Politecnico di Torino

Master’s degree Thesis:

Enhancement of drilling operations with the use of 7” casing liner, cost effective and safe.

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Abstract

This master's thesis delves deeply into a comprehensive examination of the application of a 7-inch casing liner. It meticulously considers both the economic and safety aspects of implementing this innovative approach. The focal point of this investigation is the installation of the liner hanger assembly onto the drill pipe, which presents substantial advantages in terms of both time savings and enhanced safety when compared to the conventional production casing procedure.

The liner hanger, a pivotal component in this study, offers significant benefits for subsequent well operations. For instance, it facilitates the smooth installation of a 9 5/8-inch casing with a whipstock, enabling a change in the well's directional path. Even when the drilling target changes, the use of a liner continues to reduce Non-Productive Time (NPT). This reduction is achieved by covering only the open hole and a few meters inside the previous casing (overlap), which is not only advantageous in terms of safety but also highly cost-effective.

These multifaceted considerations hold immense significance for both the overall cost of the well and the safety of personnel involved. Furthermore, the liner serves as a valuable tool for drilling engineers, aiding them in minimizing wellbore instability. This benefit arises primarily from the substantial reduction in the amount of exposed open hole time, which translates into a more stable and efficient drilling process.

Acknowledgement

I would like to take this opportunity to express my heartfelt gratitude to all those who have supported and inspired me throughout the journey of completing this master's thesis in "**Enhancement of drilling operations with the use of 7" casing liner, cost effective and safe**".

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Background of drilling operations in the oil and gas industry

Introduction:

The oil and gas industry heavily relies on drilling operations as a fundamental process for exploring, extracting, and producing hydrocarbon resources from the Earth's subsurface. Drilling operations involve the creation of boreholes or wells in order to access underground reservoirs containing oil, natural gas, or both. These operations are complex and require careful planning, advanced equipment, and skilled personnel to ensure successful outcomes.

The history of drilling operations dates back to the mid-19th century when the first commercial oil well was drilled in Pennsylvania, United States. Since then, drilling techniques and technologies have continuously evolved, enabling the industry to access deeper and more challenging reservoirs. Initially, conventional drilling methods involved the use of cable tools or rotary drills, which were labor-intensive and time-consuming. However, with the advent of modern technologies, the industry shifted towards more efficient and advanced drilling techniques. Today, drilling operations in the oil and gas industry predominantly employ rotary drilling, which utilizes a rotating drill bit attached to the bottom of a drill string. The drill string, consisting of drill pipes and other tools, transmits the rotational force to the drill bit, enabling it to penetrate the subsurface formations. As the drill bit advances, drilling mud is circulated down the drill string and returns to the surface, carrying the drilled cuttings and maintaining wellbore stability.

Drilling operations serve various purposes within the industry, including:

Exploration: Drilling exploratory wells helps identify potential oil and gas reservoirs by analyzing geological formations, rock properties, and fluid characteristics.

Development: Once a promising reservoir is discovered, drilling operations are used to establish production wells for extracting hydrocarbons on a larger scale.

Production: Drilling techniques, such as directional and horizontal drilling, are employed to enhance reservoir drainage and increase hydrocarbon recovery rates.

Intervention: Drilling operations also encompass well intervention activities like well maintenance, workovers, and well stimulation (e.g., hydraulic fracturing) to optimize production and enhance well performance.

Overall, drilling operations play a crucial role in the oil and gas industry, enabling the extraction of valuable resources from deep within the Earth. Advancements in drilling technologies and practices continue to drive the industry forward, improving efficiency, safety, and environmental stewardship.

Significance of enhancing drilling operations

The drilling process is a crucial aspect of exploration and development projects, but operational costs associated with drilling have significantly increased in the past decade [1]. This has prompted actions to reduce expenses, as drilling typically consumes more than half of the budget for field development plans [2]. To address this, drilling engineers and operations teams strive to shorten the well drilling duration and lower associated costs. Achieving drilling optimization plays a pivotal role in improving performance and reducing unnecessary expenses, ultimately enhancing the profitability of oil and gas projects [3].

Various methods have been developed for drilling optimization, such as optimizing Rate of Penetration (ROP), Mechanical Specific Energy (MSE), Torque on Bit (TOB), and cost per foot of drilling [4]. Among these, ROP optimization methods are commonly utilized [5]. However, it's important to note that high ROP doesn't always guarantee improved drilling performance. In some cases, high ROP may lead to issues like inadequate hole cleaning, reduced bit lifespan, and wellbore instability problems [6], resulting in longer well delivery times and increased costs.

To ensure drilling efficiency while maintaining safety, the relationship between drilling rate and related variables needs adjustment. The classic optimization procedure typically emphasizes increasing ROP, which is measured as the progress of a bit into rocks over time [7]. However, predicting and optimizing ROP remains a significant challenge due to the complex and nonlinear nature of the variables involved [8][9]. The main variables impacting ROP are identified as rig/bit associated variables, associated mud variables, and formation variables [10][11][12]. These variables can be categorized as controllable parameters, which can be changed to improve ROP without major economic impact, and uncontrollable or environmental parameters, which are challenging to adjust due to economic or geological reasons [13]. Controllable operational drilling parameters like Weight on Bit (WOB), Revolutions Per Minute (RPM), and Flow Rate (FR) significantly influence ROP [14]. Traditional methods to optimize these parameters include direct methods (drill rate and drill-off tests) based on human drilling experience and available standards, as well as models and formulae to predict penetration rate [15][16][17]. However, these traditional models may lack accuracy. In recent years, more data-driven approaches using machine learning, based on actual field data, have been applied for drilling rate prediction [18][19][20].

In this study, a unique approach was employed to find optimal combinations of controllable operational drilling parameters to maximize ROP. A dataset of 9356 cases from drilled wells in Southern Iraq was collected, with WOB, RPM, and FR as the input variables. Response Surface Methodology (RSM) was used to develop mathematical and statistical regression models for optimizing ROP with respect to these drilling parameters. Ultimately, the study aims to achieve better drilling efficiency by reducing drilling time and costs for future wells on the same pad.

Purpose and objectives of the thesis

This thesis aims to investigate the improvements in drilling operations achieved through the utilization of 7" casing. The primary focus is on two key aspects: time efficiency and safety. By reducing drilling time, significant cost savings can be realized, while also addressing safety concerns by minimizing the number of casing tubes used. This thesis examines the impact of these improvements on drilling operations, highlighting the benefits in terms of time efficiency, cost reduction, and enhanced safety measures.

The introduction provides an overview of the purpose and objectives of the thesis, emphasizing the significance of improving drilling operations. The utilization of 7" casing is introduced as a potential solution to enhance time efficiency and safety in drilling activities.

Time Efficiency Improvement: This section explores the first improvement achieved through the use of 7" casing: time efficiency. By employing 7" casing, drilling time can be significantly reduced. This reduction directly translates into substantial cost savings, often amounting to thousands of dollars. The factors contributing to time efficiency improvements, such as optimized casing design, streamlined installation processes, and improved wellbore stability, are discussed in detail. Case studies and empirical evidence are presented to support the argument for time efficiency enhancement with 7" casing.

Cost Reduction Analysis: Building upon the discussion of time efficiency, this section delves deeper into the cost reduction aspects associated with the use of 7" casing. The reduction in drilling time not only leads to cost savings but also enables better resource allocation and planning.

The financial implications of these improvements are examined, considering factors such as reduced equipment rental costs, minimized labor expenses, and optimized overall project budgets. Furthermore, the potential for cost savings in terms of casing materials and installation procedures is explored.

Safety Considerations and Risk Mitigation: The second improvement addressed in this thesis is safety, which is a paramount concern in drilling operations. The use of 7" casing contributes to safety enhancement by reducing the number of casing tubes required, particularly in comparison to production casing. This reduction in down tubing not only saves time but also improves safety by minimizing potential risks associated with casing installation (casing running process). The significance of safety protocols, risk assessments, and regulatory compliance in drilling operations is emphasized. Case studies and best practices are presented to illustrate the positive impact of utilizing 7" casing on safety performance.

Integration and Implementation Strategies: This section focuses on the integration and implementation of 7" casing in drilling operations. It explores strategies for successful adoption, including technical considerations, project planning, and collaboration with stakeholders. The challenges and potential solutions related to integrating 7" casing into existing drilling practices are discussed. Furthermore, the importance of training and knowledge transfer to ensure effective utilization of this casing technology is highlighted.

The conclusion summarizes the findings of the thesis, emphasizing the importance of improvements in drilling operations achieved through the use of 7" casing. The time efficiency enhancements, cost reduction benefits, and safety considerations associated with 7" casing are recapped. The potential for broader industry adoption and the overall impact on drilling performance are discussed. Finally, suggestions for future research and the continual advancement of drilling operations are provided.

By addressing the objectives of time efficiency improvement and safety considerations, this thesis highlights the positive impacts of utilizing 7" casing in drilling operations. The findings provide valuable insights for industry practitioners, enabling them to make informed decisions and implement strategies to optimize drilling efficiency, reduce costs, and enhance safety measures.

Literature Review

Overview of drilling operations and challenges

The conventional method of drilling a well has encountered various challenges, such as high purchasing, inspection, and handling costs, as well as difficulties in transporting the drill string [21]. One common problem that arises during the replacement of the Bottom Hole Assembly (BHA) or when reaching the total depth is the tripping in and out of the drill string [22]. This tripping leads to non-productive time (NPT) and well control issues, including lost circulation and wellbore instability. NPT includes several factors like stuck pipe, lost circulation, well control, mud, cement, directional, mechanical, and casing laydown [23].

In addressing these problems, an alternative drilling technique known as Casing Drilling has proven effective [24]. It has been adopted in many countries as it reduces total drilling costs by minimizing drilling time and addressing drill string-related challenges encountered in conventional drilling. Notably, reducing drill string tripping and handling times results in substantial savings, but even more significant savings can be achieved by preventing wellbore problems.

Tripping the drill-string directly causes or contributes to problems such as lost circulation, well control incidents, and borehole stability issues [25]. Many operators have been drawn to the technology of casing drilling due to the significant reduction in drilling time [26][28]. The term "non-productive time" is used to describe problem time and time associated with tool failures and inefficiencies in the industry. When using casing drilling, non-productive time refers to any time spent not actively drilling or securing the well for further operations [29].

The oil and gas industry faces a considerable challenge in reducing well costs while maximizing production for better returns on investment. Casing drilling has been a solution to some extent, eliminating the use of drill pipes and reducing tripping times and time lost to unscheduled events like 'reaming' and 'fishing' [30].

In Casing Drilling, hydraulic and mechanical energy is transmitted to the drill bit through the Drill Lock Assembly (DLA) via the casing, replacing the traditional drill string. For vertical wells, a specific drilling shoe can be used instead of the rotary drill bit [31]. Casing drilling can be used in retrievable and non-retrievable systems, with the latter involving a simple rotating casing system at the surface and a fixed drilling bit downhole. The non-retrievable system features a drillable bit, which can be drilled out when the casing point is reached or left in the well at Total Depth (TD) [32][34].

Casing drilling technology is primarily designed for multi-well offshore platforms, multi-well land operations, deep-water operations, and situations where casing needs to be placed across problem formations quickly. It has also been successfully applied as an alternative to underbalanced drilling in certain situations, such as drilling through depleted reservoirs [25]. However, some subsea well control scenarios that require pipe shearing during drilling or situations where the wellhead can only accommodate a few casing strings may not be suitable for casing drilling. To enhance drilling economics further, a more practical technique is needed to improve casing drilling technology [23].

Introduction to casing liners and their role in drilling operations

During the well planning, a geological analysis is performed to foresee the problems that will be met while drilling. In drilling phase, casing is lowered into the wellbore in order to coat it and to isolate drilled-through formations.

A casing element is a steel pipe of a variable length (11-13 meters) with male threads on one end and female threads on the other, so that a casing string is easily created and run down into the wellbore to the required depth. Casing is then cemented in place.

Cementing is carried out by pumping first slurry inside the casing string, then cement slurry flows out of the shoe, which is a device placed on the lower end of the casing string, having a valve that prevents slurry from flowing back inside the casing. Slurry rises in the annulus between wellbore and casing. Besides retaining casing in place, cementing hydraulically isolating drilled-through formations.

At ground level, casing is then secured to the flanged wellhead assembly by means of appropriate hangers.

We are now going to address the following topics:

- Functions of casing
- Casing diameter selection.

Functions of casing

As drilling operations progress, casing is lowered (run) into the borehole to carry out specific tasks. Casing diameters decrease as lower and lower depths are reached. In the next lines different classes of casing will be described and two specific topics will be examined:

Function of each class of casing

Casing point selection, or how to choose the correct depth to which a single type of casing is to be lowered (run). In the drawing shown at slide figure 1, we will find a typical reproduction of the casing diameters.

There are four classes of casings:

Conductor pipe

Surface casing

Intermediate casing

Production casing

We are now going to discuss the function of each class.

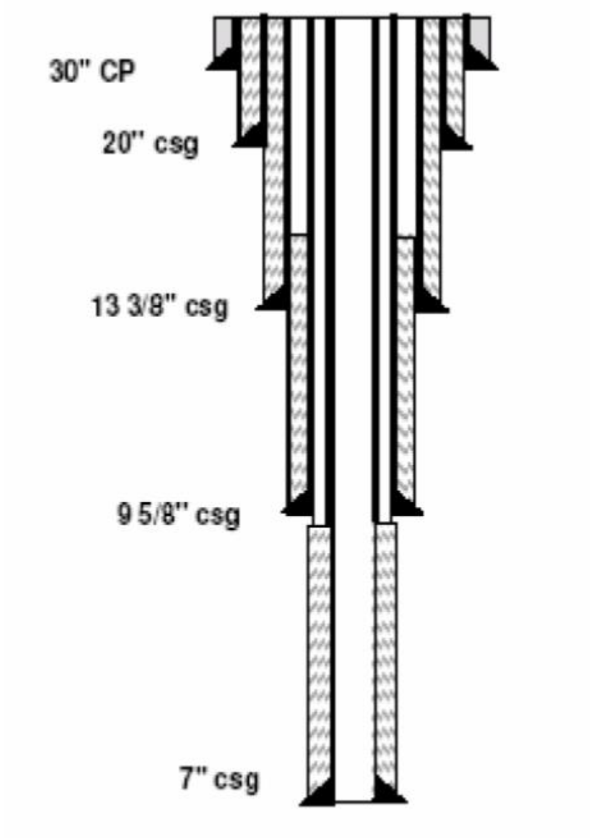


Figure 1. Casing profile

Conductor pipe (CP)

Conductor pipe is the first casing to be lowered in the wellbore. Its classic, standard diameter is 30”, even if sometimes wider or narrow size are used.

It serves several purposes:

- It allows mud to be circulate to the surface.
- It excludes surface unconsolidated soil, thus preventing cave-in, problems that could compromise the entire rig stability.
- It allows engineers to drill through shallow gas (gas pockets placed at known depth, not far from the below ground). When a such situation occurs, the conductor pipe’s shoe will be anchored right above the gas pocket and a diverter will be installed on top of conductor pipe CP. A Diverter is a type of bag preventer equipped with two pipes measuring 8 inches

diameter. If water or gas invades the wellbore, in moderated overpressure conditions, a diverter will allow these fluids to run to a safety area away from the rig site.

It is necessary to make a distinction between onshore wells and offshore wells because conductor pipe's functions and lowering procedures differ considerably for both categories.

Conductor pipe (CP) – Onshore wells

In onshore wells CP is usually driven down by a pile-driver to a depth that varies between 30 and 50 meters or even more according to the types of ground (surface formations) and their characteristics. However, in instances where bottom hole is limited to 1500 – 2000 meters, in the absence of specific problems CP's depth can be reduced to a few meters only.

CP must be driven down in a precisely upright position, since following casing strings are lowered inside CP, an oblique CP obliges the other casing strings to be run at an inclined angle as well. During drilling, oblique casing will be susceptible to a high risk of wear and tear.

Recommended procedures: If a gas pocket is present at a known depth, the CP's shoe must be positioned above it. When the conductor pipe cannot be driven due to hard surface formation (like limestone) a hole must be drilled before, CP can be lowered and cemented in place. CP can be lowered by means of a crane before rigging up.

Conductor pipe (CP) – Offshore wells

International laws regulating energy industry activities prescribe that a detailed seismic soil profile aiming at discovering shallow gas pockets be completed and submitted in order to obtain authorization to drill a well. If the presence of shallow gas (low-depth gas) is ascertained, it will be necessary to change well location, or to place the CP's shoe on top of the gas pocket.

If shallow gas is not discovered, the depth to which CP must be run is determined by the following mathematical relation:

$$Hi = \frac{d_f(E + H) - 1.03H}{(1.03 + 0.67(G_{ov\,Hi})) - d_f}$$

Where:

Hi=drive depth (actual penetration from sea bottom) in meters.

E=rotary table elevation (on sea level) in meters.

H=water depth in meters.

Gov=Sediment density at CP's shoe depth in Kg/cm2/10m.

df=Mud density in the next phase in Kg/l

offshore wells fall into two categories:

- Wells drilled from a fixed platform or from a Jack-up drilling rig.
- Wells drilled from a semi-sub (semi submersibles) or drilling ships.

Conductor pipe (CP) – Offshore wells drilled from a fixed platform or a Jack-up drilling rig

In wells drilled from a fixed platform or in those drilled from Jack-up drilling rig, conductor pipe is always driven down. Drive depth is to be calculated through the mathematical relation shown above. Before resuming drilling, a diverter (safety device described above) is to be installed on the top of the CP.

When fixed platforms are used, conductor pipe is driven as the platform itself is installed, as a result, at rigging-up time, the conductor pipe's shoe will have been driven to the required depth, as previously determined.

If the conductor pipe string driven from a fixed platform is unable to reach the predetermined depth while the platform itself is being built, as drilling operations start the inner CP shall be cleaned by the bit before resuming driving the CP down to the required depth. It is important to remember that the CP must be driven in a straight, vertical position.

Conductor pipe (CP) – Offshore wells drilled from Semi-subs or drilling ships

When semi-subs are employed, conductor pipe is always lowered and cemented into a borehole.

If the slightest doubt exists about the possible presence of shallow gas, before starting drilling operation, a small diameter (e.g., 8 ½") pilot hole must be drilled to the determined conductor pipe depth and appropriate operative procedures must be implemented.

Conductor Pipe's drive depth is always affected by water depth in the area where the well is located.

When sea bottom is about 150 meters deep or less, CP's drive depth shall be determined through the mathematical relation shown above, a riser (in simple terms: tubes linking the conductor pipe to the surface) shall be put in place, and drilling operation shall be carried out by circulating mud to the surface.

When sea bottom is deeper than 150 meters, the conductor pipe shall be lowered and cemented to a depth of approximately 45-50 meters (the CP will only serve to purpose of bearing the weight of the undersea wellhead and BOPs, at the later time). A riser shall not be used, drilling shall take place until the following casing's required depth is attained, drilling mud shall circulate to sea bottom level.

Surface casing

Surface casing is generally considered the first casing string run into a wellbore. It is lowered to a depth variable between 200 and 600 meters, according to well type and features. Functions of surface casing are:

Shutting surface fresh water out, thus preventing drilling mud from contaminating the water bed.

Excluding surface unconsolidated soil, which sometimes is open-faced, therefore avoiding cave-ins under the structure that supports the derrick. Direct experience of surface casing cementing operations shows that the volume of slurry that needs to be pumped into the annulus between borehole and casing is most of the times 50-100% higher than the theoretical calculated values. This fact is evidence of frequent borehole cave-ins.

Providing an adequate fracturing gradient available at casing shoe level.

Surface casing is actually the first casing lowered into the wellbore, and blow out preventers BOP's safety device are installed upon it. Having even a minimal value of fracturing gradient available at casing shoe level, allows for a return to normal hydraulic conditions after a kick, if correct well control procedures are implemented.

Offering mechanical support to the wellhead and casings that will be lowered later

The primary flange is welded to this casing (It can be screwed onto the first casing element, when working on unproblematic wells with depths limited to 1500 – 2000 meters). This flange is the first component of the landing assembly.

Upon it new flanged components shall be installed as other casing strings are lowered. Casing run into the wellbore shall be connected to these flanged components. As a result, surface casing shall support the compression stress of all the following casing. The drawing at the side is a graphic sketch of a 13-3/8" surface casing welded to 13-3/8" – 3000 psi primary flange.

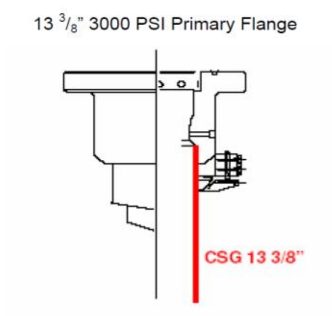


Figure 2. Surface casing head housing

Intermediate casing

More than one intermediate casing string can be lowered, according to specific wellbore characteristics. Intermediate casing serves several purposes:

Reaching an adequate fracturing gradient underneath the casing shoe

In order to make a higher choke margin available, so that the next drilling phase will be carried out in safer conditions.

Separating formations with different pressure values. Two typical situations can be identified.

1. **Increase of gap pressure gradient** – In this case the casing shoe shall be positioned on top of the over pressured strata (with values of about 1.3 – 1.4 Kg/Cm2/10m) in order to obtain a higher fracture gradient. Casing will exclude normal-pressure gradient formations, which could cause:

- **Sediment fracturing, in the weakest normal-pressure area**
- **Drilling string stuck,** drill pipes and heavy-weight drill pipes in contact with the formation wellbore wall as a consequence of high differential pressure between mud-weight generated pressure and formation pressure.

2. **Rapid change of the well's hydraulic conditions.** Once again, two typical situations can be identified.
   - **Passage from high-pressure formations to normal-gradient.**
     In this situation, casing shall be lowered to exclude overpressures and lighten mud to a considerable extent, if necessary, in order to be ready to deal with normal-gradient formations. Such a situation occurs frequently and it usually coincides with a passage from a clastic formation sand or clay to a carbonate one.
   - **The opposite situation: passage from normal-gradient formations open faced carbonate formations to clastic formations with development of overpressures.** In this case, casing should be lowered to exclude high permeable limestone, so that mud be weighted down in order to deal with the over pressured formations.
   - **Excluding unstable formations.** In tectonically disturbed areas, scaly clay can be found. If it is left uncovered for a long time, and if it interacts with mud, it can cause cave-ins and can stuck the drill string. In deep wells, it is necessary to avoid long open hole sections to prevent wellbore obsolescence, and the consequent problem of unstable formations.
     In directional wells build-up and drop-off curves must be covered as soon as they are completed, in order to avoid the risk of drill string stuck.

Production casing

This casing is positioned to cover the mineralized (Productive) area, or, in case of open hole completion, with its shoe on top of the mineralization. Production casing function's are:

- Restoring drilled-through formations hydraulic conditions by lowering casing and subsequently pumping cement into the wellbore / casing annulus.
- Making the well production phase possible by lowering the production string (Packer and tubing with safety valves) through it.

From what has been explain above, it is easy to understand that this is the most important casing string in the wellbore. Its integrity and its efficiency must be assured to last all through the productive life of the well.

Production casing designers must give careful consideration to the type of completion (single, double, open hole or cased-hole completion) and relative diameters concerns.

Engineers must assure themselves that production casing will endure the various stresses to which it will be subjective:

- Endurance of production level pressures
- Endurance of stress caused by possible high temperatures,
- Endurance of possible corrosion induced by fluids with which it will come into contact (completion brine and or formation fluid).

Casing diameter selection

In a casing design project, the step following casing point selection is casing diameter selection. The production casing (last casing to be run into a wellbore) diameter determines all others. In turn type of completion affect the production casing diameter.

We can choose between:

- Single completion (a single tubing string) and
- Double completion (two tubing strings).

Then we need to select the production tubing diameter or completion string diameter (e.g., 2 7/8” or 5”), decide whether safety valves and sliding sleeves valves needed or not.

In consideration of all these factors, the production casing diameter is selected, proceeding backward, the diameters of intermediate casing, of surface casing and of conductor pipe are chosen.

Once a choice has been made on production casing diameter, the selection process of the remaining casing diameters must answer the following needs:

- An appropriate drill bit diameter must be picked up / out. The bit will have drilled the borehole into which production casing will be run.

- This bit is going to move inside intermediate casing, that has a specific diameter. Outside casing diameter does not matter in this case. We have to take into consideration the casing drift. Drift means casing gauge (maximum diameter that can be run inside the casing), structural tolerance made known by manufactures.
- Intermediate casing will be run inside a hole drilled by a bit which will have moved inside the surface casing (once again, consider internal gauge)

Graph for selecting casing diameter.

Use of the graph shown on figure 3, following three successive steps:

- Select production casing diameter (first or third line, on top of graph).
- Select a borehole wide enough for this diameter (following narrow).
- Select previous casing dameter.

Repeat these steps until surface casing and conductor pipe measures are defined.

Paths represented by continuous lines are problem-free, while those symbolized by dashes need to be carefully thought about in view of limited annular tolerance. A particular attention will be pay to:

- Cementing operations in limited spaces.
- Outside diameters of joints
- The possible presence of dog legs
- Formations that tend to expand, or cave in.

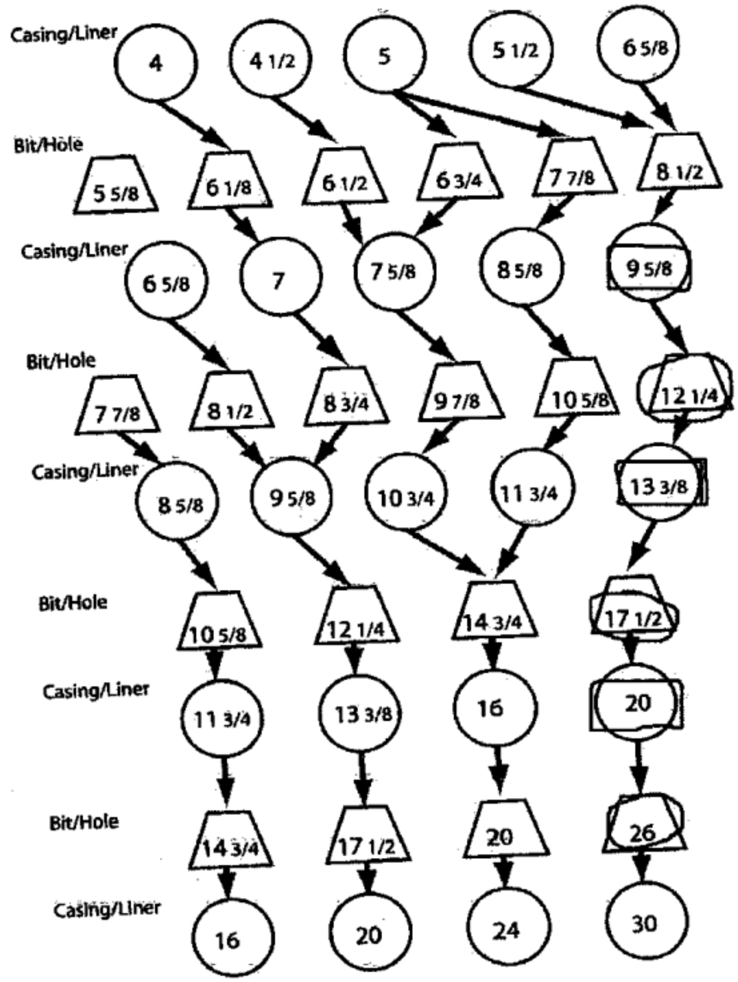


Figure 3. Graph of selecting casing diameter

Standardization of diameters, thickness, and steel degrees

Keeping several casing diameters of various thickness and steel degrees on hand means allocating considerable financial resources for long periods of time. All oil companies designed and standardized casing profiles, aiming to cut costs and to better organize their stocks.

Liner

The liner is a length of casing anchored inside the previous casing string and may or may not be tied-back to ground level. The reasons of running a liner are of an economic and technical nature. Economic in the sense of the savings deriving from not making up the casing string to the ground level (whenever possible), and by the saves of time in the casing running process.

Technical, especially in deep wells (6000-7000 m), where running a single string would involve dealing with very heavy weights and slurry displacement would require very high pressures.

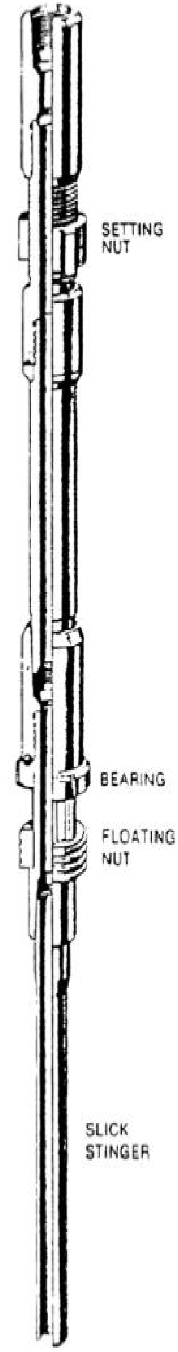
The components of liner hanger are the following:

1) Setting tool
2) Setting sleeve
3) Packer
4) Hanger
5) Flapper valve
6) Plug holder sub
7) Landing collar
8) Catcher sub
9) Float collar
10) Float shoe
11) Swivel

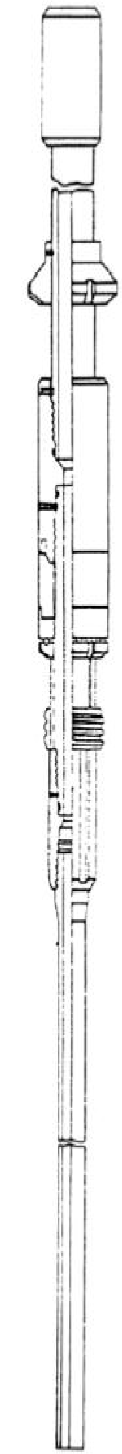
Liner Setting tool

The setting tool is the device needed for lowering and cementing a hydraulic or mechanical liner. It is also used to set the liner packer, if any. The main components of all types of setting tool are the floating nut and the bearing. The floating nut is a pin shaped element left threaded that will couple with the corresponding thread cut on the inside of the setting sleeve and bears all the weight of the liner casing.

The bearing is located above the floating nut and facilitate the releasing of the setting tool. Another component that is coupled with the setting tool is the stinger. This is a 2 7/8" diameter pup joint, threaded only at the upper end, that is screwed onto the setting tool and serves to guide and stab-in the pump-down plug. The stinger must be very smooth, with no surface roughness, because it must ensure a hydraulic seal with the O-rings on the flapper valve during the cementing process. The most commonly used setting tools are the CS type (figure 4) and the C-2 type (figure 4), which are described below. In addition to the above, Brown also manufactures another two types of setting tool: the RPP type (figure 5) and the 2 RH type (figure 5).

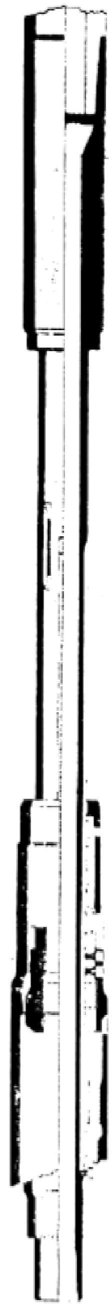


LINER SETTING TOOLS
TYPE "CS"

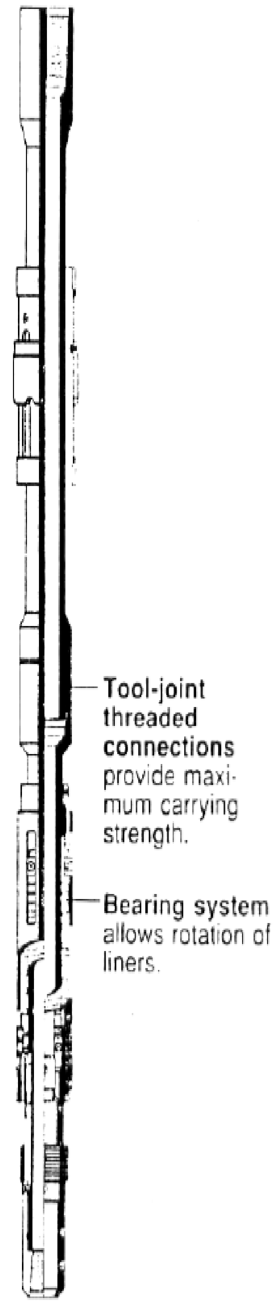


TYPE C-2 SETTING TOOL

Figure 4. Liner setting tool – CS type and C – 2 types



Brown RPP Setting Tool



Brown Type 2RH Setting Tool

Figure 5. Liner setting tool – RPP type and 2RH type

The CS setting tool has a shaped setting nut at the top that serves to induce the expansion of the SS type packer, that is now rarely used. The operation of this setting tool with the SS packer is here described simply for the reader's information. Before assembling the hanger, the packer and the setting tool, the setting nut must be screwed completely down onto the setting tool until it comes into contact with the tool joint. Then it is broken down by the same number of turns as the threads on the floating nut. The setting nut latch are aligned and slotted into the key in the SS packer Sleeve. The left threaded floating nut is screwed into the thread in the setting sleeve, by rotating the setting tool. This rotation screws the setting nut back to the top of the tool joint. Now the assembly is ready to be run into the well. When it has reached the right depth, the hanger has been fixed and the cementing job is over, the string is then rotated to the right and the setting nut consequently moves downwards till reaching the end of its stroke. Its rotation pulls down the packer sleeve, which shears the shear pins and compresses the packer rubber, who expands and consequently close the annular space between the hanger and the casing (figure 6).

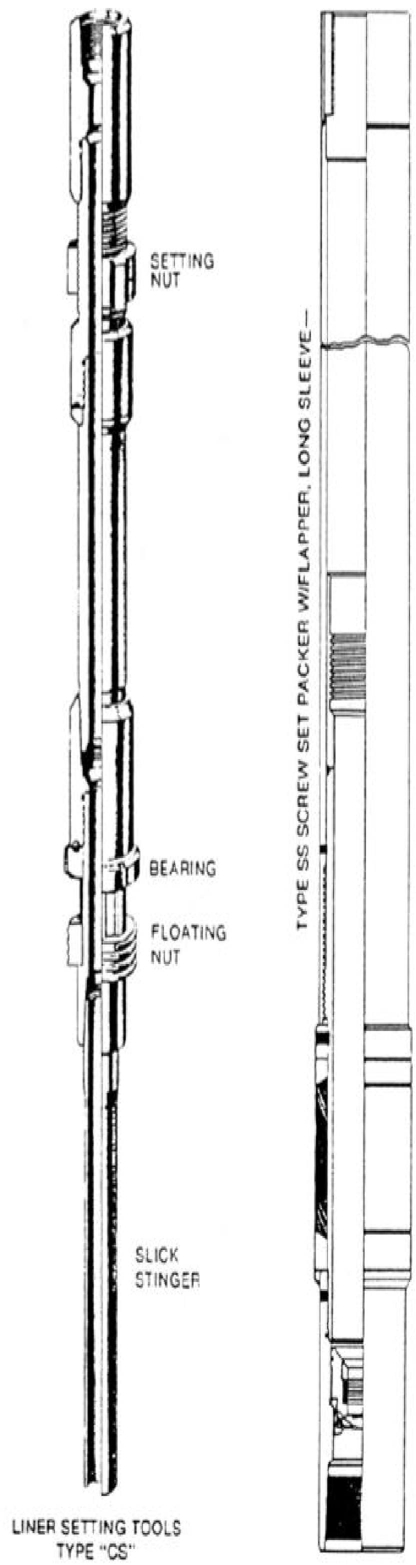


Figure 6. Liner setting tool - CS type

The C-2 setting tool is used when the liner packer is expanded not by rotation, as in the SS packer, but by applying a weight on the top of the extension sleeve. To do so, after fixing the hanger and completing the cementing, the setting tool is lifted until the latch (dog sub) come out of the extension sleeve: being sprung, the latch will then open. When the setting tool is lowered again until the latch stops on the top of the extension sleeve, the weight needed to expand the packer is released. The RPP-type setting tool is used together with the RH-type setting sleeve in deviated holes, or when the liner has to be rotated to bring it down to the bottom.

Setting sleeve

The setting sleeve is an Acme left male-female casing sub and is used to run the liner casing in conjunction with the setting tool. There are different types of setting sleeve available, depending on how they are used. The standard setting sleeve is used in wells that are not particularly complex, where the plan does not involve the tie-back to ground level. The setting sleeve with a tie-back extension needs to house the tie-back stem while tie back operation are conducted. As an alternative to the standard tie back extension, the PBR (polished bore receptacle) extension can be installed, which is smooth and highly polished on the inside so as to be able to house the PBR tie back seal assembly. The PBR can cope with high pressures.

In addition to these extensions, Brown produces the RH type of setting sleeve and the S type with the tie back extension. All the various types of extension are made in standard lengths of 6, 10, 15 and 20 feet (2, 3, 5 and 6 meter). For special uses, they can also be made as long as 40 feet (12 m).

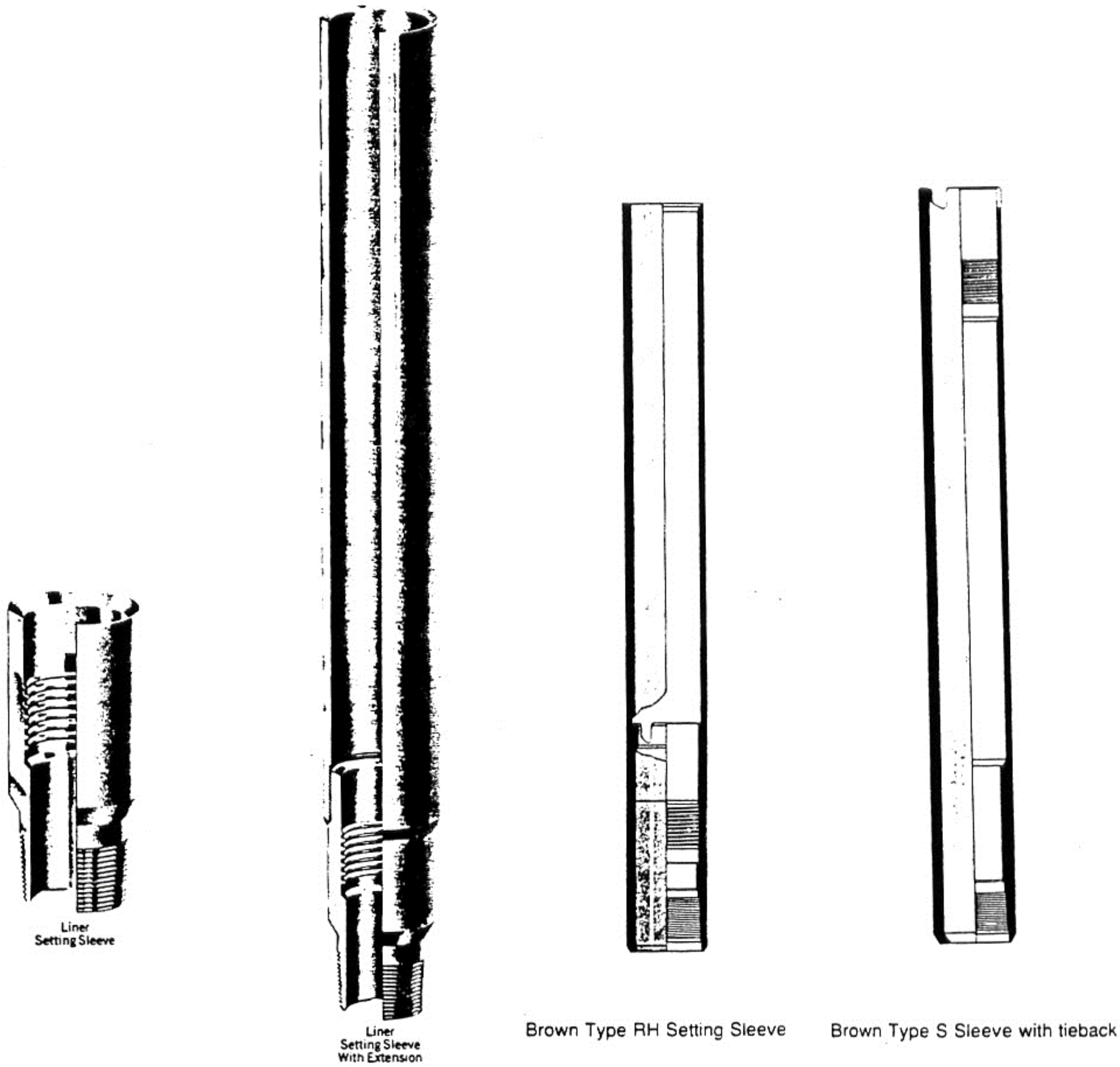


Figure 7. Liner setting sleeves

Liner packer

The main purpose of the packer is to prevent any migration of fluids or gases while the cement is setting (or becoming hard, wait on cement). In addition, the slips that are installed in many packers prevent any upward movement of the string due to downhole pressure. The packer position in the liner is just below the extension sleeve and above the liner hanger. Another two types of liner packer are the CPH (figure 8) and the High-Performance liner packer (figure 8). As explained earlier, the CPH liner packer is settled only after completing the cementing process. The C 2 setting tool is raised until the latch emerges from the extension sleeve and open under the force of their springs. Resting them on the setting sleeve and unloading some weight makes the packer rubber expand and the slips simultaneously slide along a cone and open out, adhering to the previous casing string, while keeping the packer compressed.

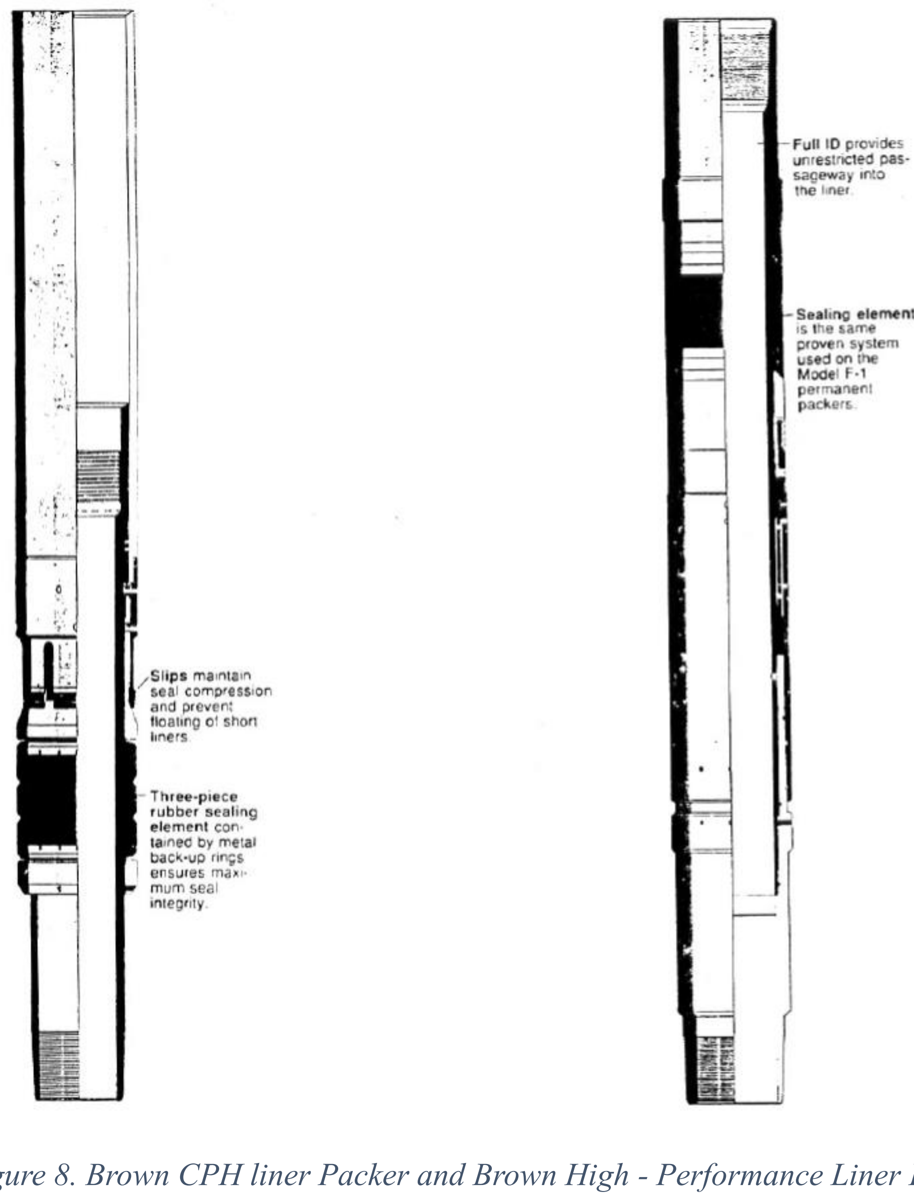


Figure 8. Brown CPH liner Packer and Brown High - Performance Liner Packer

The High-performance liner packer is set hydraulically. When the inside of the drill pipes is brought up to a pressure of 2500 psi (about 173 bar), the pressure through the hole pushes up a cylinder that enables the packer to expand after breaking the shear pins. The H type liner packer (figure 9) works on the same principle, but with the addition of anchoring slips.

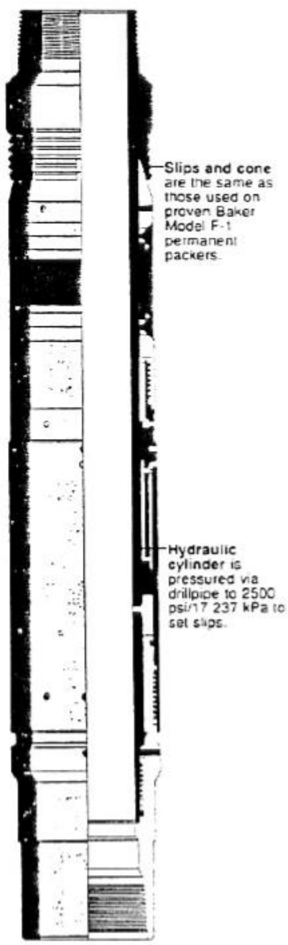


Figure 9. Brown H Liner Isolation Packer

Liner hanger

The hanger is the element that is hanged in place (mechanically or hydraulically) and holds the weight of the suspended liner casing. The hanger is set by engaging one or two sets of slips that slide along conical sleeves to grapple into the previous casing. When the liner is run, the slips are locked in the closed position. Liner hangers are divided into mechanical and hydraulic types, depending on the system used for releasing the slips.

Mechanical liner hanger

The most commonly used mechanical liner hanger is the CMC type made by Brown. (Figure 10) Once the required depth has been reached, this hanger is set by lifting the string of about 40 cm. Then, rotating a 1/4 turn to the left releases the leaf springs that trigger the slips from the locking pawl. When the string is lowered, the slips are free to slide down the sloping planes and slot into the casing. By releasing more weight (weight of the liner casing + 15-25Klbs), we can make sure that the slips are properly engaged. This type of hanger is not recommended for use in deviated or very deep wells, where it may prove difficult to turn the string (due to excessive torque) in order to set the hanger in place. The CMC type has the advantage of being able to disengage the slips if they are engaged too soon. This hanger also has two sets of slips that enable a better distribution of the stresses in the hanging section of the previous casing.

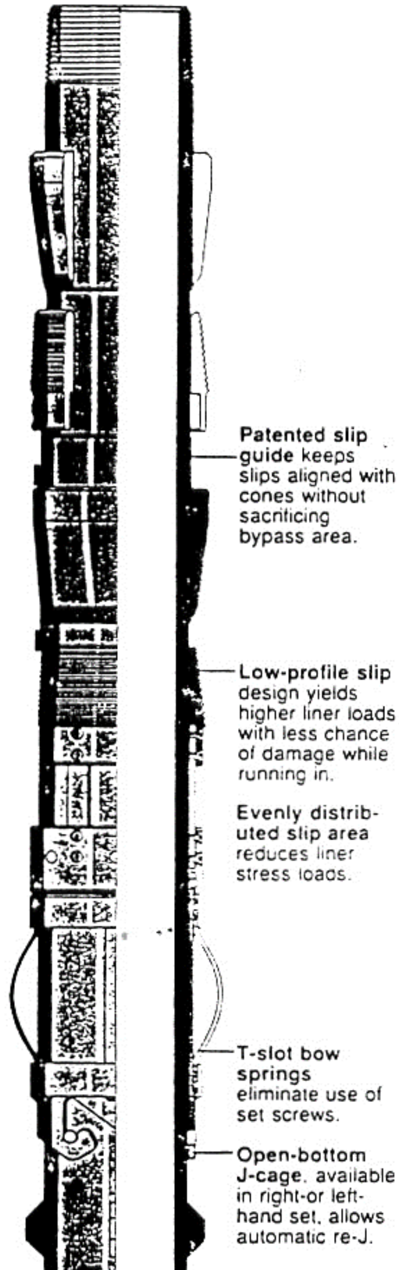
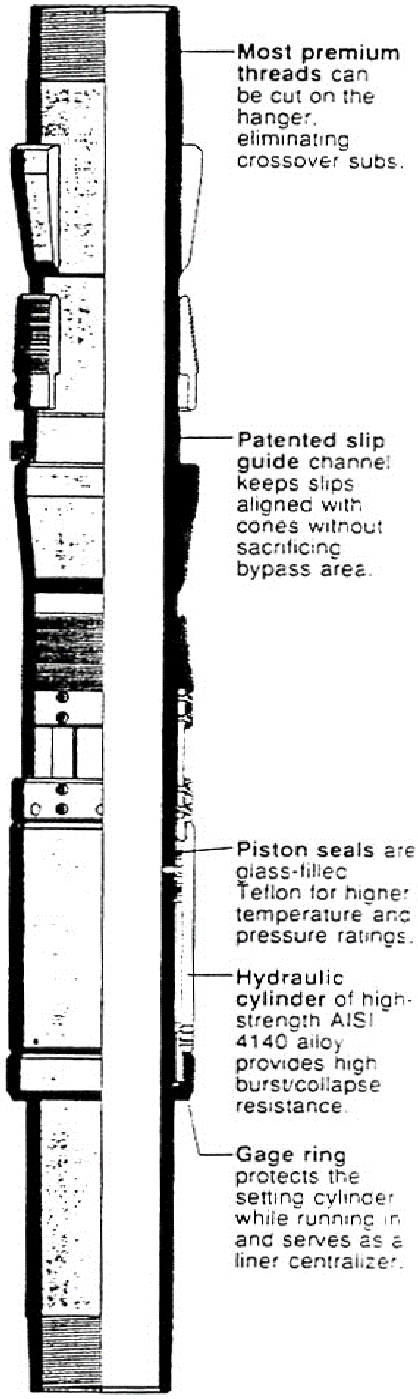


Figure 10. Brown CMC Liner Hanger

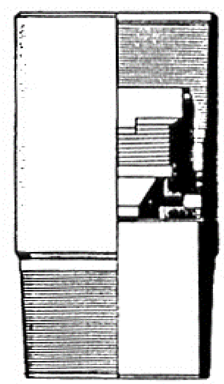
HMC hydraulic liner hanger

The HMC liner hanger is set hydraulically by pressurizing the inside of the drill pipes. A high-strength hydraulic sleeve is installed in the lower part of the hanger. A piston complete with seals is installed inside the upper part of the sleeve and all these elements are fixed in place with pins. There is a hole that put the inside of the hanger in communication with the sleeve (figure 11). After the liner has reached the required depth, and circulating has been done to clean the hole, the setting ball (sized 1-1/2”) is dropped into the drill pipes and accompanied by a low-pressure circulation (300 - 500 lpm) until it fits into its seat in the lower central part of the landing collar (figure 11).

Then the pressure is increased until the packer is set in place. After waiting a few minutes, more weight is released to make sure that the hanger is properly set. Then the setting ball and its seat are ejected by further increasing the pressure. (These pressures depend on the strength of the setting pins, known by the manufacture). The setting ball and seat drop onto the catcher sub. This type of hanger is suitable for lengthy liner casings and in high pressure and high temperature wells.



Brown HMC Hydraulic Liner Hanger



Brown Type II Landing Collar

Figure 11. Brown HMC Hydraulic Liner Hanger and Brown Type II Landing Collar

Flapper valve

The flapper valve (figure 12) is a M/F (Milled Flapper) sub with a flap check valve. To ensure hydraulic seal O-rings are provided in the middle section of the central hole, where the setting tool stinger is inserted. The flapper valve is located underneath the packer (or, if there is no packer, under the extension sleeve) and just above the liner hanger. As explained earlier, its purpose is simply to seal off the pressure between the stinger and the inside of the string during cementing and displacement operations. Generally speaking, it is preferable to remove the flap from the flapper valve because after cementing, during plug contact, the flap keeps the liner string expanded by the action of the residual pressure. Then, when the flapper valve is milled, the pressure trapped inside the casing liner is instantly released, thereby relaxing the casing. And as a result, the casing may separate from the cement and create micro-annuli thus endangering the cement bond.

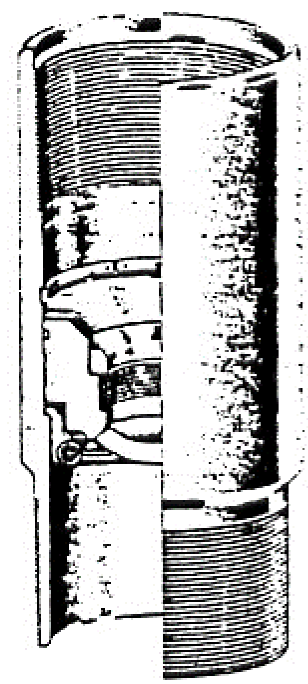


Figure 12. Flapper valve

Liner Wiper Plug holder crossover

The holder crossover bushing is a sub containing the liner wiper type II (figure 13). The plug has a set of shear pins on top. After pumping the slurry, the pump-down plug for separation of the slurry from the displacement mud is dropped. Guided by the setting tool stinger, the pump-down plug reaches the inside of the liner wiper plug wedging (hook) into the slips and forming a single body. Increasing the pressure shears the pins and the liner wiper plug, complete with the pump-down plug inside it, is driven downwards as far as the landing collar, displacing the cement on its way. The holder crossover bushing is located under the hanger and a few centimeters away from the end of the setting tool stinger. On the inside, it carries the seat for fitting the pump-down plug slips. There are also slips on the outside, in the lower part, that fit into the seat in the landing collar. In some cases, it is unnecessary to install the holder crossover bushing because the liner wiper plug is already pin set with the pins in the terminal part of the setting tool stinger (type I). The holder crossover bushing is placed underneath the hanger.

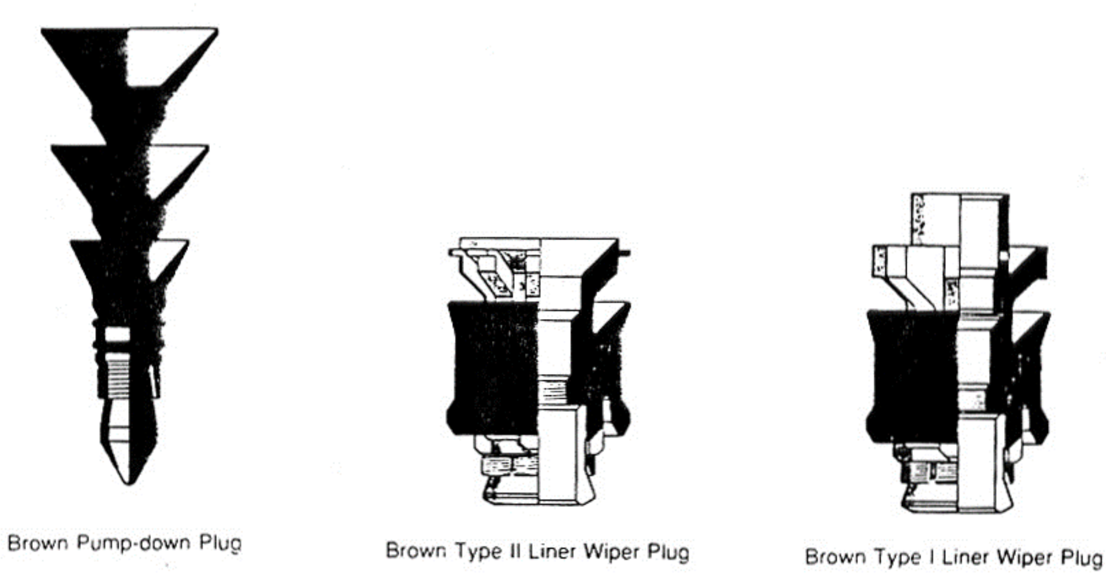


Figure 13. Liner hanger Wiper plugs

Landing collar

The landing collar is a sub containing a seat that acts as a plug stopper. This seat is designed to retain the liner wiper plug slips and enable plug contact. There are two types of landing collar. Type I (figure 14) is used exclusively with a mechanical liner hanger, so it contains no setting ball seat. Type II is complete with a seat for the setting ball and is consequently used with a hydraulic liner hanger. In this latter case, the seat for the setting ball is held in place by shear pins that break and drop together with the setting ball onto the baffle catcher sub below. The landing collar is installed a few lengths of pipe above the shoe, or according to the casing program.

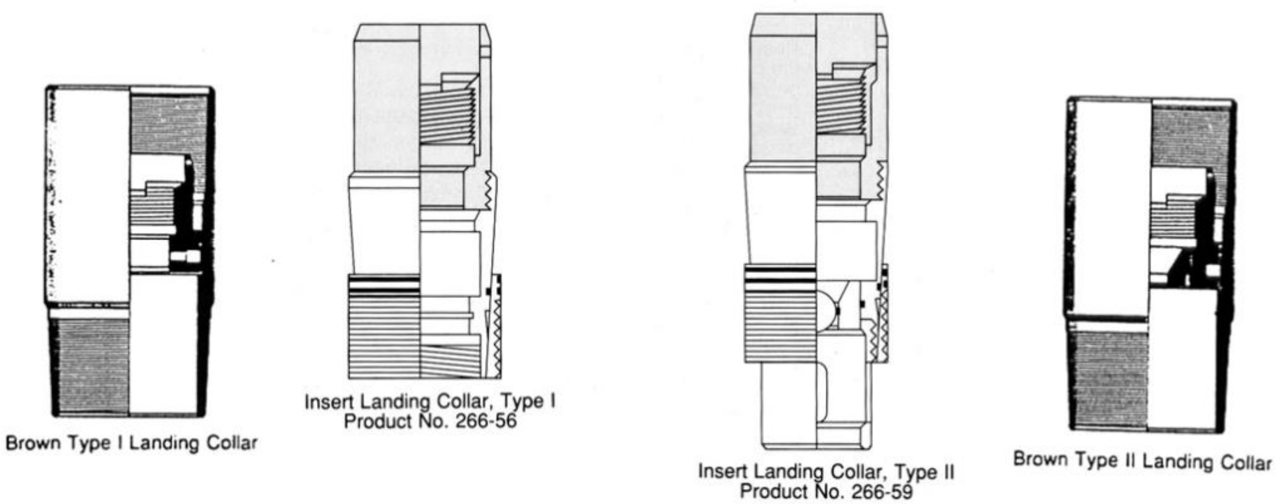


Figure 14. Landing collar

Ball catcher sub (baffle type)

The ball catcher sub (figure 15) is sub containing a perforated disc where the setting ball stops together with its seat after setting the hanger. The numerous holes in the disc allow for the passage of the slurry during the placement operation. The ball catcher sub is logically only used with the hydraulic hanger. The ball catcher sub is generally placed two pipes below the landing collar and one or two pipes above the float collar.

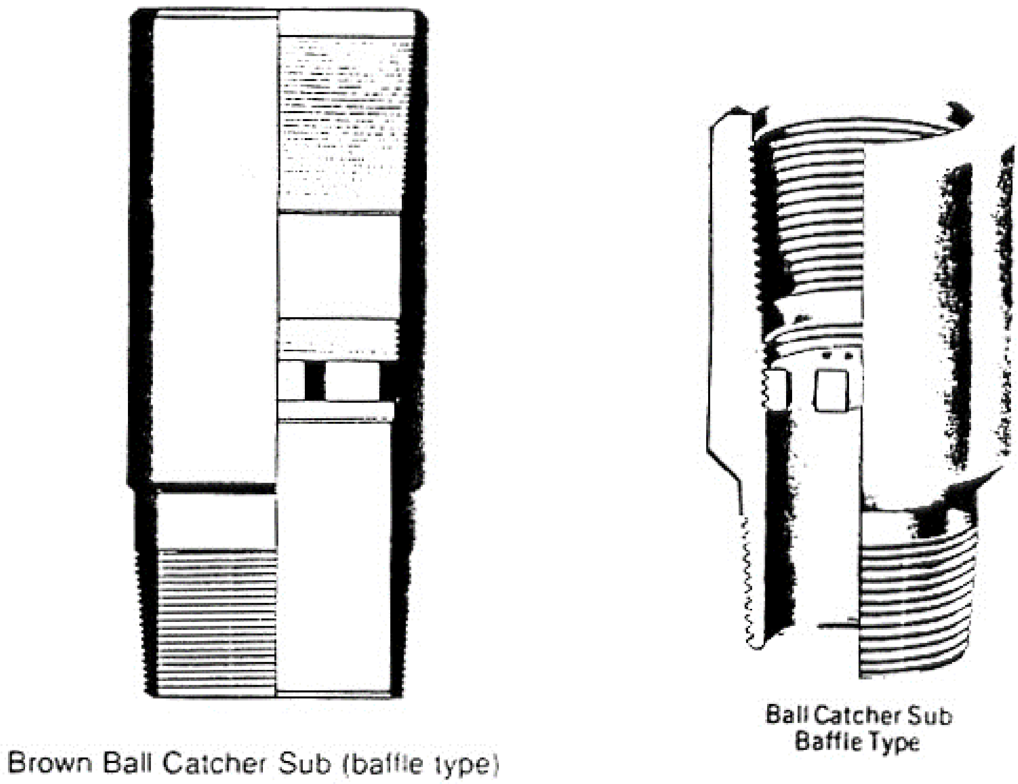


Figure 15. Ball catcher sub

Collar and shoe

Another two elements forming part of the liner casing are the collar, placed one or two pipes under the landing collar, and the shoe, placed two pipes under the collar. During the assembling of the liner, the collar and the shoe can differ in types and brands with no problem for the operations. Brown also manufactures these two elements, and the various models they offer. The differences lie exclusively in their shoes, which are made with side holes that allow for cementing to be done even if the shoe has to rest, for some reason, on the bottom of the hole (whereas this would be impossible using another type of shoe).

Liner swivel

The swivel (figure 16) is a component that proves useful when running a mechanical hanger with the J stop, where some rotation is needed to engage the slips. The swivel is positioned under the hanger and prevents any rotation of the liner casing being transmitted to the hanger by means of a supporting bearing and thus triggering a premature engagement. This may occur in deviated holes. To help the swivel, there are also spiral centralizers, which can be mounted one of the left types and one of the right types.

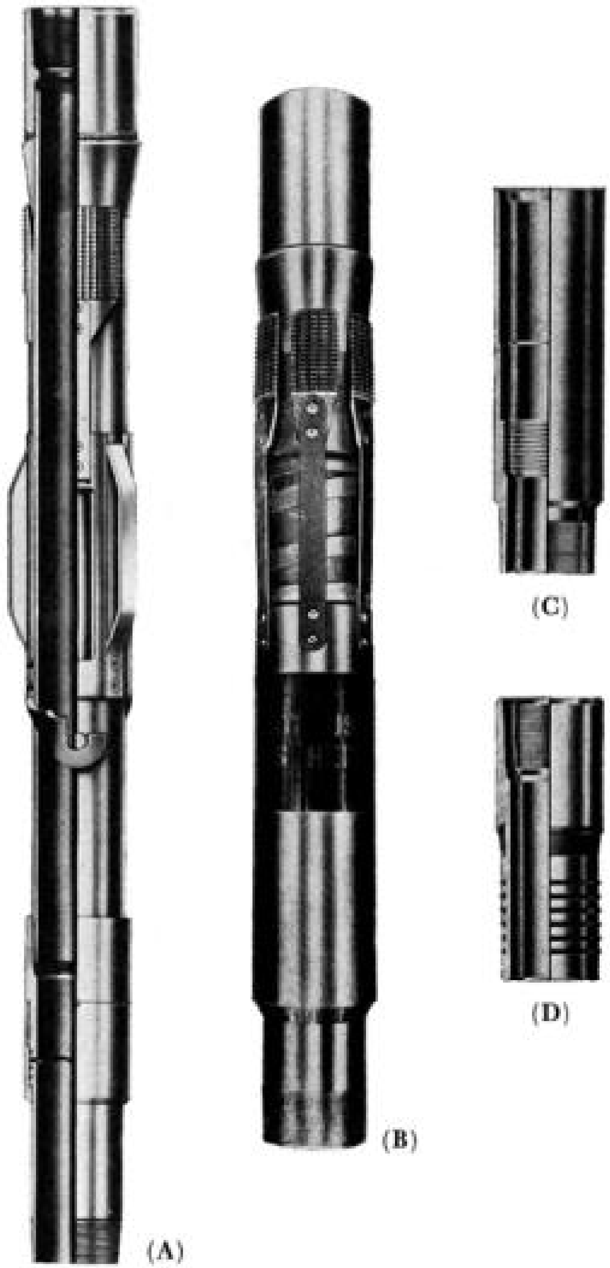


Figure 16. Liner swivel

Casing string equipment

When it comes to the construction and installation of pipelines, ensuring a seamless and secure connection is crucial for the overall integrity and longevity of the infrastructure. One critical phase in this process is the cementing of the pipeline within the hole it's being installed in. Cementing serves several essential purposes, including providing structural support, preventing fluid migration, and ensuring the stability of the entire pipeline system. To achieve a successful cementing operation, a range of appropriate components and steps must be followed.

- Cement Slurry: The cement slurry is a mixture of cement, water, and sometimes additives. It forms the core component of the cementing process and is responsible for creating a strong bond between the pipe and the surrounding geological formations.
- Centralizers: Centralizers are devices designed to center the pipe within the hole. Proper centralization ensures that the cement slurry is evenly distributed around the pipe, minimizing the risk of channeling and ensuring uniform coverage.
- Cementing Head: A cementing head is used to deliver the cement slurry down the pipe and into the annulus between the pipe and the hole. It ensures a controlled and consistent flow of the cement slurry.
- Float Equipment: Float equipment is installed at the bottom of the casing or liner string. It contains a one-way valve that prevents wellbore fluids from flowing back into the casing, ensuring that the cement slurry can be pumped efficiently.
- Liner Hangers: In certain applications, liner hangers are used to suspend the liner inside the existing wellbore. These hangers provide support during the cementing process and ensure a secure connection between the liner and the wellbore wall.
- Spacer Fluids: Spacer fluids are used before and after the cementing operation to displace drilling mud and ensure that the cement slurry interfaces cleanly with the formation. They help prevent contamination of the cement slurry and promote effective bonding.
- Pressure Testing Equipment: After the cementing operation is complete, pressure testing is often performed to confirm the integrity of the cement barrier and ensure

there are no leaks. Pressure testing equipment includes pressure gauges, pumps, and valves.

- Cement Additives: Depending on the specific well conditions and requirements, various additives may be included in the cement slurry. These additives can enhance properties such as fluid loss control, set time, and temperature resistance.
- Quality Control: Quality control measures are essential throughout the cementing process. Monitoring and verifying the correct placement and density of the cement slurry are crucial to ensuring a reliable seal.
- Monitoring and Data Logging: Real-time monitoring and data logging systems are often used to record crucial parameters during the cementing process. This data helps in evaluating the success of the operation and can be used for future reference and analysis.

The cementing of pipes within a hole during pipeline installation is a complex and critical procedure. It involves the use of various components and careful planning to achieve a secure and effective seal. The choice of components and the execution of the cementing operation play a vital role in ensuring the long-term integrity and safety of the pipeline system.,

Float shoe and float collar

These are two components that form an integral part of the casing. They are check valves positioned in the lower part of the string to enable the slurry to flow out of the casing into the annular space during cementing job. When cementing is over, they prevent the slurry from flowing back inside the pipes due to the differential pressure between the slurry on the annulus and the mud on the inside of the casing. The float collar is also the handing zone of the cementing plugs. Collars are made of lengths of pipe having the same features (grade, thickness, thread) as the casings being run. Inside, they contain a check valve that can be flap, or ball, or poppet (mushroom) type, solidly held together with cement. Valves are made of a material suitable for milling. The float shoes and float collars may be of different types depending on how they are used for. These are two check valves used in cementing processes where there are no special requirements to meet. The most commonly used float shoes and collars are manufactured by Baker (figure 17), Halliburton (figure 18) and Weatherford (figure 19).

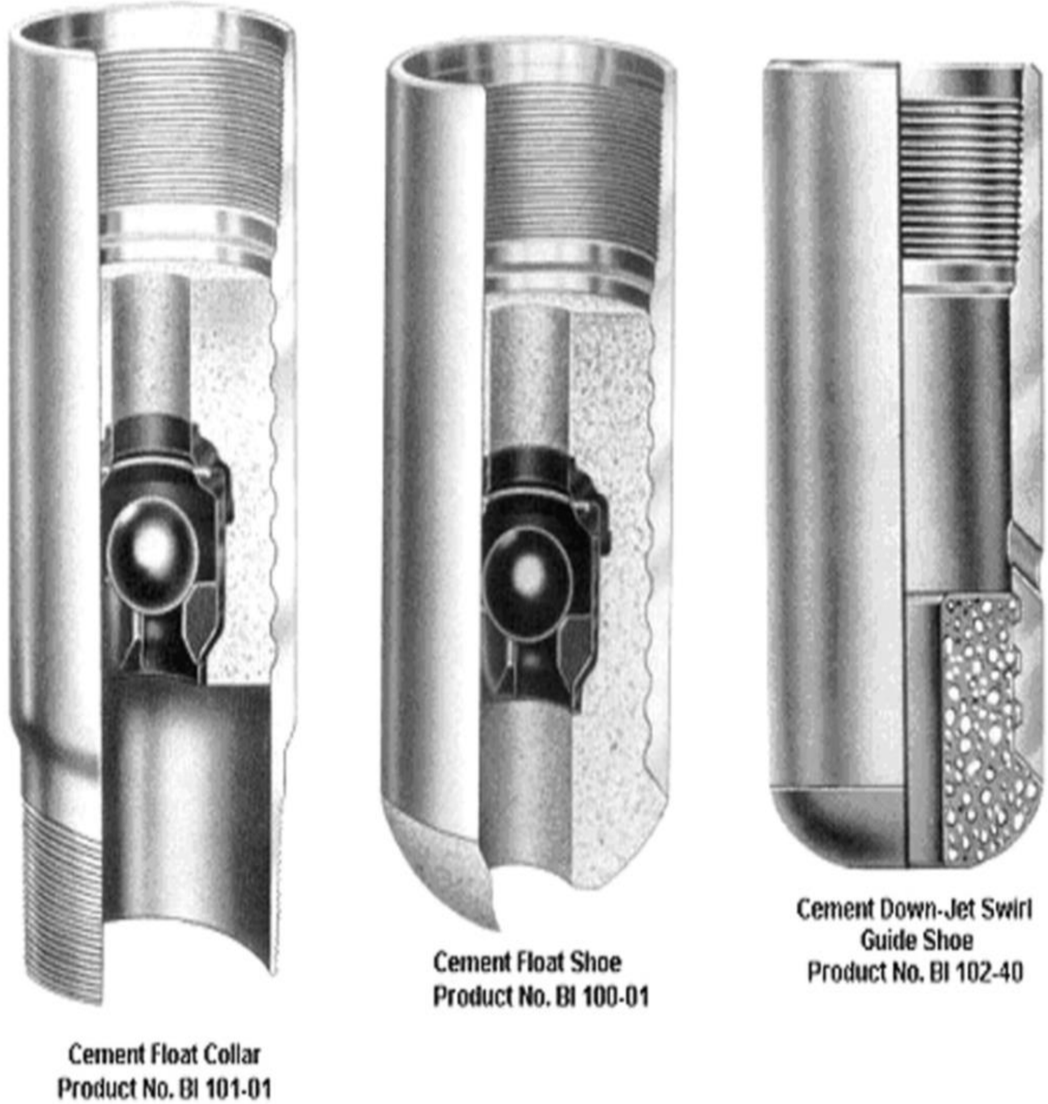


Figure 17. Baker`s float shoes and collars

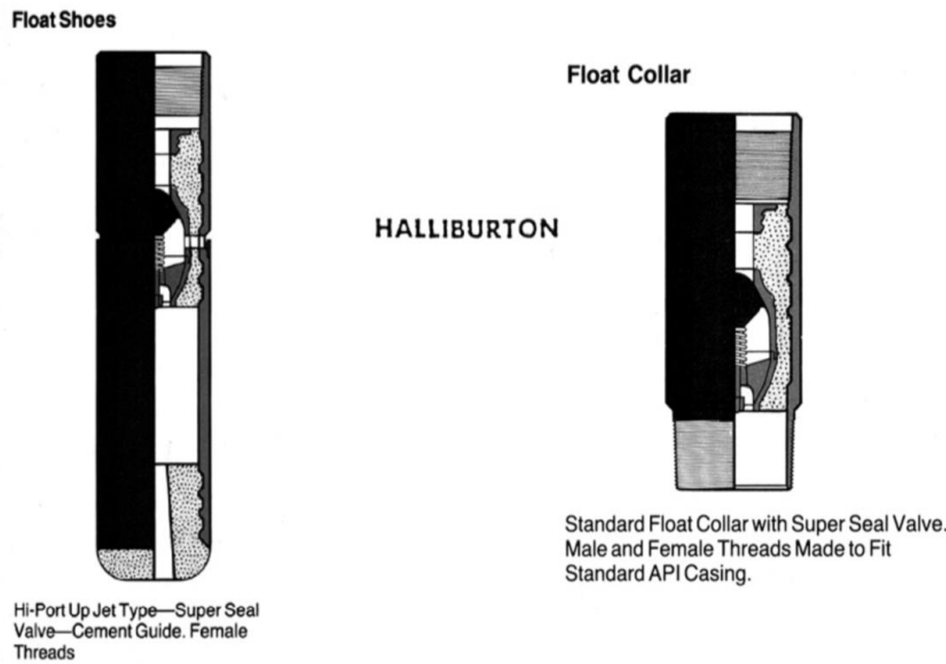


Figure 18. Halliburton`s float shoes and collars

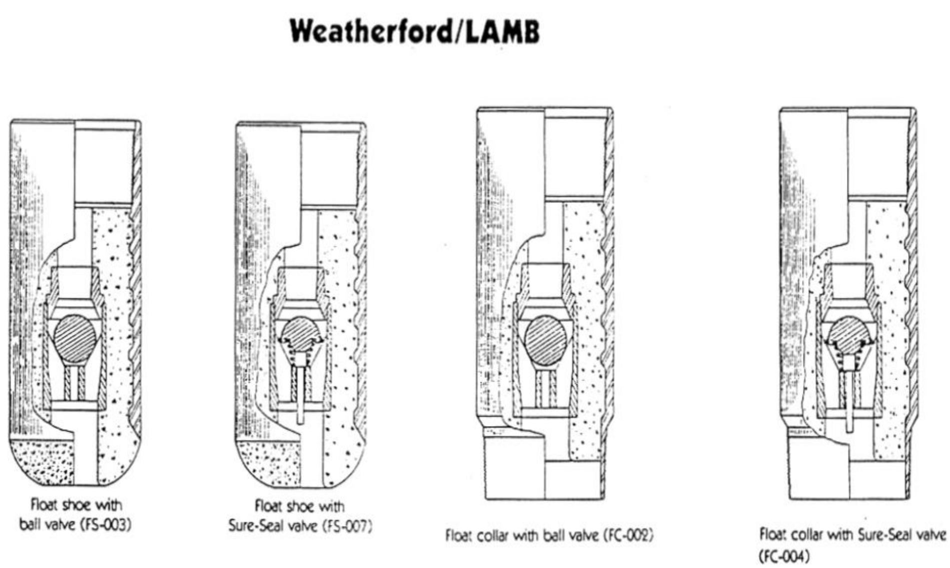


Figure 19. Weatherford`s float shoes and collars

Stab-in float shoes and collars.

This type of float shoe and collar are designed to house a stinger to pump slurry through the drill pipes without any need for displacement plugs. The upper part has a sharped opening to facilitate the stab-in of the stinger. Before the shoe is assembled, make sure that it is suitable for housing the stinger. The stinger is fitted with several O-rings in the lower part that are needed to provide a seal during cementing. A centralizer is placed above the stinger to facilitate the connections. After stub-in, a function test on the back side is performed in order to check the integrity of the O-ring placed on the stinger.

Figure 20 shows a cross-section of a Baker Hugues stab-in float collar and float shoe.

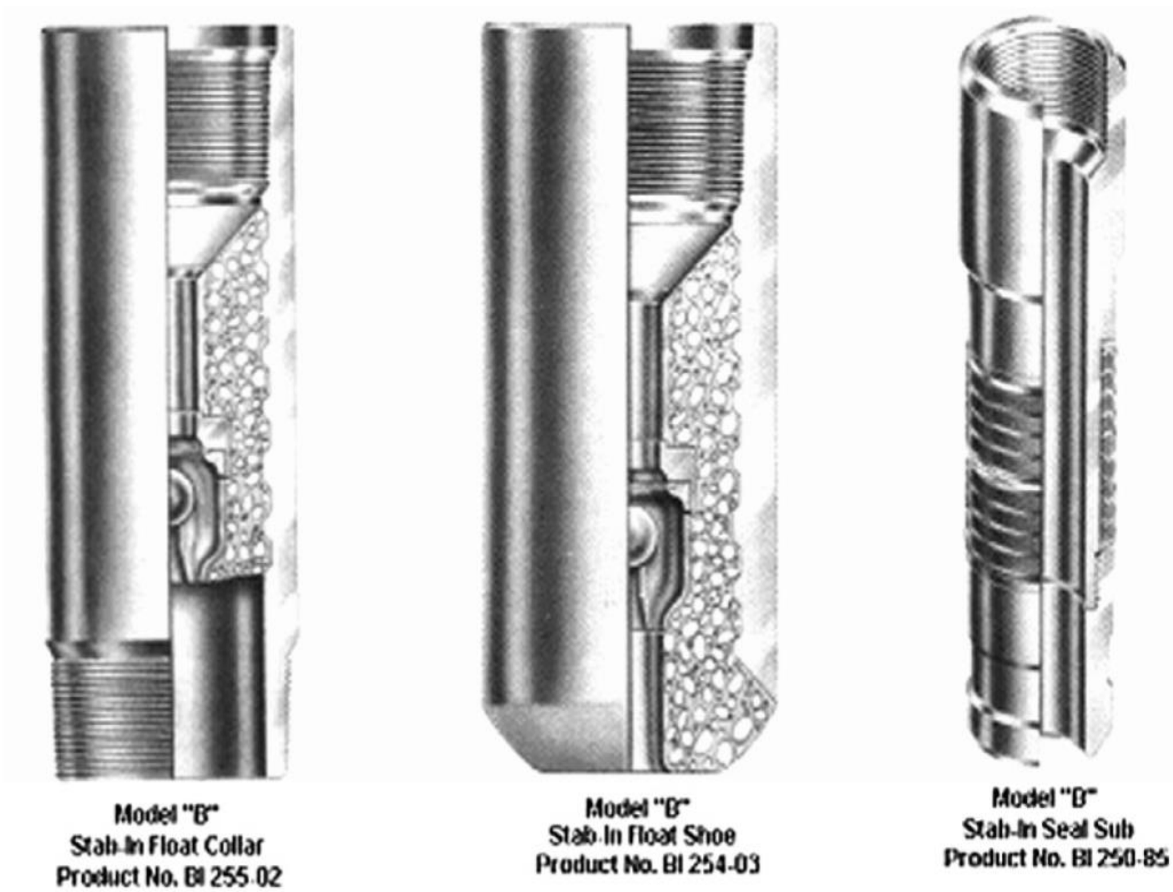


Figure 20. Baker stab-in float collar and float shoe

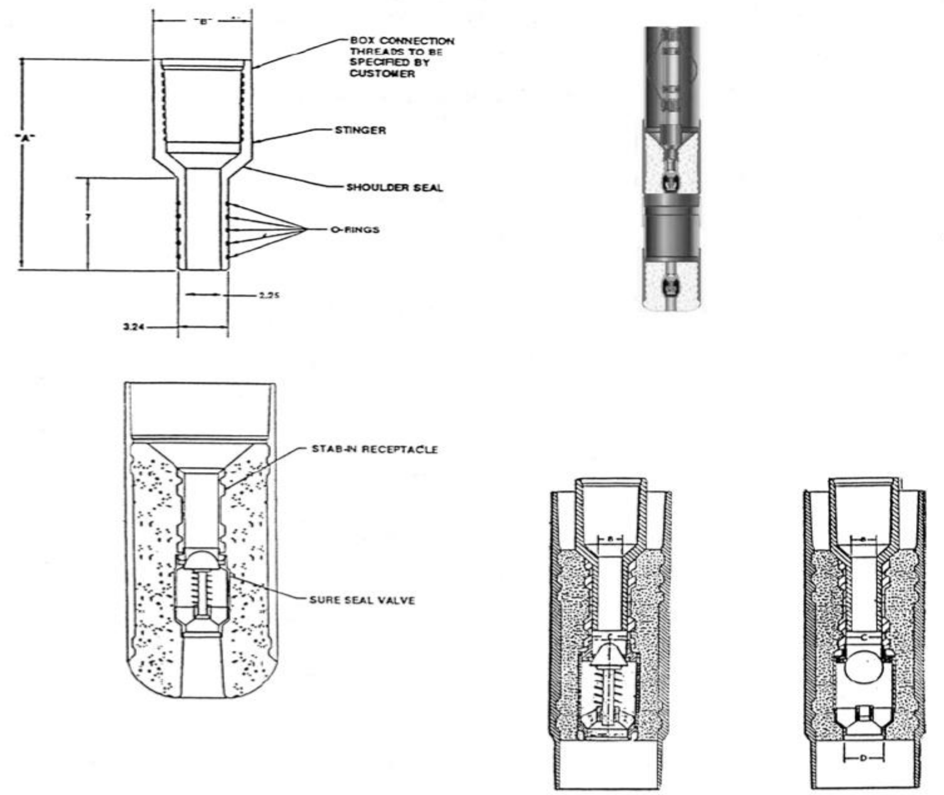


Figure 21. Weatherford shoe and cross-section of two collars

Surface equipment

Before starting to run the casings, it is important to ensure that all surface equipment is readily available and in good working order.

Spiders and elevators

Spiders are used to suspend the casing string over the rotary table so that the next pipes can be screwed on. In shallow wells, where the weight of the strings is not too great, the 200-ton B.R. hinged casing spider with the corresponding casing slips and hinge pin elevator are used to run the casings. When a string of 20" pipes has to be run in rigs equipped with a rotary table whose diameter is less than 20", it becomes necessary to remove the rotary table and fit the special beams for supporting and fixing the casing spider. In large-capacity rigs, the 20" casing can be suspended directly in the rotary table. Upon installation of appropriate casing bushings.

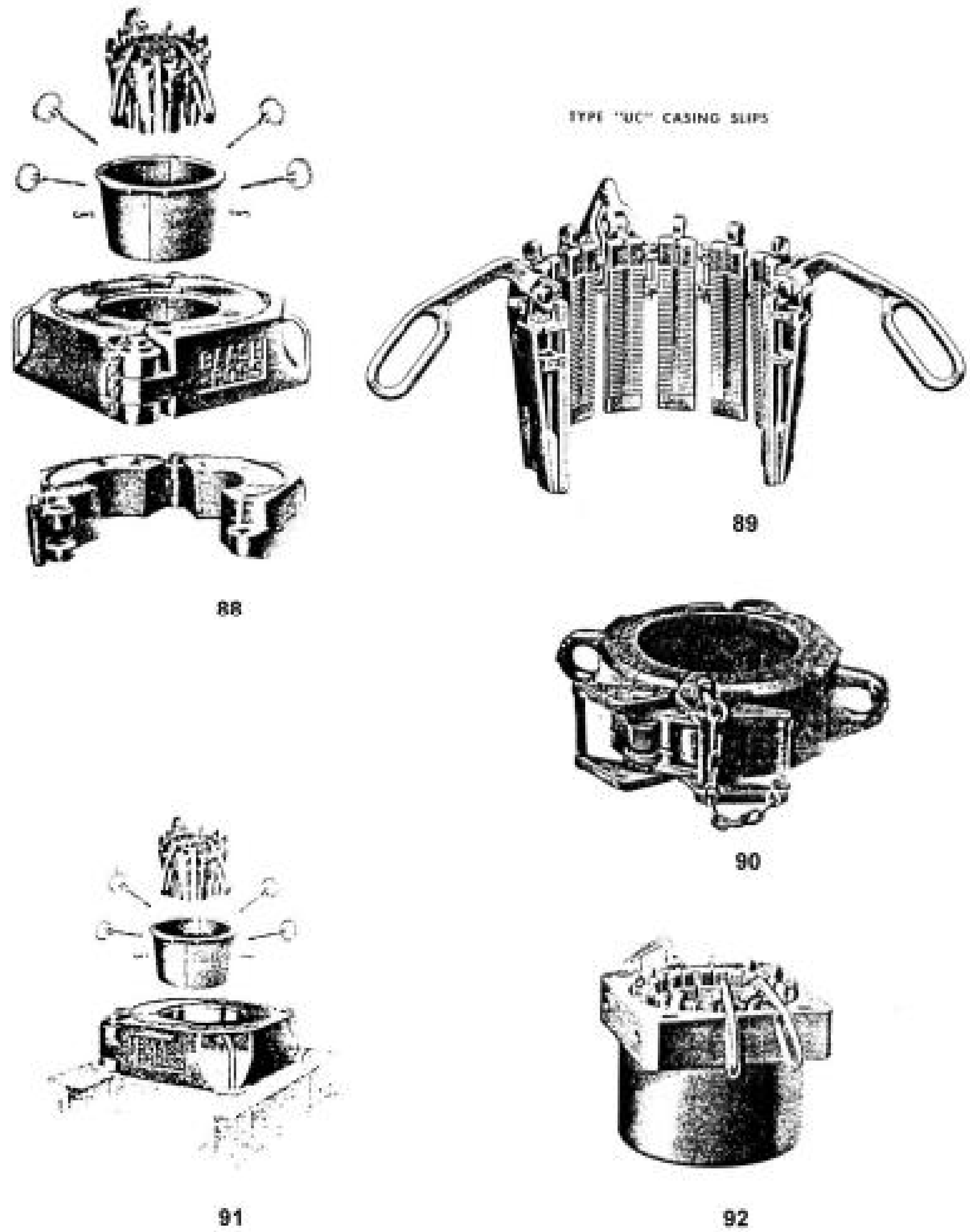


Figure 22. Casing slips and single joint elevator

When casing strings are very deep and their weight is excessive, slip type elevators are used for extra safety. This kind of elevator suspends the casing by means of slips that distribute the casing string weight on a large surface of the casing body and not concentrate it only on the shoulder of the casing-joint as it occurs by using hinge pin elevator. The slip-type elevator can be used as a spider resting on the rotary table, provide that the bell guide is removed. The suspension of the casing is obtained by a series of radial slips (fitted out with grapple inserts) who slide on high angle sliding path, thus avoiding the seizing of the slips on their seat.

Figure 23. Spiders and elevators

The slips are normally opened and closed manually, but pneumatically operated types, controlled by the driller, are also used. All models of slips elevator can handle any size of casing, simply by fitting it with appropriate size of slips.

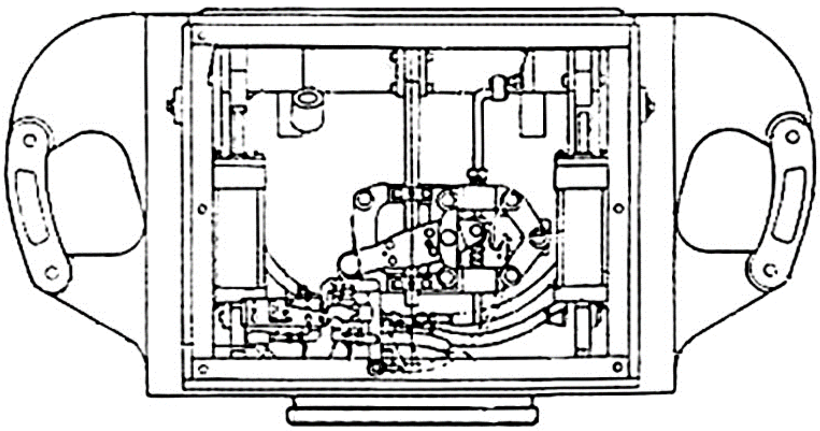


Figure 24. Side door elevator

The single joint elevator (fig. 96) is used to lift a single casing pipe from the V-door slide and align it above the pipe already suspended into the spider.

Figure 25. Single joint center latch elevator collar type

Casing power tong

The casing power tong is a hydraulic wrench for quickly and safely screwing the pipes. It is equipped with a torque system that ensures the right make-up torque of the connections. The pipes are screwed by turning a ring-shaped tong fitted out with dies who drag casing into rotation. Rotation is induced by a compressor. Oil companies use various brand of power tongs, but all of them are very similar in working system.

Oil companies generally uses the Weatherford tongs in the three main models:

- Model 7.6 Hydraulic,
- Model 16
- Model 24.
- Model 7.6 (figure 26) handle 5" and 7" pipes
- Model 16 (figure 27) handle 13 3/8" and 9" pipes
- Model 24 (figure 28) handle 20" pipes.

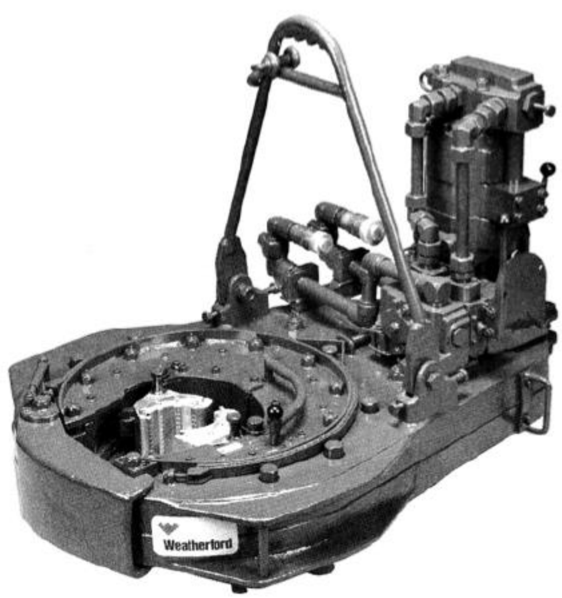


Figure 26. Weatherford Model 7.6 Hydraulic Power Tong

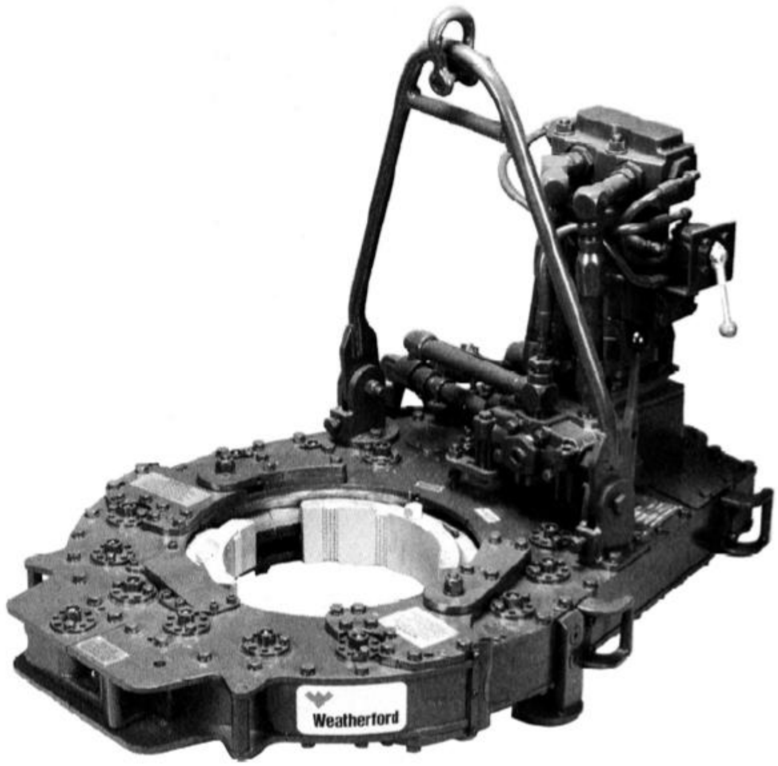


Figure 27. Weatherford Model 16 Hydraulic Power Tong

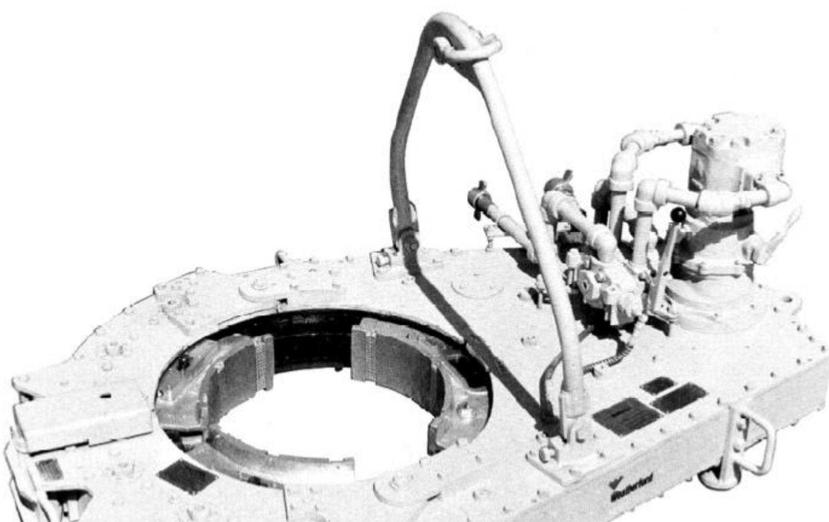


Figure 28. Weatherford Model 24 Hydraulic Power Tong

Casing positioning

The measured and numbered casing stacked on the pipe rack have to be brought into position one at a time, during the casing job, so that they can be hooked up with the single joint elevator and lifted with the travelling block ready for screwing. In the past, the casing positioned on the V-door slide where hooked to the casing laying on the pipe rack walkway with the aid of a steel sling. When the first pipe on the V-door slide was raised with the block, the second was thus drawn into the position previously occupied by the first, and so it went on. What often happened, however, was that the pipe would fall, or its thread would be damaged and it would have to be rejected. With more powerful installations and the raising of the substructures, this method became even more troublesome, so cranes were used to bring the casing into position - a method that was certainly safer and faster. A few years ago, another approach was adopted by West Coast and has since been used also by other oil companies. The pipe is arranged on a channel and brought into position on the derrick floor by means of a cableway. This solution is quick and safe. The equipment is installed on a separate truck

Whether the pipes are positioned with a crane or a cableway, it is essential to protect the male thread from shocks and dirty. The protection is achieved by using klampon or Mech-tec thread protector who are of quick and easy installation and removing or pin thread protector on the casing pin.

Cementing head

The cementing head is screwed onto the last pipe at the top of the string and enables the first cementing plug to be introduced and the second to be brought into position, thus ensuring continuity during the cementing and displacement operations. In single-stage cementing, when the circulation is over, the head will be opened and, the first plug is inserted, into the casing the safety bar is closed and the second plug is placed on top of it. Then the head is closed and the slurry is pumped in. When pumping is over, the safety bar is removed, the second plug is then released and slurry displacement begins. In the Halliburton head, there is a small lever communicating with the outside that is shifted by the passage of the plug thus indicating that it has been released by the cementing head. In the Baker head, the plug is combined with a wire that emerges from the head through a hole. When the safety bar is slid out, this wire is dragged into the borehole by the plug which is being released. Also, this system is to indicate the actual releasing of the plug.

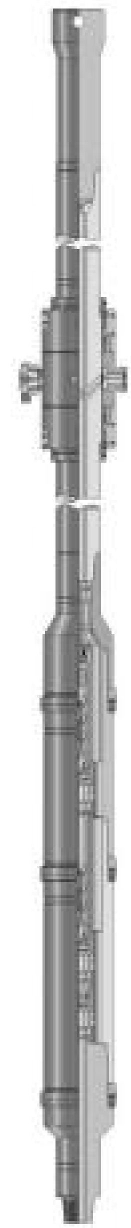


Figure 29. Top drive cementing head manifold

Existing studies on the use of 7” casing liners

The application of CwD technology in the operations within the Malay Basin has achieved a significant milestone by extending the deployment of 20" casing to an unprecedented depth of 1002 m Measured Depth (MD), a world record achievement as depicted in Figure 10. This pioneering approach was successfully demonstrated during the drilling of Well X in the year 2015.

The primary objectives underpinning the use of CwD in this project were aimed at optimizing drilling efficiency by effectively reducing Non-Productive Time (NPT), primarily resulting from challenges associated with wellbore stability and loss circulation.

The Malay Basin presents a tertiary trans tensional extensional geological setting, hosting two distinctive petroleum systems: the Oligocene-Miocene Lacustrine total petroleum system and the Miocene-coaly Strata total petroleum system. Hydrocarbon generation from source rocks commenced during the middle Miocene at burial depths ranging from approximately 1000 to 3500 m. These hydrocarbons are ensnared within the middle to late Miocene transgressional folds, draped anticlines, and certain stratigraphic traps [35]. The lithological composition of Well X predominantly consists of shale-siltstone and sandy formations. However, the shallow sedimentary arrangement tends to be relatively soft and susceptible to washout.

An analysis of offset well data revealed that among the 12 wells examined, 7 experienced partial or total loss incidents, with loss rates varying from approximately 60 barrels per hour to around 500 barrels per hour. This challenge strongly catalyzed the consideration of CwD for the top-hole section drilling.

Following a comprehensive risk analysis, a strategic decision was made to adopt a 20" CwD approach, specifically employing a 20" conductor casing for the top-hole drilling while eliminating the original 30" casing from the initial well construction plan. To counteract potential loss circulation observed in two adjacent wells, the conductor casing was designated to be positioned between 750 m and 1000 m depths. However, the maximum setting depth for the casing was limited to 1100 m due to the medium risk of encountering shallow gas. The selected conductor casing was the 20” SL-BOSS 133ppf X-56, characterized by a maximum torque value of 35.9 kft*lbs, an optimum torque value of 33.2 kft*lbs, and a minimum torque value of 30.5 kft*lbs. The torque calculations incorporated an 80% safety factor based on the maximum make-up torque for the casing. An engineering analysis conducted at 1000 m MD indicated a maximum calculated drilling torque of 27,696 ft lbs, with friction factors of 0 in cased hole and 0.4 in open hole, both well within the specified 80% limit.

In terms of hydraulic design, a plan was formulated to pump 8.6 ppg seawater at a minimum rate of 1000 gpm. The Plastic Viscosity (PV) and Yield Point (YP) for the mud design were set at 10 cP and 20 lbf per 100 ft^2, respectively. This design would lead to a total system pressure loss of 77% and generate Equivalent Circulating Density (ECD) ranging from 9.1 to 9.6 ppg. The annular velocity was consistently maintained above 160 ft min^{-1}. The execution involved the deployment of a 23"x 20" CwD, which was run into the hole to a depth of 111 m MD (Seabed) and subsequently drilled down to 1002 m MD using seawater. A regimen of hi-vis fluid was pumped after each stand drilled, and an additional pumping was done at Total Depth (TD) to ensure thorough hole cleaning. A cumulative interval of 891 m was drilled at the bottom in a span of 32 hours. The average drilling parameters encompassed a 30 m h−1 Rate of Penetration (RoP), a 900-gpm pumping rate, a 4 klbs Weight on Bit (WoB), and an 80-rpm rotating speed. It is noteworthy that the RoP was deliberately controlled to avert potential vibrational issues, as encountered in previous wells. To prepare for cementing operations, the bottom hole was effectively circulated clean, and a 10 ppg mud was displaced.

The observed torque values at the surface varied from 4 to 18 kft lbs, significantly lower than anticipated. Furthermore, the total rotation of the casing string was maintained below the threshold at which casing string failure could potentially occur.

Remarkably, the utilization of CwD, combined with the successful elimination of loss circulation during the casing drilling operation, contributed to the absence of any accidents during the entire 32-hour drilling duration for Well X [36]. Importantly, the drilling process to a depth of 1002 m MD revealed the absence of tight spots and stall-related issues, signifying effective hole cleaning practices.

Assessment of cost-effectiveness and safety considerations in drilling operations

The primary aim of the optimization process is to decrease drilling time and the associated cost for each well [37]. Engineers utilize drilling optimization to enhance the efficiency and success of well drilling. Specific goals of directional drilling include achieving high-quality boreholes, robust control over direction, capacity for high-angle builds, maximum durability, optimal penetration rate (ROP), and minimal non-productive time. These objectives can be met through meticulous design, encompassing optimization of hole and casing sizes, casing seat selection, casing load design, horizontal well trajectory, and the application of innovative techniques [38].

To optimize casing design and meet the objectives of well plans, alternative solutions are necessary. These options encompass the quantity of casing strings, casing seat placements, and cementing heights within the confines of available resources [39]. Determining casing setting depths is based on the well's pore pressure and fracture pressure, often obtained from an offset well. Additional design considerations such as kick tolerance and constraints related to differential sticking are also factored in [40].

A meticulously planned wellbore trajectory is crucial for directional and horizontal drilling, particularly in multi-well platforms where numerous factors need to be considered before finalizing the well's path. Essential mathematical formulations must be developed to accurately reflect changes in directional well planning and profiles, contributing to improved well trajectory [41].

Collaboration with the team from the initial stages of well design is essential to minimize drilling expenses and ensure a safe and regulated well completion [42]. Lummuas introduced the philosophy of optimized drilling, suggesting the use of the first well's data as a foundation for calculations and applying optimal designs and methods to subsequent wells. This approach accelerates the achievement of a field price of $6.00 per foot [43]. Optimal design and methods empower operators to drill more wells annually and develop wells that might otherwise not be economically viable.

Wells drilled with standard casing and bit sizes are referred to as "fat designs". In most fields worldwide, wells adhere to a three-section hole size structure: the surface hole with a diameter of 17 1/2" (13 3/8" casing), the intermediate hole with a diameter of 12 1/4" (9 5/8" casing), and the production hole with a diameter of 8 1/2" (7" casing), as depicted in Fig. 1 [44]. On the other hand, "slim hole design" involves reducing hole sections and casing sizes to the smallest functional dimensions. A risk-based approach can be adopted to align with the purpose of the well, considering initial cost savings related to hole size, steel/casing, disposal, and fluid requirements [45].

Slim hole drilling was a cost-effective option in the 1950s, yet its popularity declined in the subsequent decades. In the 1980s, Sweden pioneered a slim hole technique that slashed shallow reservoir drilling costs by 75%. Shifting market dynamics in the late 1980s led to a renewed interest in slim hole drilling, driven by flat oil prices and the need for cost-effective exploration. Since then, slim hole drilling has emerged as an alternative to conventional oil and gas drilling, with advancements in well completion techniques further enabling its widespread use in the early 1990s [46].

Calculation: comparison of liner and production casing time

This comparison primarily revolves around two critical factors: time and safety. As mentioned earlier, the 7" casing liner falls short of reaching the surface. Therefore, we find ourselves in a situation where a tie-back operation becomes essential. This tie-back is necessary to connect the liner to the wellhead by utilizing a casing hanger. This hanger effectively supports and secures the casing onto the wellhead housing. Let us delve into the key considerations regarding time and safety:

1. Time Efficiency: One of the primary factors favoring the use of the 7" casing liner is the time-saving aspect. When opting for the liner, we can potentially save a significant amount of time compared to running the complete production casing. The time saved in running the liner typically falls within the range of 1 to 3 days, which can be critical in drilling operations.
2. Safety Concerns: While time efficiency is crucial, safety remains paramount in any drilling operation. Both scenarios, whether running the liner or the complete production casing, require several critical operations that must be carried out with utmost care to ensure safety. These operations include:
    - Killing of the Well: Safely shutting down and controlling the wellbore to prevent uncontrolled flow of fluids or gas.
    - Pull Out of All Old Completion Assemblies: Carefully removing all existing completion equipment from the wellbore, ensuring no damage or mishaps occur during this process.
    - Running In-Hole Bit and Scraper: The introduction of the bit and scraper must be executed meticulously to avoid any complications downhole.

- Performing CBL (Cement Bond Log): This diagnostic test is critical to assess the integrity of the cement bond between the casing and the formation, ensuring the well's structural integrity.
- Running hole 7” casing bridge plug
- Performed cement plugs
- Cutting the Old Production Casing and POOH (Pull Out of Hole) to the Surface: The removal of the old production casing must be conducted safely to prevent any damage or hazards to personnel and equipment.
- RIH 9"5/8 Whipstock assy. Orientate and set Whipstock. Mill the window in 9"5/8 casing.

It is important to highlight that both scenarios involve these crucial safety-sensitive operations. Therefore, while the 7" casing liner may offer time-saving benefits during the initial installation, the overall safety of the operation remains a paramount concern that demands meticulous planning and execution. Balancing these factors is essential to ensure the success and integrity of the well completion

Killing of the well:

Well killing is the operation through which the formation fluid is replaced by completion or workover fluid (or killing fluid). This fluid has a density that counterbalances the pore pressure so that at the end of the operation the well head pressure is brought to zero.

There are basically three (3) method uses for the killing of the well

1- Circulation: Among the various well killing methods, circulation is (with Bullheading) the most commonly used; it comes after any other applied method because a well can be said to be under control only after a conditioning circulation has been completed.

    1.1 <u>Reverse circulation:</u> The killing fluid is pumped at the required density in reverse circulation (casing IN / tubing OUT) until a complete conditioning is obtained, density of the inlet fluid = density of outflow and well head pressure = zero.

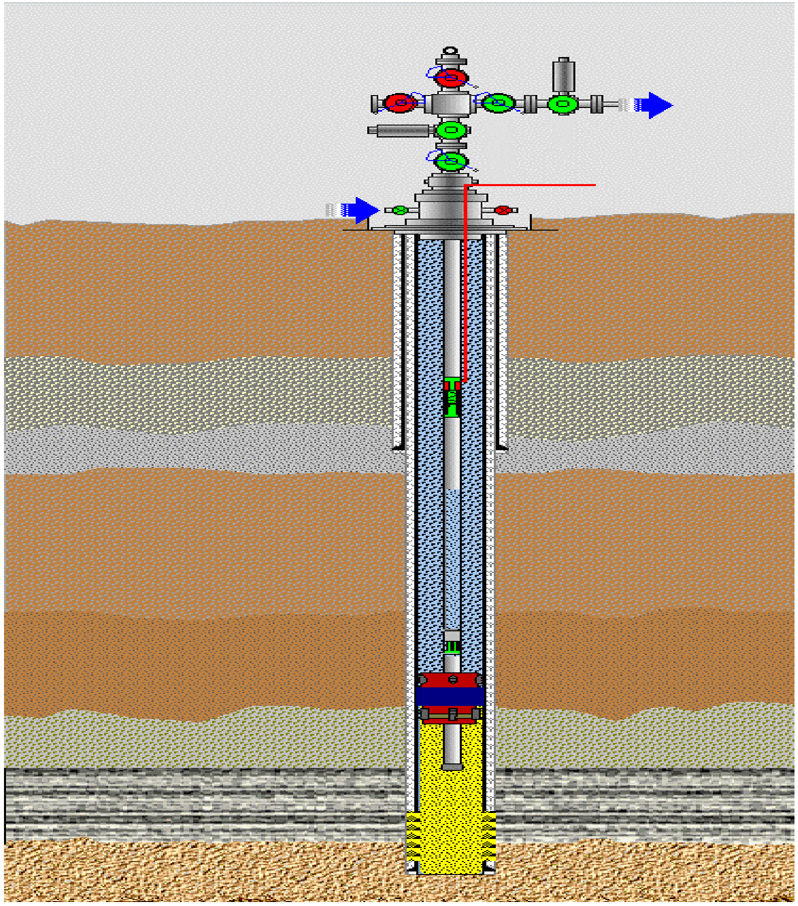


Figure 30. Reverse circulation

1.2 Direct circulation: Once the well has been conditioned in reverse circulation, before going on with the operations it is necessary to carry out a direct circulation (tubing IN / casing OUT) and then performed a flow check.

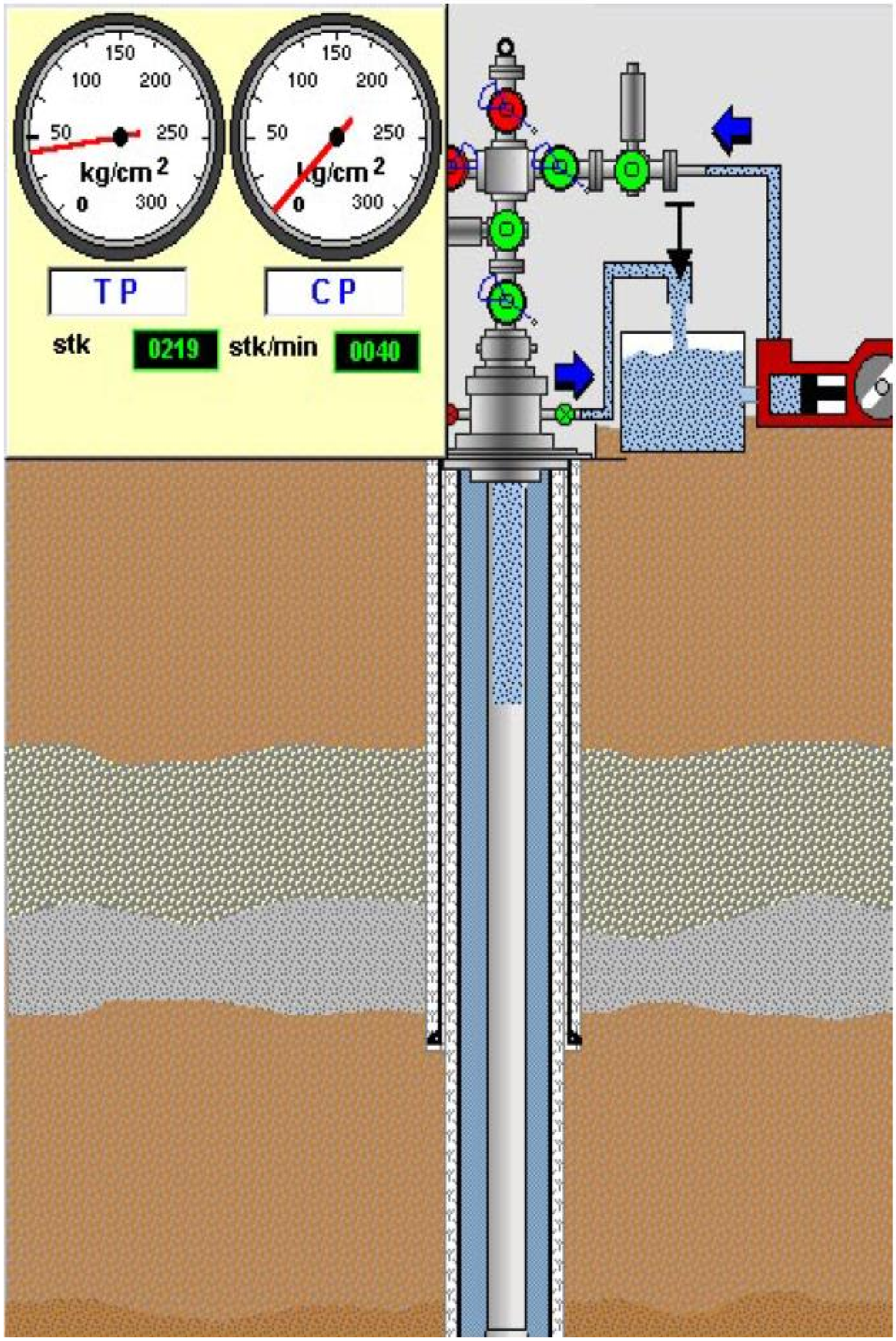


Figure 31. Direct circulation

2- Bullheading: Bullheading means to pump in the well a quantity of fluid which is equal to: Inner string volume + volume below the packer, making the formation to absorb the fluid that is in the tubing, this operation is done with the return (annulus back side) closed.

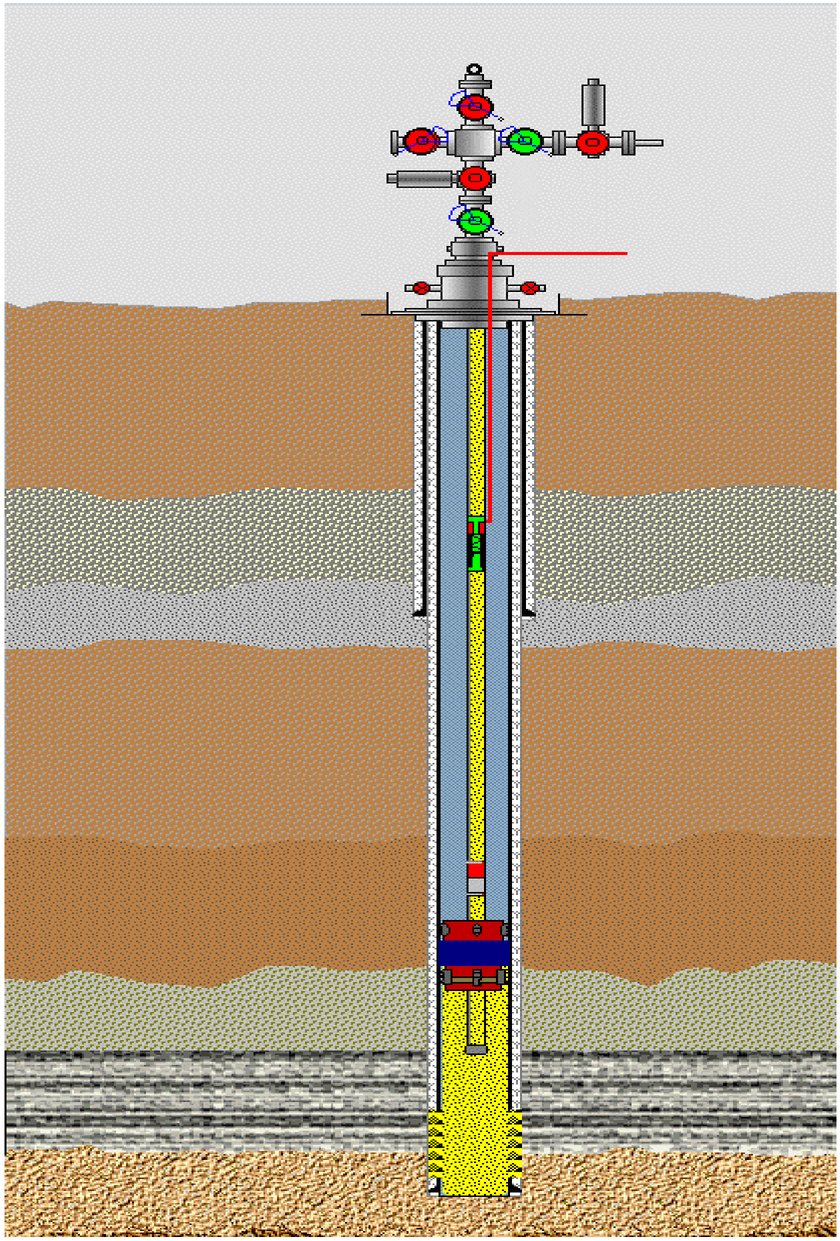


Figure 32. Bullheading

3- Lubricate and bleed: Lubricate and Bleed (alternate pumping and bleeding) consists of progressively bleeding off the gas in the well and replacing it with mud with adequate density. The lubrication and bleed technique are also used as a completion of the volumetric method to expel the gas cushion from below the BOP, keeping the bottom pressure constant.

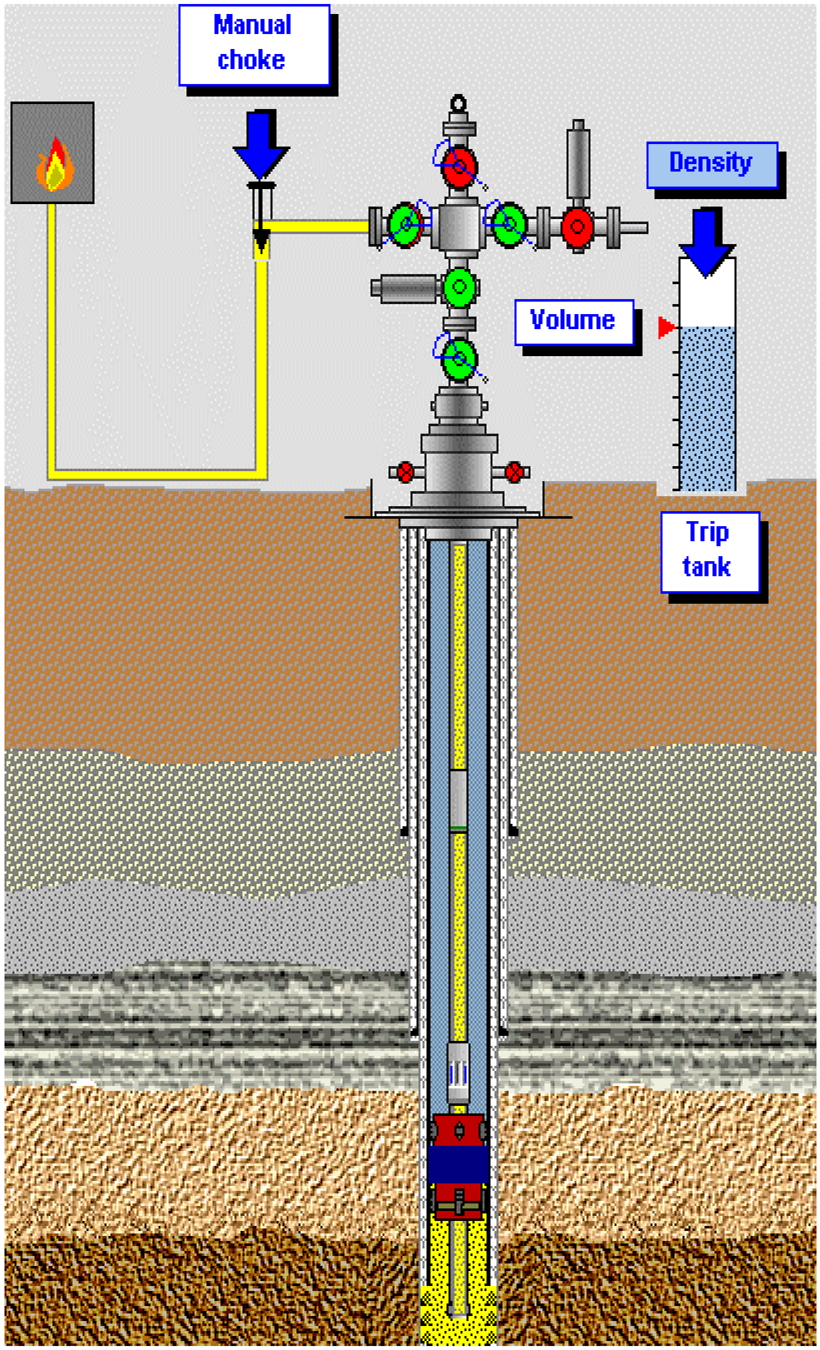


Figure 33. Lubricate and bleed

Pull out of hole old completion:

Prior to POOH old completion string, it is necessaire to respect couple of operations among that: Killing of the well using the technics explained above.

Remove Xmas tree: This operation consists of removing the Xmass-tree in order to install Blow out preventer (BOP) safety device.

Below are the following steps:

1- Closed the SCSSV (surface Control Sub-surface safety valve) safety devices installed on the completion string in order to be close once the pressure on the control line 1/4” in bring to zero, and the flatter installed on the valve will the close the inner string path, no fluid will pass through out the completion assembly.
2- Insert BPV (Back Pressure Safety Valve) valve installed on the tubing hanger housing in order to act as the second safety barrier from the SCSSV. It is very important for the safety of the well.

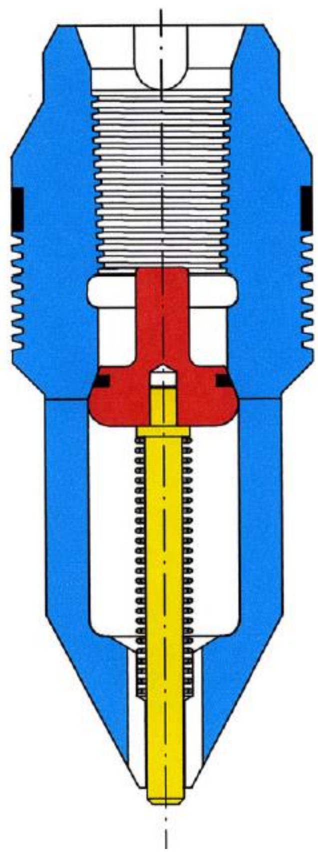


Figure 34. Back Pressure Safety Valve

3- Nipple down X/mass Tree: Remove the XMT onto the well head.

4- Install the BOP stack.

   - Pressure test BOP stack as per program, testing kill / choke lines and choke manifold, stand pipe manifold and all necessary lines.

5- Retrieved BPV onto the tubing hanger housing.

6- Break circulation in direct mode, circulating twice well volume follow by the static flow check.

7- Install tubing handling equipment (single joint elevator, side door elevator, rotary slips) hydraulic power tong and hydraulic power pack.

8- POOH old completion:

   Unset packer if installed by pulling on the string.

   Remove the tubing hanger from seat

   Lift the string with the side door elevator

   Recover the safety clamp if installed.

   Pull out and recover all completion tools (SCSSV, completion packer, landing nipple, sliding sleeves door, half mule shoe...), while filling the well from trip tank.

Running In-Hole Bit and Scraper

The scraper serves the purpose of eliminating mud cakes, cement accumulation, drill cuttings, rust, tool residues, and similar debris from the inner casing surfaces. It should be employed whenever there is a need to set a packer or bridge plug into the well, as any potential scale deposits could potentially obstruct the passage when deploying these tools. Scraping action can be achieved both with reciprocation of drill string up / down (vertical reciprocating motion) or with a rotating motion This operation is performed 50 m above and below the packer expected setting depth.

It is normally run in the well with running tools, to which it is connected by a cross-over (Box to box) bit sub; a bit must always be connected to the bottom thread. The purpose of the bit is to guide the scraper and prevent the debris inside the well to block up the circulation hole. Moreover, the bit can be used for getting around possible obstacles.

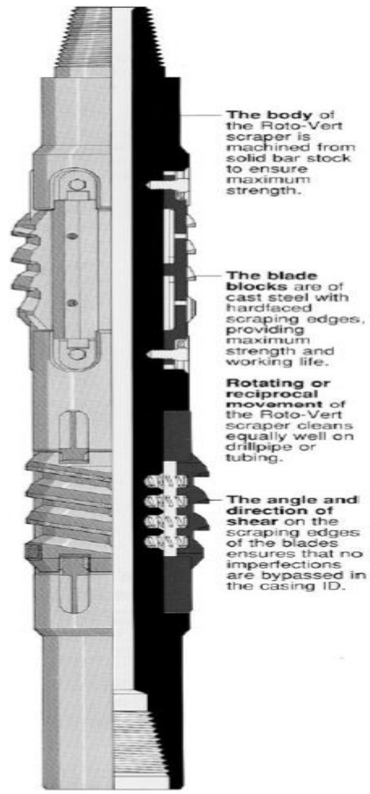


Figure 35. Casing Scraper

Performing CBL (Cement Bond Log)

In order for the cementation of a casing to guarantee hydraulic insulation of all drilled-in layers, it is necessary that:

Advancements in well cementing technology have come a long way, evolving significantly since the first casing was cemented back in 1903. Today, cementing techniques cater to a wide range of scenarios, from conventional boreholes to more challenging conditions like arctic wells, ultra-deep and high-temperature holes, water-sensitive formations, and precise placement in the face of fractured or highly permeable formations.

The foundation for achieving a successful primary cement job has been established for many years. The key lies in well-thought-out design principles that draw from an in-depth understanding of formation characteristics, cement properties, and pipe behavior. Additionally, controlled placement techniques that account for fracture gradients play a crucial role in this process. Considerations such as:

Determining the minimum practical mud density and viscosity.

Selecting the appropriate cement type.

Managing turbulent flow conditions.

Optimizing the size of pre-flushes.

Proper centralization of casing.

Employing scratchers.

Handling the pipe with care.

Making the right choice regarding casing.

For over a decade now, the oil industry has utilized wireline well logging, particularly cement bond logging, to identify the presence of cement behind the pipe and evaluate its bonding to both the casing and the formation. However, interpreting Cement Bond Logs (CBL) has been a topic of debate since their introduction, and despite their potential, they are often misused or misunderstood in the field.

Compounding the issue is the lack of standardization in the tools used by service companies, which employ different gating systems, spacings, frequencies, and more. This lack of consistency, along with challenges like sonde centering, tool calibration, and incomplete information on log headings, has occasionally perplexed petroleum engineers.

In this discussion, we delve into CBLs, exploring the information they provide and how they should be interpreted. Through comparative field tests and specific examples, we highlight potential pitfalls and misinterpretations that can arise if logging operations are not meticulously designed and executed. A typical CBL log includes an amplitude curve that measures a specific aspect of the acoustic signal. However, interpreting this curve alone can be inconclusive and misleading. Therefore, supplemental data are commonly included, such as:

Transit time to the first event of the acoustic signal reaching a minimum or predetermined amplitude.

Amplitude of the formation signal.

Variable intensity.

Oscilloscope pictures (additional measurements, although not directly related to cement bonding).

In addition to these, the CBL can also incorporate other measurements like the gamma ray curve and casing collar log (CCL), even though they may not be directly tied to cement bonding.

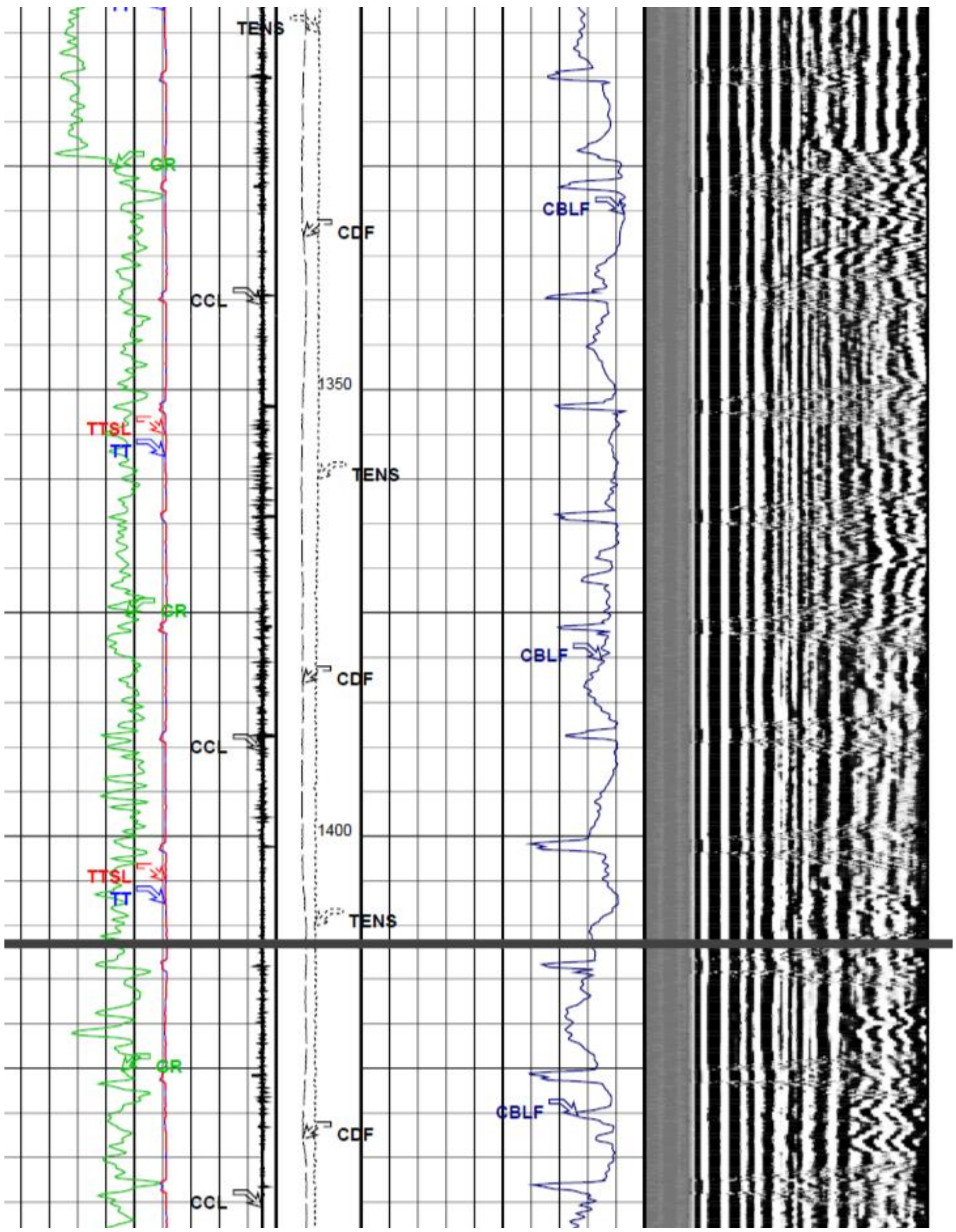


Figure 36. Cement Bond Logs

Running hole 7” bridge plug on 3-1/2” drill pipe – Case study Mboundi field well MBD2004 D

The purpose of Running in hole a 7” bridge plug into the well is to create isolation and prevent the migration of the formation gas inside the well. In Mboundi field, onshore Congo, the Halliburton EZ drill SVB was running in well MBD-2004 D, following this procedure: M/U the Bridge plug BHA, consisting of a 7” Halliburton EZ drill SVB, a running tool, and 2 x stands DC 4"3/4 components. RIH the 7” Bridge plug BHA on a 3-1/2” drill pipe from the surface to the specified setting depth. Record the weight applied in both upward and downward directions, which amounted to 80 tons and 45 tons, respectively. Break the circulation with flow rate (FR) at 300 lpm and a standpipe pressure (SPP) of 200 psi. Gently reciprocate the string, moving same up and down by 1 meter above and below the setting depth. Apply 35 right-hand turns. Pull up to 85 tons, equivalent to one-third of the tension sleeve load, and hold this position for 1 minute. Then, pull up to 92 tons, which constitutes two-thirds of the tension sleeve load, and hold for another minute. Proceed to pull up and separate the tension sleeve, confirming that it functions correctly. Lower the assembly back down and slack off by 7 tons, maintaining this tension for 10 minutes. Release the running tool. POOH running tool 5 meters above the Bridge plug. Close the Annular BOP (Blowout Preventer). Perform a pressure test on the Bridge plug at 3000 psi for 10 minutes, ensuring it holds the pressure without issues. Once confirmed, release the running tool and POOH same from the hole until it reaches the surface.

Cement plug.

Once the 7” bridge plug has been run and set in the well, a pressure test was conducted to ensure the bridge plug's integrity. The subsequent procedure involves preparing and lowering the 2”-7/8 tubing EU cement string into the well, cement string BHA is 152 meters. The cement string is run on 3-1/2” drill pipes down to a depth of 2660 meters.

The process for the first cement plug (from 2660 to 2510 meters) is as follows: First, 3 barrels of spacer were pumped, and the line was pressure tested at 3000 psi for 10 minutes, which was successful. Then, 2.99 m3 of 1.9sg Tail slurry was mixed in a batch mixer. Following that, 2.66 m3 of water spacer with a specific gravity of 1.0 sg were pumped. From the batch mixer, 2.99 m3 of Tail slurry with a specific gravity of 1.9sg, mixed with 3.9 tons of "G" cement and 1.77 m3 of mixing fluid, were pumped. Subsequently, 0.69 m3 of water spacer were pumped, followed by displacing with 6.84 m3 of 1.18sg mud. The 2-7/8” cement string was pulled out of the hole from 2660 meters to 2496 meters. The Annular BOP was closed, and a reverse circulation was initiated, resulting in the disposal of 2.5 m3 of mud contaminated with spacer and 0.8 m3 of mud contaminated with cement. The 2-7/8” cement string was then pulled out of the hole from 2496 meters to 2437 meters, Wait on cement (WOC).

The next step involved running in hole (RIH) the 2-7/8” cement string with 3-1/2” DP (15.5#) while maintaining a flow rate (FR) of 350 lpm and a standpipe pressure (SPP) of 400 psi. The cement string was tagged at 2516 meters, followed by circulating the hole volume. The cement string was subsequently pulled out of the hole from 2516 meters to 1765 meters.

For the second cement plug (from 1765 to 1615 meters), the procedure was as follows: 3 barrels of spacer were pumped, and the line was pressure tested at 3000 psi for 10 minutes, meeting the requirements. Then, 3 m3 of 1.9sg Tail slurry were mixed in a batch mixer. This was followed by pumping 2.67 m3 of water spacer with a specific gravity of 1.0 sg. From the batch mixer, 3 m3 of Tail slurry with a specific gravity of 1.9sg, mixed with 3.9 tons of "G" cement and 1.77 cubic meters of mixing fluid, were pumped. Subsequently, 0.69 m3 of water spacer were pumped, followed by displacing with 3.87 m3 of 1.18sg mud. The 2-7/8” cement string was then pulled out of the hole from 1765 meters to 1591 meters. The Annular BOP was closed, and a reverse circulation was initiated, resulting in the disposal of 5 m3 of mud contaminated with spacer and 0.7 m3 of mud contaminated with cement. Finally, the 2-7/8” cement string was pulled out of the hole from 1591 meters to 151 meters.

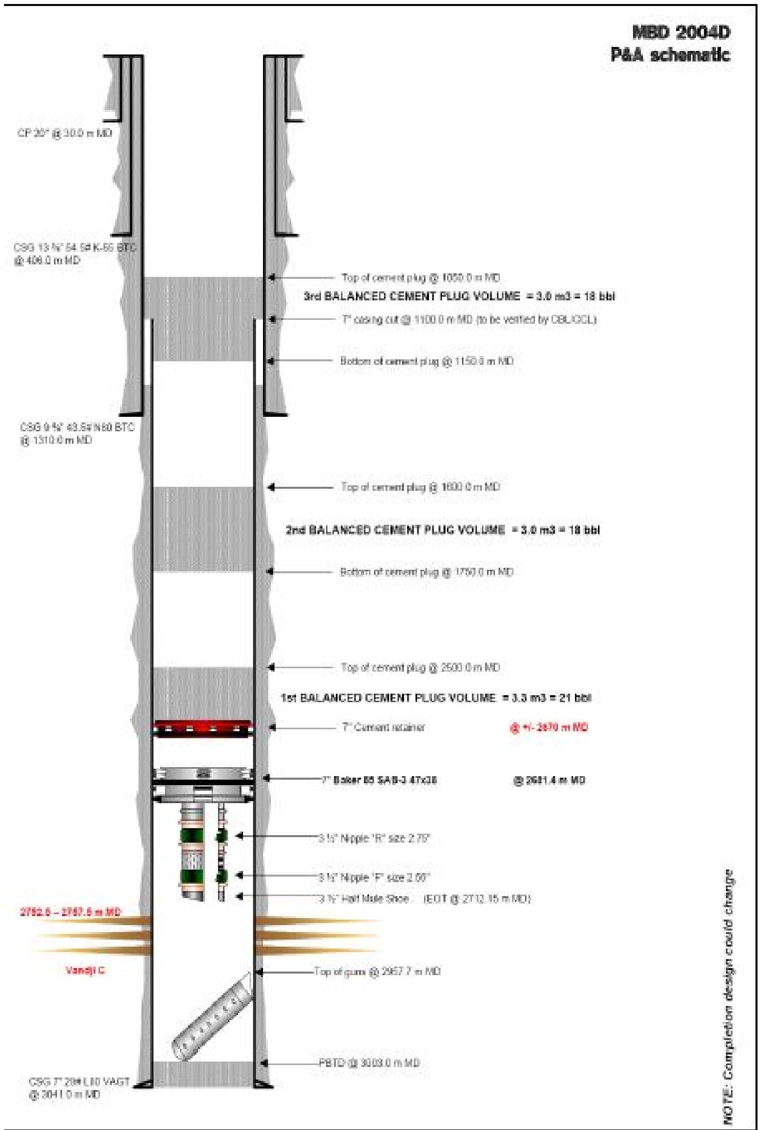


Figure 37. Well sketch

Cutting the Old Production Casing and POOH (Pull Out of Hole) to the Surface.

The procedure involves Making up the Weatherford BHA: 6 1/8" Taper mill + X/ over + 7" Casing cutter + 6" Non rotating stabilizer. M/U TDS with 1 joint of 3"1/2 DPs 15.5# and connect same to Weatherford BHA. Perform surface test with FR=500 lpm; SPP=200psi: Observed Knives open, Measure Knives length 1-1/4". Ok. RIH Weatherford Cutter BHA on 3-1/2" 15.5 # DPs to 853 m (851 m cutter depth). Perform 7" Csg cut as follow: Pick up weight=30T, Slack off weight =30T, record parameter: 100 RPM (Trq=1000 ft.lb,weight=30 T). Start cut 7" casing with 100 RPM, FR= 500 lpm, SPP=1550 psi, Trq=2000-3000 lb. Observed 750 psi pressure drop. Stop pump and rotation, control window with 2-ton slack off weight. Close 2"7/8-5 Variable Bore Ram (VBR) and circulate in direct w/FR=550 lpm, SPP= 800 psi. Had full return through "B" annulus. Circulate till clean return. POOH 7" Cutter BHA on 3 1/2" 15.5# DP's from 853m to surface. L/D 7" cutter BHA. M/U and RIH Weatherford BHA: 7" Csg Pack off + 5 3/4" Itco spear mandrel + 5 3/4" stop sub mandrel +6 1/2" X/Over + 6 1/2" Bumper sub, 1 x 5 " 19.5# G105 DP to 13.5 m. Engage spear on 7" casing and pull csg freely till rig floor. POOH and L/D 7" casing from 851 (cut depth) to surface.

RIH 9"5/8 Whipstock assembly Orientate and set Whipstock. Mill the window in 9"5/8 casing.

M/U 9"5/8 Weatherford Whipstock assembly from bottom: Hydraulic Permanent Packer + 2° Whipstock 9"5/8 43.5 - 58.4 lb/ft (with shear bolt at 24 Tons) + Milling assy (8"1/2 Steering Mill + 8"1/2 Secondary +Lead Mill OD 8"1/2 + nr.4 x 28/32" nozzles) + 6"3/4 DC + 6"3/4 MFR + 6 3/4" HEL (MWD). Connected Milling assy with the shear bolt and attached the hydraulic control line. Fill up with oil as per contractor instruction**.** Oriented Whipstock face to MWD Tool scribe line on Rotary Table in direction of face of ramp. Upload MWD datas, M/U and RIH Whipstock BHA with 1 x 6"3/4 DC to 48 m. Perform shallow test with FR=1600 lpm; SPP=480 psi. OK. RIH Weatherford whipstock assembly with 12 x 6"1/2 DCs + 17 x 5" HWDP to 316 m. RIH Weatherford whipstock assembly on 5" DP 19.5# G105 single by single to 747 m. Continue RIH Weatherford whipstock assembly on 5" DP 19.5# G105 to 821m. (Packer depth=819,5m).

Performed survey & Orientated Whipstock to 46° right side. (FR=1500 lpm, P=700psi) PUW= 56 T, SOW=48 T. Increase flow rate to 3000 lpm for 10 min, SPP=2400 psi and set Whipstock. Apply 24 Tons Slack off and shear bolt OK. Test whipstock with 27 Tons of Slack off. Ok. Determinate free rotating torque at 60 rpm = 2000-3000 Kft.lb; 100 rpm= 3000-4000 klb.ft. PUW= 53 T. Mill window on 9"5/8 Csg from 812 m to 818 m with WOB= 5–15-ton, RPM= 100, TQ= 3000-10000 ft*lb.FR= 2000 lpm, SPP= 1100 psi,

NOTE: TOP WINDOW at 812 m - BOTTOM WINDOW at 818 m

Drill 8"1/2 rat hole from 818 m to 824 m WOB= 5–15-ton, RPM= 125, TQ= 3000-10000 ft*lb.FR= 2000 lpm, SPP=1100 psi, Last sample @ 824 m: 60% claystone, 40% cement.

Reaming Up/Down and dress Window several times. OK. Pump Hi-vis pill and circulate out. Passed several times through the window without rotation and circulation. OK.

POOH Milling assy from 824 m to surface, Download data from MWD. Inspected milling assy: Lead mill: 1/4" undergauge - Secondary mill: 3/16" undergauge - Steering mill: in gauge.

Financial content - cost implications

The financial dimension constitutes a fundamental and significant factor within the realm of drilling activities, and a comprehensive examination has been undertaken in relation to the operations previously elucidated. This comprehensive evaluation underscores that the running in hole of a 7-inch casing liner into the wellbore will yield tangible benefits for the oil company, potentially leading to a reduction in drilling time by a notable margin, estimated to be in the range of 7 to 10 days, thus offering substantial cost-saving opportunities for the future endeavors of the company. The average daily cost for drilling rig is 150 – 200 k USD / day including services companies cost. The table below shows the comparable 7” liner hanger time estimates and 7” production casing.

Operations	7" Liner hanger (Hrs)	7" Production casing (Hrs)
R/U SL. Bullheading well. Injection test. Install BPV. R/D SL equipment. Prepare Brine Cacl2.	22	22
Nipple Down X/Mass Tree.	3	3
N/U BOP Stack + flow line.	18	18
BOP pressure test + R/U handling equipment. M/U Landing string 3"1/2	10	10
Unlatch pkr Anchor seal Assy. No success	3.5	3.5
R/U EWL. RIH Power cutter till 2685m. Record CBL-CCL-GR. Cut tbg at 2671m. POOH	15	15
Circulation with WBM +POOH completion (2671 m)	23	23

RIH 6"bit + 7" Scaper while M/U 3 1/2" DP. Tag cutting tubing @ 2673 m. Scraper F/2672 m T/2600 m. Circulate B/U. POOH Scraper to surface. Rack back 3"1/2 DP	24	24
RIH 7" Bridge Plug to 2662 m on 3-1/2"DP. Set BP. Test BP at 3000 psi. POOH setting tool.	16	16
M/U & RIH 2-7/8" cement stinger to 2660 m	7	7
PJSM. Perform 1st Cement plug @ 2660-2510 m.	3	3
POOH cement string at 2496 m and reverse out 2 times string volume. POOH to 2437 m. WOC. RIH and test cement plug position.	14	14
POOH cement 2-7/8" stinger up to 1765 m.	2	2
PJSM. R/U SLB HP lines. Perform 2nd Cement plug @1765-1615 m.	2	2
POOH cement string at 1590 m and reverse out circulation string volume. POOH 2"7/8 cmt stinger to surface.	6.5	6.5
RIH 7" casing cutter to 1051 m, taking into consideration several attempt to retrieve the casing	0	105
R/U and Perform CLB-VDL-CCL log in 9-5/8 casing.	6.5	6.5
M/U + RIH whipstock with MWD. Orientate and set Whipstock	17	17
Various operation: comparison between 7" casing and 7" liner		
Running in hole the 7" casing	41	96
Sum (Hrs)	233.5	393.5
Days of activities	10 days	17 days
Save days	**between 7 to 10 days is saved**	

Conclusions and future disclosures

In conclusion, the research conducted in this master's thesis has demonstrated the significant potential for enhancing drilling operations through the utilization of a 7" casing liner. The central objective of this study was to assess the cost-effectiveness and safety implications of employing this technology in the oil and gas drilling industry.

Our findings have provided valuable insights into the advantages of using a 7" casing liner. Firstly, it was evident that the incorporation of this liner can lead to substantial cost savings in drilling operations about 7 - 10 days drilling rig cost saving. By reducing the risk of wellbore instability, well control issues, and loss of circulation, drilling efficiency can be significantly improved. The resultant reduction in non-productive time and the need for costly remedial measures contribute to overall cost-effectiveness. Additionally, the liner's ability to isolate troublesome formations and minimize formation damage can further enhance well productivity and extend the operational lifespan of the well.

Furthermore, the safety benefits of implementing a 7" casing liner were a prominent aspect of this research. It was evident that this technology plays a crucial role in safeguarding drilling operations by preventing wellbore collapse, blowouts, and other hazardous incidents. The liner's ability to provide a barrier between the formation and drilling fluids not only enhances well control but also mitigates the risk of environmental damage. Moreover, the reduction in HSE (Health, Safety, and Environment) incidents associated with drilling operations can significantly improve the industry's overall safety record.

It is worth noting that the effectiveness of a 7" casing liner depends on various factors, including proper design, installation, and maintenance. Therefore, it is imperative for drilling professionals and operators to adhere to best practices and standards when implementing this technology.

In conclusion, the research presented in this thesis strongly supports the adoption of a 7" casing liner as a cost-effective and safe means of enhancing drilling operations in the oil and gas industry. The economic advantages, coupled with the significant improvements in operational safety, make it a valuable asset for drilling projects. However, it is essential for industry stakeholders to continue researching and developing innovative techniques and technologies to further optimize the use of casing liners and ensure their continued effectiveness in drilling operations. By doing so, we can continue to push the boundaries of drilling efficiency and safety, ultimately benefiting the industry as a whole.

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