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-Title-

Fundamentals And Techniques of coiled tubing drilling CTD

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May God have mercy on her soul — **رحمة الله على صاحبة الحاسوب المنجز به هذا العمل.**

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Abstract

This thesis explores the fundamentals, techniques, and optimization strategies related to **Coiled Tubing Drilling (CTD)**, an innovative drilling method that has emerged as a cost-effective and efficient alternative to conventional rotary drilling in specific well conditions. The study begins with a detailed explanation of CTD principles and system components, followed by an analysis of the various applications such as underbalanced drilling, horizontal drains, and well re-entry operations. Emphasis is placed on the operational advantages of CTD, including continuous circulation, minimal surface footprint, and reduced non-productive time (NPT). A real field case is examined to highlight practical challenges and successful optimization strategies. The thesis concludes by offering technical recommendations and future perspectives for enhancing CTD performance.

Keywords: Coiled Tubing Drilling, Slim Hole, Re-Entry, Optimization, Underbalanced Drilling, CTD, Horizontal Drain

الملخص

تتناول هذه المذكرة الأسس والتقنيات واستراتيجيات تحسين الأداء المرتبطة بتقنية **الحفر بواسطة الأنابيب الملفوفة** ، وهي طريقة حفر حديثة أثبتت فعاليتها من حيث الكفاءة والتكلفة مقارنة بالحفر التقليدي، خاصة في الآبار المعقدة أو الناضبة. يبدأ العمل بشرح مفصل لمبادئ النظام ومكوناته، ثم يستعرض التطبيقات المختلفة مثل الحفر تحت التوازن، والحفر الجانبي، وإعادة دخول الآبار. يتم التركيز على مزايا CTD التشغيلية، مثل الحفاظ على الدوران المستمر، وتقليل الأثر السطحي، وتقليل الوقت غير المنتج. كما يتم عرض دراسة حالة ميدانية لتوضيح التحديات العملية وطرق التحسين. وتختتم المذكرة بتوصيات تقنية وآفاق مستقبلية لتطوير أداء هذه التقنية.

الكلمات المفتاحية :الحفر بالأنابيب الملفوفة، الحفر الجانبي، إعادة دخول الآبار، الحفر تحت التوازن، التحسين، الأنابيب الملفوفة

Résumé

Ce mémoire étudie les bases, les techniques et les stratégies d’optimisation liées au **forage par tubes enroulés (CTD)**, une méthode de forage innovante qui offre une alternative efficace et économique au forage conventionnel, notamment dans les puits complexes ou matures. L’étude débute par une présentation détaillée des principes et composants du système CTD, suivie d’une analyse des différentes applications telles que le forage sous-équilibré, les drains horizontaux et les opérations de réentrée. L’accent est mis sur les avantages opérationnels du CTD, tels que la circulation continue, la réduction du temps non productif (NPT) et l’empreinte environnementale minimale. Une étude de cas réelle est incluse pour illustrer les défis et solutions d’optimisation sur le terrain. Le travail se termine par des recommandations techniques et des perspectives pour améliorer les performances du CTD.

Mots-clés : Forage par tubes enroulés, Trou étroit, Réentrée, Optimisation, Forage sous-équilibré, Drain horizontal

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ABBREVIATIONS :

- **CTD** - Coiled Tubing Drilling
- **NPT** - Non-Productive Time
- **BHA** - Bottom Hole Assembly
- **ROP** - Rate of Penetration
- **WOB** - Weight on Bit
- **UBD** - Underbalanced Drilling
- **MPD** - Managed Pressure Drilling
- **RSS** - Rotary Steerable System
- **TTD** - Thru-Tubing Drilling
- **CBM** - Coalbed Methane
- **HPHT** - High-Pressure High-Temperature
- **ECD** - Equivalent Circulating Density
- **MWD** - Measurement While Drilling
- **LWD** - Logging While Drilling
- **DGD** - Dual Gradient Drilling
- **E-CTD** - Electric Coiled Tubing Drilling
- **CFD** - Computational Fluid Dynamics
- **LSRV** - Low Shear-Rate Viscosity
- **PV** - Plastic Viscosity
- **GR** - Gamma Ray
- **CCL** - Casing Collar Locator
- **BOP** - Blowout Preventer
- **RCD** - Rotating Control Device
- **PDM** - Positive Displacement Motor
- **DC** - Drill Collar
- **UBHO** - Universal Bent Housing Orienting
- **OHC** - Open Hole Clad
- **RSM** - Rib Steerable Motor
- **DST** - Drill Stem Test
- **TVD** - True Vertical Depth

- **KOP** - Kick-Off Point
- **CBL** - Cement Bond Log
- **VDL** - Variable Density Log
- **GOR** - Gas-Oil Ratio
- **PFS** - Pressure Falloff Survey
- **WO** - Workover
- **CTU** - Coiled Tubing Unit
- **LANL** - Los Alamos National Laboratory
- **SLB** - Schlumberger

Introduction

During drilling operations, various problems and hazards such as stuck pipe, wellbore instability, bit wear, loss of circulation, and excessive vibrations can significantly affect the performance and success of a drilling campaign. These issues are among the leading causes of non-productive time (NPT) and increased operational costs. As the oil and gas industry continues to face challenges in terms of efficiency, safety, and economics, engineers have worked continuously to develop methods and technologies that enhance performance and reduce downtime. Among these solutions, **Coiled Tubing Drilling (CTD)** has emerged as a promising technique that combines flexibility, speed, and precision to improve drilling outcomes.

Coiled Tubing Drilling is a modern drilling method that utilizes a continuous, flexible steel pipe to drill wells or re-enter existing ones without the need for making connections. This method allows for safer, faster, and more efficient operations, especially in complex environments such as depleted zones, underbalanced wells, or mature fields requiring intervention. With the possibility of drilling while tripping in and without halting production, CTD represents a major advancement in drilling technology. However, its application requires deep understanding of the technique and a well-planned optimization strategy to fully benefit from its advantages.

The motivation behind this thesis is to study CTD as a complete system—starting from its fundamentals, moving through its field applications, and ending with techniques for enhancing its efficiency. This work aims to extract practical and technical lessons from CTD operations and propose recommendations for future applications and performance improvement. It also investigates how optimization can be applied not only in planning and design but also in real-time operations.

This thesis is structured into four chapters:

- **Chapter I: Fundamentals of Coiled Tubing Drilling** – Presents the basic principles of CTD, its history, key components, and the benefits it offers over conventional rotary drilling.

- **Chapter II: Techniques and Applications of CTD** – Discusses various CTD methods such as directional drilling, milling, logging, and underbalanced drilling, along with examples from real field cases.
- **Chapter III: Enhancing Efficiency of CTD and Optimization Operations** – Focuses on identifying the main performance challenges in CTD operations, with emphasis on hydraulic optimization, tool reliability, cost reduction, and digital solutions.
- **Chapter IV: Case Study and Future Perspectives of CTD** – Concludes the study with a field-based case analysis and explores future trends, challenges, and technological innovations in coiled tubing drilling.

Although CTD provides multiple advantages in terms of efficiency, safety, and cost-effectiveness, its full potential is often limited by technical and operational challenges, such as limited weight on bit, tool fatigue, hydraulic inefficiencies, and inconsistent optimization strategies. These limitations raise a key question:

How can the efficiency and performance of Coiled Tubing Drilling operations be improved through advanced optimization techniques, better planning, and the integration of real-time technologies?

This thesis aims to answer this question by providing a structured and comprehensive analysis of CTD systems and offering practical solutions for improved drilling outcomes. **[7]**

Chapter (01)

Fundamentals of Coiled tubing drilling

I.1 What is Coiled tubing drilling:

Coiled Tube (CT) is a continuous length of ductile steel or composite tube that is stored and transported over a large reel (see Figure 1), in which the reel diameter must be at least 40-48 times the diameter of the tubing, to avoid excessive stress. The CT Unit (CTU) consists of four basic elements:

1) Reel, for storage and transport of the CT,

2) Injector Head, to provide the surface drive force to run and retrieve the

3) Control Cabin, from which the equipment operator monitors and controls the CT

4) Power Pack, to generate hydraulic and pneumatic power required to operate the CT unit. Tube sizes for 3 drilling purposes range from 2.54 cm (1 in.) to 11.4 cm (4 ½ in.), and with an average yield strength of 344.7 MPa (50,000 psi) to 827.4 MPa (120,000 psi). The bigger the CT diameter, the deeper it can be used but the more it weighs and the less its life would be. It can be uncoiled in the well and returned back to the reel up to 50 or more times depending to the drilling conditions before metal fatigue forces retirement In oil and gas industry, the basic micro-drilling rig concept was developed by the U.S. Los Alamos National Laboratory LA NL to achieve a readily automated coiled tubing deployed drilling model to provide an inexpensive, reliable, and field demonstrated in range of 4.45 to 6.03 cm diameter holes to the depth of 200-300 m. **[2]**

I.2 History of Coiled Tubing Drilling:

CT services began 55 years ago, prior to the allied invasion of Normandy. The development of modern coiled tubing has its roots in a secret Allied project during World War II. Project PLUTO, an acronym for Pipe Lines Under the Ocean, deployed 23 ‘continuous tubing’ pipelines across the English Channel to fuel the invasion forces. Seventeen lead pipelines were deployed to a total length of 30 miles. An additional six pipelines were constructed by butt-welding 20-ft. Joints of 3-in. ID steel pipe. These tubulars were spooled into 40-ft diameter reels and deployed by towing the reel behind a ship. **[3]**

It was not until 18 years later, however, that Bowen Tools (IRI International Inc.) and the California Oil Company, developed a prototype CT workover unit with the injector head designed as a vertical, contra-rotating chain drive system built on to a string of 1.315-in. OD

pipe. The most important component of a coiled tubing unit is the injector. The origin of the injector head lies in another secret military project for the U.S. Navy. In the late 1950s and early 1960s, the U.S. Navy contracted Bowen Tools to develop an antenna transfer device for their submarine communication systems. The design that resulted from this project was a vertical contra-rotating tractor device, which deployed a 5/8". polyethylene-encapsulated brass antenna from as deep as 600-ft. beneath the surface. 'Saddle blocks' were constructed from fabric-reinforced phenolic and were installed along the middle section of both sets of chains. These blocks matched the tube diameter and secured the antenna by friction, this allowing the deployment and retrieval of the antenna. **[1]**

Since its introduction in 1963 ,coiled tubing has

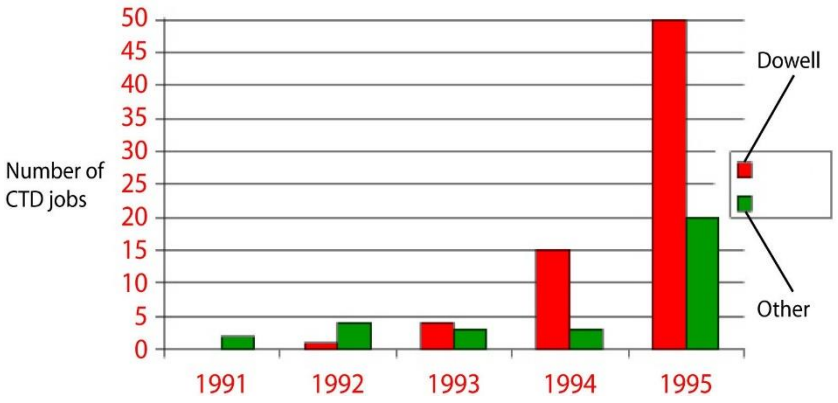


Figure I.1: Coiled tubing jobs per year

been heralded as a technology that has the potential to revolutionise the oil field

Unfortunately, mechanical failures ,mainly due to quality issues with the manual

butt-welding process and low-strength pipe, resulted in numerous fishing operations ,

and promoted an industry-wide hesitancy to use the technology. The added high oil

prices, and the oil field's unwillingness to adopt change, have limited the growth of

coiled tubing. Over the past several years, however, interest in coiled tubing has increased dramatically. The fall of oil prices in 1986 triggered the increased use of, and interest in, cost-saving technologies such as coiled tubing In the early 1990s, Arco, a leading pioneer in Coiled Tubing Drilling, began experimenting with CTD in West Texas, Oklahoma, and Alaska. Since then, the company has drilled 132 extensions or side-tracks world-wide; in Alaska (115),

California (11), New Mexico (1), Texas (1), Indonesia (3), and Algeria (1). In 1992, the company advanced CTD technologies when it developed a successful window milling system, followed by a long-term programme in Prudhoe Bay which still continues today. **[3]**

I.3 Advantages of CTD :

Coiled tubing drilling presents several advantages over conventional drilling operations:

• smaller footprint

• safer drilling operations while drilling underbalanced, especially with multiphase fluids (foam and nitrified fluids)

• continuous circulation

• faster tripping operations (continuous pipe, no connections required) • ability to monitor and subsequently control downhole pressures more efficiently

• real-time downhole measurements of surveys, logging data (GR, CCL), and pressure data at high-data rates using integral wireline inside the coiled tubing

• superior directional control due to steering at BHA (reduced reactive torque effects)

• improved pipe reliability for slim hole operations. Also, with coiled tubing, underbalanced

• tripping

• drilling

• completion can be performed

. This minimizes damage to the reservoir by eliminating the need to drill the well as is normally required with a conventional drilling rig. Underbalanced drilling also permits the well to produce while it is being drilled.

Although underbalanced drilling can also be performed by certain rigs with jointed-pipe equipment, tripping and completion activities require that the well be killed- significantly impairing any results from underbalanced drilling. Coiled tubing drilling allows the well to be maintained in an underbalanced state throughout the drilling and completion operations, virtually

eliminating any wellbore damage and possibly reducing the need for well stimulation afterwards. **[1]**

Another major advantage of coiled tubing or drilling-related activities is the ability to install a wireline inside the coiled tubing itself. The insertion and removal of any electric steering tools, packers, logging tools, or the equipment into the well is conducted in an effortless, efficient manner by simply spooling the coiled tubing. This ability to perform trips quickly is a major advantage when performing operations on deep wells.

Research and development of coiled tubing for drilling have proved it to be both technically feasible and economical in the right applications. This makes it a viable alternative to conventional drilling, especially offshore and in environmentally sensitive areas.

Coiled tubing units are used to drill in environmentally-sensitive areas because of the efficiency in using a closed loop system due to no connections. The coiled tubing drilling package also has less exhaust emissions and greatly reduced noise levels. Due to the small diameter holes being drilled, there are reduced quantities of drilling fluids to be mixed, and less drill cuttings to dispose.

The major attraction to coiled tubing drilling in the long-term is the fact that the technology is particularly advantageous when used for underbalanced drilling, short radius, and multilateral applications. **[3]**

I.4 Disadvantages of CTD:

- There are, however, disadvantages to coiled tubing drilling.
- These include the following:
- limited life of the coiled tubing itself (i.e., cycle fatigue), especially in larger coiled tubing sizes
- less industry experience compared with conventional drilling.
- reduced horizontal-reach potential, due to sliding friction.
- additional operating cost due to the need for a downhole motor.

Les liners peuvent également être utilisés pour réduire la pression différentielle entre les différentes formations, ce qui peut aider à prévenir la fracturation de la formation et à minimiser les dommages causés par l'eau ou les gaz indésirables. **[2]**

En plus de ces utilisations spécifiques, les liners peuvent également être utilisés pour augmenter la résistance mécanique de la colonne de puits. En outre, ils peuvent aider à protéger la formation contre les dommages causés par l'eau ou les gaz indésirables en empêchant leur migration dans la formation.

Il existe plusieurs types de liners, notamment les liners de forage, les liners de production, les stub liners et les scab liners. Les liners de complétion sont également couramment utilisés pour la production de fluide à travers les trous de perforation.

En somme, les liners sont un élément clé dans la conception et la construction de puits de pétrole et de gaz, et sont utilisés dans une variété d'applications pour assurer la sécurité, la stabilité et la productivité des puits. **Rate of Penetration:**

Optimizing rate of penetration with coiled tubing must be done with limited weight on bit. Due to the absence of drill collars and the helical nature of coiled tubing, weight on bit is reduced. The inability to rotate the coiled tubing also serves to increase friction and reduce the effective transfer of weight to bit. The weight transferred to the bit does come from the weight of the coiled tubing; however, available weight on bit does not increase with increased depth.

The additional weight of coiled tubing due to increasing depth is taken up in friction due to helical buckling in the vertical wellbore. Typically, rate of penetration with coiled tubing is controlled by motor/bit selection and the reduction of hydrostatic pressure on the formation (in other words, underbalanced drilling). **[2]**

I.5 Coiled tubing Drilling Equipement:

A common misconception is that the coiled tubing drilling unit is small and self- contained, and drives up on location ready to drill, with a minimum of rig-up involved. In truth, the typical Coiled Tubing Drilling unit must have much of the same equipment that a conventional drilling unit has (e.g., mud pumps, mud tanks, solids-removal equipment, mud-mixing facilities, and 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.

In addition, CTD units with 2-3/8” or 2-7/8” outer diameter (OD) coil are not exactly the small units a lot of operators are accustomed to seeing on location for typical well-service jobs. Coiled

Tubing Drilling requires high-capacity units with more associated equipment. Some of the newer units are so- called hybrid units. **[3]**

These also have a conventional pipe-handling capability, which enhances their utility. Others are being constructed primarily as small drilling rigs - they also have coiled tubing drilling capabilities. **Surface Equipement:** The basic surface components required to run a coiled tubing drilling job are:

The basic surface components required to run a coiled tubing drilling job are:

• Injector and gooseneck

• Reel

• Operator control cabin

• Power pack

• Crane

• BOP's, stripper and wellhead adapters.

• Fluid pumps

• Fluid tanks

For underbalanced drilling operations:

• Nitrogen tanks and pumps, or N2 generator

• Well control system and data acquisition system

• Lubricator

• Flow lines and/or flare system

• Separation system

I.5.1.1 : Coiled Tubing Unit

Figure I-2: Plunger pumps

Coiled tubing drilling equipment usually includes the following:

- coiled tubing and coiled tubing reel
- injector head
- power pack
- coiled tubing blowout preventer (BOP)
- control cab.

I.5.1.2 Well controle equipement :

The well control equipment typically includes:

- blowout preventers (ram-type and annular)
- accumulator units
- stripper (ram-type or radial)
- check valves
- choke lines and manifolds.

Figure I-3: Well control equipment rig-up

I.5.1.3 Returns Handling Equipement:

I.5.1.4 The fluid handling equipment can include:

- a mud return line (lines between the annular section and return tanks)
- mud tanks
- a shale shaker (removes large cuttings)
- a centrifuge
- a degasser (poor boy or vacuum)
- de-sander
- de-silter
- sample catcher
- a separator (optional)
- a mixing hopper.

Normally, there are three functions that are needed for mud tanks:

- a settling tank for mud from the well and the shaker
- an active tank for mud going into the well
- a reserve tank for new or heavier mud.

Separators are used if gas or oil is produced while drilling and are positioned so that all flow returning from the well must first pass through the separator. **[1]**

Pumping Equipment:

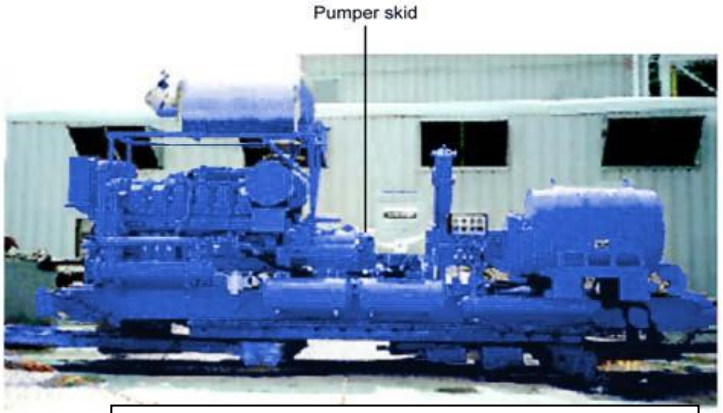


Figure I-4: Plunger pumps

Coiled tubing drilling requires long periods of continuous pumping of drilling fluids and does not normally employ the same high- and low-pressure pumping equipment used in other Schlumberger applications.

Plunger pumps capable of pumping drilling fluid for long, uninterrupted periods of time are used, similar to those used in conventional drilling operations. In order to reduce personnel required, mud pumps are positioned with controls in the coiled tubing cabin so that the operator can start and stop the pumps as may be required to operate orienting tools and other downhole equipment. **[1]**

Pump Pressure:

Pump pressure is a function of:

- pump rate
- fluid composition
- length of coil
- flowing friction inside the coil and in the annulus.

Typically, pump pressure is reduced through the use of multiphase fluid. A maximum desired pumping pressure for pipe that does not remain on the reel is approximately 4,000 psi.

Monitoring and Recording Equipment

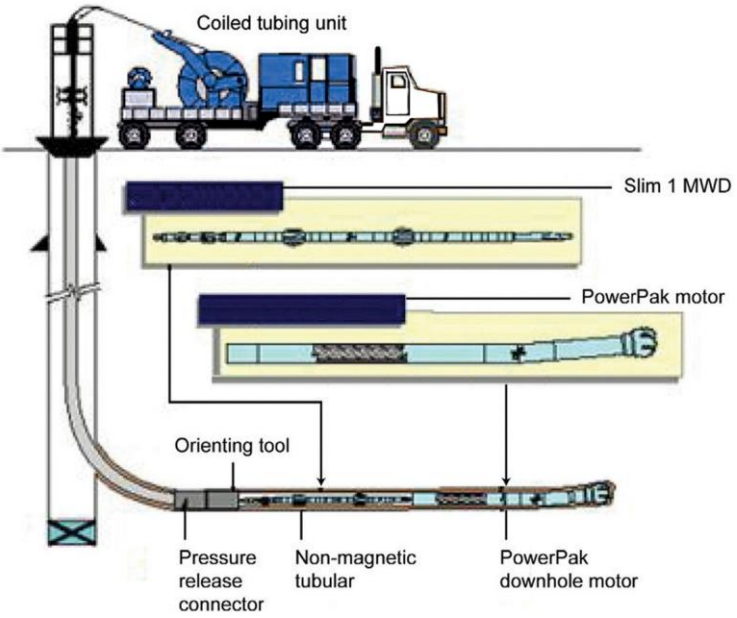
Figure I-5: CoilCAT display

In addition to the conventional coiled tubing unit instruments, coiled tubing drilling requires drilling-parameter instruments for information about activities downhole and flow-parameter instruments to monitor rates of return. The CoilCAT system is normally used for monitoring and recording drilling parameters from the coiled tubing unit, and is integrated with downhole tool measurements to provide a full monitoring package for efficient operations. The CoilCAT system communicates depth, pumping pressures, and surface weight measurements to the IDEAL system (Anadrill) where it is combined with downhole measurements of direction, inclination, gamma ray, and other sensors to provide accurate data for plotting and monitoring the directional drilling progress and geologic correlation to drilled formations downhole.

Coiled Tubing Drilling Downhole Equipment:

Bottomhole assemblies for coiled tubing drilling applications include:

- motor assembly for nonsteered drilling applications
- directional drilling assembly for directional drilling
- bottomhole assembly for window-milling operations
- bottomhole assemblies, such as those used for running liners, whipstocks, scrapers, fishing**[2]**



Bottomhole Assembly for Nonsteered Drilling Applications:

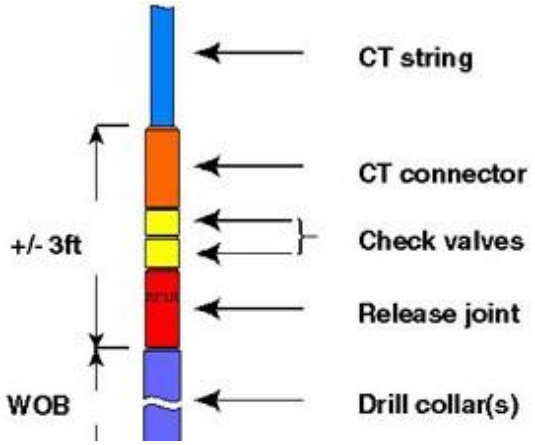


Figure I-6: ***Coiled tubing drilling operation***

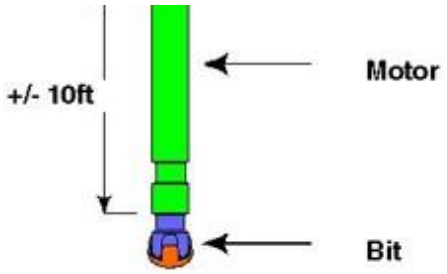


Figure I-7: Bottomhole assembly schematic

The bottomhole assembly typically consists of:

- the coiled tubing connector
- drill collars (if needed for vertical wells)
- a check valve
- a release mechanism
- a downhole motor
- a bit.

Bottomhole Assembly – Coiled Tubing Connector

Schlumberger typically uses a dimple-style connector for all coiled tubing drilling operations due to its simplicity of design and proven performance record. **[3]**

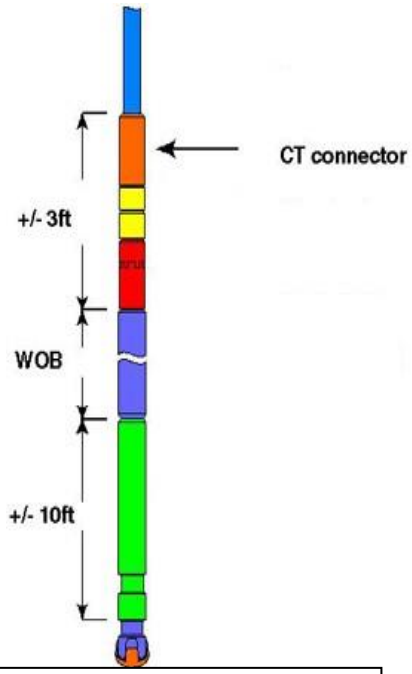


Figure I-8: Bottomhole assembly schematic:

Drill Collars

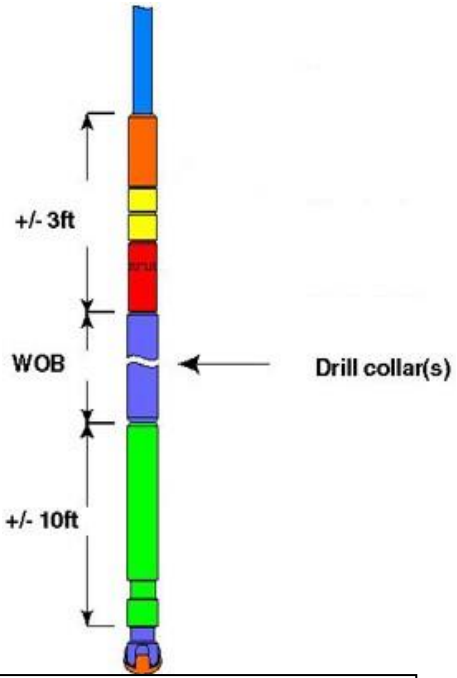


Figure I-9: Bottomhole assembly schematic:

For vertical wellbores, a small amount of drill collars (typically 2 or 3) can be used to assist in maintaining a straight wellbore. The size and exact length varies with the hole size being drilled. The resulting "pendulum" effect is most effective when drilling softer formations or when minimal weight on bit can be used to drill effectively. No stabilizers are normally run during coiled tubing drilling. Spiral downhole collars are preferred due to their reduced sticking tendencies.

Drill collars are stiff tubulars that provide weight and rigidity to the BHA. Drill collars (DC) come in either flush or spiral surfaces. To reduce the wall contact area and minimize the chance of differential sticking, spiral drill collars are preferred in CT drilling. This is due to the lack of rotation in coiled tubing. They also come in a wide range of OD and ID, but generally the OD should be kept consistent with the rest of the BHA. **[1]**

Check Valves

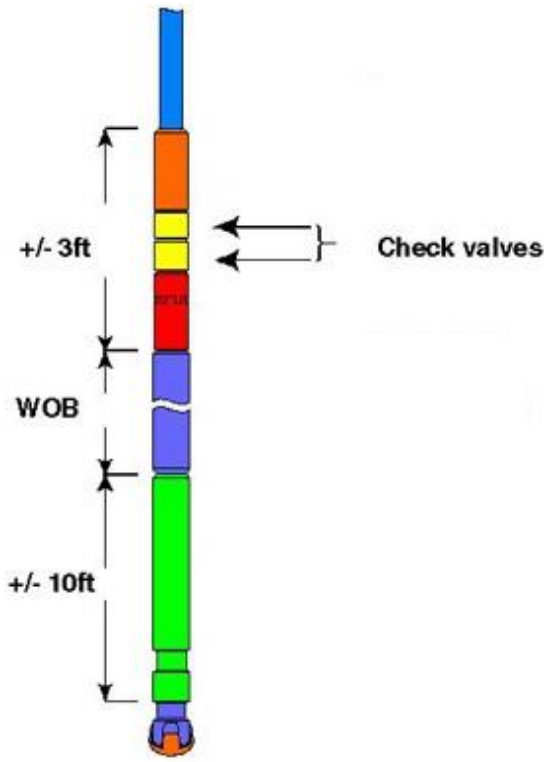


Figure I-10: Bottomhole

Check valves are run to prevent back flow into the coiled tubing that could cause plugging of the BHA. They also provide an internal safety barrier for the coiled tubing in the event of a well control event.

Generally a double check valve assembly is incorporated in the bottom hole assembly just

below the coiled tubing end connector which prevents fluids from entering the coil from the wellbore. The main reason to incorporate check valves in the assembly is to prevent an inflow of formation fluids from reaching surface if the coiled tubing develops either a pin-hole or parts at surface. There are two kinds of back-pressure valves typically used: Ball and Seat – The ball-and-seat valve is the basic type of check valve because of its simple construction, ease of maintenance, reliability, and cost. The main disadvantages are the restriction of flow area and restriction of mechanical access below the valve. Flapper-Type – The flapper-type valve is used when applications may require that a ball or dart is pumped to actuate a tool function or when flow requirements do not allow a ball-and-seat check valve to be used. **[2]**

Release Mechanism

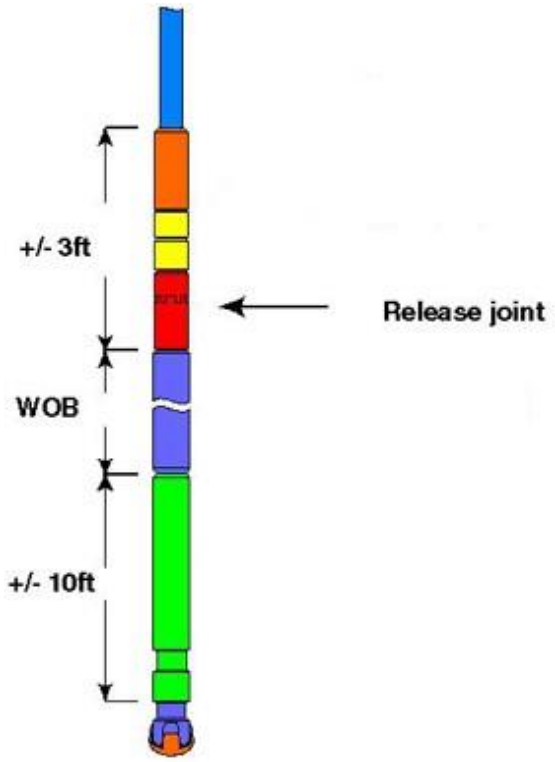


Figure I-11: Bottomhole assembly schematic: release mechanism

The hydraulic release mechanism (or joint) is operated by dropping a ball from surface inside the coiled tubing. When the ball reaches the fishing tail, the pressure rises because the ball seats against a piston, which stops the flow. This pressure then shears a set of brass pins holding the piston in place, the piston shifts, and the joint is released.

Other types of release mechanisms include:

- shear pin mechanical releases (generally not used, as the torque and vibrations during the drilling operation tend to weaken the pins)
- multicycle disconnect release (movement of the CT string above the stuck BHA element is used to operate the release mechanism).

Downhole Motors**[1]**

Figure I-12: PDM tool

The most commonly used downhole motor is a positive-displacement motor (PDM). The PDM is driven by the drilling fluid that passes through the motor. The fluid passes through a rotor/stator section (similar to a spiral) and causes rotation of the inner rotor.

Other motors are sometimes used in special applications where extreme temperature or other parameters are unfit for a PDM. Those motors include:

- turbines
- vane motors.

Here is a **positive-displacement motor.** These motors come in different configurations of rotor/stator ratios and number of stages which affect their speed and torque capabilities. Typically, higher-torque motors are preferred for coiled tubing drilling. In positive-displacement motors, there are two types of

bearing sections: **[3]**

- Some are fluid lubricated by leaking small amounts of the drilling fluid through them.
- Some contain sealed bearings, which do not require drilling fluid for lubrication.

Turbines produce high speed; however, they can be used with gear reductions to reduce speed and increase torque.

- Turbines employ multiple sections of rotating blades that are activated by fluid passing through the motor. Due to the multiple sections, turbine motors typically operate at pressures three to four times higher than PDM motors.
- **Vane motors** are typically made of metallic and ceramic/composite materials, and require very clean fluid to operate. They use vanes, similar to the design concept in a rotary engine that turn via high-pressure and low-pressure areas due to injection/exhaust ports.

Drilling Bits

The bit is often considered the focal point of a drilling system or assembly since it alone performs the role of cutting a hole through the rock formation. Just as there are many types of formations to be drilled, there is an extensive selection of bit designs and materials, many of which are designed to suit specific conditions. Consequently, selection of an appropriate bit is vital to ensuring optimized drilling results (typically assessed on ROP). When drilling rock formations, bit size ultimately determines hole size (diameter). However, formation movement during and after drilling can result in hole sizes ranging from significantly over gauge (caving and washouts) to under gauge (sloughing or tight hole). Only by combining the bit with an appropriate BHA, drilling fluids program and the application of "good drilling practices," will an accurate and stable wellbore be constructed.

In addition to providing efficient drilling action, bits must fulfill several other functions.

- Bit face cleaning – enable cuttings or drilled materials to be removed from the area once cut
- Hole gauge – create a wellbore not less than the nominal bit size, throughout

the life of the bit (wear resistant gauge)

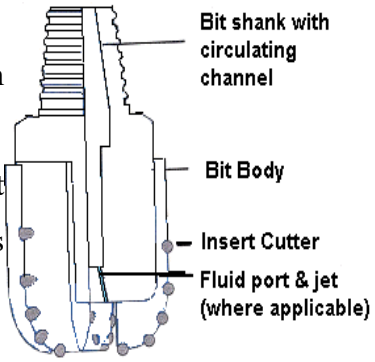
- Connect to the BHA – the bit must be securely and reliably connected to the motor or BHA

To provide these fundamental functions, the majority of bits (regardless of specific design) contain the following design elements.

- A cutter assembly or matrix which provides complete and even drilling action within the nominal bit circumference
- Ports and nozzles directing drilling fluid through the bit and around the bit face to ensure cuttings and debris are removed and to prevent overheating of cutters or mechanical components
- "Gauge wear protection", i.e., the hole drilled at the end of a bit's life should not be smaller than when new. Typically, hard-face treatments or hardened material inserts are used to reinforce friction surfaces. Experience has shown that the ability to accurately steer and/or adjust the BHA trajectory during drilling of a short-radius build-up section is hindered by long gauge protection on the bit. This should be carefully considered during the well-planning stage of a directional well and specific aspects of the well (trajectory, build-up rate, bit-type, etc.) planned accordingly.
- An appropriate tool joint capable of withstanding the forces exerted by the bit/drilling system. In addition, some means of securing the bit for make-up/breakout is either incorporated into the bit design or provided for in a separate torque adapter. Since standard bits come with standard thread connections, the making up of the bit to the BHA at the well site can be problematic due to the required torque values of the larger connections. A common practice in such cases is to have the bit pre-torqued and sent to the well site as part of the BHA. Otherwise, bits can be torqued at the well site by laying them out horizontally and using various mechanical devices, such as chain tongs, hydraulic tongs or the crane. This aspect should be recognized and addressed in the well planning stage. **[3]**

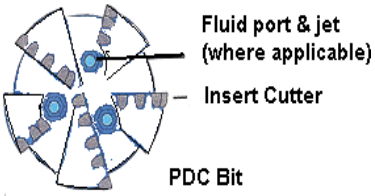
In CTD, bit speed is often higher while WOB is always less than in conventional drilling, requiring consideration of the following factors:

- CTD bits should be compatible with high speed operation.
- Roller-cone bits, which use a crushing action, do not operate as efficiently with the lower WOB inherent with CTD.
- Fixed-cutter bits require lower WOB and are better suited for CTD in uniform formations. However, performance can be sensitive to WOB fluctuations although, in general, WOB is more easily controlled with CTD than with rotary drilling.
- Major variations in WOB may induce stalling which may impact the reliability and performance of both the bit and motor.
- Fixed-cutter bits are generally available in smaller sizes than are roller-cone bits.



The relatively low flow rates associated with CTD can have a significant effect on bit hydraulics, e.g., cleaning efficiency and jetting effects available at the bit face.

- Gauge protection is important, but should be considered in terms of steerability in directional drilling, especially in the build-up section.



- The ability to backream with CTD is an important advantage in the drilling operation and this feature should be built into bits run for CTD. **[3]**

The two most common types of bits are:

- fixed cutter (sometimes called drag bits)
- roller-cone bits.

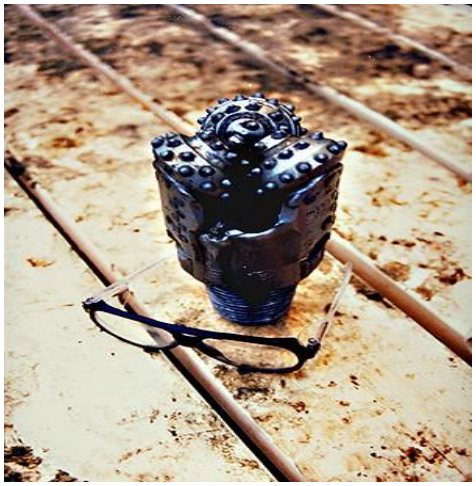


Figure I-13: **Tri-cone bit**

Figure I-14: **Fixed cutter bit**

- **Weight on Bit**

Weight on bit is a function of well geometry and hook load. Hole tortuosity and the existence of a cuttings bed can also detract from the ability to transfer weight to bit. Weight on bit cannot be calculated from the difference in hook load from off-bottom. Some of the hook load weight is lost in friction due to helical buckling.

The percentage of hook load weight transferred to the bit decreases as drilling is done through the build and horizontal wellbore. The phenomenon of stick-slip also causes the conversion of slack-off weight at surface to be transmitted to the bit unevenly, in jerky movements. This is due to the crossover from static to dynamic friction. Other factors that affect weight on bit include casing size and hole size. **[1]**

- **Bottomhole Assembly for Directional Drilling**

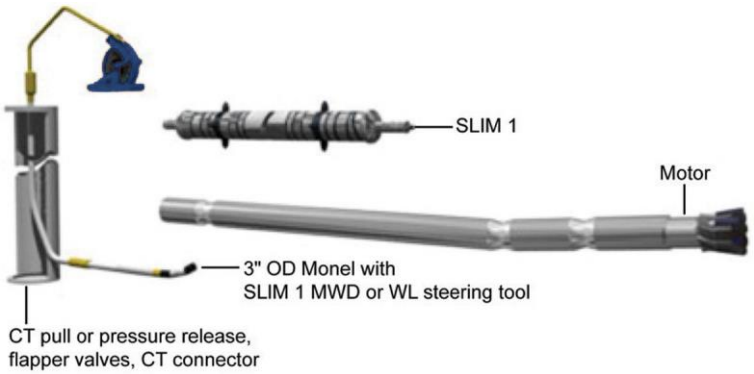


Figure I-15: Directional drilling bottomhole assembly

This illustration shows a typical bottomhole assembly for directional drilling. From the bottom up, a typical directional-drilling bottomhole assembly could include the following:

- bit
- drilling motor with bent housing
- float sub (check valves)
- UBHO (universal bent housing orienting) sub (if required)
- release tool (optional)
- orienting tool
- nonmagnetic housing for surveying instrumentation with wireline, mud pulser, or electromagnetic telemetry
- downhole instrumentation (e.g., downhole pressures, GR, CCL)
- coiled tubing connector. **[2]**

Chapter (02)

Application, Techniques and challenges of CTD

II.1 Introduction :

This chapter explores the diverse applications of Coiled Tubing Drilling (CTD) in modern oilfield operations, including re-entry wells, underbalanced drilling, It presents the key techniques that enable CTD to operate effectively in complex environments. Special attention is given to managed pressure drilling, directional control, and through-tubing operations. Despite its advantages, CTD also faces several technical and operational challenges. **[5]**

II.2 Potential Applications of CTD:

A number of older fields are now entering decline from plateau, and are producing more and more water from the initially perforated reservoir zones. Coiled Tubing Drilling can help in sustaining, or even increasing production from these zones, by being able to access reserves in a cost-effective manner.

Applications for coiled tubing drilling are:

- Drill multi-laterals from the mother-bore
- Drill side-tracks without removing the completion
- Drill underbalanced wells and increase productivity by eliminating reservoir impairment.
- Drill wells without a conventional rig
- Drill wells simultaneously with a conventional rig

Non suitable CTD Application:

As well as potential applications, CTD has a number of areas where coiled tubing is not best suited. Some of these applications are better drilled using other methods. These are:

- Drilling extended reach wells (in excess of 16,000ft)
- Drilling 8-1/2” or bigger hole sizes
- Drilling wells in unstable formations**[5]**

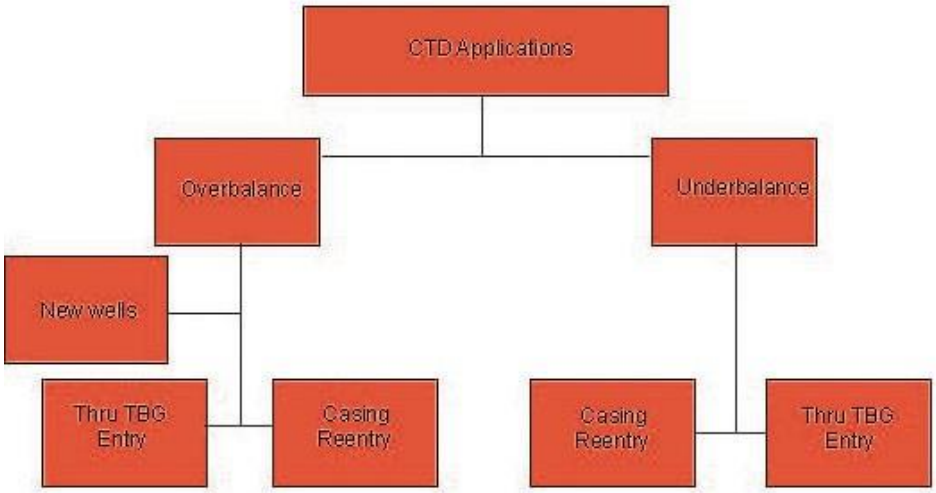


Figure II-1: Coiled tubing drilling

This graphic shows a flowchart of coiled tubing drilling applications. These may be either overbalanced or underbalanced.

Overbalanced drilling is drilling with a fluid that exerts sufficient bottomhole pressure to exceed that of the pore pressure in the rock surrounding the wellbore. Reservoir fluids are not allowed to enter the wellbore.

Underbalanced drilling is drilling with a bottomhole pressure below that of the pore pressure of the rock surrounding the wellbore. Reservoir fluids are allowed to enter the wellbore and are separated at the surface from the drilling fluid. The underbalanced technique is used to:

- prevent formation damage caused by entry of damaging drilling fluids to the formation
- minimize many drilling-related challenges, such as loss of circulation and differential sticking
- increase rates of penetration
- minimize completion costs
- increase hole-cleaning efficiency (due to reservoir inflow)
- reduce mud costs
- improve economics by providing early reservoir production.

Both techniques can be used on new and previously drilled wells. When drilling in a previously drilled well, casing reentry may be used (with tubing removed), or reentry can be done through the existing tubing, if the tubing is large enough to accommodate current equipment (3 1/2-in. tubing and larger).

Coiled tubing is especially attractive for slimhole applications, due to susceptibility to joint failure in conventional slimhole pipe. **[6]**

II.2.1 Previously-Drilled Wells:

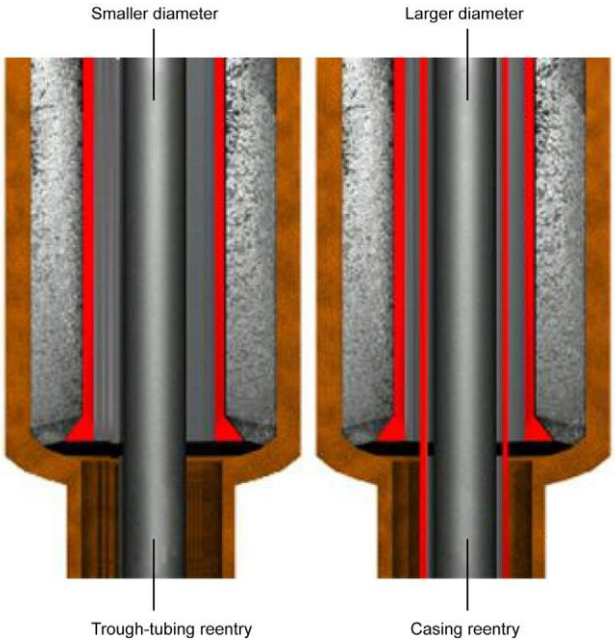


Figure II-2: Drilling reentry types

Coiled tubing drilling in previously drilled wells can be performed using either

- through-tubing reentry, or
- casing reentry. **[6]**

II.2.2 Through-Tubing Reentry Sidetrack:

Through-tubing reentry means that the coiled tubing reenters the wellbore through existing production tubing. This method requires the entire bottomhole assembly to be able to pass through the tubing. This method is used to deepen wells and for directional sidetrack to increase flow area or access new reservoir targets. The wellbore can be exited either through both the tubing and/or casing or through the casing below the production tubing.

This method eliminates the cost of:

- pulling tubing and associated completions equipment
- running production tubing after drilling.

This change of project scope significantly reduces the overall project costs and is the main market driver for this type of work.

Through-tubing re-entries can be performed with either overbalanced or underbalanced techniques. **[6]**

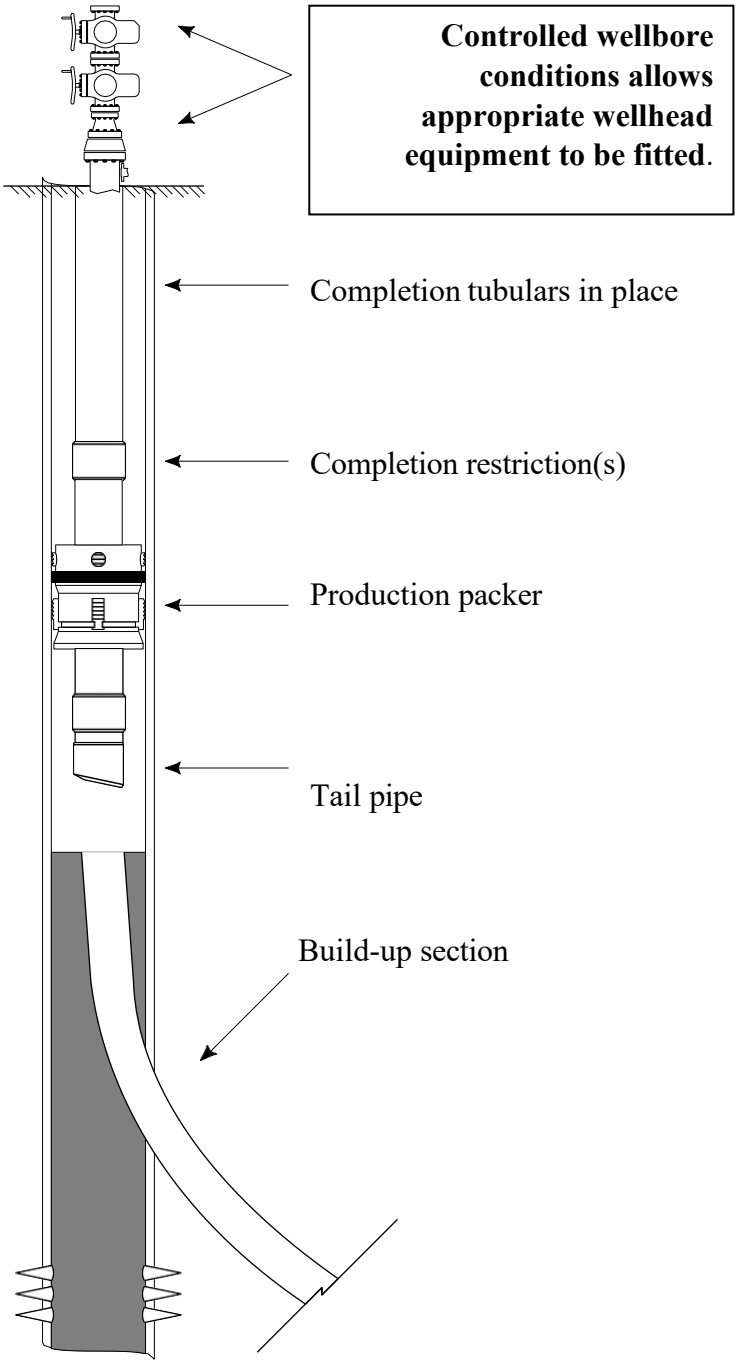


Figure II-3: Typical thru-tubing sidetrack

II.2.3 Casing Reentry Sidetrack:

With **casing reentry**, the coiled tubing reenters the wellbore through the casing—any production tubing or packers are removed prior to initiating the wellbore exit. Casing reentry is done to deepen wells or for sidetracking and horizontal drilling.

Coiled tubing is most effective economically when used to:

- perform short radius drilling
- when in environmentally sensitive locations
- offshore on platforms where a full drilling rig is cost-prohibitive.

Casing reentries can be performed with either overbalanced or underbalanced techniques. **[5]**

II.3 Techniques of coiled tubing drilling :

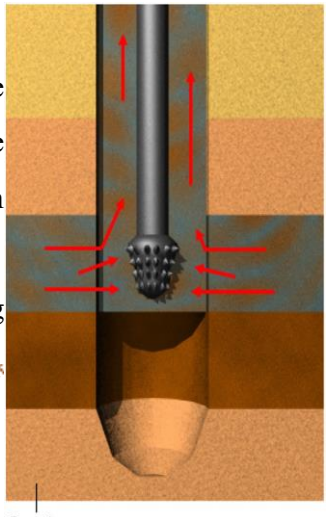
Coiled Tubing Drilling (CTD) represents a paradigm shift in drilling technology by utilizing a continuous spool of pipe instead of traditional jointed drill pipe. The techniques associated with CTD are highly specialized, enabling operations in environments that are otherwise inaccessible, uneconomical, or unsafe using conventional drilling rigs. Key techniques of CTD include **underbalanced drilling (UBD)**, **managed pressure drilling (MPD)**, **directional and horizontal drilling**, **thru-tubing drilling**, and **slimhole/microhole drilling**.

Each of these techniques addresses specific operational challenges and objectives—ranging from reducing formation damage to enabling re-entry into existing wells. This section provides a comprehensive overview of the primary CTD techniques, their principles of operation, and their key advantages and limitations. **[5]**

II.3.1 Underbalanced Drilling (UBD) Using CTD:

Underbalanced drilling is a technique where the bottom hole pressure (BHP) is intentionally kept lower than the formation pressure. The objective is to prevent formation damage, increase the rate of penetration (ROP), and enable real-time production monitoring.

In CTD-UBD, the ability to maintain continuous circulation while drilling



is critical. Fluids such as nitrogen, natural gas, or air foam are injected to lower the hydrostatic pressure of the column. Since CTD allows for pressure control at the surface, it is ideal for these operations, especially in depleted or pressure-sensitive formations.

Advantages of CTD-UBD:

- Minimizes reservoir damage
- Increases wellbore stability
- Allows for real-time hydrocarbon flow monitoring
- Reduces formation fluid invasion

Limitations:

- Complexity in fluid management
- Higher surface equipment requirements[6]

Figure II-4: Underbalanced drilling: reduced hydrostatic fluid column

II.3.2 Managed Pressure Drilling (MPD) with CTD:

Managed Pressure Drilling (MPD) is another advanced technique used in CTD operations to precisely control annular pressure throughout the drilling process. MPD with CTD is particularly useful in narrow-margin drilling windows, where the pore pressure and fracture gradient are close together.

Key components include:

- **Rotating Control Device (RCD)**
- **Automated choke manifold**
- **Real-time pressure sensors**

When combined with CTD, MPD allows for dynamic adjustments to surface backpressure, which helps mitigate kicks, reduce fluid losses, and enhance safety in high-pressure, high-temperature (HPHT) environments.

Advantages:

- Improves pressure control and safety
- Reduces non-productive time (NPT)
- Enables drilling in HPHT zones

Drawbacks:

- High complexity of setup
- Requires real-time monitoring and fast reaction systems
-

II.3.3 Directional and Horizontal Drilling with CTD:

Directional and horizontal drilling using CTD is possible through the use of **downhole steerable motors**, **bent subs**, and **Rotary Steerable Systems (RSS)**. These BHAs enable CTD operations to drill complex well trajectories, including multilaterals and sidetracks.

CTD is particularly advantageous for:

- Sidetracking from existing wellbores
- Accessing thin or bypassed zones
- Drilling extended laterals for enhanced reservoir contact

Since coiled tubing does not rotate from the surface, directional control is achieved solely by downhole tools. The absence of surface torque eliminates many mechanical issues like stick-slip and torque-induced failures.

Technological Components:

- Bent-housing motors for steering
- Gyroscopic or MWD-based navigation
- RSS for continuous steering without rotation

Challenges:

- Steering difficulties in high dogleg severity wells
- Limited bit control due to the lack of surface rotation

Advancement: Integration of fiber optic communication lines into coiled tubing has enhanced real-time data acquisition and directional control capabilities**[6]**

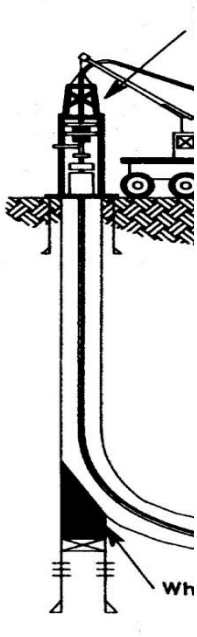


Figure II-5: *CTD setup (University of Stavanger 2010)*

II.3.4 Thru-Tubing Drilling:

Thru-Tubing Drilling (TTD) is a unique CTD technique where operations are performed **through existing production tubing**, eliminating the need to remove the tubing string or perform a full workover.

This technique is widely used for:

- Sidetracking in dead or marginal wells
- Accessing new reservoir targets
- Performing low-cost re-entries and interventions

A **slim BHA** is required, typically less than 2.5 inches in diameter, capable of passing through the existing completion string. Once inside the casing, sidetracking is initiated using a whipstock or jetting tool.

Benefits:

- Reduces operational costs and time
- Minimizes surface disruption and footprint
- Enables reactivation of previously shut-in wells

Limitations:

- Tool size constraints**[5]**

II.3.5 Slimhole and Microhole Drilling:

Slimhole drilling refers to the use of smaller-than-conventional hole diameters (typically less than 6 inches). CTD is inherently well-suited for this due to its compact equipment and flexible tubing.

Applications include:

- Shallow gas or oil exploration
- Coalbed methane (CBM) wells
- Low-cost pilot wells
- Geothermal resource access

These wells are particularly relevant in frontier exploration areas, environmentally sensitive zones, or unconventional plays where full-scale rigs are uneconomical.

Advantages:

- Lower drilling fluid volumes
- Reduced environmental footprint
- Quick deployment and mobility

Constraints:

- Limited tool size and functionality
- Less capacity for directional complexity

Industry Use: In Alaska, CTD-based slimhole wells have been used for geothermal gradient testing and pilot-scale reservoir evaluation**[6]**

II.4 Challenges of Coiled Tubing Drilling (CTD) :

Despite its advantages and growing adoption, Coiled Tubing Drilling (CTD) faces several **technical, operational, and economic challenges** that can limit its effectiveness in certain environments. Understanding these challenges is essential for optimizing CTD operations, improving equipment reliability, and selecting the right wells for application.

Protéger les équipements de surface en minimisant les risques de contamination des fluides de production et en évitant la formation de ponts de boue ou de sable. **[6]**

II.4.1 Limited Weight on Bit (WOB)

Unlike conventional drilling, which uses the weight of the drill string to apply force to the bit, CTD relies solely on the axial stiffness of the coiled tubing to transfer weight. This presents several problems:

- In extended reach or horizontal wells, the tubing can buckle or lose contact with the bottom hole assembly (BHA), reducing drilling efficiency.
- The lower WOB limits the type of formations that can be drilled economically, especially in hard rock or abrasive environments.
- Excessive tubing deformation can result in fatigue and early failure.

Mitigation Strategies:

- Use of downhole tractors or vibration tools
- Optimization of fluid hydraulics to aid in bit penetration
- Improved tubing metallurgy and stiffness profiles**[5]**

II.4.2 Fatigue and Tubing Life:

Coiled tubing is subject to **cyclic fatigue** each time it is spooled and unspooled from the reel and when it passes through the injector and gooseneck. Repeated flexing causes microscopic cracks to develop in the tubing wall, which eventually leads to failure.

Challenges include:

- Accurately predicting remaining tubing life
- Managing corrosion and chemical wear from downhole fluids
- Operational interruptions due to unexpected failures

Mitigation Strategies:

- Tubing inspection (e.g., magnetic flux leakage)
- Fatigue tracking software

Use of corrosion-resistant alloys or protective coatings

II.4.3 Limited Torque and Rotational Control

CTD systems do not rotate the tubing from surface like conventional drill pipe. Instead, the bit is rotated by a downhole motor. This causes:

- Reduced ability to manage hole cleaning, especially in horizontal sections
- Difficulty drilling through complex or interbedded lithologies
- Inability to transmit torque from surface, which limits mechanical effectiveness

Solutions:

- Use of dual-acting motors or rotary steerable systems (RSS)
- Improved hole cleaning with optimized fluid circulation and solids transport tools
- Development of surface-to-bit communication systems to guide real-time decisions

II.4.4 Real -Time data Limitations:

Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools in CTD must

function without the benefit of a wired drill pipe. This creates challenges in data transmission:

- Limited telemetry bandwidth and signal lag (especially with mud pulse systems)
- Restrictions on depth and speed of data retrieval
- Potential for signal loss in high-pressure or high-temperature environments

Recent Developments:

- Fiber optic telemetry in coiled tubing
- Electromagnetic and acoustic telemetry tools
- Enhanced MWD tools with onboard memory and post-job analysis**[6]**

II.4.5 Hole cleaning and cutting transport:

In horizontal and extended-reach wells, removing drilled cuttings is a major issue due to:

- Low annular velocities (especially with small annular spaces)
- Poor flow regimes (laminar rather than turbulent)
- Risk of stuck pipe due to cuttings accumulation

Best Practices:

- High-viscosity sweeps
- Alternating pump rates
- Downhole reamers and agitators**[12]**

II.4.6 Directional Control in Complex Trajectories:

Directional drilling with CTD requires sophisticated steering mechanisms, yet the **limited downhole orientation capability** and **lack of rotation** can restrict complex well path control. Problems include:

- Difficulty steering in high dogleg wells
- Reduced precision in multilaterals or tight radius wells
- Compromised accuracy due to sensor drift or delayed telemetry

Improvements:

- Bent housing motors
- RSS systems adapted for CTD
- Closed-loop geosteering with surface feedback**[5]**

II.4.7 Equipement and tool size limitations:

Because coiled tubing typically has a smaller diameter than conventional drill pipe, many BHA tools must be miniaturized. This presents:

- Performance limitations due to smaller motors and bits
- Reduced durability and life span of components
- Restrictions on tool combinations in the BHA

Workarounds:

- High-performance motors in small packages
- Slimhole MWD/LWD technology
- Modular BHA configurations**[12]**

II.4.8 Economic and Logistical Constraints

CTD systems are specialized and can be expensive to mobilize, particularly for deep or offshore wells. Other concerns include:

- High capital and maintenance costs for equipment
- Limited availability of experienced CTD crews
- Need for custom BHAs and planning

Economic Optimization:

- Use of CTD for shorter laterals, re-entry, and intervention rather than full-field development
- Improved logistics and regional CTD fleets
- Automation and digitization to reduce personnel costs**[12]**

II.4.9 Limited Drilling Depth and Reach

CTD is generally not suitable for extremely deep wells due to:

- Weight and strength limits of the tubing
- Hydraulic pressure losses over long distances
- Mechanical challenges in extended reach wells

Approaches to Extend Reach:

- Hybrid drilling (start with CTD, finish with rotary)
- Use of downhole tractors
- Development of composite tubing for weight reduction

Chapter (03)

Enhancing Effeciency and Optimizing Strategies Of CTD

III.1 Introduction :

This chapter focuses on identifiying and addressing key performances challenges in CTD operations.it explores optimization strategies, advanced tools, and planning methods aimed at improving efficiency, reducing costs. pratical approaches are presented to enhance overall CTD performance. **[8]**

III.2 Key Performance Indicators (KPIs) in CTD Operations :

To effectively enhance efficiency in Coiled Tubing Drilling (CTD), it is essential to first understand the metrics that define and measure performance. These metrics, often referred to as Key Performance Indicators (KPIs), serve as the foundation for evaluating the success and productivity of any CTD operation. Monitoring and analyzing these indicators allows engineers and operators to identify inefficiencies, optimize procedures, and make informed decisions that contribute to cost-effective and reliable drilling performance.

One of the most critical KPIs is the Rate of Penetration (ROP), which measures the speed at which the drill bit advances through the formation. A higher ROP generally indicates improved efficiency, provided it does not compromise tool integrity or wellbore stability. Optimizing ROP involves balancing weight on bit, rotation speed, hydraulic power, and formation characteristics. In CTD, where rotation may be limited, managing other factors like fluid properties and motor performance becomes even more important.

Another vital KPI is Non-Productive Time (NPT), which represents periods during the operation when no progress is made toward the drilling objective. Common causes include equipment failures, stuck pipe, inefficient hole cleaning, and delays due to safety issues or planning gaps. Reducing NPT is a core goal of efficiency optimization and requires proactive planning, reliable equipment, and strong crew coordination.

Tubing Fatigue and Integrity is a CTD-specific KPI that reflects the mechanical health of the coiled tubing string. CTD tubing is subjected to repeated cycles of bending and straightening, leading to metal fatigue over time. Monitoring fatigue life and using predictive models help operators extend tubing

service life without risking failure. Tools such as fatigue monitoring software and tubing integrity logs support this KPI.

Hydraulic Efficiency and Equivalent Circulating Density (ECD) Control are additional key indicators. Proper fluid circulation is crucial for cooling the bit, removing cuttings, and maintaining wellbore pressure. An imbalance can result in stuck pipe, formation damage, or well control issues. Therefore, maintaining efficient hydraulics with the correct flow rate, viscosity, and pressure drop is essential.

Bit and Motor Performance is also monitored closely. Frequent failures or reduced lifespan of these components can drastically increase operational costs and NPT. Tracking wear rates, torque output, and downhole conditions allows for better planning and tool selection.

Incorporating these KPIs into daily operational monitoring provides a real-time feedback loop that guides performance improvement. By setting target benchmarks and analyzing variances, operators can identify the root causes of inefficiencies and implement corrective actions immediately. Ultimately, the consistent use of well-defined KPIs is the cornerstone of achieving high efficiency in CTD operations. **[13]**

III.3 Pre-Job Planning:

The Pre-Job Planning Process is a primary key to a successful CTD project and meeting the desired objectives. There are two essential elements to this process 1) Preliminary Engineering On-Site Preparation. Preliminary engineering requires several steps to ensure the well is ready for CTD operations. Through thorough research and planning, the well is screened for suitability as well as feasibility, and all reasonable alternative remedial operations are considered. About half of CTD projects are sidetracks from existing wells and half are new wells. Sidetracking operations involve understanding the extent of remaining reserves and the planned wellbore position in relation to the existing wellbore. A preliminary directional plan is determined and then generated. Also, if applicable, CT simulation studies are performed to determine if the proposed well can be re-entered and worked over with smaller diameter CT for later operations. Plans are made for performing all of the needed preparatory work (i.e., P&A existing well, run caliper survey, set whipstock, etc.) before the CTD unit is set up over the well or the work is performed due to timing or other issues.

III.3.1 INITIAL WELL RESEARCH AND PLANNING

Sound CTD operations require careful and complete pre-planning and exhaustive research. The first task for the CTD project manager is to interpret the well proposal and objectives using the following criteria: Define ultimate objectives. The project objectives must be clearly defined and benchmarks established for measuring achievements. Is the objective to expand CTD research, or to provide a commercially viable product, or to drill for appraisal, production, delineation or exploration purposes? Will this wellbore be utilized again for another sidetrack? If so, how should the completion be set up to accommodate future sidetracks? Acquire accurate data. The complete well history including a mechanical history and reservoir considerations is generated. An annotated production plot of the well highlighting fluctuations in production is needed. An updated wellbore sketch with all tubular dimensions noted as well as any problems such as tight spots, holes in tubing/casing, plugs, fill and fish left in hole should be validated by the mechanical history. Formation description of each horizon to be encountered including but not limited to bottom-hole temperature and pressure, rock properties, formation dip angle, lost-circulation zones, faults and/or high permeability streaks, and any offset well data available are supplied by the Reservoir Engineer and/or Geologist. **[9]**

III.3.2 Well Research

It is essential that all information concerning the well be freely communicated to the parties involved. The Reservoir Engineer (RE) should confer with the Geologists and ensure that the placement of the well will be optimal as well as feasible. It is imperative that the field map, reservoir isopach, and formation cross-section be reviewed in detail prior to proposing the well to the CTD Engineer. Research and discussion of the type of well needed to accomplish the objective should be fully resolved (e.g., will this be a deepening of the well, a sidetrack or a well drilled from the surface?). There are three major areas of criteria that must be considered for candidate selection:

.1-Mechanical

•minimum restrictions

• competent tubing, caliper history • true vertical depth (TVD) distance from packer to target zone to incorporate the kick-off point and landing horizontal

• well inclination: vertical, high angle (inclination 50-90°) or horizontal

• two-string kick out due to low packer or damaged straddle completion

• amount and/or cost of preparatory work for CT rig

• what is the future utilization for this wellbore? (set up completion to allow for future through tubing work)

• indications of potential lost circulation in target sands: injection well, fraced, or losses noted in drilling original hole

2. Reservoir

• Will proposed target cross faults or sands with differential pressures too high to handle (i.e., will high pressures cause excessive losses to lower pressure zone)?

• Existing reserves value of current completion – too high to risk?

• Existing production rates and sand quality in target zone – too poor for even horizontal to provide sufficient rate? • Net pay with knowledge of water/oil contact and gas/oil contact

• Object of sidetrack? !"Horizontal for productivity !"Extend or convert to horizontal to reach infill target !"Replace damaged production liner with new twin well

• Do sand quality/formation damage issues dictate running a slotted liner versus a cemented/perforated liner?

• Reservoir description: rock type, faulting, geological changes in zone, formation dip

3. Directional

• KOP in optimal direction and preferably not in shale zone. Is there good cement behind casing at this point?

• Horizontal length needed – can CT reach target with acceptable WOB?

• Azimuth changes – will coil lose too much weight transfer while steering toward target? **4.Other**

• Can the formations to be encountered be drilled with CT? If rock types dictate the use of roller-cone bits, is sufficient bit weight available? **[12]**

III.3.3 Well Planning :

An information package including the research and discussion of location and target for the well should be sent to the CTD Engineer for review and preliminary study. The CTD engineer should review in extensive detail the information package, well history and wellbore sketch for any possible problems that might change the risk of the well. Once it is determined that the well is a viable candidate for CTD, a preliminary directional plan should be developed by the CTD engineer and the Directional Planner. A step-by-step procedure should be followed to determine the feasibility of the well and to identify the drilling hazards, risks and controls. After feasibility has been determined and drilling risks and hazards assessed, personnel and equipment requirements are established by the CTD engineer. Due to the complexity of these projects, use of a suitable project planning program is highly recommended. A contract for the project operations is set up with the CTD contractor and the planned objectives presented, as well as personnel and equipment requirements. The CTD contractor should be provided with as much information as possible that allows for planning personnel and equipment usage and also any input the contractor may have on the project. Cost of the project can now be generated with all aspects of the operation in mind, and the necessary permits and approvals applied for from governing agencies. As discussed in the following sections, drilling and contingency procedures are written with each section tied into the objectives of the well. **[9]**

III.3.4 WELL AND SITE PREPARATION:

Well data gathered earlier should be reviewed again to determine the status of the existing well. No CTD work should begin until the wellbore condition is fully understood. Any recent well work performed should be documented and all files updated. The CTD engineer will then plan the workover operations required prior to the CTD rig coming to location. Some of the operations that may be required are (but are not limited to) well kill, removal of any restrictions in the wellbore (i.e., mill nipple, clean out fill), drift tubing and tag TD, change out live gas-lift valves to dummies, pull or lock open the subsurface safety valve, run a thru-tubing whipstock, and P&A existing perforations. Site preparation for the project

is an important initial consideration whether the well is onshore or offshore. The engineer plans for transportation to the site, as well as plans rig position on the well-site pad or platform. Consideration should be made for heavy equipment use for leveling the pad onshore or the possible need for an additional crane and skid beams for offshore. The equipment layout is vital to a successful operation and a detailed drawing should be provided as part of the procedure for moving and rigging up the CTD unit and equipment. To make this effective, the CTD contractor needs to be highly involved in this portion of the preparation. For offshore operations, a seabed survey should be reviewed and supplied to the contractor. **[9]**

III.4 Optimized Bottom Hole Assembly (BHA) Design:

The Bottom Hole Assembly (BHA) plays a pivotal role in the efficiency of Coiled Tubing Drilling (CTD) operations. An optimized BHA design ensures that the energy delivered from the surface is effectively transmitted to the drill bit, improving Rate of Penetration (ROP), directional control, and reducing downhole failures. Because CTD does not rely on surface rotation like conventional drilling, the design and performance of the BHA become even more critical in achieving drilling objectives, especially in horizontal or complex well profiles.

An optimized BHA typically includes a mud motor, drill bit, Measurement While Drilling (MWD) tools, and in some cases, Logging While Drilling (LWD) systems. The configuration and compatibility of these components are carefully selected based on formation properties, well trajectory, and drilling goals. Downhole mud motors are essential in CTD, as they provide bit rotation independently of the surface. High-performance motors with adjustable bend angles and higher torque ratings enhance penetration while maintaining directional control. Motor selection depends on expected downhole conditions, fluid compatibility, and bit requirements.

Bit selection is equally crucial. Polycrystalline Diamond Compact (PDC) bits are often preferred for their durability and efficiency in soft to medium-hard formations. For harder or abrasive formations,

roller cone bits may be used. The bit's cutting structure, nozzle arrangement, and flow path are optimized to improve cutting removal and minimize vibration.

Integration of MWD and LWD tools into the BHA enables real-time monitoring of inclination, azimuth, gamma ray, and formation properties. This allows directional decisions to be made instantly and helps avoid costly corrections later. These tools also help identify zones of interest for reservoir evaluation, improving the overall value of the drilling operation.

To further improve BHA efficiency, anti-vibration tools and stabilizers can be included to reduce harmful downhole oscillations that cause tool failure or inefficient drilling. Vibration and shock not only damage components but also reduce drilling speed. By incorporating these tools, the BHA operates more smoothly and consistently, improving both tool life and operational performance.

BHA optimization also involves pre-job modeling and simulation using software that evaluates tool interaction with formation, tubing stress, and borehole trajectory. Engineers use these simulations to predict how the BHA will behave under different scenarios, allowing for proactive design adjustments before going to the field. **[11]**

III.5 Efficient Fluid Management and Hole Cleaning:

Efficient fluid management and effective hole cleaning are central to enhancing the performance and reliability of Coiled Tubing Drilling (CTD) operations. Drilling fluids in CTD are responsible for multiple critical functions: cooling and lubricating the bit, suspending and transporting cuttings to the surface, maintaining wellbore stability, and controlling downhole pressures. Unlike conventional rotary drilling, CTD operates at lower annular velocities and may use specialized fluids such as foams or nitrified fluids, making fluid design even more vital.

Proper hole cleaning ensures that cuttings are continuously and efficiently transported to the surface without settling in the wellbore, which can lead to stuck pipe, pack-offs, and increased torque and drag. In horizontal or highly deviated wells, these risks are amplified due to reduced gravity assistance. To combat this, operators must optimize several parameters: **flow rate**, **fluid viscosity**, **pump cycles**, and

circulation patterns. The use of dual-phase fluids (like foam or air-mist) is common in underbalanced CTD environments, reducing hydrostatic pressure while maintaining effective cuttings transport.

Hydraulic modeling plays a key role in planning efficient fluid systems. Engineers use simulation software to predict flow regimes, pressure drops, annular velocity, and cuttings concentration. Real-time downhole sensors can provide feedback on pressure, temperature, and flow behavior, allowing fluid parameters to be adjusted instantly to maintain efficient hole cleaning.

Another critical factor is **fluid compatibility** with formation lithology and downhole tools. The wrong fluid chemistry can damage motors, corrode tubing, or react with the formation, causing swelling or instability. Therefore, laboratory testing and pre-job compatibility assessments are essential before fluid selection.

Advanced fluid management also involves the use of **automated mixing and pumping systems**, which ensure consistent fluid properties and reduce human error. These systems monitor pH, density, and viscosity, making on-the-fly adjustments during operations.

CTD is challenged by the inability to rotate the CT string, small annular clearances in the open hole, low annular velocities inside the tubing and casing, high fluid friction losses in the CT, low initial WOB and rapidly diminishing weight transfer as the hole is drilled. Critical design criteria for a fluid that meets these challenges include minimizing formation damage, fluid loss, pump pressure, and stuck pipe while maximizing cuttings suspension, cuttings transport, weight transfer, shale stability and overall hole conditions for successful liner cementing. A typical recommended fluid for CTD overbalanced drilling is a solids-free bio-polymer consisting of: 1. Brine based liquid with 5% KCl and 3% NaCl 2. Premium grade, highly clarified Xanthan bio-polymer 3. Interfacial tension reducer and lubricant 4. A biocide 5. KOH for pH control “Solids-free” means that no particulate matter is put in the fluid for either density or fluid loss control. If needed, the resulting fluid density of 8.8 ppg can be increased to 10 ppg by adding KCl and NaCl. This fluid relies on the viscoelastic properties (note: viscosity is not a function of time; when circulation is stopped viscosity rises quickly to low shear-rate viscosity and remains there; when static viscosity does not increase) and the increased low shear-rate viscosity (LSRV) of the fluid to control filtrate invasion into the formation.

With a LSRV of 60,000-80,000 cps, leak off to the formation can be controlled in permeable formations up to 5 darcies. Depth of filtrate penetration will vary with LSRV, temperature, overbalance pressure, formation permeability and formation fluid viscosity. This fluid is able to control fluid loss at overbalanced differential pressures of 500 psi under static conditions and 1000 psi while circulating. It is recommended that this fluid be mixed at the drilling fluid company's mixing facility and transported to location, due to the special shearing and filtering facilities required. Control parameters for a typical CTD fluid are:

Weight: 8.5-8.9 ppg

LSRV: 60,000-80,000 cps

Lubricant: 3% by volume

PV: 8-9

pH: 9.0-9.5

Even though solids content of the fluid is initially zero, drilled cuttings that are not removed by solids-control equipment build up in the system. Increasing levels of drilled solids will increase PV, pump pressure, chip hold-down and drag while decreasing ROP and weight transfer. A linear motion shaker and a high-speed centrifuge are used to maintain total solids concentration to below 1%. A new fluid system should be used at the start of the horizontal section and fluid from the build section discarded. Once solids content is above 1%, it is recommended that the fluid be traded for a new fluid system. Maintenance at the rig of this fluid requires monitoring and maintaining LSRV above 60,000 cps by adding either dry or liquid bio-polymer as needed. Solids-control equipment should have a linear-motion shale shaker with a minimum 210 mesh; 250 mesh is preferred when available. The centrifuge is a high-speed unit that can process approximately half of the flow stream while drilling. To take advantage of every opportunity to remove solids, the centrifuge should be run while tripping as well as while drilling. **[11]**

III.6 Emerging and Advanced Techniques to Enhance CTD Efficiency :

As Coiled Tubing Drilling (CTD) evolves, the integration of emerging and advanced technologies continues to push the boundaries of operational efficiency. Beyond traditional methods, several cutting-edge techniques are now being adopted to improve performance, reduce risk, and enhance the economic viability of CTD. This section highlights some of the most promising innovations that contribute to the next generation of high-efficiency CTD operations.

- **Dual Gradient Drilling (DGD) with CTD**

  DGD allows for the manipulation of pressure profiles in deepwater or HPHT wells by applying two different pressure gradients—at seabed and surface. When combined with CTD, it enables drilling through narrow-margin formations by balancing annular pressure with precision. This technique enhances wellbore stability and allows continued operations without the need for additional casing strings, thereby saving time and reducing costs.

- **Expandable Tubular Deployment via CTD**

  Expandable tubulars are used for wellbore repair, zonal isolation, or casing remediation. Deploying them with CTD allows for precise placement in live wells or highly deviated boreholes. This technique minimizes operational footprint and downtime. It also supports slimhole re-entries and well life extension without major workovers.

- **High-Frequency Downhole Telemetry**

  The use of electromagnetic or acoustic telemetry systems in CTD allows for the transmission of high-speed data from downhole to surface. These systems significantly improve response time in directional control, formation evaluation, and tool health monitoring. Real-time telemetry enables proactive decision-making and enhances drilling performance in complex or high-risk environments.

- **Modular Bottomhole Assembly (BHA) Optimization**

  Custom-designed modular BHAs offer flexibility for switching between different CTD tasks, such as milling, underreaming, or directional drilling, without full tool redressing. This reduces rig time and increases operational efficiency. Modular BHAs also allow operators to fine-tune their assemblies to meet specific formation challenges.

- **5. Real-Time Torque and Drag (T&D) Modeling Systems**
  Integrated T&D models use live sensor data to predict mechanical friction, identify potential sticking points, and guide operational decisions. These models allow for safe and optimized tubing movement in complex well geometries. By adjusting parameters like fluid density, WOB, or RPM, operators can prevent tubing fatigue and maximize drilling efficiency.
- **6. Foam and Aerated Mud Optimization Systems**
  Specialized systems dynamically control the quality, injection rates, and properties of foam or aerated fluids during underbalanced CTD. These techniques improve hole cleaning, enhance bit cooling, and prevent formation damage—especially in low-pressure or depleted zones. Foam systems also lower water consumption, contributing to sustainability goals.
- **7. Smart Wearables and Augmented Reality (AR) for Field Personnel**
  The introduction of wearable smart devices—like helmets with AR displays and biometric sensors—improves operational awareness, training, and safety compliance. These tools enable technicians to visualize complex procedures and receive remote guidance, reducing the chances of error during critical CTD operations.

These emerging innovations reflect the broader trend of intelligent, agile, and data-driven drilling in the oil and gas industry. By incorporating such techniques, CTD operations can achieve greater precision, lower cost per foot, and improved well outcomes. Continuous investment in R&D, cross-industry collaboration, and digital integration will further expand the role of CTD as a future-ready**[9]**

III.6.1 New Technologies

Implementing new technologies can make great difference to drilling operation. The new technologies are intended to give better solutions than the existed services in the marked. This section will list few new technologies that can make positive impact to the overall project feasibility. **[10]**

III.6.1.1 Rib Steerable Motor (RSM)

In conventional drilling, the Rotary Steerable System (RSS) allows dynamic control of well trajectory with rotating drill pipe and slide mode drilling is no longer required to kick the well to the desired direction This is simply achieved by three independent hydraulically powered ribs as it shown in fig 6-1.

Generally, the RSS enables drilling smoother wellbore with less tortuosity in more complex trajectories because of its ability to actively controlling the steering system With conventional motor, the tool must be rotated by the orienting sub in order to achieve the desired direction. This tool is capable to steer the drilling bit without a need for rotating the entire BHA and eventually compensates for the CT rotations limitation and exclude the use of the orientation sub**[13]**

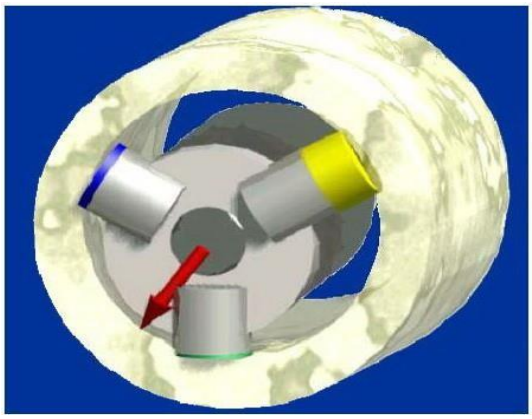


Figure III-1: Indepedent adjustable rib.

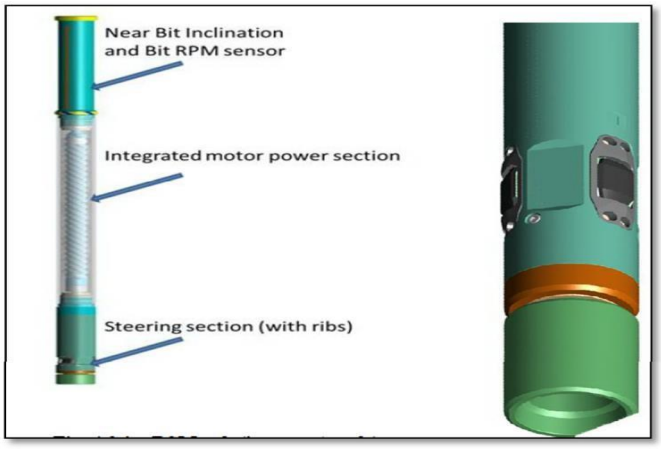


Figure III-2: RSS motor..

As illustrated in figure III-2, the new 3in Rotary Steerable Motor (RSM) used for CTD operations consists of near bit inclination, bit RPM sensor, integrated motor power section and steering section that is incorporated with the ribs. This tool that is designed for drilling 3 ½-in and 4 ¾-in hole sizes can be also run on e-line. This will allow for instantaneous communication with the tool because of faster telemetry link between surface and downhole equipment.[39]

The four operating modes which are available for the ribs can be listed as in the following:[39]

- "Off mode": All ribs are retracted within the OD of the tool to prevent unintended steering. This is typically used when RIH and when POOH.
- "Inclination Hold Mode": Automatically controlled ribs in order to keep the current hole inclination.
- "Steer Mode": The engagement and dis-engagement is controlled internally to achieved the desired azimuth and hole inclination.
- "Center Mode": Steering is minimized with uniformly engaged ribs.

The drill bit is driven with the incorporated power section mud motor that is operated within a wide range of maximum 120 gpm flow rate and differential pressure up to 1450 psi. This tool is

designed to be fully compatible with all existing CTD downhole monitoring and MWD equipment

The main advantages this tool can offer are:

- The inclination measurement sensor is placed closer to the drill bit which makes it easier to define the hole inclination and proper action is taken when the drilling is heading to unintended direction. This will help to target thin beds that are typically the purpose of promoting CTD application.
- Reducing wellbore tortuosity by actively controlling the tool ribs to maintain the angle needed for drilling the tangent section. In conventional BHA, this is done by routing the well path left and right to get the desired direction in which eventually results in snake shaped wellbore.

- Reducing the drag on the CT and longer laterals can then be drilled with CTD. This is related to the point above, as smooth hole will reduce the friction forces acting on the CT and more WOB will be available at bottom so that it will be possible to drill deeper targets.

III.6.1.2 HydraSetTM CT Jar

The limitation of small overpull available at surface has a high impact on CTD planning especially when candidate wells are to be drilled in old reservoirs with low pressure and high pressure formation overlap with drilling operation. A high mud weight will then shall be chosen to maintain borehole stability for the high-pressure formations and creating high stuck risk situation. This is due to the high overbalanced condition in the depleted.

Keeping in mind that coil cannot rotate, this will present the hole cleaning as abig challenge and needs to be proper understood by using proper modeling in order to prevent none productive time associated with performing hole cleaning trips. When reservoir characteristic allows underbalanced drilling, the cutting removal and tubing stuck problems will be no longer an issue. Furthermore, CTD operation in Canada has proved that drilling of 200m can be drilled without wiper trips For long horizontal wells where slack weight in not available, the solutions' of new designed jar for these wells is made by using the pressure provided through pumped fluid, the jar can be set and fired until the BHA is being released. This eliminates the force need at surface and

Figure III-3: HydraSet™ CT Jar .

does not affect the life cycle of the coil. This jar provides very high impact force and by manipulating the pumping pressure with no need to move the CT at surface. The pressure chamber incorporated within the tool allows infinite number or resting and firing until the tool is no long stuck . **[10]**

III.6.1.3 Dynamic Excitation Tool

The objective of this tool is to reduce the static friction acting against the CT and the BHA in order to prevent helical buckling and possibly CT lock up. It improves the weight transfer and enables CTD to extend its horizontal reach. This tool has been tested in Ullrigg test rig in Stavanger- Norway to qualify it for CT operation and to compare the drag forces and the WOB difference with and without the tool included in the BHA. Furthermore, the tool has successfully performed jobs in CTD performed in Alaska and received positive feedbacks from onsite personnel.

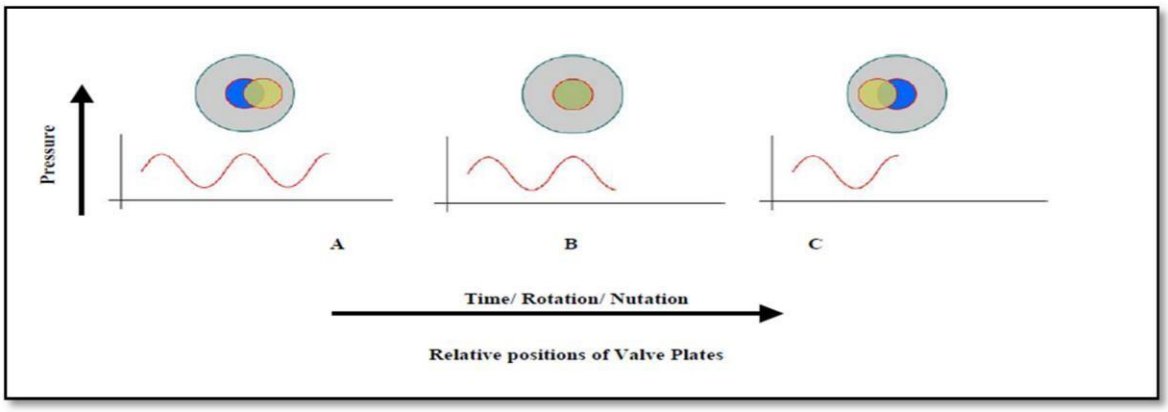


Figure III-4: Dynamic excitation tool -valve's plate

This tool operates by the mean of converting the pressure pulses created by changing of the flow area into mechanical vibration acting in the axial direction. **[11]**

III.6.1.4 Open hole Clad (OHC)

This technology was initially developed to eliminate the risks encountered by unstable formations such as high pressure and/or thief zones associated with re-entry drilling where pressure regime along the well varies significantly. This steel tube can give the mechanical support needed to prevent formation collapse into the wellbore and provide the hydraulic isolation that stops fluid loss in to the formation.

The OHC can be set at any zone along the wellbore without a need to be tied-in into the previous casing .

The setting area needs to be under reamed in order to prevent reduction in the hole size. However, the expandable type (Clad-thru-Clad) does not reduce the hole size and therefore, 1the drilling can be carried out to planned TD with the same bit size.

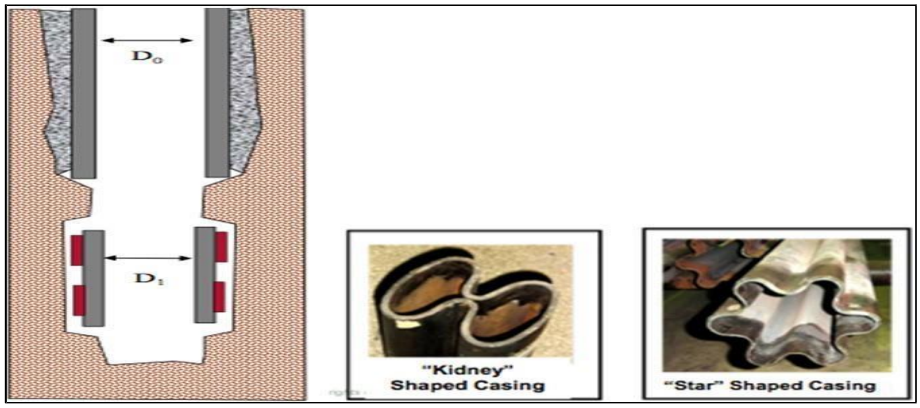


Figure III-5: Open clad thru clad.position .

The clad is normally set in the area which has been recently drilled. It is run to current well TD and required expansion pressure is applied to initiate the setting sequence. **[10]**

III.7 Optimization strategies

III.7.1 Cuttings Transport and Hole Cleaning:

Efficient cuttings transport is vital for maintaining hole stability and preventing tool sticking. Inadequate cuttings removal can lead to borehole problems, decreased rate of penetration (ROP), and increased wear on the Bottom Hole Assembly (BHA).

Computational Fluid Dynamics (CFD) simulations have shown that several parameters significantly influence cuttings transport, including:

- Drilling fluid viscosity and density
- Flow rate and annular velocity
- Backflow nozzle angle, diameter, and number

Optimization involves selecting appropriate fluid systems and configuring nozzle designs to maximize the carrying capacity of the fluid while minimizing pressure losses. Real-time monitoring technologies, such as distributed temperature and pressure sensors, provide actionable data that can be used to dynamically adjust parameters during drilling. **[9]**

III.7.2 Friction and Buckling Mitigation

Friction between the coiled tubing and the wellbore can limit the lateral reach of the tubing, particularly in extended-reach drilling applications. Helical buckling, sinusoidal buckling, and lockup can all reduce the efficiency of CTD operations.

To address this, the use of vibration tools has proven highly effective. Axial and torsional vibration systems are integrated into the BHA to reduce wall contact forces, thus minimizing drag and friction. This technology enables:

- Extended reach in horizontal sections
- Reduced surface pumping pressures
- Improved tool conveyance and well access

Additionally, surface modeling tools are used to predict buckling thresholds and optimize CTD trajectories based on frictional loads and tubing stresses. **[11]**

III.7.3 Electric CTD (E-CTD) Systems

Electric CTD systems represent a significant advancement in CTD technology. These systems integrate electrically powered BHAs that allow for precise control, high-speed telemetry, and reduced reliance on hydraulic systems.

Advantages of Electric Coiled Tubing Drilling ECTD offers several distinct advantages over conventional CTD operations, which have been demonstrated with the completion of Phase I. To summarise, these include:

- maintaining bit speed independent of flow rate
- immediate data feedback via high quality telemetry path
- increased reliability of drilling assembly

- reversible rotational direction
- osuitability to underbalanced drilling applications
- dynamic balance of circulation and formation pressures

By employing E-CTD, operators can steer and monitor the wellbore with greater accuracy, respond quickly to changes in formation behavior, and optimize drilling paths to avoid hazards. **[9]**

III.7.4 Hydraulics Optimization

Hydraulic efficiency is central to effective CTD operations. Poorly optimized fluid systems can result in inefficient hole cleaning, high surface pressures, and damage to the formation.

Key optimization strategies include:

- Designing the circulation system to match bit and motor requirements
- Adjusting annular velocities to maintain cuttings suspension
- Selecting appropriate fluid additives for rheological control

Advanced hydraulic modeling software is often employed to simulate downhole conditions, enabling engineers to select optimal pump rates and nozzle configurations before field implementation. **[10]**

III.7.5 Economic and Operational Planning

Economic optimization is equally important in ensuring the success of CTD projects. A comprehensive cost-benefit analysis should be conducted to determine the feasibility of CTD over traditional drilling methods.

Studies have shown that CTD—especially when used underbalanced—can:

- Reduce total well costs by up to 37%
- Accelerate project timelines
- Access marginal or depleted reservoirs with minimal formation damage

However, operational risks such as stuck pipe, pressure control failures, and tubing fatigue must be addressed through proper planning, contingency protocols, and rigorous training.

Chapter (04)

Case Study

IV Case Study

IV.1 Hassi Messaoud field description:

Hassi Messaoud field is one of the most complex fields in the world. During geological history, this field underwent an intense tectonic evolution characterized by compressive and distinctive phases. On the other hand, by the diagenetic transformation in the reservoir during its burial during geological time, until the deposit took shape as represented by the current configuration. These events can sometimes improve the petrophysical parameters as they can deteriorate them. **[11]**

IV.1.1 Geographical location:

The field of Hassi Messaoud is located at 850km south east of Algiers and at 350km far away from the Tunisian borders. Its Lambert coordinates in south Algeria are:

From [790.000 to 840.000] East.

From [110.000 to 150.000] Nort

Figure IV-1: Hassi Messaoud geographical location.

IV.1.2 Geological borders:

The Hassi Messaoud field occupies the central part of the Triassic province. Due to its surface and reserves, it is the largest oil field in Algeria that extends over nearly 2200 km² of area. It is limited: In the North-West by the deposits of Ouargla [Gellala, Ben Kahla and Haoud Berkaoui]. In the South-West by the deposits of El Gassi, Zotti and El Agreb. In the South-East by the deposits; Rhourde El Baguel and Mesdar. Geologically, it is limited. To the West by the depression of Oued M'ya. To the South by the pier of Amguid El Biod. To the North by the structure Djammâa-Touggourt. To the East by the shoals of Dahar. Rhourde El Baguel and the faults of. Ghadames. **[11]**

IV.2 Hassi Messaoud Cambrian field:

At reservoir depth, the structure is a large, flat anticline, irregularly undulating eroded at the top; and its general orientation is south-southwest—north-northeast.[2]

The stratigraphic succession may be described as follows: (1) On the granitic basement, the Paleozoic is represented by the Cambrian "Hassi Messaoud sandstones," about 520 m thick; it is divided into three units: R3, R2, and Ra. Ordovician sediments are present around the structure; the most complete Ordovician deposits are on the flanks. (2) The Mesozoic formations cover the field to the ground surface. About 3048 m thick, they are unconformable on the Paleozoic. (3) The Tertiary is represented, away from the structure, by Eocene and Mio- Pliocene deposits

The main Cambrian reservoir, Ra, is formed by sandstone-quartzite, the thickness of which ranges from 0 to 147 m, according to the degree of pre-Triassic erosion. The average thickness is 61–101 m. Oil was trapped in the Cambrian reservoir mainly during the Mesozoic Period; had entrapment occurred earlier, hydrocarbons would have escaped during the pre- Triassic erosion

To illustrate, Figure IV.2 gives an example on the MD #775 Cambrian Ordovician reservoir stratigraphical lithology. **[11]**

CAMBRIAN	DH/ QUARTZITE DE HAMRA	3 344	Quartzitic
	GRES D'EL ATCHANE	3 369	Sandstone
	ARGILE D'EL GASSI	3 383	Black Claystone
	ZONE DES ALTERNANCE	3 433	Sandstone follwel by tightly interbeded shale and sanstone
	Réservoir RI (D5)	3 453	Sandstone/Quartz
	Réservoir D4	3 498	Sandstone/Quartz
	Réservoir D3	3 524	
	Réservoir R2ab	3 636	
	Infracambrien		

Figure IV.2: MD #775 Cambrian-Ordovician stratigraphy.

IV.3 Presentation of the First Case: The Well *"MD-321*

Well:	MD-321	***Zone:***	***1B***	**"Oil Producing Well"**
Reference:	**Phase 18-2005**			

Objective of the Operation

This workover operation aims to drill a lateral drain in the D4 reservoir using a slim hole technique along azimuth N 320°, with a displacement of 600 meters.

- Perform bottom-hole cleaning and inspection inside the liner.
- Conduct electric line operations to calibrate depth measurements.
- Window milling in the liner.
- Drill the lateral drain with a target depth (Ztble) of 147.5 meters.

Drain	***Toit (m)***	***Mur (m)***	***Azimuth***	***Deplacement (m)***
D4	***3380***	***3392***	***N320 °***	***600***
	-3232.5	***-3242.5***		

- Effectuer un DST (flow test). **[11]**

IV.3.1 Purpose of the Intervention:

To restore the well to production by drilling a horizontal drain using slim hole technology, with the goal of increasing its production potential. **[11]**

IV.3.2 Current Well Status:

The well has been shut-in since 31/03/2005 due to zero production rate.

Production parameters: (before shut-in)

Q m^3/h	GOR	P tête	P 7"	P 9"5/8	Cumul Np m^3
2.78	56	34.7	//	//	1050908.79

Reservoire Pressure 379 Kg/cm² @-3200m C/abs

PFS du 20.08.2006

IV.3.3 Well Data

Location Coordinates X = *797251.125* *Y= 124998.039*

Z (sol) = 142.26m *Z (Table)= 147.41 m*

Surface casing *13" 3/8 @ 331 m* *Cimenté jusqu'au surface.*

Intermediate casing N°1 ***9" 5/8 @ 2329 m***

Intermediate casing ***7 " @ 3321m***

CBL Data 7" du 03/03/80

Côte de	***à***	***Etat de cimentation***
Sabot	***2660***	***Bonne à moyenne***
2660	***2355***	***Médiocre***
2355	***2100***	***Bonne à moyenne***

Colonne 4''1/2 NVam cimentée @ 3268m Top ciment 1740m

Production liner	*LCP*			
	Top:	*3268.20 m/TR*	***Btm:***	*3446.50 m/TR*

CBL VDL of 05/21/98 Data 4"1/2

Coast of	***has***	***State of cementing***
Bottom	*3370*	*Good*
3370	*3343*	*Pretty good*
3343	*3331*	*Good*
3331	*Liner head*	*Fair to good*

Perforation of the liner

Date of Perforation	Society of Service	Goal of the Operation	Density Shooting	Well Conditions	Intervals of Perforation
02/07/1998	HALLIBURTON	PRODUCTION	6	UNDERWATER	3331 3343
10/16/2002	HESP		6	The amount includes the puncture charge and the Stim tube charge.	3404 3398
06/24/1998	HALLIBURTON	FRAC	6	UNDERWATER	3398 3404
07/29/1998	SPES	PR	6	UNDER RAW	3423 3435

Neighboring Wells:

Neighboring water injection wells:	*Md170* *Md354*	*Located 1000m to the south* *Located 1127m to the east*
Neighboring gas injection wells:	*Nothing*	

IV.4 Geological characteristics

Drain division and petrophysical characteristics

Drain	*Top(m)*	*Btm(m)*	*K(md)**	*-(%) **	*So (%)**	*Sw (%)**	*D/Silt*	*-e*	*Sw e*	*Vcl e*
D5	*3306*	*3353*	*1.52*	*7.26*	*21.41*	*31.03*	*0.049*	*8.24*	*25.44*	*13.76*
D4	*3353*	*3395*	*2.63*	*6.33*	*22.41*	*10.02*	*0.042*	*7.44*	*13.57*	*6.80*
D3	*3395*	*3418*	*3.59*	*7.67*	*32.10*	*24.05*	*0.052*	*9.87*	*21.69*	*8.87*
D2	*3418*	*3442*	*4.88*	*8.30*	*29.39*	*14.31*	*0.045*	*9.84*	*12.34*	*8.29*
ID	*3442*	*3462*	*3.76*	*8.76*	*21.98*	*29.23*	*0.075*	*8.40*	*25.54*	*15.75*

***NB: Core** results. e Elan*

* From 1042 to 1412 m/TR. LIAS LD2:

From 2595 to 2648 m/TR. The clayey Triassic at 3169m

The sandstone Triassic at 3257m

The eruptive Triassic at 3266m Alternation zone 3289m The Cambrian Ri at 3306m

The Cambrian Ra at 3448m

The bottom 6" at 3462m CE, 3459m CS. The water level is at 3490m to -3343m (abs).

IV.5 Production characteristics

Date Measure	Diam. Duse (mm)	Flow rate (m³/h)		GOR	Pressure (kg/cm²)			Water flow rate (l/h)	
		Oil	Gas		Head	Pipe	Separ.	Recovered	Injected
10/05/1980	9.5	10.49		133	96.8		9.1		
01/14/1982	12	10.12		122	54.2		13		
24/02/1984	19.5	10.36		162	27.7		10		
10/02/1985	19.5	6.8		133	34.6		7.7		
05/12/1985	15	7.51		140	29.1		6.6		
07/12/1987	15	7.51		125	29.1		6		
04/08/1988	15	5.95		120	31		6		
01/18/1989	11	4.97		124	34.3		3.9		
05/06/1990	11	4.74	1016.93	217	31	11.3	1.4		
03/09/1990	17	7.11	1112.11	129	20.3	12.5	5		
12/30/1991	17	6.13	1250.36	187	17.7	13.4	6.4		
05/25/1992	18	6.92	1433.44	198	18.5	11.4	7.5		
02/15/1993	18	6.32	1362.59	208	17.3	13.5	4.2		
09/07/1993	18	5.07	932.34	165	15.4	12.4	6.2		
10/17/1994	18	4.19	736.38	160	15.5	12.5	7		
07/08/1995	18	8.43	1283.73	124	19.2	13.3	5.3		
01/09/1995	18	3.1	419.77	117	20.8	8.8	5.2		
01/12/1995	18	6.92	1059.41	138	16.7	12.5	7		
03/16/1996	18	4.68	958.89	181	17	13	4		
07/17/1996	18	2.57	463.33	157	16.8	13.5	4.4		
11/23/1996	18	4.94	818.03	148	17	11.5	6.3		
01/15/1997	18	6.42	1045.73	143	16	13	5.6		
04/20/1997	18	6.13	1117.94	172	19.5	15.2	8.4		
05/31/1997	18	6.13	1037.09	139	15.2	12.5	4		
10/25/1997	18	5.34	1006.65	168	15.7	12.8	6		
09/01/2005	12.7	1.1	61.68	56	15.5	12.5	2.86	0	

IV.6 Well History:

► MD 321 of zone 1B drilled completed in March 80 with anchored 4"1/2 tubing, the reservoir covered with a 5" strainer. The well was put into production in May of the same year with a flow rate of around 12m3/h.

► the well flow rate declined steadily, caused by the fall in its reservoir and bottom pressure, until 1989 when the flow rate reached 5m3/h.

► This pressure drop caused the appearance of asphalts at the bottom and in the reservoir, considerably affecting the permeability of the area. Since then, the well has been maintained by scraping and matrix treatment interventions with reformate, which has given better results, increasing the flow rate from 02 to 06 m3/h.

► The well was selected for hydraulic fracturing in 98, a WO was scheduled.

MD-321WOprog.doc Page 6 06.12.2006

► 16/02to 06/13/98 WO Intervention No. 01:

► Tubing ascent during the day.

► Milling the 5" strainer.

► Restoration of 9"5/8 and 7" casings.

► Descent of a 4.5" cemented liner.

► Recompletion of 4.5" frac type well.

► June 24, 98 perforation of the liner from 3398m to 3404m

► July 2, 98 perforation from 3331m to 3343m for frac

► July 4, 98 Shaddow frac negative fracturing behind the 7" casing.

► July 7, 98 kick off at negative CTU.

► July 29, 1998: Production perforation from 3423m to 3435m. Attempts to start the well were unsuccessful

► July 4, 1999 stimulation, the treatment is abandoned following a communication detected between the 4.5" and 7" tubing. A second intervention was applied in June 2000 but abandoned due to a wellhead leak. The well is held firm and a WO has been scheduled.

► 01/30/10to 01/13/02 WO Intervention No. 02: reconditioning of the 7" casing and lowering of a 4"1/2 cemented tie back to 1700m from the surface.

► February 6, 2002: Acidification + tube clean + kick off without results.

► February 26, 2002: Shaddow frac targeting the D3, passing behind the 7."

► March 28, 2002: attempted coilfrac without results, high constraints + jammed packer.

► 04/10to 26/05/02 Snubbing intervention: fishing out the packer and cleaning at the bottom at 3436.15m, with an 88mm crown.

► 02/08/05stimulube and negative start attempt.

► The well remained closed for the next 3 years.

► 01to 03/01/05 acidification of the well to 3451m cc.

► 05/01/04kick off OK, well put back into production with a flow rate of around 2m3/h for 3 months then it dropped to 00, the well is closed for zero flow, it is selected for a short radius in CTD in phase 18_2005. **[11]**

IV.7 Details of the work:

1-Check and clean the bottom of the liner.

-Circulate the well with a mud of density 1.25 and observe its stability.

-Go down with a 4"1/2 scraper tool and clean the tubing + the liner at the bottom, i.e. at the 3446m C/1tr mark.

2-Carry out the electrical operations to recalibrate the dimensions.

-Perform a GR recording with the CTD and recalibrate the log with a GR log performed at the WL to determine the KOP level of the drain.

3-Window opening through the liner.

- Lower a wipe stock oriented in the N320° azimuth into the well and anchor it to the coast planned for the KOP.
- Lower the cutter and create a window in the 4.5" liner.
- Lower the ST tool and carry out the drain curvature, check the losses (or gains) of mud in the formation and adjust the mud density.

Ztable = 147.5m Azimuth N320°

5-Drilling the drain.

- Drilling of the lateral drain in the interval 3380m to 3392 with a displacement of 600m, including the azimuth N320°.
- After drilling a few meters into the reservoir, convert the drilling into underballance, a quantity of mud with a density of 1.25 must be placed on site to neutralize the well if necessary.
- When drilling the drain, check the return of the effluent. If you notice high GOR, contact the well technical department.

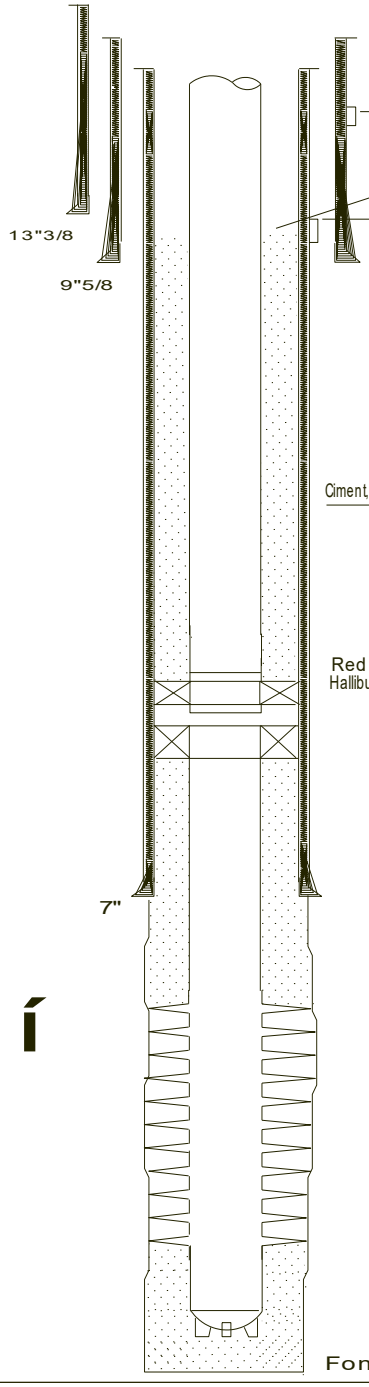
5-Perform a DST (flow test)

SONATRACH
DIVISION PRODUCTION
REGION HASSI-MESSAOUD
D.E.P

COMPLETION 4"1/2 NEW VAM ANCRE | MD321

X : 797 250.85
Y : 124 997.80

M M		COTES	
OD	ID	ELEC/VM	SOND/TR
			338.00
			2328.50
114.30	99.57		
122.00	96.39		
		3259.51	3266.31
		3260.53	3267.33
		3261.20	3268.00
		3261.40	3268.20
			3321.00
114.30	99.57		
122.00	96.39		
		3439.20	3446.00
		3439.70	3446.50
127.00	100.00	3442.70	3449.50



Olive FMC Filet 4"1/2 NV B x 4"3/4 Acme H
Ajustage avec 278 Jts 4"1/2 NV P110
Csg 7" Coup. ... 14Cm
Tbg Head FMC 11" x 7"1/16 5000
Adapteur FMC 7"1/16 x 4"1/16 5000
1.re VM + 2.me VM (CIW) 4"1/16 5000
Croix 4" x 3" 5000
Vanne Curage 4" (CIW) + Vanne Lat.rle 3" Crown
Porte Duse raglable 3"5000 (CIW)
Csg patch 11"1/8 (9Jts 9"5/8 API 47# ... 96m)
Top Ciment EA ... 1740m
Csg patch 8" 3/8 (45 Jts API 32# P110 ... 386.6m)
Z SOL : 142.26
Z TABLE : 149.91
Z 1VM : 143.11
ZONE : 1
HT : 7.65m
Tubing 4"1/2 N.VamN80 MP110 13.5#
Pds Train:64T CS:6370 Ft.Lbs
Ciment avec 15.9m3 d2.06-Cimentation moyenne ... bonnne
Red 4"1/2 LTC M x 4"1/2 Vam F L:0.60m
Halliburton Anneau de Cimentation 4"1/2 LTC L:0.84m
Sabot Guide 4"1/2 LTC L:0.25m
Ensemble suspension BROWN 4"1/2 LTC
PACKER - HANGER - SWIVEL
Haut perfos
Tubing 4"1/2 LTC (6 Jts L=177.68m)
Bas Perfos
Fond Snubbing : 3436.15m
Fond Work Over
Sabot Brown 4"1/2 LTC
Fond initial
SNUBBING : 26.5.02

Conclusin

And

Recommendations

Conclusion

The oil and gas industry continues to face mounting challenges as it seeks to balance production efficiency, operational safety, and cost-effectiveness, especially in increasingly complex and mature reservoirs. Within this context, **Coiled Tubing Drilling (CTD)** has established itself as a forward-thinking and highly adaptable drilling technique. Unlike conventional rotary drilling, CTD offers unique capabilities such as continuous circulation, live well entry, reduced rig-up time, and minimal surface disturbance. These characteristics have elevated CTD from a niche intervention method to a mainstream operational strategy in a wide range of petroleum applications.

This thesis has explored CTD from both a **theoretical and practical perspective**. In Chapter 1, we laid the foundation by outlining the historical development, design principles, and core components of CTD systems. A comparison with conventional drilling methods revealed that CTD provides significant operational benefits in specific use cases, particularly in re-entry operations, slim hole drilling, and underbalanced environments. The **flexibility and efficiency of CTD systems** make them well-suited for the modern oilfield, where rapid execution and minimal environmental impact are key drivers.

Chapter 2 focused on the **variety of techniques and field applications** of CTD. Whether employed in milling operations, horizontal sidetracks, logging while drilling, or cleanout jobs, CTD has proven to be a reliable tool capable of adapting to complex downhole conditions. The ability to maintain circulation throughout the operation ensures better well control and formation protection, particularly in sensitive or pressure-depleted zones. However, the success of these techniques is closely tied to well planning, equipment selection, and operational execution.

Chapter 3 addressed the **challenges and optimization strategies** associated with CTD. While the technique presents several advantages, it also comes with limitations—namely, restricted weight on bit (WOB), limited torque transfer, coiled tubing fatigue, and tool length constraints. Overcoming these obstacles requires detailed pre-job planning, hydraulic modeling, and real-time monitoring during operations. Innovations such as advanced BHA design, high-performance downhole motors, rotary steerable systems, and electric CTD (E-CTD) are

continuously improving the performance envelope of CTD operations. Moreover, data acquisition and digital analytics are becoming integral to identifying inefficiencies and enhancing real-time decision-making.

Chapter 4 presented a **real-world case study** which demonstrated the practical application of CTD in a complex reservoir. The analysis provided valuable insights into how planning, execution, and post-job evaluation influence the outcome of a CTD job. Lessons learned from field data underscore the importance of equipment reliability, effective hole cleaning, and the use of automation where feasible. Furthermore, the case illustrated that CTD not only serves as a drilling tool but also as a strategic method for extending the productive life of wells, especially in mature fields where conventional drilling may no longer be viable.

Collectively, the findings of this thesis confirm that Coiled Tubing Drilling is **not merely an alternative but a strategic enhancement** to modern drilling operations. With proper optimization, CTD can reduce non-productive time (NPT), improve well economics, and ensure greater operational flexibility. It is particularly useful in remote or logistically constrained environments, and its lower environmental footprint aligns with the industry's sustainability goals.

However, to fully realize the potential of CTD, it is critical to **continue investing in research, field trials, and training**. Industry-wide collaboration is needed to advance tool technology, refine operational workflows, and integrate intelligent automation into CTD systems. In addition, operators must maintain a rigorous focus on safety, data quality, and performance tracking to support continuous improvement.

As the energy sector transitions into a future shaped by complexity, digitalization, and sustainability, Coiled Tubing Drilling is well-positioned to play a transformative role. By uniting innovation with operational precision, CTD offers the industry an effective means of optimizing production, lowering risk, and unlocking new reserves in challenging formations.

Recommendation:

To further improve the application and outcomes of Coiled Tubing Drilling in both field and experimental contexts, the following recommendations are proposed:

1. Strengthen Pre-Job Engineering and Simulation

Perform detailed simulations for well trajectory, tubing stress, hole cleaning, and hydraulic modeling before operations begin. This reduces uncertainty and improves execution reliability.

2. Invest in Real-Time Monitoring and Data Analytics

Utilize Measurement While Drilling (MWD), fiber-optic sensing, and surface analytics platforms to optimize decision-making in real time and reduce reactive interventions.

3. Advance Tool Reliability and BHA Design

Select robust downhole tools specifically designed for slim hole and high-build-rate trajectories. Modular BHAs and advanced motor technologies can significantly improve rate of penetration (ROP) and directional control.

4. Integrate Automation and Digital Solutions

Adopt semi-automated or fully automated CTD control systems to improve operational consistency, reduce human error, and enhance safety performance—especially for repetitive or complex operations.

5. Enhance Crew Training and Technical Capacity

Develop specialized training programs for CTD operators, focusing on coiled tubing fatigue management, surface control, real-time data interpretation, and emergency response.

6. Apply CTD in High-Impact Scenarios

Prioritize the use of CTD for re-entries, depleted reservoirs, live well interventions, and sidetracks where economic and operational benefits are most evident.

7. Evaluate Economic Feasibility Case by Case

While CTD offers significant savings in some environments, a well-by-well cost-benefit analysis should guide its selection to ensure long-term value and efficiency.

8. Support Innovation through Field Pilots

Encourage collaboration between operators, service providers, and research institutions to test new CTD technologies—such as expandable tubing, managed pressure CTD, and coiled tubing drilling with casing.

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