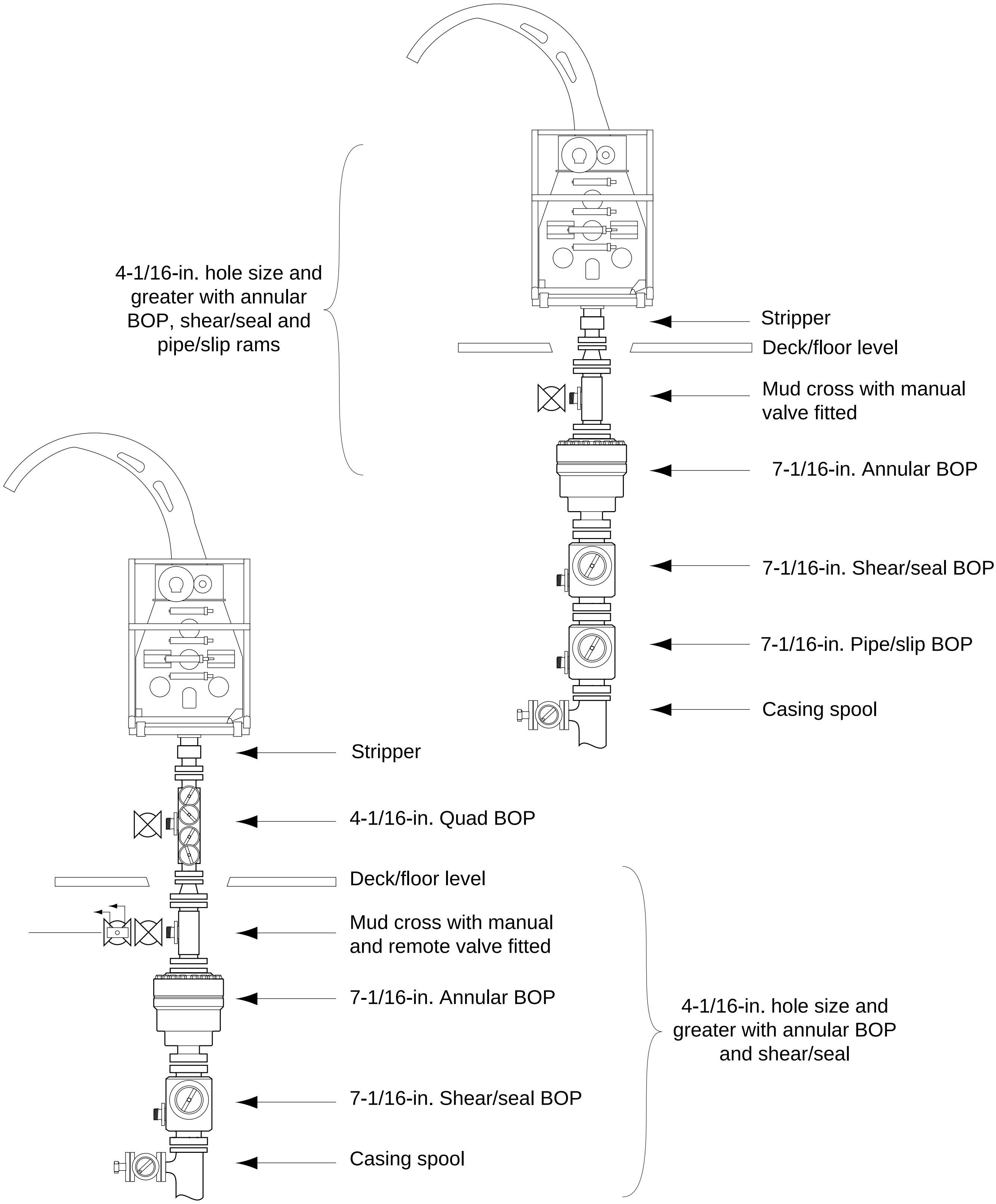

Figure 18b. Typical well control equipment configurations – for hole sizes 4-1/16-in. to 6 3/4".

with the BOP rating. The manifold must be a drilling type choke manifold with two manual chokes and one pressure gauge (some applications may require a remote operated choke). This equipment is as important as the BOP for the rig safety (Fig 17).

• Mud return line – normally not part of the well control equipment but when using two BOP stacks, the mud return must be closed if it is necessary to shut in the well. This is achieved with a remote operated valve installed on the outlet of the mud return mud cross.

• BOP controls and instruments – the stripper and BOP are controlled from the CT unit control cabin.

For the 7-1/16-in. BOPs and the remote operated valves on the mud return or choke lines, the control position is located on the accumulator or Koomey unit that must be positioned next to the CTU cabin. Remote controls between the Koomey unit and the CTU BOP command panel can be adapted if necessary.

4.4 Kick Detection Equipment

When drilling overbalanced, rapid detection of kicks or losses is essential in slimhole drilling applications. There are two common methods used in kick detection systems. Both have advantages and disadvantages when used in CTD operations.

• Flow comparison (flow in vs. flow out)

• Mud tank level monitoring

4.4.1 Flow Comparison

One of the best ways of detecting a flow variation, is to have a flow meter on the pump suction and one on the wellbore return line. The flow difference (Δ flow) is monitored and recorded versus time. A Δ flow increase indicates a kick, while losses are indicated by a drop in Δ flow.

A mud-pump stroke counter and a flow meter fitted on the mud return line can also provide adequate data for flow comparison. The outputs of both devices plotted versus time can give a reasonable indication. However, an assumption of constant pump efficiency must be made. A variety of flowmeters are available for this application. A low-pressure electro-magnetic flow meter like the Dowell Mag Flow can be used on the return line.

4.4.2 Mud Tank Level Monitoring

While in principal this system is simple, it is only efficient if the tank section is small enough to enable a small volume variation to be detected. An accurate monitoring and recording system is needed to provide a suitable display. A general trend versus time display format is required, a digital display is not sufficient. The Martin Decker-Totco sensor system is currently recommended.

4.5 Mud Sytem

4.5.1 Mud Tanks

There are three types, or functions, of mud tank, i.e., settling, active and reserve. Additional tankage or storage facilities may be required for water (Fig 19).

Settling tank

This is the first tank through which the wellbore returns pass. The shale shakers (where fitted) willl normally be located above this tank. An overflow system from the settling tank passes to the the active tank. The settling tank volume is typically 10 to 15 BBL for 2 to 3 bbl/mn flow rates. A large (butterfly) valve is generally fitted to the base of the tank to allow easy removal of the accumulated solids.

Active tank

The active,or suction, tank stores the drilling fluid and supplies the mud pump suction. If continuous treatment or additive is required it may be added to this tank. The tank volume is generally around 50 BBL for 2 to 3 bbl/mn flow rates. This allows a mud volume buffer to help stabilize the mud characteristics. Smaller volume active tanks may be used, however, key fluid parameters such as viscosity and density can vary quickly if the mud volume is small.

The active tank suction is manifolded to allow recirculation and precharging of the high-pressure pump. In addition to the recirculation line, a tank agitator is required to maintain the homogenity of the fluid.

Reserve tank

The reserve tank(s) are used to store a reserve of drilling fluid and also provide a facility for mud treatment or preparation. Ideally, the reserve mud volume should be equal to the hole volume plus the active and settling tank volumes. However, this may be reduced if the well type

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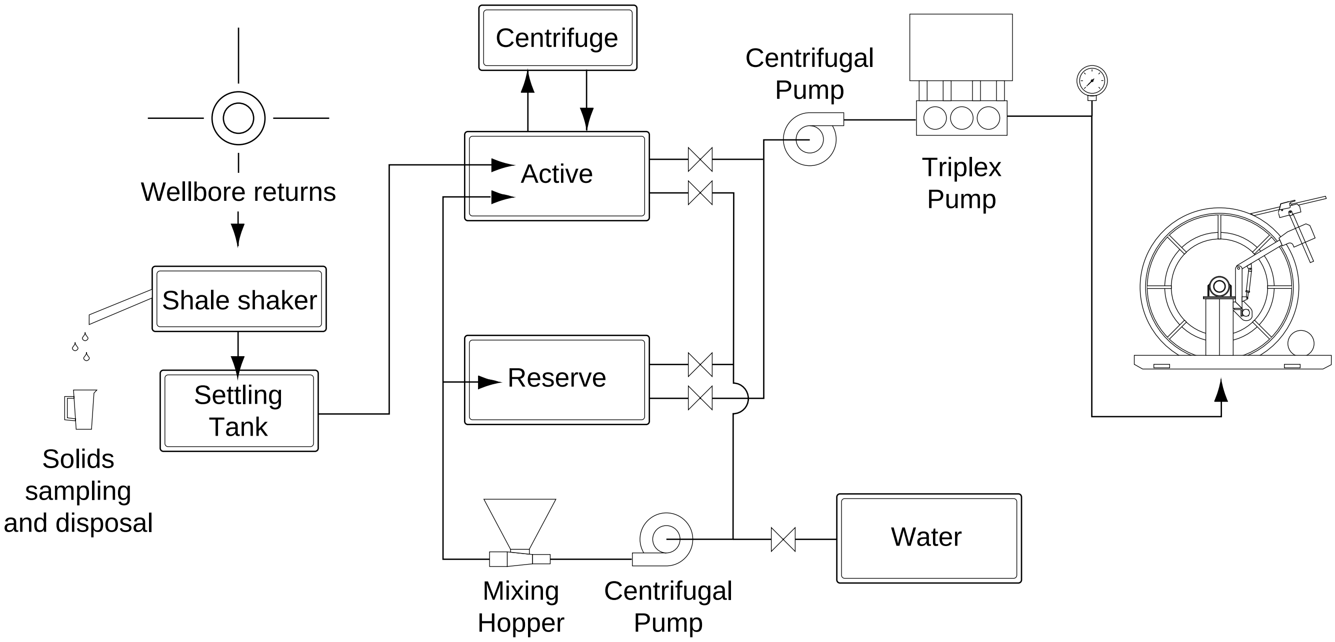


Figure 19a. Typical configuration of drilling-fluid equipment – overbalanced operations.

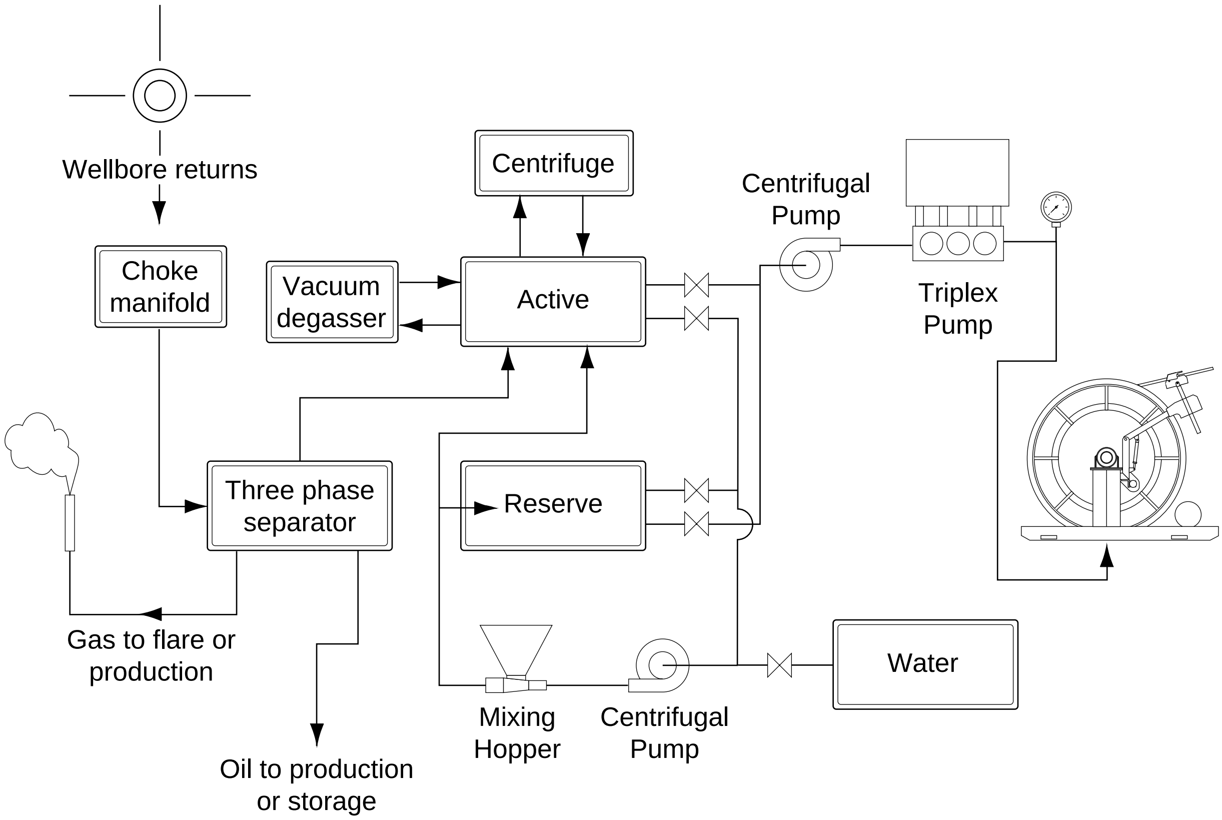


Figure 19b. Typical configuration of drilling-fluid equipment – underbalanced operations.

(exploration or development), downhole pressure or risk of losses allow. Approximately half to one third of this volume can be provided in re-entry of depleted reservoir wells. Similar to the active tank, the reserve tank should be fitted with a recirculation and agitation system to allow conditioning of the mud.

4.5.2 Mud Treatment Equipment

Shale shaker

A shale shaker is necessary for exploration wells to get rid of the large cuttings produced in the top hole section and to collect cuttings for geological analyses.

CTD operations on re-entry wells often do not require shale shakers because of the very small cuttings generated by the high-speed bit/motor combinations. Short well deepenings, can generally be performed without a shaker.

Centrifuge

The centrifuge is an essential item for most CTD applications except short well deepening and shallow new wells. The centrifuge removes very fine cuttings and avoids their recirculation, which would in time increase the drilling fluid density. Any uncontrolled variation in fluid density and solids content can increase the risk of sticking or wellbore instability.

Gas Separation System

Two types of mud degassing equipment is commonly used (similar to conventional drilling operations).

• Poor boy degaser – located on the mud return line, it knocks out gas using a system of baffles. The resulting gas is vented from a stack designed to route gas away from work areas.

• Vacuum degaser – creates a partial vacuum in a closed tank to knock out remaining gas. This system requires an additional centrifugal pump. Generally the two systems are combined for maximum efficiency.

Three phase separators

On underbalanced CTD operations, the mud returns are directed to the choke manifold then to a conventional three-phase production separator. The separated gas, oil and solids are then routed to disposal, production or storage facilities. The gas is either flared or sent to the production line. The oil is either sent to the production line or stored for later hauling. The residual solids are removed either periodically or upon completion of the project.

4.6 Pumping Equipment

4.6.1 Low Pressure Pumping Equipment

Low-pressure pumping equipment is necessary for transferring, mixing and conditioning the drilling fluid. In addition, the high-pressure pumping equipment requires low-pressure charge pumps to operate efficiently. An adequate pre-charge system is especially important if kick monitoring equipment is relient on the pump stroke counter for fluid inflow data.

A low-pressure manifold system is typically used with two low-pressure pumps to enable flexibility and redundancy (Fig. 19). The fluid mixing system typically comprises a hopper and jet mixing system supplied by fluid from a centrifugal pump.

4.6.2 High Pressure Pumping Equipment

The high-pressure pump specifications depend largely on the hole depth and diameter. For holes smaller than 4-3/4-in., it is unlikely the pressure will exceed 5,000 psi and a flowrate of 2.5 BPM. For larger holes, typically vertical exploration wells, the flow rate may be up to 6 BPM. Some redundancy in pumping equipment and capacity is generally required.

A high-pressure pump remote control panel is generally installed in the CTU cabin. This is necessary to alter or stop the pump flowrate for tool operation or orientation. In addition, close control of the CTU and pumping equipment is necessary if the downhole motor stalls.

High-pressure piping and manifolding is generally assembled from 2-in. treating line, chicksans and the necessary valves and accessories.

4.7 Monitoring & Recording Equipment

• Conventional CTU monitoring equipment – required to record the string cycle and pressure data for analysis with CoilLIFE. A TIM* device should also be regarded as critical monitoring equipment.

• Other monitoring recording systems like the PC based Prism 2 and 3 software provide real time acquisition, recording and display of the data from a variety of sensors. It provides the CT operator with digital display or plots versus time through bar charts or strip charts on a monitor in the CTU cabin and also allow data analysis in the CTU or in an office. It makes the CTD job safer (kick detection) and drilling more efficient (all parameters displayed versus time, show to the CT operator the trends, rate of penetration etc).

4.8 Pipe Handling Equipment

This pipe handling equipment is used for handling jointed pipes e.g. drill collars, tubing joints, casing joints etc.

• Tubing spider slips – used to hold the BHA or jointed tubing when making up or breaking two joints.

• Elevators – used to handle single joints of DC or tubing or casing.

• Safety clamps – used as a safety device to prevent the string from falling into the hole, if the slips do not hold and the string slides.

• Tubing power tong – used to make up or break the BHA, casing or tubing connections at the proper torque.

• Crane – used to handle single joints of BHA, casing or tubing. If necessary, it may be used to handle/run the whole BHA or casing string if within the crane capacity.

• Substructure and jacking system – used to pull or run a whole casing or tubing string. Has a 170,000 lbs pulling capacity–single joints are still handled by the crane.

4.9 Ancillary Surface Equipment

• Substructure – used as a drill floor when tripping the BHA and as a support for the injector head when drilling or tripping the CT.

• Generator – provides electricity to the portacabins, the flood lights, the centrifuge, the monitoring equipment, the koomey unit etc.

• Electrical distribution panel – provides electrical connection between the generator and the various electrical devices with all necessary breakers and safety features.

• Flood lights – to provide lights for safe and efficient operations at night.

• Air compressor – provide air to start the CTU engine if the tractor is not on location, or provide compressed air as needed.

• Miscellaneous – cutting torch and welding machine:

4.10 Safety and Emergency Equipment

• Emergency kill – emergency kill on the CTU engine and pump engines.

• Fire fighting equipment – CO_2 fire extinguishers on CTU power pack, pumping unit power pack, near the portacabins, near the fuel tank.

• H^{2S} protective equipment and gas detection equipment– generally provided by the operator.

• Eye wash station – located next to the mixing facility with a precharged tank filled up with treated water.

• Mud handling protective equipment – apron, goggles, long sleeve gloves for chemical handling.

• First aid kits.

4.11 Equipment and Consumables Chcklists

The checklists shown in Fig. 20 through Fig 21 are intended as a guide for the compilation of checklists for specific operations.

COILED TUBING DRILLING EQUIPMENT CHECKLIST

	Offshore Wells	Onshore Wells	Short Well Deepening	Other Wells	Provider (guide only)
Coiled tubing equipment					
CTU control cabin	X	X	X	X	Dowell
CTU Power pack	X	X	X	X	Dowell
CT injector head	X	X	X	X	Dowell
CT reel	X	X	X	X	Dowell
Jacking frame	As required	a/r	a/r	a/r	Dowell
Crane	As required	a/r	a/r	a/r	Dowell/client
Well control equipment					
BOP – Ram	X	X	X	X	Dowell/rental
BOP – Annular	X	X	X	X	Dowell/rental
Wellhead adapters	X	X	X	X	Dowell/rental
Mud cross	X	X	X	X	Dowell/rental
Riser and/or spacer spools	X	X	X	X	Dowell/rental
Accumulator unit	X	X	X	X	Dowell/rental
Choke manifold	X	X	X	X	Dowell/rental
Flowmeters	X	X	X	X	Dowell
Pit/tank level indicators	As required	a/r	a/r	a/r	Dowell/rental
Drilling fluid equipment					
CTD mud treatment unit	n/a	If available	-	X	Dowell
Alternative equipment–					Dowell
Remote controlled pump unit	X	X	X	X	Dowell
Settling tank	X	X	X	X	Dowell
Active tank (with paddle agitators)	X	X	X	X	Dowell
Reserve tank	As required				Dowell
Centrifugal pump and power pack	X	X	X	X	Dowell
Low pressure mixing hopper	X	X	X	X	Dowell
Pump unit (standby)	As required				Dowell
Drill water tank	n/a	X	As required	X	Dowell
Centrifuge	X	X	n/a	X	Dowell/rental
Cuttings bin	X	X	X	X	Dowell/client
Flareline	As required				Dowell/client
HP filter screens (Slim1)	X	X	n/a	As required	Dowell
Three-phase separator	As required	a/r	a/r	a/r	Well Testing
Vacuum degasser	As required	a/r	a/r	a/r	Dowell
Pipe handling equipment					
Jacking substructure	As required	a/r	a/r	a/r	Dowell
Power tong	X	X	X	X	Dowell/rental
Spider slips	X	X	X	X	Dowell/rental
Elevators and clamps	X	X	X	X	Dowell/rental
Lifting sub(s)	X	X	X	X	Dowell/rental

Figure 20a. Coiled tubing drilling equipment checklist.

COILED TUBING DRILLING EQUIPMENT CHECKLIST (continued)

	Offshore Wells	Onshore Wells	Short Well Deepening	Other Wells	Provider (guide only)
Ancillary surface equipment					
Substructure (if jacks not used)	As required	X	X	X	Dowell
Fuel tank and pump	n/a	As required	-	-	Dowell
Generator	As required	a/r	a/r	a/r	Dowell
Electrical distribution panel	X	X	a/r	a/r	Dowell
Cabin(s) (furnished)	X	X	a/r	-a/r	Dowell
Potable water tank	As required	X	a/r	a/r	Dowell
Lighting	As required	a/r	a/r	a/r	Dowell
Air compressor	As required	a/r	a/r	a/r	Dowell
Steam cleaner	X	X	a/r	a/r	Dowell
Location mats	-	As required	a/r	a/r	Client
Monitoring and recording equipment					
Totco monitoring system	X	X	X	X	Dowell
Dowell PAQ*	X	X	X	X	Dowell
Multi channel recorder	X	X	X	X	Dowell
Flowmeters	X	X	X	X	Dowell
PACR*	X	X	X	X	Dowell
TIM* device	X	X	X	X	Dowell
Safety equipment					
Emergency engine kill	X	X	X	X	Dowell
H2S safety equipment	As required	a/r	X	X	Dowell
Gas detection/monitoring equipment	X	X	X	X	Dowell
Fire extinguishers	X	X	X	X	Dowell
Sewage system (cabins)	n/a	As required	-	-	Dowell
Eye wash station(s)	X	X	X	X	Dowell
Casing/liner running equipment					
Elevators and clamps			As required	a/r	Dowell
Casing or liner joints			As required	a/r	Client
Casing shoe or float			As required	a/r	Client
Liner hanger			As required	a/r	Client
Running/setting tool(s)			As required	a/r	Dowell
Drill collars			As required	a/r	Dowell/rental
Drop ball sub				a/r	Eastman

Figure 20b. Coiled tubing drilling equipment checklist.

COILED TUBING DRILLING CONSUMABLES AND MISCELLANEOUS SERVICES CHECKLIST

	Vertical Well	Short Well Deepening	Sidetrack Well	Provider (guide only)
Equipment spares and consumables				
Pump parts	X	X	X	Dowell
Shaker screens	X	X	X	Dowell
Mud unit sparts	X	X	X	Dowell
CTU parts	X	X	X	Dowell
Well control equipment parts	X	X	X	Dowell
Fuel, oils and lubricants	X	X	X	Dowell
Drilling consumables				
Drill water	X	X	X	Client
Potable water	As required	a/r	a/r	Client
Diesel				Client
Mud products				Dowell/client
LCM	As required	a/r	a/r	Dowell/client
Cement (and additives)	As required	a/r	a/r	Dowell
Bits	X	X	X	Dowell/client
Core bits	As required	a/r	a/r	Dowell/client
Logistics				
Vehicles for crew	Onshore only			Dowell
Helicopter or crew boat	Offshore only			Client
Consumables haulage	X	X	X	Client
Vacuum truck	Onshore only			Client
Cuttings disposal	X	X	X	Client
Radio communications	As required			Client
Sidetracking equipment				
Whipstock	-	-	As required	Dowell/Vendor
Whipstock anchor	-	-	As required	Dowell/Vendor
Setting tool (s)	-	-	As required	Dowell/Vendor
Gyro/survey equipment	-	-	As required	Dowell/Vendor
Mill(s)	-	-	As required	Dowell/Vendor
Low-speed motor	-	-	As required	Dowell/Vendor
Logging tools and service				
CCL (for sidetrack KOP)				Schlumberger
CBL (for sidetrack KOP)				Schlumberger
Other services as required				Schlumberger

Figure 21. Coiled tubing drilling consumables and miscellaneous services checklist.

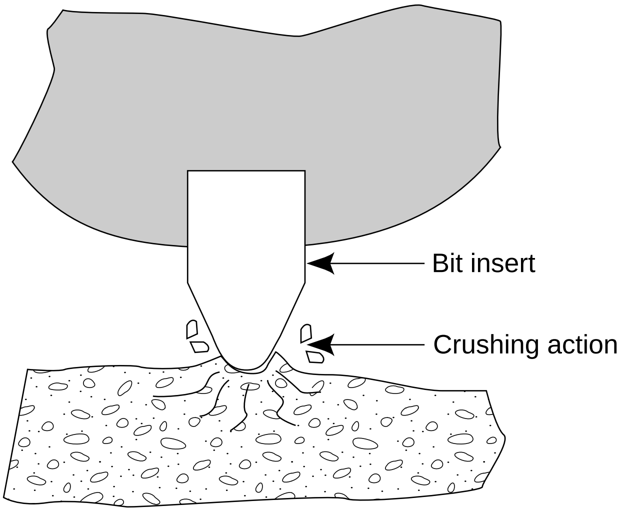


Figure 22. Rock bit cutting characteristis.

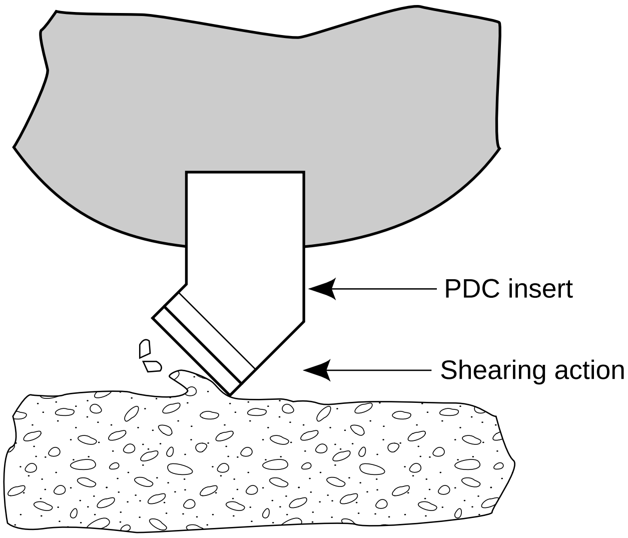


Figure 23. PDC bit cutting characteristis.

5 DOWNHOLE EQUIPMENT

The downhole tools and equipment required for any CTD project is dependent on the complexity and specific conditions under which it is to be completed. Most tools and equipment used in association with CTD may be summarized in the following categories.

• Bits

• Downhole motors

• Downhole CT equipment

• BHA for vertical well or well deepening
    -Drill collars

• Directional drilling BHA
    - MWD or WL steering tool
    - Monel, UBHO
    - Orienting tool

• Special BHA components
    -Drilling jars
    -Thruster
    -Underreamer

• Fishing tools
    -Overshots
    -Fishing jars, spears
    -Magnets, junk catchers

5.1 Bits

Depending on the hole diameter, two kinds of bits are typically used. For 4-3/4-in. holes and larger, rock bits, tricones or drag bits are used. For holes smaller than 4-3/4-in., drag bits are generally used.

The motor/bit combination for any application is critical and can drastically change the rate of penetration (ROP). The use of small downhole motors developing high RPM and little torque makes the drag bit selection difficult and it is recommended that selection is made by consulting bit manufacturers with the following information.

• Formation type, hardness and abrasiveness

• Torque developed by the motor (high torque motors are recommended)

• RPM of the motor

• Available WOB

• Drilling fluid type and flow rate

Experience in a particular area/formation is the best basis for recommendation of bit/motor combinations.

5.1.1 Rock Bits

Rock bits or tricone bits have three rollers with bearings that can be sealed or non sealed i.e. mud lubricated. There are two main categories, steel tooth bits and insert bits. Both are available in different tooth design to drill very soft to very hard formations, the insert bit life is generally longer and it is more expensive than the mill tooth bit.

Roller cone bits operate by crushing, gouging and deforming the rock (Fig. 22) with the drilling efficiency being dependent on the weight-on-bit (WOB). Rock bits or tricones are designed to turn at relatively low speed (generally not more than 150 RPM) and are not reliable for diameters smaller than 4-3/4-in. The risk of losing cones is high, especially when used in small diameters and with high RPM.

5.1.2 Drag Bits

Drag bits do not have any bearings or rotating parts and are designed to cope with the high RPM of the downhole motors. Two main types of drag bits are used: PDC bits (Polycrystalline Diamond Compact) and TSP bits (Thermally Stable Polycrystalline).

TYPICAL PDM SPECIFICATIONS

Hole size	**6-in. to 7-7/8-in**		**4-3/4-in. to 5-5/8-in.**			**3-1/2-in. to 4-1/8-in.**	
Motor OD (Nom in.)	**4-3/4**		**3-1/2**			**2-7/8**	
Motor type	**Low Speed**	**High Speed**	**Very Low Speed**	**Low Speed**	**High Speed**	**Low Speed**	**High Speed**
Maximum RPM	140 to 250	350 to 450	170	400	600 to 700	400	800
Operating torque (ft/lbf)	1500	950	700	500	300	300	200
Flowrate (gpm)	250	250	110	110	100	100	100
Max differential pressure (psi)	350	500	400	500	700	500	700

Figure 24. Typical PDM specifications.

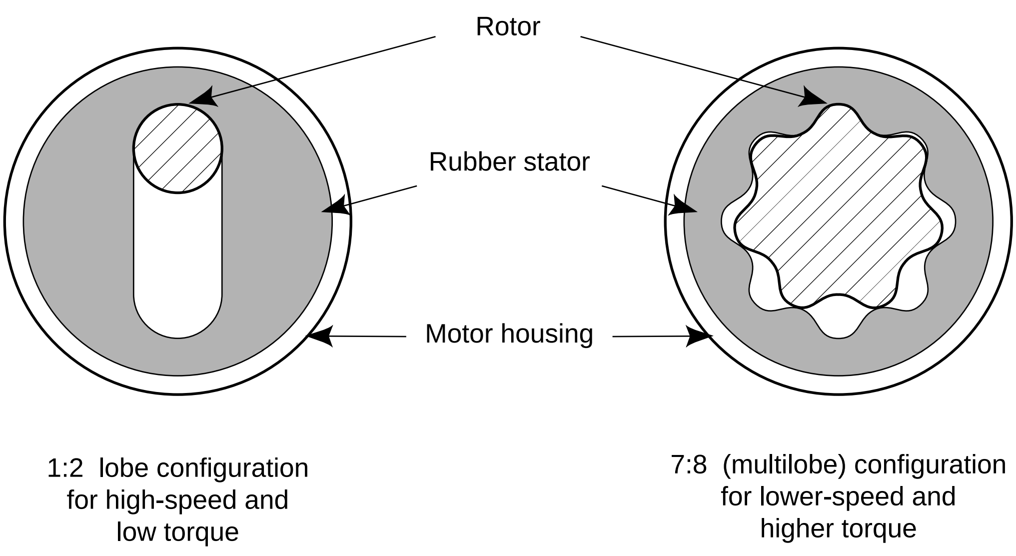


Figure 25. Typical PDM stator/rotor configurations.

PDC bits operate by shearing rock material much like the action of a machinists tool on a lathe. TSP bits have a similar cutting action, but are more tolerant of heat so are suitable for harder formations. However, the TSP bit cutting surface is significantly smaller than the PDC cutter, consequently penetration rates are typically less. In general, drag bits operate more efficiently with less WOB than roller cone bits but are more sensitive to rate of rotation.

Some drag bits, and all rock bits, are equipped with tungsten carbide nozzles that are interchangable and available in different diameters. The nozzles create a jet impact onto the formation and help clean the bottom of the hole. Most small drag bits do not have nozzles but have ports which give a jetting effect (Fig. 23).

5.2 Downhole Motors

There are three types of dowhhole motor; turbines, vane motors and positive displacement motors.

• Vane motors – there is limited experience with this type of motor. Currently, only one manufacturer continues to develop vane motors (Volker Stevin).

• Turbines – not yet available in small diameters.

• Positive displacement motors (PDM) – available in all sizes but especially small diameters.

5.2.1 Positive Displacement Motors

The basic specifications for PDMs relate to the following criteria.

• OD – the size of a motor has a direct bearing on most of the other criteria, e.g., larger motors output greater torque and require a greater flow rate (Fig. 24).

• Number of stages (stator and rotor lobes) – the number of stages define the type i.e. low or high speed (Fig. 25). In general, for a given size of motor, the greater the number of lobes,the higher the motor torque and the lower the output RPM.

• Maximum flow rate – each size of motor is designed to operate within a specific throughput volume of fluid. Multi-lobe motors typically have a wider flow range with a higher maximum allowable flowrate. This can be an important consideration which effects the hole cleaning ability for a given bit/motor combination.

The flow rate through motors is frequently used to characterise performance, e.g.,

• RPM versus flow rate.

• Operating torque versus flow rate.

• Maximum pressure drop – when a motor is operated off-bottom, a certain pressure loss is required to turn the rotor. This pressure loss and RPM is proportional to flow rate. A typical no-load pressure loss is ±100psi for motors used in CTD applications.

As WOB is applied, the pressure required to turn the rotor will increase. This increase in pressure is generally called the motor differential pressure (Pressure on-bottom – Pressure off-bottom).The motor torque-output is directly proportional to the motor differential pressure. For a typical 3-1/2 or 2-7/8-in multi-lobe motor the pressure drop across the motor can be 500 psi or more.

• Differential pressure at max operating torque – the power output curve of a PDM is parabolic (Fig.26). Although the operating characteristics of the motor will change with "operating hours" the same general performance profile will be maintained. All motors have a maximum recommended differential pressure. At this point, the optimum torque is produced by the motor.

• Maximum stall torque – if the WOB is increased sufficiently to cause the motor differential pressure to rise above the maximum recommended, a stall is

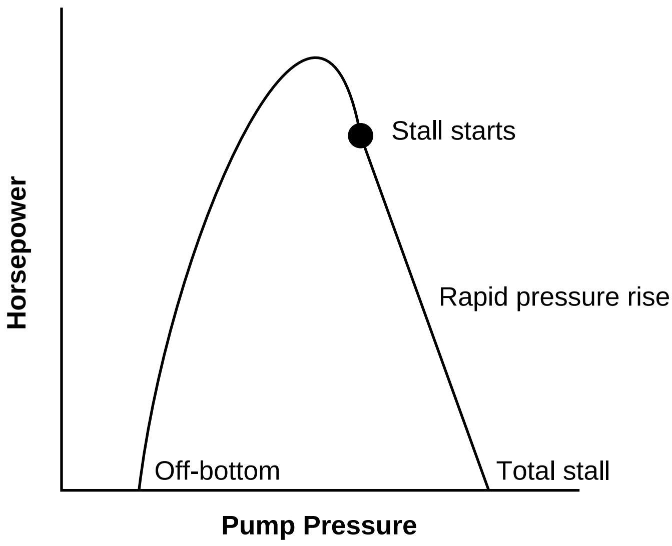


Figure 26. Typical PDM performance curve

likely. At this point, the stator distorts allowing some passage of fluid without turning the rotor, i.e., the drilling fluid flows through the motor without turning the bit. A sharp pressure increase will result, and no variation will be evident as further WOB is applied. The motor is stalled and severe damage will result if pumping continues.

Other specifications like maximum overpull and maximum WOB are generally not limiting parameters for CTD applications.

Recommendations regarding the selection of PDMs include the following.

• OD – select the largest possible motor size.

• RPM – select a low-speed high torque motor for slim holes, with the highest maximum torque rating for the given size. A high flow-rate is desirable to ensure adequate hole cleaning.

• Large motors (4-3/4-in.) – the maximum stall torque plus a 30% safety margin should be less than 80% of the maximum allowable torque of the CT string.

5.3 CTD Downhole Equipment

CT Connectors

After performing several jarring and pull tests of various type CT connectors, it is recommended that a grub screw connector be used for CTD applications.

Disconnecting subs

For CTD applications in large vertical hole (6-in. or greater), a pull disconnect release is recommended.

In re-entry wells or deep vertical wells, pull disconnects (such as Griffco) are not recommended due to very limited overpull margin it allows because of the drag.

For MWD applications, the Dowell/Anadrill drilling head, which includes a ball actuated disconnect, is recommended.

Wireline steering tool BHAs can include an electrically operated disconnect (Anadrill Cobra), or a pull disconnect with a fail safe (Baker Inteq BHA).

Check valves

Double flapper valves should be used on top of the pressure disconnect in case of disconnection in a kick situation (even if a float valve is installed on top of the motor).

5.3.1 BHA For Vertical Wellbores

The BHA required to drill vertical wellbores comprises conventional components, the larger versions of which are commonly used in conventional rotary drilling applications.

A typical CTD BHA for drilling vertical wellbores will include the items shown in Figure 27.

Drill collars are used to provide the weight on bit (WOB), with the CT being kept in tension at all times. This creates a pendulum effect which, in the majority of circumstances will maintain a vertical wellbore. Spiralled drill collars are recommended to minimize differential sticking–especially for slide drilling applications. The selection of drill collars of the appropriate size (OD) is dependent on the bit/hole size. The following recommendations are made.

Hole size	Drill Collar OD
>6-in.	4-3/4-in.
3-3/4 to 4-3/4-in.	3-1/8-in.
<3-7/8	2-7/8-in.

5.3.2 BHA for Deviated Wellbores

The BHA required to successfully drill deviated wellbores contains several specialized components which, in most cases, have been specifically developed for CTD applications.

There are no drill collars in this BHA. The weight on bit is provided by CT string, part of which will be in compression.

A typical CTD BHA for drilling deviated wellbores will include the items shown in Figure 28.

5.4 Principal Components of a Directional BHA

Directional BHA used for CTD are also called steerable systems. A steerable system provides the directional drilling engineer with data to enable information relating to the the tool face, wellbore inclination and azimuth to

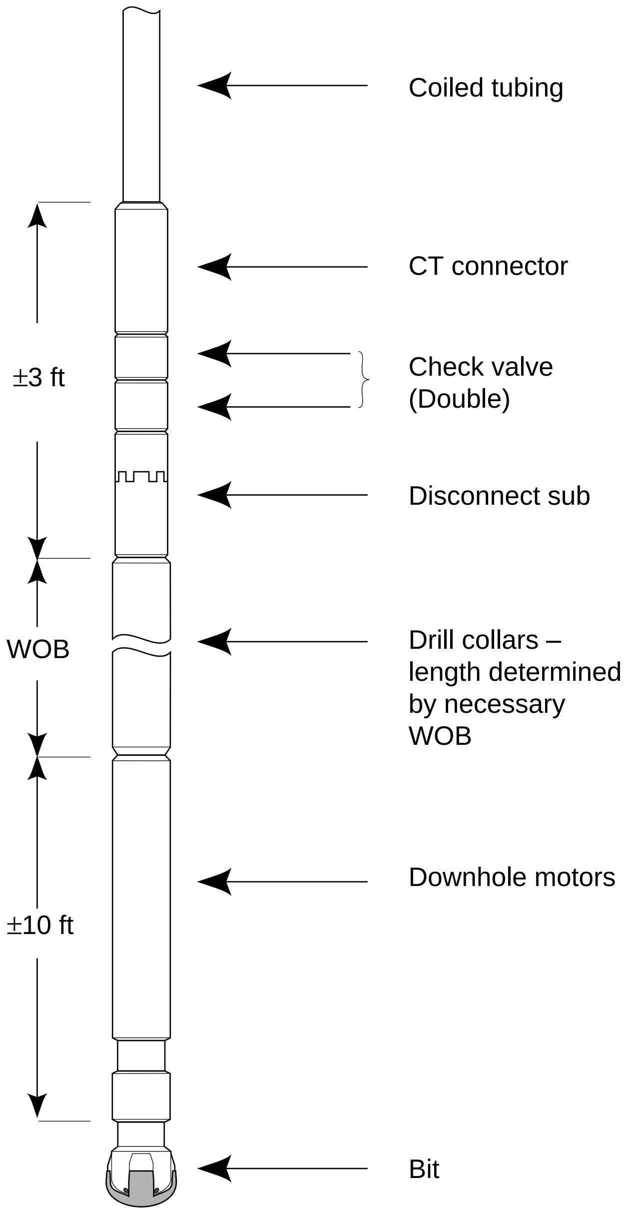


Figure 27. CTD BHA for vertical wellbores.

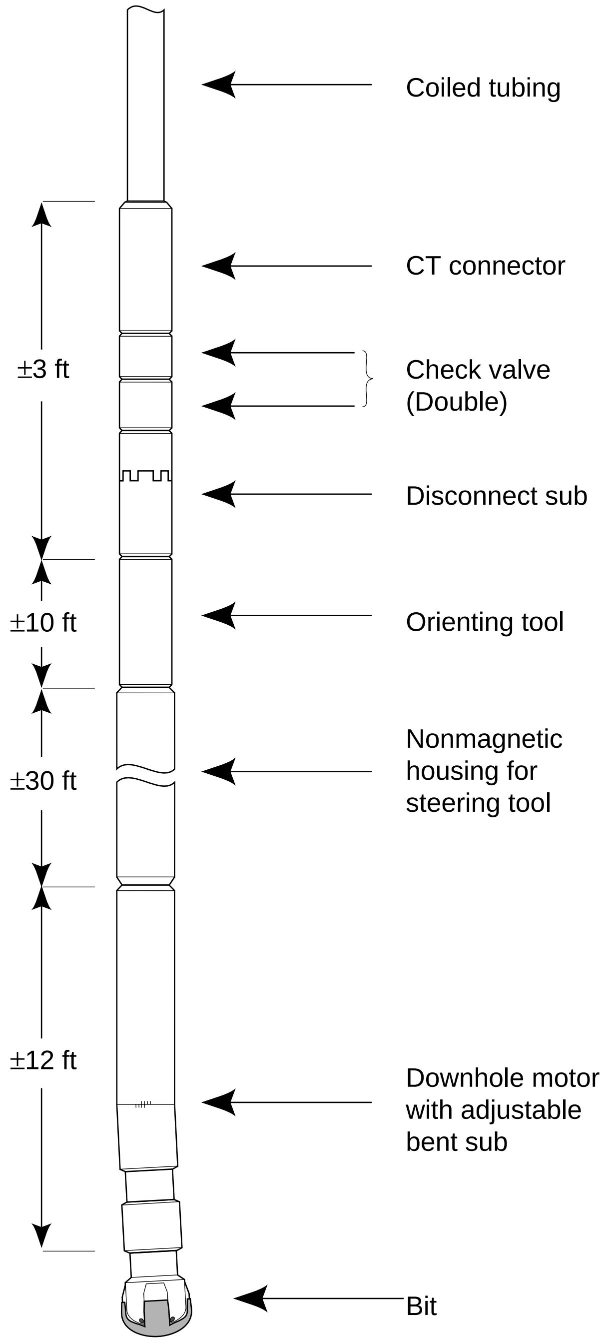


Figure 28. CTD BHA for deviated wellbores.

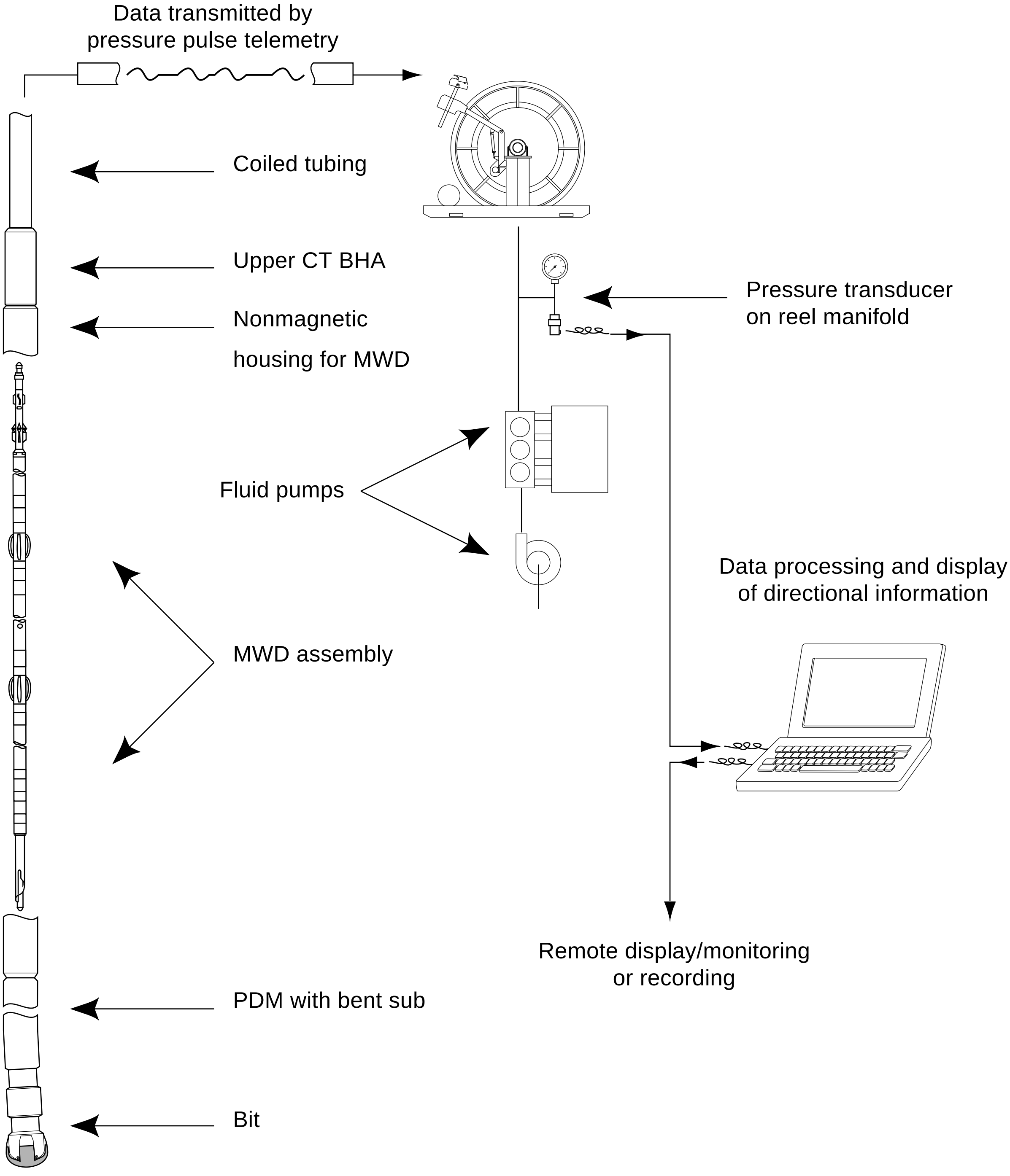


Figure 29. MWD system schematic diagram.

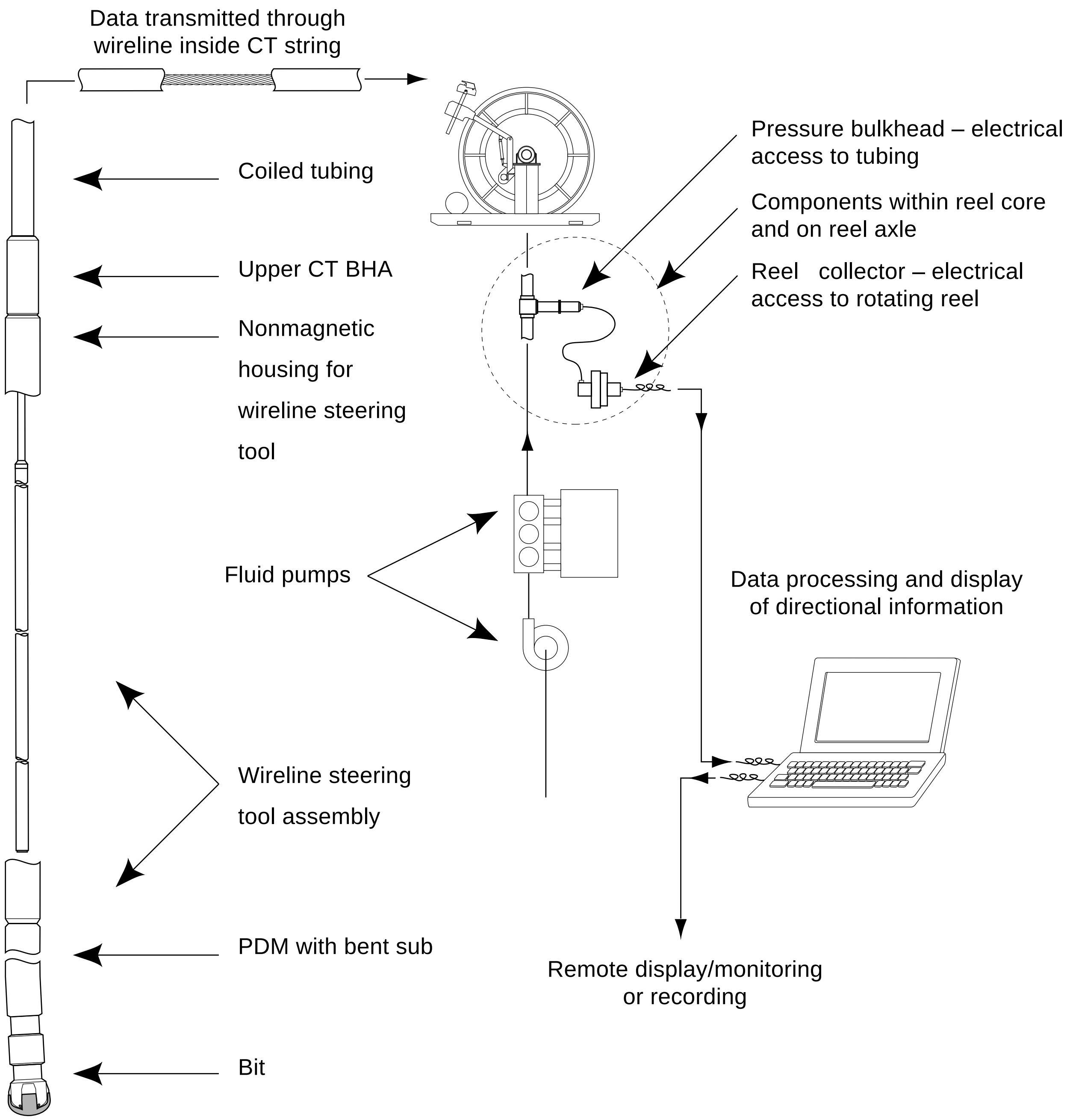


Figure 30. Wireline steering system schematic diagram.

be monitored and recorded. By combining this information with the measured depth of the wellbore, the progress of the wellbore can be compared, and if necessary corrections to the planned wellbore profile, can be made by changing the toolface i.e. the relative position of the bent housing to the low (or occassionally high) side of the wellbore.

Two steerable systems are commonly used in CTD applications:

• Wireless steerable BHA including a measurement while drilling (MWD) tool.

• Wireline steerable BHA including a wireline steering tool

MWD Tool/System

The MWD tool sends data to surface by inducing coded pressure pulses in the drilling fluid being pumped through the CT string. The signals recovered at surface are decoded and displayed using a PC.

A schematic diagram of the Slim 1 MWD system is shown in Figure 29.

The principal advantage of the MWD system is the absence of wireline and electrical connections which are a potential source of problems.

The disadvantage of the MWD system is the slow data rate, i.e., one tool face every 30 seconds, one survey (inclination and azimuth) every 30 minutes. However this is generally sufficient to control the trajectory of a CTD wellbore. Since the downhole components are sensitive to debris within the drilling fluid, it is generally necessary to use a high pressure filter system. This is typically located adjacent to the reel manifold.

Wireline Steering Tool

Wireline steering tools are basically the same type of tool as MWDs but data is transmitted to surface through a wireline. The advantage being the high data rate which provides almost real time measurement. However, the number of electrical connections required presents a number of potential problems (Fig. 30).

Some operating conditions, e.g., drilling with foams and gaseous fluids, preclude the the use of MWD systems since pressure pulses are absorbed by the fluid column. In such circumstances the wireline steering system and associated toolstring must be used for directional control.

Monel – Nonmagnetic Drill Collar

A non magnetic tubular is required to house the steering tool assembly. This typically comprises two 15 ft sections of 3-in. OD drill collar made of non magnetic material to limit magnetic interference.

Orienting Tool

An orienting tool is necessary to change the orientation of the tool face. The MWD system incorporates an orienting tool which rotates in 30° increments. This tool can only be used with a wireless steering system. Similar orienting tools are available to be used with wireline steering tools (Sperry Sun and other vendors). They generally provide a low torque, with the toolface correction being made off bottom.

Three main types of orienting tool are currently available

• Pump actuated orienting tools

• Electrically operated orienting tools

• Hydraulically operated orienting tools

Pump actuated orienting tools

The first generation Dowell Anadrill CTD orienting tool is an indexing tool which is actuated by shutting down the pump, then resuming circulation. Each cycle causes the lower section of the tool to rotate 30°.

Electrically operated orienting tools

A wireline provides electrical power to a DC motor in the orienting tool which drives a gear train (Dowell, Anadrill, Cobra) or a hydraulic pump (Baker Inteq) to adjust the tool face angle.

These orienting tools provide high torque and allow tool face correction while drilling. Alternative tools are operated or controlled by electrical or hydraulic systems through cables or conduits installed in the CT string.

•Hydraulically operated orienting tools

A hydraulic orienting tool is operated via hydraulic control line(s) installed in the CT workstring (Camco and Transocean)

5.5 Specialized CTD Tools

Float Sub

The float sub (where fitted) is installed above the motor to prevent wellbore fluids from entering the BHA and workstring. The internal valve closes in the event of a kick or underbalanced drilling situation. A Baker 1R float installed in a 3-in. OD sub is recommended.

Drilling Jars

It is recommended that drilling jars are included in a CTD BHA if there is a risk of sticking through formation instability of differential pressure.

Underreamers

There are two common conditions in which underreamers enable a larger hole to be drilled. In through tubing applications where a fixed restriction limits the bit size, and in conventional applications where the CT string cannot provide the necessary WOB. It is not generally recommended that drilling and underreaming are undertaken at the same time. Instead, it is preferable to drill a pilot hole which is then underreamed to the desired size.

The underreamer is positioned in the BHA above the bit or bullnose.

Thruster

Thrusters were developed to avoid the consequences of the heavy vibration, which is typical of equipment used in slimhole applications. The thruster dampens vibrations and equalizes the WOB.

Fishing Tools

A selection of fishing tools should be prepared for, or at least be on stand-by during CTD operations. The nature and size of the fishing tools will be dependent on the CTD BHA to be used and the anticipated downhole conditions. Fishing tools may be needed at any time, appropriate contingency plans should be prepared during the well planning phase of the operation.

A typical fishing tool selection will include the following items.

- GS fishing tool (or similar) – to suit the fishing neck of the release joint being used.
- Overshots and spears – available in a variety of sizes and configurations to suit the toolstring in use.
- Junk catchers and magnets – Appropriate precautions must be taken at all times to avoid the introduction of junk to the wellbore. In addition, it is recommended to have fishing tools for small items and junk on site at all times.

6 MANUFACTURERS AND SUPPLIERS

The following sections lists manufacturers and suppliers of equipment and tools which can be required during CTD operations. This is prepared for information purposes and does not necessarily constitute a recommendation or preference. In most cases, it is the ability of available suppliers to provide a reliable and efficient service that determines the ultimate choice of equipment.

Bits
- Baker Hughes
- Security
- Hycalog
- Smith

Motors
- Anadrill
- Drillex
- Baker
- Black Max

Steeriable CTD systems
- Dowell Anadrill wireless BHA (with Slim 1)
- Dowell Anadrill wireline Cobra BHA
- Baker Inteq (wire line system)
- Sperry Sun (wireless system)
- Camco (wire line system)
- Drillex (wire line system being devloped)

Fishing Tools and Equipment
- Tristate
- Enterra

CONTINGENCY PLANNING

1 INTRODUCTION

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 results in a worsening of the circumstances or problem. The potential risk to well security and personnel safety can be quickly compounded in such circumstances. Therefore, contingency planning, in some form, must be part of every Dowell CT operation.

The level of contingency planning will generally reflect the conditions, potential hazards and/or complexity of the intended operation; i.e., 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.

The role of contingency planning in CT services is illustrated in *Fig. 1* and defined below. The following definitions should be understood by personnel involved with the design or execution of Dowell CT services.

- Normal Operating Procedures — Procedures prepared to ensure correct execution of the intended operation in a safe manner. Job procedures or guidelines must be prepared for every CT operation, and will generally comprise a sequence of actions, checks or controls.

- Contingency Plans — Contingency plans should be prepared as a reference source to be used as a guide in the event unplanned conditions are encountered during an operation. By necessity, some plans may include emergency procedures required to maintain control of well pressure or surface equipment. However, CTU operators must be fully familiar with such emergency procedures, and be capable of conducting them without reference to prepared plans or procedures.

- Emergency Procedures — Emergency procedures may be defined as immediate responses to conditions which threaten well security, or personnel safety. Such responses are enacted as a result of detailed training, familiarity with equipment and executed with the knowledge and awareness of the wellbore and operational conditions.

In each of the above, consideration must be given to three key areas of responsability.

• Well Security

• Personnel Safety

• Equipment, Tools and the Intended Operation

As a supplement to any contingency plans, the source and availability of any special equipment or services should be noted (e.g., chemical cutting services).

2 CONTINGENCY PLANNING

Due to the high number of variables, it is impractical to detail all aspects of contingency planning required for CT services. The following guidelines are provided to assist with the preparation of contingency plans which should be specifically designed for each operation or campaign.

Several actions outlined in the contingency plans involve the participation of additional personnel or departments (e.g., The involvement of production facilities and personnel when flowing a well to reduce wellhead pressure). Therefore the requirements, and/or limitations, of related facilities and personnel must be considered during the preparation of contingency plans.

For the purpose of presentation the contingency guidelines are categorized as follows.

• Workstring Integrity

• Stuck or Damaged Workstring

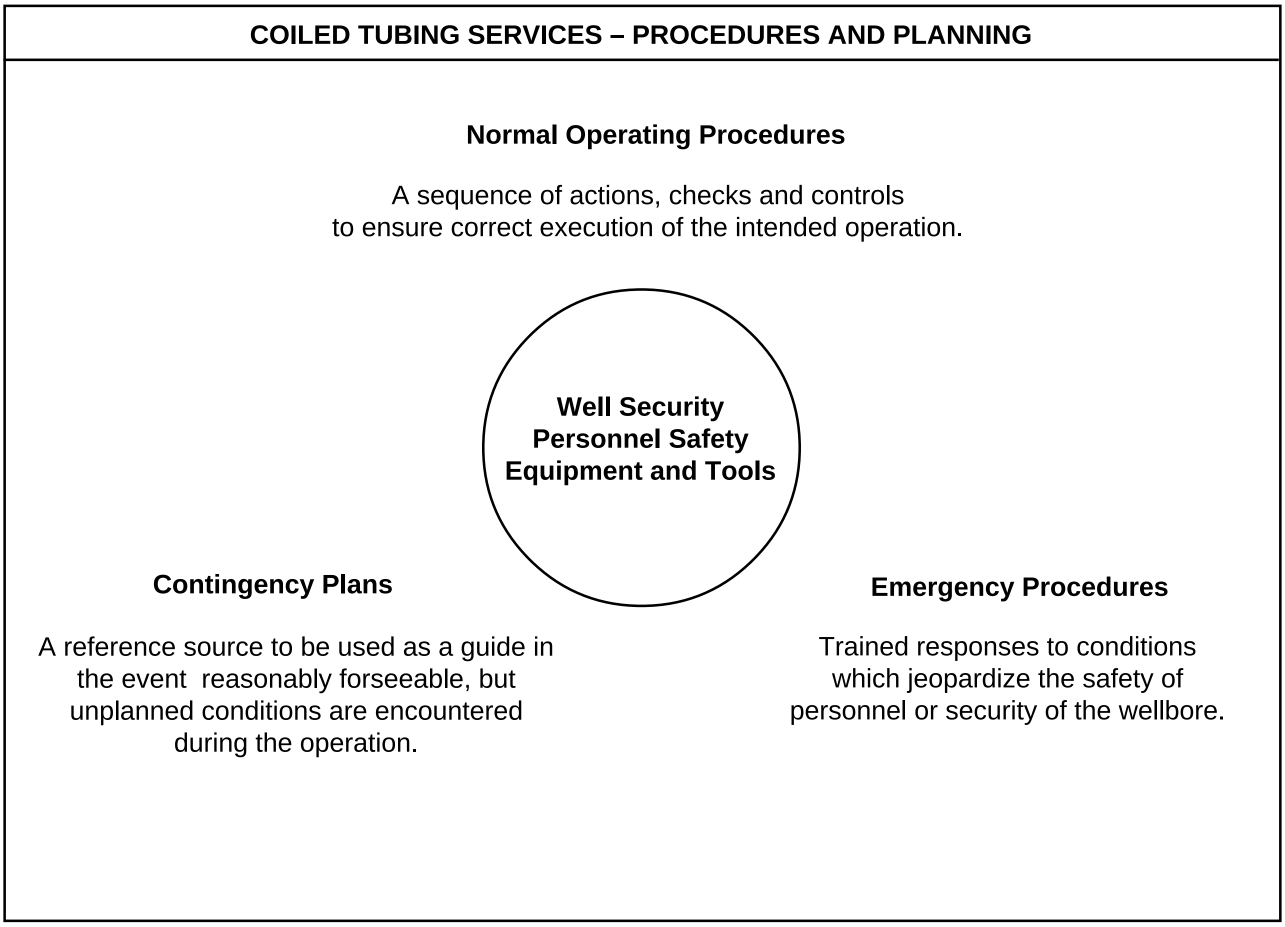


Figure 1. Coiled tubing services contingency planning

• Pressure Control Equipment

• Coiled Tubing Equipment

• Operational

2.1 Workstring Integrity

The introduction of fatigue tracking and reel history recording methods has significantly reduced the number of workstring failures and leaks. Nonetheless, fatigue, corrosion and mechanical damage can result in tubing leaks of varying severity. Regardless of the cause, workstring leaks are unacceptable, and must result in the suspension of the operation pending repair or replacement of the workstring.

2.1.1 Leak at Surface

The presence of 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.

Most leaks are discovered while pulling out of the wellbore. However, the actions taken should be identical regardless of tubing direction.

a. RIH to place leak between the stripper and the BOP pipe rams. The well is now secure, allowing time to consider subsequent actions.

b. The next step is dependent on the type of fluid in the workstring.

Nitrogen - Calculate the effect of bleeding the workstring internal pressure to zero, considering the likelihood of collapsing the tubing under bottom hole conditions with (a) nitrogen in the string, and (b) water in the string.
(i) If tubing collapse is unlikely with nitrogen in the string, proceed to step (c).

(ii) If tubing collapse is likely with nitrogen in the string, prepare to displace the workstring to water.

Acid or Corrosive Fluids - Displace the workstring to water. Consideration must be given to exposing the pressure control equipment to the acid or corrosive fluids at the leak point.

c. Note the weight indicator reading and wellhead pressure before closing the slip rams and the pipe rams.

d. If applicable, consult with production personnel in preparation of (i) flowing the well to reduce the wellhead pressure, or (ii) commencing well kill operations.

Note: When flowing the well with CT in place, consideration must be given to the pressure drop across tools (e.g. packers) and the resulting forces.

e. Bleed off workstring pressure to check the operation of the check valves. If check valves are not fitted, see (k.) thru (s.). Observe reel inlet pressure and the wellhead pressure (the CTU wellhead pressure sensor will indicate the pressure at the leak point).

f. When check valves are confirmed as holding, prepare to retrieve the workstring.

If check valves do not appear to hold, see (k.) thru (s.)

g. If possible, circulate clean water to leak point prior to equalizing pressure across the pipe rams.

h. Open the pipe rams and slip rams.

i. To avoid further damage or complete failure of the tubing minimize the internal pressure/pump pressure in the tubing as it passes over the gooseneck and reel.

j. Continue to slowly circulate clean water as the workstring is retrieved. Personnel must keep clear until the weakened area is safely spooled on the reel. Paintmark/flag the leak area after it is spooled on the reel.

Check valves not fitted or are passing.

k. If the tubing leak is considered minor, prepare to retrieve the workstring. If the leak is considered significant see (p.) thru q.

l. Circulate clean water to leak point prior to equalizing pressure across the pipe rams.

m. Open the pipe rams and slip rams.

n. To avoid further damage or complete failure of the tubing minimize the internal pressure/pump pressure in the tubing as it passes over the gooseneck and reel.

o. To avoid migration of well fluids continue to slowly circulate clean water as the workstring is retrieved. Personnel must keep clear until the weakened area is safely spooled on the reel. Paintmark/flag the leak area after it is spooled on the reel.

Severe leak - check valves not fitted or are passing.

p. If the tubing leak is considered severe, prepare to kill the well.

q. If possible, kill the well leaving the workstring intact. Use the workstring to circulate kill weight fluid.

2.1.2 Parted Tubing at Surface

There are two major concerns associated with the workstring parting on surface. One issue is well security and the presence of a tube extending through the wellhead. However, an instantaneous hazard exists as the free end(s) of the tubing react to the workstring internal pressure. Operator reaction to such events should be instinctive.

a. Stop injector head and shut down pumping equipment.

b. If the tubing has parted and fallen through the stripper BOP, (typical overpull break) close the blind rams to regain control of the well. Shut in well, as allowed by position of tubing, and prepare for well kill and or fishing.

If the tubing is supported by the chains, close the slip rams and pipe rams.

c. Confirm that the check valves are holding. If check valves were not used, or are passing, close the shear rams, withdraw the tubing stub and close the blind rams to regain control of the well.

d. Kill the well.

e. Withdraw sufficient tubing to allow a cold roll connector to be fitted. Retrieve the workstring.

2.1.3 Parted Tubing in the Wellbore

A workstring which has parted in the wellbore will generally be indicated by a sudden change in the weight indicator (weight loss) and/or a variation in circulating pressure. Attempting to tag a known restriction may confirm the tubing has parted, if the apparent depth is greater than previously noted.

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.

a. On suspicion that the workstring has parted in the wellbore, attempt to asses the length of tubing remaining. The loss of a heavy toolstring below the CT connector may give similar indications to a parted workstring.

b. Kill the well.

c. Slowly recover the remaining tubing. Close the blind rams when the stub has been withdrawn.

2.1.4 Plugged Tubing

Most CT applications require fluids to be circulated, either as part of the treatment or to maintain well conditions suitable for continuing the operation (e.g., to prevent tubing collapse).

2.2 Stuck Workstring

There are many ways by which a workstring can become stuck. In addition, the term stuck is often applied to a number of conditions all of which impede the progress of the CT operation (e.g., severe overpull or under-weight conditions, stuck down - free up, stuck up - free down, stuck up - stuck down)

Selection of the appropriate action or treatment to resolve the condition depends on several factors. The following points should be considered.

• Wellbore geometry

• CT toolstring geometry

• Presence of fines or small solids (circulatable) in wellbore or treatment fluids

• Presence of junk or large solids

• Characteristics of treatment, produced or wellbore fluids

• Stuck point assessment
An important aspect of CT operations in stuck or restricted-movement conditions is localized fatigue of the workstring. It is often instinctive, and frequently effective, to work the tubing string in and out of the wellbore in an attempt to pass a hang-up point. However, the localized fatigue which is induced as the tubing is cycled around the gooseneck and reel can rapidly lead to failure of the workstring.

The weight indicator response can be used 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.

The interval over which the weight loss is observed also can be used 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 penetration, or pull through, fill material.

2.2.1 Obstruction Going In-Hole

There are a number of conditions which hinder, or even prevent, the progress of the CT or toolstring into the wellbore. Determining the cause of such conditions is important, not only to allow the operation to continue, but to avoid the potential of worsening conditions which may ultimately lead to a stuck workstring.

The following conditions can hinder the progress of tubing or toolstrings being run into a wellbore.

Downhole

• Mechanical

Nipple or restriction profile hang-up
Collapsed or damaged well tubulars
Toolstring hang-up (e.g., centralizer or underreamer)
Severe dog leg
Deviation/lock-up

• Hydraulic

Piston effect in non-perforated wellbores
Piston/surge effect of close toolstring OD and production tubing ID (packers)
Differential sticking

• Fill Material

Produced sand or fines
Junk

• Reaction Products

Scales
Paraffin or asphalt deposits
Hydrates

Near Wellhead

• Mechanical

Incomplete opening of valves - (swab, master, lubricator DHSV/SSSV)
Wellhead or pressure control equipment profile
Toolstring hang-up (e.g., centralizer or underreamer)
Distorted tubing hanging-up in stripper

• Hydraulic

Piston effect in non-perforated wellbores
Piston/surge effect of close toolstring OD and production tubing ID (packers)

• Reaction Products

Scales
Paraffin or asphalt deposits
Hydrates

2.2.2 Stuck Coming Out-of-Hole

The techniques which can be used to free a stuck workstring are significantly hampered if the ability to circulate fluids is also lost. Consequently, at least a slow circulation rate should be maintained throughout the operation if the threat of annular plugging exists. Pump rates should be minimized while cycling the tubing to reduce the induced fatigue.

a. Attempt to work the string free - the string tension must never exceed 80% of the string published yield value.

b. Attempt to locate stuck point (see 2.6 Determining Stuck Point)

c. Analyse stuck-point data in conjunction with wellbore and toolstring details, treatment records and available information to determine the mechanism of sticking.

d. If a release joint or mechanism is included in the toolstring, and the stuckpoint is thought to be below the tool, prepare to activate the release.

In the absence of a release mechanism the techniques have been frequently used in successful recovery of stuck tubing strings. A moderate overpull should be applied to the tubing string as these techniques are tried.

• If stuck due to drag or fill, circulation of a slick fluid to the stuck point should be attempted to “lubricate” the tubing.

• Surging the well by rapidly bleeding pressure from the annulus can be effective.

• Circulating a dense fluid into the annuls while displacing the tubing string to nitrogen increases buoyancy effects.

If the string remains stuck, prepare to kill the well and sever the tubing above the stuck point (see 2.7 Cutting CT at Surface)

2.3 Mechanically Damaged Workstring

Mechanical damage to the workstring is of concern for several reasons.

• The pressure capacity of the workstring may be weakened to the point of failure.

• The tensile capacity of the workstring almost certainly will be weakened.

• The efficiency of pressure control equipment can be compromised (e.g., stripper efficiency).

• If severe, distorted tubing will not pass through pressure control equipment bushings.

• Even small damaged areas can lead to unpredictable failures due to the effects of localized stress.

2.3.1 Collapsed Tubing

Workstrings are more frequently at risk of collapse than burst. The collapse resistance of a tube is significantly reduced as axial tensile force is increased, and/or the ovality of the tubing increases. Consequently, tubing collapse typically occurs near the wellhead where the axial tensile force is greatest, or at the bottom-hole end where the hydrostatic/applied pressure is greatest.

A collapsed tubing string can be indicated by an increase in circulating pressure, severe leakage of wellbore fluids past the stripper, or an overpull caused by the distorted tubing being forced through the stripper bushing.

Following confirmation that a collapsed section of tubing exists, the following guidelines should be followed.

a. Verify that wellhead and workstring internal pressure conditions will prevent further propagation of the collapsed section. Once collapse of a tube has been initiated it is easily propagated by a relatively low pressure differential.

b. Run in hole with CT sufficient to ensure that undamaged CT is located over the pressure control equipment. The operation of slip rams, pipe rams and stripper packer is severely jeopardized by collapsed tubing.

c. Close the slip rams and the pipe rams.

d. Kill the well.

e. Cut the CT and lift clear the injector head. With suitable lifting clamps, fish the remaining CT using a rig or crane. If sufficient CT remains in the wellbore, join the CT with a cold roll connector and re-rig the injector head when the collapsed section of tubing has been removed.

2.3.2 Damaged Tubing at Surface

Kinked or damaged tubing will typically be identified by the TIM† as it is being spooled from the reel. A close inspection must then be made to determine the extent of damage before the tubing is run through the injector head. Appropriate action can then be determined following consideration of the following points.

• Extent of damage

• Location of damage

• Intended application and anticipated forces

• Availability of a substitute reel

2.4 Pressure Control Equipment

The application and control of pressure control equipment is typically regulated by local or national authorities. Should the integrity or efficiency of the equipment be in doubt, the intended operation must be suspended and the well secured until all pressure control equipment requirements are met.

The equipment configuration may allow several options to be considered in overcoming malfunctions or failures. However, it is generally required that two barriers against well fluids and pressure be in place at all times. The priority in contingency planning or emergency procedures must be to maintain or regain the required level of protection before proceeding with the operation.

2.4.1 Stripper Packer Failure

Gross leaks at the stripper packer are easily identifiable and cause obvious safety and environmental hazards. Less severe leaks can be more difficult to detect, especially if the injector head is poorly lit or some distance from the control cabin. However, such leaks can still pose a significant hazard and should be rectified as soon as possible.

a. If a tandem or dual stripper is fitted, energize the remaining stripper packer to maintain control of the well. Replace the failed stripper packer at the earliest opportunity the operation will allow.

   If a single stripper is being used, close the slip rams and pipe rams to regain control of the well. On high pressure gas wells, close the pipe rams first. Swift action reduces the risk of the cutting or damaging the ram seals during closure against an increasing flow.

b. On applications with a high wellhead pressure, consider flowing the well to reduce wellhead pressure while repairs are made.

c. Replace the stripper packing element. On top loading stripper models it is necessary to hang off the string from the slip rams and bleed off inside chain tension to facilitate removal of the stripper bushings or packer.

d. Energize the stripper packer. If possible, pressure test packer to 80% of wellhead pressure.

e. Equalize pressure across the pipe rams, pick up string weight and open the slip rams.

2.4.2 Leak in Riser/Lubricator Above BOP

Leaks in the riser or lubricator section above the BOP are often caused by an unstable equipment rig-up which can result in high bending moments being exerted on connections or flanges. In the event of a leak, the stability of the equipment rig-up must be checked and improved as necessary.

a. Carefully stop the injector head to avoid further stressing the leak point.

b. Close the slip rams and pipe rams to regain control of the well. In the case of severe leak, close the pipe rams first to minimize exposure and effect of wellbore fluids.

c. Bleed-off the remaining pressure above the pipe rams and monitor to ensure that the pipe rams are functioning.

d. On applications with a high wellhead pressure, consider flowing the well to reduce wellhead pressure while repairs are made.

e. For a flanged connection, stabilize the injector head and check/re-torque the flange bolts.

   For pin and collar connections, assess the feasibility of breaking the connection to fit (cut and join) a new O-ring. This is generally only feasible where the injector head is supported and stabilized by a mast or jacking frame. Since this process requires the injector head to be raised while the tubing is held in the slips it may only be completed safely where no wellhead pressure exists.

   If the leak cannot be repaired assess the leak.

Slight Leak Conditions

f. If pumping equipment is available, begin pumping an inert fluid into the BOP kill port and POOH as quickly as is safe to do so. If the wellbore conditions allow, the inert fluid will flow to the leak point, thereby reducing the hazard.

Pumping fluids containing lost circulation material must be done with caution, since the solids in the fluid may compromise the subsequent operation of pressure control equipment.

If pumping equipment or fluid is not available, attempt to POOH. If a hazard is presented by flammable or toxic well fluids, proceed as for severe leak conditions.

Severe Leak Conditions

g. Kill the well

h. Open BOP rams and recover the workstring

2.4.3 Leak in Riser/Lubricator Below BOP

Leaks in the riser or lubricator below the BOP are of special concern since they cannot be controlled by the primary or secondary well control equipment. Where fitted, shear/seal BOPs can be activated to regain control the well. However, the workstring and/or toolstring below the shear/seal will be parted

In the absence of shear/seal pressure control equipment, a rapid assessment of the situation is required.

Slight Leak Conditions

a. If pumping equipment is available, immediately begin pumping an inert fluid down the CT production tubing annulus and POOH as quickly as possible. If the wellbore conditions allow, the inert fluid will flow to the leak point, thereby reducing the hazard.

Pumping fluids containing lost circulation material must be done with caution, since the solids in the fluid may compromise the operation of pressure control equipment.

b. If pumping equipment or fluid is not available, attempt to POOH. If a hazard is presented by flammable or toxic well fluids, proceed as for severe leak conditions.

Severe Leak Conditions

a. Ensure that there is sufficient space between the end of the toolstring and any potential hang-up points (well TD, nipples or bridge plugs etc.) This is necessary to allow the cut tubing string to fall clear of the wellhead valves.

b. Stop the injector head and activate the shear rams.

c. Close the swab valve or master valves (whichever is quickest, safest or most accessible) to regain control of the well.

d. Prepare for well kill/fishing operations.

2.5 Coiled Tubing Equipment

Only items of equipment which can directly jeopardize well security are included in this section. Additional contingency plans should be prepared for special or unusual equipment configurations, as required.

2.5.1 Loss of Power or Control

a. Close the slip rams and the pipe rams. Close the manual locks on both sets of rams in case of hydraulic leakage.

b. If applicable, apply the reel brake.

c. Maintain circulation as required (e.g., to prevent tubing collapse or the settling of wellbore solids)

d. Repair or replace power unit or components.

2.5.2 Reel Swivel Leak

In the event of a reel swivel leak, a rapid assessment of the conditions may be necessary. For example, when circulating fill material from the wellbore, interrupted or reduced circulation may result in sticking the workstring. In addition, the nature of the fluid inside the workstring may determine necessary action (e.g. it is undesirable to stop circulation with cement or acid in the workstring, but it is extremely hazardous to sustain a high-pressure leak of corrosive or flammable fluid.

a. Stop the injector head and pumping equipment.

b. Resume pumping an inert liquid until the workstring is cleared of corrosive or cementitious material, and/or until the wellbore conditions can allow circulation to be stopped.

c. Stop pumping and close the reel-core valve to isolate the workstring

d. If required repair/replace the swivel, pressure test the assembly and proceed with the operation.

2.6 Operational

Some consideration must be given to possible events concerning the operation which may be reasonably foreseeable. The following list of wellbore or treatment conditions can be considered as foreseeable in certain circumstances.

Circulating Applications

Lost circulation/returns
Well/formation kick
Interruption to fluid supply
Insufficient fluid supply (rate or volume)
Treatment fluid out of specified limits
Unable to penetrate/RIH

Downhole Tool Operations

Suspected tool failure/malfunction
Unable to penetrate/RIH
Depth correlation appears incorrect

2.7 Determining the Stuck Point

When attempting to free a stuck workstring it is necessary to determine, as accurately as possible, the point at which the workstring is held. The completion, or well geometry, data are generally good indicators of potential stuck points. However, if possible, a stretch test/ calculation should be conducted to confirm/determine the stuck point.

The worksheets shown in *Fig. 2* and *Fig. 3* are intended to help record and calculate the data required to determine the CT stuck point. The accuracy of this technique is greatly dependent on the accuracy of the information input. Therefore, it is essential that accurate information is gathered on tapered string dimensions, etc., before applying the calculation.

CT Stretch

The following procedure should be used to determine the stretch (Δl) in the CT string.

a. Apply sufficient tension to the tubing to ensure that the string is in tension at the stuck point.

b. Mark the CT just above the stripper.

c. Apply additional tension (10,000 lb if possible, but never exceed 80% of the string yield tension).

d. Accurately measure the tubing stretch by measuring the distance the mark has moved. Note the exact additional tension applied.

Nontapered String

The approximate location of the stuck point on a non-tapered string may be calculated by following the calculation procedure shown in *Fig.2*.

Tapered String

To accurately determine the location of the stuck point of a tapered string, the length and cross-sectional area of each taper section in the well must be known.

The stretch resulting from the applied load is then calculated for each taper section. This series of calculations should begin with the top taper section and progress through the deeper sections until the sum of the calculated section stretches is greater, or equal to, the actual measured stretch.

The calculation procedures shown in *Fig. 2* and *Fig. 3* should then be used to determine the stuck point location on a tapered CT string.

2.8 Cutting the Coiled Tubing at Surface

Before the CT is cut at the surface, the well must be killed. If possible, this should be conducted by circulating through the CT. This will maintain a kill-weight column of fluid inside and outside the CT string.

If circulation is not possible, bullhead the kill fluid down the annulus. In this event, account must be taken of the injection pressure limits imposed by the well tubulars and equipment, and the risk of collapsing the CT.

Once the well has been killed, the following procedure should be followed.

a. Confirm the status of the well by conducting a 30 min flow check on the annulus and the CT at the reel manifold. If practical, a heavier fluid should be spotted in the CT string to avoid any “U” tube effect from flowing fluid when the cut is made at the injector head.

b. Determine/confirm the stuck point.

c. Determine the point at which the surface cut is to be made after consideration.

- The distance the tubing will have to be moved to apply the appropriate overpull.

- The pressure control equipment which may be required.

Generally, this point will be 12 to 24 in. above the injector head which will allow the safe handling of the CT, and facilitate the handling of the pressure control equipment and tools.

d. If possible/practical, run the tubing in-hole 12 to 24-in. to straighten the CT below the point to be cut.

e. Clamp the CT at the reel to prevent the reel back tension from interfering with the cutting process. Remove the gooseneck top rollers and leave sufficient slack between the reel and injector head to allow for easier handling.

f. Carefully run the injector head to pull the CT and correctly position the point of cut.

g. Close the slip rams and secure the CT above the point of cut with a winch or tugger line. Attempt to reduce the strain on the CT at the point of cut to safeguard the person making the cut.

h. Cut the tubing with a hacksaw. Beware of sudden tubing movement during and after the cut.

i. Spool the cut end onto the reel, allowing sufficient “tail” to temporarily join the tubing should that be necessary.

j. Rig up the pressure control or wireline equipment as necessary. The pressure control equipment shown in *Fig. 4* is intended to provide a means to secure and circulate through the CT after the string has been cut downhole.

2.8.1 Preparation for Cutting Tubing Downhole

The procedures and preparation required when cutting tubing will depend on the application, well conditions and subsequent operations. However, to ensure that the safety of personnel and well pressure control is not jeopardized the following points must be considered.

Note. Explosive and chemical cutting tools must only be assembled and prepared by experienced and qualified personnel.

- When cutting a CT work string, the well must be killed and flow checked.

  If possible, circulate a higher density fluid into the CT in the well. This will help prevent spillage as the CT is cut above the injector head.

- If tubing/fish is to be retrieved, it may be advantageous to leave a sufficient "stub" to facilitate fishing and retrieval. When the resulting fish is to be retrieved thru-tubing, it is easier to re-engage the tubing in the production tubing than in the casing or liner below.

- To ensure that a complete cut is made the cutter (explosive or chemical) should be centralized with the correct standoff from the tubing to be cut. To achieve this, cutters are designed for the common tubing sizes. However, a check must be made to ensure that tools are compatible with wall thickness of tubing to be cut.

  A complete tubing string/well schematic must be made available for the cutting technician.

- It is recommended that the pressure control equipment illustrated in *Fig. 4* be used to maintain the well security when the cut is made. The cutting tool dimensions, before and after firing, should be considered when making up this equipment.

2.8.2 Explosive Cutters

The technician or engineer running the explosive cutter will be responsible for ensuring that the correct procedures and actions are followed. However, the following points will generally apply.

- The normal wireline/explosives handling safety procedures must be applied and enforced.

- An overpull of approximately 10% over the string weight, should be applied to the tubing string prior to firing the cutter.

- After the cut is made, allow any pressure or flow equalization to cease before attempting to retrieve the cutting tool.

COILED TUBING STRING STUCK-POINT CALCULATION WORKSHEET

Length of CT in the Well.......................(ft)

Measured Stretch.......................(in.) at Applied Load.............................(lb)

NONTAPERED STRING

Length to Stuck Point $L = \frac{A\ E\ \Delta l}{12\ F}$

$$\frac{\text{Cross-Sectional Area.....................(in.}^2\text{) x 29,000,000 x Stretch......................(in.)}}{\text{12 x (Applied Load)....................(lb)}} = \text{Length to Stuck Point} = \text{.......................(ft)}$$

A – Cross-Sectional Area = $\frac{\pi}{4}$ $(OD^2 - ID^2)$

F – Applied Load (at the time the CT stretch was measured at surface)

Δl – Measured Stretch

E – Constant for Young's Modulus of Elasticity (29,000,000)

L – Length to Struck Point

TAPERED STRING

1. Determine the actual tubing string stretch for a given load.

2. Using the calculation form overleaf, determine the taper section in which the stuck point is located. Starting with the top section, calculate and add the stretch induced in each taper section until the sum is greater or equal to the actual measured stretch.

3. Determine the location of the stuck point in the last taper section by applying the following formula. The value for Δl (Stretch) is obtained by subtracting the sum of the free taper sections calculated stretch from the measured stretch.

   Length to Stuck Point $L = \frac{A\ E\ \Delta l}{12\ F}$

   $$\frac{\text{Cross-Sectional Area.....................(in.}^2\text{) x 29,000,000 x Stretch......................(in.)}}{\text{12 x (Applied Load)....................(lb)}} = \text{Length to Stuck Point} = \text{.......................(ft)}$$

   A – Cross-Sectional Area = $\frac{\pi}{4}$ $(OD^2 - ID^2)$

   F – Applied Load (at the time the CT stretch was measured at surface)

   Δl – Stretch

   E – Constant for Young's Modulus of Elasticity (29,000,000)

   L – Length to Struck Point

4. Add this length to the lengths of the free taper sections.

Taper Section No. 1 Length ....(ft)

Taper Section No. 2 Length ....(ft)

Taper Section No. 3 Length ....(ft)

Taper Section No. 4 Length ....(ft)

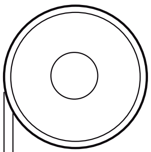
Taper Section No. 5 Length ....(ft)

Length from Stuck Point to the Last Taper Section ....(ft)

Total Length to Stuck Point ....(ft)

Figure 2. Stuck point calculation worksheet.

COILED TUBING STRING STUCK POINT CALCULATION
TAPERED STRING WORKSHEET



Length of CT in the Well......................(ft)

Measured Stretch......................(in.) at Applied Load.............................(lb)

Weld Location.................(ft)

Wall Thickness................(in.)

Cross-Sectional Area (A)...................($in.^2$)
$A = \frac{\pi}{4}(OD^2 - ID^2)$

Taper Section No. 1 Length ....(ft)

Tubing Stretch in Taper Section No. 1 $\Delta l = \frac{12\,F\,L}{AE}$

$$\frac{12 \times (\text{Applied Load})\ldots\ldots(\text{lb}) \times \text{Taper Section Length}\ldots\ldots(\text{ft})}{\text{Cross-Sectional Area}\ldots\ldots(\text{in.}^2) \times 29{,}000{,}000}$$

Taper Section Stretch = ...(in.)

Weld Location.................(ft)

Wall Thickness................(in.)

Cross-Sectional Area (A)...................($in.^2$)
$A = \frac{\pi}{4}(OD^2 - ID^2)$

Taper Section No. 2 Length ....(ft)

Tubing Stretch in Taper Section No. 2 $\Delta l = \frac{12\,F\,L}{AE}$

$$\frac{12 \times (\text{Applied Load})\ldots\ldots(\text{lb}) \times \text{Taper Section Length}\ldots\ldots(\text{ft})}{\text{Cross-Sectional Area}\ldots\ldots(\text{in.}^2) \times 29{,}000{,}000}$$

Taper Section Stretch = ...(in.)

Weld Location.................(ft)

Wall Thickness................(in.)

Cross-Sectional Area (A)...................($in.^2$)
$A = \frac{\pi}{4}(OD^2 - ID^2)$

Taper Section No. 3 Length ....(ft)

Tubing Stretch in Taper Section No. 3 $\Delta l = \frac{12\,F\,L}{AE}$

$$\frac{12 \times (\text{Applied Load})\ldots\ldots(\text{lb}) \times \text{Taper Section Length}\ldots\ldots(\text{ft})}{\text{Cross-Sectional Area}\ldots\ldots(\text{in.}^2) \times 29{,}000{,}000}$$

Taper Section Stretch = ...(in.)

Weld Location.................(ft)

Wall Thickness................(in.)

Cross-Sectional Area (A)...................($in.^2$)
$A = \frac{\pi}{4}(OD^2 - ID^2)$

Taper Section No. 4 Length ....(ft)

Tubing Stretch in Taper Section No. 4 $\Delta l = \frac{12\,F\,L}{AE}$

$$\frac{12 \times (\text{Applied Load})\ldots\ldots(\text{lb}) \times \text{Taper Section Length}\ldots\ldots(\text{ft})}{\text{Cross-Sectional Area}\ldots\ldots(\text{in.}^2) \times 29{,}000{,}000}$$

Taper Section Stretch = ...(in.)

Weld Location.................(ft)

Wall Thickness................(in.)

Cross-Sectional Area (A)...................($in.^2$)
$A = \frac{\pi}{4}(OD^2 - ID^2)$

Taper Section No. 5 Length ....(ft)

Tubing Stretch in Taper Section No. 5 $\Delta l = \frac{12\,F\,L}{AE}$

$$\frac{12 \times (\text{Applied Load})\ldots\ldots(\text{lb}) \times \text{Taper Section Length}\ldots\ldots(\text{ft})}{\text{Cross-Sectional Area}\ldots\ldots(\text{in.}^2) \times 29{,}000{,}000}$$

Taper Section Stretch = ...(in.)

Δl – Stretch

L – Length of Taper Section

A – Cross-sectional Area of the CT Taper Section

F – Applied Load (At the time the CT stretch was measured at surface.

E – Constant for Young's Modulus of Elasticity

Figure 3. Stuck point calculation - tapered string worksheet.

- Avoid circulating through the cut string until the cutting tool has been retrieved.

2.8.3 Chemical Cutters

The technician or engineer running the chemical cutter will be responsible for ensuring that the correct procedures and actions are followed. However, the following points will generally apply.

- The normal wireline/explosives handling safety procedures must be applied and enforced.
- The chemical cutter should not be fired in a dry tubing string. It is generally necessary to have 100 ft of fluid above the tool.
- The cutter should not be fired directly above a bull plug or solid obstruction. It is generally necessary to lower the tool a short distance after firing to ensure that the anchoring system is disengaged. A short bumper jar is sometimes run above the tool to assist in this process.
- If the string to be cut is known, or suspected, of being scale coated, it may be necessary to run a cleanout shot prior to the cut being made. This generally consists of detonating a quantity of primer cord at the site of the intended cut.
- An overpull of approximately 10% over the string weight, should be applied to the tubing string prior to firing the cutter.
- After the cut is made, allow any pressure or flow equalization to cease before attempting to retrieve the cutting tool.
- Avoid circulating through the cut string until the tool has been retrieved.

2.8.4 Coiled Tubing Retrieval

After the CT has been cut and the cutting tool string retrieved, circulation through the CT may commence. In cases where the well was not killed by circulating

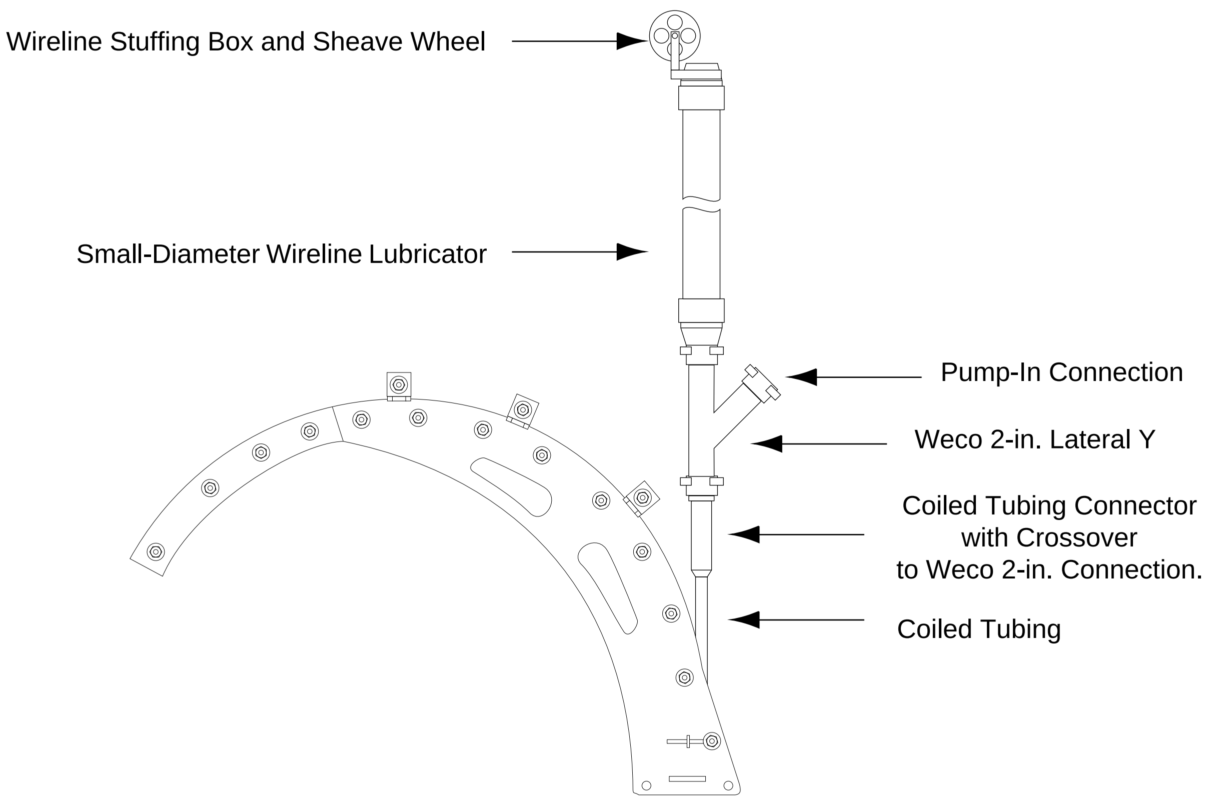


Figure 4. Pressure control and circulating equipment rig-up.

through the CT, at least 1-1/2 wellbore volumes should be circulated to ensure that a continuous column of the required kill-weight fluid exists.

Prior to rigging down the pressure control equipment, a flow test should be conducted to verify the well status.

To recover the cut tubing string, the tubing must be joined temporarily by a double roll-on connector. This will allow the tubing to be spooled onto the reel. The reel-drive hydraulic circuit should be operated at a reduced backpressure until the tubing joint is three to four wraps on the reel.

An accurate track of the tubing recovered must be kept to avoid withdrawing the end from the injector chains. Howver, in most cases, tubing cut by an explosive cutter will not pass through the stripper.

Further explanation of the equipment and techniques used for cutting CT may be found in the references listed in Section 4.

3 EMERGENCY PROCEDURES

The objective of emergency procedures is to secure existing or potentially hazardous conditions sufficient to enable a review of possible options (contingency plans) to be safely made. The procedures must be executed with minimal delay or consultation and are typically associated with the operation of well pressure control equipment or devices. Consequently, all CTU operators must be fully familiar with the equipment in use. In addition, operators should be constantly aware of current and potential well conditions.

4 REFERENCES

The following references are recommended for job design information or for further reading.

Internal Technical Manuals (ITM)

Coiled Tubing Operators Manual. ITM-1099. 1992

Safety and Loss Prevention Manual. HSE-8005. 1991

Coiled Tubing Equipment STEM I - June 1992

DEPLOYMENT SYSTEMS

INTRODUCTION

As the complexity of CT applications has grown, so too has the average length of toolstring required to perform the desired service or work. Since one of the major benefits of CT applications is safe life well working, it was a fundamental requirement that some means of safely installing long toolstrings in live wells was devised. The conditions under which this must be achieved vary considerably. For example, the configuration of many offshore locations is such that up to 60ft of riser can be fitted between the wellhead (swab valve) and the operating level (impact deck or rig floor). Conversely, onshore locations carry the inherent disadvantage of already having the swab valve located above the safe working level (ground level).

Four basic systems have been used within the Dowell organization and are outlined in the following section. Note the first two methods described have evolved into the improved safe deployment system and are not generally recommended for use on live wells.

- Lubricator deployment•
- Tool deployment
- Safe deployment
- CIRP

1 LUBRICATOR DEPLOYMENT

The evolution of solutions to this problem started by treating the CT equipment and toolstring in a similar fashion to wireline, i.e., rig-up sufficient riser or lubricator to “swallow” the toolstring and support the entire assembly by a crane and necessary guide wires (Figure 1).

While this configuration could be used to complete a variety of operations it resulted in a heavy suspended load (injector head) and provided little in the way of contingency options. For example, if a problem was encountered with the injector head, it was very difficult to reach and inspect/repair while 60 ft above ground level.

The principal disadvantages of this system included:

- A large crane (capacity and height) was required to support the injector head
- Operator visibility of all CT and pressure control components was limited
- Injector head access is restricted
- Personnel are exposed to suspended loads during the rig up procedure

* Mark of Schlumberger

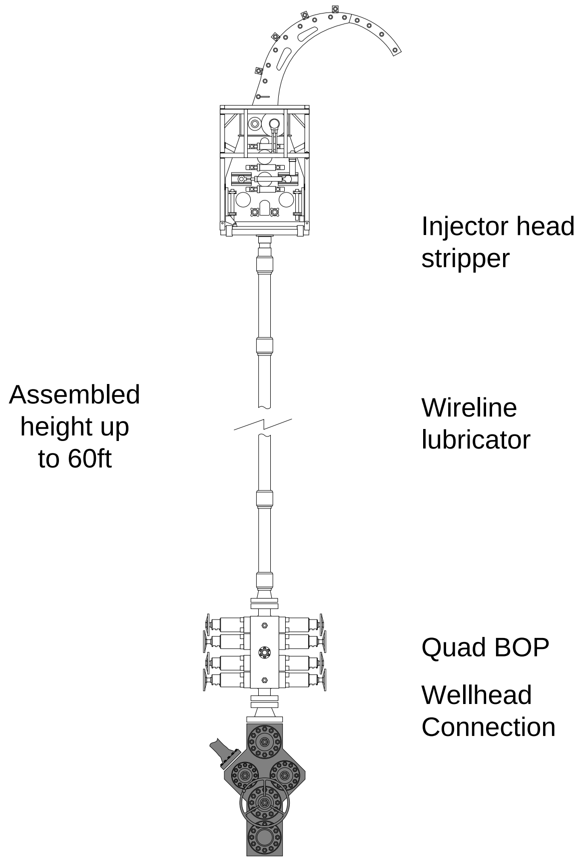


Fig.1 Lubricator deployment - equipment configuration.

2 TOOL DEPLOYMENT SYSTEM

Since the disadvantages listed above were significant operational and safety issues, an alternative deployment method was developed. The system relied on a bar (deployment bar) installed in the BHA to provide a means of holding and sealing on the BHA to enable the operation to be conducted in stages. This enabled the working height of the injector head to be significantly reduced and provided a means of ensuring pressure integrity (pressure testing) at all stages.

2.1 Tool Deployment Sequence

The installation (deployment) sequence entailed:

a. The tool string and lubricator assembly is rigged as for wireline operations and the toolstring RIH until the deployment bar is opposite the BOP slip and pipe rams (Figure 2).

b. The pipe and slip rams are closed to secure wellbore pressure and hold the bar in place (Figure 3).

c. Pressure is vented from the lubricator allowing the bottom connection to be broken, gaining access to the deployment bar top connection. This connection is broken and the lubricator assembly and running tool is laid down.

d. A short riser section is attached to the stripper and the appropriate connection is made up to the CT toolstring.

e. The injector head is lowered slowly until the toolstring connection can be made up to the deployment bar. The toolstring connection is made up, after which the injector head is further lowered to enable the riser connection to be made (Figure 4).

f. When all connections have been made, confirmation of pressure integrity is made, the pressure is equalized and BOP rams are open allowing the tool string to be RIH (Figure 5).

While this system provided a major advancement in the handling of long toolstrings in live wells, some major factors still required addressing.

- There is a high dependency on crane operator skills during crucial stages of the operation.
- Operators are still exposed to suspended loads during the rig-up and rig-down periods.

3 SAFE DEPLOYMENT SYSTEM

Overcoming the deficiencies summarized above required the development of new equipment and techniques to enable greater control and safety associated with the deployment operation. A deployment bar is still utilized in the BHA, however, several new items of surface equipment are required (Figure 6 and 7).

Quick Latch

Provides a quicker and safer means of connecting the lubricator/injector head assembly to the wellhead equipment. The quick latch (QL) is operated remotely, thereby removing the risks associated with operators working beneath suspended loads.

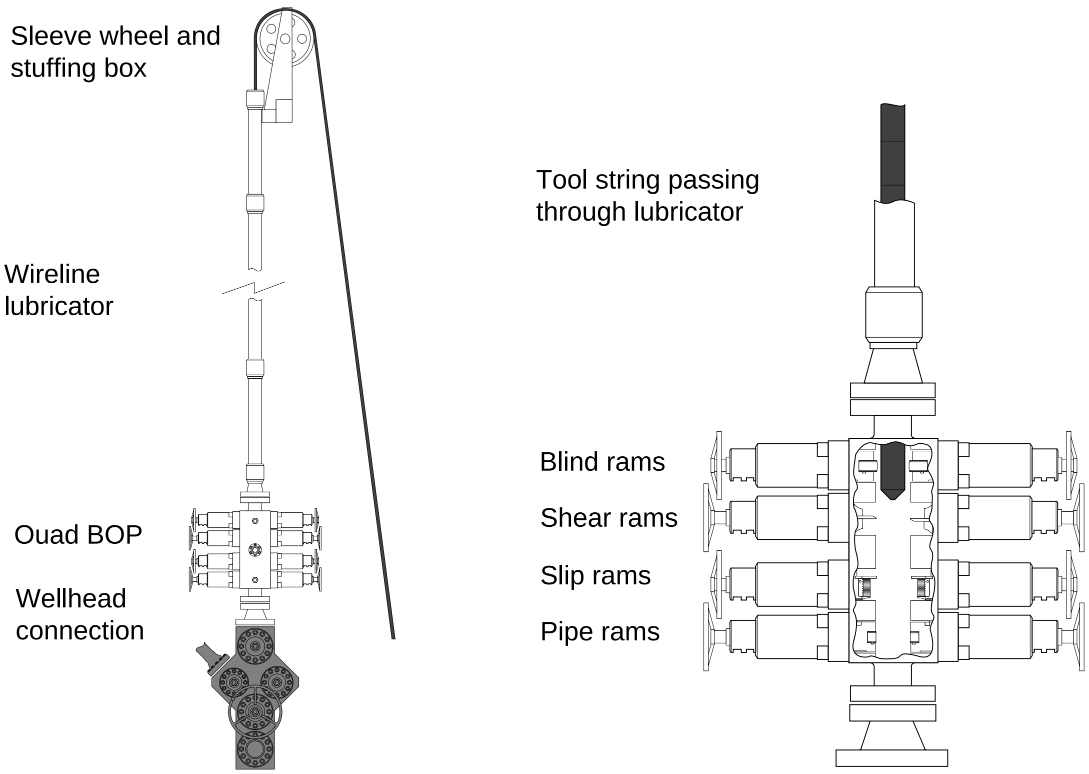


Fig. 2 Insalling the toolstring.

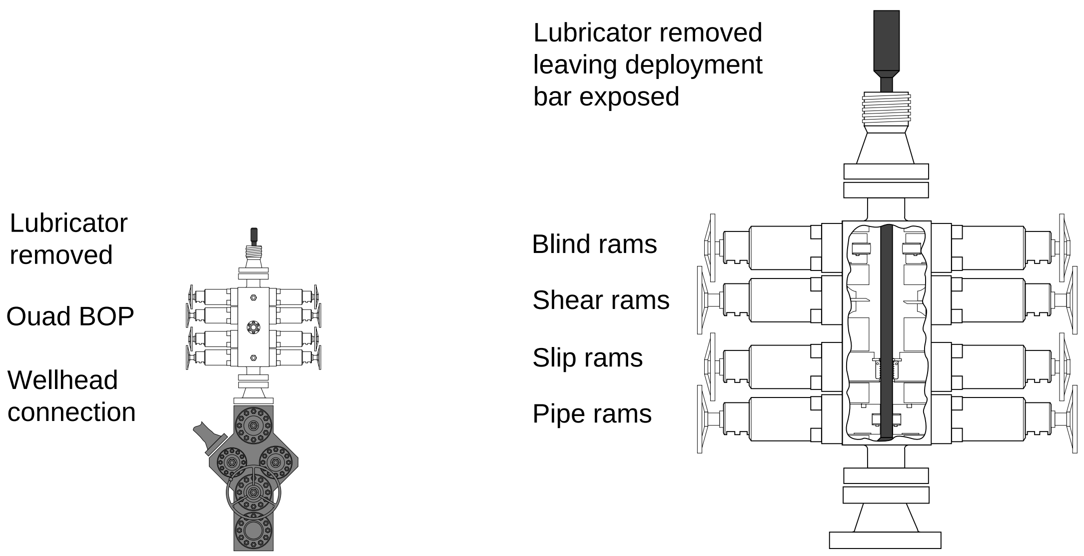


Fig. 3 Hanging off the toolstring.

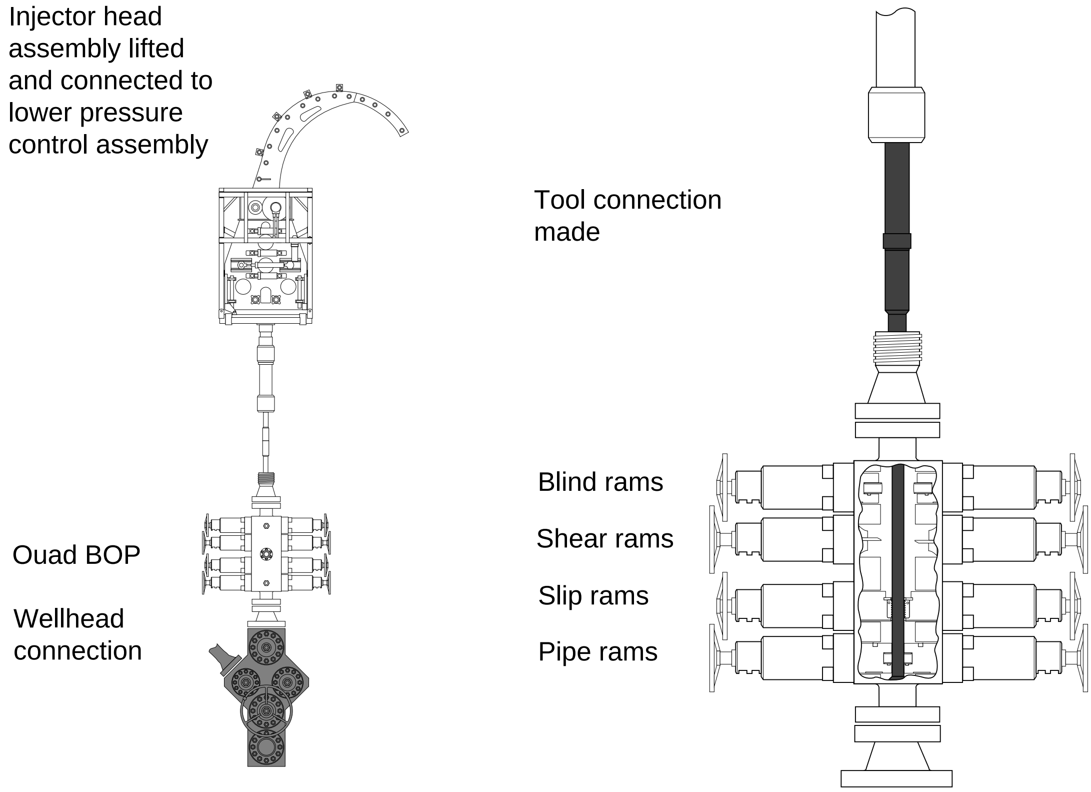


Fig. 4 Connecting the toolstring and running string.

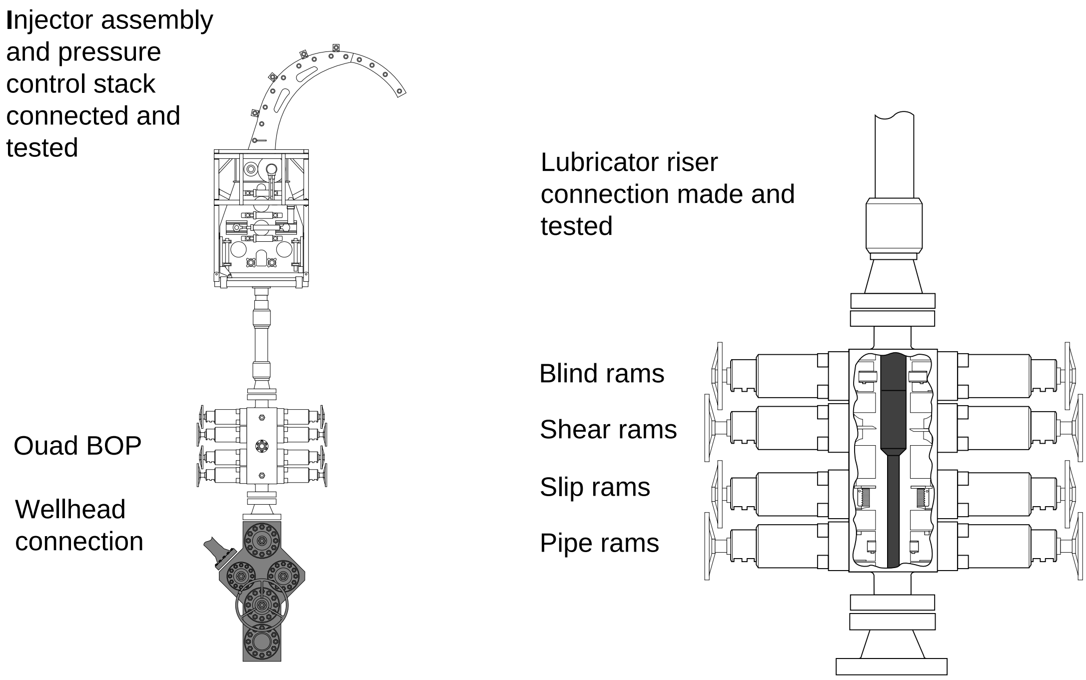


Fig. 5 Running the toolstring.

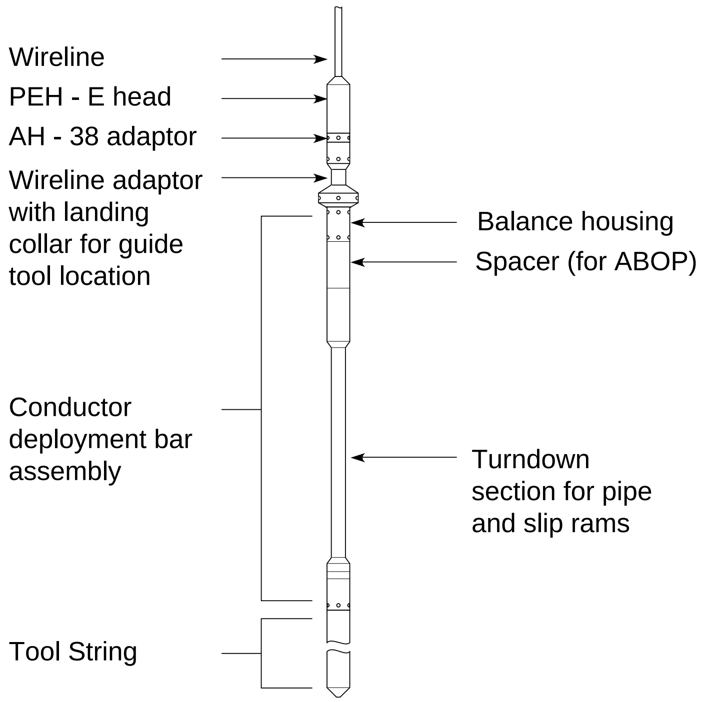


Fig. 6 Safe deployment system tool string.

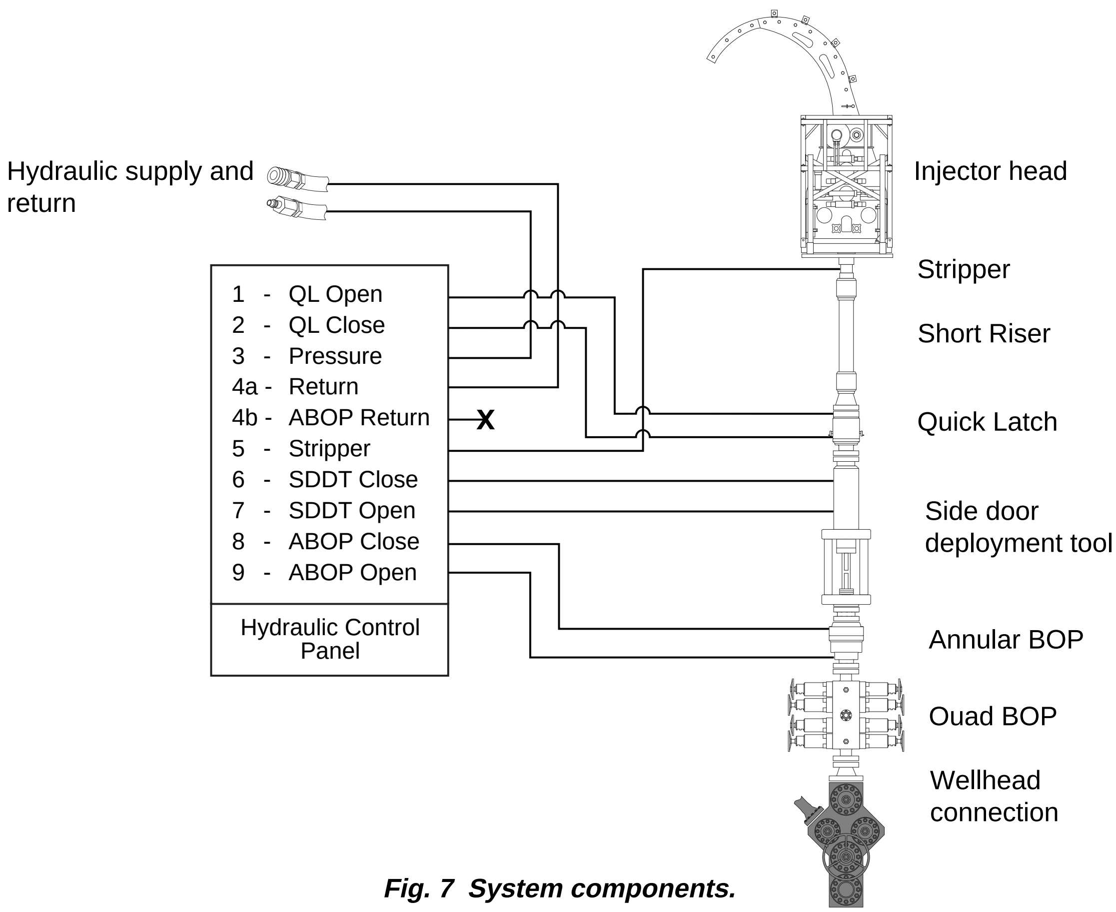


Fig. 7 System components.

Side Door Deployment Tool

Enables the toolstring to be connected after the injector head assembly has been connected and secured. This provides several operational and safety benefits.

- CTU operator controls toolstring connection process.
- Injector head is grounded (electrically) before toolstring connections are made up.

Annular BOP

The annular BOP (ABOP) provides a contingency pressure containment function by sealing the annular gap around the tool sting or CT string as required (double barrier).

Hydraulic Control Panel

To ensure all operating functions can be completed from a position with clear line of sight, all safe deployment systems are controlled from a hydraulic control panel. The hydraulic connections (flow and return) to the panel is typically made through the auxiliary BOP hydraulic supply on the CTU.

Downhole Equipment

The downhole equipment consists of a deployment bar and a quick connect union system to enable easy and safe make-up of the toolstring. A guide tool fitted in the SDDT enables positive indication that the deployment tool is properly positioned across the BOP rams.

Additional Operating Requirements

The following operating requirements have been identified as key factors which may jeopardise the safety or efficiency of the operation.

- Cranes must be certified as capable of operating at the required height, reach and weight.
- Wellhead equipment should be inspected to ensure that the additional weight and loading can be safely supported and secured.
- Sufficient securing points should be available at ground level.
- A work platform should be erected to enable easy/ safe access to the SDDT.

3.1 Safe Deployment Sequence

The safe deployment sequence includes the following basic steps.

Note: this sequence is provided for information purposes only and does not include all details of checks and procedures necessary when designing a procedure.

a. Rig up equipment as shown in Figure 7

b. Assemble toolstring and install in wireline lubricator. Make up the QL connector to the lubricator.

c. Lift the lubricator on to the wellhead assembly and latch the QL.

d. Equalise pressure to the lubricator, open the well-head valves and lower toolstring into wellbore until the tool locates in the SDDT guide (Figure 8).

e. Close BOP slip and pipe rams (and the ABOP) and vent the lubricator pressure.

f. Open the SDDT window and disconnect the running tool and remove the lubricator assembly (Figure 9).

g. Fit upper QL connection to injector head assembly and make up upper toolstring.

h. Lift the injector head assembly, latch QL, and secure guy wires/chains.

i. Open the SDDT window, run in with CT until toolstring connection can be made up (Figure 10 and 11).

j. Close the SDDT and pressure test completed rig up (constrained by WHP below pipe rams/ABOP).

k. Equalise pressures and release pipe and slip rams, tag stripper to verify depth settings and proceed to RIH (Figure12).

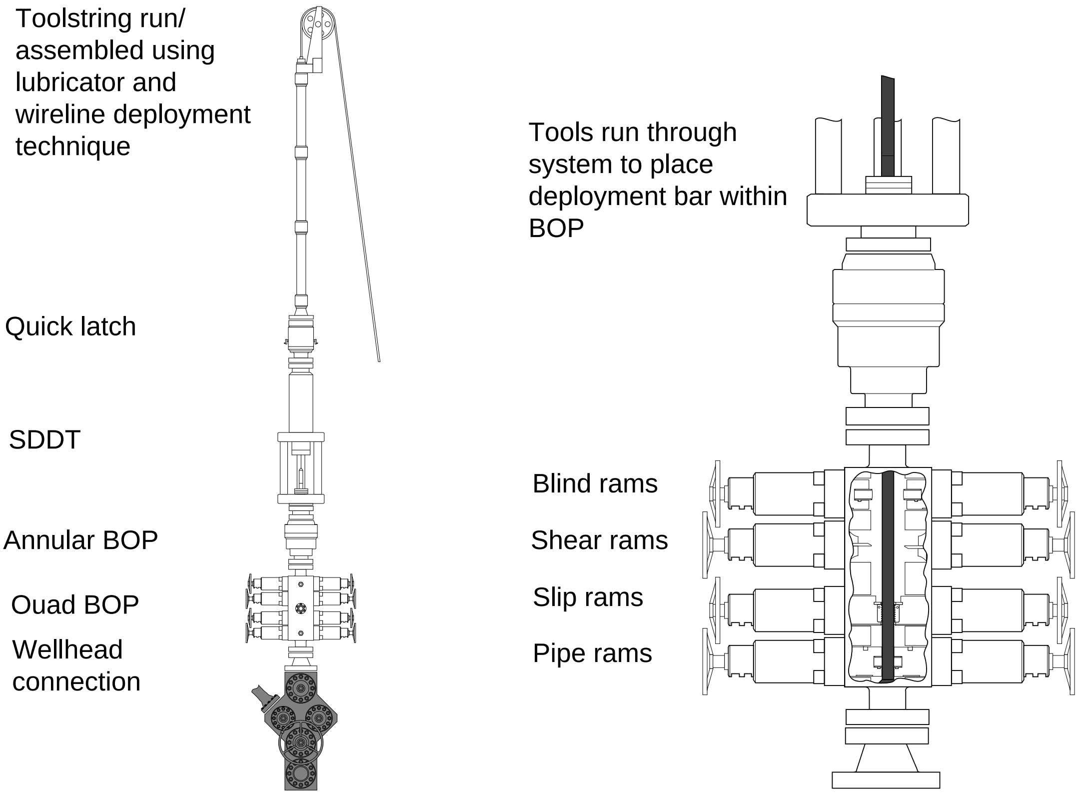


Fig. 8 Installing the toolstring.

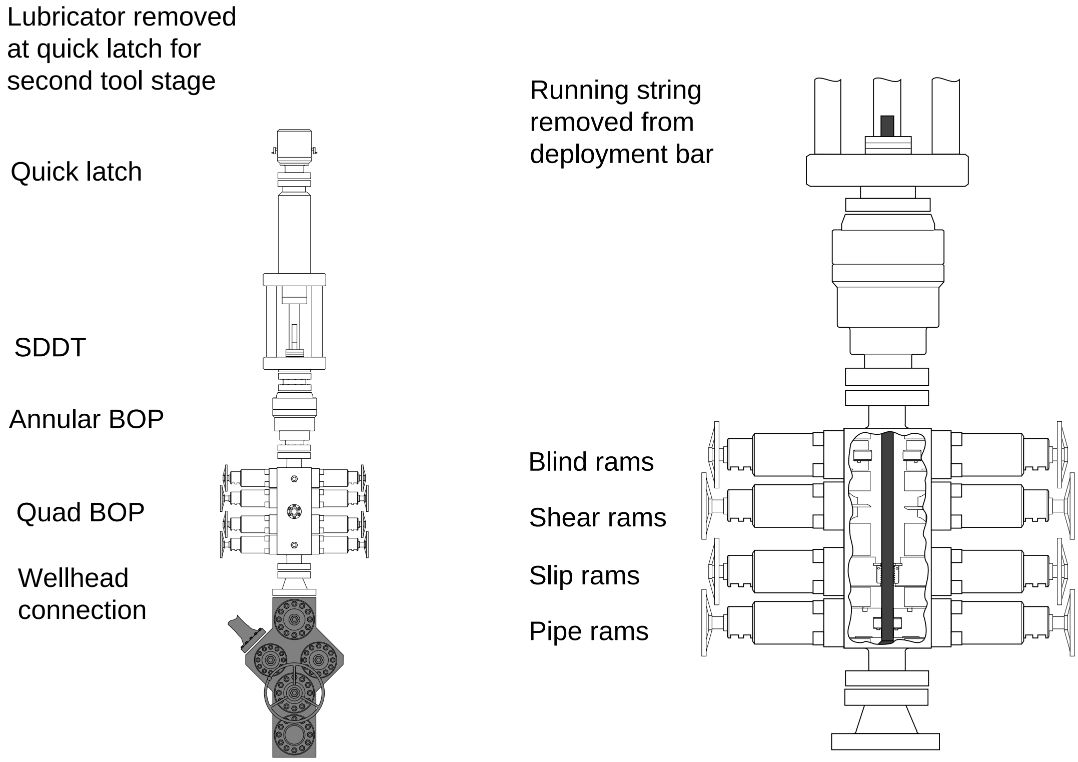


Fig. 9 Hanging off the toolstring.

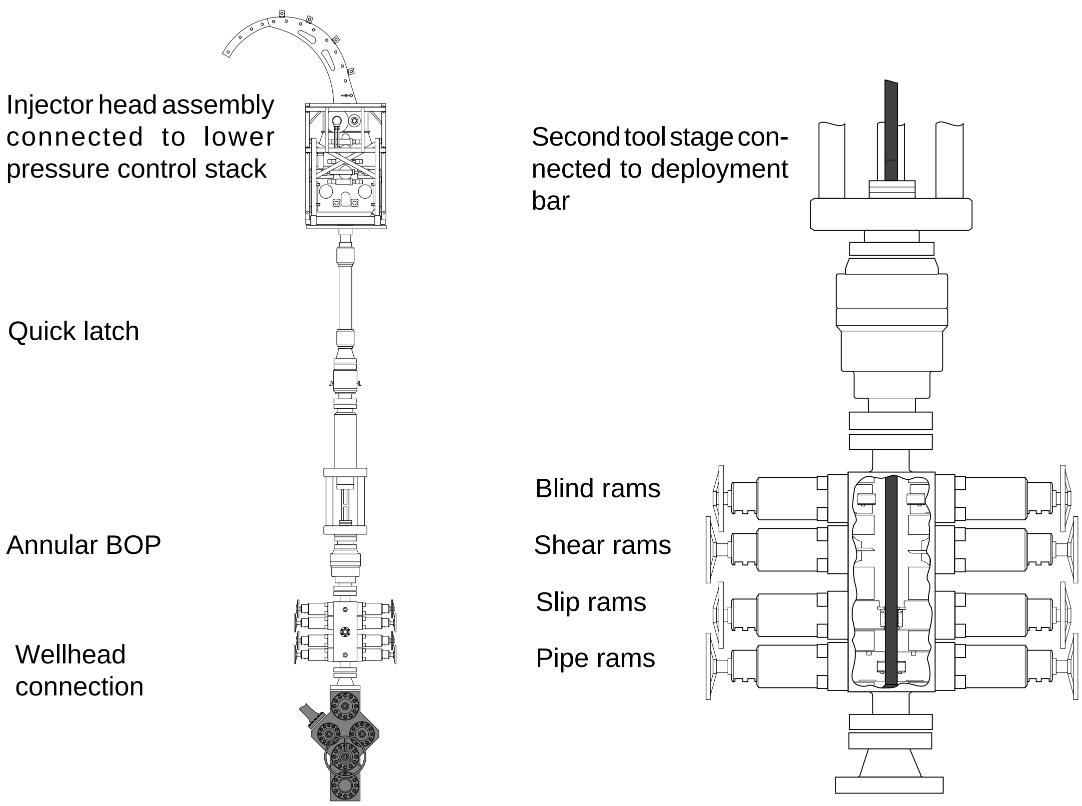


Fig. 10 Connecting the running string and toolstring.

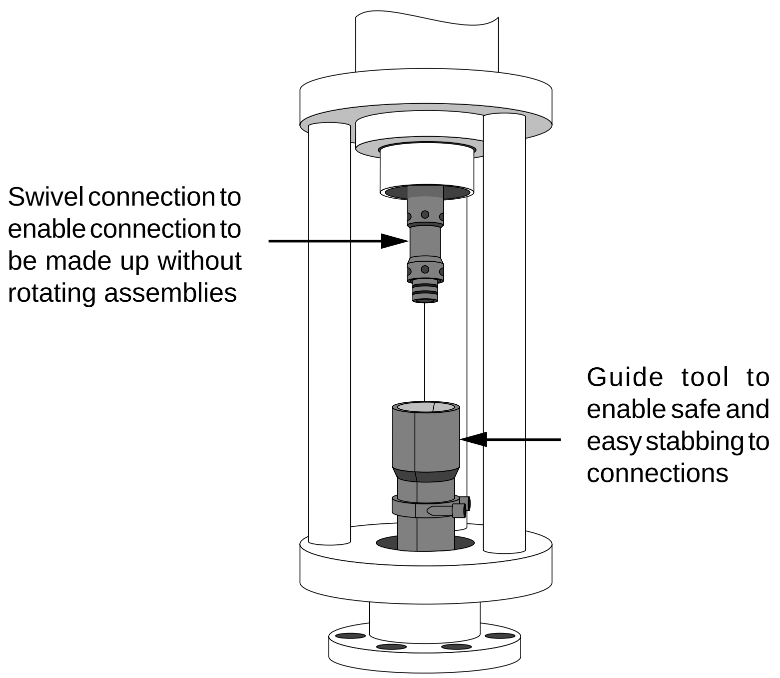


Fig. 11 Guide tool and swivel connector.

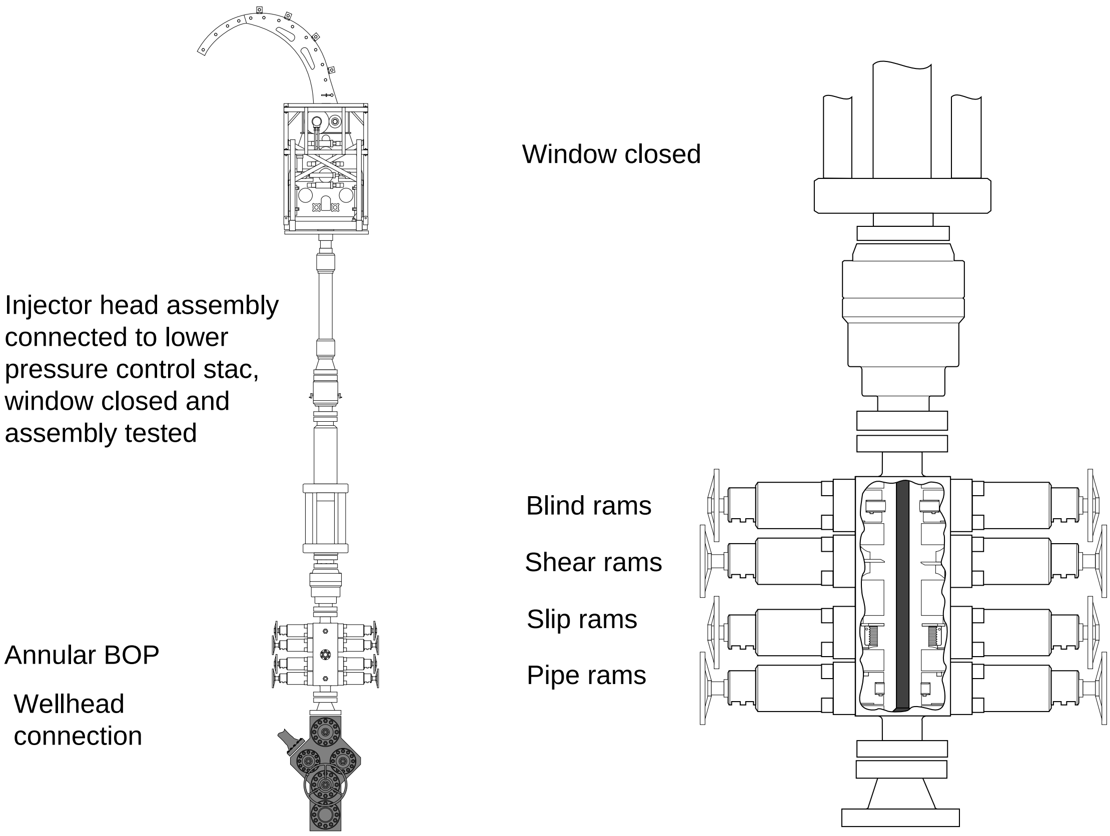


Fig. 12 Running the toolstring.

4 COILED TUBING CONVEYED TCPS

In addition to the increase of coiled tubing in conventional applications in recent years, there has been a similar growth in the volume of perforating operations being carried out on CT. This brought the requirement for a specialized firing head to enable the safe conveyance of the gun string and reliable initiation of the perforating process. Additional features required of the system included the ability to place an underbalance cushion and the option to release the guns in the rathole.

4.1 Circulation Ball Firing Head (CBF)

The Circulation Ball Firing Head (CBF) was developed using existing Schlumberger technology and utilizes standard firing mechanisms, shear pins and operating principles (Figure 13).

Features

- Fired by predetermined tubing pressure, only when ball is in seat.
- Unaffected by absolute (hydrostatic) pressure.
- Unaffected by water hammer while running in hole (firing pin release sleeve moves upward).
- While running in hole, tubing is filling up.
- Insensitive to vertical drops.
- Allows circulation in either direction, both prior to and after gun firing.
- Adaptable to all Schlumberger guns.

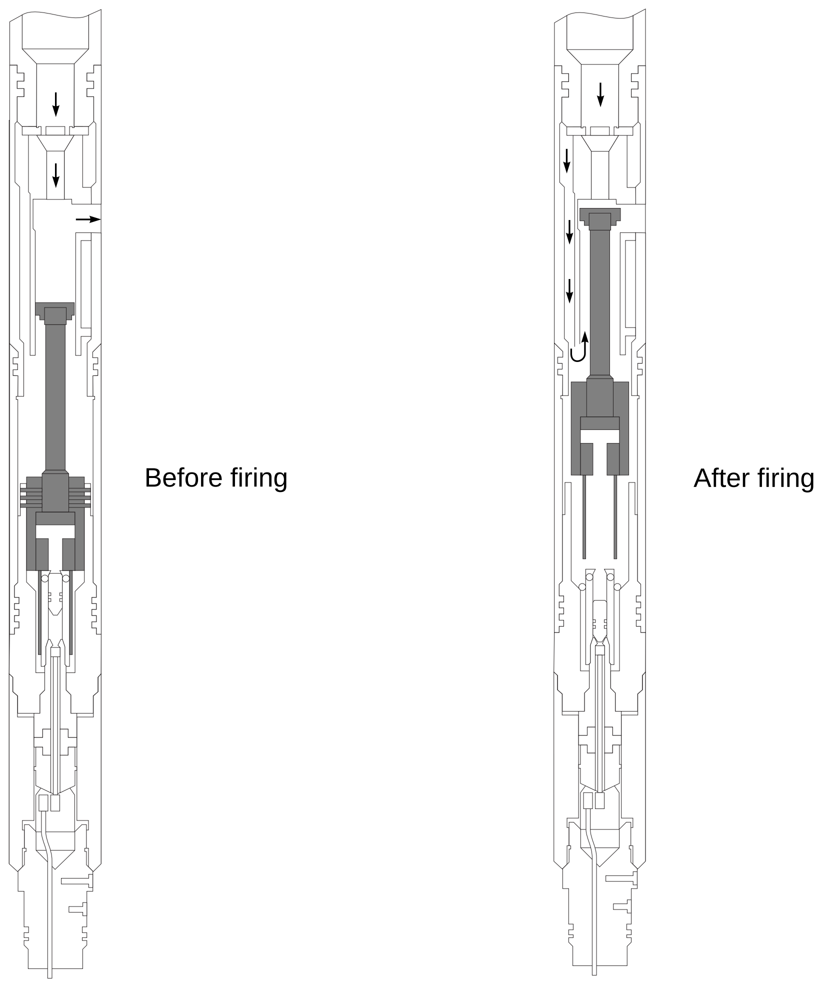


Fig. 13 CBF Firing head components

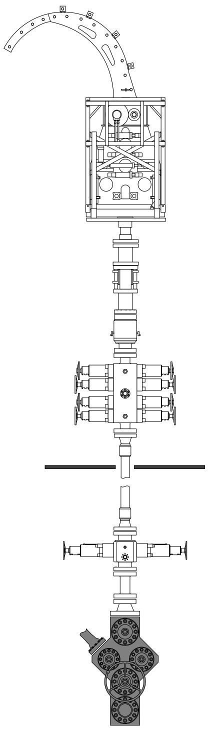


Fig. 14 Equipment configuration (general) for conventional CT operations

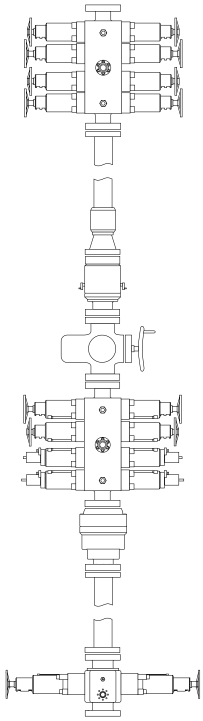


Fig. 15 Typical equipment configuration for CIRP operations

- Shear pinnable for pressures up to 6,000 psi above hydrostatic, in 500 psi increments.

Other derivations of the CBF are available. The CDF and BCF permit gun detonation if direct ball drop is not possible, or if wellbore restrictions require alternative tool assemblies (e.g., slimmer tools).

The CBF allows circulation in either direction before and after firing the guns. Fluid pumped down the CT string tubing flows through a ball seat at the top connector housing and out of the upper set of ports in the connector housing to the wellbore.

4.1.1 CBF Operation

When ready to fire, a ball is pumped through the coil and lands on the ball seat. The fluid from the CT string is then diverted to the annular space between the double walls of the connector housing, through the lower set of ports and upward to the bottom side of the piston.

The top side of the piston is open to wellbore pressure via the upper ports. Upward movement of the piston is resisted by a set of shear pins. These are loaded by the head of the piston rod pushing upwards on the inner sleeve of the shear set.

When sufficient pressure is applied through the coil, the piston, the piston rod, shear set inner sleeve and release sleeve all move upward. When the lower end of the release sleeve passes the ball bearings, the balls drop out releasing the firing pin to detonate the guns.

The piston, piston rod, shear set inner sleeve, and release sleeve all continue to move upward, until the piston is above the upper ports, gain allowing circulation when pumping through the coil tubing.

Once pumping ceases, the piston, piston rod, shear set inner sleeve and release sleeve stay in place allowing reverse circulation whenever desired.

If they drop downward, below the upper ports, the ball can be pumped off its seat, allowing reverse circulation. If pumping through the coil is resumed, the inner parts will move as described.

4.2 CIRP Deployment System

The CIRP Deployment System (Completion Insertion and Retrieval of long gun strings under Pressure) is designed to allow the running and retrieval of long tool strings, regardless of available lubricator. Connections are made inside the pressure control stack at wellbore pressures utilizing the Safeconn connector system (Drexel).

Applications for this technology include the running of perforating guns, logging tools, sand screens, coiled tubing drilling assemblies or any application where tool string length exceeds available surface riser/lubricator height.

The special snaplock connector allows long gun strings to be run and retrieved under pressure. Placed between two guns, the tool allows the operator to connect and disconnect the guns inside a specially modified BOP stack without direct access (Figure 14 and 15). On long gun strings several connectors may be used.

A sealed ballistic transfer is used on both sides of the connection. Figure 16 shows the snaplock connector in the disconnected and connected conditions.

The special BOP uses two modified rams to operate the snaplock connector. Both rams have a secondary ram located within the primary ram mechanism that provides additional functions (Figure 16).

The large lower ram serves as a no-go ram, closing to a diameter only slightly larger than the slick joint. It also has matching gear teeth that engage in the no-go groove to prevent rotation of the lower portion of the snaplock connector.

The large upper ram closes to a diameter just slightly larger than the OD of the connector and serves as a centering guide. The smaller internal ram is equipped with a rack that, when extended, engages the pinion gear teeth located at the top of the breech lock sleeve of the connector. The rack thus turns the breech lock sleeve to unlock and lock the connector.

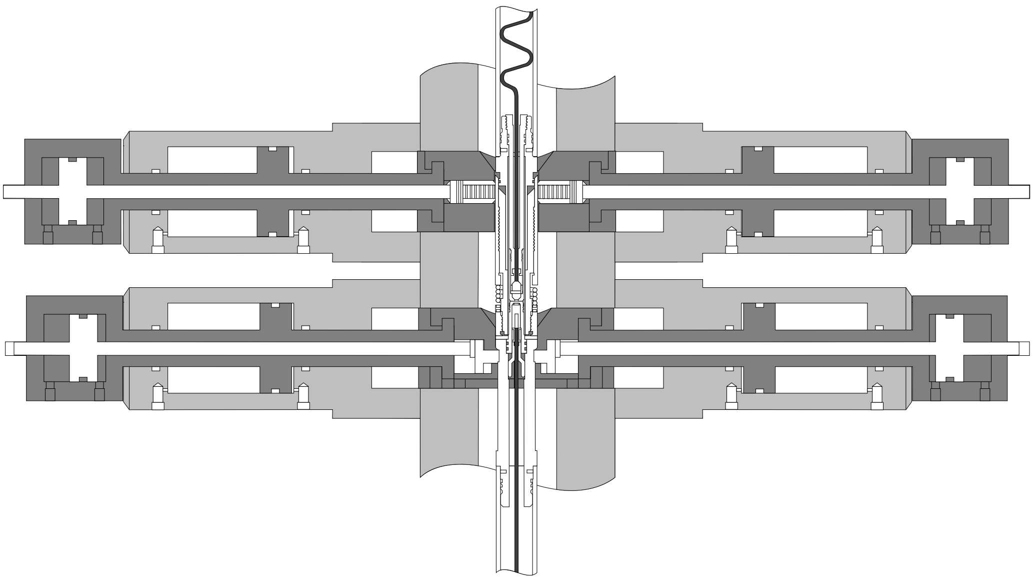


Fig. 16 CIRP System components

The lower half of the snaplock connector has a breech lock sleeve with a series of buttress type grooves (Figure 17). Approximately 50% of the grooves have been cut away longitudinally to make a series of vertical slots in the grooves. A fork sub inside the breech lock sleeve has external grooves matching those in the breech lock sleeve. The fork sub also has approximately 50% of the grooves cut away longitudinally. This leaves grooved fingers, which when lined up with the cut out section (slots) of the breech lock sleeve, allows the fork sub to slide into the breech lock sleeve until it shoulders.

The stinger sub (upper half of tool) also has external grooves on it which are partially milled away, creating grooved fingers on the OD. When the remaining grooves of the breech lock sleeve and the grooved fingers of the fork sub are aligned vertically and rotationally, a slot is created so that the grooved fingers of the stinger sub can slide in and when properly aligned vertically, the breech lock sleeve can be rotated (one half the width of the fingers on the Fork Sub). This places the breech lock sleeve grooves over half the fork sub fingers and half over the stinger sub fingers, locking the two halves of the tool together vertically. A special key placed between the fork sub and the breech lock sleeve limits the rotation of the breech lock to 15º, relative to the fork sub to ensure consistent locking and unlocking.

A torsion spring attached to the breech lock sleeve and anchored to the fork sub with the torque ring, keeps the breech lock sleeve in the locked (engaged) position unless forcibly overcome by an outside force (such as the ram rack). Approximately 20 foot pounds torque is required to rotate the breech lock sleeve to the unlocked position.

During make-up or break-out, the guns can be run-in or retrieved under pressure using either coiled tubing or a wireline. Using wireline (if available) is typically easier and faster since make-up and break-out of the lubricator is simplified.

The number of snaplock connectors and the number of lifts required on a particular job is determined by the length of lubricator that can be used.

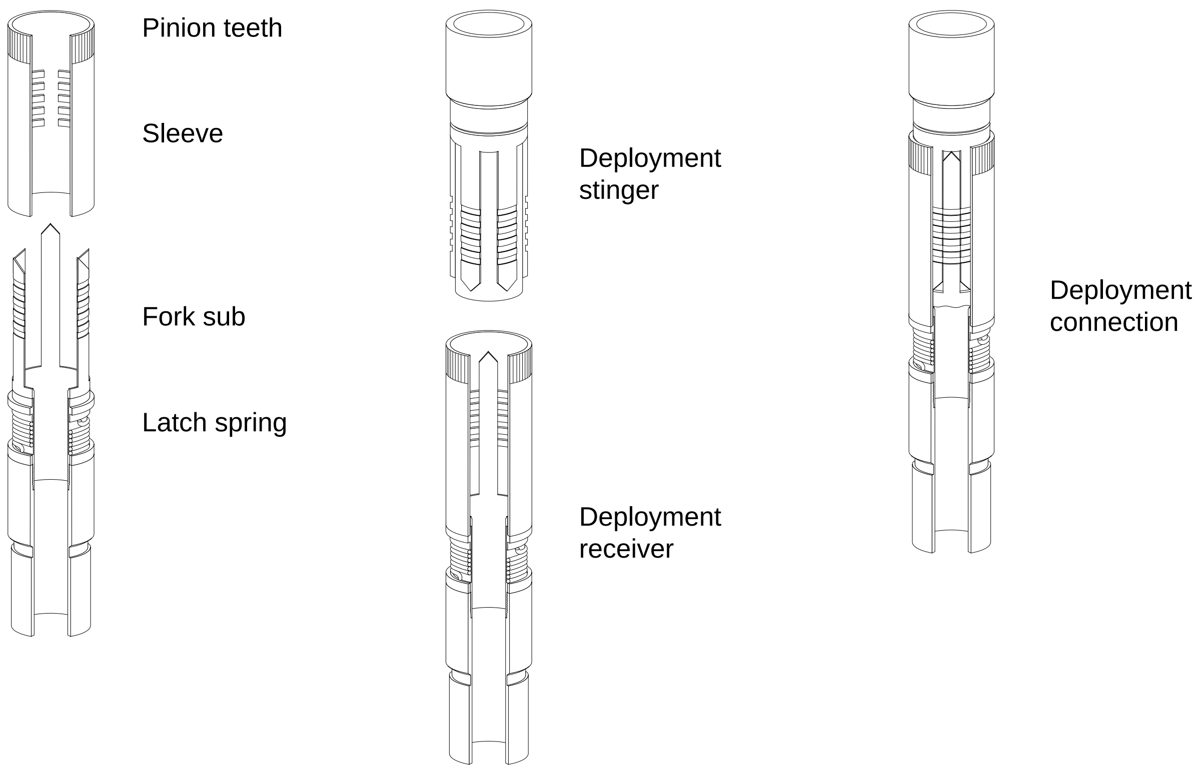


Fig. 17 CIRP Deployment conectors

4.2.1 Operation

The following discussion is intended to provide basic understanding of the system and does not contain sufficient information to enable job design or execution.

The BOP stack is made up on the wellhead with single or double master valves between it and the lubricator (Figure 14 and 15). A special pick-up and lay-down assembly is typically required. This consists of a standard pick-up nipple, a short gun (for weight) and the top half of a snaplock connector.

The top gun of a string is dressed with the lower half of a snaplock connector. If more than one lift is to be made, the lower end of each subsequent lift will also require the upper half of a snaplock connector.

Although lengths may allow the firing head to be picked up with the last lift, it is good practice to pick up the safety spacer with the last gun lift and to make a special lift for the firing head alone. This allows the firing head to be connected with the guns safely below the BOP stack.

With the first lift (bottom of the gun string) made up on the pick-up and lay-down assembly and inside the lubricator, the lubricator is made up on the wellhead as shown. The lubricator is then slowly pressurized to equal wellhead pressure. When the lubricator pressure equals the wellhead pressure, the master valve(s) are opened.

With the master valve(s) open, the first gun section is lowered into the wellbore until the slick joint of the snaplock connector is opposite the no-go rams (lower set of rams) of the BOP stack (Figure 18).

At this time, the no-go rams are closed on the slick joint and the string slowly lowered until it stops. This should be when the ram lock groove at the top of the slick joint reaches the ram (Figure 19). Note: the slick joint below the ram lock groove is smaller than the upset above the groove.

The lock ram is then closed (Figure 20) to prevent movement in the lower section of the snaplock and locking it against rotation. Next the guide rams (upper set of rams) are extended to centralize the upper end of the snaplock.

A pull test is performed to ensure that the snaplock is secured in the proper position within the BOP. The gun string is then hung-off on the rams.

The robot arm (within the guide rams) is extended to rotate the snaplock connectors breech lock sleeve to the unlocked position. The upper half of the snaplock connector is then slowly pulled out of the lower half with the cable.

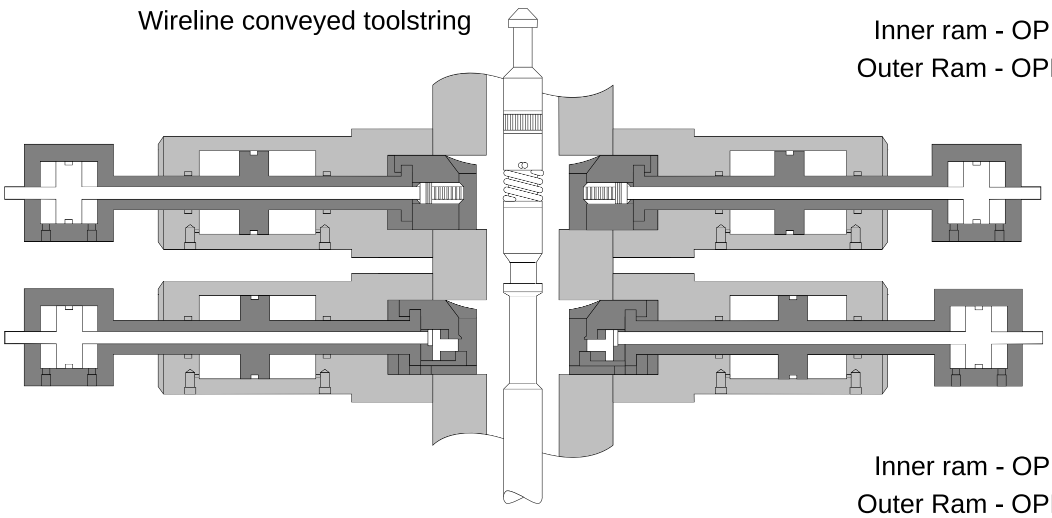


Fig. 18 Run in to position the slick joint

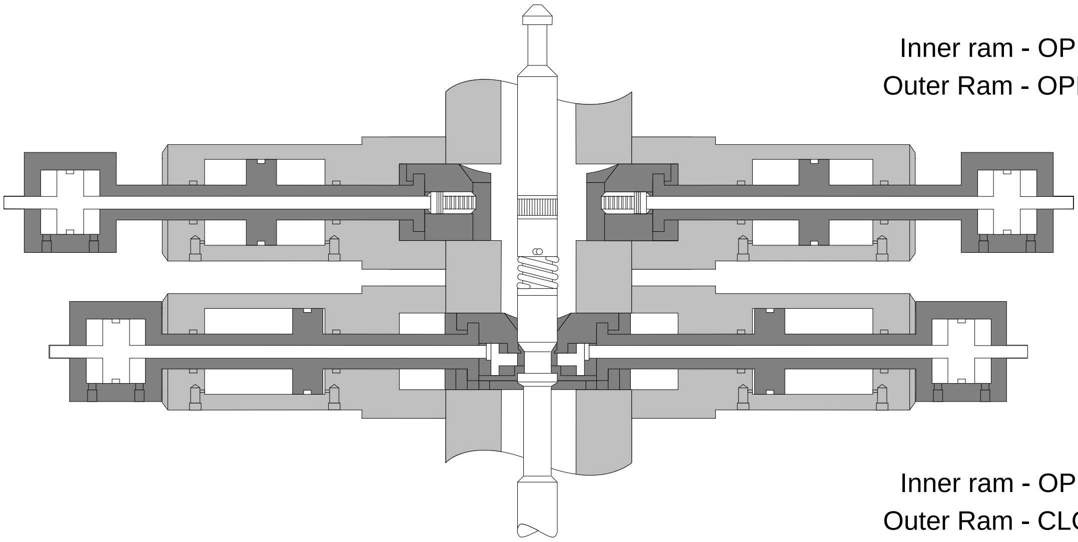


Fig. 19 Close no go rams and set down tool weight

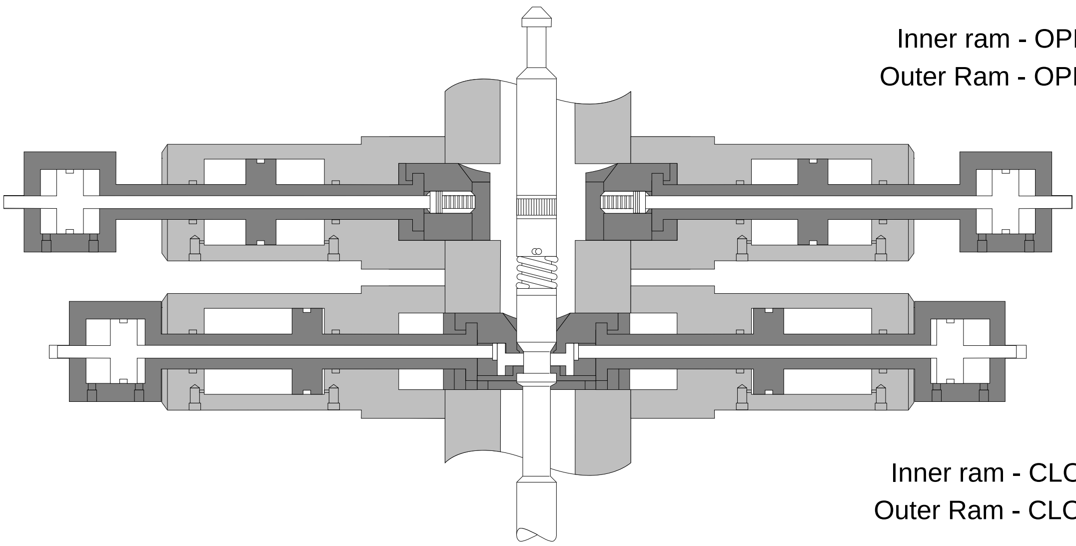


Fig. 20 Close locks and perform pull test

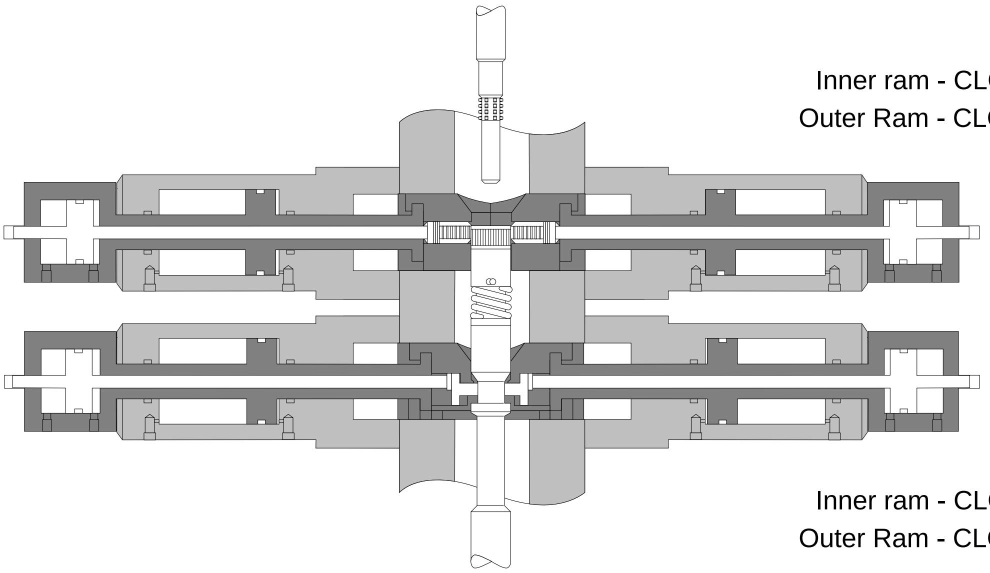


Fig. 21 CIRP Close guide rams and engage rack to disconnect running tool

When the upper half of the snaplock connector is safely in the lubricator (above the top of the BOP stack and valves), the master valve(s) are closed (Figure 21).

With the master valve(s) closed, the pressure on the lubricator is slowly bled off and the lubricator removed ready for the next lift.

With the second lift inside the lubricator, the lubricator is reconnected to the BOP stack and the internal pressure slowly brought up to equalize wellhead pressure. When the pressure is equalized, the master valve(s) are opened and the second gun section is slowly lowered to engage the snaplock connector (Figure 22). The stinger on the bottom of the second lift enters the mating snaplock section hung off on the no-go ram.

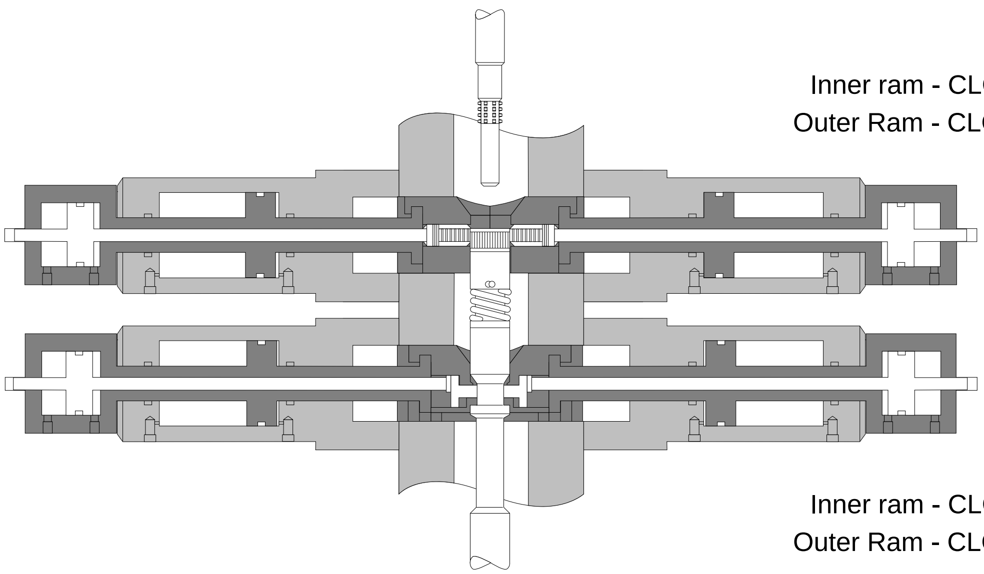


Fig. 22 Run in with next tool string

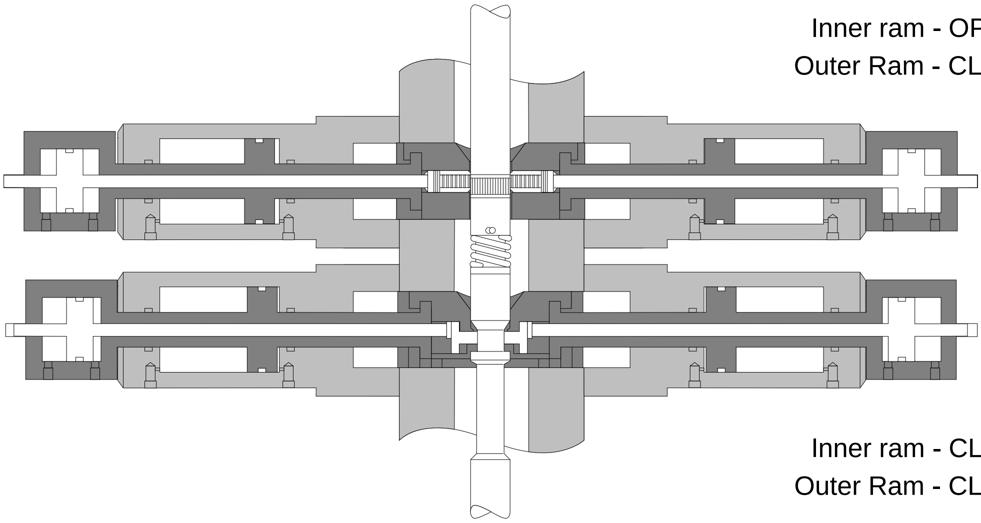


Fig. 23 Stab male stinger, open rack and pull test connector

With the second gun section landed, the robot ram is retracted, engaging the breech lock between the stinger (attached to the bottom of the second lift) and the lower half of the snaplock (attached to the top of the first lift). The cable is then raised, applying a pull to the connection to ensure it is correctly engaged.

When it is confirmed that the snaplock connector is engaged, the overpull is decreased to equal the weight of the gun string and the guide rams, lock rams and no-go rams are opened. The gun string is then lowered until the slick joint of the snaplock connector between the top of the second lift and the pick-up and lay-down assembly is opposite the no-go ram.

At this time, the no-go rams are closed on the slick joint and the string slowly lowered until it stops. This should be when the ram lock groove at the top of the slick joint reaches the ram. The lock ram is then closed, as before, to prevent movement of the lower BHA section.

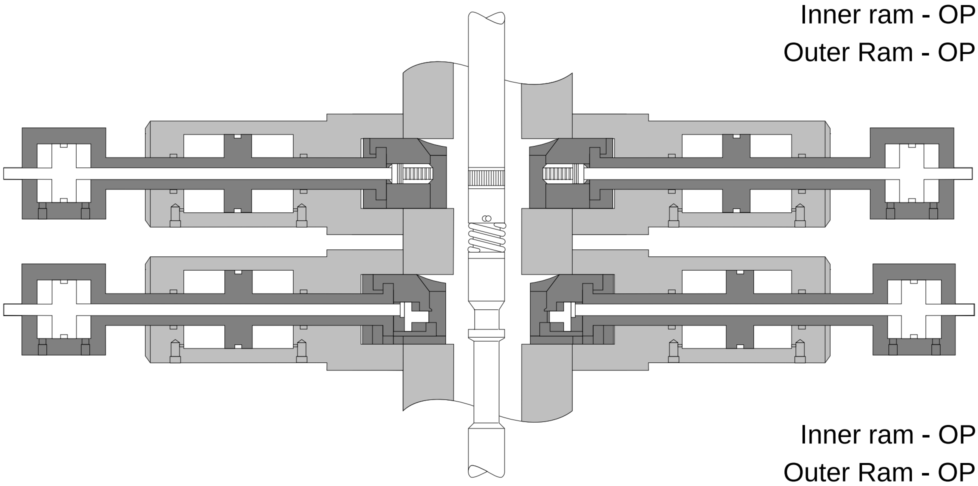


Fig. 24 Open guide rams, locks and no-go rams and RIH

The disconnection sequence as outlined above is repeated.

The installation sequence is repeated on each gun section as required to run the desired total length of guns.

The safety spacer with a snaplock connector looking up is the second last section to be installed. After the safety spacer lift is landed and locked in the no-go ram, the pick-up and lay-down assembly is laid down, the wireline stuffing box is removed from the lubricator, and the lubricator attached to the coiled tubing stripper. A coiled tubing firing head such as the CBF with a snaplock connector stinger on the bottom of the firing head is prepared and attached to the bottom of the coiled tubing as shown in (Figure 23).

The lubricator is attached to the BOP stack.

If it is necessary to pressure test the firing head it can be safely done at this time, while the firing head in the lubricator and not yet attached to the gun string. After testing, the lubricator pressure is equalized with the wellhead pressure.

With the no-go ram open the string is then lowered in the well (Figure 24).

4.3 Depth Correlation of Guns When Conveyed on Coil

When perforating with conventional TCP guns, a gamma ray/CCL electric line lay is the normal practice prior to setting the packer. The same technique is used when electric line perforating is performed on CT. However, in purely hydraulic the operation is more complex.

The most common method uses a memory logging string. This involves performing an initial drift run with the CT, which is the memory PL string. The correlation procedure requires a careful and methodical approach in order to get it right without complications. Typically, two tool strings would be run to provide full back up on the tool functions. The reference point on this type of job is the coil tubing check valve. This is because the check valves are common to both BHAs.

The correlation procedure may be summarized as follows:

- Perforation logs are taken from electric line logs.
- CBL/VDL/GR log will show the casing pip tag on Schlumberger depth.
- Five minute stations are done on the coil. Flags are made on the coil at the top and bottom points.
- Coil depth at the top and bottom flags are noted. These depths are taken after moving in the up direction only.
- MPL tools are generally run through the zone of interest, and this should include some GR characteristics.
- If the zone is flat with its GR response, choose another nearby zone with some more activity.
- 300 ft is about the minimum logging interval and 1,800 ft per hour is the ideal speed.
- The flagging procedure is repeated for a total of three up passes at the same speed.
- Pull out of hole. Make a CCL time mark on each memory unit and record carefully.
- Rig down tools and read memory.
- Plot data corrected for time and depth.
- Logs can be corrected to match electric line log.
- When running TCP guns, run to bottom flag, and move accordingly up or down to compensate for depth error, locate, and fire.

COILED TUBING UNIT SIMULATOR

1. INTRODUCTION

Controlled environment training (e.g., classroom training) of coiled tubing operators has historically been restricted to so called awareness and knowledge training. Acquiring operating skills was largely left to experience on coiled tubing units in the field. However, in developing any skill, minor mistakes and mishaps are virtually unavoidable. Close supervision during the early stages of on-the-job training has generally been an adequate means of ensuring the necessary levels of safety and reliability were maintained within the service.

As the equipment, techniques and applications associated with CT services become more complex, higher demands are placed on the operator. In the high risk environment of well site operations, the consequences of even minor incidents can be severe. Consequently any means of accelerating progress around the operator learning and skills curve is advantageous.

With the availability of powerful computers and ever more realistic simulation environments, the concept of a full sized coiled tubing unit simulator has been developed and delivered. The system enables trainee operators to acquire and practice basic skills within a controlled classroom environment. Specific training programmes have been designed to expose trainees to operating conditions that increase in complexity as they advance. Problem areas can be identified and if necessary specific focus can be maintained to meet the needs of individual trainees. In such cases, the ability to measure or monitor progress is beneficial to the confidence of both the instructor and the trainee.

The CTU simulator integrates a CTU console with electronic hardware, specialized software, and advanced sound and visual systems to provide a simulated environment encompassing the key features of modern CT operations . Several contingency scenarios have been programmed ensuring the trainee operator gains familiarity with potentially dangerous situations, before exposure to the real world.

*** Mark of Schlumberger**

2. THE LEARNING PROCESS

Modern training is an integrated process utilizing a variety of media and technical aids to convey awareness and knowledge to trainees. In ascending their career path, trainees/operators are typically exposed to a sequence of new job functions or techniques requiring further development of awareness, knowledge and skills. Such a career path can be illustrated as a series of ‘S’ shape curves.

It has been established (notably within the aerospace industries) that the introduction of training simulators significantly reduces the time required to achieve necessary competency levels (Figure 1 and 2). In addition this is achieved in the relative safety of the classroom, without exposing the trainee to dangers of the well site. Similarly, clients can be assured that risks associated with operator in-experience are minimized.

2.1 Interactive Training

While the simulator expedites familiarisation with field operations it is essential that trainees follow the same equipment configuration and set up procedures as in “real life”. Ensuring the trainee uses the same analytical path for set up options reinforces the importance of a comprehensive training syllabus which then must become second nature for field operations. For example, a variety of components and configuration options are provided for selection, so the trainee has to give due regard to position and performance of the individual items as well as their interaction with the assembled system.

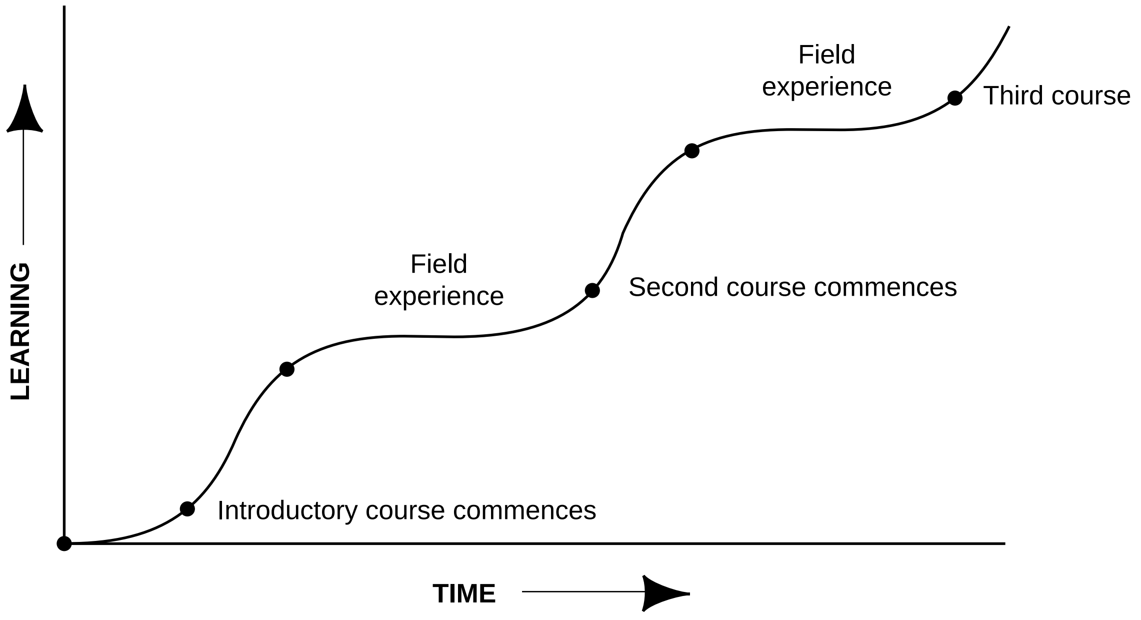


Figure. 1 The learning curves

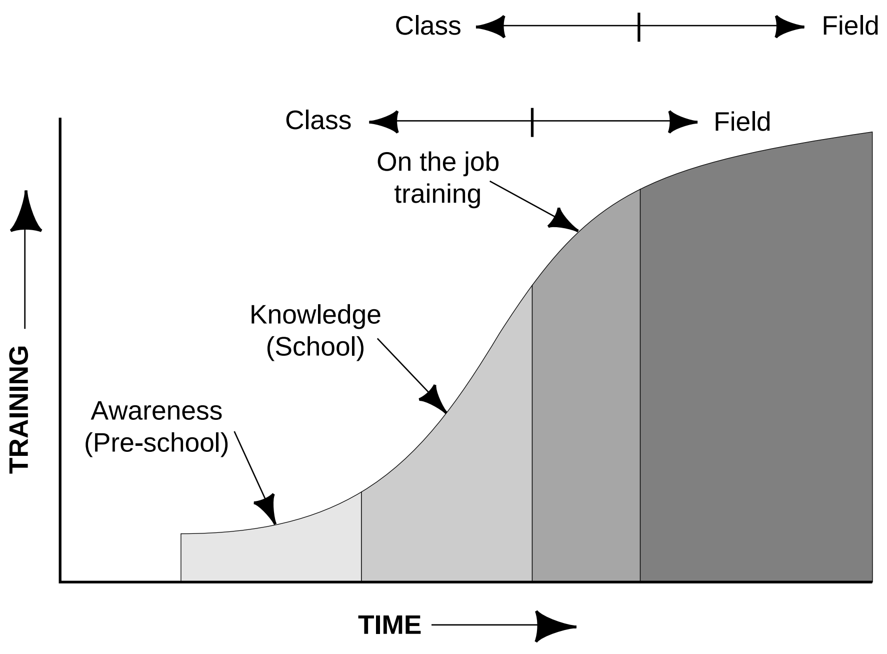


Figure. 2 Simulator assisted learning curve

Another important benefit of simulator training relates to recognition of self-advancement during the course, particularly when career limiting competency based assessment is taking place. The simulator provides real time hard-copy outputs of the key operational parameters (such as pressures, weight, depth etc.) which can be used over several sessions to monitor progress.

Trainee enjoyment is a secondary factor which also has important benefits. After long periods of theory, simulator exercises are often viewed as the highlight of a training programme. Learning value is more concentrated and the simulator is often preferred to lecturing.

The simulator was designed and manufactured to reflect typical CTU control panels (Figure 3). The simulator consoles incorporated original levers and valves to retain the required look and feel. For example; hydraulic control actuators were adapted to receive electronic micro switches giving the correct feel when operating the valve handles. This resemblance to originality not only serves for rapid visual recognition by the trainee but results in the exercise being treated seriously by even the most sceptical students.

The ability to stage malfunctions or contingencies during the course of an exercise provides the greatest benefit to simulator training. Here the instructor can readily test reaction times and the thought sequence of the trainee. Malfunctions programmed into the simulator included equipment failures, tubing run-away, hydraulic failures, circulation leaks, tight hole and choke malfunctions.

2.2 Coiled Tubing Operations

Training programmes can be structured with different themes depending on the classification of the trainee. For example, two categories are immediately apparent. The first relates to training programmes for coiled tubing operators and field service supervisors with direct responsibility for setting up and operating the CT equipment. The second category includes field engineers who are generally responsible for designing and supervising the overall operation which may include additional equipment and systems associated with the CTU.

Simulator exercises are similar for both groups and are typically contained in one of four categories:

- Setting up the unit
- Executing the job as designed
- Emergency response simulation
- Pressure control exercises

A fundamental requirement of operators is that they can correctly “sweep” or “scan” the unit instrumentation. Primary hydraulic system gauges require more frequent scanning than secondary or supporting systems, while the weight indicator, wellhead pressure and circulating pressure gauges require almost constant monitoring. This basic operator skill is a prerequisite to successfully completing the initial simulator practical assessment.

Job execution training requires the trainee to complete a list of job instructions such as would be required to undertake a specific operation, e.g., wellbore fill removal, logging or well kick-off. Such training and assessment focuses on the operation of the key coiled tubing unit components, e.g., injector head control, applied reel back tension, stripper control, operation of the level-wind and understanding the power pack and hydraulic systems.

When the trainee has gained familiarity with the general controls, a variety of operating conditions or malfunctions can be introduced into the simulation exercise (Figure 4). These are categorised in four main equipment or operational areas:

- CT string malfunction - pin-hole, parted string
- Equipment failures - power pack, prime mover, 30 gpm pump etc
- Downhole problems - tight hole, lockup, wellbore fill
- Pressure Control - gas influx, choke washout, pump failure

It is the experience of applying the methodology in response to these conditions that is one of the key benefits of a training simulator. Although much of the simulator training could be performed on a conventional coiled tubing unit and test well set-up, the critical aspects of problem recognition and learning a trained response would be difficult if not impossible in a comparable time frame.

In addition, it is only within the controlled environment of a classroom that the instructor can accurately and consistently assess competence on repeatable unbiased basis. Trainees who are likely to become excessively stressed under emergency conditions are readily identified and can be offered additional coaching.

Although the CTU simulator provides a reliable basis for training and assessing skills, it is only one part of a comprehensive competency based training programme for Dowell CTU personnel.

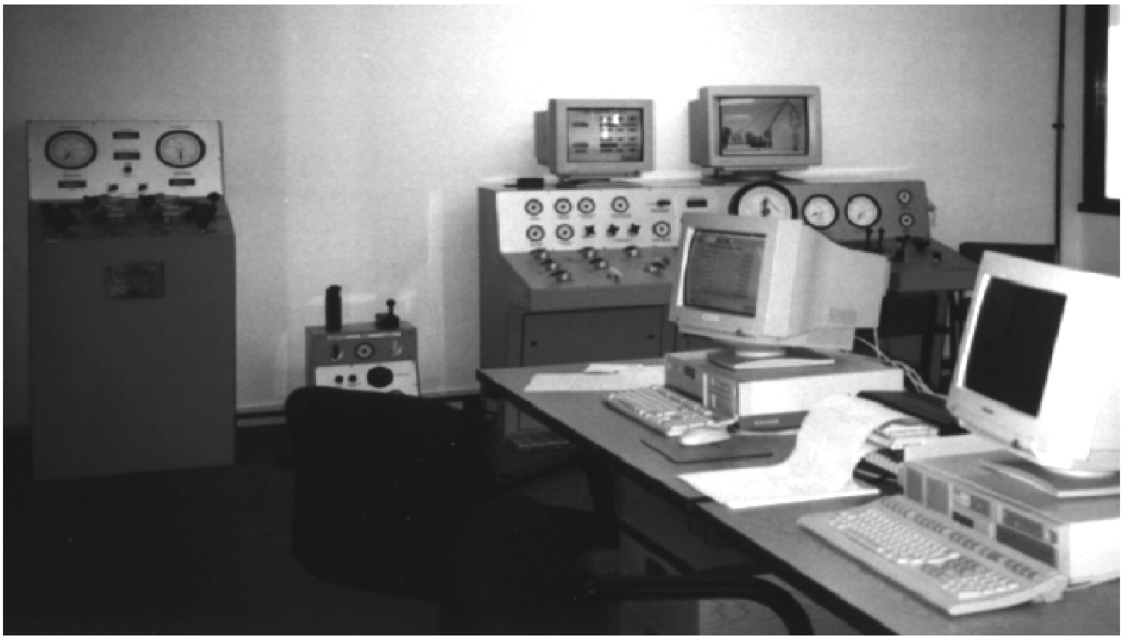


Figure. 3 Dowell CTU simulator - UTC 1997

Figure. 4 CTU simulator - training exercise in progress