



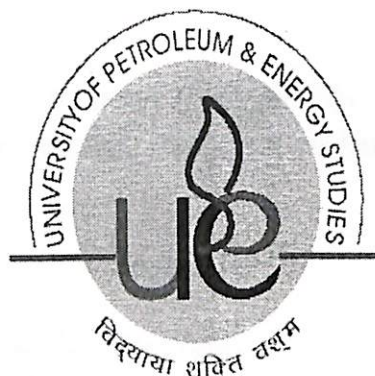
COILED TUBING DRILLING (CTD)

By

Kartikey Joshi (R010206025)

Rahul Dev Chauhan (R010206042)

B.Tech- Applied Petroleum Engineering-Upstream



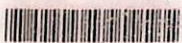
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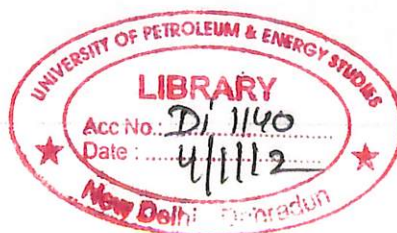
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COILED TUBING DRILLING (CTD)

A thesis submitted in partial fulfillment of the requirements for the Degree of
Bachelor of Technology
(Applied Petroleum Engineering)

By

Kartikey Joshi

Rahul Dev Chauhan

Under the guidance of

Dr. B.P.Pandey (Project Mentor)
Dean Emeritus & Professor of Eminence

Approved

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Dean

College of Engineering
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May, 2010



CERTIFICATE

This is to certify that the work contained in this thesis titled “COILED TUBING DRILLING” has been carried out by Kartikey Joshi & Rahul Dev Chauhan under my/our supervision and has not been submitted elsewhere for a degree.

Mentor

Dr. B.P. Pandey (Project Mentor)
Dean Emeritus & Professor of Eminence
May 2010



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By

Kartikey Joshi

Rahul Dev Chauhan



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ABSTRACT

Horizontal and highly deviated wellbore drilling has been catalyst for developing new and innovative drilling techniques and producers over the last 10 years. Coiled tubing drilling is one of these new techniques which has proven its viability. Serious attempts to directionally drill using coiled tubing began in 1991 but it was not until third quarter 1991 that the first serious attempt was made to drill not only directionally, but horizontally using coiled tubing.

A common misconception is that a CT-drilling unit is a small self contained unit that drives up on location ready to drill with a minimum of rigup involved. In truth, the typical CT-drilling unit must have much of the same equipment that a conventional drilling unit has (e.g., circulating pumps, mud tanks, solids-removal equipment, mud-mixing facilities, well-control equipment). It commonly requires about five to six truckloads of equipment and possibly more if the drilling operation is to be done underbalanced. Also, CT-drilling units with 23/8-, 27/8-, or 31/2-in. outer diameters (OD's) are not exactly the small unit most operators are accustomed to seeing on location for typical well-service jobs. These are necessarily high-capacity units with more associated equipment.

The downhole equipment for CT drilling can be simple or quite complex. For a simple vertical-drilling project, it may consist of a bit, a downhole motor, and a few drill collars. It is much more elaborate for a directionally drilled well. A typical directional bottomhole assembly (BHA) consists of a bit; a bent-housing mud motor; a steering tool to sense and transmit the directional data; an array of optional sensing devices, such as gamma ray and other logs, bottomhole-pressure (internal and external), weight on bit, bit torque, temperature, and vibrations; and an orientation tool to change the direction of the bit.

Normally the operators are confused whether to use coiled tubing in drilling operations or not but there are two applications of CT where coiled tubing stand out from all others in terms of economics and success. They are True Underbalanced Drilling (Preventing Formation Damage) and Through-Tubing Laterals.

CT drilling has lots of advantages like fast trips, horizontal and highly deviated wells, portability, two way telemetry, etc but there are disadvantages also like low circulation rates, non rotating tubing, short tubing life and small hole diameter.

We can say that Coiled-tubing (CT) drilling is a technology of the current decade. The question that many operators have regarding CT drilling is, "Should we consider using CT drilling in our operations?" CT drilling has a considerable number of advantages over conventional drilling methods in certain applications, but it also has a number of limitations that an operator must be aware of. The decision to use CT for drilling must be based on its capabilities because conventional economics seldom favour its use as a drilling method. CT does have unique capabilities that make it excel in true underbalanced drilling and in certain re-entry applications.

Finally a case study to show under which conditions coiled tubing was used over conventional drilling, what were the problems faced in using CT and how they are overcome.



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1. INTRODUCTION

Coiled tubing refers to a metal piping, a long, continuous length of pipe wound on a spool. The pipe is straightened prior to pushing into a wellbore and rewound to coil the pipe back onto the transport and storage spool. Depending on the pipe diameter (1 in. to 4 1/2 in.) and the spool size, coiled tubing can range from 2,000 ft to 15,000 ft [610 to 4,570 m] or greater length, used for interventions in oil and gas wells and sometimes as production tubing in depleted gas wells, which comes spooled on a large reel. Coiled tubing is often used to carry out operations similar to wire line.

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

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

Traditional Applications

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

Growth Applications

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

The main benefits over wire line are the ability to pump chemicals through the coil and the ability to push it into the hole rather than relying on gravity. However, for offshore operations, the 'footprint' for a coiled tubing operation is generally larger than a wire line spread, which can limit the number of installations where coiled tubing can be performed and make the operation more costly. A coiled tubing operation is normally performed through the drilling derrick on the platform, which is used to support the surface equipment, although on platforms with no drilling facilities a self supporting tower can be used instead.

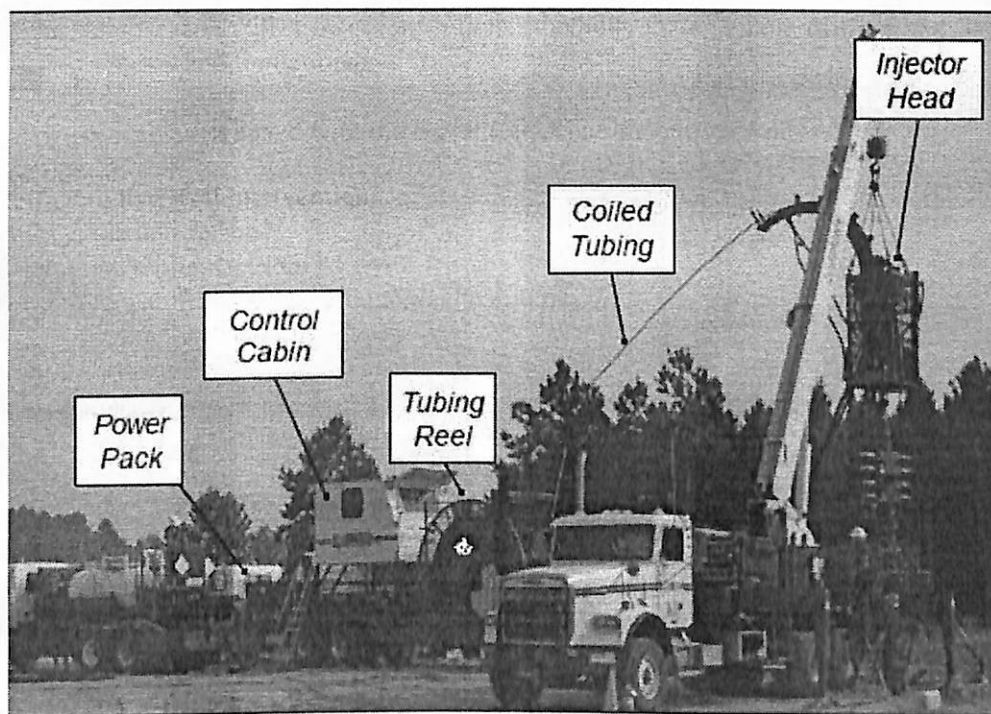
Coiled tubing can also be fitted with internal electrical conductors or hydraulic conduits, which enables downhole communication and power functions to be established between the BHA and surface. In addition, modern CT strings provide sufficient rigidity and strength to be pushed/pulled through highly deviated or horizontal wellbores. This enables successful execution of downhole operations that would be impossible to perform with conventional wireline approaches, or would be cost prohibitive if performed by jointed-pipe. The use of CT has continued to grow beyond the typical well cleanout and acid stimulation application. This growth can be attributed to a multiple factors, including advances in CT

technology and materials as well as the increased emphasis on wellbores containing a horizontal and/or highly-deviated section.

Openhole drilling with CT technology is truly a product of the 1990's. In 1990, Fultz and Pitard¹ showed that it was a feasible concept, and Ramos *et al.*² reported on its use in a successful producing-horizontal-well case history in 1992. The technology was conceived, was born, and grew within this decade, and its growth and successes in this brief time interval are astounding. CT offers a number of advantages and unique capabilities over conventional methods for openhole drilling and likewise has a number of disadvantages and limitations.

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

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



Trailer Mounted CT Unit and Crane

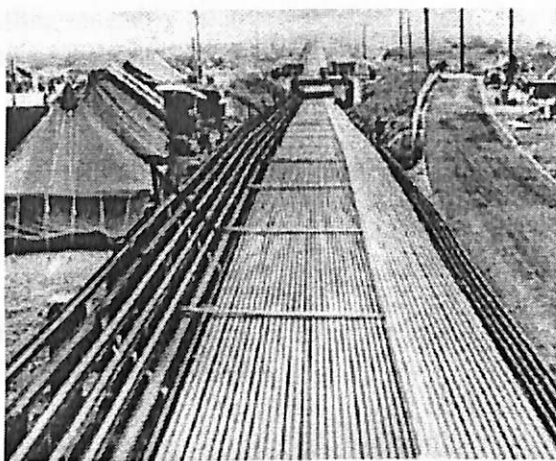
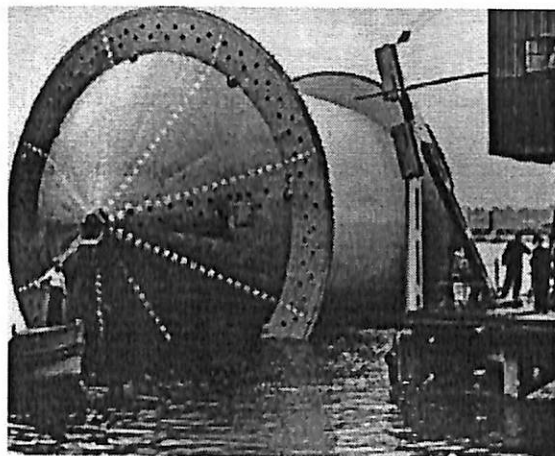
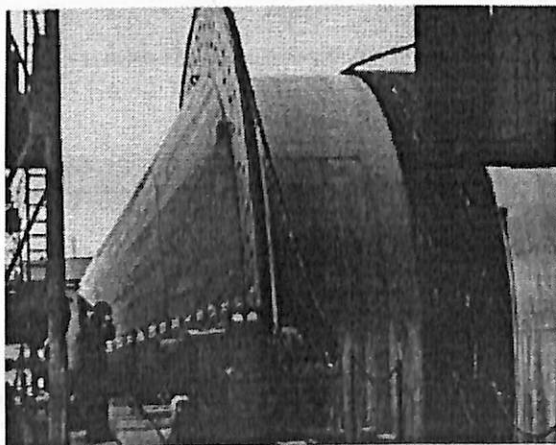
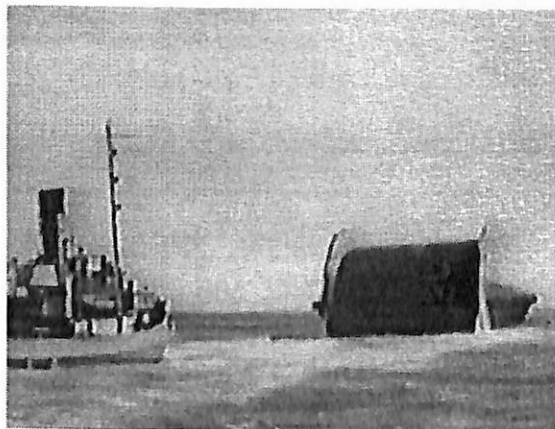
2. HISTORY

2.1 ORIGIN OF COILED TUBING

Prior to the Allied invasion of Europe in 1944, to supply the Allied armies, engineers developed and produced very long continuous pipelines for transporting fuel from England to the European Continent. This project was named PLUTO (Pipe Lines under the Ocean) which included laying of several pipelines across the English channel. The successful fabrication and spooling of continuous flexible pipeline laid the foundation for further developments that eventually led to the tubing strings used in modern CT.

In the late 1940's, few concepts relating to the injection of continuous tubing or cable into live wellbore were patented. In 1950 several concepts related to drilling with continuous, flexible strings were patented. Bowen Tools developed a device in which antennas are used for submerged submarines. The antenna is a 0.625in. brass tube which is spooled on to a reel storage and was capable of drilling a depth up to 600ft. This system used the same principle of the contra-rotating chain drive that would be later adopted for CT injectors. The California Oil Company and Bowen Tools, in 1962, developed the first fully functioning CT unit, for the purpose of washing out sand bridges in wells.

Operation PLUTO





A STEP IN DRILLING

In Drilling, the techniques and equipment associated with Coiled Tubing Drilling (CTD) have undergone rapid development since the first operations attempted in 1991.

The availability of reliable large diameter CT which enabled sufficient hydraulic horsepower to be delivered downhole was the principal stimulus for this activity. 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 to this the larger and heavier wall tubing provides the necessary weight for efficient drilling and to safely withstand the torque and fatigue imposed by drilling operations on the site.

After following several successful vertical well drilling recompletions, serious attempts to directionally drill using coiled tubing began also in 1991.

Although feasibility studies and project evaluation began in 1990, it was not until third quarter 1991 that the first serious attempt was made to drill not only directionally, but horizontally using coiled tubing. A Dallas, Texas based operating Company, Oryx Energy, took the initiative by working with a coiled tubing company and three directional service companies to attempt to drill the first medium radius horizontal wellbore with coiled tubing employing a combination of proven downhole tools, experimental downhole tools drilling techniques. A non-rotatable drillstring instead of near conventional rotatable steerable drilling assembly was adopted via an "orienting tools" which would, on command, orient the steerable drilling assembly relative to coiled tubing, thus obtaining wellbore inclination and azimuth contrabability. This new drilling technique was one of the latest innovations in drilling that has been commercialized in the 90's.

In 1991, a coiled tubing drilling task force to utilize the expertise of several organisations within the Schlumberger group was established by Dowell. 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.

To support the new tools and equipments, a step-by-step approach was adopted to ensure that operational capability was developed.

2.2 THE EVOLUTION OF CT EQUIPMENTS

In 1960's and 1970's, both Bowen Tools and Brown Oil Tools improved their designs to accommodate CT up to 1in. OD. By the mid-1970's, around 200 of the original-design CT units were in service.

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

Along with injector heads CT strings were also undergoing some significant development.

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



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

By the late 1960's, tubing strings were being milled in much longer lengths with fewer butt welds per string with steel properties improved. The resulting improvement in string reliability significantly benefited coiled tubing services.

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

Some new coiled tubing drilling rigs have the capability to drill and case well with dramatic improvements in time savings. Advancements with heavy duty coiled tubing drilling technology are leading to larger 3-1/2" and 4-1/2" tubing for drilling requirements.

Tenaris was the first in the industry to produce 2-7/8", 3-1/2" and 4-1/2" OD CT and the first in the world certified to ISO 9001. They has produced the world's heaviest as well as the longest continuously milled coiled tubing work strings.

In this century the pressure control equipment, in single, combi double or quad solid unibody construction, is now available in 3.06-inch through 7.06-inch sizes for working pressures up to 15,000 psi for H₂S service. Work reels and injectors for tubing sizes from one inch to 4.5 inches and depths to 25,000 feet are also available.

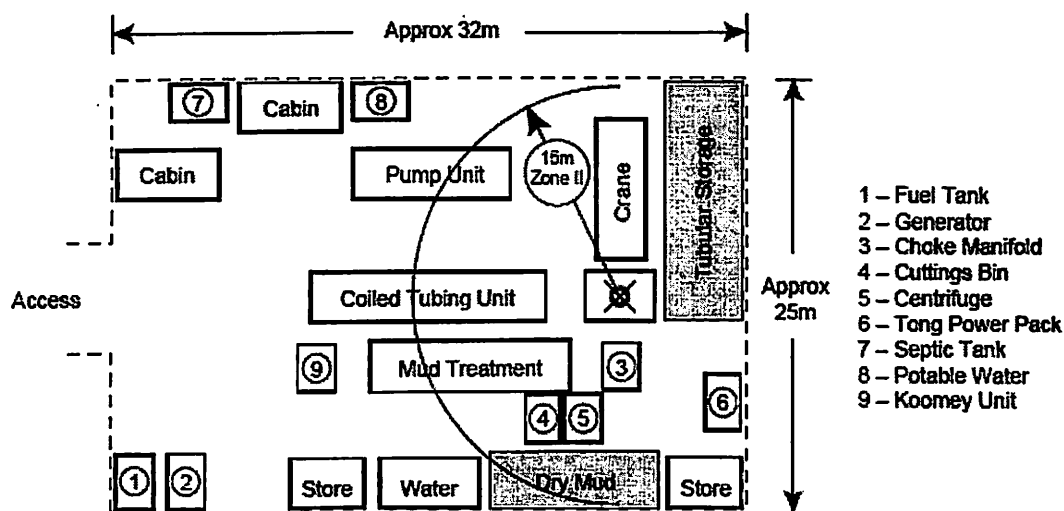
Thus CT is getting equipped with more and more advanced equipments and technologies.



3. COILED TUBING DRILLING UNIT SURFACE EQUIPMENTS

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 coiled tubing drilling projects can be categorized as follows:

- Coiled tubing drilling substructure or rig
- Coiled tubing equipment Package
- Pressure control equipment
- Kick detection equipment
- Mud storage and treatment equipment
- Pumping equipment
- Pipe handling equipment
- Ancillary surface equipment
- Safety and emergency equipment



Typical CTD equipment and location layout – heavy set up

3.1 CTD SUBSTRUCTURE OR RIG

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 Coiled tubing drilling. Substructures designed specifically for CTD offer the greatest potential for efficient CTD operations. 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.



3.2 CT EQUIPMENT PACKAGE

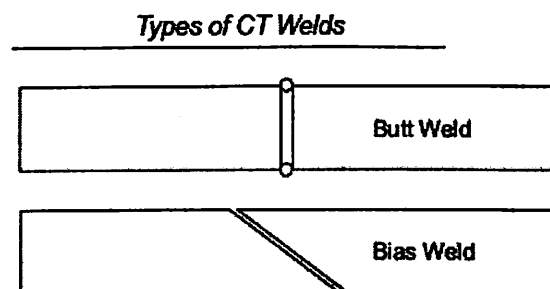
3.2.1 COILED TUBING

For new directional wells, coiled tubing 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 deepening 1-1/2-in CT can be used in certain circumstances.

Raw Material & Manufacturing: Today all coiled tubing begins as large coils of low-alloy carbon-steel sheet. The coils can be up to 55 in. wide and weigh over 24 tons. The length of sheet in each coil depends upon the sheet thickness and ranges from 3500 ft for 0.087 in. gauge to 1000 ft for 0.250 in. gauge. The first step in tube making is to slice flat strips from the coil of sheet using a slitting machine and then ships the coils of strip to the CT mill for further processing. The sheet's thickness sets the coiled tubing wall thickness and the strip's width determines the OD of the finished coiled tubing.

Before 1987, the mills used butt welds to join together sections of tubing for a string of CT. Unfortunately, a butt weld was generally the location where the coiled tubing string failed due to fatigue. The butt weld had inferior mechanical properties compared to the parent tube, particularly in the heat effected zone (HAZ), and the weld profile concentrated into a narrow band the stresses caused by plastic deformation of the coiled tubing in the surface equipment. After 1987, the tube mills began using bias welds to join the flat strips together prior to milling, and this resulted in a dramatic increase in the working life of CT strings. The mechanical properties of the bias strip welds is almost same as that of its parent strip in the as-welded condition, and the profile of the weld distributes stresses evenly over a greater length of the CT.



In this way the CT manufacturer splices strips with similar properties together using bias welds to form a single continuous strip the length of the desired coiled tubing string. This strip is stored on an accumulator called "Big Wheel". A tapered string can be manufactured by joining strips of different thickness or using strips with a continually changing thickness. The CT mill forms the flat strip into a continuous tube and welds the edges together with a continuous longitudinal seam.

The most common low-alloy carbon steels used for coiled tubing are thermo-mechanically controlled rolled ASTM A606 Type 4 modified and modified ASTM A607.

CT products are available with OD from 1.0 in to 4.5 in, although larger diameters up to 6.625 in have been produced in short lengths for testing. The range of yield strengths of the CT material is also increased. Nowadays CT can be purchased with yield strengths ranging from 55 Kpsi to 120 Kpsi.

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

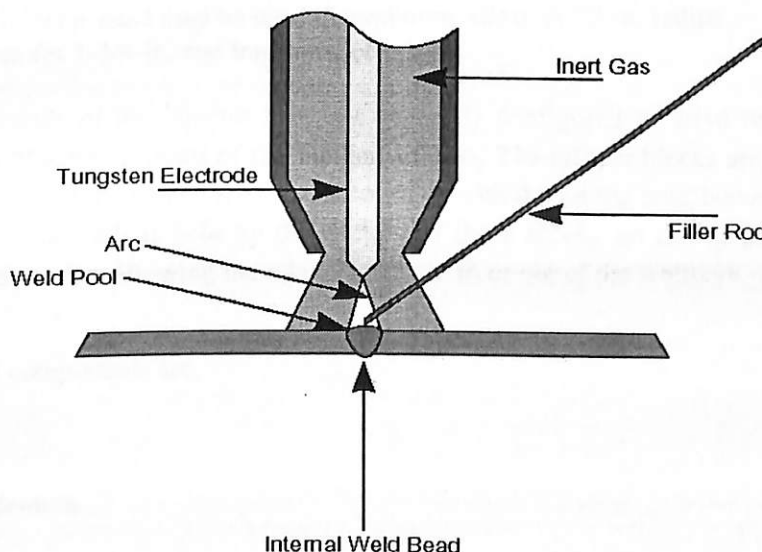
Electro-magnetic proximity sensor – Here proximity sensors are used to measure the diameter and ovality of the coiled tubing. Two diametrically opposite proximity sensors each measure the distance from the probe to the surface of the CT. The distance between the probes is known, and thus the diameter of the CT can be calculated.

Electro-magnetic flux leakage – Here magnets are used to induce a magnetic field into the pipe wall. Hall effect sensors around the pipe sense leakage of the magnetic flux from the wall. This flux leakage gives an indication of cracks and pits both inside and outside the pipe. Average wall thickness can be calculated as it gives an indication of how much steel is in a given portion of the pipe.

Ultrasonic - UT technology is commonly used in pipe manufacturing facilities to inspect new pipe. It measures wall thickness accurately and gives indications of cracks, inclusions and pits. This device, called Argus, measures a localized wall thickness at 12 locations around the circumference of the pipe with an accuracy of ± 0.005 ". 1200 wall thickness measurements are made per second (100 at each location) which provides a thorough coverage of the pipe as it is moving in and out of a well.

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

For permanently repairing CT work strings **TIG welding** is the best method. It uses the heat generated by an arc formed between a tungsten electrode and the work-piece. During the welding process, an inert gas floods the weld location to remove contaminants from the weld site. The joint may be formed either by melting the edges without adding filler (autogenous weld) or, more commonly, by feeding a filler rod into the molten pool. The TIG welding technique is generally restricted to materials less than 0.280 in. (7.1 mm) thick. The low heat input and the slow deposition rate of this technique make it ideal for use with coiled tubing.





Alternatives to Carbon Steel CT:

Corrosion Resistant Alloy- The coiled tubing manufacturing companies are working on corrosion resistant alloy (CRA) CT materials. The corrosion resistance to wet carbon dioxide (CO₂) of the 16Cr alloy is better as compared to 13% Chrome and to conventional carbon steel (QT 900). 16Cr material has a very small corrosion rate compared to these other two materials. Also the fatigue life of the CRA material is approximately three times the life of conventional steel CT. Testing of the 16Cr material in H₂S indicates that this material will require a special inhibition when used in a sour environment.

Titanium- For highly corrosive environments coiled tubing mills produce small quantities of CT made of titanium or stainless steel, but the high cost of these materials has severely limited their use. Titanium is the most preferred material for such an application, but it is difficult to weld and costs approximately 10 times as much as carbon steel.

Composites- Another alternative to steel for manufacturing coiled tubing is a composite made of fibers embedded in a resin matrix. The fibers, normally glass and carbon, are wound around an extruded thermoplastic tube (pressure barrier) and saturated with a resin such as epoxy, in a continuous process.

Benefits of composite coiled tubing compared to carbon steel include:

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

Disadvantages of composite CT as compared to carbon steel CT, including:

- 3-5 times the cost (at the end of 2000)
- maximum operating temperature around 250 °F
- significantly lower stiffness – critical buckling force is much less

3.2.2 INJECTOR HEAD

For new 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 coiled tubing.

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 coiled tubing in the well is held by the friction of these blocks on the tubing surface. Hydraulic motors drive the chains, thus allowing the tubing to be run in or out of the wellbore.

Major injector-head components are.

- Hydraulic motors
- Drive chains
- Chain tensioners
- Gooseneck or guide-arch
- Weight indicator



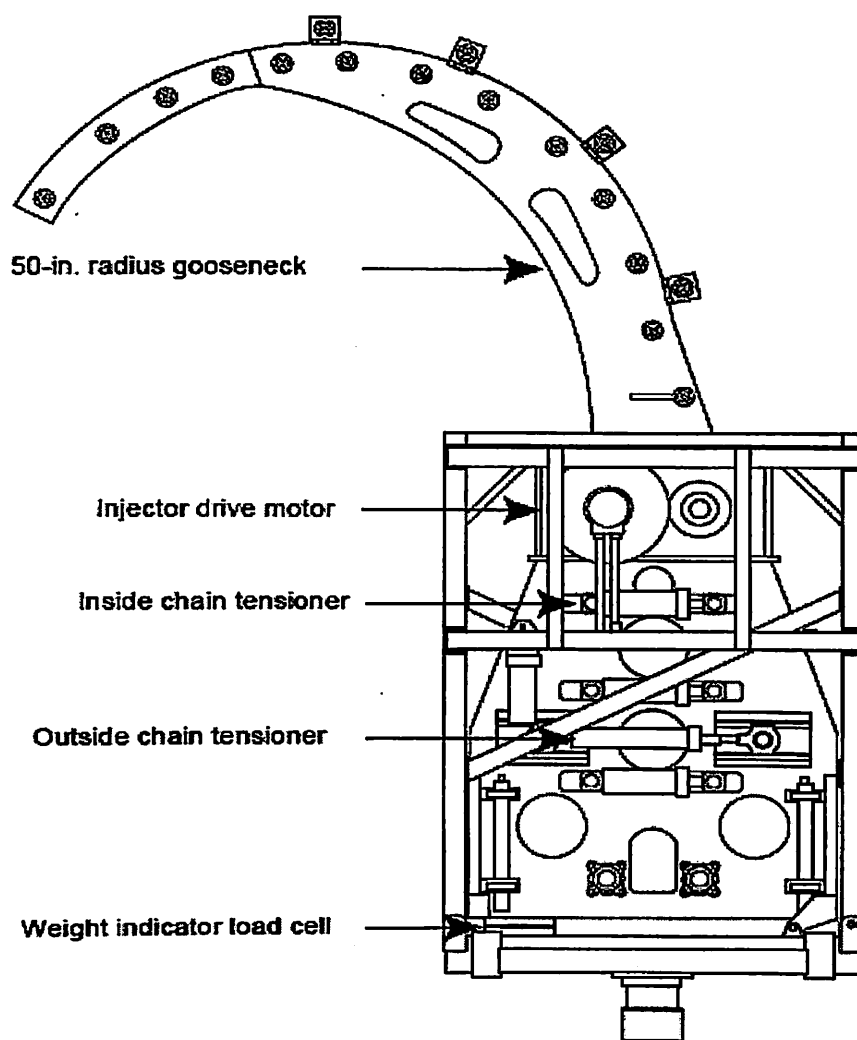
Hydraulic Motors: The hydraulic motors provide the traction required to move the tubing in or out of the well. By controlling the pressure and flow rate of the hydraulic fluid delivered to the motors, the speed and potential force exerted by the injector head can be controlled. Two motors synchronized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

Drive Chains: The chains consist of links, gripper blocks and roller bearings (conventional chain). As 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.

Chain Tensioners: As the tubing is run deeper into a well, the load on the injector chains increases, which requires an increased force to the gripper blocks to maintain efficient traction. This is achieved by the use of applied hydraulic pressure in the inside chain tensioner system. Hydra-Rig offers a choice of chain and tensioner systems. The traditional design of gripper block include 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).

Gooseneck or Guide-arch: 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.

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 also includes the effect of the wellhead pressure and buoyancy. The weight indicator also tells the operator that when the tubing tags or hangs up on an obstruction. Weight indicators operate hydraulically, electronically or as a combination of both. A recording device is always incorporated into the weight indicator system.



Hydra-Rig HR 240 injector head, side view.

3.2.3 COILED TUBING REEL

The coiled tubing 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



Reel Drum: The capacity of any reel drum for a given size of tubing is calculated using the 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.

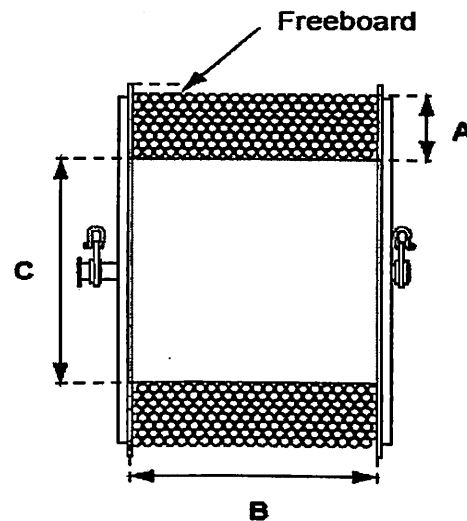
K Values for Different Tubing Sizes

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

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

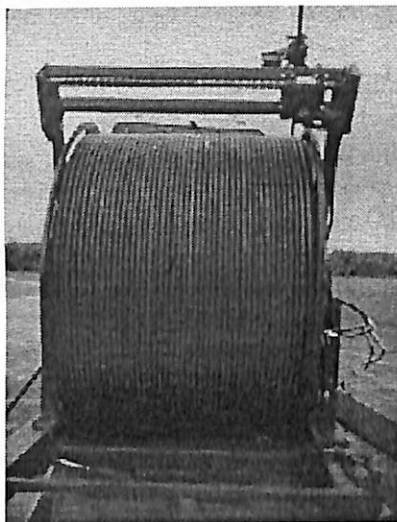


Reel drum capacity.

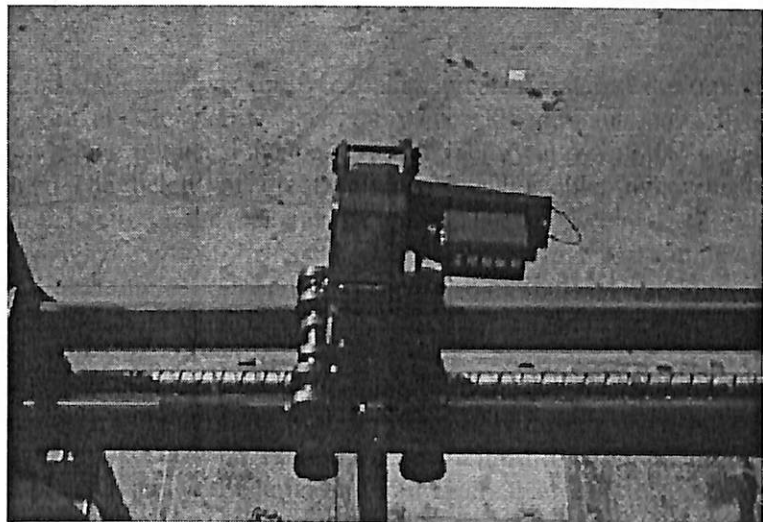
Reel Drive System: The reel is driven by a hydraulic motor which incorporates a safety device to protect the reel and the hydraulic system if there is a mechanical failure or operator error. The motor drives the reel shaft via a drive chain and shaft sprocket. On some of the latest designs of reel, the 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.

Levelwind Assembly: To minimize the strain and possibility of mechanical damage to the tubing, the tubing should be spooled evenly onto the reel. The levelwind assembly is designed to automatically spool the tubing on and off the reel, although 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. The levelwind also provides a convenient mounting position for a depth counter or encoder and tubing monitoring equipment. In addition, equipment required to apply coiled tubing lubrication or corrosion inhibitor is also mounted on the levelwind assembly.

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 at least consists of valve within the reel core to isolate the tubing. Most designs incorporate a pressure deboster/transducer so that the operator can read the fluid pressure as it enters the reel.



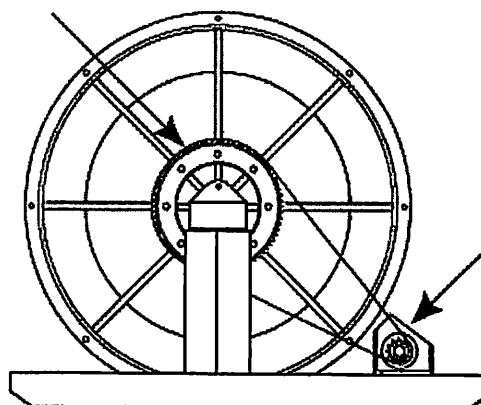
Fully Loaded CT Reel



Level Wind Assembly & Mechanical Depth Counter

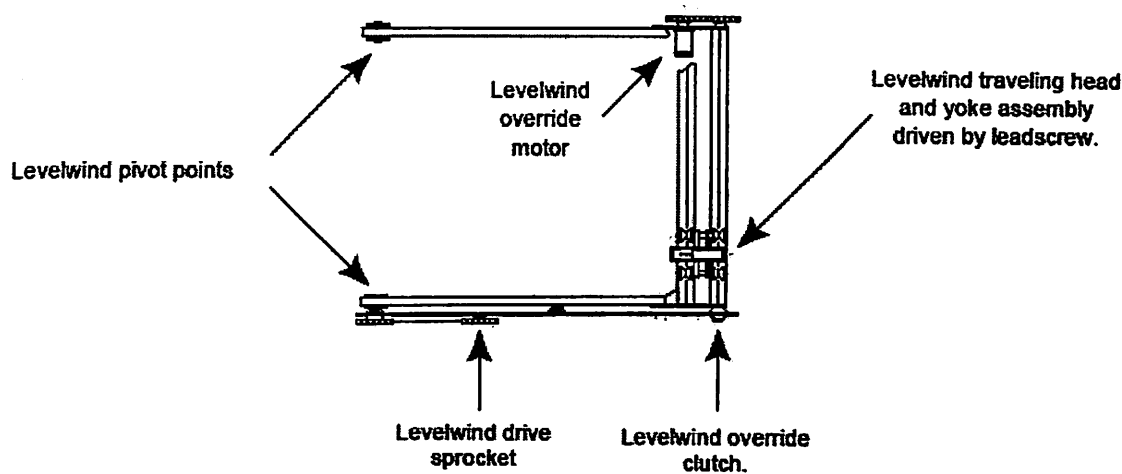


Reel and levelwind
drive sprocket



Reel drum drive
motor and
sprocket

Typical Hydra-Rig reel drum configuration.



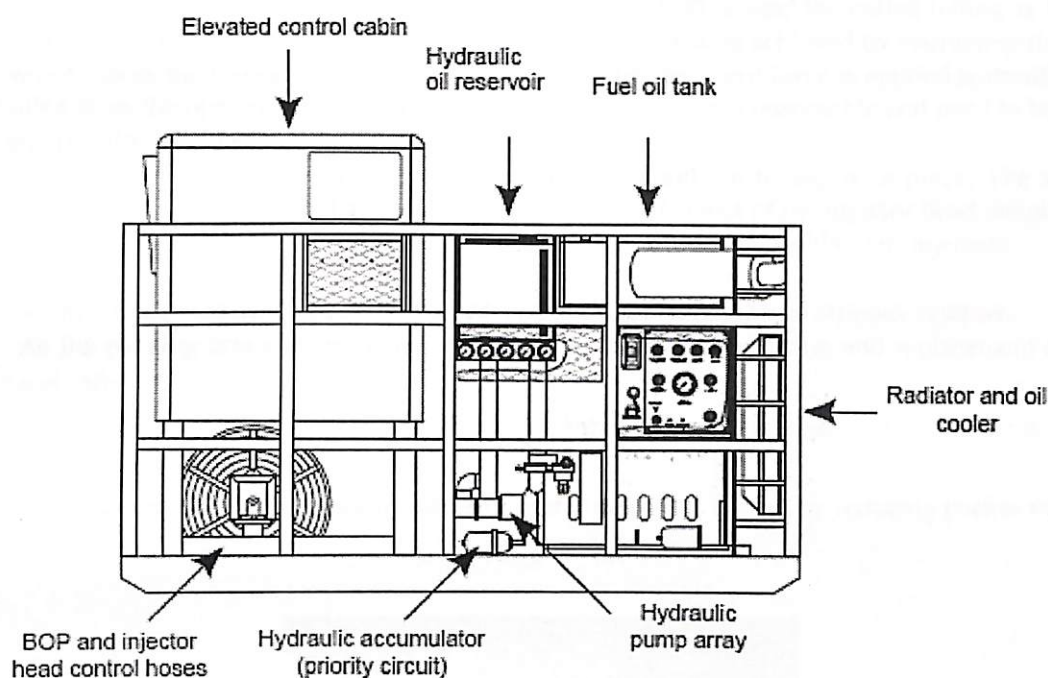
Hydra-Rig reel levelwind assembly.

3.2.4 POWER PACK

The power pack provides the hydraulic energy to operate the CT unit (CTU) functions and controls. 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:

- Engine
- Pumps
- Pressure control valves
- Hydraulic reservoir

- Filters and strainers
- Heat exchanger
- Hydraulic fluid



Power pack principal components (3 piece CTU)

3.2.5 CRANE

For onshore operations, an independent crane truck is there to an integrated crane CTU trailer. Boom length must be sufficient to handle a 40 ft pipe/BHA over the substructure.

3.2.6 CONTROL CABIN

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

It contains all necessary controls and instruments to allow the CT operation to be run from one control station. 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.

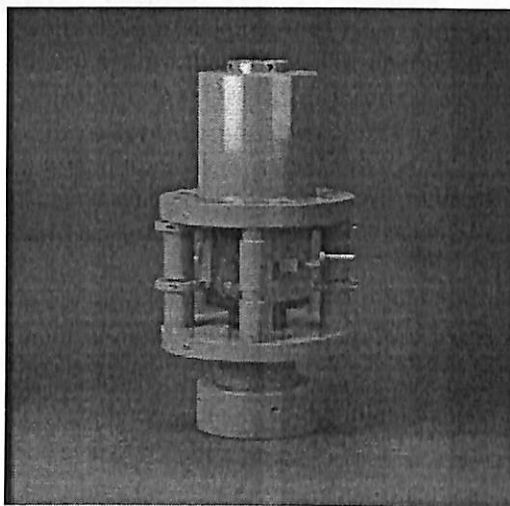
3.3 PRESSURE CONTROL EQUIPMENT

3.3.1 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. As the packer inserts are consumable and 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.

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

- As the packing arrangement is more accessible, therefore inspection and replacement are easier and safer.
- The stripper assembly can be mounted closer to the injector-head chains as now there is no longer a requirement to access the stripper from above.
- The extended guide and bushings helps in centralising of CT, thereby reducing packer wear.



Side Door Stripper

3.3.2 QUAD AND COMBI BOPs

The BOPs most commonly used within Dowell are Texas Oil Tools 10,000-psi Working Pressure, H2S 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 capabilities for added safety during offshore operations. Quad BOPs comprise the following components:

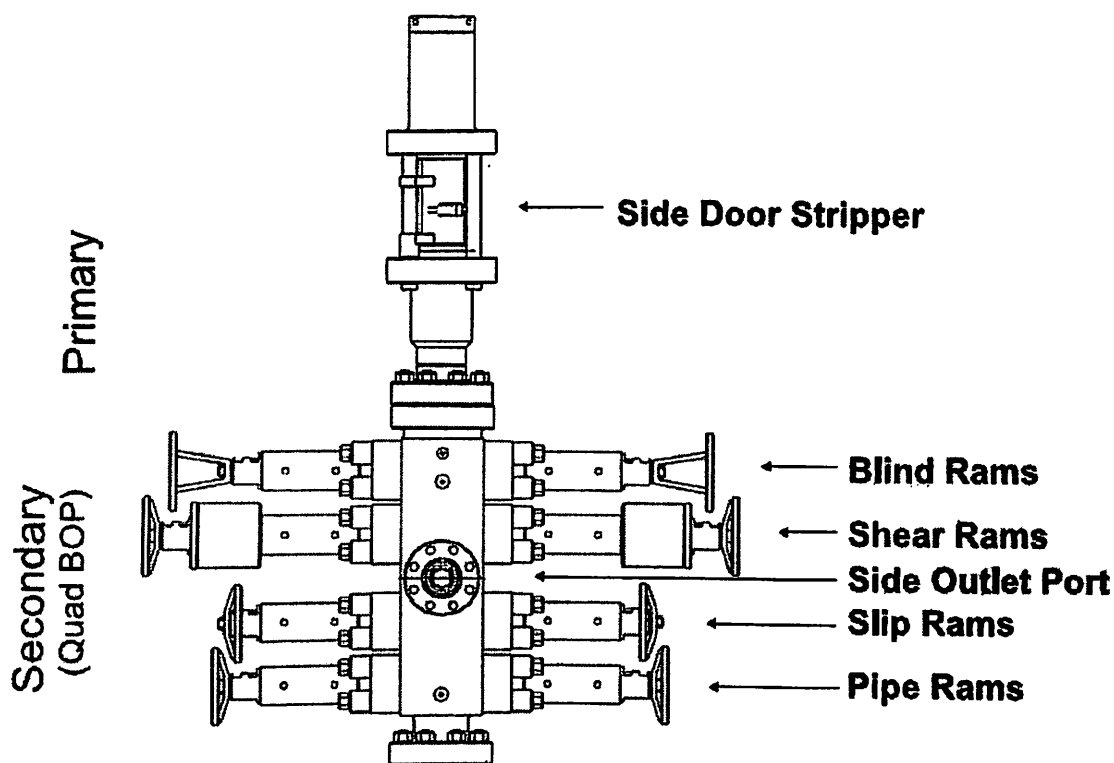
Blind rams: Blind rams are designed to isolate pressure from below when there are no obstructions (such as tubing or tools) in the bore of the BOP. This design has a seal arrangement which uses the well pressure to help keep the rams closed and sealed once they have been activated.

Shear rams: They 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.

Slip rams: They are fitted with hardened steel inserts which are shaped to the profile of the tubing. When closed, they grip the CT and support the weight of the tubing in the well, or force act to push the tubing from the wellbore. Slip rams are normally closed in conjunction with the pipe or shear rams.

Pipe rams: They 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.

Stack for Standard CT Operations (Texas Oil Tools)





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

Top and bottom connections: The type and size of connections on the blow out preventer may vary, although they generally will be pin and collar, or flange connections.

Side port and pressure port: These ports 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 gives 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.

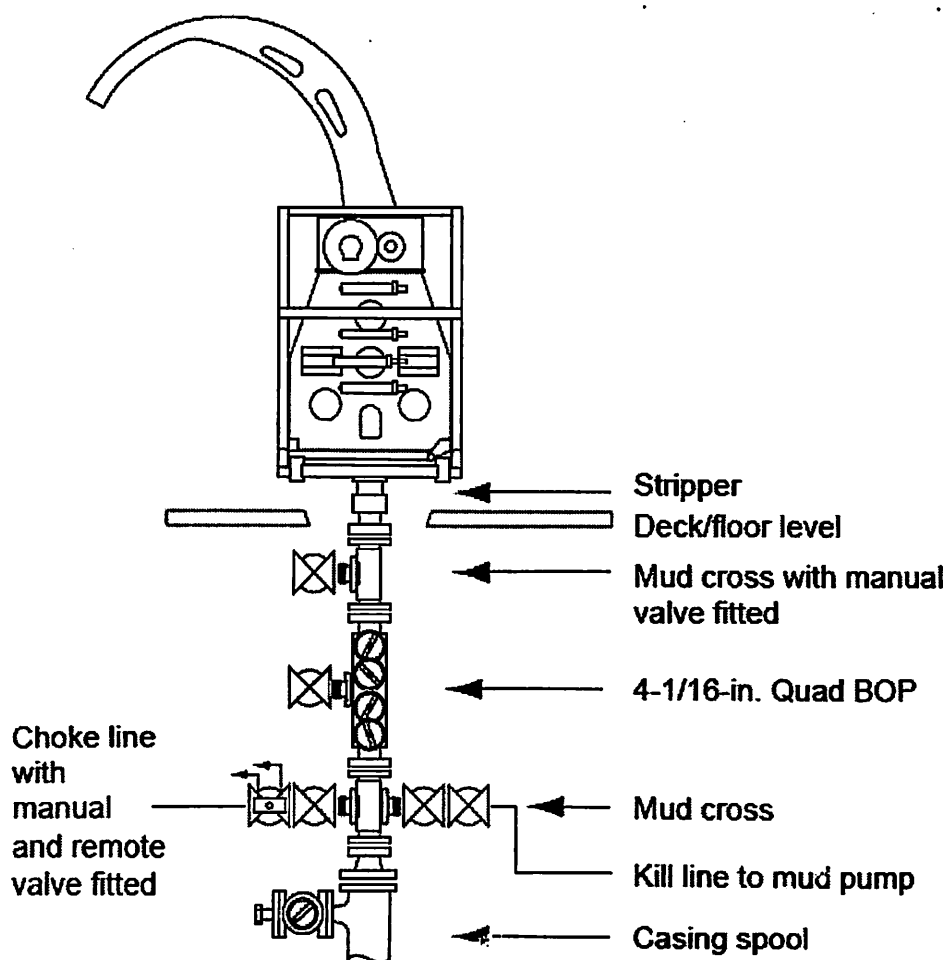
Kill line: It used to kill the well by pumping through the annulus.

Choke line: It is used to divert the flow to the choke manifold and control a kick and choking wellbore returns.

Choke manifold: Pressure rating must be consistent with the BOP rating. The manifold must be a drilling type choke manifold with two manual chokes and one pressure gauge.

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 can be 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 coiled tubing unit control cabin.



Typical well control equipment configuration:

3.4 KICK DETECTION EQUIPMENT

When drilling overbalanced, rapid detection of kicks or losses is essential in slimhole drilling. There are two common methods used in kick detection systems. Both have advantages and disadvantages when used in CTD operations.

3.4.1 Flow comparison (flow in vs. flow out): The best way of detecting a flow variation, is to have a flow meter on the pump suction and on the wellbore return line. The flow difference (D flow) is monitored and recorded versus time. Increase in D flow indicates a kick, while losses are indicated by a drop in D 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 flow meters are available for this application. A low-pressure electro-magnetic flow meter like the Dowell Mag Flow can be used on the return line.



3.4.2 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 required to provide a suitable display. A digital display is not sufficient and so a general trend versus time display format is required.

3.5 MUD STORAGE AND EQUIPMENT SYSTEM

3.5.1 MUD TANK

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

Settling tank: This is the first tank through which the wellbore returns pass. The shale shakers (where fitted) is generally 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/min flow rates. A large (butterfly) valve is normally fitted to the base of the tank to allow easy removal of the accumulated solids.

Active tank: This 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 around 50 BBL for 2 to 3 bbl/min 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. Along with recirculation line, a tank agitator is required to maintain the homogeneity of the fluid.

Reserve tank: They 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 (exploration or development), downhole pressure or risk of losses allow. Nearly 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.

3.5.2 MUD TREATMENT EQUIPMENT

Shale shaker: A shale shaker is necessary for exploration wells to remove the large cuttings produced in the top hole section and to collect cuttings for geological analyses. Coiled tubing drilling 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 deepening, can be performed without a shaker.

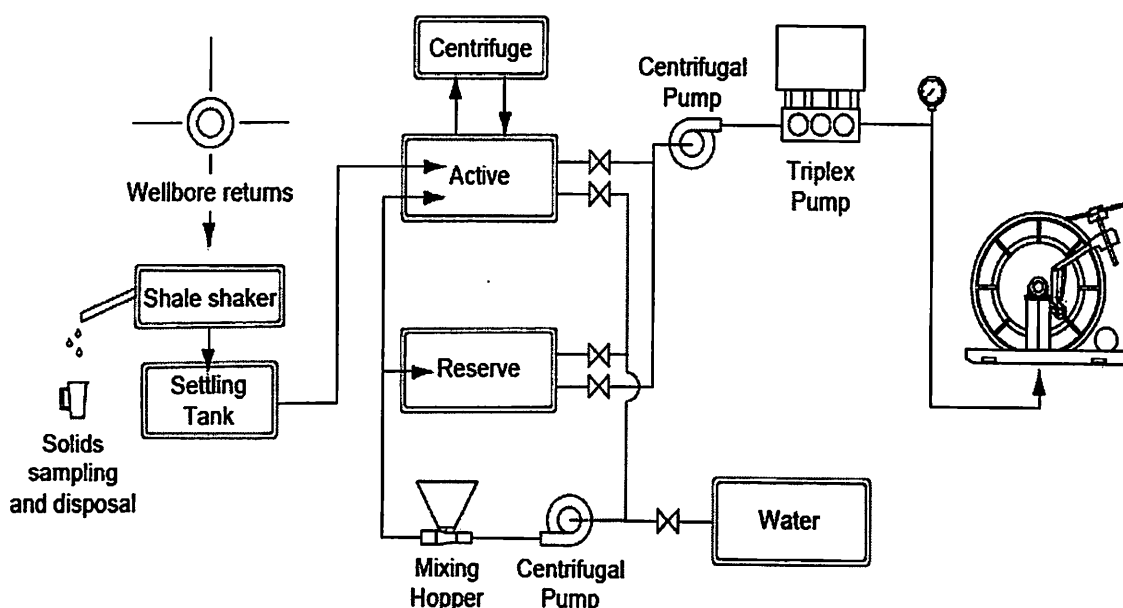
Centrifuge: The centrifuge is an essential item for most CTD applications except short well deepening and shallow new wells. It removes very fine cuttings and avoids their recirculation, which would in time increase the drilling fluid density. Any uncontrolled variation in fluid density and solids content can increase the risk of sticking or wellbore instability.



Gas Separation System: Two types of mud degassing equipment are commonly used (similar to conventional drilling operations).

- **Poor boy degasser** – Installed 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 degasser** – It creates a partial vacuum in a closed tank to knock out remaining gas. This system requires an additional centrifugal pump. Above two systems are combined for maximum efficiency.

Three phase separators: On underbalanced coiled tubing drilling 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.



Typical configuration of drilling-fluid equipment – overbalanced operations.

3.6 PUMPING EQUIPMENT

3.6.1 LOW PRESSURE PUMPING EQUIPMENT

They are 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 reliant 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. The fluid mixing system typically comprises a hopper and jet mixing system supplied by fluid from a centrifugal pump.

3.6.2 HIGH PRESSURE PUMPING EQUIPMENT

The high-pressure pump specifications depend mainly on the hole depth and diameter. For holes smaller than 4-3/4-in the pressure will not 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 coiled tubing unit cabin. This is necessary to change 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, chocks and the necessary valves and accessories.

3.7 PIPE HANDLING EQUIPMENT

This 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 drill collar 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 required, 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. Its pulling capacity is 170,000 lbs—single joints are still handled by the crane.

3.8 ANCILLARY SURFACE EQUIPMENT

Substructure: Used as drill floor when tripping the BHA and as support for the injector head when drilling or tripping the coiled tubing.

Generator: It provides electricity to the port cabins, flood lights, centrifuge, monitoring equipment, the kookey unit etc.

Electrical distribution panel: It provides electrical connection between the generator and the various electrical devices with all necessary breakers and safety features.

Flood lights: Used to provide lights for safe and efficient operations at night.



Air compressor: Used to 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.

3.9 SAFETY AND EMERGENCY EQUIPMENT

Emergency kill: Emergency kill on the coiled tubing unit engine and pump engines.

Firefighting equipment: CO₂ fire extinguishers on CTU power pack, pumping unit power pack, near the port cabins, near the fuel tank.

H2S protective equipment and gas detection equipment: normally provided by the operator.

Eye wash station: Located adjacent 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, etc.

First aid kits



4. COILED TUBING DRILLING UNIT SUB-SURFACE EQUIPMENTS

The downhole tools and equipment required for any CTD project depends on the complexity and specific conditions under which it is to be completed. Most tools and equipment used in association with CTD can 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

4.1 BITS

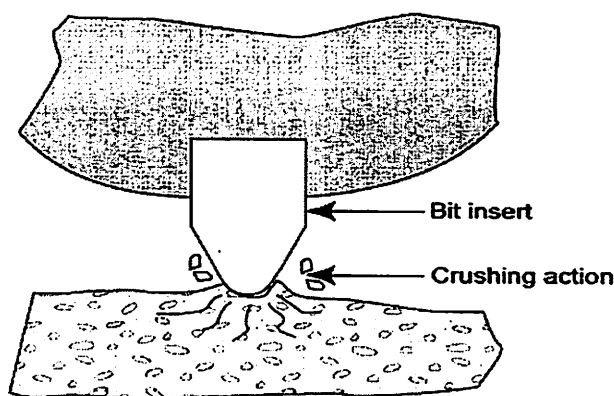
Depending on the diameter of hole, two kinds of bits are normally used. For 4-3/4-in. holes and larger, rock bits, tricones or drag bits are used. For holes smaller than 4- 3/4-in., drag bits are generally used. The motor/bit combination is really important depending on application and can drastically 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 motor (high torque motors are recommended)
- RPM of motor
- Available weight on bit (BOB)
- Drilling fluid type and flow rate

4.1.1 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 types, 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 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 cone lose is high, especially when used in small diameters and with high RPM.



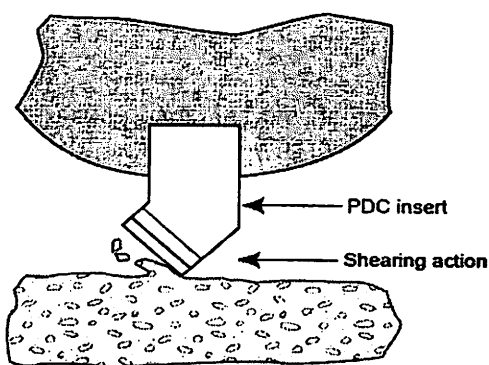
Rock bit cutting characteristics.

4.1.2 DRAG BITS

They don't 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).

PDC bits operate by shearing rock material much like the action of a machinists tool on a lathe. TSP bits also work similarly, 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 weight on bit 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 interchangeable and available in different diameters. The nozzles create a jet impact onto the formation and also clean the bottom of the hole. Most small drag bits do not have nozzles but have ports which give a jetting effect.



PDC bit cutting characteristics.



4.2 DOWNHOLE MOTORS

There are three categories of downhole motor; turbines, vane motors and positive displacement motors.

- Vane motors – There is limited experience with this type of motor. Currently, only one manufacturer is developing vane motors (Volker Stevin).
- Turbines – Not yet available in small diameters.
- Positive displacement motors (PDM) – Available in all sizes but especially small diameters

4.3 CTD DOWNHOLE EQUIPMENT

4.3.1 CT CONNECTORS

A grub screw connector is preferred over others for use in CTD applications as it performs well during several jarring and pull tests.

4.3.2 DISCONNECTING SUB

For coiled tubing drilling applications in large vertical hole (6-in. or greater), a pull disconnect release is preferred. In re-entry wells or deep vertical wells, pull disconnects (such as Griffco) are not recommended due to very limited overpull margin which it allows because of the drag.

Normally, for MWD applications, the Dowell/Anadrill drilling head, which includes a ball actuated disconnect, is recommended. Wireline steering tool BHAs may include an electrically operated disconnect (Anadrill Cobra), or a pull disconnect with a failsafe.

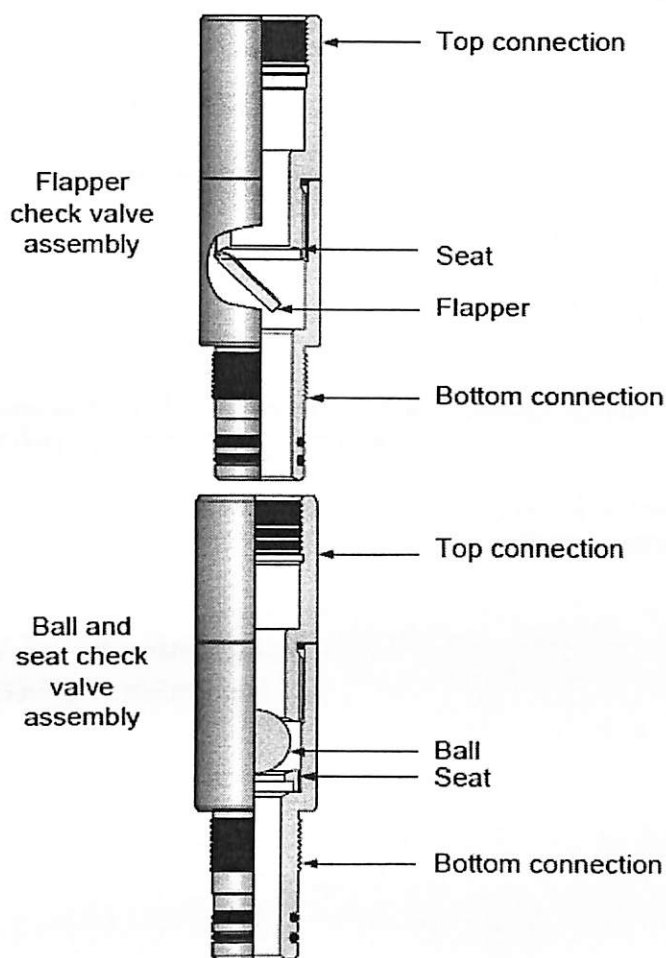
4.3.3 CHECK VALVE

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).

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 tool string 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 full-bore opening or unrestricted flow area is required.

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).



4.4 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:

- Bit
- Downhole motors
- Drill Collars
- Disconnect sub
- Check valve
- CT connector
- Coiled Tubing

Drill collars are used to provide the WOB, with the CT being kept in tension at all times. This creates a pendulum effect which, in the most of situations will maintain a vertical wellbore. Spiralled drill collars are preferred to minimize differential sticking—especially for slide drilling applications. The choice 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.

4.5 BHA FOR DEVIATED WELLBORES

The BHA required to successfully drill deviated wellbores consists several specialized components which, in most cases, are developed for CTD applications.

There are no drill collars in this BHA. The weight on bit is provided by coiled tubing string, part of which will be in compression. A typical CTD BHA for drilling deviated wellbores consists following items

- Bit
- Downhole motor with adjustable bent sub
- Non-magnetic housing for steering tool
- Orienting tool
- Disconnect sub
- Check valve
- CT connector
- Coiled tubing

PRINCIPAL COMPONENTS OF DIRECTIONAL BHA

Directional BHA used for CTD is also known as steerable systems. A steerable system provides the directional drilling engineer with data so that he can get information about tool face, wellbore inclination and azimuth to 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 required 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 occasionally high) side of the wellbore.

Two steerable systems are normally used in CTD applications:

- Wireless steerable BHA including a measurement while drilling (MWD) tool.
- Wireline steerable BHA including a wireline steering tool



MWD TOOL

The MWD tool sends data to surface by inducing coded pressure pulses in the drilling fluid being pumped through the CT string. The signals received at the surface are decoded and displayed on a screen.

The biggest advantage of the MWD tool is the absence of wireline and electrical connections which normally causes a lot 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. But this is normally sufficient to control the trajectory of a CTD wellbore. A high pressure filter system is required adjacent to the reel manifold, as the downhole components are sensitive to debris within the drilling fluid

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 is high data rate which provides almost real time measurement. However, the number of electrical connections required poses a lot of potential problems.

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

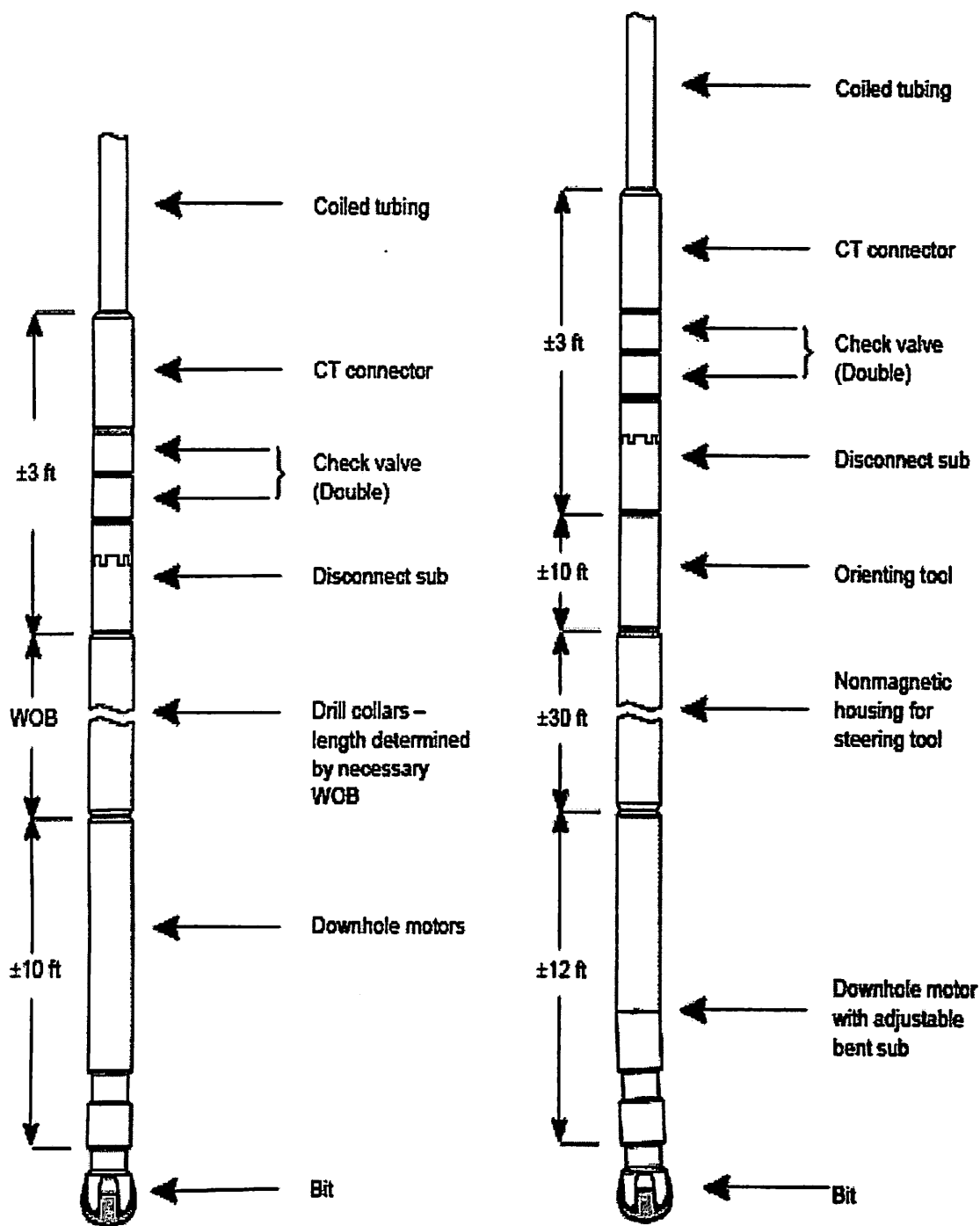
To change the orientation of the tool face an orienting tool is required so the MWD system incorporates an orienting tool which rotates in 30° increments. This tool can only be used with a wireless steering system. Similar orienting tools are available to be used with wireline steering tools (Sperry 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 discussed below:

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 coiled tubing string.

Hydraulically operated orienting tools: A hydraulic orienting tool is controlled via hydraulic control line(s) installed in the CT workstring (Camco and Transocean).



CTD BHA for vertical wellbores.

CTD BHA for deviated wellbores.



4.6 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 normally used.

Drilling Jars: A jar is as a device which delivers a sudden shock (up or down) to the tool string. Here in coiled tubing applications, jar assemblies normally consists of sliding mandrel arrangement which gives brief and sudden acceleration of the tool string above the jar.

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

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

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 under reamers 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. Drilling and under reaming should not be undertaken at the same time. Instead a pilot hole should be drilled first and then under reamed to the desired size.

The under reamer is positioned in the BHA above the bit or bullnose.

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). It is 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. It 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)

Thruster: Thrusters were developed to get rid of the effects of the heavy vibration, which is typical of equipment used in slimhole applications. The thruster dampens vibration and equalizes the WOB.

Fishing Tools: A selection of fishing tools should be prepared for, or at least be on stand-by during coiled tubing drilling operations. The nature and size of the fishing tools will be dependent on the coiled tubing drilling 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 normal fishing tool selection will include the following items.

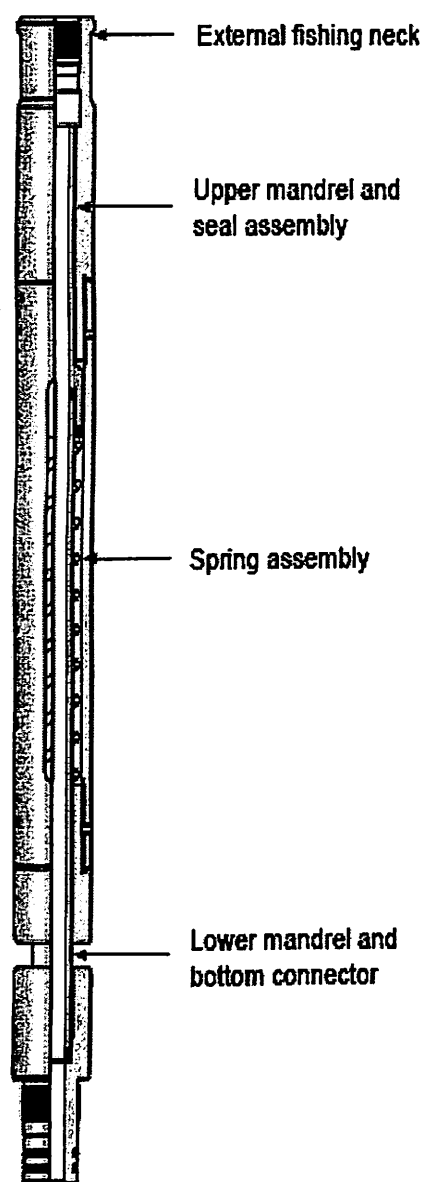
- *GS fishing tool (or similar)* – To suit the fishing neck of the release joint being used.



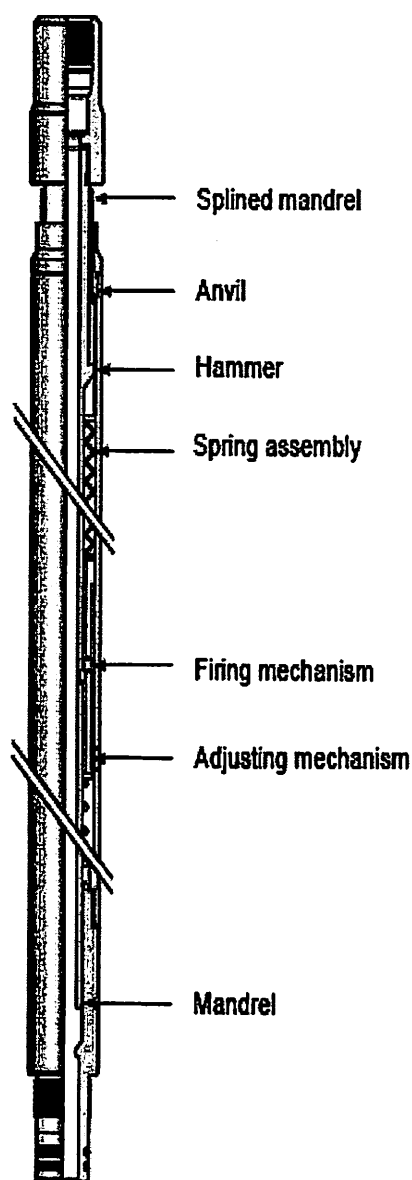
• *Overshots and spears* – Available in a variety of sizes and configurations to suit the toolstring in use. Overshots are designed to engage over the fish to be retrieved, gripping on the OD surface of the fishing neck.

Spears are designed to engage the fish by gripping on the ID surface. Although the preferred method of engaging a fish is by overshoot, the spear provides a useful alternative when retrieving a fish with a suitable bore.

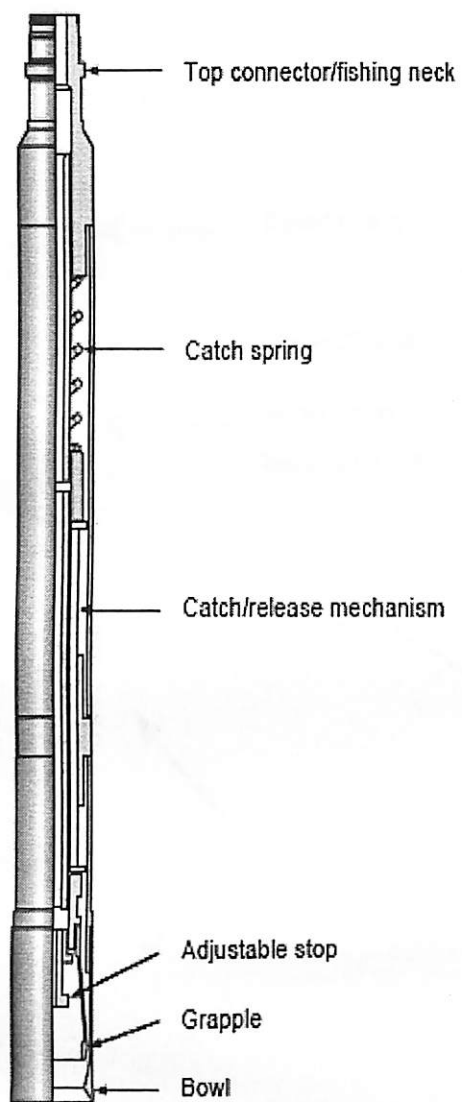
• *Junk catchers and magnets* – They are used to avoid the introduction of junk to the wellbore. Sometimes fishing tools are required for small items and junk on site.



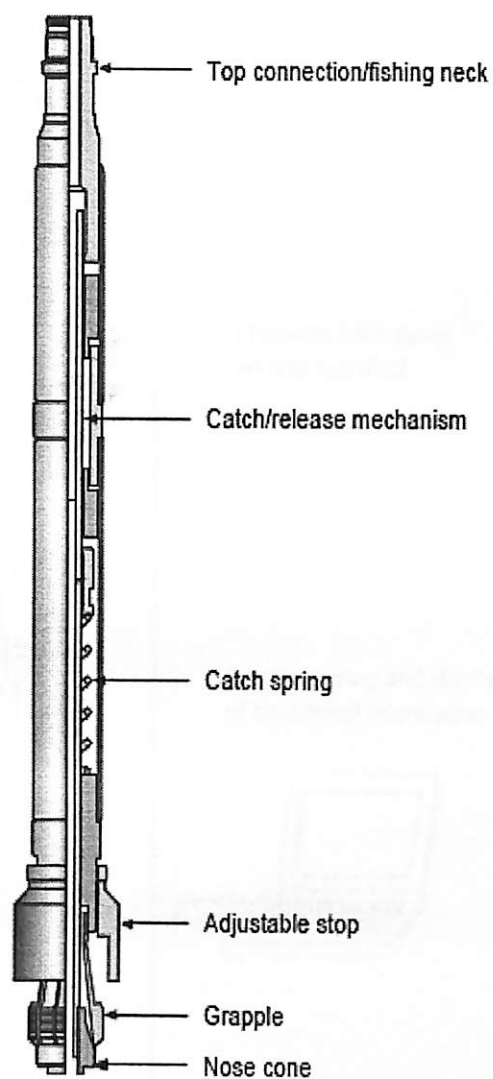
ACCELERATOR



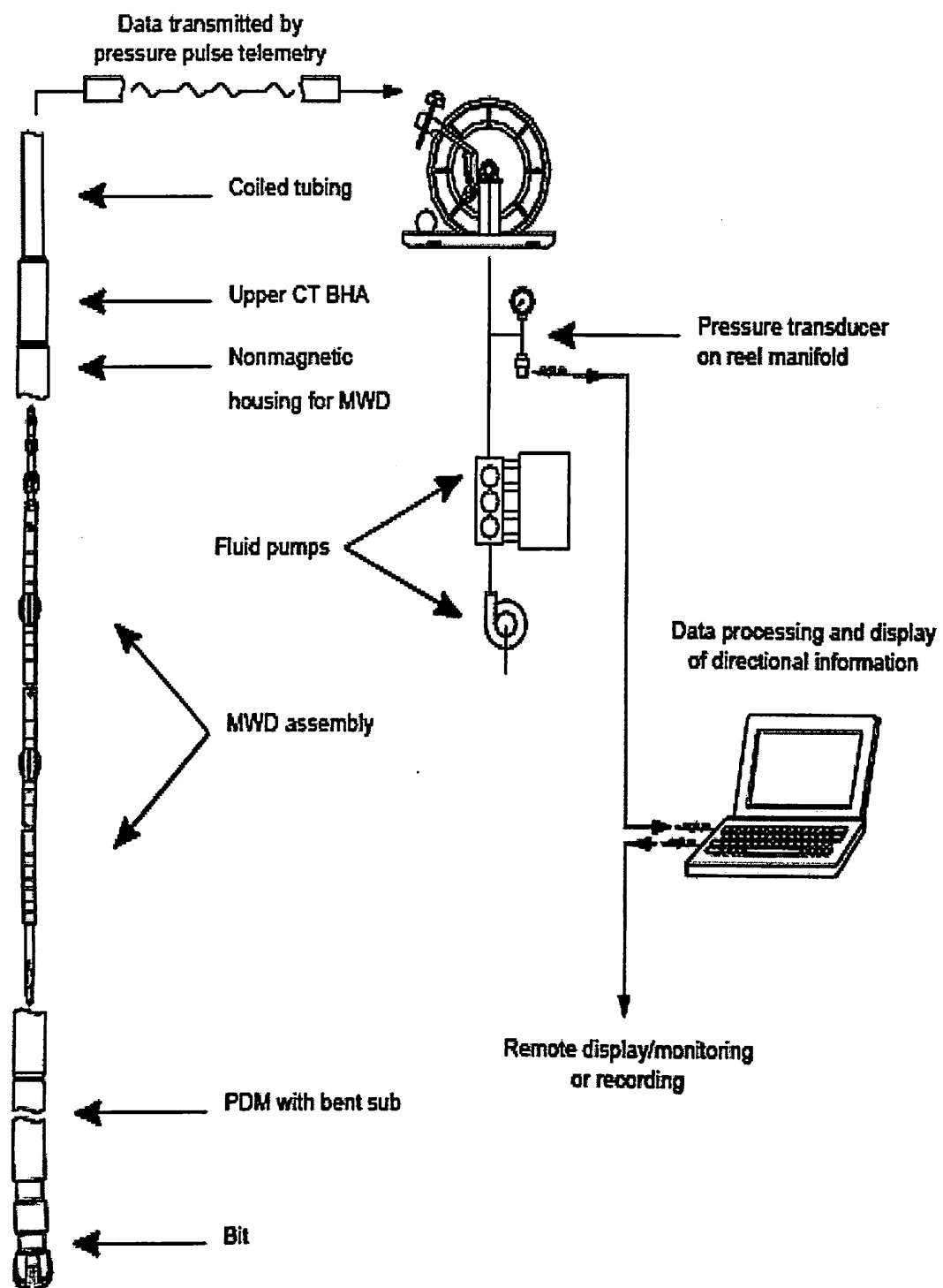
JAR



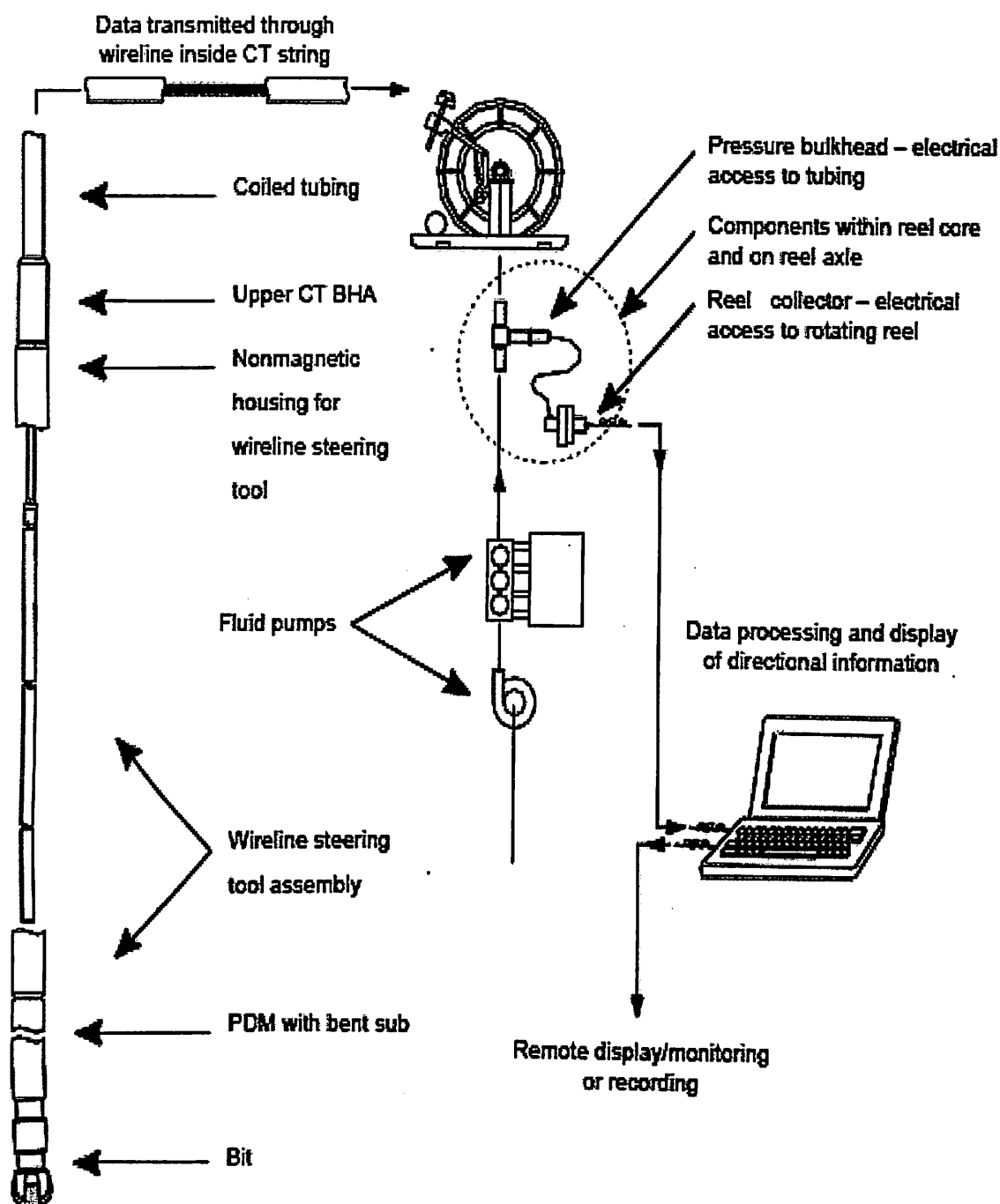
Overshoot



Spear



MWD system schematic diagram.



Wireline steering system schematic diagram.



5. EXECUTION

5.1 WELL CONTROL (OVERBALANCED DRILLING)

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.

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.

5.2 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

5.2.1 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 scraper to the KOD

5.2.2 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).



5.2.3 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

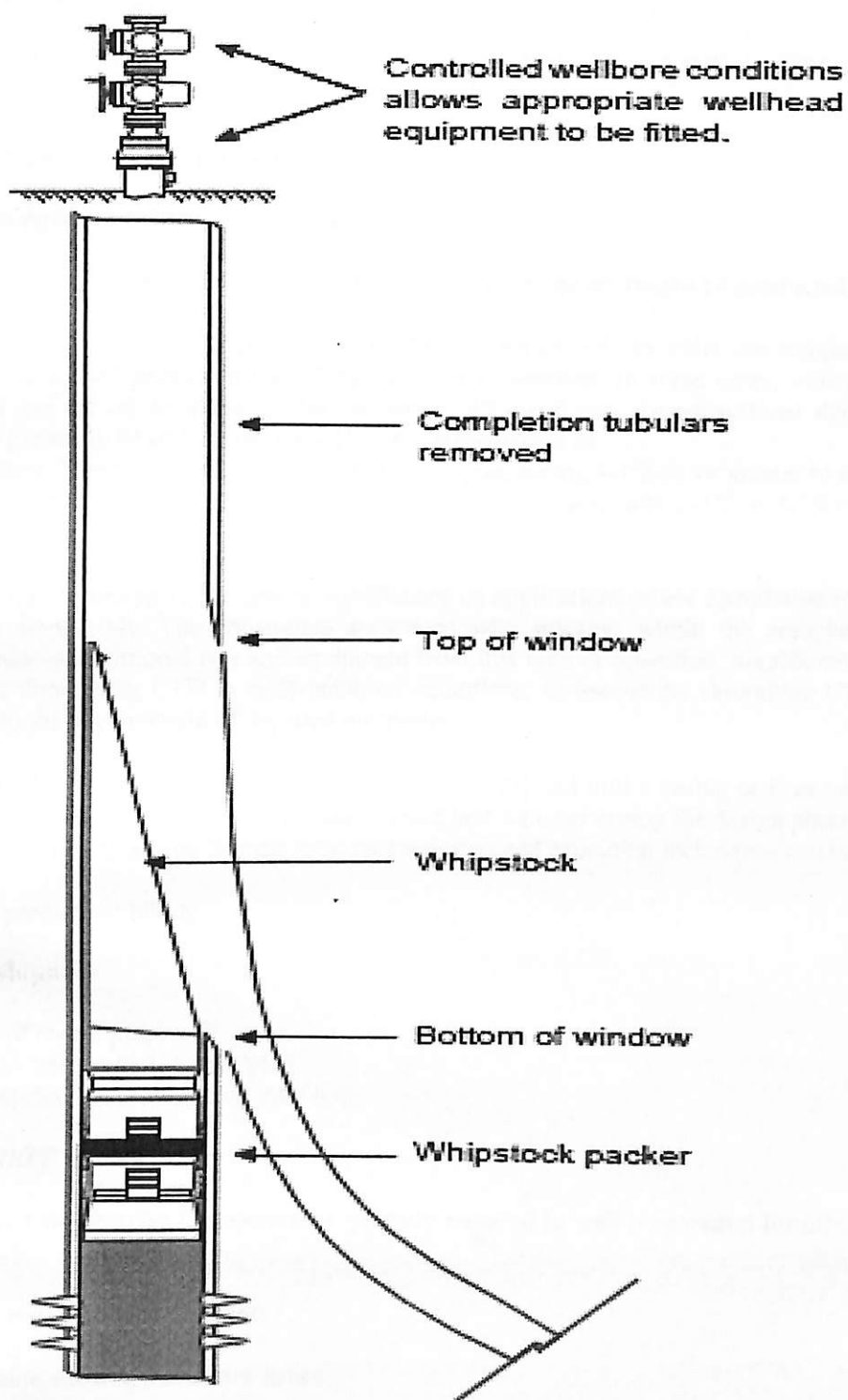
Starting mill/whipstock lug combination

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.
- 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.

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.



Typical conventional sidetrack configuration.



5.3 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.

- Whipstock in production tubing
- Thru-tubing whipstock
- Cement kick-off techniques
 - Time drilling in a cement plug
 - Whipstock in cement plug pilot hole

5.3.1 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.



5.3.2 WHIPSTOCK IN PRODUCTION TUBING

If the kick off is to be performed from the production 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.

5.3.3 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.

5.3.4 CEMENT KICKOFF 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

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 ($\pm 0.25^\circ$)
- 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:

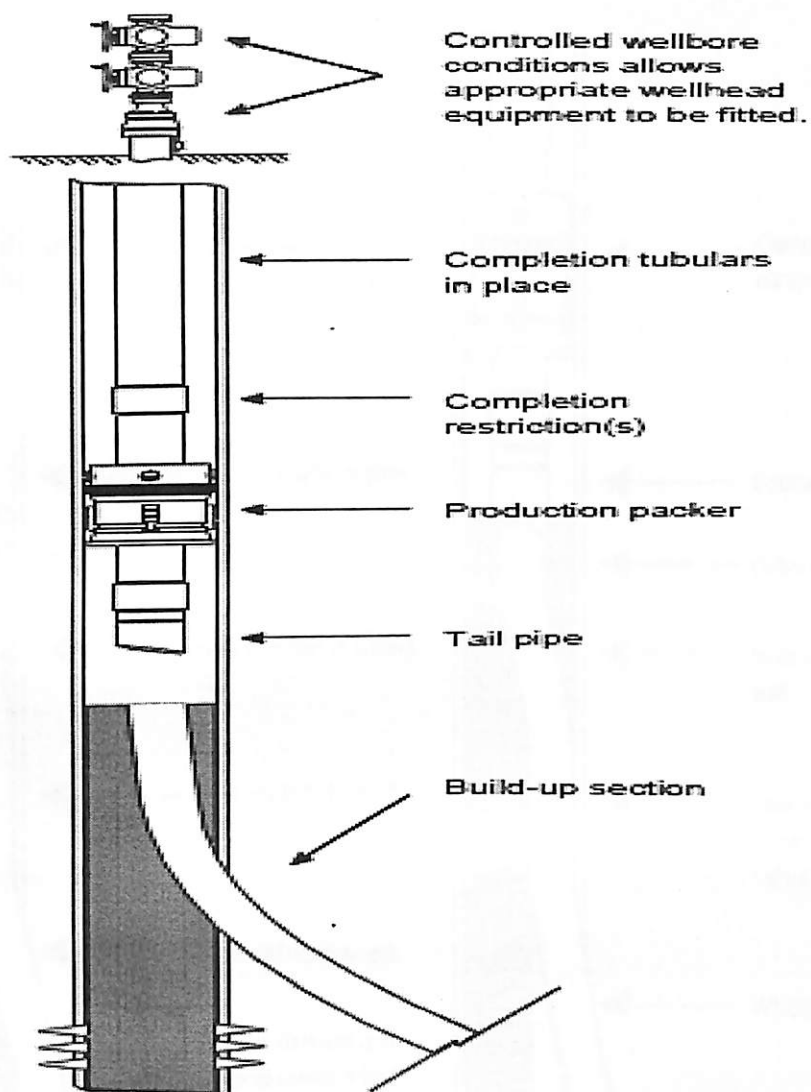
- The BHA is retrieved and the bend changed to a higher angle ($\pm 2.5^\circ$).
- The window is milled using a time drilling technique, i.e. milling with low WOB (or low motor differential pressure), running the CT string in short intervals (1/4-in. or 1/2-in. only) with predetermined delay intervals. 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.



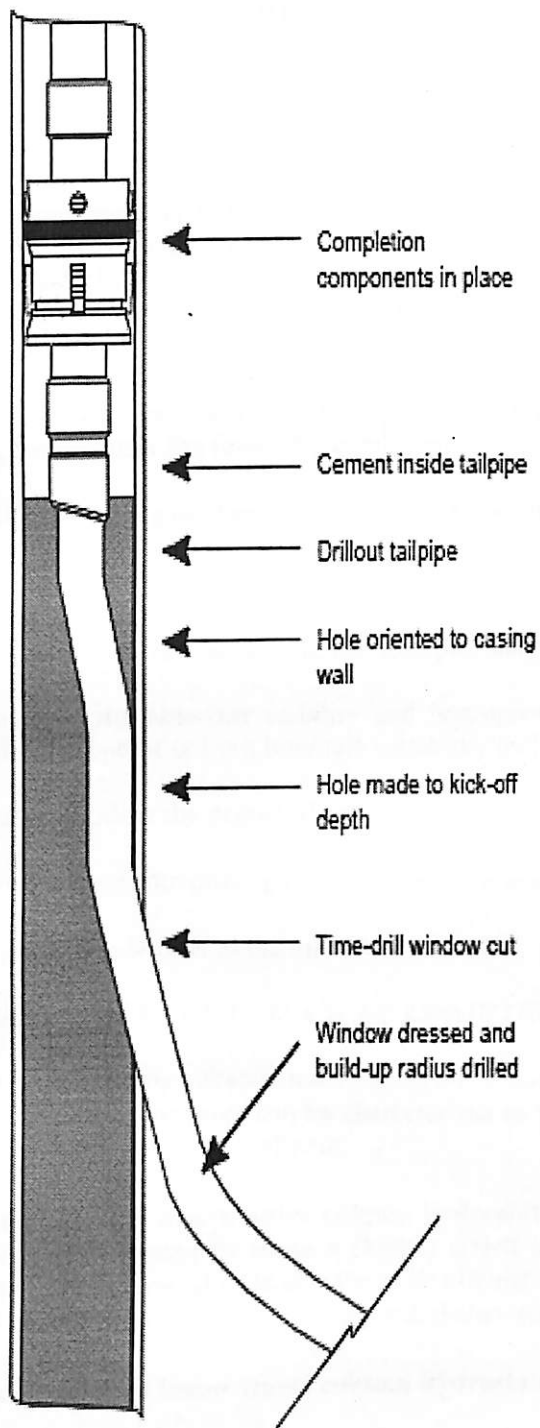
- The window is then dressed using a water melon mill assembly similar to that outlined in the conventional sidetracking section. A bull nose (no bit) is made up at the bottom of the water melon mill to avoid drilling out the cement by accident while dressing the window.

Whipstock set in the cement plug pilot hole:

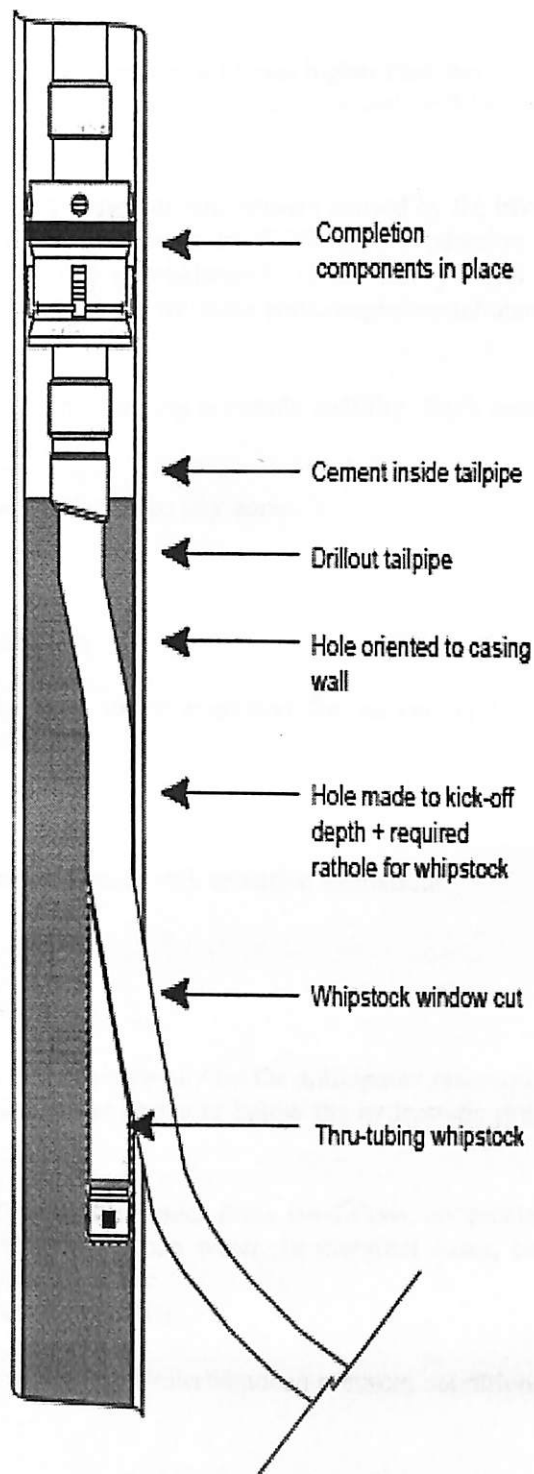
- The pilot hole is drilled in the cement plug approximately 10 ft deeper than the KOD. This rat hole is used to set the bottom section of the whipstock.
- The BHA is retrieved and the appropriate whipstock is run to bottom.
- After carefully tagging bottom, the whipstock assembly is correctly oriented using an orienting tool. By applying weight, the slips of the whipstock are set against the casing/cement. Additional weight parts the shearstud 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.



Typical thru-tubing sidetrack configuration.



Time-drilled cement kick-off (thru-tubing).



Whipstock cement kick-off (thru-tubing).



5.4 UNDERBALANCED DRILLING

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.

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 control 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.

5.4.1 CREATING UNDERBALANCED CONDITIONS

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. 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.

5.4.2 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 underbalanced is of limited value. A downhole annulus-pressure sensor helps to accurately monitor the bottom hole pressure.



5.4.3 DRILLING MUD

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.

5.4.4 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 lubricator 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.



5.5 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.

SUBSTRUCTURE WITH JACKING SYSTEM

Jacking systems run or pull wellbore tubulars without the requirement for a mast. 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.

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.



6. COILED TUBING DRILLING 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

6.1 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

6.2 TECHNICAL FEASIBILITY

The following areas should be investigated and the relevant criteria determined

- Weight on bit
- Annular velocity
- Pumping pressure and rate
- CT string tension
- CT life/fatigue
- Torque
- CT reel handling
- Directional requirements



6.2.1 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.

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.

The minimum recommended DWOB available for CTD in various hole size ranges is shown below.

Openhole Recommended Diameter (in.)	Minimum DWOB (lbf)
3-3/4 to 4	1000
4-1/8 to 4-3/4	1500
5 to 6-1/4	2500

6.2.2 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).
- Horizontal hole sections – 100 ft/min (depends a great deal on the length of horizontal section and the drilling fluid characteristics).



6.2.3 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

6.2.4 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.

6.2.5 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.

6.2.6 CT LIFE & 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.

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.

6.2.7 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.

6.2.8 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 lowflow 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.

6.3 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.

6.3.1 BASIC EQUIPMENT & 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
- Downhole tools
- Associated services

6.3.2 PROCEDURES & 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)

6.3.3 DRAWING & SCHEMATIC DIAGRAM

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

6.3.4 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

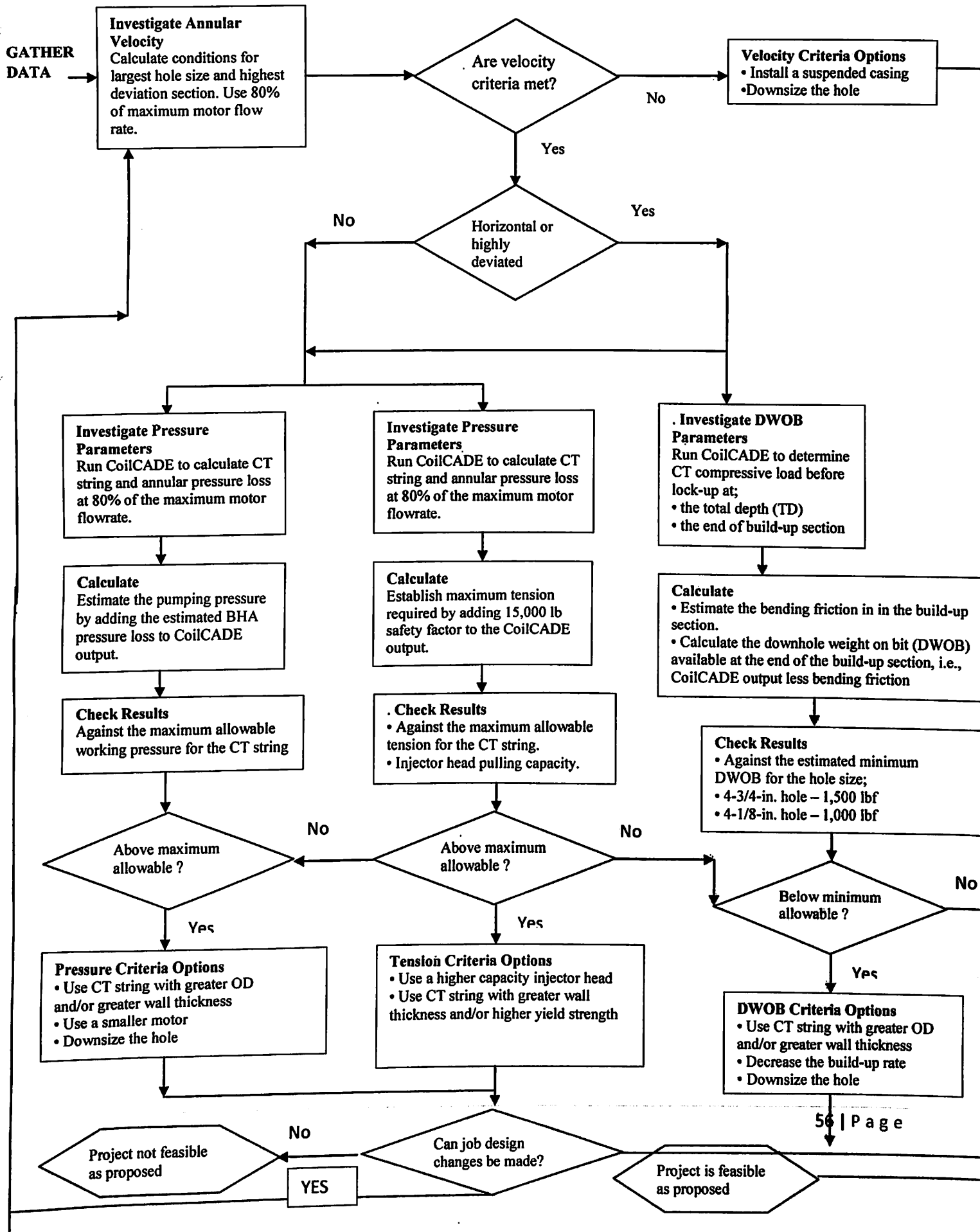


6.4 ADMINISTRATIVE PREPARATION

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

Step By Step Feasibility Study Flowchart





7. OTHER OPERATIONAL AREAS & USES OF COILED TUBING

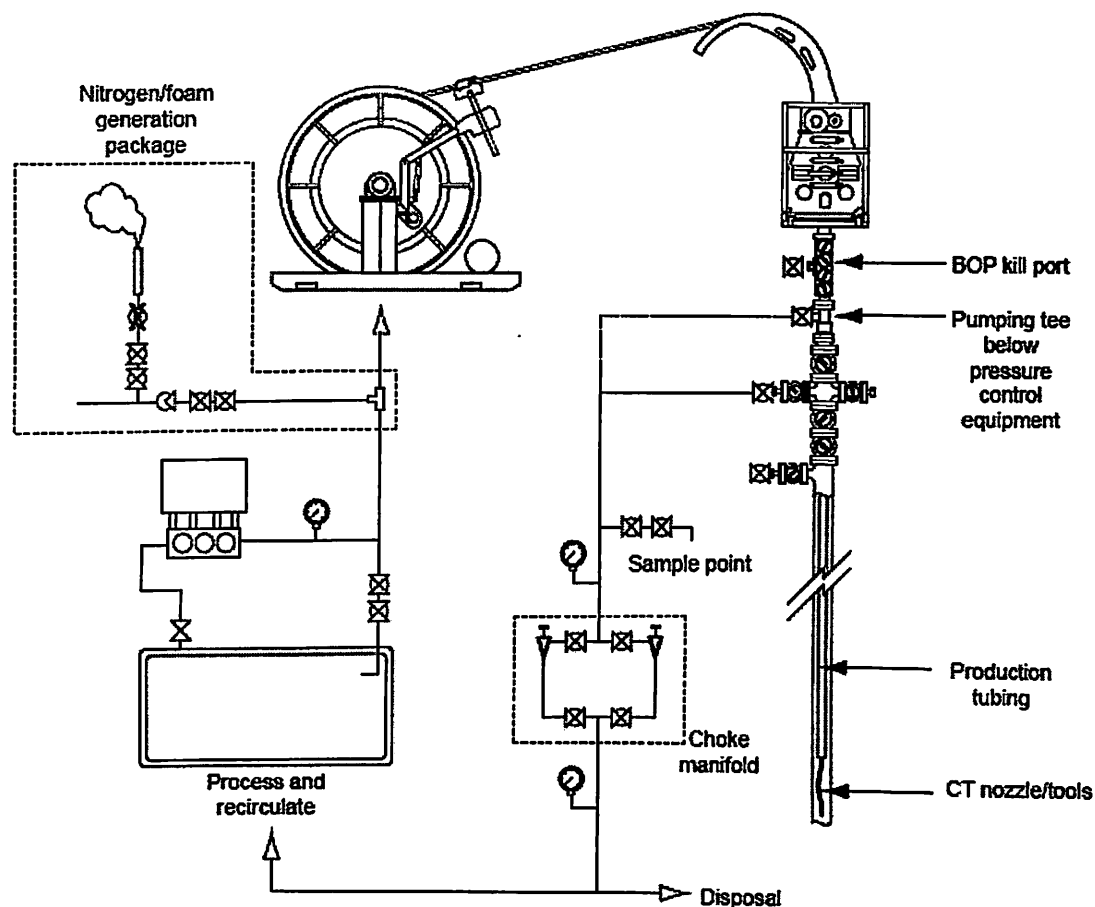
7.1 CT CAPABILITIES

- Drill and trip under pressure.
- Fast trips.
- Continuous circulation while tripping pipe.
- Continuous, high-quality two-way telemetry between surface and downhole for real-time data and control.
- Slimhole capability.
- Small location size.
- Portability.

7.2 USES

7.2.1 Circulation:

The most popular use for coiled tubing is circulation or deliquification. A hydrostatic head (a column of fluid in the well bore) may be inhibiting flow of formation fluids due to its weight (the well is said to have been killed). The safest (though not the cheapest) solution would be to attempt to circulate out the fluid, using a gas, frequently nitrogen (*Often called a 'Nitrogen Kick'*). By running coiled tubing into the bottom of the hole and pumping in the gas, the kill fluid can be forced out to production. Circulating can also be used to clean out light debris, which may have accumulated in the hole. Coiled tubing umbilicals can convey hydraulic submersible pumps and jet pumps into wells. These pumps allow for inexpensive and non invasive well cleanouts on low pressure CBM gas wells. These umbilicals can also be run into deviated wells and horizontal lateral.



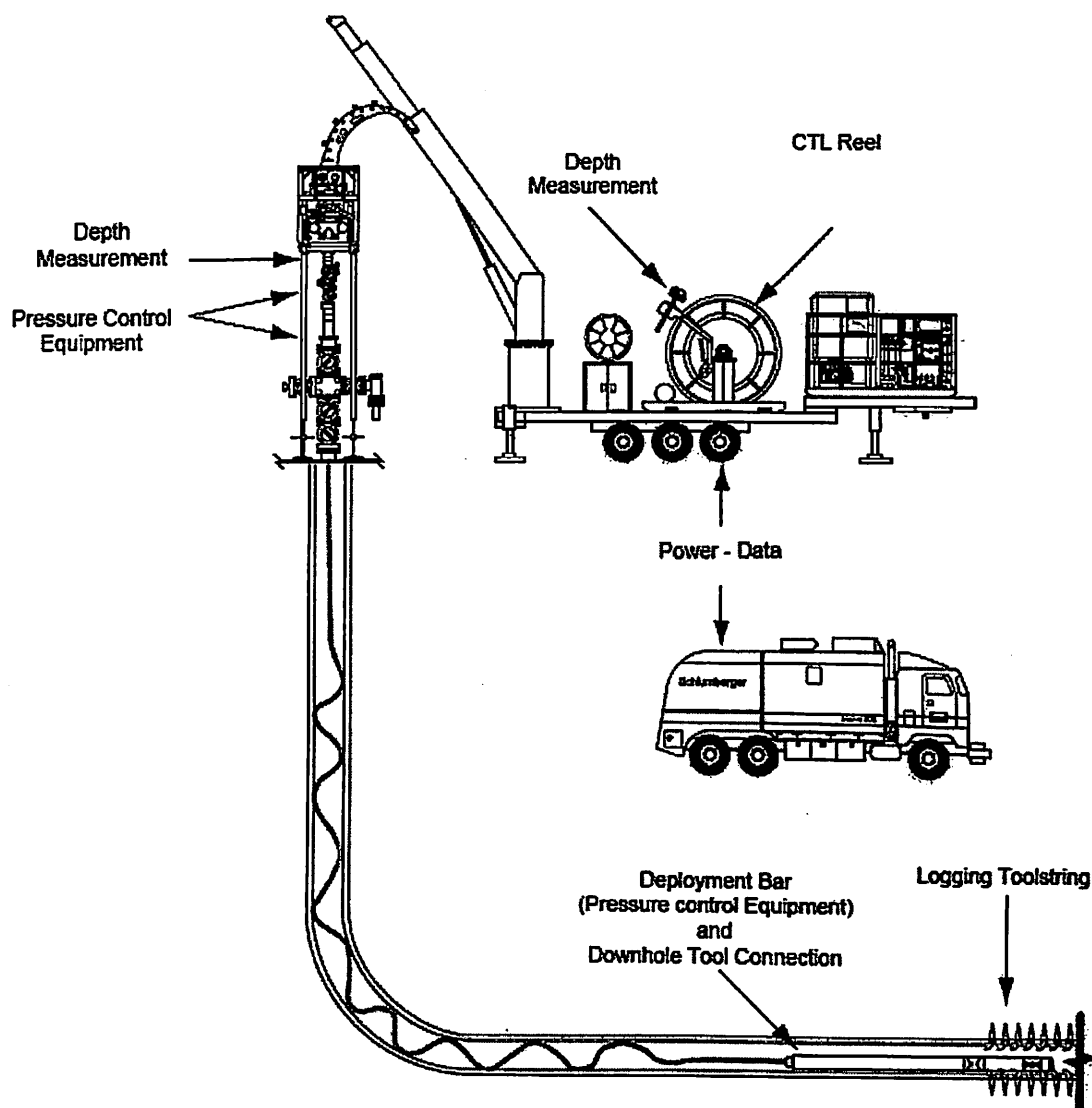
Typical foam equipment configuration for fill removal.

7.2.2 Pumping:

Pumping through coiled tubing can also be used for dispersing fluids to a specific location in the well such as for cementing perforations or performing chemical washes of downhole components such as sandscreens. In the former case, coiled tubing is particularly advantageous compared to simply pumping the cement from surface as allowing it to flow through the entire completion could potentially damage important components, such as the downhole safety valve.

7.2.3 Logging & Perforating:

These tasks are by default the realm of wireline. Because coiled tubing is rigid, it can be pushed into the well from the surface. This is an advantage over wireline, which depends on the weight of the toolstring to be lowered into the well. For highly deviated and horizontal wells, gravity may be insufficient. Roller stem and tractors can often overcome this disadvantage at greatly reduced cost, particularly on small platforms and subsea wells where coiled tubing would require mobilising an expensive mobile drilling rig.



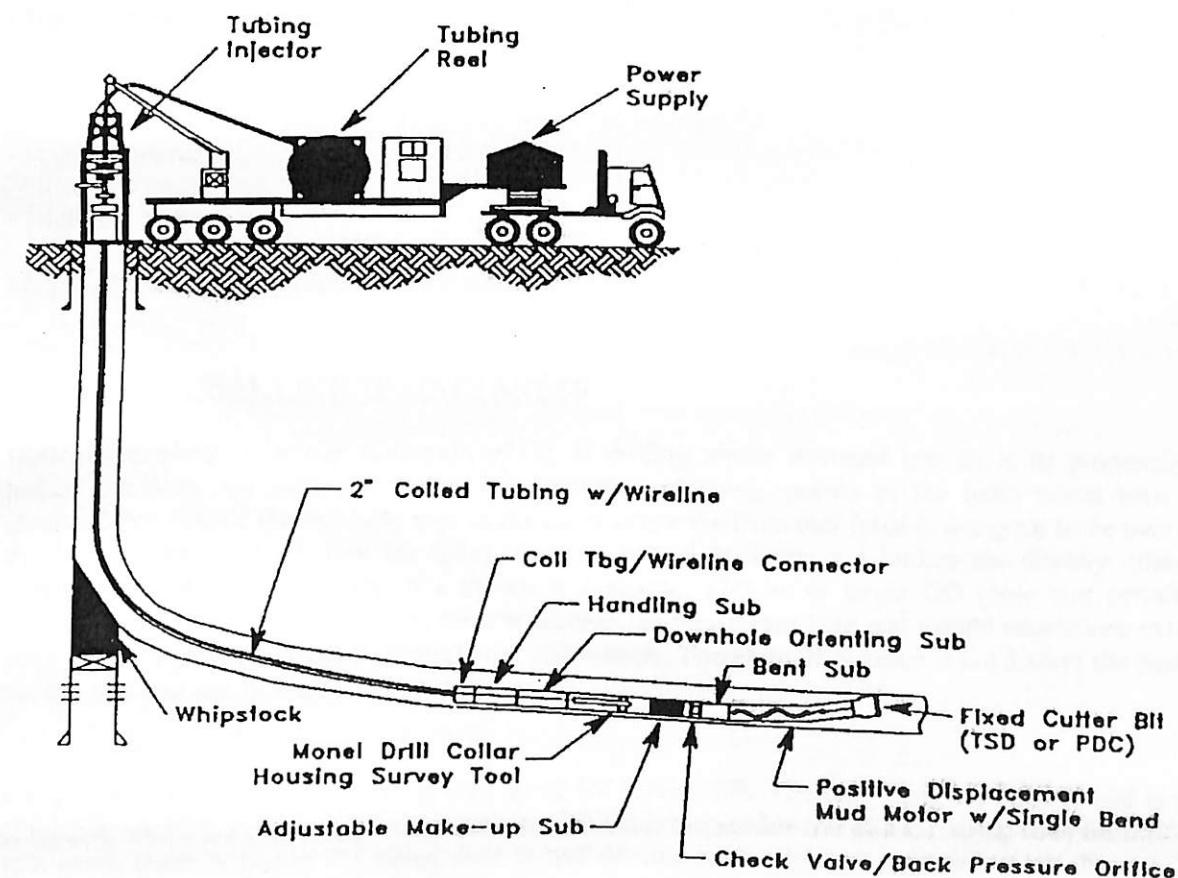
CTL system principal components

7.2.4 Production:

Coiled tubing is often used as a production string in shallow gas wells that produce some water. The narrow internal diameter results in a much higher velocity than would occur inside conventional tubing or inside the casing. This higher velocity assists in lifting liquids to surface, liquids which might otherwise accumulate in the wellbore and eventually "kill" the well. The coiled tubing may be run inside the casing instead or inside conventional tubing. When coiled tubing is run inside of conventional tubing it is often referred to as a "velocity string" and the space between the outside of the coiled tubing and the inside of the conventional tubing is referred to as the "micro annulus". In some cases gas is produced up into the micro annulus.

7.2.5 Drilling:

As discussed above, a relatively modern drilling technique involves using coiled tubing instead of conventional drill pipe. This has the advantage of requiring less effort to trip in and out of the well (the coil can simply be run in and pulled out while drill string must be assembled and dismantled joint by joint while tripping in and out). Additionally, the coiled tubing is stripped into and out of hole, providing a hermetic seal around the coil and, if desired, allowing the well to flow during drilling operations. Instead of rotating the drill bit by using a rotary table or top drive at the surface, it is turned by a downhole motor, powered by the motion of drilling fluid pumped from surface. Drilling which is powered by a mud motor instead of a rotating pipe is generally called **slide drilling**.





8. PROBLEMS ASSOCIATED WITH COILED TUBING

Every new invention/technology is always associated with some limitations and problems.

8.1 CT LIMITATIONS.

- Cannot rotate.
- Limited fishing capabilities.
- Small diameters.
- Limited reach in horizontal laterals.
- Low circulating rates.
- High circulating pressures.
- Short tube life.
- High maintenance.
- High daily costs.
- Limited availability of high-capacity units.

8.2 OPERATIONAL CONSTRAINTS AREAS

Helical Buckling: A severe limitation of CT in drilling highly deviated laterals is its propensity for helical buckling and subsequent “lockup” (cessation of string motion as the helix exerts increasing contact force against the borehole wall to the point where the frictional force is too great to be overcome by forcing additional CT into the hole). Because helical buckling and lockup are directly related to bending stiffness and clearance, if a choice is available, 3 1/2-in. or larger OD (hole size permitting) would always be selected. However, there is another limiting factor. Size and weight restrictions exist for most public highways, bridges, underpasses, and tunnels. Therefore, the choice is not always the best size but the size that can be transported to location.

CT Service Life: Much has been written about CT service life. The only thing we want to add is some comments about the commonly asked question, “What is the service life of a CT string used for drilling?” In a word, short. A typical CT string used in well-service work might be expected to last through 30 or more jobs, depending on well conditions.

For simple deepening jobs that involve only vertical drilling, a CT string might be expected to last for as many jobs, but the number drops significantly for directional drilling. For horizontal wells that have casing set through the build section to horizontal so that the CT string drills only the lateral, the string might drill six to eight wells. If the build section (or sidetrack kickoff and build) also is drilled with the CT string, the life may be only two to three wells, and possibly only one. This is not encouraging from a



cost standpoint; however, new approaches to reduce the number and severity of the bending cycles on the tubing show a lot of promise by increasing fatigue life by as much as 300%.

Directional Orientation: One of the more problematic areas of CT drilling is in the mechanics of directional orientation. As mentioned previously, a downhole orienting device orients the tool face in the desired direction to drill the required trajectory because the tubing itself cannot be rotated. This presents several problems.

One problem is the reactive torque in the tubing caused by the torsion generated by the motor and the drag of the bit as it rotates. CT has relatively low tensional stiffness, which makes orientation difficult in systems that require orientation under static conditions. It is not unusual to have to orient the tool face as much as 270° clockwise from the desired orientation to compensate for reactive torque once the motor starts turning. In addition, an inability to maintain a constant weight on the bit while drilling also affects the magnitude of the reactional torque and, hence, the orientation.

Another directional problem arises from the inability to rotate. In conventional rotary drilling of directional wells, there are two modes of drilling with a downhole motor, sliding and rotating. In slide drilling, the drillstring is not rotated, which allows the bent housing and/or subs to build angle or turn in the desired direction. Once the desired inclination and direction are established, the drillstring is rotated so that both the drillstring and motor are rotating. The drillstring rotation offsets the effects of the bent housing and a constant direction can be maintained (at least in theory). An added benefit of drillstring rotation is that the penetration rate often is twice that attained with slide drilling alone. Because all CT drilling is slide drilling, the effects of the bent housing cannot be offset by rotation to maintain a constant direction. The CT procedure is to change the orientation of the tool face continually to drill in the desired direction and to maintain a relatively smooth wellbore. With static orienting tools, this requires a lot of downtime for orientation. This leads to the temptation to drill too far before making corrections, which results in a tortuous wellbore trajectory through which it may be difficult, or impossible, to retrieve the BHA.

One more factor that adds to the orientation difficulty is residual curvature in the CT. The CT is straightened as it passes through the injector into the wellbore, but the tubing still retains some curvature as it unloads elastically from the injector. This residual curvature affects directional orientation and control.

Newer systems have real-time dynamic orienting tools that can be reoriented continually while drilling. This allows an experienced CT operator to make course corrections so that a relatively smooth wellbore can be drilled without stopping the pumps or injection into the hole. Not all CT-drilling units currently have this capability. As a next step, closed-loop orientation that does not require direct operator intervention is being tested and adjustable stabilizers to eliminate the bent housing and orienting tool altogether are under development. If successful, these tools could offer significant improvement to current methods.

Cuttings Removal: Rotation is a primary factor in cuttings removal in highly deviated wells. It helps propel the cuttings into the flow stream; induces crosscurrents; and crushes cuttings into smaller, more transportable sizes. In the absence of rotation, cuttings removal in a highly deviated well becomes difficult and failure to remove cuttings often results in stuck pipe and/or lost circulation.

In highly deviated laterals drilled with CT, special measures must be taken to ensure that cuttings are removed from the wellbore. A common method is to make periodic short trips based on a maximum



distance or time drilled between short trips and/or pressure buildup as seen on a downhole annular-pressure monitor.

Although the CT unit lacks rotational capacity, a short trip with CT often is a more effective means of cuttings removal than the same operation with a conventional rig because the CT unit can maintain continuous circulation throughout the trip. Other successful methods include viscous-fluid sweeps and foam sweeps. One of the more common causes of stuck pipe in CT drilling appears to be a tendency to drill too far between periodic efforts to remove cutting build up.

Penetration Rates: Several factors contribute to why penetration rates for CT drilling usually are somewhat lower than those for conventional methods in highly deviated directional wells. These factors are related primarily to the inability to rotate the CT string. The fact that all CT drilling is slide drilling with a downhole motor is one reason for the lower penetration rates. As previously discussed, this method results in a penetration rate nearly half that of drillstring rotation with the same downhole motor.

Another reason for lower penetration rates is the difficulty in getting consistent weight on the bit. A conventional drillstring in rotation transmits weight to the bit almost continuously as it is applied from the surface. However, because CT does not rotate, maintaining a constant weight on the bit is difficult because of the slip/stick nature of borehole friction on the CT drillstring. Experimental thrusters have been designed to lock onto the borehole wall and apply constant weight to the bit by means of a hydraulic piston, but the success of this type of device depends on having a relatively ingauge hole and on resetting the anchor and piston in minimum time.

Another predominant reason for lower penetration rates is the additional time required to remove cuttings buildup, as discussed earlier. Despite all this, higher penetration rates on the order of 60 to 200 ft/hr are being achieved, especially in underbalanced situations. 3 With experience in particular areas, CT operators are achieving fast enough penetration rates that this is no longer considered to be the impediment it once was.

Depth Control: Determining measured depth with CT is approximate at best, especially in highly deviated wellbores. Depth normally is measured by a counter device between the reel and the injector similar to that used on a wireline unit. Unlike a wireline unit, however, the CT is not under full tension (or compression) in that location because the injector on top of the wellhead supports all the CT in the hole. (Some units do have a depth-measuring device between the injector and the pressure packoff, but the distance between these is very small and a support device may have to take the place of the depth meter to prevent buckling of the tube if the well is under pressure.)

In addition, the fact that the CT is not totally straightened by the injector as it enters the wellbore also produces a fair amount of drag on the wellbore wall (there is residual elastic bending in the tube, causing the lower portion of the tube to curve). All this indicates that CT depth measurements are not considered reliable.

Alternatives exist, however, for most CT-drilling operations. If the well is a new well, a radioactive collar (which can be detected by a gamma ray device on the CT for depth correlation) can be run on the bottom of the casing. In the case of an existing well, the magnetic device in the steering tool often can be used to detect the existing casing shoe. For re-entries, electric wireline often is relied on to set sidetracking tools so that an accurate depth can be attained. Once in open hole, the last known measurement checkpoint, the depth counter, and logging-while-drilling correlations have to be used.

Fishing Operations: While the ever-present specter of a fishing operation looms in any drilling operation, it is much greater in CT drilling. The inability to rotate, lack of bending stiffness, and poor



depth control are significant, if not critical limitations, to CT-fishing success. The most common fishing event for CT in open hole is a stuck BHA. While CT does have the advantage of allowing the well to flow to reduce differential pressures and to spot pipe-freeing agents or acid readily around the BHA, the advantages stop there. It is impossible to run a free point, to back off, or to cut off a string of CT downhole with the presence of an electric line and/or hydraulic lines inside the tubing. Therefore, a disconnect is run on top of the BHA.

The disconnect most commonly is a force/shear device; however, hydraulic and/or electrically actuated devices have been developed recently. If the pipe is not stuck above the BHA, it usually is possible to disconnect the BHA and retrieve the CT. The BHA sometimes can be recovered successfully by fishing with the CT. However, conventional tools and methods are required in most cases, which means moving the CT unit off the well and moving a conventional workover rig on. Here, a combination conventional/ CT rig has a distinct advantage. Despite all this, some operators report relatively successful fishing experience for BHA's with wash pipe and slow-rotating downhole motors. If a disconnect cannot be accomplished, the fishing job is a virtual nightmare if it is worth doing at all. The process is tedious, time consuming, and expensive, and the prospects for success are grim.

Experience Factor: An extremely important criterion in the decision to use CT drilling is the experience of the CT service company. A good CT driller must be an accomplished slimhole directional driller with a high degree of working knowledge of both CT and MWD. Currently, this is rarity. It is not unusual to find two service companies drilling with CT in the same area, with one company outperforming the other by a margin of as much as two to one on time to drill.

This obviously is an indication of the newness of the application of the technology and certainly will improve with time and experience. For now, however, operators must be aware that large discrepancies in drilling time often exist because of differences in training and experience. Unfortunately, at this time, there are only a few geographical areas in the world where experience truly is adequate.

Cost: The single biggest negative for the use of CT drilling probably is high daily costs. Few, if any, situations currently exist where an equivalently sized conventional drilling rig does not have a lower daily cost than a CT-drilling unit. The key here is "equivalently sized." In some locations, there are no equivalently sized conventional rigs (e.g., most offshore locations). In a comparison of CT-drilling-unit and conventional-drilling-rig costs, the CT unit often costs four to six times more than the equivalent conventional rig.

The decision to use CT for drilling cannot be based on a simple one-to-one economic comparison because the CT would lose almost every time, except where an equivalent conventional rig is not available or where the mobilization cost of a conventional rig is much greater than that for the CT unit. The question that faces many operators is how to quantify formation damage in terms of cost. As an example, in Canada, where the majority of the CT drilling is done, the cost of drilling underbalanced with CT typically is about 40% higher than the cost of a conventionally drilled balanced well. Despite this significant difference, many operators have found that the cost of the CT underbalanced drilling is more than offset by reduced formation damage and increased production. So, one must often look further than conventional economics based on daily rig costs to justify the use of CT for drilling. The unique capabilities of CT are almost always the deciding factor for its use.

CT Drilling Failures: CT-drilled wells now number in the thousands, with relatively few experiencing serious problems. While we prefer not to think about the possibility of failures in any of our operations, it is foolish not to consider the consequences of a failure should one occur. Anyone who drills a well with any type of equipment must consider the possibility of a fishing job. We must assume that, if a CT fishing



job becomes necessary, it likely will have to be accomplished with a conventional-type rig with jointed pipe. The first obvious question is whether a conventional rig can be used in this particular application (i.e., mobilization, location size, portability, costs, and other such factors).

This is a serious consideration that can mean long delays and excessive costs. While the literature on CT drilling is full of success stories (which conspicuously never mention actual costs), Cox⁵ reported one trouble-filled case history that stands alone in its honesty and candor. Much has been learned since that paper was written, but it should be required reading for anyone contemplating the use of CT for drilling.

To be totally fair, however, one should also note that, despite the myriad problems that arose in that particular case, public records indicate that the well involved has been producing at more than 10 times the rate of the conventionally drilled vertical wells surrounding it.

9. COILED TUBING: THE NEXT GENERATION

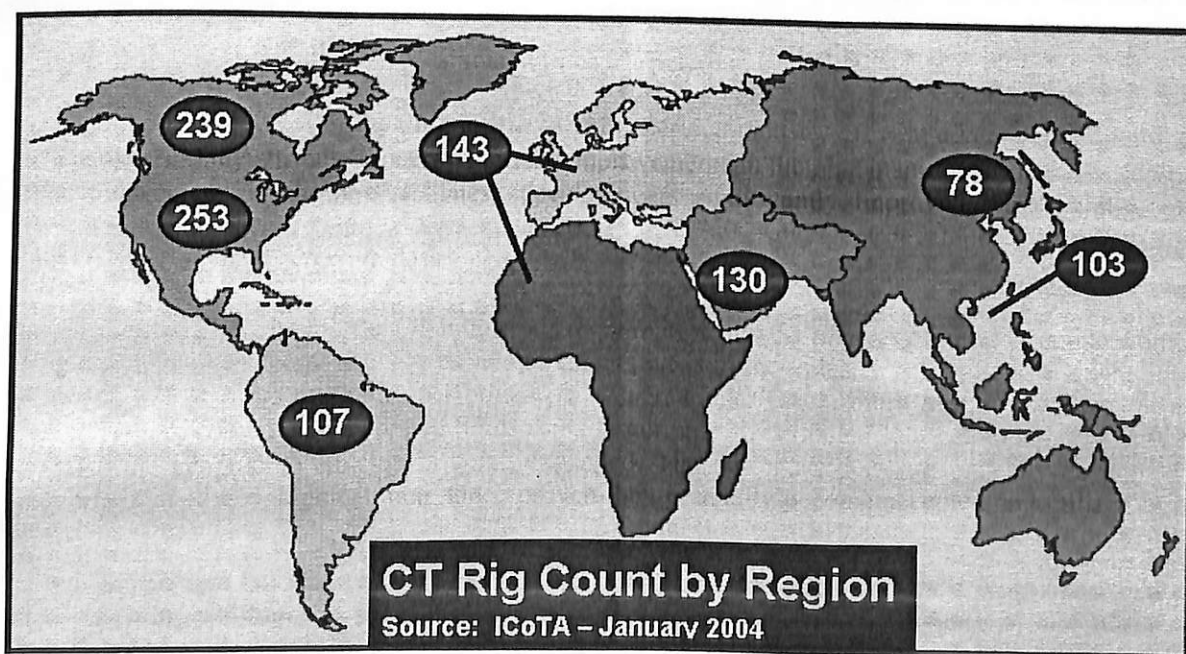
9.1 CT INDUSTRY STATUS

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

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

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

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





9.2 WORLD WIDE CURRENT SCENARIO

In today's maturing oil and gas provinces, the petroleum industry depends on advances in technology to extract additional quantities of hydrocarbons from depleted reservoirs. Due to cost and physical limitations, many of today's artificial lift methods cannot be applied to slimhole wellbores (specifically, those with 2 7/8" casing cemented in as the production string). In order to maximize recovery, coiled tubing pumping systems (CTPS's) are now being installed in slimhole wells to pump off the fluids in these wellbores.

- The first successful installation of a CTPS to de-water a slimhole gas well was completed by Anadarko Petroleum Corporation in October 2002 in the Carthage Field of East Texas.
- Coiled tubing drilling is being used in the Niobrara Chalk in Kansas, where Advanced Drilling Technologies is drilling a well per day at savings of 35% to 40% per well.
- The horizontal re-entry market has great potential for CT drilling, according to Xtreme Coil Drilling. It's an application that has been used with success in Alaska, where a combination of coiled tubing and specialized tracking tools can go as deep as 10,000 ft, then horizontally 2,500-3,000 ft for a total measured depth of nearly 13,000 ft.
- Academy Services, a Nabors subsidiary, has built 13 hybrid rigs, including one with a 15,000-ft depth capacity that will be used in Alaska's Prudhoe Bay for oil re-entries and workovers. All but two of the rigs are in Canada — the other two are in Casper, Wyo. and Bakersfield, Calif. In the US, the rigs are rated to 5,000 ft and generally utilize a 2 7/8-in. coil. In Canada, the rigs are rated from 6,500 ft to 10,000 ft and use a 3 1/2-in. coil.
- Three re-entry horizontal production wells have been drilled in Austin Chalk, Texas, USA using 2" directionally controlled coiled tubing with 3 7/8" bits.
- Coiled tubing drilling on the Alaskan North Slope. A typical CT re-entry at Prudhoe Bay, Alaska, USA consists of running and expandable whipstock through existing 4 1/2" tubing and setting it at the kick off depth in 7" casing, squeezing existing perforations by running CT to the top of the whipstock and pumping cement, milling out profile nipples at the end of the tubing and cutting a 3.8" casing-exist window, drilling a 3 3/4" sidetrack hole, deploying a 2 3/8" liner on CT without a hanger in the lower tail pipe, cementing the liner above the 200 ft above the casing exist window and perforating the liner using hydraulically activated guns run on CT.
- Coiled tubing stimulation results in the Hassi-Messaoud field, Algeria. Production from Well MD 264 increased more than threefold from 38 m³/d [239 bbl/d] to 120 m³/d [755 bbl/d] after pumping a hydrofluoric [HF] organic acid stimulation treatment through coiled tubing using an inflatable anchoring packer to isolate the lower target interval from an upper interval, which had previously been hydraulically fractured.
- BP Sharjah Oil Company initiated coiled tubing underbalanced reentry drilling operations from existing wellbores in the Sajaa gas field of the United Arab Emirates (top). Most of these wells had been recompleted with cemented 7-in. liners tied back to surface and 5-in. production tubing



9.3 NATIONAL CURRENT SCENARIO

- Cairn Energy India Pty Ltd (CEIL) is the Operator of the Ravva offshore block located on the east coast of India. CEIL has planned to conduct barge based coil tubing operations in the Ravva block during the first quarter of 2009. The services are required to cleanout sand fill, stimulate, possible tubing cutting on coil and possible thru tubing sand control in 3 firm and one contingent well.
- Coiled Tubing (CT) applications are performed to intervene in completions installed in the lateral section of Panna wells in Western India Offshore. Coiled tubing is used to operate the sliding sleeves to operate the various sections of installed well.
- Coiled Tubing is used to heat up the tubing for preventing the crude to become wax in tubing in Mangla Field, Rajasthan by CAIRN.

9.4 EVOLVING TECHNOLOGY FOR FUTURE

Predicting what we can expect to see in the future is not pure speculation; the technology is already moving in new directions. Underbalanced drilling to reduce formation damage is now a proven success for many operators, and the advantages of using CT for this operation are unparalleled. So-called hybrid rigs that have both CT and jointed-pipe-handling capabilities show promise in eliminating many of the problems associated with CT alone. Means of increasing CT fatigue life by 200% by placement of the reel above the injector and by as much as 300% by a special guide in conjunction with a larger reel diameter are already in operation. Riserless subsea drilling and intervention systems with CT are being developed.

Almost anything written about CT drilling is out of date by the time it is in print because any numbers of CT-drilling related projects currently are in the conceptual to advanced stages of development.



10. CASE STUDY: RE-ENTRY HORIZONTAL PRODUCTION WELL WITH COILED TUBING DRILLING IN AUSTIN CHALK, TEXAS USA.

PROBLEM: ORYX Energy Company re-entered a vertical well in the Pearson field, Texas, USA, completed in Austin Chalk. Horizontal drilling in Austin Chalk using mud commonly encounters total lost circulation. To reduce mud losses formation damage and costs, water is often used as drilling fluid. But this decreases the bottom hole hydrostatic pressure lower than the formation pressure- underbalanced drilling.

To combat annular pressure from formation flow during drilling, conventional rig uses a rotating stripping head or rotating BOPs to seal the annulus. Actually the well is killed each time the trip is made.

SOLUTION TAKEN: Drilling with the help of coiled tubing.

By using the coiled tubing unit which has its annulus sealed throughout drilling by the stripper. Thus ORYX was able to run in and out the hole without killing the well. This improved the safety and avoided the expense and potential damaging effects to the formation pumping brines to kill the well prior to tripping.

PREPARATION OF WELL: To prepare the well, ORYX used a conventional service rig to completely remove the existing hardware, set a whipstock and finally sidetrack out of 4 1/2", casing at a true vertical depth of 5300ft. Drilling was then continued using 2" coiled tubing, downhole mud motor, wireline steering tool, a mechanical downhole orienting tool and 3 7/8" bits.

An average build up rate of 15°/100 ft was achieved and a horizontal section drilled for 1458 ft.

BOTTOMHOLE ASSEMBLY: Main components of Downhole BHA are-

Drilling String: ORYX employed a reel consisting 10050 ft of 2" outside diameter coiled tubing with 5/16", mono conductor cable inside the tubing.

Orientation tool: Because coiled tubing cannot be rotated from surface. To alter drilling direction, a downhole method of changing tool face orientation is needed. To achieve this ORYX deployed tool that changes tubing reciprocation to rotation- compression rotated the tool face to the right and extension to the left. Once adjusted, the tool face was locked in place using a minimum 250psi differential pressure across the tool.

Direction Survey Tool: The survey tool inside nonmagnetic collar relayed direction information to the surface via the wireline.

Directional BHA: Two assemblies are used depending on the build rates required-a double bend assembly consist of a conventional 2 7/8" bent housing, mud motor coupled to a single bent sub, or a steerable assembly comprising a single bend motor.

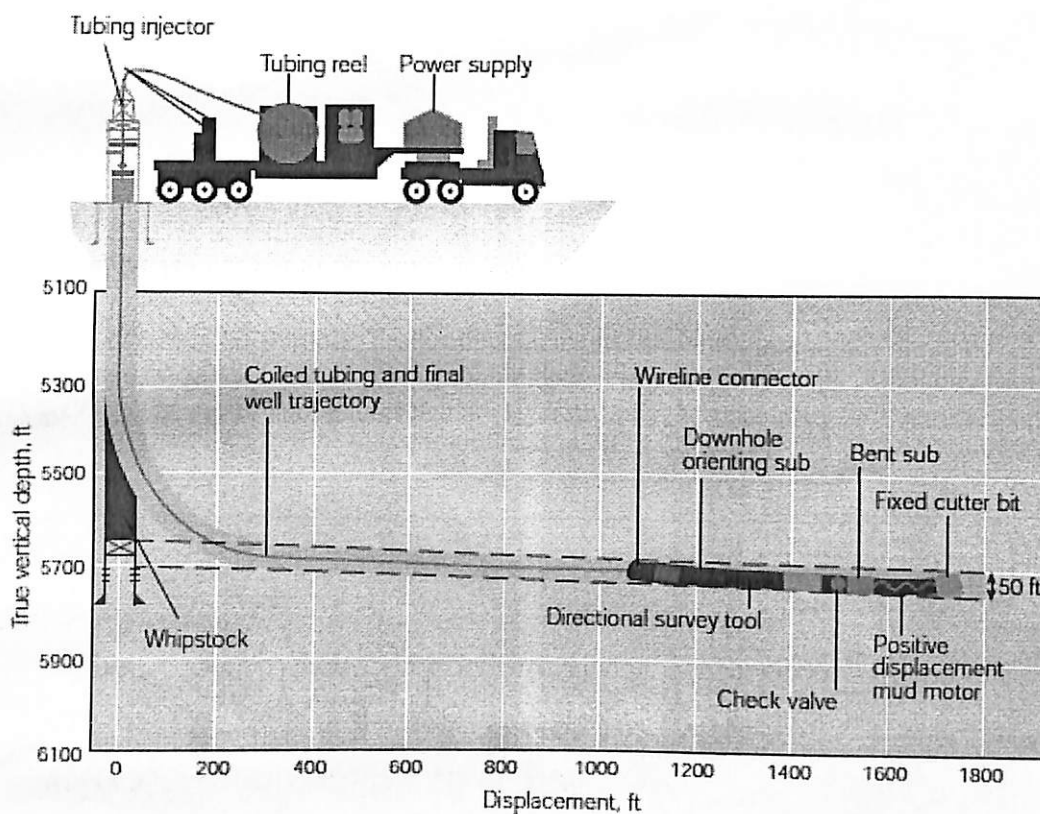
Bit: Thermally stable diamond bit are used to drill the curve and build sections and polycrystalline diamond compact bits to drill the lateral section.

CHALLENGES FACED: Orienting the tool face was not difficult but maintaining it was hard because of the unpredictable reaction of the coiled tubing to the torque generated by the drilling motor's rotation.

Drilling was also slowed by failure of BHA components, particularly the orienting and direction survey tools.

CONSEQUENCES: These difficulties affected the final cost analysis. The total cost was estimated by ORYX at twice that of using a conventional rig- non-drilling time was responsible for nearly 40% of this.

RECOMMENDATION: As purpose designed equipments becomes available like MWD Tool and drilling procedures are refined, coiled tubing should deliver more cost-effective, slimhole, lateral wells. Now days we have advance orienting tools that are Hydraulically, Mechanically or Electrically operated.



Final analysis of the Oryx well in Austin chalk, Texas, USA. With a steerable bottom-hole assembly, the horizontal section was drilled within its 50-ft vertical window.



11. CONCLUSION

CT drilling has become one of the fastest growing technologies of the decade. The technology currently is operable and continues to improve. The ability to monitor downhole conditions (such as bottomhole pressure, actual weight on bit, and vibrations, among others) and to obtain wireline-quality logs in real time while drilling is unique to CT drilling and can provide invaluable information for the operator. Selection of CT drilling over conventional drilling methods must be based almost entirely on the unique capabilities of CT rather than on a conventional day-rate cost comparison. In areas where high mobilization costs and/or restricted location space requirements prevail, CT drilling is an attractive alternative.

Currently, the most obvious niche for CT drilling is in underbalanced drilling to prevent formation damage. In this arena, it is unequalled. Through-tubing re-entry for multilateral drilling is a relatively new application in most areas, but CT is being used successfully and the future potential is encouraging as improved tools are developed. The future of CT drilling looks encouraging. From the first CT drilled horizontal well reported in 1992, the technology has improved to the point of wide acceptance and application. Developments under way and those slated for the near future should add increased potential and reliability to this rapidly growing technology.



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