



POLITECNICO DI TORINO
Department of Environment, Land and Infrastructure Engineering

Directional Drilling Tools Assessment and the Impact of Bottom Hole Assembly Configuration on the Well Trajectory and Operation Optimization

Master's Thesis in Petroleum and Mining Engineering
by

ABDULGHAFFAR JEBUR

Supervisor

Prof. RAFFAELE ROMAGNOLI

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Abstract

Directional drilling and steering a well with a 3D trajectory path has become very popular to satisfy multiple objectives such as enables reaching farther and more complex targets, surface versus target location, well anti-collision on a crowded platform, completion and artificial lift needs, landing the reservoir section in a favorable direction, and maximizing the length of the lateral for optimum production.

Accurate directional design and wellbore positioning are some of the pillars of the safety and economy of the project and affect the entire drilling program. The operator's objective mainly is to drill the section from shoe to shoe in one run by increase bottom hole assembly (BHA), surveying (MWD/LWD), and drill bit consistency and using optimized parameters. This must be validated by the ability of the planned BHA to drill the well path and deliver the expected build/drop/turn/hold as per required dogleg severity (DLS), thus, the design and selection of BHA is a crucial aspect.

Since the BHA is considered the drill string's backbone which is the main element in the successful well path drilling and different configurations can change the drilling performance noticeably. So, this thesis studied these three BHA components, investigate the different technologies and the deflection methods used in directional drilling, and evaluating its BHA that is used to control the directional drilling with its application criteria and areas. Details methods of steerable systems and the new technology now available to the high volume market. Investigate drilling surveying (MWD/LWD) and data transmission techniques and the recent advanced technology.

Because the bit design should be matched with the BHA for giving a good performance, the thesis documents the technologies of the drill bit, specifications, and factors involving improving its design, requirements of operational compatibility, functional challenges, and stabilization.

Moreover, it provided the technical characterizations of these keys in the BHAs and it introduced what these components pose of some limitations and risks that must be identified and managed closely, to avoid sacrificing the overall success of a project.

This work came up with the BHA engineering considerations in the planning phase and how the total system consistency is necessary to pave the way to the design and modeling phase that will lead to delivering the most appropriate selection.

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Abbreviations

I	I nclination
L	L eft
M	M iddle
R	R ight
AZ	AZ imuth
BA	B it A ggressiveness
BH	B ottom H ole
BI	B it I nstability
CS	C ompressive S trength
CH	C ased H ole
DC	D rill C ollar
DD	D irectional D rill(ing/er)
DH	D own H ole
DL	D og L eg
DP	D rill P ipe
DS	D rill S tring
EM	E lectromagnetic T elemetry
GR	G amma R ay
HC	H ydrocarbon
in	i nch
ft	f oot/ or feet
PD	P ressure D rop
RF	F low R ate
MD	M easured D epth
MS	M ulti S tation
OD	O utside D iameter
OH	O pen H ole
QC	Q uality C ontrol or check
RS	R otary S teering
rev/gal	r evolution g allon
SF	S afty F actor
ST	S ide T rack

S&V	Shock & Vibration
TD	Total Depth
T&D	Torque & Drag
US	United States
SU	Soviet Union
WS	Whip Stock
AKO	Adjustable Kick Off
BUR	Build Up Rate
BHA	Bottom Hole Assembly
bps	bit per second
CDE	Conical Diamond Element
CPF	Cost Per Foot
deg	degree
DHM	Down Hole Motor
DSA	Drilling System Automation
DLS	Dog Leg Severity
HDL	High Dog Leg
DMS	Drill Mode Survey
DVS	Diameter Vertical Stabilizer
EOU	Elipse Of Uncertanty
ERD	Extend Reached Drilling
FEA	Finite Element Analysis
Fig	Figure
GPM	Gallon Per Minute
IFR	In Field Refrence
KOP	Kick Of Point
KSA	King Suadi Arabia
LWD	Logging While Drilling
max	maximum
min	minute(s)
MPT	Mud Pulse Telemetry
MWD	Measuring While Drilling
MSE	Mechanical Specific Energy
MSA	Multi Station Analysis
NPT	Non Productive Time
NOV	National Oil Varco
MSS	Magnetic Single Survey
PDC	Pollycrystalline Diamond Cutter
PDM	Positve Displacment Motor
S-T-B	PuSh The Bit
P-T-B	Point The Bit

RPM	Rotary Per Minute
ROP	Rate Of Penetration
RSS	Rotary Steerable System
RSB	Rotary Steerable Bit
RST	Rotary Steerable Tool
TCI	Tungsten Carbide Insert
Tem	Temperature
TSP	Thermal Stable Polycrystalline
TOB	Torque On Bit
TVD	True Vertical Depth
VDS	Vertical Drilling System
VMA	Valve Motor Actuator
WOC	Wait On Cement
WPU	Wellbore Position Uncertainty
WOB	Wait On Bit
WDP	Wired Drill Pipe
CPSM	Continous Proportional Steering ethod
DOCC	Depth Of Cut Control
DART	Design Application Review Team
GCAAT	Gyro Compass All Attitude Tool
HBUR	High Build Up Rate
HDLS	High Dog Leg Severty
HWDP	Heavy Weight Drill Pipe
NMDC	Non Magnatic Drill Collar
OWSG	Operator Wellbore Survey Group
RSDS	Rotary Steerable Drilling System
RSDBs	Rotary Steerable Drill Bits
RTPS	Real Time Productivity Searing
SBTB	Short Bit - To - Bend
UBHO	Universal Bottom Hole Orientation
WPTS	Wellbore Positioning Technical Section
HIDWG	High Inclination Drilling With Gyro
ISCWSA	Industry Steering Committee Wellbore Surveying Accuracy

Chapter 1

Introduction

1.1 Background

As the exploration for oil remain a priority for the countries in the world to sustain its energy resources, the continuous discovery of the different complex subsurface reserves, and technology with economics assist the continuous hydrocarbon extraction from the current reservoirs, directional drilling (DD) becomes more and more dominant in the well drilling. Drilling in the offshore by multi-well platforms also build upon DD.

Besides that, since the easy oil has not been much in hand, tapping these complex subsurface targets is facing more challenges which enforces engineers to improve the accuracy and designing of the directional drilling. New technology and optimizing of the drilling process are aiding the accuracy in reaching the required targets. Addressing several issues including enhancing total ROP and reducing drilling costs and the uncertainty related to boreholes placement, to eliminate the challenges in the directional drilling.

In the beginning, it was known all oil and gas wells were drilled vertically, this means the bottom of the hole was directly under the drilling rig. Later on, deviated drilling was entered the oil and gas industry.

Nowadays Production requires that wells be produced from a common area like platform and offshore locations will reduce the expense of placing production equipment offshore, or in the arctic. One platform can include several wellheads if wells are drilled directionally from one location. A platform reservoir drainage area depends on extended reach drilling (ERD), on that basis number of platforms and wells for each of them will be designed. This technology is maximizing the economics of hydrocarbon production and minimizing the environmental impact of the operations.

Considerations of platforms sizing is a crucial matter, for example, the structure of one platform cannot be seen and dive under sea level. The structure could be larger than two or three football fields and with tall more than the tallest buildings in the world. A load of the structure is important to the expense of this tall framework. Each ton of material on the decks will add accordingly to the costs, so space is a choice. Nonetheless, it essential that to drill as many wells as possible from one platform will save the big cost of the project, [1].

Although the high cost of these platforms, directional drilling has allowed the development of many subsea hydrocarbon pools in an economic aspect. However, companies are making every effort to reduce drilling costs for these production platforms. Its well-known investment of hundreds of millions or billions of US dollars for these platforms, before a single drop of oil or cubic foot of the gas, is produced, [1].

The BHA is the tools between the bit and the drill pipe which are the main component to achieve the required trajectory. Over the years, BHA has grown from one or two simple drill collars to quite a complex array of tools, stacking up above the bit about 500 to 1,000 ft. (150 to 300 m).

Many configurations of these BHA are adopted in the drilling industry, the degree of the complexity is different from one to another upon on the planning phase for the specified well. As we will see later, these configurations could be external or included in the drill string, the latter also has various classifications that were developed over the years to the more recent modern ones.

Technically, involving the drill bit, MWD/LWD, steerable motor, is used to deviate and control well paths, through adjusting the bent motor assembly at the surface and no any control on degree of motor bent in borehole. Shortage in this technique can be seen later.

In late 1990s, RSS have been invented to overcome shortcomings related to steerable motors through the capably for providing optimized directional control and reducing the drilling costs by improves ROP, more efficient whole cleaning, elimination of sliding mode drilling, obtain smoother trajectory, less chance of differential sticking, and drill further interval with one BHA.

However, using RSS has some concern like tools failure and cost of services etc., due to high technology of electrical and mechanical components. Furthermore, in problematic formation where there is a probably of losing BHA, expensive element in BHA will rise the cost in case fishing operation isn't succeed to fish the whole BHA. The cons and pros has been aforementioned direct the drilling program designer to evaluate selecting RSS as directional techniques compared with alternative techniques.

1.2 Motivation and Objective

Generally, through planning phase to drill the well, designer make the best efforts to find the optimum solution for selection the BHA whether it's conventional or more modern technique based on steerable system because some deviation techniques may introduce better performance comparing to others.

Since high percentage of the current drilled wells in the world upon on the most recent generation of BHA configuration, especially of bit type, MWD/LWD, and steerable system, so evaluating the development of these three basic elements in the BHA and assess its employments in the various subsurface situations can be generally considered with the following factors, the *main motivation* for this thesis:

1. The best engineering practice for performance assessment by evaluating trajectory of well for each type of BHAs, ROP, hole condition.
2. Directional drilling project bear highly cost, so that, any optimization in BHA selection, will improve the drilling operation from both an engineering performance and saving drilling time, thus saving quite amount of budget.
3. Supergiant fields are developed by high number of wells included in more than one drilling contracts, different well trajectories are selected in these numerous wells, so understanding the subsurface conditions with different BHAs and apply the most suitable one for giving high wellbore quality and less cost will be illuminate the company for the development operations.
4. Since matured and new fields are progressively developed, improved wellbore positioning is curial to optimally produce these fields because more wells are being drilled within tighter corridors in modern oil and gas projects.
5. Companies endeavor for seeking a new approaches enables the industry to utilize previously inaccessible reserves and drive field economic further, this mean the focus in maturing fields must be turned to the remaining smaller reservoir targets, so, the crucial aspect is the provision of technologies for the wellbore construction to access these remaining resources.
6. The continuous demands for new technologies as the current drilling environments and the challenging wellbore profile push existing proven technology to its limits or exceed its capabilities, especially in BUR and steering performance.

Chapter 2

Directional Control Techniques Overview and Comparison

2.1 History of Directional Drilling (DD)

Historically, in 1895, special tools and techniques were being utilized to recover the fish lost in the borehole, and this was the first directional drilling (DD).

Offshore oil reserves were in the subsurface of Huntington Beach, the first controlled directional well was drilled in 1930. Unfortunately, drilling was across lease lines to produce reserve belongs to another owner, resulting in legal problems. Two secret wells completed, at that time was used for unethical purposes that are, to consciously cross property lines in order to yield more oil than different producers in the field. Later on, in 1932 it was noticed that these wells had been deviated and bottomed under the sea, [2].

The bits, knuckle joints and whip-stocks were utilizing which was oriented by an early form of the single shot instrument, and directionally drilling into the offshore oil deposits.

No more attention had given to controlled DD until the time when a relief well was drilled to kill a blowout a wild well near Conroe, Texas in 1934. This techniques were used to touch the producing formation near the blowout and the drilling was near the surface location of the blowout, [2].

In 1941, the Soviet Union invented the turbo-drill. Then in 1944, the first horizontal oil well was drilled in the Franklin Heavy Oil Field, Pennsylvania, at a depth of 500 ft.

In the 1950s, the cluster wells began to be used. In the 1960s, DD was applied in the offshore oil field, such as the Gulf of Mexico and the North Sea. In the 1970s, the

PDM was presented by various companies, such as Dyna drill, Navi drill, Baker drill, Christensen, and Smith.

In the 1980s, to enhance the control accuracy and adaptability for DD, (MWD) was invented and widely applied, and the computer aids' drilling was also involved due to the application of computer techniques.

In the late 1980s, steerable motor drilling, involved with PDC drill bits as well as MWD was introduced, these technique enhanced the productivity of DD and the accuracy of placing the well trajectory. These tools decreased the requirement for continuous changing of the BHA that is more required with rotary drilling and could employ the MWD survey to apply more control over the well's trajectory. A key to the quick development of horizontal drilling in the mid-1990s was beyond the steerable motor framework.

Nonetheless, operators noticed the constraints of these devices. Drillers frequently need to exchange between different modes when using the steerable motors, i.e. a non-rotating '*sliding mode*', when the assembly's bent housing would be adjusted to divert the well path and '*rotating mode*' when rotating the whole drill string to drill a straight section.

It was regularly troublesome to introduce required tool adjustments from the surface for amid sliding, particularly in long horizontal sections. Also cleaning the hole without pipe rotation was more challenging, hence, this required regular short trips. Drilling ahead with a bent assembly along the hole trajectory arouses hole issues like edges, over-gauge hole, and spiraling, that obscure casing runs.

Rotary steerable (RS) frameworks were introduced to adapt the requirement for bent tools, to take care of the borehole quality with steady string rotation, and to give automated downhole control along the drilled section. Coming into view these capacities which make the DD to earn another forwarding skip in placement accuracy and productivity, permitting the standard usage of complex 3D well profiles and extend reach drilling (ERD).

Though the RSD idea bloomed in the 1980s, the practical systems were noticeably accessible after several years.

In the late 1990s, the well-known Power-Drive has developed by Schlumberger which is the willpower of its rotary steerable armada, in that event, it has seen the enormous development of the technology. It was commercially first to run in 1996, and so, there have been around 230 Power-Drive tool runs in more than 40 wells to date and counting a huge sum of hours of operation.

Currently, DD are becoming more accurate and economical through continuing research and development of new tools and techniques.

2.2 Main Terms and Definitions in Directional Drilling(DD)

2.2.1 Direction Measurements

Survey tools measure the direction of the wellbore on the horizontal plane with respect to North reference, whether it is True or Grid North. There are two systems, [3]:

Azimuth(AZ)

In the azimuth system, directions are expressed as a clockwise angle from 0° to 359.99° , with North being 0° , (Fig.2.1)(L).

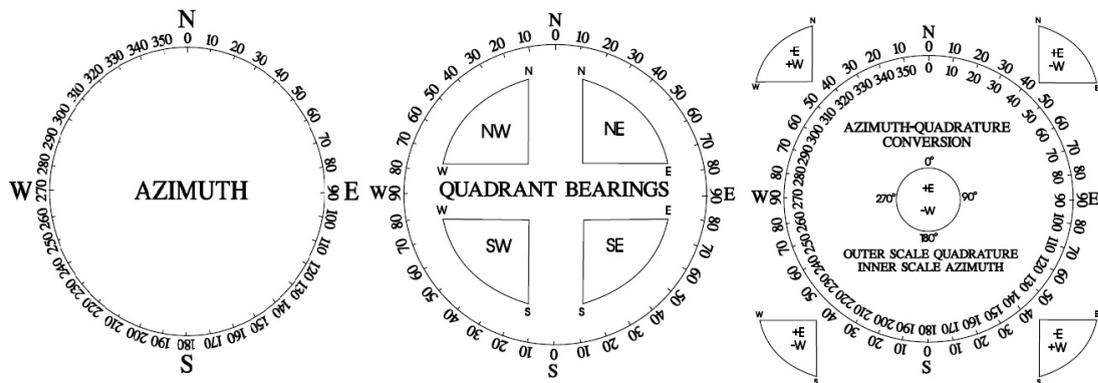


Figure 2.1: The Azimuth System(L), The Quadrant System(M), Conversion from Quadrant to Azimuth Systems(R), [3]

Quadrant Bearings

In the quadrant system (Fig.2.1) (M), the directions are expressed as angles from 0° - 90° measured from North in the two Northern quadrants and from the South in the Southern quadrants. The diagram in(Fig.2.1) (R) which illustrates how to convert from the quadrant system to azimuth, and vice versa.

2.2.2 The Target

That or those geological units (s) into which the well is to be drilled, the termination point of the well path (includes geographical coordinates and depths in meters), [4]. The geologist in assistance with other disciplines is usually specifying the target, with an acceptable tolerance (e.g. a circle of radius 100 ft. having the exact target as its center).

2.2.3 Types of Directional Patterns

The well generally penetrates different formations, thus, the planned pattern is must be reasonable and can be done with the least drilling problems.

Type 1- Build and Hold

Features:

Shallow kick-off point (KOP).

Build-up section (which may have more than one build up rate).

Tangent section.

Applications:

Moderately deep wells with moderate horizontal displacement, where intermediate casing is not required.

Deep wells with large horizontal displacements.

Type 2-(S Type Well)

Features:

There are several variations:

Shallow KOP - Build, hold and drop back to vertical.

Build-up section - Build, hold, drop and hold (illustrated above).

Tangent section - Build, hold and continuous drop through reservoir.

Drop-off section.

Applications:

Multiple pay zones.

Reduces final angle in reservoir.

Lease or target limitations.

Well spacing requirements.

Deep wells with small horizontal displacements.

Disadvantages:

Increased torque and drag.

Risk of keyseating.

Logging problems due to inclination.

Type 3-(Deep Kickoff and Build)

Features:

Deep KOP.
Build-up section.
Short tangent section (optional).

Applications:

Appraisal wells to assess the extent of a newly discovered reservoir.
Salt dome drilling.
Repositioning of the bottom part of the hole or re-drilling.

Disadvantages:

Formations are harder so the initial deflection may be more difficult to achieve.
Longer trip time for any BHA changes required.
Harder to achieve desired tool face orientation with downhole motor deflection assemblies (more reactive torque).

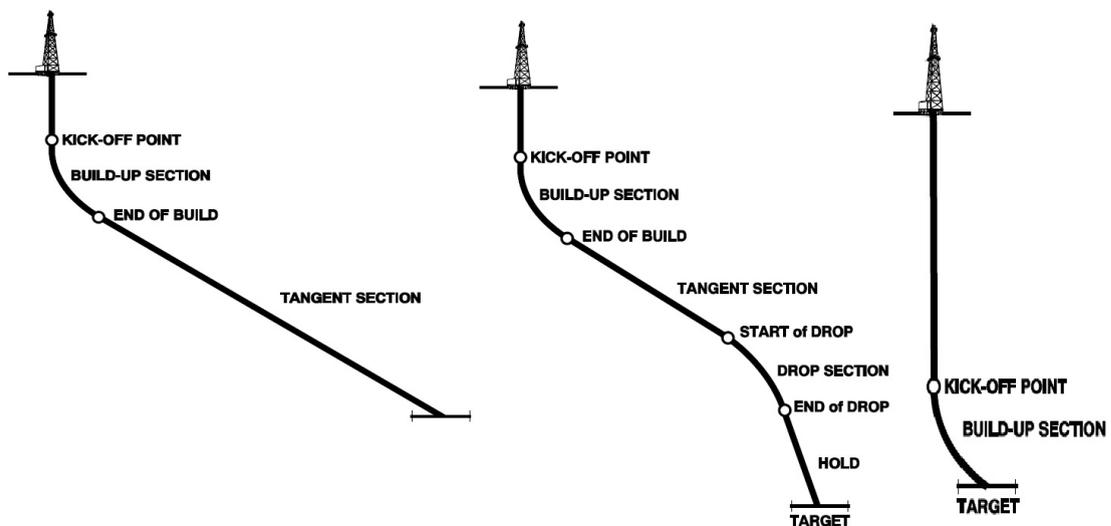


Figure 2.2: Type 1 (Build and Hold)(L), Type 2 (S Type Well)(M), Type 3 (Deep Kickoff and Build)(R), [3]

2.2.4 Planning the Well Trajectory

This is not as easy a task as it might seem at first glance especially on a congested multi-well platform or on a land cluster. As will be seen later, many aspects must be carefully considered before calculating the final well trajectory.

The rotary drilling method still plays a very important role in the petroleum industry even to this day. To distinguish the vertical from the directional wells, the wells are considered to be vertical when its target is located directly below its surface location.

As shown in Fig.2.3, the deviation angle between the hole and the vertical is primary and the azimuth of deviation is usually secondary, while the other well trajectory types have a different deviated angle, [5].

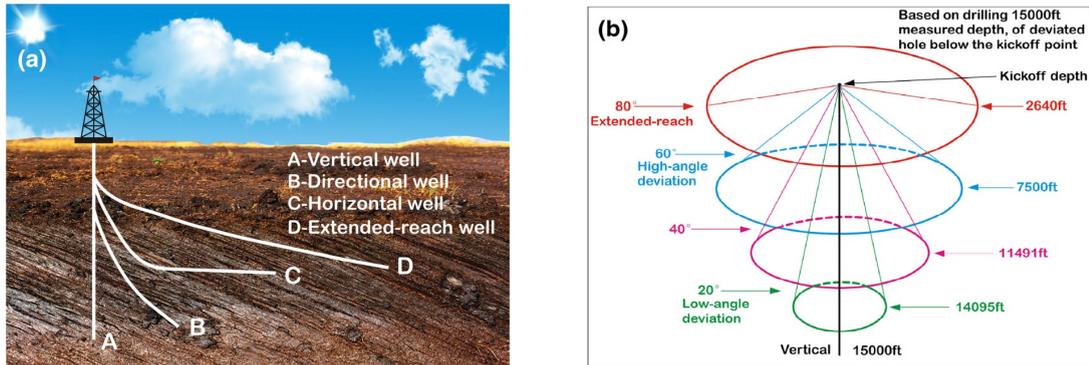


Figure 2.3: The schematic plot of different kinds of wells. (a) Four typical kinds of wells, (b) the classification of well types based on deviated angle, [2]

2.2.5 Catenary Curve Well Plan

A catenary curve is a natural curve that a chain, cable, or any other line of uniform weight assumes when suspended between two points. A similar suspension of a drill string would also form a catenary curve. So the catenary method is the well should be as a continuous smooth curve, all the way from KOP to target one.

Obtaining a smoother drilled wellbore is a high priority, which means drag and torque are reduced, and less chance of key seating and differential sticking, but in reality, this might be not achieved.

Thus it's essential to pick BHAs which will continuously give the required gradual rate of the build. Although the catenary method has been tried, with some success, it is not widely used.

2.2.6 Kick-off Point, Build-Up Rate, Tangent Section and Drop-off section

Kick-off Point, Build-Up Rate

Several elements indicate the selection of both the KOP and the BUR, include hole pattern, maximum tolerable inclination, required horizontal displacement, casing program, mud program, and keep the well path at a safe distance from existing wells.

The range of BUR is usually 1.5°/100' MD. to 4.0°/100' MD. for normal directional wells. Taken into account, the maximum permissible DLS when choosing the appropriate rate.

Tangent Section

When the inclination of the well up to 80°, the area which can be covered from a single platform is nearly 8 times that covered when the maximum inclination is 60°.

Fields experience has demonstrated that problems are aggravated when tangent inclinations are less than 15°, because of the tendency for the bit to walk (i.e. change in azimuth) so needing extra time keeping the well on course.

Generally, high inclination angles can lead to excessive drill string torque and drag, hole cleaning, casing, logging, cementing, and production problems. But using current technology can avoid them.

Drop-off section

The rate of drop off in S-type is chosen to ease casing problems and minimize completion and production problems. It has less drill pipe tension that is run through deeper doglegs and less time spent rotating below the dogleg. Thus, it is much less critical to drilling.

2.2.7 Nudging

On platforms, this technique is employed for some reasons like:

- 1- Spread out conductors and surface casings to avoid any collision.
- 2- To spud from a slot located on the opposite side of the platform from the target, in case other wells exist in between.
- 3- When the horizontal displacement is large compared to the TVD, it's essential to build angle right in the first shallow section to avoid a high build rate later on. Basically, it's at a low rate (e.g. 1°/100') in the chosen direction.

Several techniques are used for “nudging” as jetting, mud motor of 9.5" OD or greater with a 17.5" bit and a 1.5° or 2° bent sub which is the most common method.

2.2.8 Proximity (Anti-collision) Analysis

As mentioned, on multi well platform or cluster, it's necessary to keep small distances between slots to avoid the collisions risk of directly beneath the platform. Calculating these distances between the other wells at frequent intervals in critical sections using the EC*TRAK software (BHI) or COMPASS.

Survey uncertainty must also be determined for both the existing and proposed wells. Basically, drilling companies established criteria for the minimum acceptable separation, which are related to calculations of “cone of error” or “ellipse of uncertainty”(EOU).

2.2.9 Survey Design Process

Constructing a survey program can be summarized as define objective, selecting a survey. Check the objective to be met. As seen in Fig.2.4

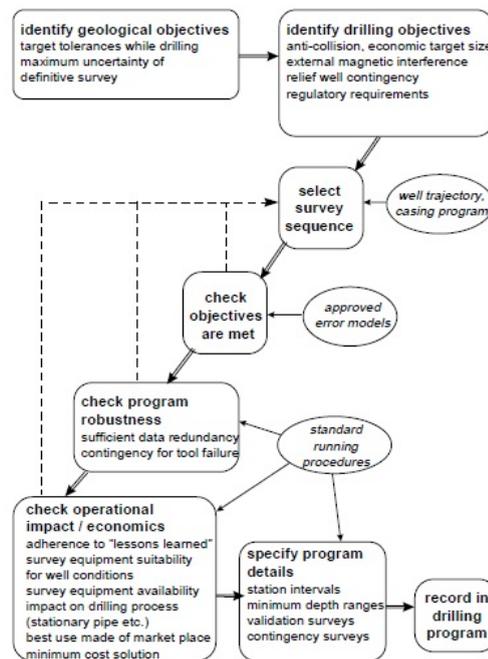


Figure 2.4: Flowchart for survey program design

2.3 Reasons and Applications of Directional Drilling

Directional drilling is a complex and recent technique in which wellbore can deviate from the planned trajectory to tap a specific end target. Currently, it is generally employed for a wide range of underground areas and can go far away from a few surface points.

Since the fact that the HC reservoir geometry has a lateral length more than vertical one so it will have more chances to achieve potential reservoir exposures through the deviated section of the well. At last, HC reserves can be extracted with the directional wells.

As shown in Fig.2.5, the applications of directional drilling can be arranged under the following categories, [2].

- Horizontal drilling • Drilling beneath inaccessible locations • Relief Wells
- Shoreline drilling • Controlling vertical holes • To avoid geological problems
- Multilateral well • Offshore development drilling • Non-petroleum uses • Sidetracking
- Cluster drilling • Salt dome drilling • Fault control • Extended reach wells

Horizontal and extended reach wells are a special case in directional drilling due to more difficult features, it generally is similar to directional drilling but more complex because of longer tangent and horizontal section, higher build rates and drift angles, includes angles greater than about 60, more commonly about 70°–90°, Fig.2.3.

Conventional directional wells could be drilled to an inclination of around 60°. Inclinations more than 60° give rise to many drilling problems that substantially increase the cost of the operations.

The horizontal wells classification can be well-known using the angle-build rates which are in degrees per 100 ft. of measured depth (MD).

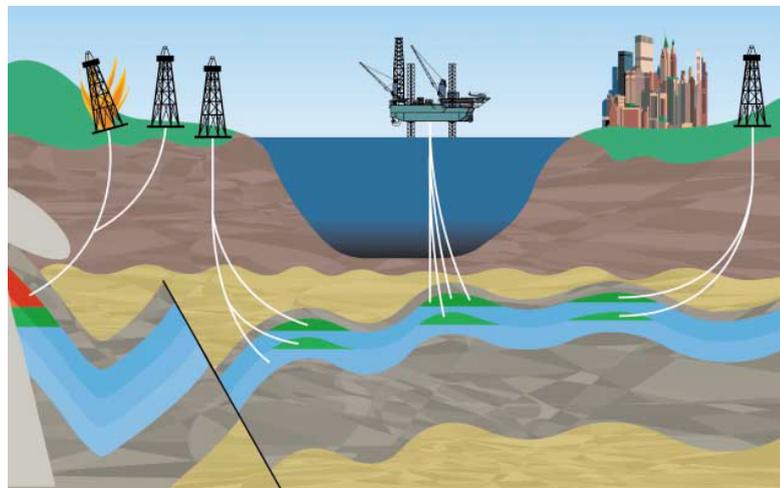


Figure 2.5: The applications of directional drilling, [6]

2.4 Vertical Drilling System (VDS)

It's also a very important technique for deep and ultra-deep drilling, it's another type of directional tool and it is applied to avoid deviation and drill vertically and quickly, as a result, improving the ROP. The VDS can avoid frequent straightening and automatically keep the borehole vertical.

Despite the conventional techniques, like steerable assembly, the eccentric-axis assembly, eccentric rigid-flexible assembly, pre-bending dynamics, anti-pendulum assembly, etc., also could be used to straighten, but, trip in and a trip to change the drilling tool out

are frequently done. It maintains a wellbore vertically, without compromising critical drilling parameters: WOB, flow rate, and bit speed.

Baker Hughes Inteq developed the initial VDS tool. In 1988, the initial VDS was used to drill continental scientific wells for the KTB program in Germany,[7]. In the KTB program, the maximum hole inclination was controlled in a range of 0° - 1° successfully.

Afterward, the development of VDS tools has been commenced. Presently, four kinds of typical VDS tools are available, the Halliburton Sperry-sun V-Pilot system, Baker Hughes Verti-Trak system, Schlumberger Power-V system, and Smart Drilling GmbH ZBE system, [7].

2.5 Directional Drilling Technology Development

Principally, upon the nature of the subsurface beds, directional methods are classified into the following:

- 1- *Passive* directional drilling: The trajectory of the well coincide with the natural deflection of beds, the well trajectory cannot be controlled accurately.
- 2- *Active* directional drilling: Some tools are employed to control the well trajectory along the expected path and the tool axis deviates from the borehole axis using an artificial method. During that, conventional BHA and WS were used to drill directional wells.

The deflection tools cause the bit to drill the ongoing hole at a specific angle and since they are used at the KOP to start building an angle from the vertical, it's occasionally termed kickoff tools.

In order to force the bit to deviate from its usual path, one of the two following methods are adopted:

- 1-Directly to push the bit sideways by means of WS which is external to the string.
- 2-Employ tools included in the drill string.

These tools make the bit rotating around an axis at an angle to the axis of the main part of the assembly, to achieves that adequately, the operator must not rotate the drill string at least until he achieves the required trajectory, this mean just the bit is rotating by involving of the downhole motor. Though the recent technology couple these two methods involving pushing the bit sideways by tools mounted in the BHA. This method involves the use of a rotary steerable system.

To that end, the selection of techniques and deflection equipment upon several elements like; the required deflection degree, hole depth, formation hardness, temperature, with or

without casing, and economics. The formation in which the deflection is to be made is considered to be the top influential element since it is the only element under control.

Fundamentally, the deflection equipment employed as a part of directional drilling can be categorized as the following sets shown in fig.2.6.

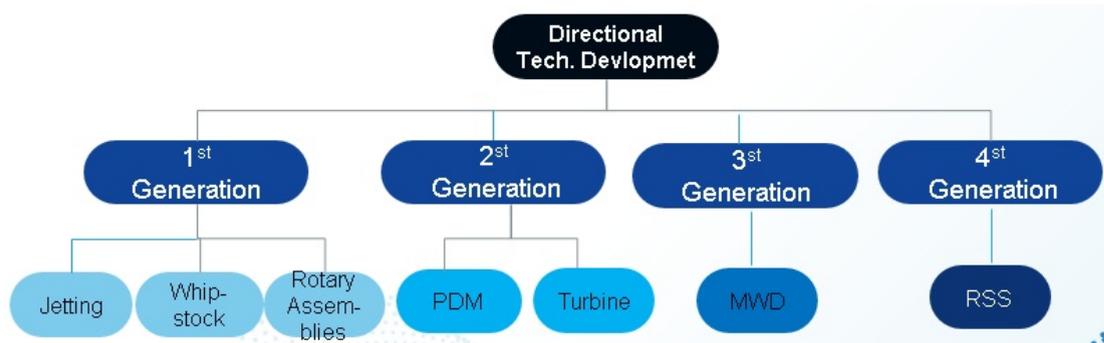


Figure 2.6: Generations of Deflection Equipments

There is no big difference between the downhole equipment are used in directional and horizontal drilling with vertical drillings, such as the stabilizers, DC, DP, fluted spiral DC, HWDP, compressive pipe, substitute sub, short pony DC, and so on. Advanced directional tools lead to directional technique development. Accordingly, the main tools can be summarized as follows: deflector, downhole motor(DHM), (RSSD), (VDS).

2.5.1 The First Generation of Directional Technique

Jetting

It's relevant to fragile and friable formations. This technique uses one BHA to deviate the wellbore which can be kicked off and built up to the requested inclination. Special jetting bits or a standard long-tooth bit can be exploited with two blank (or very small) nozzles and other one huge nozzle. An example of jetting BHA involving:

Bit, Near-bit Stab, (UBHO) subs, MWD, NMDC, Stabilizer, DC, Stabilizer.

As mentioned earlier, the formation should be suited for jetting. After the jetted interval has been done, starting jetting and drilling the initial couple of feet with adequate room left on the Kelly. The big nozzle is oriented in the planned direction and a strong circulation rate is achieved while jetting.

A pocket is washed in the formation contrary to the vast nozzle if the formation is appropriately delicate. To "bury" the near-bit stabilizer, it should jet enough hole length. The bit can be pulled off the bottom and the pocket "spudded". The way is to hang the string about 5' off the bottom, then let it fall, getting it with the brake so the extent

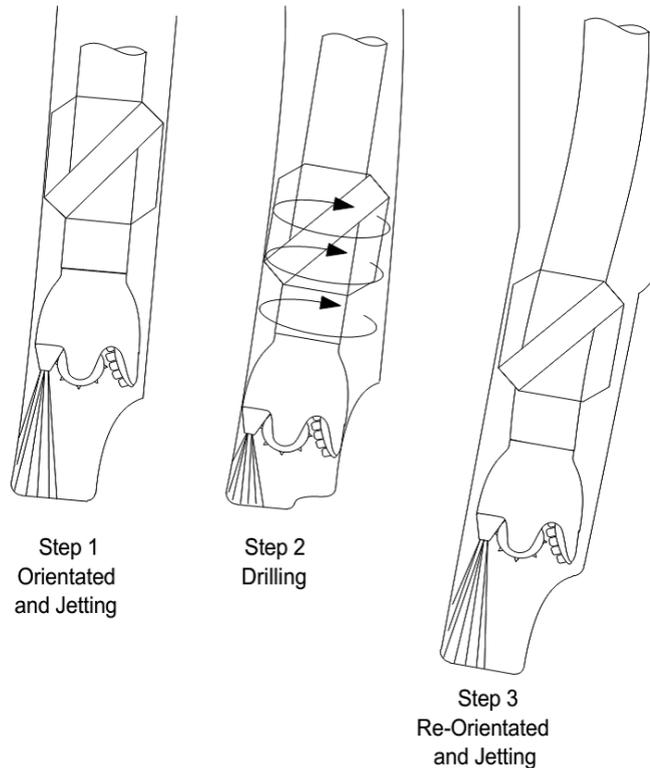


Figure 2.7: Jetting deflection method, [8]

of the string makes it spud on the bottom (as opposed to the full weight of the string). Spudding can be oppressive on drilling line, drill string, and derrick and must be kept to the minimum possible level.

Fixing the pumps for about half of that are employed for jetting afterward 4 to 5 feet have been jetted. The drill string is rotated. Since high torque (near bit stabilizer wedged in the pocket), It could be urgent to pull off bottom.

It's usually using low rpm and great WOB to bend the collars over the near-bit stabilizer and power the BHA to finish the pattern set up while jetting. The rest of the length on the Kelly is drilled down.

The jet should be oriented in the direction of deviation, to clean the hole preceding connection/survey. The orientation setting (tool face setting) afterward the survey is modified as needed, dependent upon the results achieved with the previous setting. It's recommended to observe dogleg severity and executing reaming.

The operation is reused regularly till the required inclination has been gotten. Then, when satisfying the hole inclination which can build up the ultimate angle using only rotary drilling.

If necessary, little direction fluctuations can be made. The jetting method is appropriated with MWD or the strategy of single-shot, for employing a strategy of single-shot the drilling should be suspended, running gyro inside a string, sit on UBHO sub-profile then deviated hole azimuth and inclination are recorded.

Streaming BHAs. It difficult to keep enough WOB when drilling in fragile formation because of hole erosion, so it's required a more flexible jetting BHA. The ordinary BHA and jetting BHA are two principle contrast of nozzle and stabilizer position type.

Advantages and Disadvantages of Jetting Technique

Advantages

- Errors in the survey are less compared to PDM/Bent sub alternative as there is no offset in the assembly.
- The "tool face" can be directed more precisely than when using a PDM, torque might not be there when jetting, the importance of this principally when close to other wells.
- Closer surveys to the bit can be done than when using a PDM.

Disadvantages

- Severe doglegs can develop unevenly over short sections of a hole as it's known the initial issue with jetting is that intermitted. The determined dogleg is really a normal stimulus over the agglomerated interim between surveys. Somewhat of this dogleg may have been built in the jetted short section of the hole. In this piece of the hole, the severity of actual dogleg might be in fact higher than that was taken from the surveys. MWD can be involved for real-time assessment of dogleg severity so that the inconsistent in well trajectory be excluded.
- The formation usually becomes too firm for efficient jetting/spudding below 2,000' TVD. It's preferable to use a mud motor/bent sub kickoff.

The Directional Control with Conventional Bottom Hole Assemblies (BHA):

BHA design which is to drill the planned trajectory is an important aspect of directional drilling. We shall concentrate on the basic principles used in directional control when drilling with rotary assemblies. The correct design of the assembly and use of suitable drilling parameters are the main elements to control the angle inclination of directional wells during rotary drilling.

It's the initial and active directional method, and the benefit is for cleaning hole, reducing dogleg angle, reducing drill-string drag, and saving costs. However, there is a lack of ability to control well AZ. This BHA with multi-stabilizer only can be utilized to control the hole inclination depend on the pendulum effect or lever principle. The BHA can be classified as angle build, angle drop, angle hold, or stiff BHA according to the function.

One of the less costly techniques utilized to deviate a well is rotary BHA and it is recommended to apply whenever possible. But the drawback, it's not simple to predicts the actual response of a rotary BHA, and relatively impossible to control the right or left-hand walk.

The more trips number required to change the stabilizer position along with the BHA or to make a correction run with a motor makes the rotary BHA is not cost-effective, thus rotary BHA's are a few times used today to accomplish cretin applications.

Furthermore, most rotary steerable assemblies and steerable motor assemblies utilize the techniques learned from rotary BHA. Generally, what is run in the hole to drill, ream or circulate is a BHA in which the arrangement of bit, stabilizer, reamers, DC, subs, and special tools used at the bottom of the drill string. A simple one is a bit, DC, and DP and is usually called a slick assembly and is very limited employed in DD and often confined to the vertical section where the deviation is not a problem.

The three fundamental types of BHAs used in directional drilling are seen in (Fig.2.8):

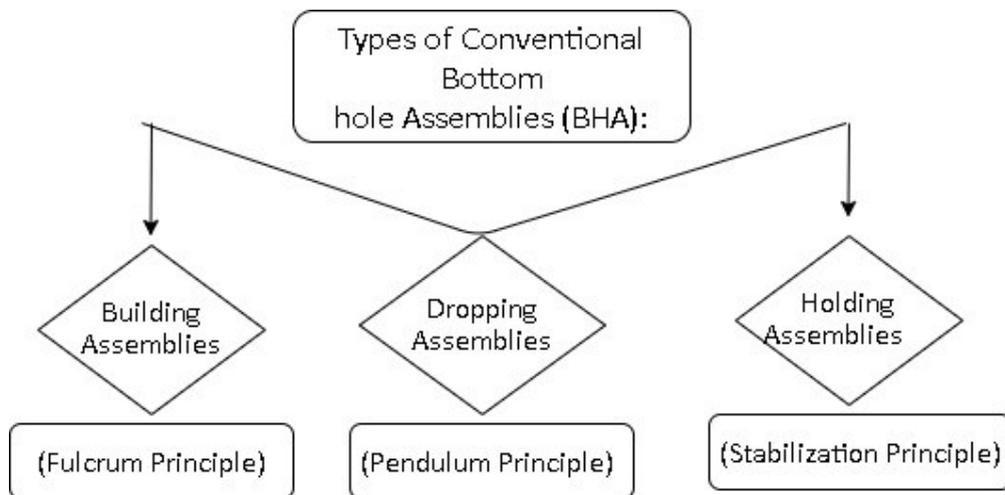


Figure 2.8: Types of BHAs used in directional drilling

A dropping assembly is designed to decrease hole inclination, a building assembly is designed to increase hole inclination, and a holding assembly is designed to maintain hole inclination (Fig.2.9). The idea should beared in mind, a building assembly may not always build an angle. Formation nature may make the assembly to drop or hold an angle. The same is valid for the holding and dropping assemblies.

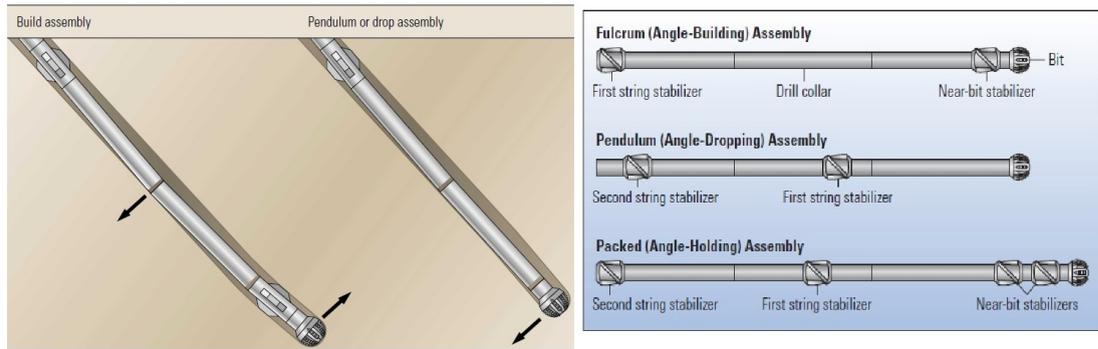


Figure 2.9: Changing direction without a downhole motor. Careful placement of stabilizers and DC allow the directional driller to build angle or drop angle without a steerable BHA. Generally, the placement and gauge of the stabilizer(s) and flexibility of the intermediate structure determine whether the assembly will build or drop, [6],[19].

Factors Affecting Bit Trajectory:

Factors which can affect the directional behavior of rotary assemblies which many of them are interrelated include (Fig.2.10):

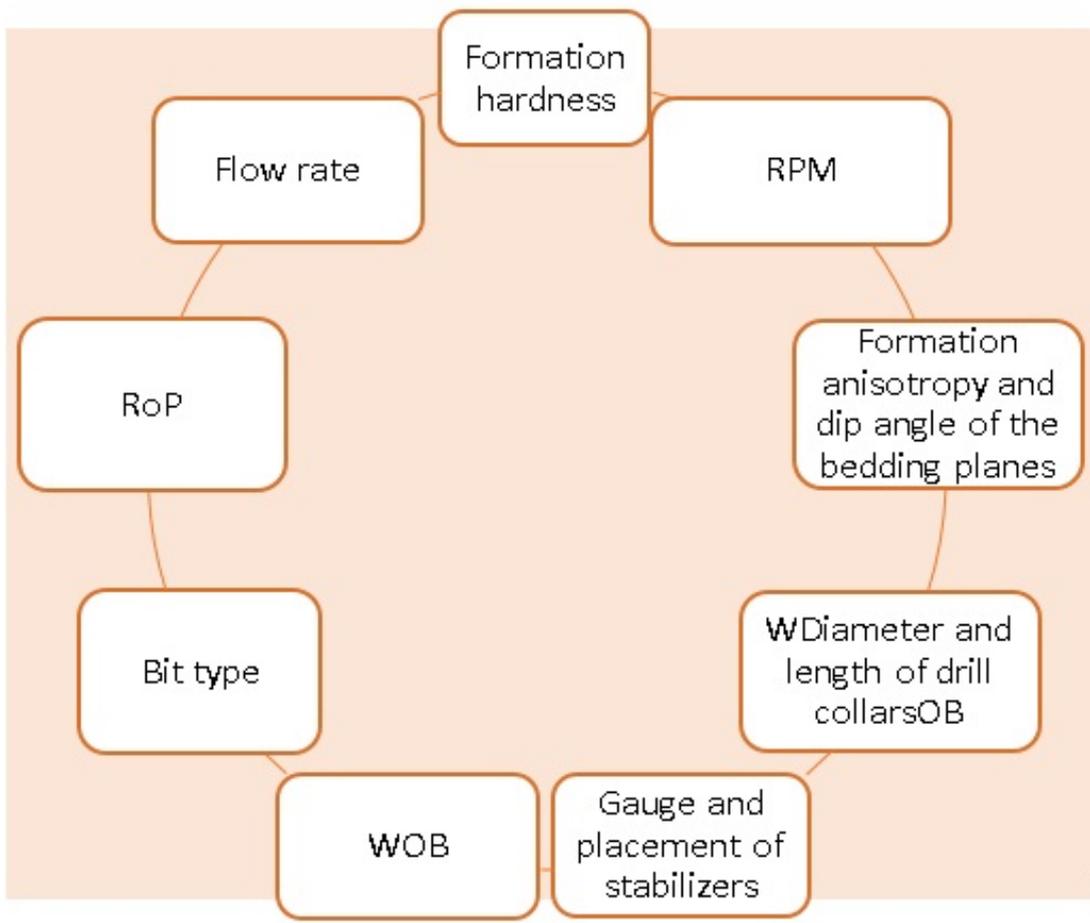


Figure 2.10: Factors which can affect the directional behavior of rotary assemblies

Advantages and Disadvantages of Conventional BHA Technique

Advantages:

- As it's not necessary to use Steerable Motor or RSS, so it's inexpensive.

Disadvantages:

- Little or no control over the azimuth of the wellbore, despite some control over hole inclination, could be done by this method.
- The distance between stabilizers, drill collar diameter and stiffness, formation dip, rotary speed, weight on bit, formation hardness, and bit type are affecting dogleg. The ability to balance the BHA against these factors can be essential for tapping a required target.

The Whip Stock/Deflecting Wedge (WS)

The whipstock is one of the initial down-hole deflecting tools, it is a specialized tool used to guide the drill bit to deviate from the borehole axis to the desired direction, therefore, before run in the hole, the directional process is performed. The WS control azimuth, it defeats the shortages of the conventional BHA.

This method still used adequately in sidetracking, which is an operation for deviating in an original hole at a point above the bottom and drilling a new hole in a different direction, it can be done in either open or cased hole, common uses are for drilling another objective located away from the original wellbore or bypassing a fish. As well as, the ultra-deep drilling with high temperature, which makes PDM failure, this method may be an effective alternative.

However, this technique possesses the disadvantages of complex operations, poor control accuracy, repetitive and multiple trips, failure to deviate, and waste of time and cost. The tool face is fixed when changing the well azimuth, also known as a fixed tool face mode. The tool face must be adjusted discontinuously to continue changing the well azimuth, leading to the original hole and new hole exist in a tapered plane, thus it is termed as the azimuth adjusting mode on a tapered plane.

WS is available in variation for different functions. A retrievable WS is pulled out of the hole with another assembly. A non-retrievable WS which is called permanent casing WS. On the other hand, it is working on to deviate from a stuck fish; when the deflection has been resolved, it is left in place thereafter. To ensure a clean seat for the tool, a circulating WS is used to flush out cuttings by guides flow to the bottom of the wellbore.

The usual BHA used with this type listed in Fig.2.11.

The cleaned hole is needed before running the WS. Then when reaching the bottom, circulation is launched. The WS sunken face is aligned in the predetermined direction. The wedge toe is anchored firmly set up by applying sufficient weight to shear the stick.

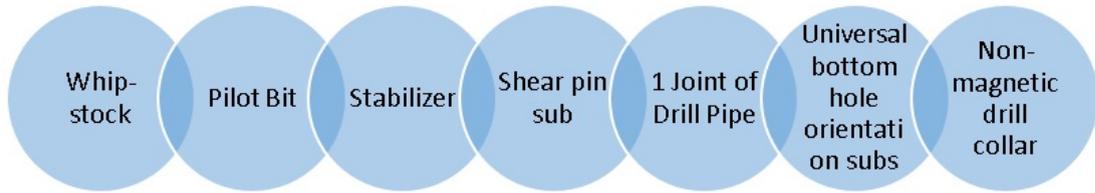


Figure 2.11: Usaul BHA used with whip stock

The bit is let down the WS encounter. Rotate the drill-string and rat hole are drilled at a controlled rate for around 15' - 20', as seen in Fig.2.12

Then the driller retrieves the WS and opens the rat hole by a pilot bit with a hole opener. Another trip employing a full-gauge bit with near-bit stabilizer and active BHA is made afterward. Approximately, 30' are drilled, acquired of further hole deflection. Next, a directional BHA of full-gauge is run and continuing of convenient drilling.

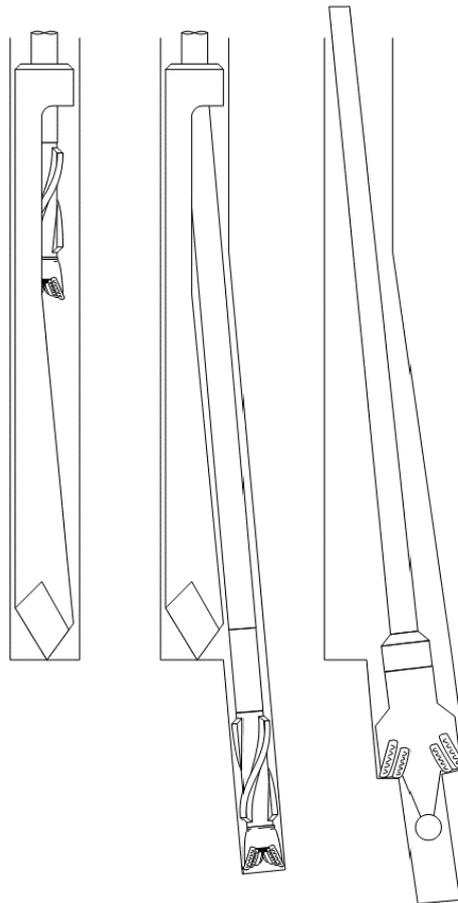


Figure 2.12: Whipstock deflection method, [8]

The valuable matter is that it is a hardware basic bit of which requires no much maintenance and has no temperature detention. In different circumstances, it is time-consuming with the number of "trips" included. Since the WS produces a sharp, sudden,

deflection as such, a severe dogleg, so it's another serious shortcoming, which could move up to ensuing issues in the wellbore.

Generally, deflection tools defined as a wedge-shaped steel tool having a tapered concave groove down one side to guide the WS bit into the wall of the hole and can be classified into the two types:

The Removable Whipstock:

This can be used to straighten vertical wells that have become crooked or generate deflection in an open hole. As shown in Fig.2.13(a), the WS compose of a steel wedge with a chisel-shaped point at the bottom to avoid any movement during drilling,[9]. The tapered concave shape reduces wear as it has hard facing. A collar at the top of the WS assists to pull out the tool once the first section drilling has been done. The WS is connected to the drill string by a shear pin. When it's run in the hole, the tool face of the WS is correctly positioned by rotating the drill string.

The chisel point is engaged firmly into the formation or cement plug by applying surface weight, shearing off the retaining pin, and starting the drilling. Below the toe of the WS, a pilot hole of small-diameter is drilled to around 15 ft.in depth. The bit and WS are pulled out after this rathole survey has been acquired. After then, reaming out the rathole to full size be means of hole opener. Once generating the deflected section, a rotary assembly can be run to continue the sidetrack.

The Permanent Whipstock:

In a CH, the major functions of this type are by-passing collapsed casing or sidetracking around a fish. As shown in Fig.2.13(b), at the KOP, a casing plug is set to present a base for the WS, [9]. A mill is run with the WS to cut a “window” in the casing.

When the WS is set in the recommended direction and the retaining pin is sheared, the milling operation starts. After cutting the window, pulling the mill out of the hole and pilot bit of a small diameter is run to the bottom, so, the pilot hole is reamed out to full size. After then, running a rotary assembly to continue the sidetracking.

Innovating downhole anchor with a WS assembly (The TrackMaster OH system) was introduced to industry to address the challenges of sidetracking in OH and CH wellbores and set WS in OH without concern for cement plug integrity. By lock an anchor in place and establish reliable KOP at a precise depth and orientation required- usually in just one trip,[10].

In OH, if KOP for sidetracking, the WS is set in the open wellbore and directional BHA can be utilized immediately to launch the sidetrack. The OH system has two options

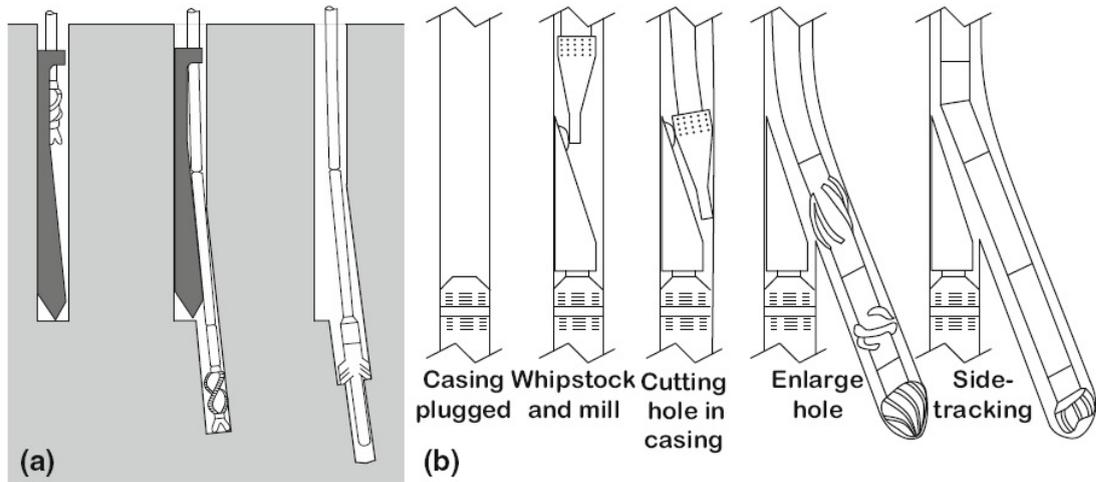


Figure 2.13: The schematic diagram of removable (a),[9] and permanent whipstock(b),[2]

to set the WS, which is based on whether the driller will need to access or isolate the section beneath the KOP.

Whilst if KOP in the CH, the driller must set WS, mill a window through the casing and drill a few feet of rat hole to verify the sidetrack. Afterward changing to directional BHA to extend this hole.

The Trackmaster OH-C WS and cement system are used when the operator needs to isolate the section beneath KOP, so by a single trip can set WS and cement plug. Since the anchor holds the WS in place, the driller can start sidetracking without WOC.

The TrackMaster CH WS system is utilized to initiate full-gauge windows in high-grade steel and chrome casing.

The OH system includes five subassemblies:

- A multi-cycle bypass valve to permit the MWD telemetry of directional data for the AZ orientation of WS.
- A running tool to set the anchor.
- A drill bit to create the ST.
- A WS, or steel ramp to verify a KOP.
- An anchor to hold the WS in place.

2.5.2 The Second Generation of Directional Technique

The invention of the DHM and monitoring method was the typical feature during that time.

1. The DHM generally includes PDM, turbo-drill, and an electric drill. PDM and turbo-drill use volume of the circulating mud and the pressure to rotate the bit and



Figure 2.14: Sidetracking after pumping cement. With its anchor in place, the Track-Master OH-C system permits drillers to sidetrack without having to wait for cement to cure,[10].

electric drill uses the electric energy for this activity,[2]. An efficient method to change the borehole direction is achieved by combining this with other tools (bending joint, bending rod, eccentric joint, or similar tools).

2. Hydrofluoric acid inclinometer and photographic inclinometer are included in the monitoring method. Firstly, the fixed drill string mode is the way to adjusting AZ, the idea is fixing the entirety drill string i.e. the tool face is fixed during the adjustment operation and allows the DHM to rotate the bit. Secondly, the AZ adjusting mode on a tapered plane in which the tool face can be adjusted continuously, i.e. the new hole and original hole exist in a tapered plane. Nonetheless, the trajectory becomes more smooth and accurate comparing with the first generation,[2].

2.5.3 The Third Generation of Directional Technique

This generation is due to advanced monitoring method or tools and this makes the directional operation has been greatly simplified. Even more, this generation is still currently the major method for directional and horizontal activities. The typical feature in this stage is an improvement in the measured and controlled accuracy by the invention of MWD in which, the directional operation can be achieved while drilling.

Furthermore, to deliver more efficiency in DD and since the initial PDM tool is straight, the PDM tools have been designed with a bending housing, such as single bent PDM, double bent PDM, the straight PDM, etc. The single bent PDM is a popular motor, which has a bend constructed near the lower end and belongs to a fixed tool face mode.

2.5.4 Down-hole Motor (DHM)

A DHM represents the most popular deflection technique in current use, including PDM and turbo-drill. Its mission to drive the bit without rotating the whole DS. A special sub placed above the motor to provide the deflection to create a side force on the bit.

To define a steerable assembly is a BHA whose directional behavior can be modified by adjustment of surface controllable drilling parameters including rotary speed and weight on bit. Without BHA removal from the wellbore, there is the ability to change its behavior to steer them toward the desired objective.

The principle is by dipping the bit axis with respect to the hole axis and/or initiate side force at the bit. "Rotary Drilling Mode" is achieved if the body of the motor as well as the DS is rotated from the surface, afterward, the bit will tend to drill straight ahead. Contrarily, "Sliding Mode", when it's not rotated from the surface and the bit will drill a curved path designated by the orientation of the side force or the dip of the bit axis.

A DHM uses fluid flow to produce an independent of string rotation downhole rotation, and an angled bend for orientation of the tool face,[11]. However, with the motor in "sliding mode" (DS is stationary), the bit is generating torque and drag(T&D) which results in tool face fluctuations and reduced directional control,[12]. Transfer of weight to the bit can be irregular which will produce varying torque due to changes in the depth of cut and overall resulting in a reduced ROP. A severe doglegs and high tortuosity of the well when there is a lack in controlling the tool face. This may lead to further DH problems when it comes to casing and well completion. These problems will become more significant as the length of horizontal and directional complexity sections increases.

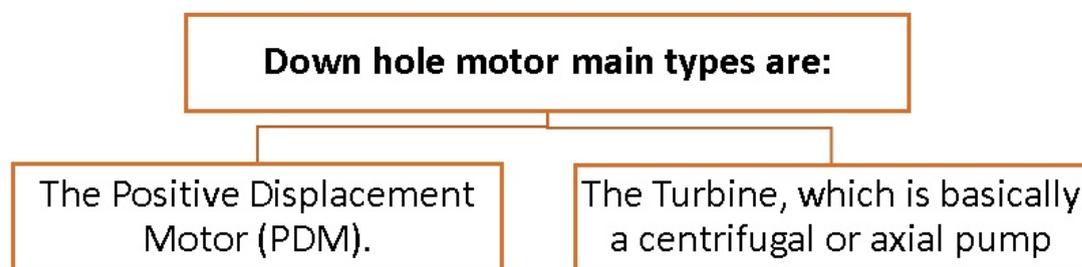


Figure 2.15: Down Hole Motor Main Types

The tool's design is exclusively unique. A turbine was commonly applied a few years earlier. However, it's just used currently as a part of extraordinary applications since the improvements in a bit and PDM configuration.

Since it's not easy for the fluid to pass through the tool, the valve which mounted on top of the tool to by-pass the mud to the motor and fills the drill string, and works on drain

the drill string while making a connection or tripping out. Once the pumps are started, this valve automatically closes.

The following two parts consist of the multi-stage motor in the PDM:

1. The solid steel rotor of a helical configuration.
2. The rubber molded stator with a spiraled, around cross-section and when fluid is enforced under pressure into the cavities which are formed between the rotor and stator, rotation is achieved.

The lower end of the rotor is connected to the top of the drive shaft by a universal joint or connecting rod. This connecting rod converts the eccentric motion of the rotor to smooth rotary movement at the top end of the drive shaft, as well as to transmitting motor torque.

The drive shaft runs inside a bearing assembly which assumes both axial and lateral forces. Axial bearings and radial bearings permit rotation and the drilling fluid lubricates it. Part of the mudflow is diverted through the bearing housing for lubrication and passes out between the bearing assembly and bit sub. The main part of the mudflow passes through a port in the driveshaft and is directed down to the bit. Fig. 2.16 shows the turbine and PDM standards operation.

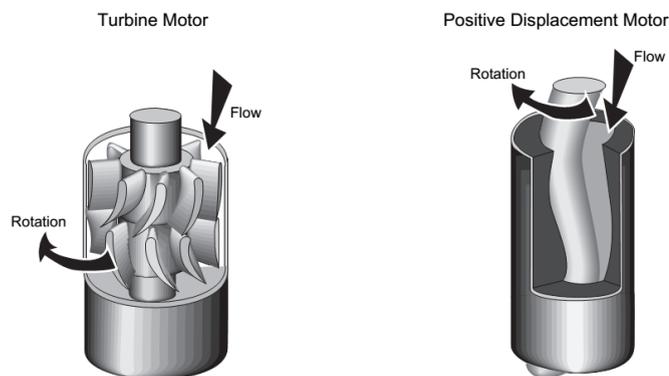


Figure 2.16: Principles of operation of turbine and PDM,[8]

2.5.5 Positive Displacement Motor (PDM) Components

In the 1940s, the first PDM tool is invented by Smith drilling tools. In the 1950s, the commercialized PDM tools are produced to apply in directional drilling. PDM tool is used more worldwide as a result of successful application in directional and horizontal drilling. In the 1970s, various companies, such as Dyna drill, Navi drill, Baker drill, Christensen, and Smith, produced the PDM.

The PDM includes a motor section, dump valve, universal joint, and bearing assembly as shown in Fig. 2.19. At the upper end of the motor, the dump valve is connected while at the lower end of the motor the universal joint is installed, also at the lower end of the universal joint, the bearing assembly is connected.

The dump valve does not allow the motor rotating while running into the hole or pulling out of the hole. The motor section consists of two main parts: the stator and rotor, the rotor is a steel shaft which is shaped in the form of a spiral or helix, while the stator is a molded rubber sleeve which designs a spiral passageway to accommodate the rotor, and the rubber sleeve is engaged to the steel body of the motor,[9].

The motor section function is supplying the power for rotating. To explain that, the geometrical difference between the rotor and stator forms a series of cavities. So once the drilling fluid is pumped, it will seek a path in these cavities between the rotor and stator. Thus as the mud continues to flow through the passageways, it enforces the shaft to rotate clockwise.

The universal joint is linked to the rotor and rotates within the bearing assembly, which is then transferred to the bit. The most critical component is the bearing assembly, as the PDM operating hours are usually determined by the endurance of the bearings. The two functions are achieved by this bearing assembly are: control the central position of the drive shaft to ensure smooth rotation and transmits the axial loads to the drill bit,[2],[9].

At present, the manufacturers of PDM tools provide the market with a wide range of diameters, 2–11", and the most common size is 6–3/4" for 8–1/2" wellbore. The lobes number in the motor is so crucial point because if the number of lobes is increased the speed will increase and reduces torque for a given size, so for high torque, the common motors utilize two lobes and one rotor.

Also, the availability of a wide range of speeds in RPM PDM tools, about 100–800, the most common operational speeds range 150–300 RPM.

Another important aspect, the material of the stator is a decisive factor for PDM tools. As high temperatures and oil-based muds affect most of the elastomer components, which cause swelling, the manufacturers have been tried and tested various rubber and elastomer materials,[2],[9]. By the continuous improvement in elastomer compounds, PDM tools can withstand temperatures up to around 200 C.

To explain more in details the PDMs components which are comprise five major elements from top to bottom, as in Fig. 2.19, they are:

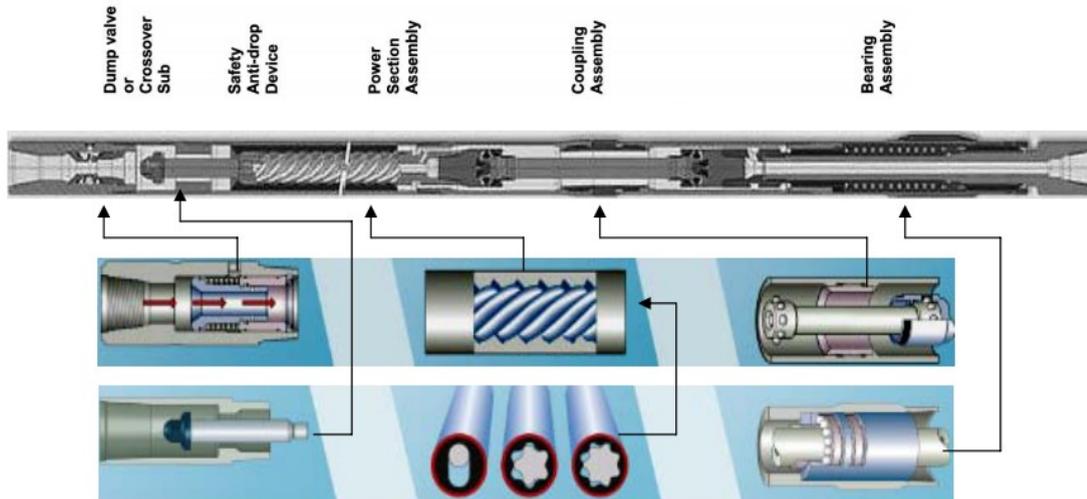


Figure 2.17: The schematic diagram of a typical PDM tool, [13]



Figure 2.18: (A) Bearing Assembly, (B) Universal Joint Assembly, (C) Adjustable Bent Housing/Fixed Housing, (D) Power Sections, (E) Dump Valve/Blank Sub



Figure 2.19: PDMs components

Dump Valve Assembly:

Help the fluid to deplete or fill the DS while tripping simultaneously. When a flow rate is set up, the cylinder of the valve is constrained down, shutting the ports to the annulus. Therefore, all the fluid is directed through the motor. When the flow rate turns out to be not as much as this lowest point, a spring returns the valve cylinder to the "open" position, which opens the ports to the annulus.

It's customary to run a float sub as near the motor as could be allowed in order not to allow solids entrance from the annulus while the pumps are shut-in.

It is enticing to run the dump valve as it helps the string to be pulled dry, and it permits the drill string to fill on the trip in the hole. If the ports are not blocked off by formation without a dump valve the motor is working in a good way, it can be set down and unseat by a sub which is having similar connections or run with the ports obscured, (fig.2.20).

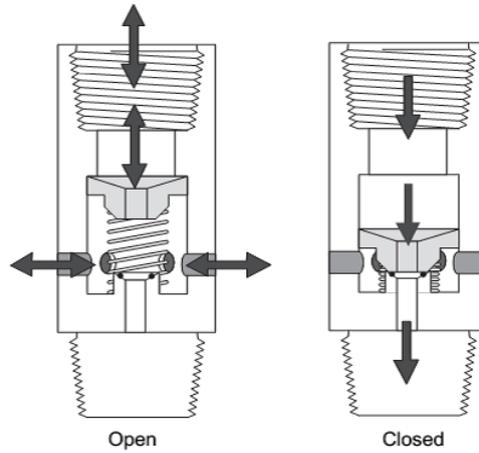


Figure 2.20: Typical Dump Valve Assembly, [8]

Power Section:

The PDM is a turnaround utilization of the Moineau pump. The liquid is pumped into the motor's dynamic depressions. The shaft is rotated inside the stator by the power of the fluid development. The power of rotation is afterward transmitted through the interfacing rod and driveshaft to the bit.

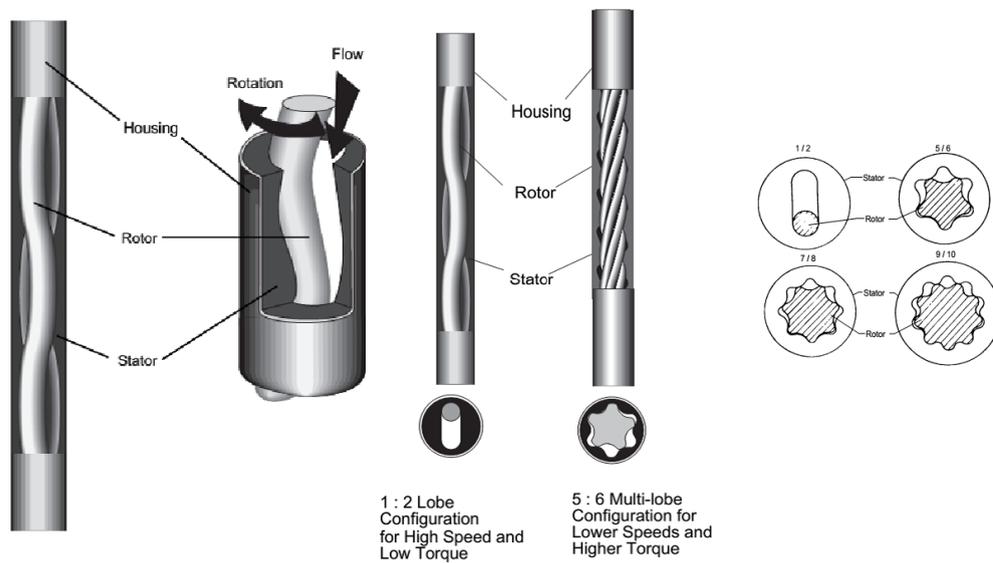


Figure 2.21: PDM lobe configurations with different speed and Torque(L), Illustrations of various motor lobes profiles (R), [8]

The rotor is a spiral-helix shape of chromed composite steel whilst the stator is an empty steel housing, fixed with a shaped set up elastomer rubber compound. During the manufacturing, a cavity spiral-shaped is produced in the stator and the rotor is configured with coordinating the "Projection" profile and comparative helical pitch to the stator, this is done with one lobe less. The rotor is embedded inside the stator along these lines.

When assembled, both the stator and rotor frame a constant seal along their coordinating contact focuses. The cases of 1-2 and 5-6 rotor/stator design in (fig.2.21).

A stage is each entire spiral of the stator. A slight obstruction fit between rotor OD. furthermore, stator ID. controls motor power. The types of mud motors which are high-speed, moderate speed, medium-speed. This is finished by changing the pitch of the motor stages and by the quantity of "Flaps" and resultant depressions of the stator.

The quantity of lobes is considered the more prominent, so, whenever a higher motor torque simultaneously with a lower RPM. For example, the Dynadrill F2000S and the Drilex PDMs are multi-lobe motors while a D-500 Dynadrill is a 1-2 lobe motor. A variety of applications are available for 1-2 LOBE and multi-lobe motors. The power section is usually called the motor section.

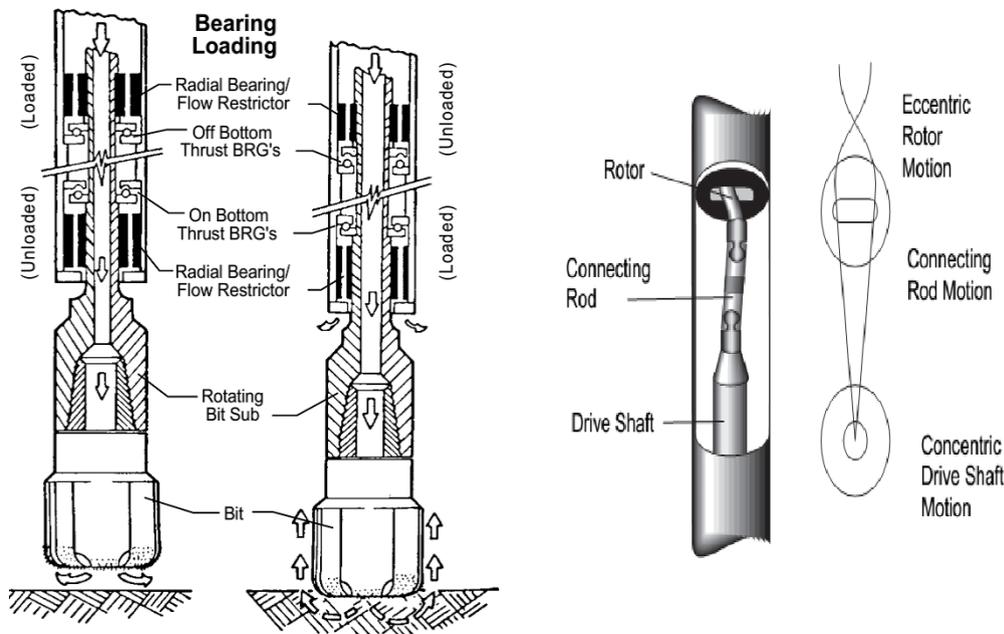


Figure 2.22: Typical PDM bearing loading(L), Typical PDM connecting rod assembly(R), [8]

Transmission Assembly (Connecting Rod Assembly):

It transmits the rotational speed and torque from the rotor to the drive shaft and the bit. It's connected to the lower end of the rotor. General joints change over the flighty movement of the rotor into concentric movement at the drive shaft. On a few models of mud motor, to avoid erosion by the mud, a strengthened rubber "boots" cover the U-joints, Fig.2.22(R).

Bearing and Drive Shaft Assembly:

The driveshaft is an empty steel segment which is developed unbendingly. It is sustained inside the bearing housing by pivotal and radial thrust bearings. The bearing assembly

transmits rotational power and drilling thrust to the bit. The majority of the fluid flows directly to the central point of the driveshaft to the bit, Fig.2.22(L).

The following PDM, as an example, composed of some fundamental bearing components:

- Off-bottom Thrust Bearings: it assists the rotor weight and the hydraulic thrust, interfacing rod, drill bit, and driveshaft when the tool is hanging off the bottom and rotating unreservedly. It's generally composed of a ball bearing.
- Radial Support Bearings: its sleeve-type which is used for both lower and upper radial bearings, and these radial bearings in the Anadrill motor compose of a sleeve that is made of tungsten carbide-coated. They also control the mudflow through the bearing assembly and this mud as a rule 4-10% is employed to lubricate and cool the shaft, thrust, and radial bearings. The occupied mud correct level is governed by the pressure drop over the bit and the state of the bearings. There is another option to the mud-lubricated bearing which is a fixed oil-filled BEARING. It can be used as a fixed where destructive MUDs are there, where there is a prerequisite for a low-pressure drop over the bit. or a quantity of LCM of different sizes is pumped.
- On-bottom Thrust Bearings: It transmits drilling load from the non-rotating motor housing to the rotating drill bit.

They are either involved in diamond friction bearings (e.g. Dynadrill F2000S) or ball-bearing races (e.g. anadrill motor). The rotating bit (drive) sub is the main remotely moving piece of a mud motor. It has standard API bit box connections.

In some type of PDM, a crossover/saver sub is employed between the dump valve and the stator housing.

To explain hydraulic performance which is generally true for bit pressure drops (PD) up to 1500 psi. In motor, most of the PD occurs in the power section. By maximizing the flow areas through the design of motors the PD is maintained at the lowest possible point. The majority of the drilling fluid passes down through the hollow output shaft to the bit after a move across the power section. To provide lubrication and cooling, about 10% of the mudflow is redirected through the bearing section which is then discharged to the annulus above the bit box.

When bit nozzle plugging or indispensable increase of flow rate (FR) or mud weight, the maximum specified bit PD will exceed. A higher percentage of mud may pass through the bearing assembly. High attention should be taken when running motors with a high-PD across the bit. Where it is paramount to use a high FR which exceeds the maximum specified, it's needed to insert the nozzle in the top of the hollow rotor. This permit part

of the total fluid flow to by-pass the power section but be available at the bit for jetting and hole cleaning.

PD and bit speed increase in proportion to the FR when running in free conditions. As torque is consumed at the bit, the PD across the motor will increase generally by an increase in weight. For any given FR, about 70% of stall torques is a maximum power torque. Because stall can occur immediately, so drilling at maximum power torque is desirable. Despite the motor have lower stall torque at lower FR but torque output is independent of the free-running pressure drop across the motor.

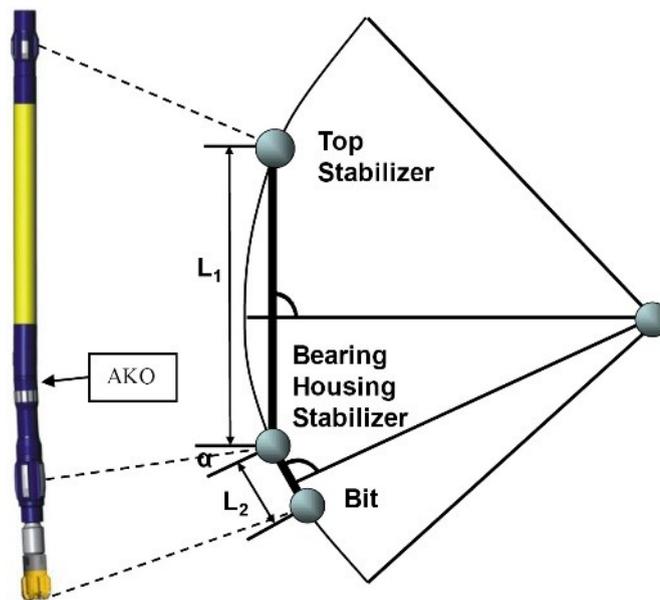


Figure 2.23: Three-point geometry of a steerable motor system, [14]

Three-point geometry of a steerable motor system

BUR is influenced by L_1 , L_2 , and AKO (Adjustable Kick-off Sub) and is adjusted to enable the assembly to get the required deviations. The AKO is the degree bend of the bent housing, L_2 is referred to as bit-to-bend length (feet). BUR is the amount of deviation an assembly can yield and it is a ratio between directional degrees of change over length, i.e. deg./ft.

When α increase, since of changes in L_1 , L_2 , and AKO, the BURs also increase as the reduced radius of curvature is defined in the three-point geometry system. The motor uses short bit-to-bend (L_2) configurations and AKO to increase BUR capabilities.

Higher AKO gives higher BURs but increases component stress when rotating because of the eccentric rotation of the bit. The stress increasing the lead to damage to internal components resulting in possible downhole motor failures and higher maintenance costs.

By reducing the bit-to-bend length, BURs can be increased without increasing the AKO angle, resulting in less component stress because of a smaller eccentric rotation.

Modeling of motor and bit combinations by BHASysPro™ software, to determine BUR capabilities and the locations of possible component damage.

Deflections and Stresses are determined by user inputs and three-point geometry; the outputs include BUR capabilities and bending limits for each component. The bending limits indicate where component stresses can lead to damage.

Performing BHASyPro™ modeling iterations by comparing AKO settings and different motor geometries. Motor geometries modeling optimizing resulted in the most current designs of the Short Bit-to-Bend (SBTB) technology. It can achieve BUR, rotate at higher RPM contributing to ROP, and prevent component damage when drilling to TD,[14].

Optimization is a crucial factor for vibrations mitigation, ensures minimization of drilling vibrations. The mud motor is chosen by the optimization team with size and lobes, stages, and revolutions per gallon.

The Gallon per Minute (GPM) capacity range of the motor. The selection should be made to suit the high GPM requirement for hole cleaning and in anticipation of high torque fluctuations while drilling.

Technology Considerations in Motor

Conventional motors are usually delivering high speed and low torque, but suffering from premature failure. The failures are based on rubber chunking from the thick layer of the stator that surrounds the rotor.

To optimize the downhole motor drive, the service company reduces the amount of elastomer in the power section by up to 60%. The motor can handle higher differential pressure creating as much as 50 to 100% higher torque relative to a conventional motor.

Slower speed motor with 0.08 revolutions per gallon (rev/gal) instead of the standard 0.16 rev/gal motors does not require high RPM to increase ROP; therefore, reducing the number of revolutions downhole by 50% would increase the life of the cutting structure by minimizing the overall wear rate of the PDC cutters. It also minimized downhole vibrations and allowed the cutters to shear the formation more efficiently,[15].

While drilling laterals for deep wells, the risk of differential stuck with directional mud motor BHA is too high. Most of the laterals are drilled with RSS or motor-powered RSS.

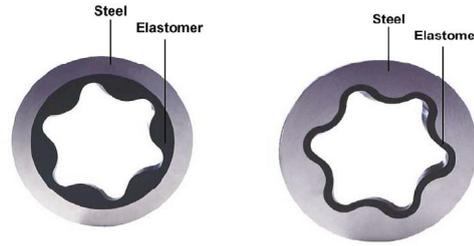


Figure 2.24: Conventional stator geometry (A) and pre-contoured stator of new high-performance motor (B), [15]

Operational Problems Associated with PDM

Bit Condition: In a comparison of run time with a normal rotary assembly, bit life may be minimized by the greater bit rotation of some of these tools. Frequently PDM stalling for no possible reason, like pump output constant and no extra weight applied, may refer to a locked cone on the bit.

Bit Stall out: Attention when picking up off bottom must be taken on shallow depths if the bit stalled out, to avoid disengaging of the Kelly drive (Top drive) as the reactive torque may be big enough to affect friction developed in the hole and twist the whole drill string.

Bit Pressure Differential: The pressure loss across the bit directly affects the amount of fluid flowing through the bearings. Extremely pressure drop will violate the designed flow and result in damage to the radial bearing.

Stall out Pressure Decreasing: The motor becomes weaker when the tool wears and the pressure loss through the tool or differential pressure reduces. This becomes probable when the stall out pressure gradually reduces. The tool should be replaced on the next trip as it continues to work but at reduced power.

PDM Observations

An increase in surface pressure causes motor stall which should be avoided as it erodes the motor service life.

- Pressure drop through the motor whilst working is 50 psi to 800 psi.
- Temp. limits are about 270°F, and higher temp. stators have been developed.
- LCM can be pumped safely, with care should be taken to add the material slowly and evenly dispersed.
- Keeping sand content in the drilling fluid to a minimum.
- Bearings wear is allowed in the order of 1 mm-8 mm, depending upon tool size.
- Flushing the tool out with water before laying down. Generally, low aniline point drilling fluids can affect the rubber stator,[3].

Characteristics

- Torque is proportional to a differential pressure of the motor which makes the tool very simple to operate.
- RPM is proportional to the flow rate. Hydraulic horsepower consumed, where P is the pressure drop (psi) across the motor and Q is the flow rate (GPM),[3].

2.5.6 Turbo-Drills

Tools of this technique can be employed for both directional and vertical wells. Historically, in 1873, a single-stage turbo-drill is used in Chicago, however, no actual use are record until the 1920s, in the US and the SU, the developments and researches of the turbo-drill were refreshed again. In the 1940s, the SU again had fulfilled more developments for this tool. By application of the turbo-drills in the USSR, enormous numbers of oil and gas wells were drilled.

A series of rotors and stators consists of the turbo-drill, each rotor-stator pair is called a (stage), The number of stages depends on the requirement and may vary from 1 to 250 stages, as shown in Fig.2.25. The stators are fixed to the body of the turbo-drill while, the rotors are blades that are installed on a vertical shaft,[9],[2]. Each stage also can add an equal share of the total power and the total torque.

The pressure drop of drilling fluid through each stage should be constant. Turbo-drills are available in different sizes, the minimum diameter one is 2-7/8 in, and the maximum size is about 9 in, due to its complex structure, they cannot be used in small diameter holes. Rotational speeds in Turbo-drills are higher than PDMs and it is in the range of 2000 RPM, so bit selection becomes more restrained than PDMs, this makes the impregnated bits are more common because of the high rotational speed.

Cone and PDC bits can be used with Turbo-drills to drill vertical, horizontal, directional, multi-branched, ERD. A bent sub or a new type of bent housing is used in the turbo-drills to achieve the mission of DD.

There are several shortages include high rotational speeds, short bit life, low torque, short bearing life, and too many quick-wear parts. So, many special turbo-drill had been developed to overcome these shortages, such as the turbo-drill with gearbox, the turbo-drill with low speed and high torque, the turbo-drill with spiral housing, and other new turbo-drills.

Nowadays, the main usage of this technique is to increase ROP and drill extended-reach wells. Furthermore, the property to bear a high temperature (reached 260°C) in

comparison with PDM tools makes the turbo-drill tool withstand the tough operations in the geothermal drilling.

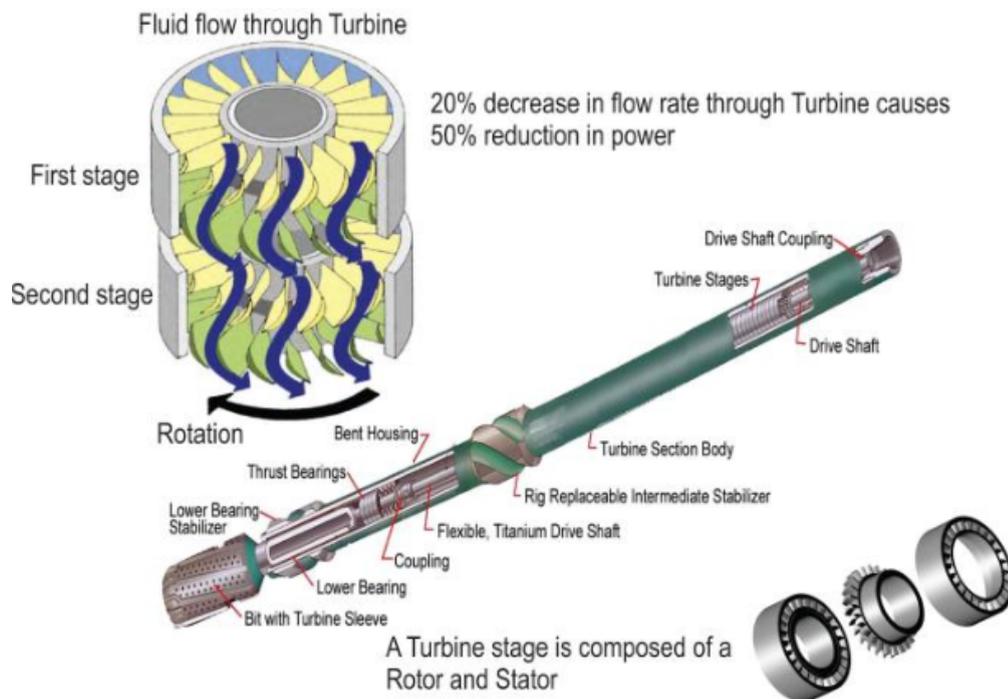


Figure 2.25: The schematic diagram of a typical turbo-drill, [16]

Turbine Observations:

- A minimal surface indication regarding a turbine stalling.
- High-pressure drop through the tool, about 500 psi to over 2000 psi.
- The turbine can operate in high-temperature wells due to minimal rubber components.
- Pumping of LCM does not readily allow in turbines.
- Drilling fluid sand content should be kept to a minimum.
- A by-pass valve does not require.
- The maximum allowable bearing wear is usually of the order of 4 mm,[3].

Turbine Characteristics:

- Torque and RPM are inversely proportional, if RPM increases, torque decreases, and vice versa).
- RPM is proportional to the flow rate at a constant torque.
- Torque is a function of blade angle and the number of stages, mud density, flow rate, and varies if weight-on-bit varies.
- Optimum power output takes place when thrust bearings are balanced.
- A stabilized turbine used in tangent sections will cause the hole to “walk” to the left.
- On the bottom, just at a stall, the turbine accomplishes max. torque and RPM is zero.
- Optimum performance is at half the stall torque and half the runaway speed, the

turbine then achieves max. horsepower.

- Off the bottom, the turbine RPM will reach “run away speed” and torque is zero.
- Flow rate Changing make the characteristic curve to shift,[3].

2.5.7 Orientation Sub and Bent Sub

Both of the orientation sub and bent sub are short segments of drill collar with a length of 2 ft, the designing of Muleshoe and key is helping the survey for the orientation of bent sub. In the bent sub, the axis of the lower connection is designed slightly off-vertical, the offset angle can be in the range of 0.5° to 3° .

This bent sub enforces both the DHM and the bit to drill in a selected direction that is determined by the tool face, which causes the deflection amount depends on the hardness of the formation, the motor stiffness, and the offset angle of the bent sub.

A typical deflecting assembly is shown in Fig.2.26, the bent sub is connected at the upper end of the DHM (PDM or Turbo-drill), and the orientation sub is connected at the upper end of the bent sub to survey the bent sub orientation. When the survey tool is seated it will give the direction of the tool face as the Muleshoe key of the orientation sub is aligned with the scribe line,[9].

There is also a NMDC that is connected above the bent sub which can adapt surveying tools to measure the orientation of the bent sub when the BHA is run to the bottom. To commence the directional drilling, without rotating the drill string, the downhole motor is operated and the bit is driven by the pumped drilling fluid through the drill string.

The development of DHM with bent housing makes the directional operations can be achieved without the orientation and bent subs, and this was because of the necessity to deal with particular cases such as improving operation efficiency, deflecting through a casing window, improving directional opportunity, etc..

The bent housing is mounted between the stator and bearing assembly to provide a slight bend of 0° - 3° with about six increments in deviation per degree of bend. A bent housing can be installed within the motor itself and at both the upper and the lower end of the down-hole motor and generally, it is installed at the lower end of the down-hole motor to satisfy a high deflection capacity.

2.5.8 The Fourth Generation of Directional Technique

This due to drilling automation and the typical feature of this stage is the invention of the RSDS which permits us to achieve complex wellbore geometries, including directional,

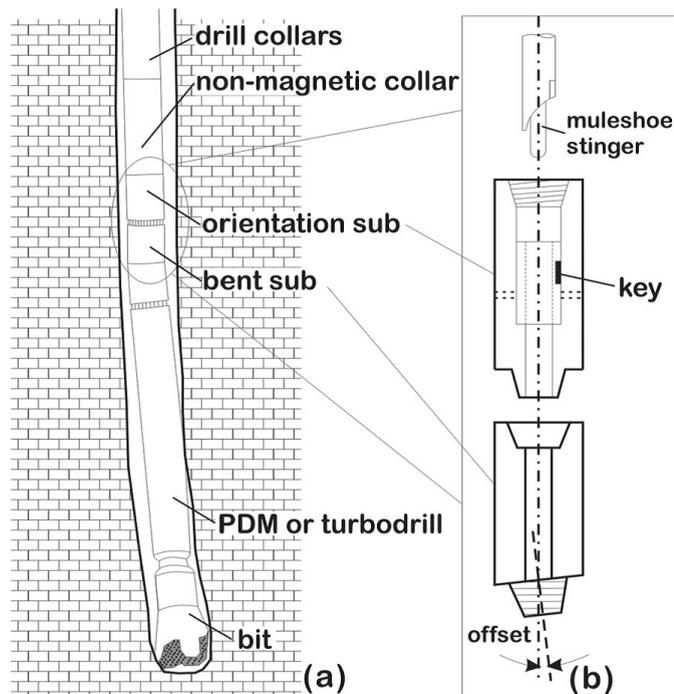


Figure 2.26: The schematic diagram of bent sub and deflecting assembly

horizontal, and ERD wells. It eliminates the sliding mode difficulties of conventional steerable motors by allows continuous rotation of the DS while steering the well.

It assists to improve the drilling efficiency and controlled accuracy and decrease the DS drag as this drag is always opposite to the direction of motion. Presently, the classification of RSDSs into two groups, the more prevalent (dogleg control) systems and the less mature (deviation control) systems,[6].

Classification of (dogleg control) which called likewise the conventional RSDS systems into two types: the more common “push-the-bit” systems, including the AutoTrak system and PowerDrive system and other common commercial types, on the other side, the less mature “point-the-bit” systems, including the Geo-Pilot system and CDAL system and also other common commercial types.

The (deviation control) systems are matured from the conventional BHA, the diameter variable stabilizer (DVS) is used to control the well deviation.

2.5.9 Rotary Steerable Drilling System (RSDS)

History of (RSDS)

During the 1980s, a new framework of technology has been introduced to the field which is steerable motor drilling, involved with PDC drill bits as well as MWD, These techniques

enhanced the productivity of DD and the accuracy of placing the well trajectory.

These tools decreased the requirement for continuous changing of BHA that is more needed with rotary drilling and employ the MWD survey recordings to apply more control over the well's trajectory. A key to the quick development of horizontal drilling in the 1990s was beyond the steerable motor systems.

The increased use of RS tools has necessitated further consideration into the design of them to capitalize on the potential of improved drilling performance that these systems offer to possess many beneficial qualities in comparison to the other techniques.

An RSS can make changes in I&AZ without stopping drill string rotation. This leads to a smoother hole, cleaner, and less drag. A smoother transfer of weight to the bit will lead to increased ROP.

(ERD) wells are behind the fact that RSS technology was refreshed after quite a few years of mud motors' domination in the drilling market. The steerable motor's ability was inadequate to fit the requirements of productive and economic drilling of ERD wells.

Offshore drilling represents another area where RSS dressed to be very effective with its ERD complicated horizontal wells and complex geometries of well trajectory.

RSS Characteristics:

RSS has the following advanced characteristics compared to DHM:

- RSS permit vigorously steering the bit, AZ&I, while continuously rotating the DS.
- Permit changing well trajectory according to DH real-time data.
- The assembly tool-face is oriented by the downhole guidance system.
- Smooth wellbore creation as the systems use a continuously adjusted steering function.
- As Geo-steering applications, RSS can be tied-up with more or less MWD/LWD tools.

Steering Principal:

Two operating principles are often referred to when discussing RSS namely push the bit or point the bit.

(Push-the-Bit (s-t-b)) Working Principle

Applying side force on the bit is the principle in this system, pushing it against the borehole wall to obtain the required trajectory,[17]. Schlumberger PowerDrive system and Baker Hughes AutoTrak system are typical systems under this type which is well be taken as an example to illustrate the working principle (Fig.2.28).

The device mechanically uncomplicated and compact, containing a bias unit and a control unit that adds only 12½ ft. to the length of the BHA,[6]. The bias unit exerts force in

a controlled direction to the bit while the whole drill string rotates, this unit locates directly above the bit. Also, the bias unit has three external, hinged pads that are energized by the controlled mudflow through a valve; the valve profit from the mud pressure difference between the outside and inside of the bias unit,[18].

The control unit, which is mounted behind the bias unit, involves sensors, self-powered electronics, and a control mechanism to supply the magnitude and direction of the bit side loads needed to accomplish the requested trajectory.

The three-way rotary disk valve activates the pads by diverting mud into the piston chamber of each pad as it rotates into alignment with the required push point, the point opposite the desired trajectory in the well as seen in fig.2.27,[6].

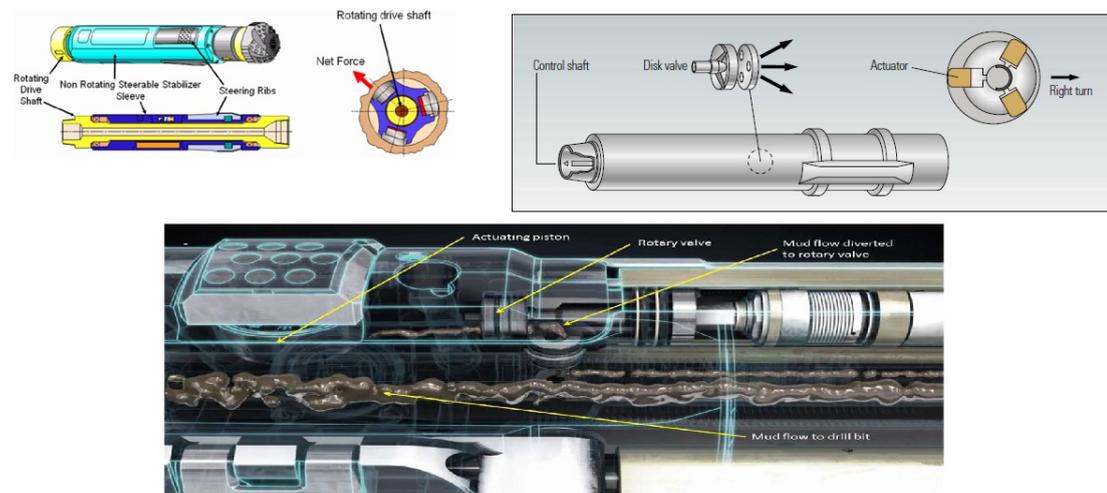


Figure 2.27: Push-the-bit, [19](L), Three-way rotary disk valve, [6](R), Rotary valve and valve chamber, [24](lower)

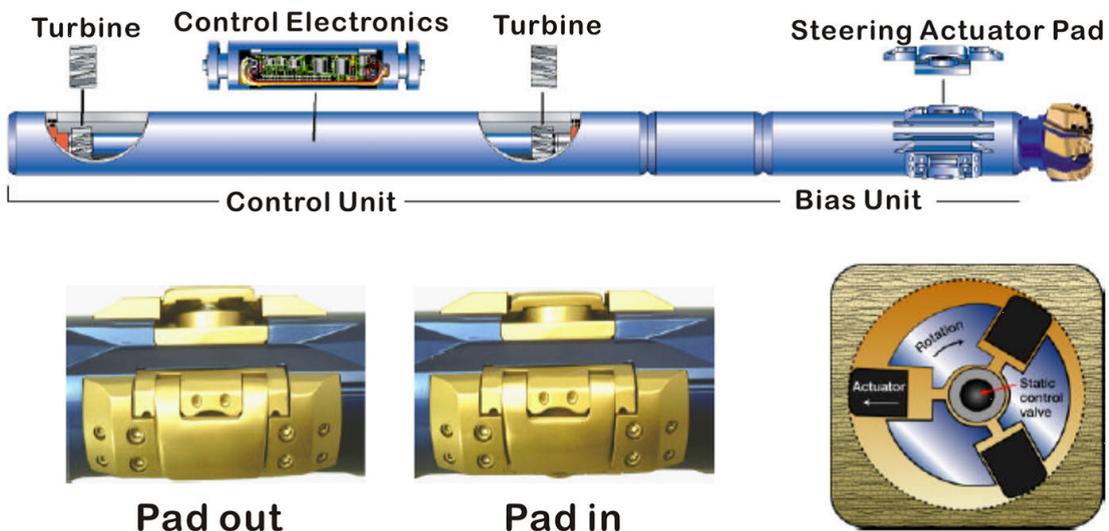


Figure 2.28: The Schlumberger PowerDrive system, [6]

(Point-the-bit (p-t-b)) Working Principle

This system utilizes the same principle of the bent-housing motor systems, Fig.2.29. The bent housing in this system is contained inside the collar, so it can be oriented to the required direction when the DS is rotated, as in Fig.2.30,[17].

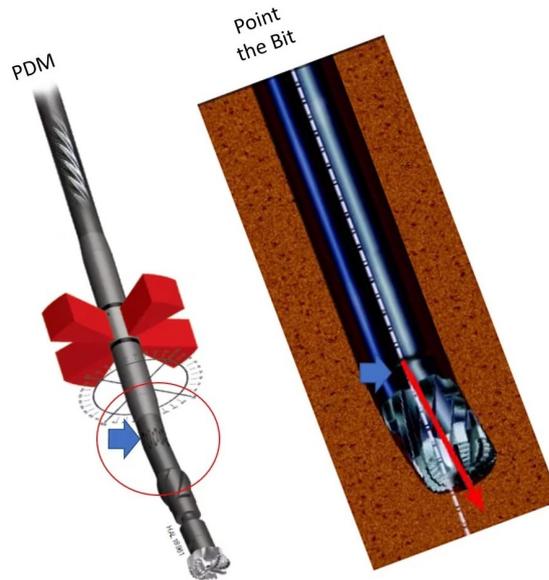
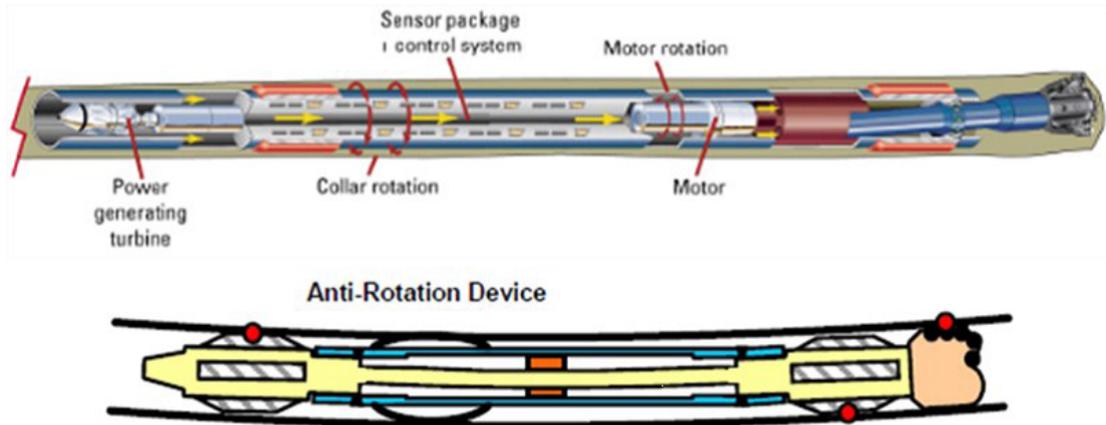


Figure 2.29: Same principle of point the bit & motor systems



Internally deflected driveshaft on a non-rotating housing

Figure 2.30: Point-the-bit

The Halliburton Sperry-sun Geo-Pilot system and Gyrodata CDAL system are included in this system. To explain the working principle of “p-t-b” systems, the Geo-Pilot system is a typical example (Fig.2.31), which mainly consists of the internal rotary shaft, non-rotating outer housing, dual eccentric rings. One eccentric ring is installed another internal, the dual eccentric rings are a type of controllable eccentric unit, the internal ring can arrange the internal rotary shaft to deflect, so the dogleg carried out

by mechanical means, so the bit is tilted relative to the rest of the tool to perform the required trajectory.

Strictly speaking, in this system, well trajectory is changed by changing the tool face angle, the trajectory changes in the direction of the bend,[20]. A servo motor that rotates at the same rate as the DS is controlling this bend orientation, but counters to the DS rotation. This permit the tool face orientation to stay in geostationary, or nonrotating, while the collar rotates,[18].

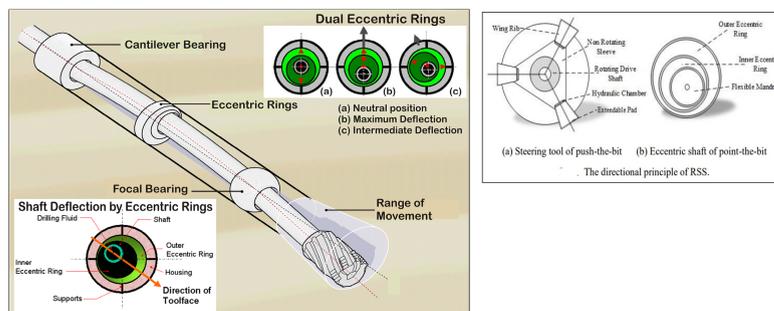


Figure 2.31: The Halliburton Sperry-sun Geo-Pilot System(L), Directional principle(R)

The Hybrid (Push and Point-the-bit) System

The PowerDrive Archer RSDS as seen in Fig.2.32 that is developed by Schlumberger is an example of this system,[21, 22]. So, it has the features of both of the previously mentioned systems. Four actuator pistons within the drill collar push against the inside of an articulated cylindrical steering sleeve, which pivots on a universal joint to point the bit in the required direction, and this is unlike the (s-t-b) systems, the PowerDrive Archer system does not depend on external moving pads to push against the formation.

Furthermore, four stabilizer blades on the outer sleeve above the universal joint provide side force to the drill bit when they contact the borehole wall, enabling this RSDS to do the same as a push-the-bit system.

At the present, the maximum build rate for the 8½ in. hole-sized PowerDrive Archer RSDS tool is about 17°/100 ft. i.e., the precise and accurate control makes the RSDS put the well trajectory in the reservoir’s sweet spot and extend the horizontal to total depth with higher build rate capacities, it kicks off deeper and keeping verticality at higher depths,[20].

Also, since the electronic control system is an important factor to operate RSDS, the heat-related damage must be controlled to protect the tool’s electronics boards. Nowadays, each of the AutoTrak systems, PowerDrive systems, and the Geo-Pilot system almost can operate at a high temperature of 200°C. However, the temperature in geothermal drilling

often exceeds the maximum capacity of RSDS, so, to protect the tool's electronics boards from heat-related damage, it is necessary to control drilling parameters and additional off bottom circulation.

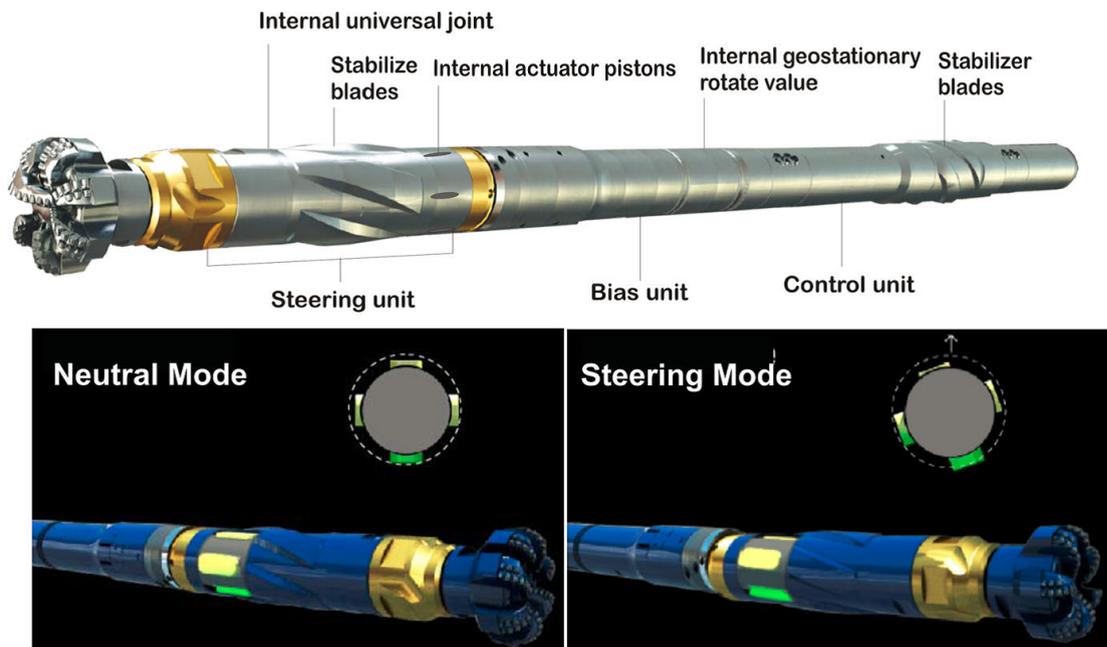


Figure 2.32: The Schlumberger PowerDrive Archer rotary steerable system. This hybrid system combines actuator pads with an offset steering shaft-all located inside the drill collar for protection from the downhole environment, [19]

Motor Supported RSS

Any of the previously discussed RSS whether it is of S-T-B or P-T-B when it is supported by motor section above it Fig.2.33 for increasing the lower part of the BHA RPM to minimize the tendency of a stick-slip vibration and use lower surface RPM for String and /or casing wearing and torque. The AutotrackExtreem of Baker and GXT MARSS of Halliburton is examples of this design.

Furthermore, by modifying the conventional motorized RSS to having both the MWD and RSS tools below the motor instead of only the RSS below the motor as seen in Fig.2.34. This modification enables get closer measurements to bit with the full transmission of all downhole data to surface to optimize the drilling parameters, and increasing (BHA) stability to prolong the run duration,[23].

This leads to apply higher RPM on the MWD tool by both the surface and motor-added RPMs which yield more fatigue and stresses on the MWD tools. Therefore, all MWD mechanical components had to be upgraded to the latest modification recaps for higher RPM operations.

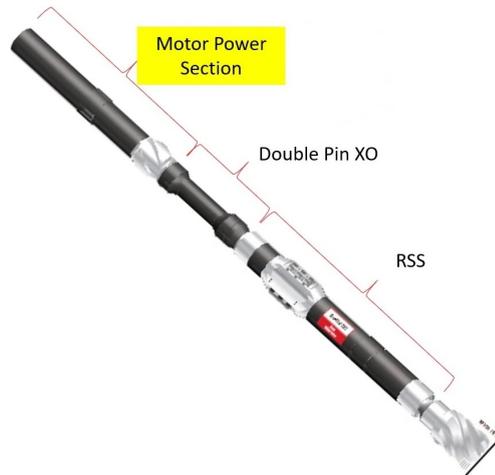


Figure 2.33: Motor Supported RSS

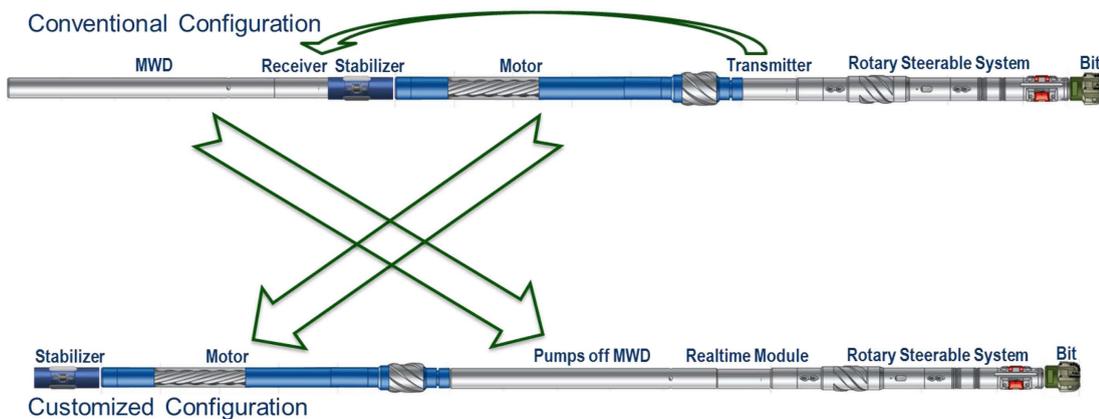


Figure 2.34: Conventional vs. Customized BHA Configurations, [23].

Key Requirements Drive RSS Deployment

For the recent era, the RSS tool design becomes simple, reliable, easy to live with, sufficiently slick to minimize the chances of sticking, rapid repair anywhere in the world with minimal tooling, it should allow of switching off bias at any time when commanded to do so, thus, the bit is not tilted or biased sideways when this is not required, or even undesirable, the ability to automatically hold AZ&I, and surely it should be cost-effective.

To have a look to the RSS market, over the years it has grown and changed, by 2017, RSS accounted for more than 60% of the US DD market and from 2016, the majority of the global directional drilling market was addressed by RSS technology, 72% of RSS wells push the bit and only 21% pure point the bit.

Economics and a lower oil-price environment are strong drivers affecting activity. From 2014 to 2016 activities are dramatically declined, horizontal footage drilled in the US fell by 53%, however, horizontal footage as a percentage of total footage drilled rose

from 68% to 81%, and by 2018 was expected to increase further to 89%. These numbers indicate a change in the RSS tools market, i.e. more and longer horizontal sections[24].

A report on the global RSS market indicates that the total North American RSS market share of directional service companies ranked 5th and below grew from 5% in 2016 to 11% in 2018, more than doubling in 2 years and indicating a potential commoditization of the RSS market, specifically in North America. According to Spears (2017 and 2018).

Regarding the RSS tool for the post-2014 world, several key requirements were identified are listed below. With minor modifications, the following rules could serve as a template for any new drilling or measurement tool design in the current era.

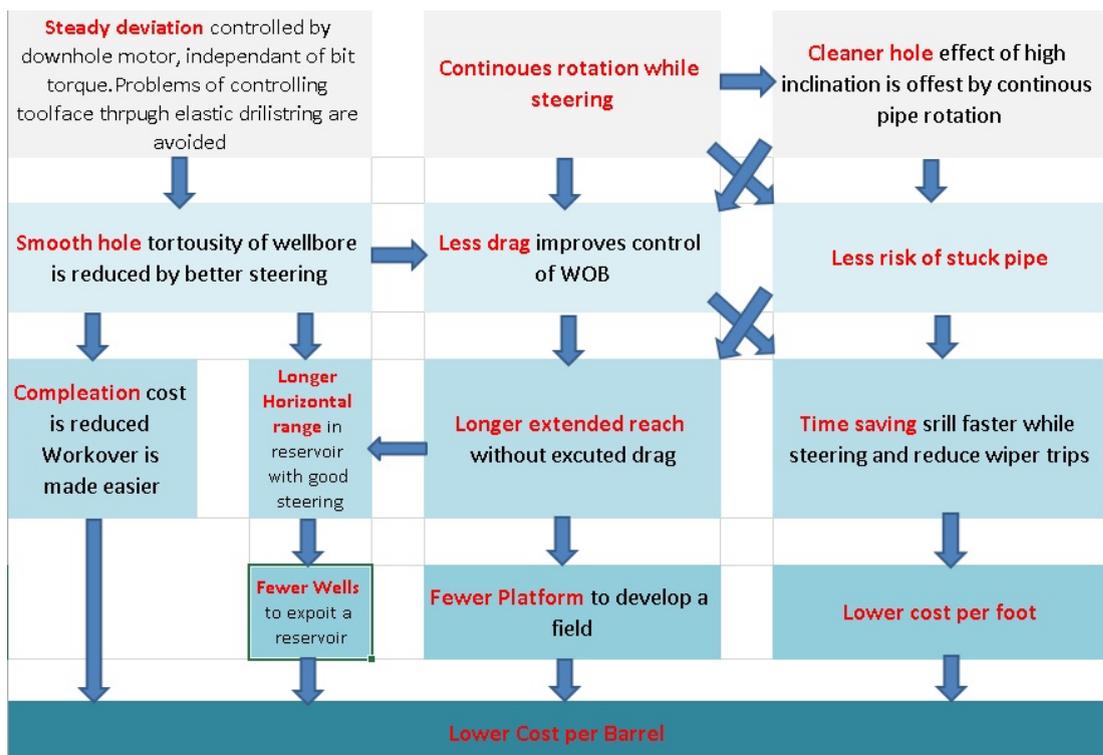


Figure 2.35: The Benefits of RSDS

Simplicity: Mechanical simplicity, reliable, cost-effective, and easy to live with. It had to be easy for both the service company and the operator.

Repair Anywhere: Repairable with a break-out machine, an overhead crane, and a simple tool chest. All parts are subject to wear and erosion (pad, seals, piston, hinges, chokes, bushings, valve, motor, and gearbox) are contained in a single valve/motor/actuator (VMA) assembly which can be removed as a single piece from the tool outside.

Slick Assembly: When the risk of being stuck, it can be significantly mitigated by making the assembly as slick as possible, for example, stabilizer design and junk slot area, minimum 20 flow area and only one fixed stabilizer, 1/4 in. under gauge.

Off Switch: When drilling out of casing; reaming; and wiper trips and longer horizontal sections mean that (T&D) become ever-increasing, challenges capable of drilling straight. Each of the actuators can independently be switched on or off, allowing full bias, zero bias, or any proportion in between those two extremes. When the bias is switched off, the bias unit effectively becomes a concentric, slightly under-gauge near-bit stabilizer.

Motorized: Currently more than 50% of RSS runs are motorized, i.e (PDM) is run above the RSS to increase horsepower at the bit, decouple the BHA from torsional drill string oscillations, and mitigate the effects of stick-slip as described.

Torsional Strength: Top drives and PDMs output increasingly high amounts of torque and power. The tool design to accommodate a high torque, achieved partly by designing the steering collar, and partly by the use of a full diameter construction with no sleeves or driveshafts, so that potentially highly stressed features see relatively little bending-the bending being taken in a separate and featureless flex collar.

Layout: A bias unit immediately behind the bit, three hinged pads, each of which is extended in turn, up to once per revolution, by a mud-actuated piston immediately behind it. Selective actuation of these pads creates an effectively offset (eccentric) near-bit stabilizer just a couple of feet from the bit cutting structure-the exact length depending on bit gauge and shank length. A collar stabilizer sits about 11 ft. from the bit, this creates a three-point geometry which defines the maximum geometric dogleg capability of the system, Along with the drill bit and the effectively offset near-bit stabilizer created by the steering pads.



Figure 2.36: Layout of RSS tool, [24].

Immediately uphole of the steering pads is a corresponding set of brushless DC electric motors. Each of these motors controls its valve that in turn controls the supply of drilling mud under pressure to one of the above-mentioned actuating pistons.

Chapter 3

Directional Survey Technique

3.1 Overview

To pinpoint the wellbore location and direction, a directional engineer depends on measurement from both the magnetometer and accelerometer and gyroscopes.

Previously, high accuracy guidance methods required a stop in drilling operation to get a directional survey, but advances in geomagnetic referencing now allow companies to utilize real-time data acquired during continuous drilling to actually locate the directional wellbore,[\[25\]](#).

Accurate wellbore positioning is a key for safe drilling and production wells and it is crucial to where each well relative to the reservoir. Minimizing wellbore position uncertainty is critical in:

1. Avoiding a collision with any neighboring wells.
2. Drilling relief wells.
3. Penetrating the driller's target with the required precision.
4. Obtain good quality of logging data or geosteering in thin reservoir sections.
5. While drilling appraisal wells to ensure accurate reserve estimation and optimize hydrocarbon recovery.

Today, many deviated and horizontal wells navigate through the reservoirs instead of only penetrate it. This is done by utilizing the MWD tools which will give a directional accuracy within a fraction of degree. As these tools approved success and become more dependent on well guidance, the necessity to know the uncertainty in accurate quantified positions has increased. This chapter will review the aspects of wellbore surveying and the modern technique used.

3.2 Historical perspective

The oldest method was lowering a glass bottle of acid downhole and holding it stationary long enough for the acid to etch a horizontal ring in the bottle. Then once retrieving the device out hole, the ring's position was interpreted for inclination.

The single-shot mechanical drift indicator is another simple survey tool. Also, inclination and magnetic azimuth were recorded by (MSS) and (MMS) surveys. The device took a shot or photograph, of compass cards downhole whilst the DS stationary every 90 ft. during an active change of direction and every 200 to 300 ft whilst drilling straight ahead.

In fig.3.1, this downhole device measures drift, or deviation from vertical using a pendulum, or the “plumb bob” principle. The sharp-tripped pendulum is lowered onto a disk into which it punches two holes that mark an initial measurement than a verification measurement. In these examples, the inclination is 3.5° . The technique does not indicate azimuth but may be reliable for surface hole intervals and shallow vertical wells in which dogleg severity (DLS) and inclination (I) are not significant.

There was always a demand for more precise survey instruments, so it was developed over the next years. Development of sensors and mud pulse telemetry of MWD simultaneously with the DHM allow continuously updated digital measurements for the well trajectory.

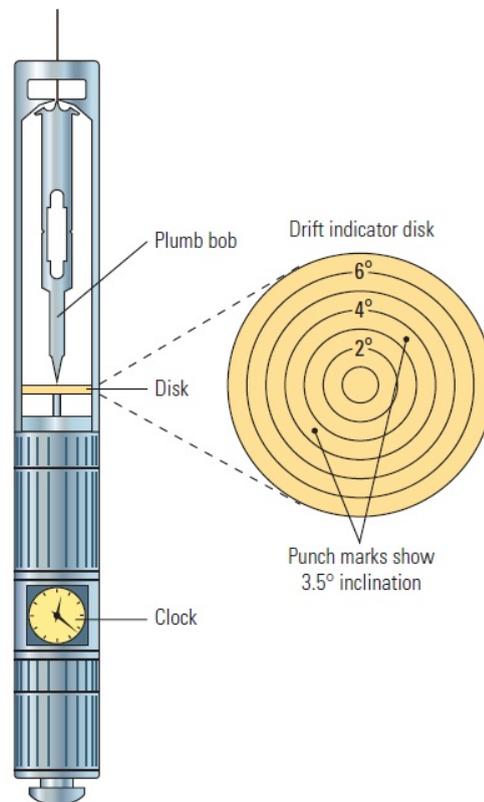


Figure 3.1: Mechanical drift indicator, [5].

3.3 Survey Methods Classification

There are two sets in the classification:

1. The more common is MWD tools.
2. The less popular is post-drilling measurement tools.

The magnetic single-shot instruments(MSS), electronic single-shot instruments, magnetic multi-shot instruments(MSS), and electronic multi-shot instruments are employed to measure the wellbore trajectory after drilling, however, it's inefficient and inconvenient for directional drilling, [2, 22].

3.4 Directional Data Classification

Three kinds of downhole data are available which need to be measured during drilling as shown in Fig.3.2. The MWD tools are used to measure both the directional and the drilling engineering data, while the formation information is matured from the conventional logging technique and employed for geo-steering drilling to adjust the geological target in real-time.

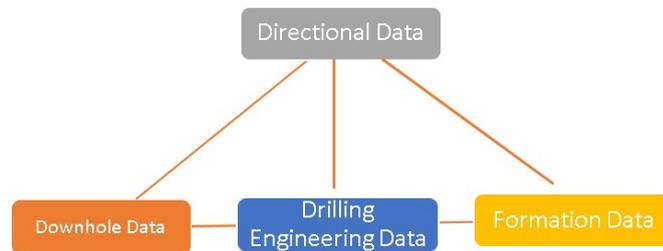


Figure 3.2: Directional Data Classification

3.4.1 Directional Information

The directional information assists the directional driller to realize where the well is going, and what the effects of his steering efforts are. In fact, the MWD tools have the ability to catch directional surveys in real-time, [17].

The inclination and azimuth (I & AZ) are measured by the accelerometers and magnetometers which are transmitting the data of (I & AZ) to the surface. So by using the survey data, the location and trajectory of the wellbore can be calculated. Also, the MWD tools commonly able to provide the survey of tool face during a stoppage in drilling, which will be a benefit in directional drilling using the RSDS tool, whipstock (WS), bent(sub), and housing down-hole motor (DHM).

3.4.2 Drilling Engineering Data

Several engineering measurements have a vital role to improve drilling efficiency and prevent downhole accidents, These data such as the WOB, down-hole pressure, mudflow volume, vibration, torque on bit (TOB), rotational speed, temperature, etc. usually, is measured utilizing a special separate sub/tool and uploaded by MWD tools.

This information will contribute to supporting the identification of the downhole conditions and the operation status of drilling tools in real-time, which enhance the drilling operation more efficient, safe, and economic. As well as, this data is also worthwhile to Geologist who is responsible for the subsurface data in the area of drilling activity,[17].

3.4.3 Formation Data

Formation data in real-time can be recorded by the conventional MWD tools, either on their own or in connection with separate subs/tools, this is so-called LWD that is derived from the conventional wireline logging techniques. The relevant data of subsurface formation such as, the natural gamma-ray, formation pressure, resistivity, porosity, density, acoustic-caliper, magnetic resonance, etc.

The tool length effect:

The presence of several tools in the BHA configuration in specific length depending on the designer, include down-hole motors, sub, and LWD tools, so bear in mind the length effect, this means, the measuring point of directional information has to move up. Therefore, Drilling tools designers developed a near bit inclination device to catch directional data at the drill bit. The near-bit measurements, such as (I & AZ), gamma-ray, aid the driller to closely monitor drilling progress,[20].

3.5 Principles of MWD and Magnetic Spacing

MWD tools are integrated into the BHA. The process steps are illustrated in fig. 3.3, accelerometers measure the strength of the earth's gravitational field component along their axis while magnetometers measure the magnetic field along their axis.

Then, through a set of mathematical equations, converting these measurements to the survey parameters (I, AZ, and Depth) which are then utilized to obtain wellbore position coordinates (Northing, Easting, TVD) by applying any survey calculation method, e.g Minimum Curvature, [26].

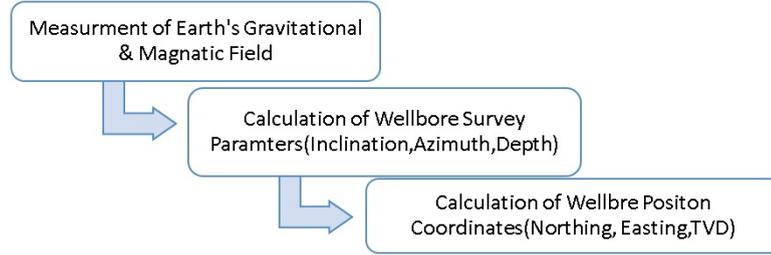


Figure 3.3: Process of Estimating Wellbore Position from MWD tools

MWD generally involves a non-magnetic drill collar (NMDC), including an instrument of a survey in which are mounted these 3 magnetometers and 3 accelerometers and some technique of sending the data from these to surface.



Figure 3.4: A non-magnetic drill collar (NMDC), [27].

It is always possible to work out which way is 'down' with three accelerometers installed orthogonally, and it is always possible to work out which way is North (Magnetic) with three magnetometers.

The following equations can be used to convert from three orthogonal accelerations, G_x , G_y and G_z (sometimes called A_x , A_y and A_z) and three orthogonal magnetic field measurements, B_x , B_y and B_z (sometimes called H_x , H_y , and H_z), to the inclination and direction (Magnetic), [27].

$$I = \cos^{-1} \left(\frac{G_z}{\sqrt{G_x^2 + G_y^2 + G_z^2}} \right)$$

$$A = \tan^{-1} \left(\frac{(G_x B_y - G_y B_x) \sqrt{G_x^2 + G_y^2 + G_z^2}}{B_z (G_x^2 + G_y^2) - G_z (G_x B_x + G_y B_y)} \right)$$

Figure 3.5: Conversion Equations from MWD field measurements to inclination & direction, [27].

Where the x and y are the cross-axial axes and the z-axis is considered to point down a hole. Care should be taken when identifying the axes and reading raw data files as some tools are arranged with the x-axis downhole and y as well as z from the cross-axial components.

Also, consistency in units might not be found in that, some systems output accelerations in mg, others in gs, and some in analog counts. Similarly, the magnetometer outputs can be in counts, micro Teslas, nano Teslas.

The accelerometers are tiny weighing machines, measuring the weight of a small proof weight suspended between two electromagnets. Held horizontally they will measure zero and held vertically they will measure the local gravity field.

Theoretically, inclination measurement could be done with only one accelerometer but a z-axis accelerometer is very insensitive to the near-vertical movement because of the cosine of small angles being so close to unity, As well as we also need the instrument to provide the tool face (rotation angle in the hole).

Various types of magnetometers are available, usually, consist either of a small electromagnet used to cancel the Earth's magnetic field component or a coil with alternating current used to fully magnetize a core alternating with or against the Earth field component.

If the tool face is needed as an angle from magnetic north corrected to our chosen reference (true or grid), using the x and y magnetometers and resolve $\tan^{-1}(B_x/B_y)$ and if the angle is needed from the hole high side, resolving $\tan^{-1}(G_x/G_y)$.

Due to some practical causes, most MWD systems switch from a magnetic tool face to a high side tool face when the inclination exceeds a preset threshold generally set between 3 and 8 deg.

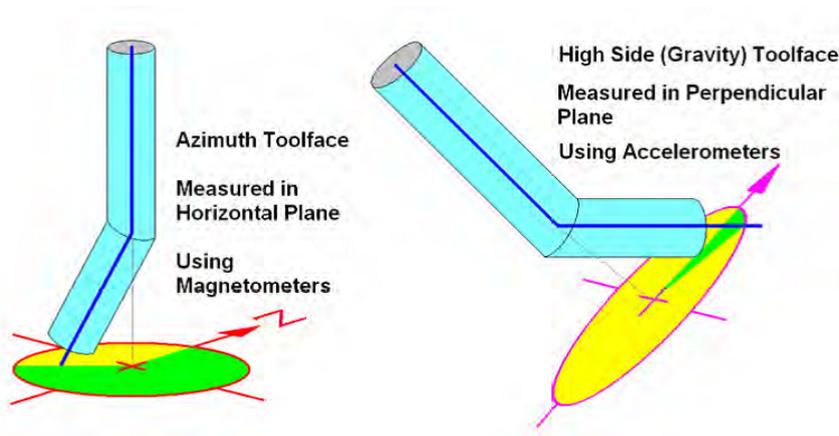


Figure 3.6: Tool Phase, [27].

3.6 Survey Errors Modelling

3.6.1 Positional Uncertainty and Errors

As it's known in the industry, in each measurement, errors may occur due to tool or environment. Accuracies availability from a stationary survey made with MWD are on the order of ± 0.5 for azimuth, ± 0.1 for inclination, and ± 1.0 for tool face, [25].

Parameter	Gyroscopes (ADXRS150)	Accelerometers (MS9010)	FluxGate Magnetometers (CTM-DT06)
Range	$\pm 150^\circ/\text{s}$	$\pm 10 \text{ g}$	$\pm 100000 \text{ nT}$
Scale Factor	12.5 mV/(deg/s)	200 mV/g	5V/G $\pm 5\%$
Nonlinearity	0.1% of SF	0.8% of SF	-
Bias calibration	$+2.5 \text{ V} \pm 0.3 \text{ V}$	$< 50 \text{ mg}$	$\pm 0.005 \text{ G}$
Noise	$0.05^\circ/\text{s}/\sqrt{\text{Hz}}$	$0.140 \text{ mg}/\sqrt{\text{Hz}}$	$\leq 0.1 \text{ nT}$
Bandwidth	40 Hz	1000 Hz	350Hz

Figure 3.7: Characteristics of Sensors, [28]

Wellbore position is located within an ellipsoid of uncertainty (EOU), the ability to determine trajectory based on the accumulation of the error from wellhead to TD, more than indicating a point in space.

Uncertainty in vertical or along hole path is less than the lateral one, and if represent it cautiously along a trajectory, the EOU gives a volume shaped like a flattened cone.

As in fig. 3.8 which is showing slices of the ellipsoids of uncertainty (EOUs) obtained from standard MWD (blue) and from higher accuracy MWD (red) survey. The (I & AZ) uncertainty is in the XY plane perpendicular to the borehole. The depth uncertainty is along the Z-axis of the borehole. When shown at a dense series of points along the well trajectory, they form a “cone of uncertainty”. The high-accuracy method delivers a wellbore with smaller positional uncertainty.

A rigorous mathematical procedure for combining various error sources into one 3D uncertainty ellipse was developed by ISCWSA and WPTS.

As MWD measurement accuracy decreases with increasing hole inclination and also effected by North to East direction, so, understanding the behavior and contribution of each survey error source and screens the error terms contributing most towards WPU is important.

Anticipating the contribution of each error source as a function of well path direction and inclination will allow knowing position uncertainty of individual wells. The visualization of error sources will deliver a more focused approach towards reducing the WPU,[26].

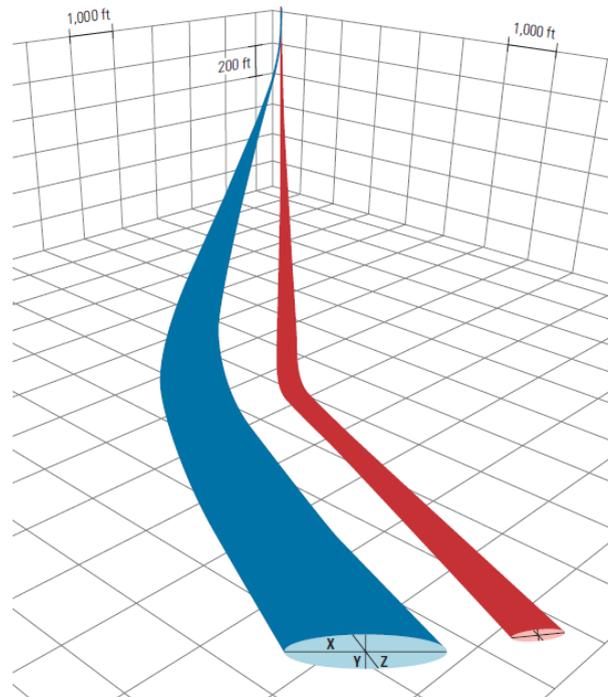


Figure 3.8: Planned well trajectories [29].

A list of common error sources which distort the survey data is provided below, [26].

1. Depth reference errors.
2. Tool misalignment errors.
3. Magnetometer bias/scale errors.
4. Temperature effects.
5. Magnetic drill string interference.
6. Accelerometer bias/scale errors.
7. Survey resolution.
8. BHA SAG.
9. Errors in reference values of a total magnetic field, dip angle, and declination errors.

Besides that, the errors in estimated azimuth from magnetometer observations can be classified as, [30]:

- Temporal variations of the magnetic field.
- Magnetized minerals in crustal rocks.
- Magnetic interference caused by magnetized-drill string components.
- Magnetized constituents in drilling fluid.

3.7 Improving Well Position Accuracy

When employing magnetic guidance to position the wellbore accurately, one must bear in mind to eliminate or take into account two sources of survey errors: Local variations between magnetic north and true or geographic north, and interference caused by magnetized elements in the drill string.

Multi-station Analysis (MSA) is an analysis of survey data from multiple wells that taken influences of the crustal field and time-varying disturbance field beside secular variations in the main magnetic field. This method is key to address these interferences[25].

Furthermore, using Geomagnetic Referencing as another method for enhancing wellbore position accuracy.

Multistation analysis (MSA) and magnetic in-field referencing (IFR) have already demonstrated the potential to decrease the effects of errors because of magnetization of drill string components along with variable errors caused by irregularities in the magnetization of crustal rocks in the vicinity of wells.

Although directional-drilling applications are considered on a local-scale basis, variations in the magnetic field must be taken into account to significantly reduce the uncertainty of the well position,[30].

3.7.1 MWD Magnetic Spacing

In fact, when using magnetic sensors in an MWD tool, it must be sufficient magnetic isolation to avoid significant magnetic influences from the other drilling equipment.

3.7.2 Drill String Magnetic Interference

Rotation of metallic body drill string and its shape causes the magnetization to be aligned along the drill string axis which means locally disturb the Earth's magnetic field. Accurate measurement of magnetic azimuth is difficult as the horizontal component of the Earth's magnetic field is locally corrupted. The insertion of non-magnetic drill collars (NMDC) into the drill string will only reduce (do not remove it) this effect, for sensible magnetic azimuth measurement.

3.7.3 Pole Strength Values

The polarity and intensity of magnetic interference are not easily predictable. In many cases, the use of magnetic NDT techniques causes interference which of course has nothing to do with geographic location. The numbers suggested here are merely a guide and certainly not an upper limit,[25].

Upper Pole Lower Pole : Drill collars up to + 900 μWb . Stabilizers and bit up to -90 μWb . 10m drill collar below NMDC up to -300 μWb Turbines up to -1000, μWb

3.7.4 Azimuth Error

The magnetization of the drill string affects the observed horizontal component of the local magnetic field. A magnetic compass detects the horizontal component of the Earth's magnetic field. The compass error increases with an inclination and with increased easterly or westerly azimuth of the wellbore.

3.8 Corrections Applied to Magnetic Surveys

An analysis of industry survey of error codes being utilized across companies. A collaborative workgroup was formed under the Operator Wellbore Survey Group (OWSG). OWSG is a subcommittee of the SPE Wellbore Positioning Technical Section (SPE-WPTS). The SPE-WPTS originated as the Industry Steering Committee on Wellbore Surveying Accuracy (ISCWSA), which affiliated to the SPE and became a Technical Section.

The possible processing and corrections applied to magnetic surveys are as follows, and always appear in the same order in the names,[\[31\]](#):

IFR1–In-Field Referencing, also known as Crustal Anomaly Correction.

IFR2–In-Field Referencing with Time-varying Correction (also known as Crustal Anomaly with Time-Varying Corrections, which includes Interpolated In-Field Referencing).

AX–Axial Drillstring Magnetic Interference Correction for Single Stations.

SAG–Correction for the Sag of a Bottom Hole Assembly due to Gravity.

MS–Multi-Station Correction.

Steering Committee on Wellbore Survey Accuracy (ISCWSA) error models is used by the industry for estimating the Wellbore Position Uncertainty (WPU),[\[26\]](#).

State of the art error modeling is mainly dependent on collaborative work within the SPE Well Positioning Technical Section (WPTS), formerly the ISCWSA.

Earth's magnetic field is the reference adopted for MWD azimuth calculations. In modern MWD instruments, the sensor errors are small in comparison to typical variations in the Earth's magnetic field. So, MWD positional uncertainty is due to environmental effects from natural fluctuations in the magnetic field and disturbances caused by adjacent magnetic material.

Independent entities are usually developing methods available to the MWD companies for dealing with the effects of magnetic field variations.

A subgroup within the WPTS, the Operators Wellbore Survey Group, generated a new set of models cover the most basic methods to higher accuracy systems sophisticated

integrating axial interference corrections and geo-magnetic referencing techniques referred as in-field referencing (IFR). The multi-station analysis (MSA) in MWD directional surveying making more improvements in survey quality.

The situation is quite different for gyro surveying in which determining the direction of the Earth's rotation vector. Gyroscopic tools are far less accurate than the stability of the Earth's rotation rate. The SPE WPTS provided the drilling industry with a framework for mathematical error modeling of gyroscopic survey tools, and not to provide numerical error parameter inputs because service providers use different sensors and tool mechanizations.

Comprehensively, External effects on accuracy involve BHA deflection, axial misalignment, drill string-induced interference, and geomagnetic field variations,[30].

3.8.1 Major Corrections

Depth Correction:

There are many sources of error affecting both drill pipe and wireline length downhole but depth correction will usually address the mechanical and thermal stretch. These account for the major depth errors and can be as much as 0.2%.

SAG Correction:

This is an inclination correction to allow for the natural bending of the BHA under its own weight. It increases with an inclination and can be 0.5° or more.

IFR Correction:

This refers to the local correction of magnetic declination and is derived from an In-Field Referencing survey of the oilfield. This can be up to 1° in places.

Magnetic Interference:

This applies to azimuth only and corrects for the magnetic influence of the BHA itself. It is particularly important when using short non-mag collars.

3.9 Wellbore Surveying Using Gyros

Continuous and stationary methods are included in the current gyro survey. Continuous gyro surveys measure the changes in (I&AZ) at more frequent intervals (generally every

foot) and the absolute value of them is derived by summing the incremental changes from a known start orientation.

The initial orientation is often established at the surface using fore-sighting methods or other sources of attitude data that can be made available above ground, including satellite navigation data, or down-hole by using a gyro compassing survey(s), [30].

Stationary commonly taken at a pipe or stand length intervals (10m – 30m). Gyro compassing techniques utilization to determine wellbore (I&AZ) and to establish the trajectory of the well, positional data are derived then combined with long-hole depth measurements in a curve fitting process.

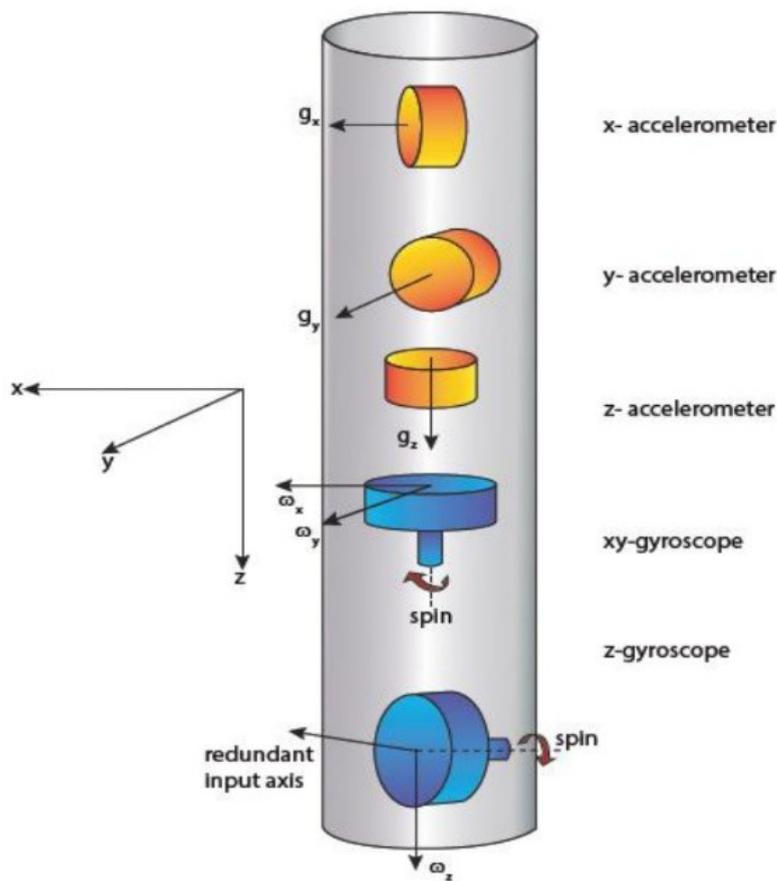


Figure 3.9: Sensor layout schematic, [30].

3.9.1 Gyro Error Model

The main sources of measurement error in an XYZ gyro system are gyro bias, gravity-dependent errors (mass unbalance and quadrature error), gyro misalignment, scale factor imperfections, and random, spin sensitivity and isoelastic effects noise. These errors are measured and compensated for during the calibration process.

3.9.2 Quality Control (QC)

QC processes involving georeference checks relative to the local Earth's gravity and rotation fields, multi-station tests, independent verification surveys, and repeated measurements, are required to ensure a survey reliability level consistent with the demands embedded in instrument performance/error models.

3.9.3 Gyro-Compass All Attitude Tool (GCAAT)

When a lattice of wellbores is constructed at different vertical depths and close to one another, accurate knowledge of the path of each well is clearly crucial, the best possible survey technique and tools need to be utilized to ensure safe and reliable drilling and get high-quality surveys. In the latest technological developments, significant differences in performance are identified through the examination of published error models for these different types of survey,[\[32\]](#).

Two possible approaches to well positioning: the conventional approach based on magnetic MWD including IFR aiding and the relatively new all-attitude gyro. Both strategies offer survey information at any attitude, however, each is subject to performance limitations as a consequence of lots of causes.

Wellbore position uncertainty estimation (error modeling) is a key factor in safe and cost-effective drilling which has improved greatly over the last 20 years by many researchers. Recent developments in gyro surveying technology led to the introduction of a new all-attitude gyro survey tool called the Gyro-Compass All Attitude Tool (GCAAT).

The features of this technique are as follows:

1. The GCAAT enables gyro compassing at all attitudes.
2. The GCAAT eliminates the traditional survey issues associated with high angles or east/west surveys.
3. The GCAAT tightens up uncertainties allowing adjacent wells to be drilled through increased confidence in the center to center distances.
4. In drop mode on the last trip out of the well the GCAAT provides an economical gross error check on MWD surveys before casing being set.
5. The lateral uncertainty of a GCAAT survey is 50% lower than that achieved using MWD for long horizontal east/west wells,[\[30\]](#).

3.9.4 When to Run Gyros

It is nearly always a benefit running gyro surveys to measure accuracy and verify of the MWD surveys, but the benefit has to be worth the cost. In certain circumstances running gyros is the only choice for a safe and adequately accurate survey. The scenarios below (apart from no.1) are assumed that the gyro used is of sufficient accuracy to exceed the accuracy of the MWD. Depending on the type of gyro and the expected performance of the gyro must be ascertained by suitable QC to ensure adequate accuracy.

1. In case magnetic interference from nearby steel prevent the use of MWD, which includes: a) Measuring close to adjacent wells. b) Measuring inside casing. c) Measuring close to casing shoe. d) Measuring close to a fish or when side-tracking close to the original casing. e) Measuring close to the surface or shallow beneath the rig.
2. When DLS exceeding 60/100 ft, but the MWD is surveyed every 90 ft, the MWD survey interval will not adequately represent the well path. Here the gyro delivers a higher resolution survey and can be required at very small intervals although 25 ft is common.
3. In case TVD accuracy is needed less than 3/1000 on step out. This is hard to accomplish by MWD in an open hole and while the accelerometers may be just as accurate as the gyro sensors in the vertical plane, the measurement environment, and hole quality cannot provide this accuracy level confidently.
4. Anywhere, where using MWD alone cannot be meet the separation factor requirements.
5. When the dimensions of the target are less than 2% of the step out (1% if IFR is employed). The directional driller will not have sufficient room in this size of the target to steer successfully without minimizing in uncertainty afforded by a high accuracy gyro survey.
6. When side-tracking the hole where the original one has a fish or casing and the accuracy requires an adequate survey during the side-track section close to the original hole.
7. When drilling close to fault blocks, lease lines, geohazards, or other 'hard-line' boundaries where MWD uncertainty wastes too much pay.

3.10 Drill Mode Survey Technology (DMS)

Conventional MWD surveys are taken when static and are usually time-consuming. So, taking directional surveys without waiting for surveys to be sampled and drilling stopped will optimize drilling with reducing NPT and stuck pipe. So, to achieve that, DMS and

continuous survey with static mode are developed, the DMS relies on the same six-axis arrangement as with static surveys, improved by increasing their sampling rate, rolling averaging, processing speed, sensor timing to allow for varying RPM's, temperature change and also increasing the sensors technology,[33].

Improving sensor technology to allow for the stability of measurements with temperature changes, sensor timing/electronic latency has to be understood very accurately to allow for varying RPM's and the effects of drilling environmental, shocks, and eddy currents have to be investigated and compensated for.

Filtering and processing the six axes to a Pseudo-state due to the survey tools rotation during drilling. Survey algorithms were adjusted to enable this pseudo-state stable data generated, as inputs to provide accurate survey outputs.

Tool Feature Analysis:

A typical comparison between a traditional static survey and a dynamic survey taken using the spin rig is presented in table 3.10. The results show good data correlation.

Static Survey						
Depth	RPM	Azimuth	Inclination	Magnetic DIP	Total G	Total H
6000	0	153	68	66.9	1001.1	48502

DMS(Rotating Survey)						
Depth	RPM	Azimuth	Inclination	Magnetic DIP	Total G	Total H
6000	0	153	68	66.9	1001.1	48609
6000	60	153	68	66.9	1001.1	48606
6000	120	153.1	67.9	66.9	1001.2	48606
6000	180	153.2	67.9	66.9	1001.3	48633
6000	240	153.2	67.9	66.9	1001.3	48657
6000	300	153.4	67.9	66.9	1001.3	48660
6000	360	153.4	67.9	66.9	1001.3	48756

Figure 3.10: Static Survey Vs Dynamic Survey (DMS) Results without Eddy Currents, [33]

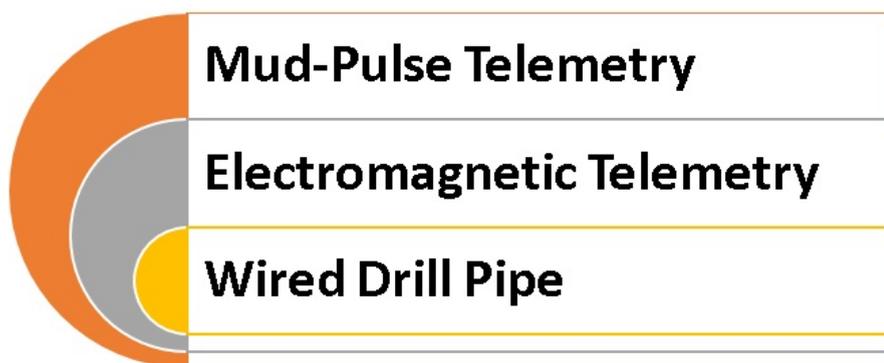


Figure 3.11: Data Transmission Technique

3.11 Data Transmission Technique

The transmission technique of downhole data can be classified into three types depending on the transmission medium as illustrated in Fig. 3.11:

3.11.1 Mud-Pulse Telemetry (MPT)

MPT is the most common method to transmit downhole data (include LWD and MWD data) to the surface through the pressure pulses of drilling fluid inside the drill string,[22].

To create a pressure fluctuation and propagate within the drilling fluid towards the surface, a down-hole valve engaged to restrict the flow of the drilling fluid, this is to assist in transmitting DH data, which they are received from the standpipe pressure sensors.

This means pressure signals that are received from the standpipe pressure sensors will express this required information. Afterward, importing the received pressure signals into the computer processing system and translated it into the measurements.

Principally, the measurements are summarized into an amplitude or frequency modulated pattern of mud pulses. In the present, the MPT is classified into the following three groups, Fig.3.12.

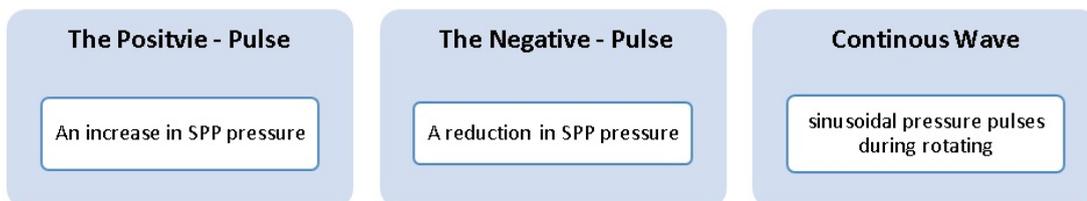


Figure 3.12: Mud-Pulse Telemetry Classification

(a) Positive-Pulse MWD tools:

It's the most prevailing method employed by MWD tools as shown in Fig. 3.13(a), the valve is opened and closed to initiate pressure pulses. In the case of closing the valve, there is an increase in pressure that is recorded at the standpipe. Therefore, this method is known as positive-pulse.

(b) Negative-Pulse MWD tools:

As mentioned in the previous method, the valve is opened and closed to generate pressure pulses as shown in Fig. 3.13(b), When the valve is opened, there is a reduction in pressure that recorded at the standpipe. Therefore, this method is known as negative-pulse.

(c) Continuous-Wave MWD tools:

The valve is regulated opened and closed to create sinusoidal pressure pulses during rotating as shown in Fig. 3.13(c), Any digital modulation pattern with a continuous phase can be utilized to charge the data on a carrier signal. The most generally applied modulation pattern is continuous phase modulation,[22]

Present mud-pulse MWD tools are substantially the positive- and negative-pulse, their stability is much better than a continuous wave MWD tool, despite the transmitting rates (0.5 -3.0 bit/s) are lower, and the costs are also lower. The continuous wave MWD tool can deliver a bandwidth of up to 18 bit/s.

In fact, if the length of the wellbore is increasing, the transmitting rate decline to a rate as low as 1.5 - 3.0 bit/s at a depth of 10,000 m. Additionally, when drilling fluid is aerated or using aerated underbalanced drilling, their compressibility is increased, which affects the transmitting ability to drill fluid to be lower. So that, WDP telemetry or the electromagnetic MWD is favored.

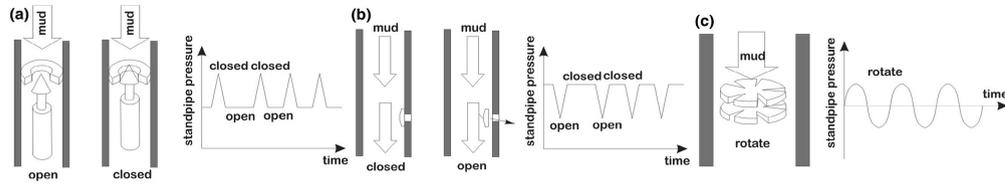


Figure 3.13: Three kinds of Mud-Pulse Telemetry Methods:(a) Positive-Pulse,(b) Negative-Pulse and(c) Continuous Wave

3.11.2 Electromagnetic Telemetry (EM)

It's known also as the EM-MWD tools which integrate a transmitting sub antenna in the drill-string, and another received antenna is mounted on the surface, as in Fig.3.14.

Electromagnetic waves are created by the EM-MWD tool using the emitting sub antenna, this electromagnetic waves transmit downhole information through the formation to the surface, they are received on the surface by the antenna, after then, they are sent to the surface process center and interpreted into measurements. So, the EM-MWD tool transmit data by emitting electromagnetic waves through the formation instead of pressure pulses through a fluid column.

There are several advantages of this method, such as high data rates, time saved by transmitting surveys during a connection, and the ability to operate in conditions where mud-pulse telemetry cannot, such as the aerated underbalanced drilling and air drilling.

The EM-MWD allows a bandwidth of up to 400 bit/s. but sometimes it drops when drilling abnormally deep wells and attenuating formations which cause the signal loses

strength immediately, therefore EM-MWD becomes illogical in these beds. So, several enhanced techniques of EM-MWD signal strength and detection have been invented to beat on this problem, wire repeaters, the drill-string repeaters, casing repeaters, etc., as examples of these inventions which are frequently employed in air drilling and aerated underbalanced drilling.

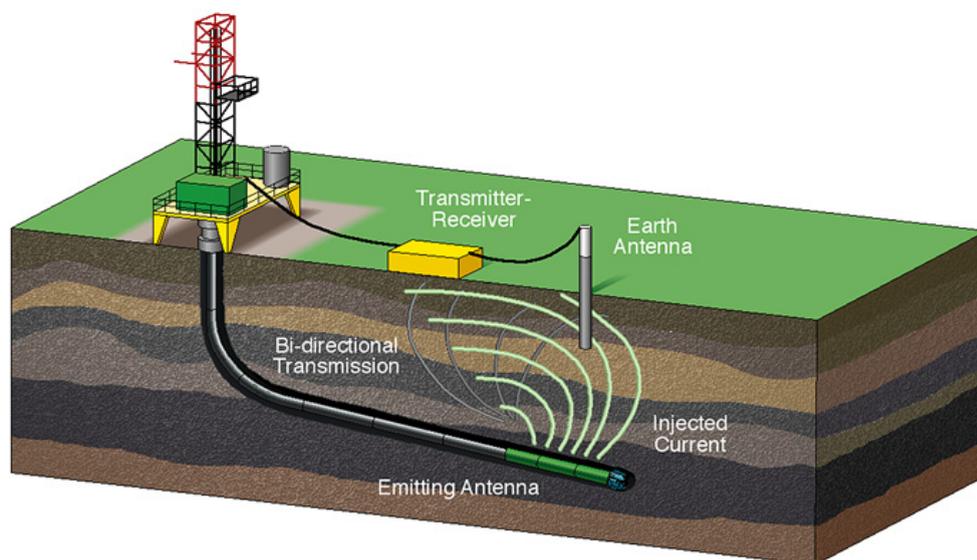


Figure 3.14: The schematic diagram of electromagnetic telemetry,[34]

3.11.3 Wired Drill Pipe (WDP)

Intelligent drill-string or electric drill-string are other names for this method. In 1997, the first WDP was invented, which was sponsored by the US Department of Energy and the company Novatek.

In 2001, funding for the drill pipe project(DP) and an additional DP data transmission project has been launched by the National Energy Technology Laboratory (NETL), the results of the research consist of the Intellipipe and IntelliServ network.

In 2006, (IntelliServ's product) is the first commercial WDP was applied in Myanmar,[35]. At the present, NOV company is producing the IntelliServ, a broadband networked drilling string system, that is employed to transfer DH data to the surface.

The components of the IntelliServ network are installed in drill string components (Fig.3.15), called IntelliPipe, which transmit downhole data at 57,000 bits/second [35]. The WDP provides a high-speed telemetry channel from subsurface to surface, and it permits transmitting data to downhole tools for closed-loop control.

Furthermore, the nodes of the survey also can be fixed up along the entire drill string length that aids operators to acquire data along the wellbore (Fig.3.15). The measurements can comprise all of the downhole data, such as the drilling engineering, formation, and directional information.

Although, formation properties, fluid properties, and depth are no longer affect data transmission, but, some shortages exist such as: the WDP still too costly, the WDP cannot work even only one connection isn't available, the reliability still needs to be improved due to the tandem link scheme.

The heat-related damage is another aspect, because of MWD tools measurement depend on electronic technology, precaution must be taken to protect the tool's electronics boards. Nowadays, few MWD tools can be operated under the high temperatures of 200 C and most of them can work under 150 C.

As it is known, the bottom temperature in geothermal drilling always higher than the maximum capability of MWD tools, that cause MWD/LWD tools unstable, so the necessity for additional off-bottom circulation and control drilling parameters to protect the tool's electronics boards from heat-related damage.

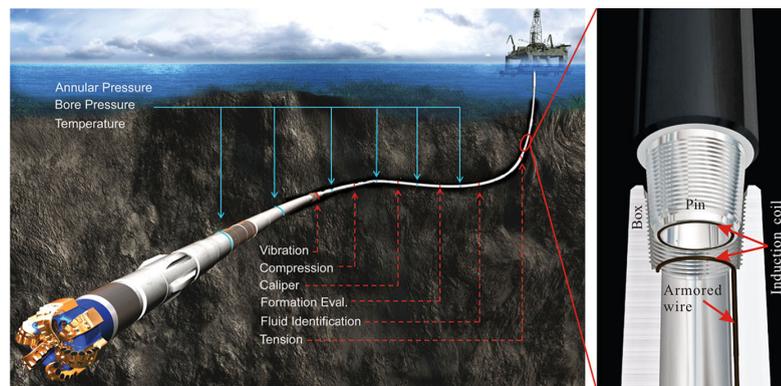


Figure 3.15: The schematic diagram of wired drill pipe

WDP telemetry enables for full real-time understanding of the DH drilling situation since DH measurements are received instantaneously at the surface (without the need for flow).

Drilling dysfunctions are detected at an early stage which allowed for quick corrective actions. This leads to improved real time DH tool status/function monitoring and optimum drilling optimization. The enhanced reaction and mitigation to S&V, in turn, increased the DH tool and bit life. A decrease in the number of bit/BHA trips is the result.

This permits real-time “recorded” quality MWD and LWD data to be transmitted directly to the surface, and near-instantaneous commands (downlinks) to be sent to

MWD, LWD, and RSS whilst drilling. WDP telemetry allows bi-directional, high-speed data transmission to and from downhole equipment at speeds up to 57,600 bps.

A detailed analysis of the wells drilled with WDP telemetry illustrated the quantified telemetry time savings in comparison with the other wells drilled with conventional (MPT),[36].

WDP enabled well time savings are divided into the following categories:

- Instantaneous Transmission of Data.
- Drilling Performance (ROP).
- Frequency of Bit/BHA-Trips.
- Other Sources of Efficiency.

Instantaneous Transmission of Data:

Fig.3.16 shows an example of the time spent to take a check survey and transmit the data to the surface with MPT. Approx. 15 min. of rig time is spent per check survey.

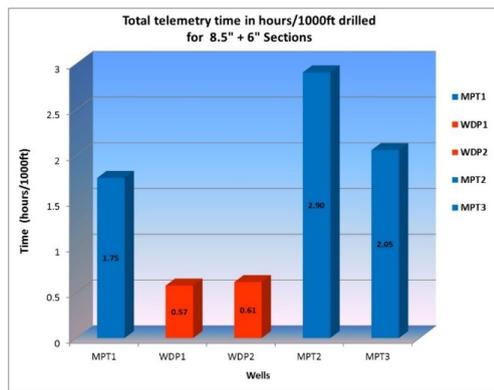


Figure 3.16: Actual normalized telemetry time, [36]

In theory, the WDP telemetry time should be close to zero. This was not done because of the specific dual pulsar BHA setup, which was used. The wells drilled with the WDP were fitted with two additional components in the BHA: a mud motor power section (added to the RSS system) and an interface sub (to connect to the DH network). The motor-driven RSS was set up with its own pulse to send data to the surface, whilst the LWD system also retained its own pulse, in the event of downtime of the WDP network. This last pulse was rarely used, as the uptime of the WDP network was very high,[36].

The specific BHA’s used on the WDP wells, still required some off bottom downlinks to communicate with the downhole tools. Besides that, time was spent on shallow hole tests of the backup MPT system. These as the main activities as reasons for the actual telemetry times found on the WDP wells.

Increasing drilling performance (ROP) from between 200% up to 300% compared to the offset wells, drilled with the MPT, whilst with MPT the ROP was limited, especially when high-level LWD tool suites were being run, because of the limited bandwidth of the MPT system.

Mud pulse downlinks can potentially damage the formation, especially when drilling within a narrow pressure window. They can also induce possible washouts in surface equipment (wash pipe etc.) and will not allow for a steady WOB when downlinking while drilling.

On the other hand, the WDP downlinks can be sent at any time and are invisible. The undesired downhole pressure fluctuations are eliminated and it also saved valuable rig time as there was no problem with the decoding of the downlinks.

Fig. 3.17 shows the ROP achieved for the different wells and telemetry types used. The average ROP achieved on WDP was found to be 203% higher when compared to the average ROP achieved on the wells drilled with MPT, saving 35.6 hours for the operator (per 1500 ft. section).

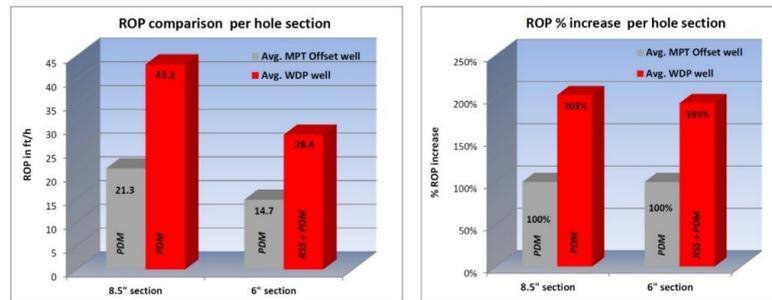


Figure 3.17: ROP comparison per hole section, [36]

Smart Wired Pipe: Drilling Field Trials

The business drivers that have developed in the recent era, drilling systems automation DSA and WDP. A high-bandwidth digital backbone running between the drill bit and the surface, WDP delivers the digital backbone required by DSA and advanced MWD/LWD services.

As the availability of a reliable, high data bandwidth, bi-directional communication method between the surface and downhole is key for digitalization and automation of the oil field and drilling systems automation requires a downhole digital backbone for closed-loop control, so the introduction with the successful field trial of a micro-repeater wired pipe (smart pipe) successfully fulfill this issue.

This innovative concept enables drilling systems automation and LWD applications, such as seismic-while-drilling with long-string sensors. The first users of the system are drilling operations, however, it is used in other ones, such as tubing conveyed wireline operations.

The system design focuses on reliability: failure of multiple components will not affect telemetry. The system uses battery-powered micro-repeaters (a fail-safe signal booster) placed within the box of every tubular and totally encapsulated dual RF-resonant antennas to transmit records among tubular.

The system gives a 1-Mbps backbone data rate, with a very low latency of $15\mu\text{sec}/\text{km}$, and with a maximum payload of 720 kbps, making it best for control-loop applications. The prototype system has been rigorously field-tested throughout drilling in Oklahoma as the first trial in 2016 covered drilling operations, the second in 2017 covered controlling downhole technology; both were successful.

The conventional telemetry technologies (electro-magnetic, mud-pulse, and acoustic) that enabled MWD services were in subjective decreasing order of importance. In all of these methods, the successful transmission of data depends on environmental factors.

With EMT, the signal travels through the earth, and depth, formation resistivity, and mud resistivity limit universal application. MPT uses circulating drilling fluid in the pipe bore, its rheological properties affect, for example, in foam, MPT may not be possible. With acoustic telemetry, which uses the wall of the drill string as a telemetry channel, contact between pipe and the borehole wall severely attenuate signal strength.

In WDP telemetry, data transfer is largely unaffected by environmental concerns because a dedicated cable within the bore of the drill pipe serves as the telemetry conduit. The component and system reliability are of primary concern as a cable run along the center of the drill string with multiple couplers to jump signal across drill pipe tool joints have a large number of electrical and mechanical components.

Chapter 4

Rotary Steerable Drill Bits (RSDBs)

4.1 Overview

Drilling as quickly as possible from casing shoe to casing point without compromising borehole quality is the operator's goal everywhere, and to accomplish this goal, the drill bit has a big role here and must withstand variations in lithology, formation compressive strength, and numerous other factors.

Day after day, new bits are introduced to the industry by the manufacturers, which have conical diamond cutting elements arrayed across its faces with a different design, is attaining extended run lengths and increased penetration rates through challenging formations. Selecting bit also have to delivers *higher build rates* and a *balanced steering response* in directional drilling applications.

This chapter will document main directional bit types, characterize the technical issues associated with the PDC/RST combination, and show how *appropriate* bits address them.

4.2 Drill Bits Classification

The classification of drill bits on the principle of the cutting mechanism, into two groups: the roller cone bits, the fixed cutter bits, and the hybrid bit.

Different kinds of certain bits are designed to comply with the specifications for directional drilling, sidetrack drilling, reaming drilling, motor steerable drilling, rotary steerable drilling, core drilling, slim hole, air drilling, pilot drilling, casing drilling, etc. Thus, we can select the appropriate bits to conduct corresponding drilling.

4.2.1 The Roller Cone Bits

The roller cone bit involves the body, leg, cone, bearing, sealing, nozzle, and tooth. It drills mainly by crushing or fracturing the rock with “tooth” on cones that roll across the face of the borehole as the bit is rotated. Depending on the manufacture of the teeth, the roller cone bits are classified into two classes, such as the milled tooth bits and the tungsten carbide insert (TCI) bits.

1. The milled tooth bits (steel-tooth bits) with cones that have wedge-shaped teeth milled directly in the cone steel itself,[37], fig.4.1 (a).
2. The TCI bits have shaped teeth of inserted tungsten carbide press-fit into drilled holes in the cones, as the tungsten carbide material has an extreme hardness, so it is applied to the surfaces of the teeth to improve durability, fig.4.1 (b).

The applications of roller cone bits include highly abrasive formations, soft abrasive formations, and hard formations. The roller cone bits can adapt to low RPM, high RPM, high temperature, high WOB, and PDM tools.

For deep or geothermal drilling, the high-temperature roller cone bit can be specially designed to endure high-temperature drilling environments like geothermal wells for extended periods. The TCI roller cone bits used to drill hard and abrasive lithology to access steam or hot rock in basement formations are exposed to temperatures that exceed 260 C.

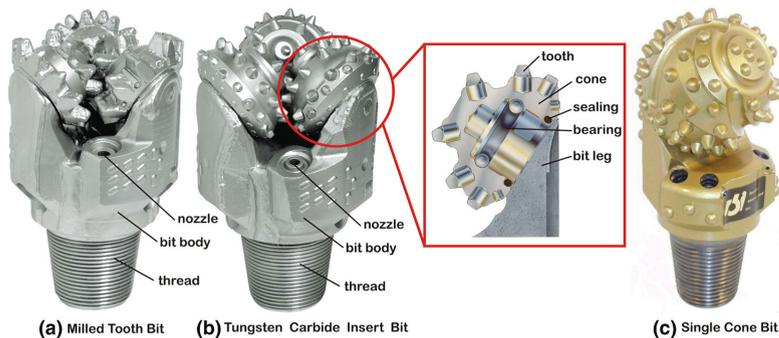


Figure 4.1: The typical roller cone bits

4.2.2 The Fixed Cutter Bits

It utilizes cutting mechanisms that are much easier than the roller cone bits since the elements of cutting do not move relative to the bit. Also, depending on the manufacture of the teeth, the fixed cutter bits can be classified into four groups, the polycrystalline diamond cutter (PDC) bit, drag bit, natural diamond bit and impregnated bit, fig.4.2.

1. The drag bit which is just can be employed in soft formations and considered the first type of drill bit used in rotary drilling, so currently, it has rarely been used in oil drilling.
2. The PDC bit: As it approved some advantages like high ROP, long life, and long drilling footage, so it's the most common drill bit in use now. The PDC bit involves the body, cutter, and nozzle. The cutters are arranged on the blades of the bit in a staggered pattern with the diamond-coated cutter surface facing the direction of bit rotation to provide full WOB, high RPM, high temperature.

The tooth of the PDC cutter is inserted tungsten carbide cylinder with one flat surface coated with a synthetic diamond material. PDMs, turbodrills, even the RSDS. PDC bits can be applied in hard, soft to medium, and homogeneous formations, however, drilling in abrasive and hard beds has been impractical for PDC bits.

3. The natural diamond bits are similar to impregnated bit, but the main difference is the cutters. In this type of bit, the natural industrial-grade diamond cutters are embedded within the bit body matrix, while the thermal stable polycrystalline (TSP) diamond cutters are used in the impregnated bit.

Greatest hardness and high durability are the characterizations of the diamond, which can adapt to the hard abrasive formations. Also, the diamonds are expensive, however, the durability of the bit also quite high, hence, this is the reason behind its strong competitiveness in petroleum drilling.

Different styles of these bits for both motor and rotary drilling in hard or abrasive formations in the market, and it has been widely used in RSDS drilling, turbo-drills drilling, and core drilling.

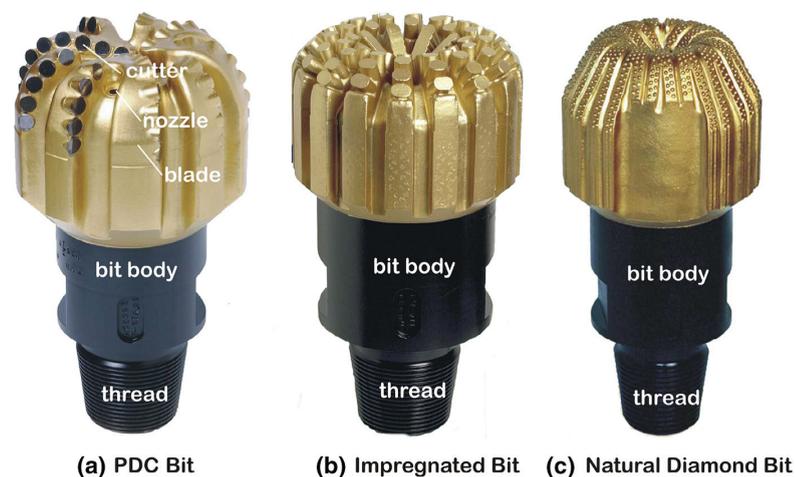


Figure 4.2: The typical fixed cutter bits

4.2.3 The Hybrid Bits

It combines both rolling cutter and fixed cutter elements that have been come to solve the issues associated with using only fixed cutter PDC in the hard abrasive formations and complex directional drilling operations due to the performance as PDC drill bit cannot replace the cone bit, [38]. Table 4.1 shows the overall hybrid drill bit advantages over the other types.

Hybrid vs PDC bits	Hybrid vs TCI bits
• Increased footage potential	• Increased ROP potential
• Improved drilling dynamics/toolface control	• Less WOB requirements (typically 80%)
• Decreased torsional vibration (stick-slip, whirl)	• Less axial vibration (bit bounce)

Table 4.1: Overall Hybrid Drill Bit Advantages,[39]

Two designs are introduced to the market, one is a small size twice wing, double-cone bit, the other is the slightly larger size of Mito wing, tricone bit, depend on these six blades PDC drill bit and drill four knives wings, and vice blades and short positions were replaced cone size. So, the peripheral part of the borehole drilling is achieved by the cutters and blades, Also, the center position of the borehole is lied on the surgeon wing PDC cutter to complete break rocks, see fig.4.3.

The breaking of rock depends on the blades, cones, and their mating. Designing of the hybrid drill bit serve reducing drilling time in the most troublesome applications. Several features related to this technique handle highly interbedded formations with performance consistency and great tool face control, those features are rock-crushing strength, the stability of roller cones, the continuous shearing action of diamond bits, and the cutting superiority.

Other facts, in comparison to roller cone bits, the driller can lower WOB and increase ROP with a less bit bounce. Also, in comparison to PDCs, the durability is undoubtedly enhanced in inter-bedded formations, more consistent and lower drilling torque, less stick-slip, and better directional control and stability.

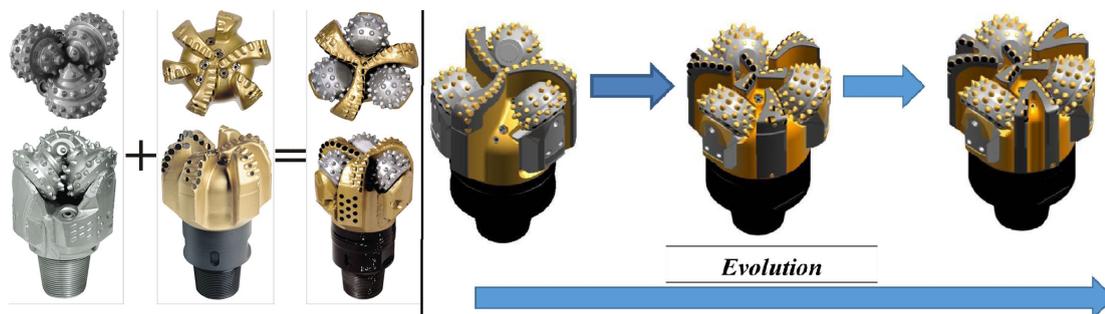


Figure 4.3: The hybrid bit and its evolution, [39]

4.3 Design Development

4.3.1 Operational Compatibility between RSBs and RSTs

As mentioned in ch.2, the RST has address most of the technical and operational limitations, which previously hindered directional drilling efficiency, however, the benefits can only be achieved if RSTs are used with appropriate bits and efficient *partnerships* should establish between them; i.e. *compatibility* between them, especially in the absence of slide mode drilling. This compatibility can only be done if there is *behavior reciprocity* between them. The appropriate bits work on address the functional, stabilization, and compatibility issues of specific RSTs.

When RST actuation value (tilt, side force, or both) in place, the RSB must translate this actuation into stresses and accomplish effective “side cuts” into the borehole wall. Amongst different detrimental side effects, a bit with more side cutter may reduce unit contact stress per cutter, hence reduces the efficiency of their side cutting,[40].

Fig.4.4, which is shown on left, PDC bit with active gage configuration, for a given actuation value, the high side-cutter count will reduce stresses at the borehole wall and thus steering efficiency. On the right, PDC bit with a reduced side-cutter count, The side-cutters have been mounted on a depth controlling relieved surface. Such an arrangement improves side cutting efficiency, making it predictable and controllable.



Figure 4.4: PDC bit with active gage configuration(L) and PDC bit with reduced side-cutter count(R), [40].

4.3.2 Functional Challenges

The following are important performance qualifiers for the drill bit when attached to the steering system:

Durability: Must be maximized. It depends on a PDC bit’s design philosophy and the

loading types it sees while in operation. Other factors such as BHA makeup, formation drillability, and operational conditions also influence it.

ROP: Must be also maximized. Considering formation drillability issues, the bits must be developed and/or selected with ROP superiority as a primary requirement.

Steerability and responsiveness: The drill bit should be of short length and has the ability to move laterally, therefore capable of accurate and immediate response to the directional changes generated by the tool. This will result in improved dog leg potential.

Stabilization Requirements: Lateral and torsional vibrations are the dominant modes in RSS operations which is normally associated with the steer and hold modes, whirl and axial can also be experienced. A PDC bit's total torque component, generated as a result of gage and/or shoulder activity has to be low in magnitude. Also, this torque component should exhibit minimal fluctuations, to reduce torsional vibrations.

One or more of the following situation can cause the lateral and torsional vibration:

1. Inconsistent side cutting action.
2. Ineffective side cutting action (lack of surface relief on gage pad).
3. Lower resultant contact stresses.

The lateral excitations are caused by the inability of a PDC bit to stay “in-cut” under the influence of an RSTs specific actuation. When stabilization is made the primary objective in bit development, ROP maximization, improved durability, and efficient steering can be achieved.



Figure 4.5: Difference in Make up Length

Shortened bit “make-up” length to enhance steering efficiency without compromises to side cutting effectiveness and gauge retention. Bit length effects are only beneficial after RSB’s have met the required technical challenges – functional, stabilization, and compatibility.

4.3.3 Matched Drill Bit Design

The cutting structure on the bit should match the formation being drilled; prevention of stick-slip that can affect ROP and directional performance. The gauge and bit nose profile are important features for achieving high dogleg. A flat nose profile produces enhanced steerability by reducing the central cone size,[41].

The gauge profile is a critical component in the overall system performance as well as high dogleg capability. For PTB RSS systems, sufficient relief on the gauge pad is needed to allow full deflection without contact, this is crucial to give room for the bit to tilt. A bit gauge pad that is full gauge will result in high contact loads that negatively affect dogleg capability and may cause tool damage.

Bit requirements (Fig.4.6) include the following:

- Recommended bit gauge length a minimum of 3 in.
- Makeup length is as short as practical.
- Bit gauge pad must be stepped, tapered, or relieved with no active gauge pad cutters.
- Pinup.

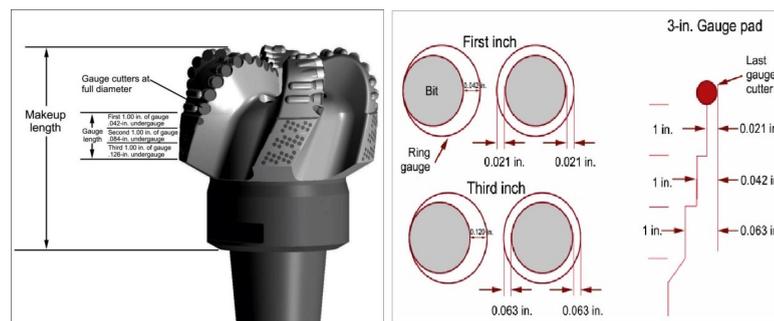


Figure 4.6: Bit profile and design features, Bit designed with taper gauge and short makeup length, [42].

4.3.4 Drilling Bits Configuration for Motor and RSS

It's known that specific applications require completely different bit design features; the profile and the drive system will greatly influence the design characteristics. Despite the drive system is not the only factor, it is a key factor. Usually, design changes are often more extreme for the motor than for the RSS application,[43].

The design factors affect the bit and BHA directional performance and must be carefully placed. So, tool face control will be exceedingly crucial to guarantee that good quality builds are satisfied very early in the interval. The gauge configuration, back rake angle, and depth of cut could change dramatically on each design as the higher DLS would require much higher side cutting from the bit.

Gauge Configuration

The gauge configuration in motor applications does not have to be relieved, stepped, or utilize any other configurations. To increase the build rate, the preferred gauge length is usually short (2 to 3 in.). Whilst in RSS, gauge configurations differ per RSS tool requirements and specifications, a gauge can be relieved, stepped, or full gauge.

The configuration of the gauge pad is almost always defined by the tool requirements of the directional company, in other words, one specific RSS tool almost always requires a long (6 to 8 in.) and full gauge pad for its p-t-b system. For another RSS p-t-b system, however, a specific under gauge per 1 in. gauge length is almost always a requirement of that tool.

The following gauge configuration needs to be evaluated when selecting the bit.

- Long or Short.
- TSP protection.
- Straight or spiral.
- Stepped or non.
- Active or Passive.
- Back reaming cutters.
- Drop-in-drilling cutters.

Benefits of Bit with Taper Gauge Pad and Short Length

A relieved or taper gauge is designed at a minimum of 3 in. to allow the bit to tilt and eliminate hole spiraling at the same time. The taper gauge pad stepped at 0.021in. Design drill bit with taper gauge pad help reducing torque and stick-slip vibrations, hole spiral. Enough hole spiraling severity causes BHA hanging when gauge length less than 3 in. and this tends to be severer with more aggressive PDC bits and harder formations, on the contrary, when the bit gauge is 3 in. or greater, the problem is diminished.

The p-t-b RSS bit needs room to tilt in the tool face direction when deflected. If the gauge pad is a full gauge, it will result in contact with a very high side load that will increase torque and reduce build rate capability. Shorter makeup length increases bit side force, which has a direct result of increased DLS capability,[42].

Cutter Technology

Generally, the highly abrasive-resistant cutters provide the proper diamond interface design, edge geometry, and diamond table thickness for a maximum run. Cutter durability is highly required to achieve the best steerable performance because the side cutters affect bit steerability and ROP. Consequently, sharp premium cutters are an important factor in directional drilling success,[15], fig. 4.9.

The cutters of conventional fixed cutter bits easy to wear and affect the bit life as it's fixed on the bit body. To overcome this matter, a rolling PDC cutter named the ONYX 360 are developed by SMITH, it really increases PDC bit durability by spinning 360, as

shown in Fig.4.7, the entire diamond edge is positioned in the high wear areas of the cutting structure of the ONYX 360 rolling PDC cutter's is used to cut the formation. The cutter's diamond edge can be stayed sharper longer, extending the ONYX 360 cutter life far beyond that of premium fixed cutters due to the cutter's rotating action.

The development of a 16 mm cutter size was done to yield increased strength and durability by the output obtained from the implementation of the 13 mm ONYX 360 cutter. In comparison with fixed-cutter-only bits, PDC bits that included ONYX 360 rolling cutters showed run-length escalate up to 57%, resulting in fewer bit trips and lower drilling costs, 4.7.



Figure 4.7: The comparison of fixed PDC cutter and ONYX 360 cutter

Cutters have the following features:

- Cutter Design: Oval, Scoop, Triforce, FANG, etc.
- Count (Number) and Size.
- Chamfer.
- Depth of Cut Control (DOCC):

Good torque control is necessary for a motor application. In bit design, the existence of depth of cut control elements is important to ensure maximum tool face control and smoother directional drilling.

Whilst in RSS applications, it is considered less of an issue as the tool is self-orienting, and tool face control is not observed. This does not mean that controlling the torque is not important, but torque in terms of tool face control is not critical.

The bit can be made more or less aggressive by controlling the depth of cut in the cone profile area by increasing or decreasing cutter exposure. This reduces stick-slip vibration as BHA penetrates rocks of various hardness and reduces bit-induced torsional vibration with increased (WOB).

The depth of cut control element has been. Using sophisticated design software normally assist to carefully calculate the shape and height of the (DOCC) elements and strategically placed on the cone, shoulder, and gauge area to obtain the best placement and torque fluctuation control.

Furthermore, bit design optimization includes analyzing and calculating the expected variation in the formation of compressive strength and formation abrasiveness.

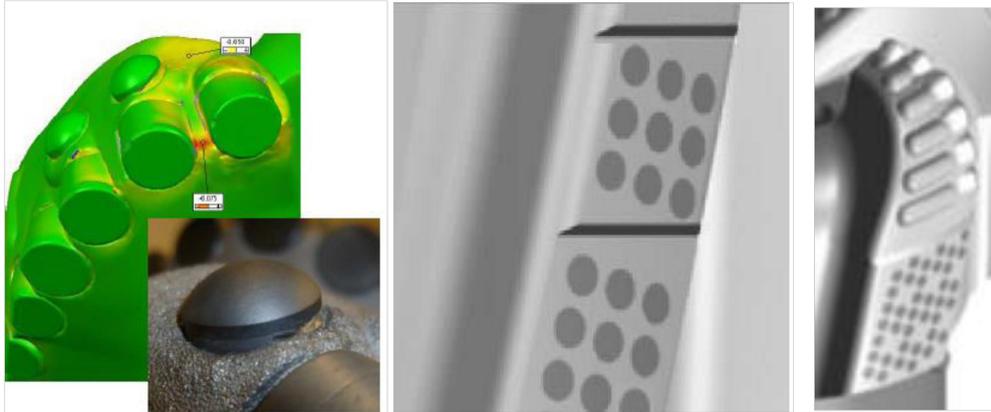


Figure 4.8: Depth of cut control elements(L), Unique gauge design for directional RSS applications (M and R) [43].

- PDC Cutter Placement:

Backup cutters sit behind the primary cutters are set only for the four primary blades that have been approved better than when including on all blades. They are slightly offset in such a way they do not engage the rock immediately. Instead, they engage the rock at a later stage after the primary cutters wear down as a result of drilling abrasive formation. Also, incurred wear flats, they acted as dampeners absorbing the applied WOB. A second row was also added to improve the durability of the bit where it was most needed. Diamond volume management helped to increase both the PDC bit's aggression and durability.

- Back rake angle:

Is the amount that a cutter in a bit is tilted in the direction of the bit rotation. Its value has a big role in the bit aggressiveness, fig.4.10.



Figure 4.9: Backup cutters(L), PDC design with 10 blades,19-mm cutters achieved the fastest ROP(B), [15].

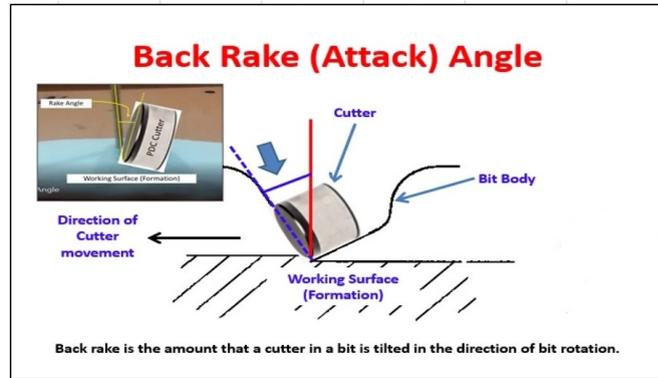


Figure 4.10: Back rake Angle

4.4 Effect of Lithology on Bit Efficiency

When drilling into certain formations, several factors such as (S&V) to DH tools, slow ROP, and damaged bits affecting the job efficiency. Carbonates containing chert, hard or abrasive sandstones, interbedded sands and shales, clays containing pyrite, and conglomerates are particularly tough on drill bits. Facing such formations could enforce the operator to exchange their damaged bit for something harder trip. Often, bit selection requires a compromise that balances impact and wears resistance against ROP. Normally, ROP increases following a bit change but the NPT spent tripping out of the hole and back adversely impacts efficiency and costs, however when encounter noticeable slow in ROP, operators has to choose between tripping for a new bit to increase ROP or staying on bottom and enduring the lower ROP, Each choice exacts a penalty in terms of time.

Operator experience in drilling through a particular formation generally drives bit selection within the local field. Some plays lie beneath basalts, which can be especially hard and abrasive. Clastic rocks may reduce ROP when the cuttings stick to the bit and obstruct the bit's junk slots and its known, sandstones and siltstones often cause abrasive wear. A range of lithology commonly is existing in carbonate beds, some of which are more difficult to drill than others, from hard and brittle dolomites to soft marls and limestone. Evaporates are also founded in a variety of challenges which are inhibited drilling efficiency in laminated gypsum, cutter overload in hard anhydrite, and washouts insoluble salts. Commonly, compressive strength (CS) of rocks tends to increase with depth, some formations are spectacularly hard and having (CS) that range from 207 to 380 MPa [30,000 to 55,000 psi], so formation depth also plays a role in bit selection. Based on thickness, may need several bits and several days to penetrate through.

As it's geologically known, most formations are not homogeneous. Frequently, multiple or mixed lithologies lie between the bit and the next casing point. The transition from one rock type to another that may cause durability problems and bit damage can produce

high instantaneous impact forces, cyclic lateral forces, and vibrations that can lead to accelerated bit failure and wear. Once retrieving a PDC bit, the failure due to vibration will have chips, fractures, and gross cutter breakage, all attributable to severe impacts on the diamond table of the PDC cutting structure. Therefore it's necessary to match the right bit to the formation which is laid in the section.

At the surface, changes in lithological sequence may be noticed as fluctuations in ROP or rotary torque, however, these indications just hint at what is going on downhole. As an example, soft shale offer hard drilling, belong to the presence of pyrite nodules or calcite concretions, which are significantly harder than the shale mass itself. An abrasive, hard sandstone may lead to accelerated cutter wear or damage. Concretions of Calcite (CaCO_3) can have (CS) over 260 MPa [38,000 psi], formed through solution deposition, and may range from a few cm to 30 cm (1 in. to 1 ft.) in diameter. These concretions whereas the surrounding shale may have a (CS) of around 34 MPa [5,000 psi]. Also, small nodules of pyrite [FeS_2], often found in shale, can be problematic.

The decision to make operating parameters modification to support further drilling or tripping for a new bit is an important one, which is indicated by the characteristics of the formation, the required bit performance, and bit design.

Increasing (WOB) in hard rocks to overcome their shear strength needed to fail the rock and keep an acceptable ROP. On the other hand, higher WOB significantly increases cutter loading, which can cause microchipping of the diamond table in PDC cutters. As the cutter wear flat area increases, the bit will dull, then increasing frictional heating at the interface between cutter and rock, possibly weakening the diamond cutting element.

Considerable torque at the bit is facing when building angle in the curve trajectory of the directional drilling, which can create tool face control difficulties for some PDC bits, making it difficult to maintain trajectory.

To address such challenges, the Stinger Conical Diamond Element (CDE) was developed to give a powerful thicker layer of diamond than conventional PDC cutters. The cutter array has enabled operators to drill significantly longer intervals than was possible using conventional PDC bits by improving ROP. StingBlade bits were able to drill continuously from shoe to casing point in single run through formations in which this was previously impossible.

An array of Stinger cutting elements across the bit face are incorporated in the StingBlade conical diamond element bit. These cutting elements may be located anywhere from a bit center to gauge. Also, this new design has delivered improved tool face control in challenging directional applications.

Chapter 5

Planning the Design and Optimization of the BHA

5.1 Overview

In the predrill planning, the successful project must set up the details of the integrated BHA technology, the knowledge of dependencies, and check any offset experience besides the available data. Also, the final performance of the integrated system that provides the required well placement.

The software application provides confidence in the planning phase that the bit responses, in combination with the deployed steering system and the overall BHA set-up, would deliver the planned well profile. During the planning phase, enable the teams to select the best BHA setup, including the most efficient and supportive bit design.

5.2 BHA in Well Planning

Drilling companies allocate significant resources to improve well planning, rig management, and drilling schedules. Many aspects are involved in well planning, different disciplines and individuals are working on designing various programs for the well (drill string design, bit program, mud program, casing program, etc.). The drilling performance and the reduction of drill stem(S&V) are focused in well planning. Thus, modeling methodologies such as drill string statics, dynamic tools, and ROP modeling are applied to determine the optimum (BHA) components and drill bit design. However, more attention is required on drill stem fatigue, (NPT) and their impacts on drilling operations.

These companies are focusing on optimization processes development to reduce time and cost of well delivery, by including three basic performance improvement cycles (fig. 5.1).

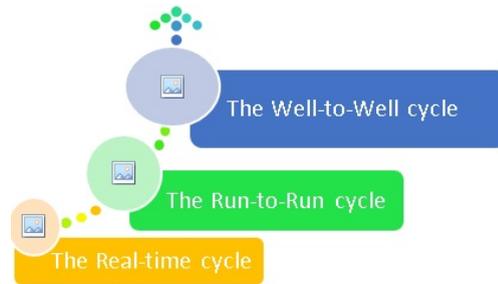


Figure 5.1: Three basic performance improvement cycles

Besides that, the following three methods are used to evaluate the expected planned BHA tendency:

- Only by evaluating offset well BHA performance record, assuming the BHA will perform similarly. It's reasonable but no wells are drilled identically.
- Simple modeling based on a three-point contact calculation, assuming the curvature produced will be constant, without considering downhole parameters such as bit/formation interaction, different formation stiffness, dip, and other uncertainties. Acceptable for the downhole motor steering tendency but is not always accurate for the natural rotational tendency of the BHA.
- With various steering mechanisms and higher dogleg capability requires a new method of tendency prediction.

5.3 BHA Engineering Consideration in Well Planning

5.3.1 Anti-collision Consideration

Once we have other producers in the vicinity of the proposed well, fig.5.2, an unplanned intersection with an existing well can lead to consequences of undesired events range from financial loss to a catastrophic blow-out and loss of life. The well collision avoidance process includes rules that determine the allowable well separation, surveying, the management of the associated directional planning, assurance, and verification.

So, the calculation of proximity of an adjacent well(s) is one of the necessary aspects in well planning and selecting the BHA. When the result of the separation factor (SF) of critical value such as 0.70 which is less than 1.0 presents a mathematical possibility of well collision due to overlapping Ellipses of Uncertainties (EOU). To manage the risk and safely drill the well, the survey error uncertainty needs improvement and instead

of using a conventional MWD, a novel solution utilizing High Inclination Drilling with Gyro (HIDWG) tool to safely manage and mitigate the risk of well collision along with Advance Hybrid (RSS) yield higher precision drilling control. when the SF instantly improves from 0.70 to 1.0, the collision risk will be reduced to an acceptable level, and the well design will comply with the drilling standard,[44].

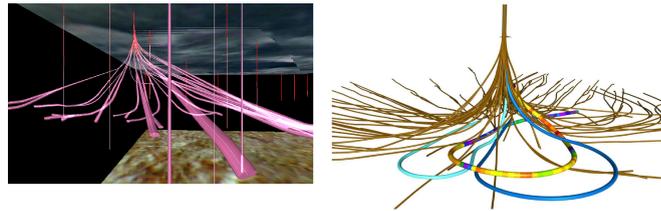


Figure 5.2: Anti collision Consideration(L),(R, [45])

5.3.2 Degree of Tortuosity

A measure of deviation from a straight line. It is the ratio of the actual distance traveled between two points, including any curves encountered, divided by the straight line distance. Tortuosity is used by drillers to describe wellbore trajectory, by log analysts to describe electrical current flow through rock, and by geologists to describe pore systems in rock and the meander of rivers,[46], fig.5.3(R).

It's crucial to evaluate the effectiveness of the steering mechanism on wellbore tortuosity which is defined as any unwanted deviation from the planned well trajectory. Since the steering mechanism differs among the diverse kinds of tools, so, one steering mechanism over every other can produce a less-tortuous wellbore,[47], as seen in fig.5.3(L).

Besides that, optimizing flow during production,[6], as shown in fig.5.3(M).

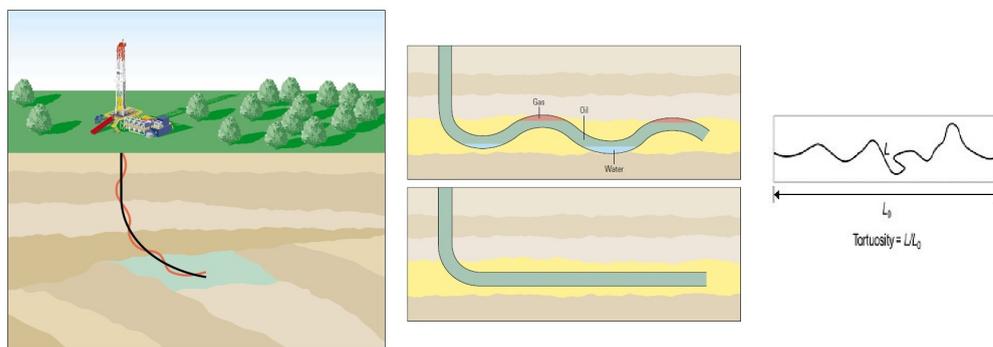


Figure 5.3: Optimizing trajectory(L), [6],Optimizing trajectory in horizontal well for production, [6], Tortuosity(R), [46]

CPSM demonstrates how this mechanism can offer advanced wellbore high-satisfactory by lowering wellbore tortuosity.

To study the tortuosity in any offset wells, it should have a common trajectory and geology and they use a very similar BHA design.

The wireline inclination data are utilized to show the benefits of wellbore quality and measure wellbore tortuosity. These data are in comparison with the real MWD survey to spotlight the existence of the micro DLS that can't be measured using standard surveys. High accuracy and high-density wireline data are normally recorded over very short lengths (i.e. typically 0.25 ft.) is the most accurate method to assess the wellbore tortuosity. The MWD surveys usually record over a long interval depending on well section requirements (i.e. typically anywhere from 30 ft. to 95 ft.). Therefore, the apparent tortuosity from those measurements is inaccurate because of the poor inclination hold within a long interval that is averaged over that interval.

Tortuosity can cause many issues such as running and floating liners, induce torque and drag, resulting in an increase in pickup weights, an increase in side forces, and a reduction in buckling margins. To evaluate any additional signs of tortuosity, High-Resolution continuous survey methodology can run in parallel. To define the well path, it's often not enough to capture the real characterization of the well with just one station per stand. Thus, in some scenarios, this could lead to well engineering simulations misinterpretation because the unseen extra tortuosity is not applied in the torque and drag analysis.

The software can do this processing by merging the static MWD or RSS data with the continuous single-axis data to deliver a more refined definition of well trajectory.

In the end, checking the new High-Resolution inclination agrees with the static inclination at the same depth stations. To establish worst-case scenarios, tortuosity value assumed in both vertical and tangent sections in build and drop sections should include in the planning phase,[48].

Alrushud's team in their study, more than 700 wells were reviewed and analyzed for that reason. The wireline records evaluation suggests that drilling with (CPSM) drastically reduces 4-5 times in average tortuosity, 3-4 times in average dogleg severity, and 5-6 times in average angle change. Intervals drilled with CPSM are greater continuous and smooth as compared with push-the-bit and point-the bit mechanisms,[47].

Wellbore quality is an important factor during drilling, completion, and production operations of an oil and gas asset. RSS tool is intended to improve drilling performance while ensuring the integrity of the wellbore by correctly sharing time between off and steering modes. An LWD ultrasonic imager has been developed to provide ultrasonic caliper measurements and high-resolution wellbore images in water and oil-based mud environments, see fig. 5.7, [24].

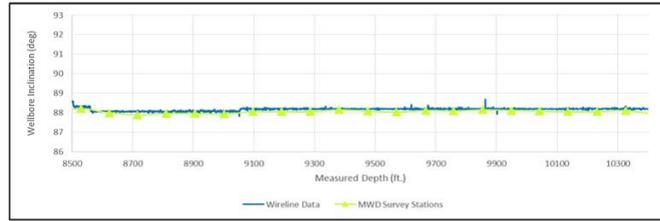


Figure 5.4: A comparison of wireline inclination data against the MWD survey stations while utilizing the CPSM drilling mechanism, [47].

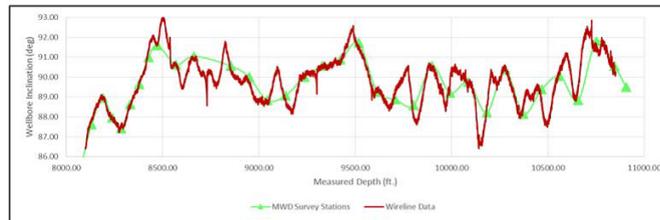


Figure 5.5: A comparison between wireline inclination data and MWD survey stations while utilizing point-the-bit steering mechanism, [47].

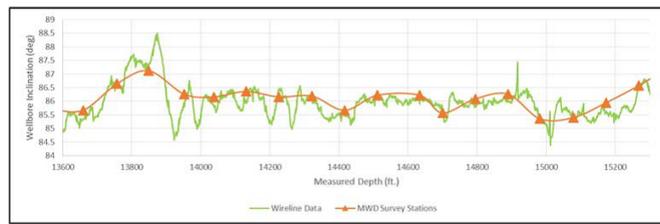


Figure 5.6: A comparison between wireline inclination data and MWD survey stations while utilizing push-the-bit steering mechanism, [47].

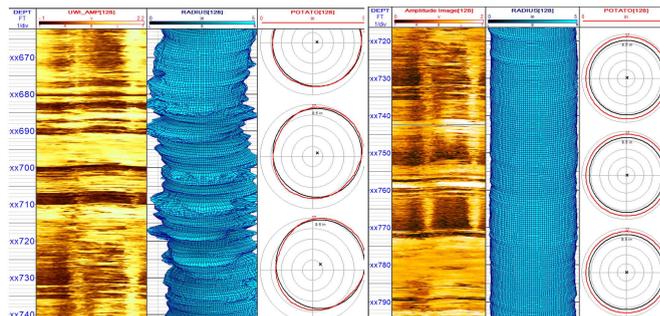


Figure 5.7: Track 1: Depth, Track 2: static amplitude images, Track 3: radius wellbore shape, Track 4: potato plots. (a) Left: Mud motor, (b) Right: RSS, [24].

5.3.3 Evaluating the Shock, Vibration, Torque, and Axial Forces

The BHA mission success is limited by severe (S&V), high torque, and high axial forces (fig.5.8) that lead to failures on downhole BHA components. This mission also affected by other problems like unstable drilling parameters, extremely (ROP), and poor wellbore quality, leading to excessive reaming and back reaming as well as stuck pipe events and difficulties to maintain wellbore verticality.

Performing various (FEA) on the interaction between BHA, drilling bit, and formations drilled, revising the bits selections, identifying areas of opportunity to introduce “*fit for purpose technologies*” on cutters and bits profile will serve to eliminate these unwanted forces in the BHA system.

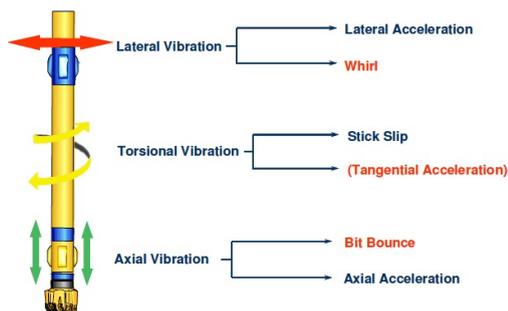


Figure 5.8: Three Main mode of Downhole Vibration, [49]

Generally, results of the vibration models indicate that the drill stem lateral vibration behaves as a function of the length of both drill pipe-drill collar (DP, DC), (GR) response, and (WOB). The analysis of drill stem vibration effect on the mechanical specific energy (MSE) is inconclusive in some depths. To mitigate S&V, most of the time we need to decrease the drilling parameters to allow the BHA drill through layers in a gentler manner, while the ROP will be decreased.

WOB and torque with the motor-powered RSS BHA will be transmitted through the motor driving shaft, motor stator, and stator housing.

Torsional vibration will be dampened and absorbed by the motor power section because of the non-rigid, rotating engagement between the motor rotor and stator.

The motor has a higher bit of total RPM than RSS BHA, allow us more room to utilize various surface RPM/ WOB without scarifying too much ROP, which usually assists to mitigate the lateral shock above the motor (MWD and LWD tools). But, a drawback of motor-powered RSS BHA is the RSS will have a much higher total RPM, which usually causes higher lateral (S&V) on the RSS tool or tools below the motor.

5.3.4 The Stabilizers' Count, Size, and Position in BHA

The stabilizers' count, outer diameter and spacing along the BHA length is an important parameter in BHA design. Given the directional targets to hold tangent, the BHA with specific stabilizer configuration will effect (BUR) or hold tendency; thus allow more or less WOB to be applied. The table 5.9 summarizes the pros and cons of more stabilizers versus fewer stabilizers in the BHA,[50].

More Stabilizer	Less Stabilizer
Potentially less lateral vibration	Potentially more lateral vibration
Lower danger of differential sticking	Greater danger of differential sticking
More torque and drag	Less torque and drag
Center LWD tools	No LWD tools centering
Potentially increase magnetic interference	Less connections, less interference magnetometers

Figure 5.9: Pros and Cons of Stabilizers' Count in BHA.

Stabilizers' involvement in the BHA can help to prevent and mitigate the S&V, furthermore, properly designed stabilization with proper size can reduce the risk of mechanical and solid induced stuck pipe. To mitigate the risk of mechanical and solid induced stuck pipe, for example; the size of stabilizers can be reduced by 1/8" and the profile of stabilizer has a high wrap angle which results in a low junk slot area has been redesigned, (fig.5.10).



Figure 5.10: Redesign of stabilizer help on reduce stuck risk, [51].

To prevent and mitigate the S&V on BHA, the stabilizers set up with the BHA in the (FEA) software. S&V data acquired in actual runs are compared with (FEA) results and prove the (FEA) result's accuracy. Then various sizes and profiles of stabilizers / different stabilizer positions are simulated with FEA to find out the best BHA design, [51].

5.3.5 HBUR - Capable Steering System Technology Considerations

As operators are continuously seeking to drill increasingly complex wells to reach un-swept reserves, wells of such complexity need the new drilling technology to meet the challenge. Some wellbore required continuously high rates of curvature and tight DLS control.

When evaluating the drilling environments and the challenging well profiles and we obtain the conclusion that they push existing proven technology to its limits or exceed its capabilities, mainly in regards to steering performance and BUR requirements.

When assuring that a standard RSS available in the market could not fulfill the challenging requirements, it's obvious could only be covered by the combination of a new HBUR RSS and a HBUR-capable PDC bit, since HBUR capability, delivered reliably are required in addition to precise directional control with the highest wellbore quality,[45].

Based on two decades of RSS experience which is equipped with the latest design improvements and features, there is a new system that delivers BURs of up to 12°/100ft with exceptional directional control and high hole quality. Improvements to the main design(fig.5.11) to enable the HBUR capability and optimize overall steerability include:

- Steering pad redesign with new geometry to optimize contact area with the formation.
- New hydraulic piston setup with two pistons for each pad to increase steering force.
- Shorter steering unit design enabling a compressed three-point geometry.

Improvements to the steering unit design to increase its reliability and durability, such as a stronger driveshaft, an improved mud-bearing design, and integrated vibration and stick-slip sensors to support real-time drilling optimization.

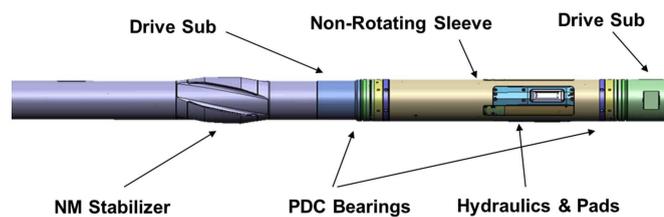


Figure 5.11: High Build Rate Steering System Technology, [45].

Furthermore, a newly designed HBUR RSS was commercially released by the service provider which provides 3D drilling and steering capabilities with continuous string rotation where no orienting or sliding is needed, capable of building up to 15°/100 ft. As of end-August 2013, the system has drilled about 6.5 million feet in 127,162 total circulation hours among different United States (US) Land plays,[52].

In unconventional reservoirs drilling, the RSS BUR capabilities constrain its growth and prevent companies from successfully drilling curve and lateral sections in one run. Thus, designers made efforts to improve the capabilities of RSS to satisfy the requirements of horizontal wells in those reservoirs. Due to limited vertical depths and lease spacing to achieve horizontal orientation, BUR are needed to maximize the lateral lengths in the formation. The tools should allow lateral control to reduce tortuosity, to developing HDL in the curve, facilitate easy casing running and optimize multistage fracturing,[53].

Unlike HBR S-T-B RSS systems which is required a significant ROP reduction to produce more side-cutting effect, a true HBR P-T-B RSS enables the required build rates to be satisfied without sacrificing the ROP as the bit face is the primary cutting structure initiating the required dogleg while making the hole.

In P-T-B RSS, to increase the eccentric offset, and the shaft deflection and make larger radial clearance within the inserts, the stabilized seal protector is installed on the lower sleeve as the fulcrum point, which is near the bit to minimize hole enlargement and

maximize BUR, then extensive (FEA), stress and fatigue analyses are performed to ensure reliable operation at a higher bend angle that does not affect the life of the driveshaft. Changes could be made to the shaft geometry to reduce bending stress while maintaining torque carrying capacity at the higher bend. Modifications also could be made to increase internal space in the lower bias unit, (fig.5.12).

The fulcrum point geometry is modified by extending the fulcrum point closer to the bit. The lower housing is modified and extended, and the fulcrum pad contact area is optimized to transfer the load of the borehole wall without exceeding the formation of compressive strength (CS). Exceeding the formation (CS) at the fulcrum pad contact can result in hole enlargement, which negatively affects dogleg capability. The increased bit bend angle and optimized fulcrum geometry, along with matched BHA and bit design, enabled the achievement of high dogleg capability in a true PTB system that also provides optimum hole quality,[41].

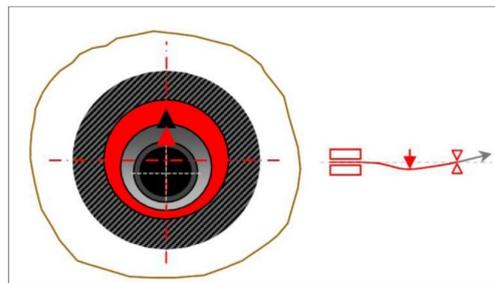


Figure 5.12: Point-the-bit RSS uses a pair of cams or eccentric rings, one nested inside another, to create a deflecting force on a rotating drive shaft. The drive shaft is supported at each end by bearings, with the cams midway between the two bearings,[42].

5.3.6 HBUR - Capable PDC Bit Considerations

As mentioned in ch4, the bit must match and satisfy a ‘Total Systems’ approach to its design. Consequently, a key consideration in BHA design that the drill bit for the system to ensure, BUR capabilities, stability, steerability, and maximum durability, wear-resistant and thermally stable cutter that would remain sharp to drill very distinct sections (vertical, build section and horizontal) in one trip,[52].

The bit gauge design to enable the bit to deliver the tilt angle enables achieving the required BUR without causing excessive lateral aggressiveness and overcome the resulted local doglegs to drill a good hole quality to overcome the encountered high drilling torque and ease running casing to the bottom. An optimized cutting structure reduces cuttings surface friction, improving hydraulic cleaning efficiency and ROP while at the same time providing good bit of stability and reduction of dynamic dysfunctions.

The introduction of the high-BUR RSS system required the design and provision of a well-matched, high BUR-capable PDC drill bit that.

Initially, local applications engineer should analyze the geology, well path, anticipated parameters, and section aims depend on these data, Design application review teams (DART) is a cross-functional team of research engineers, marketing personnel, applications engineers, and design engineers from the company's drill bit and drilling system product line will design or modify system-specific bits for each new area to enable optimum performance. This interdisciplinary approach has proven to be very effective to ensure the objectives and goals of the entire system are met.

The process includes:

1. Review of existing dull conditions and performance from recent offsets.
2. Utilization of sophisticated software drilling models to review potential performance and stability for a system-specific bit and cutter type.
3. Laboratory evaluation for model verifications.

5.3.7 BHA Modeling and Optimization – Addressing the Drilling Challenges

BHA performance can be affected by many factors, some of which can be accurately predicted and modeled, and others cannot. Since the variance of factors and broad combination, the steering tool design incorporates a level of safety factor to account for these variances. However, as the tool's performance is pushed to greater levels, the amount of safety factor reduces as the performance limits of the tools are reached.

Application of extensive BHA modeling requires accurately establishing the geometry behavior of the tool in terms of the basic loads applied to the tool and resulting deflections. Besides, the bit interaction with the formation is critical to modeling the dogleg response. This bit model characterization as a function of drilling parameters, formation type, bit cutting, and gauge structures.

Numbers of BHAs configurations for a specific size for each hole are normally under consideration, each of these BHAs is put through a dynamic analysis in the BHA modeling software. Axial, lateral, torsional vibrations, and bending stresses are analyzed and compared among each configuration to study the impact of stabilization, micro-tortuosity as well as weighted friction factors to design a *fit-for-purpose BHA* capable of delivering on well placement expectations, as well as improving on BHA longevity, and reducing tripping issues,[54].

In the case of any specific HDL RSS, BHA modeling is developed specifically to characterize the response of this tool and incorporated to tune the load and deflection responses of the BHA model.

The enhanced BHA modeling, which combined an enhanced geometry behavior model with bit interaction with the formation, enables a correlation between axial and lateral ROP. This correlation yields a better characterization of the DLS response,[42].

5.3.8 Total System Approach

Basically, as both the bit and steering system key to each other's performance, they are considered as a *total system*. Engineers should work closely together to fully optimize the BHA for the HDLS and straight tangent section requirements.

The holistic bit-steering system pre-modeling and bit-tilt calculations provide a high level of confidence that the specific chosen HBUR RSS system would produce the required DLS, not achievable with standard RSS/bit systems.

Focusing on a total system approach which includes an integrated HBUR (RSS), specific (PDC) drill bit technology includes features for a smooth torque response, enhanced (ROP), improved durability, and precise steering control, its design to integrate with (HBUR) drilling system capable of delivering the required hole.

For example of complex situation, as in fig. 5.2(R) a well required a 255° azimuth turn at a rate of 5°/100ft while maintaining an inclination of 88° in 12¼-in. This second complex well required the 8½-in. hole section to be turned through 200° of azimuth at 8.5°/100ft while maintaining a 90° inclination,[45].

Safety Range for Higher Doglegs in the Modelling

To assess BHA contact forces, bending moments, and BHA misalignment over a range of dogleg severity (DLS) values, the (FEA) drill string modeling software are used, the analysis results should confirm that the continuous specific (DLS) required for the trajectory would not compromise the BHA integrity and still would leave a safety range for higher doglegs (HDL), in case any unplanned correction was required.

The Overall Stability of the BHA System

The operator normally focuses on new PDC bit technology, state-of-the-art steering system, and best operational practices to come with new technology that is suitable for special cases of drilling. The research and development testing new stability features to control lateral instability utilizing two main tools:

- Laboratory tests performed on a full-scale downhole simulator and an atmospheric surface rig.
- Computational modeling to simulate the bit's dynamic behavior including a detailed interaction between the bit and various rock formations.

The overall stability of the bit/steering system should be observed when changing the bit response to applied WOB and torque. In some design, the cutting structure is arranged so that an imbalance force pushes to counteract the off-center force, thus improving stability.

The imbalance force concept is used by the design team to take benefit from two key factors:

- 1) Providing a net imbalance force that could help stabilize the steering assembly.
- 2) Enhance bit stability characteristics to reduce the bit's contribution to vibration, which could lead to uncontrollable resonance, [15].

BHA Directional Tendency Prediction

Directional tendency prediction is a useful aspect to know well propagation which is a complex transient process, affected by the bit, BHA, formation drilled, and drilling parameters used. This means the three-point contact theory, which is today still used, does not always give satisfactory prediction due to oversimplification. Therefore, researchers and inventors progressively working to provide a better tool to design the BHA through the advancement in digital technology and modeling.

Based on the (FEA), which is allowed to calculate BHA deformation and forces, a new directional tendency prediction workflow was developed, [55].

During drilling, axial and torsional loading, wellbore contact and gravity force, etc are affecting the BHA tendency. By the software platform, every time the BHA design is created or changed, the tendency is automatically calculated, the results are displayed as traffic lights based on comparison with the planned trajectory. The modeling relies on detailed models of various downhole equipment including steering tools and bit cutting interaction with the rock, [55].

Chen's team developed a new program that allows users to run static and dynamic models in the same application which will save time and minimize errors. For solving Lubinski's BHA equations directly in the static model, the program uses the newly developed generic algorithm. Accuracy and computation efficiency are the strengths of the new algorithm, as compared to the conventional finite-element based BHA programs. Also, the program is run fast on a personal computer (PC) with an intuitive user interface, make it easy to optimize BHA design in the office and the rig site. Static is used for optimal BHA design for maximum steerability, bending moment calculations to minimize fatigue failure, and

BHA SAG corrections to improve survey quality. The dynamic model is based on a hybrid of analytical and FEA methods to calculate the critical rotary speeds of the BHA, [56].

An example of BHA evaluation to serve the tendency prediction, DD job failures were carefully analyzed for the period 2014 and 2015 in wells drilled in the KSA to evaluate the performance and efficiency of the (PDM) and (RSS) during drilling operations. A total of 7772 runs were reviewed and the information was classified according to tool size, number of runs, operating time, lost time, number of failures, and hole size, [57].

In PDM failures, it was observed that 45.41 of the problems occurred before 50 hours of operating time. In RSS, the study revealed that 49.59 of the failures occurred before 50 hours of operating time. The causes of the failures were a combination of different factors such as vibration, temperature, type of drilling fluids used, and reservoir properties such as H₂S and CO₂ content, [57].

5.4 The Foundation of Geosteering by the BHA Design

Definition: Geosteering is a proven concept which enables the delivery of productive wells by ensuring such wells stay within the target reservoir and sweet spot, and are precisely placed relative to fluid contacts. By combining geosteering with reservoir engineering concepts, a workflow is applied in real-time, is called Real-Time Productivity Steering (RTPS) in which by quantitative estimates of the well's productivity can be determined to further evaluate the performance of the geosteering and aid in decision-making, [58].

The foundation of the geosteering process is the design of BHA. The well optimum placement in the interested zone is achieved through the integration of BHA with borehole images measurements in real-time which provide accurate trajectory control and characterize structural profile while drilling. The trajectory can be landed precisely into the desired best quality reservoir utilizing this borehole image and proactive log correlation, even if actual target depth and the formation dip become much different from geological prognosis.

Despite structural variation and reservoir property change, the trajectory during the lateral section also can be controlled effectively in the high-quality reservoir, [59].

A geomechanical evaluation also revealed that wellbore stability can be significantly improved by maintaining the wellbore within a single layer or pressure regime.

Drilling wells in the minimum horizontal stress direction are particularly challenging as the formation causes S&V to the BHA. Hence the expected common failure to the BHA

elements, usually slowing ROP, and due to heterogeneity across the reservoir layers being drilled, both geometrical and differential stuck-pipe situations can frequently occur. Thus, mud type, BHA design, and formation characteristics are all contributing factors,[54].

Utilizing azimuthal at-bit-gamma images and inclination measurements positioned only 1 m from the bit, preferred RSS, and modeling software for rapid, accurate data interpretation assist for wellbore positioning.

As it is known, the traditional MWD tools are located often more than 7 m behind the bit, but at-bit-gamma sensor provided quadrant gamma-ray, at-bit azimuthal gamma-ray, and gammy ray imaging in real-time, continuous inclination measurement. During the landing

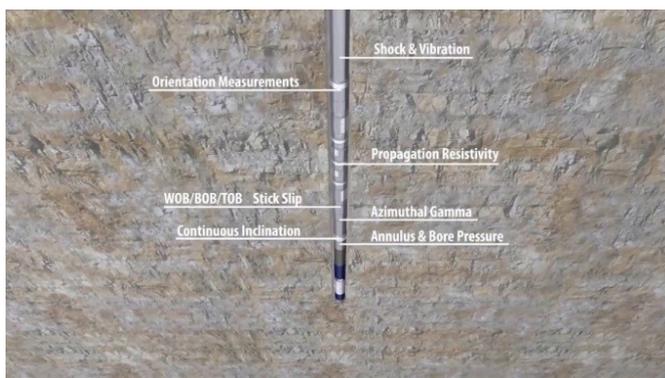


Figure 5.13: Downhole Survey Tools

process, the optimized BHA enable directional changes to be made to accommodate geosteering interpretations that refined the geological model to minimize uncertainties related to the reservoir top and bounding formation dips, when landed, the well should successfully be steered within the bed.

The integration of all available data, including mud logging, offset-well petrophysical logs, seismic, and real-time (LWD) images should be used to overcome dip uncertainty and maintain the wellbore within the thinly laminated bed,[42].

The LWD system performed well in the high dogleg application:

- At bit azimuthal gamma sensor to picking formation tops and in identifying the shift between the subjects well and the offset wells.
- The deep-reading azimuthal resistivity tool to show its depth of investigation and further steering options capabilities, and the ability to operate in a high dogleg environment,[41].

Using a deep azimuthal resistivity distance-to-boundary tool as a solution in a new multi-layer bed boundary detection scheme. It is coupled with a novel sophisticated high definition stochastic seismic inversion, providing the ability to resolve multiple bed boundaries above and below the tool, clearly understand formation dip, and improve understanding of the boundary azimuth angle,[60].

Chapter 6

Conclusions and Recommendations

6.1 Conclusions

The main findings, which were obtained from the entire research in this thesis, are outlined below along with the thesis work scope.

6.1.1 The Primary Deflection and Directional Techniques

- Although using the *jetting* to divert the wellbore has some benefit, but the drawback of severe doglegs (DL) can be developed unevenly over short sections of the hole and the condition of fragile formation makes it an unpractical method.
- The less costly technique utilized to deviate a well and the initial, active directional method is the directional control with *conventional BHA* has the benefit for cleaning hole, reducing dogleg angle, reducing drill-string drag, and saving drilling costs, however, lack of ability to control well AZ, difficult to predicts the actual response of a rotary BHA lead to a few times used today to accomplish cretin applications.
- *PDM tool* is used more worldwide as a result of successful application in the horizontal and DD, however, operational problems associated such as time-consuming to orient the bend in the motor for steering, frequently PDM stalling, pressure differential, poor hole cleaning while sliding and minimize ROP, RPM of the drill string is limited by motor bend, the over-gauged hole is expected are considered constraints for this tool.

6.1.2 Rotary Steering Systems

- The *RSS tool design* is become reliable, easy to live with, sufficiently slick to minimize the chances of sticking, rapid repair anywhere, allowed of switching off bias at any time, the ability to automatically hold azimuth as well as inclination, and surely it reduced CPF, has led to growing rapidly and more acceptable over the years.
- The *intelligence in RSS design* combines smart technology-advanced electronics, sophisticated algorithms, multiple sensors, survey packages, and high-speed processors with some of the highest processors mechanical specifications on the market deliver high reliability.
- There are some *distinctions between the different types of RSS* has to be perfectly focused on when choosing any of them to be more fit to the environment of the drilled hole, such as reaction from formation, mechanical weakness, the response to trajectory change.

6.1.3 Rotary Steerable Drill Bits (RSDBs)

- The development of rotary steerable PDC bits (RSBs) must be tied into the operational medium and actuation mechanisms of specific RSTs and be compatible with RSTs.
- RSBs must maximize ROP and have the durability to out-last RSTs.
- The effects of well profiles, especially departures on RSB vibration characteristics must always be analyzed.
- RSBs must exhibit effective stabilization characteristics in both the steer and hold phases of drilling.
- A specific cutter placement has to provide in superior dull condition, i.e. increased bit life.
- An arrangement of active gauge cutter will minimize the frictional resistance enforced by a conventional gauge pad, and increase the aggressivity of the gauge section.
- An anisotropic index for bit designs is beneficial for determining the effects of cutter back rake, profile, and out of balance forces on the steerability of a design.
- The relationships between aggressiveness (BA), instability (BI), and dog-leg requirements (DLS) must be optimized.
- Optimizing the force balance, shorter bit gage pad, shorter and flatter bit face profile, higher sleeve's blade spiraling.
- RSBs must exhibit efficient side cutting and superior gauge retention characteristics.
- Bit Design for Push the Bit RSS: Shorter and require more laterally aggressive pads. Aggressive short gauges for high dogleg. Slightly longer more passive gauge for hole

quality concern.

- Bit Design for Point the Bit RSS: Longer than usual. Less active preferably tapered long gauge pads which act as fulcrum point near bit stabilizer. This system allows the use of a long-gauge bit to reduce hole spiraling and drill a straighter wellbore.

6.1.4 Directional Surveying Techniques

- Accurate wellbore positioning is key for safe drilling and productive wells.
- Selection of the suitable surveying technique contributes to avoiding collision with any neighboring wells, Penetrating the driller's target with the required precision, obtain a good quality of logging data, or geosteering in thin reservoir sections.
- Utilize real-time data acquired during continuous drilling is an important aspect.
- Involving in the drilling program to acquire the three kinds of downhole data measured during drilling (directional, drilling engineering, and formation information) is considered a foundation for optimizing the project.
- Take into account sources of survey common errors especially local variations between magnetic north a true or geographic north and interfere caused by magnetized elements in the DS and must eliminate them and apply approach towards reducing the WPU.
- Account for geomagnetic field variation associated with crustal magnetism and temporal magnetic field variation and reducing drill string magnetic interference.
- Directional engineers place well targets by depending on real-time downhole measurements and small EOUs. By developing of a high- resolution geomagnetic reference models which help improve survey quality control and processing for drill string interference compensation by utilizing customized acceptance criteria.
- Geomagnetic referencing enhance well positioning accuracy, minimize placement uncertainty, and mitigates the risk of collisions with legacy wells.
- GRS saves rig time and cost and aid to reach well target when used in real-time hole navigation.
- If we don't get the message out that wellbore positioning is worth spending money on, we will continue to waste reserves and occasionally risk lives.

6.1.5 Total BHA Configuration

- The perfect target is shoe to shoe one signal run section.
- Select the best BHA configuration for each well section, including the most efficient and supportive bit design and the deployed steering system, and study the overall BHA set-up response in the planning phase to satisfy the most efficacy operations.

- Drilling engineers have to use the well-to-well cycle, the run-to-run, and the real-time cycle as well as by simple modeling or sophisticated model to predict the tendency for more optimum results.
- Reduction the BH vibrations as much as we can.
- Improvement hole geometry by satisfying smoother DLS.
- Searching for an efficient partnership to RTS with bit combination.
- Basically, a well-matched bit-BHA total system, helps deliver:

Improved borehole quality. Increased drilling performance. Extended reliability. Reduced directional uncertainty. Safety assurance and cost-effective

- In supergiant field's development, a high number of drilled wells with different trajectories and BHAs, the quality of the suggested BHA configuration improves over time, because the database grows knowledge and help construct a road map for the optimum, cost-effective drilling.
- To steer within the formation, including the orientation measurement, continuous inclination, azimuth gamma, WOB/TOB/stick-slip, propagation resistivity, and annulus with pore pressure in the BHA.
- The most modern BHAs technique allowed to maximize ROP in complex targets, unconventional, deep water, and mature fields with 400 RPMs and DL capabilities of 18°/100 ft.

6.2 Recommendations

Due to the development of the oil and gas exploration industry and the excessively complexly of downhole environment, there are several aspects including both the tools manufacturing development and field practical application that still need to be addressed in the future.

- **Angle Build Hole Rate:** Further validating and application of modern BHA configurations that satisfy the high build hole rate and advanced techniques in the field.
- **BHAs Simulation Field Data :** Apply real field data simulation to different BHAs through the confident software with different wellbore trajectories and cover a wide range of the drilling environments to investigate the limitations of the tools and realize the capability of each type of the BHAs.

-
- **Directional Mechanism:** Researching more deep in the results of the applications of each type of steering system in the BHAs with different drilling environments to introduce useful classification to the field.
 - **Control Methods:** Real field operations and verification for some RSS control methods which are still in simulation stage as several advanced control techniques including fuzzy control, adaptive control, sliding mode control, and others have been developed and achieving applications on downhole position control, trajectory tracking, disturbance control, and attitude control.
 - **Downhole Real-time Condition Measurement and Data Processing:** As in the real working conditions lots of perturbation and noise will disturb the measured data. Thus, it's necessary to develop data filtering and data mining technologies.
 - **Mathematical Model Establishment:** The key point to obtain excellent control effects is the availability of exact and rigid mathematical model of RSS. In the presence of RSS control systems, most mathematical models selected cannot imitate the real working pattern as their installation and state observer designs are normally form on some simplifications and assumptions. Upon the evolution of automatic techniques, neural network, deep learning, and other intelligent modeling techniques based on learning mechanism, these new techniques will be joined with, least square method, autoregression, augmented state space method, and other traditional system identification techniques to broadly use data-driven, model analysis, and others to achieve approximation between the mathematical model and real working process of RSS.
 - **Manufacturing Materials:** Adopting structures or new-style materials in all types of RSS especially to eccentric shaft and other auxiliary mechanisms in the point-the bit RSS because of the limitation of material and mechanical structure which are subject to mechanical oscillation, corrosive stratum, mudstone, etc.
 - **Sealing Performance of BHA:** Further enhance the sealing performance in the downhole BHA as flowing of drilling mud into the inner directional mechanism will cause damage.
 - **Other Development Trends:** The hybrid class RSS will have satisfying progress and prospect, the point-the-bit RSS is also developing into a leading steering mechanism. On the other hand, wireless communication, bidirectional communication, has made noticeable progress in reliability, real-time, and anti-interference. Due to LWD/MWD superior property, it is replacing wireline logging.

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