Chapter Two

Literature Review and Theoretical Background

This chapter presents the literature study on slim hole drilling technology along with theories used to design and analysis of slim hole sidetracking from abandoned well.

2.1 Literature Review:

2.1.1 Introduction:

In the oil and gas industry, wells can be intended to drill in many different ways to serve multiple purposes depending on the design and operators requirements. Since there is a high demand for oil and gas worldwide and the technology is emerging with pace, the current trend is to drill wells in cheaply, safely and more efficient manner. This can be achieved by developing new types of wells that can lead to a low cost. For instance, slim hole well which can minimize the drilling cost and risk and may help cut the rig time that can lead to an increasing the recovery rate. Therefore, the concept of smaller size hole has the possibility to offer smaller drilling rig with potentially smaller surface area. In addition, it offers reducing the required for mud and cement volumes, with required smaller reserve mud pit.

There is an improvement in equipment and the technology but still the petroleum industry needs to minimize the cost of drilling with more difficult wells such as deep wells, HPHT wells. Advance technology means that we can safely drill new wells with small diameter and with minimum borehole problems.

2.1.2 Cost Analysis:

C.R. Hall and A.B. Ramos Jr (1991) developed the concept of slim hole horizontal drilling program in Pearsall Field located in South Texas. It was decided to develop an extensive horizontal drilling program to drill new wells in this area. The idea was to reduce costs in such areas where productive rates were not contingent on the size of the lateral wellbore. Three wells were drilled to evaluate the proposal using a smaller drilling rig to the intermediate casing point. The drilling rig was released, then the work over rig replaced to drill the curve and lateral section. This offered two benefits. The first one was that was a small drilling rigs could drill the upper hole

more rapidly than the workover rig and at reduced cost than that required to drill conventional wells. Secondly, the less expensive workover rig could more easily manipulate the tubing used for the drill string.

Results from study seen in slim hole horizontal drilling operation showed a significant cost reduction. The cost of this slim hole horizontal wells from first well is reduced 20% while savings nearly 32% of conventional design and 16% from the reduced hole design were also seen.

The results from these wells show that slim hole horizontal drilling operation, whether re-entry or newly drilled wells provides significant potential for cost savings. Based on the results, this technology shows a great promising projects and would continue to do so to meet the needs of oil industry.

Forasol and Elf Aquitaine Production (Dupuis and Sagot,1995) described an approach to further reduce drilling costs with the purpose-built slim-hole. By integrating various services into the rig design, service costs can be saved by making use of integrated equipment and drilling crew.

As a result, slim hole reduced volumes of cement required for operations, cement slurry is prepared in two batch tanks and pumped by the rig pumps. Cost savings are accrued since a dedicated cementing unit is not needed.

Tao Zhu and Herbert B. Carrol (1995) studied case use of slim hole drilling to re-enter wells are categorized into two methods: sidetracking existing wells or deepening existing wells.

In this technique of sidetracking, a portion of the existing casing is milled out by either applying section milling or window milling operations. Then the hole is sidetracked to directional section. Window milling operation does not need a cement plug for kicking off and less casing is removed compared to section milling. In this case, the sidetracking is achieved while cutting out the window. Therefore, window-milling operation can reduce the time required for sidetracks.

ARCO Alaska (Pearson et al.,1996) achieved significant cost reductions by combining slim-hole drilling and completion technology with increased efficiency in planning and procurement of consumables.

A goal was set for the Kuparuk River for reducing well costs by 30%. Early results with the revised operations and efficient procurement showed that the potential exists for exceeding 30% as the equipment and procedures are fine-tuned and optimized.

OMV AG and Oil & Gas Tek International Limited (Kroell and Spoerker, 1996) They provided a review and analysis of slim-hole production and hydraulics issues. They believe that the drilling industry has conclusively demonstrated that slim-hole technology can be used to reach objectives and is usually technically and economically feasible. They discussed completion and production aspects and the impact of slim wellbore diameters. For most cases, constraints on production are minimum, although more planning for completions, artificial lift, etc. will likely be required.

They also state that "only low- to medium-permeability reservoirs should be completed with slim holes. Production constraints may offset the advantages of initial cost savings.

Union Pacific Resources Company reports continuing cost savings averaging 30% for drilling horizontal slim-hole laterals out of existing wells the alternative is to drill a new well from the surface. A large number of vertical wells in the Austin Chalk were completed with 5-in. casing.

Baker Huges and Husky Oil Operation (Hollies and Szutiak,1997) reported the successful application of slim-hole drilling techniques to revive the drilling problem for re-entry well in the Rainbow Lake Field. In the slim hole approach, intermediate liner (4 ½ inch) was run into the curve, then the lateral is drilled with a reliable 3 -7/8 inch slim hole system. According to Husky, the completion of these wells resulted no more expensive than the conventional single- size version.

The analysis was based on several drilling operation, namely mechanical, hydraulics, well control, surge and swab, torque and drag t issues.

2.1.3 Hydraulic:

Hassvein et al. (1992) constructed a model to predict the pressure loss for slim hole drilling. The model, which is constructed by theoretical and numerical analysis and experimental measurements, incorporates the effect of eccentricity, drill string rotation and rheology.

The model result included rotation has been constructed using a combined numerical and experimental approach for the non-rotating case the model is also valid for non-slim hole cases of pipe, concentric and eccentric annuli. The model applies to Newtonian fluids, power law fluids, Bingham fluids and Herschel-Bulkley fluids.

Forasol, Elf Acquitaine Production, Total, Institut Fran~aisd uP&role and Geoservices (Dupuis et al.,1995) reported the results of experiments to validate a kick-control method and a pressure-loss model for use with slim-hole applications.

They determined that the impact of rotation on pressure losses is keyed to the Taylor and Reynolds numbers. For Re < 1000, pressure losses in the annulus increase with rotation. For Re > 1000, the impact of rotation is greatly reduced. Experimental results of well-control events showed that it is best to not perform a flow check after a kick has been detected, but rather to quickly close the BOP.

The Mining University of Leoben and Oil & Gas Tek International (Thonhauser et al.,1995) critically analyzed the effectiveness of slim-hole hydraulics models. They compared field results from five deep slim holes to various approaches for modeling hydraulics. It was determined that, in many cases, various phenomena impact hydraulics behavior and are not accounted for the existing simulators.

They concluded that current models can only approximate hydraulics in slim wells, and additional improvements are required.

The Institut Frangais du Pbtrole, Forasol, and Elf Aquitaine Production (Cartalos et al.,1996) developed a hydraulics model for slim-hole geometries. Developed under the Euroslim project, the model was devised to predict flow behavior in the restrictive flow channels between slim drill pipe and casing. Their model accounts for eccentricity of the drill pipe and effects of rotation. Close agreement was obtained with results from three field wells.

They found pressure losses are lower in eccentric annuli in both laminar and turbulent flow, but may be greater in transitional regimes.

2.1.4 Well Control:

P.K. Prince, BP Exploration Operating Co. Ltd., and E.E. Cowell (1993) presented a safe method of modifying commonly practiced conventional well kill techniques to take account of the high annular pressure losses and circulate out the influx in a controlled manner.

They obtained modified conventional well control technique preferred to dynamic methods because, it gives more accurate control of the well and easier to implement, the time of highest risk of an influx occurring is during connections and maintain safety margins slim hole drilling.

2.1.5 Buckling Analysis:

Wen jun huang et al. deduced new buckling equation in horizontal well from loves work. Because there are no approximation in derivation and the Buckling equation is an accurate model.

The result show the new buckling equation provided more comprehensive describe of tubular buckling behaviour and boundary condition play important role in the buckling behaviour.

Ferda Akgun et al (1999) presented a finite element method to assess the critical buckling load (CBL) of drill collars (DCs). Then, CBLs of DCs with stabilizers placed at different configurations.

The weight of the section of a drill string below the neutral they found point is assumed to be equal to the weight on the bit (WOB) and also Increase in CBL not only depends on the number of stabilizers, but also, the location of stabilizers in the BHA.

2.1.6 Torque and Drag:

Johan E. McCormick (2011) attempts to describe the practices and the evolution on torque and drag reduction methods and accurate account for it and discussed many methods.

He Concluded his work by finding ways to reduce torque and drag in a significant effort in solving the challenges in sustaining the global energy demand.

2.1.7 Surge and Swab Pressure:

Ruchir srivastav et al. (2012) presented the results of experimental investigations conducted to study the effects of eccentricity on surge and swab pressures. Experiments were performed in a test setup, which consists of fully transparent polycarbonate tubing, and inner pipe that moves axially using a speed controlled hoisting system.

Results confirm that trip speed, fluid rheological properties, annular clearance and eccentricity significantly affect the surge pressure. In some cases, eccentricity can reduce surge and swab pressure by around 40%. Applying regression analysis, a generalized correlation has been developed to account for the reduction in surge pressure due to the eccentricity of the drillpipe. An accurate surge pressure model is

very important in planning drilling operations, mainly in wells with narrow safe pressure window, slim holes and low-clearance casings.

2.2 Theoretical Background:

2.2.1 Well Planning:

The planning of a directional well requires the following information (Rabia H):

1. Surface and Target Co-ordinates: UTM, Lambert or geographical.

2. Size of and shape target(s).

3. Local Reference Co-ordinates: For multi-well sites, these must include template, platform centre and slot location.

4. Required well inclination when entering the target horizon.

5. Prognoses Lithology: including formation types, TVD of formation tops, formation dip and direction.

6. Offset well bit and BHA data: Required for bit walk, building tendencies of BHA's.

7. Casing programme and drilling fluid types.

8. Details of all potential hole problems which may impact the directional well plan or surveying requirements.

9. A listing of definitive survey data of all near-by wells which may cause a collision risk. For offshore drilling, this listing should include all wells drilled from the same platform template or near-by platforms and all abandoned wells in the vicinity of the new wells.

2.2.1.1 Bottom Hole Targets:

The objective of an oil/gas well is to reach the target: pay zone. However, there may be other objectives in drilling a well in addition to intersecting the pay zone, including:

• defining geological features such as faults or pinch-outs.

• defining reservoir structure.

• intersecting another well as in relief well drilling.

Irrespective, the number of objectives involved, the coordinates (in UTM, Lambert, or Geographic). For well planning purposes, it is more convenient and simpler to express the coordinates of the surface location and target in terms of local

coordinates. The target given by the geologist is not a single point in space but a circle of say 150 ft in radius.

Rectangular coordinates of a target are usually given in feet/meters North/South and East/West of the local reference point.

The rectangular coordinates can be used to calculate the departure (horizontal displacement) between the surface location and the bottom hole target as follows (Rabia H):

$$\text{Departure} = ((\Delta E/W)^2 + (\Delta N/S)^2)^{1/2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.1)$$

Where:

Δ denotes difference in coordinates between E/W or N/S

Polar coordinates can be derived from the rectangular coordinates. They are expressed as a distance (departure) and as a direction (either Quadrant or azimuth). Polar coordinates are derived from the rectangular coordinates as follows (Rabia H):

$$\text{Azimuth} = \tan^{-1} ((\Delta E/W \text{ Coordinates}) / (\Delta N/S \text{ Coordinates})) \ldots\ldots\ldots\ldots (2.2)$$

2.2.1.2 Well Coordinates:

Well coordinates are usually referenced to either the wellhead for single well operations or to the central platform for offshore operations. The surface reference point is given 0.0 N and 0.0 E coordinates to eliminate the use of large numbers.

When carrying out anti-collision analysis for a cluster of wells, it is important to refer the coordinates of the wells to a central reference point, either the surface TVD (ss) of the centre of the geological structure or the centre of the central platform (Rabia H).

2.2.1.3 Well Profile: Definitions

2.2.1.3.1 Inclination Angle:

The inclination angle of a well at any point is the angle the wellbore forms between its axis and the vertical.

2.2.1.3.2 Measured Depth:

Measured depth (MD) is the distance measured along the well path from one reference point to the survey point, Fig.**2.1**. Measured depth is also known as Along Hole Depth and is measured with the pipe tally or by a wireline.

2.2.1.3.3 True Vertical Depth:

True vertical depth (TVD) is the vertical distance measured from a reference point to the survey point. TVD is usually referenced to the rotary table, but may also be referenced to mean sea level, Fig.**2.1**.

2.2.1.4 Determining the Kick-off Point:

The Kick-off point is defined as a point in the wellbore at a given vertical depth below the surface location where the well is to be deviated away from vertical in a given direction up to a given inclination at a given build rate. The selection of the Kick-off point is made by considering the geometrical well-path and the geological characteristics. The optimum inclination of the well is a function of the maximum permissible build rate (and drop rate if applicable) and the location of the target.

2.2.1.5 Build-Up/Drop off Rates:

The maximum permissible build up /drop off rate is normally determined by one or more of the following:

- The total depth of the well.
- Maximum torque and drag limitations.
- Mechanical limitations of the drill string or casing.
- Mechanical limitations of logging tools and production strings.

The optimum build up and drop off rates in conventional directional wells are in the range of 1.50° to 30° per 100 ft, although much higher build up rates are used for horizontal and multilateral wells (Rabia H).

2.2.2 Planning the Well Profile:

One area of well planning in which directional companies are closely involved is the planning of the well Profile. Again, this is not as simple a task as it might seem at first glance, particularly on a congested multi-well platform. There area number of aspects that must be carefully considered before calculating the final well path.

2.2.2.1 Types of Well Profiles:

If the position of the surface location is known and given the location of the target, its TVD and rectangular coordinates, it is possible to calculate the best well profile that fits the coordinates of the surface and the bottom hole target that fit this

data. The well profile is plotted in the vertical plane as shown in Fig.**2.1**. This figure also describes the various sections of a directional well (Rabia H).
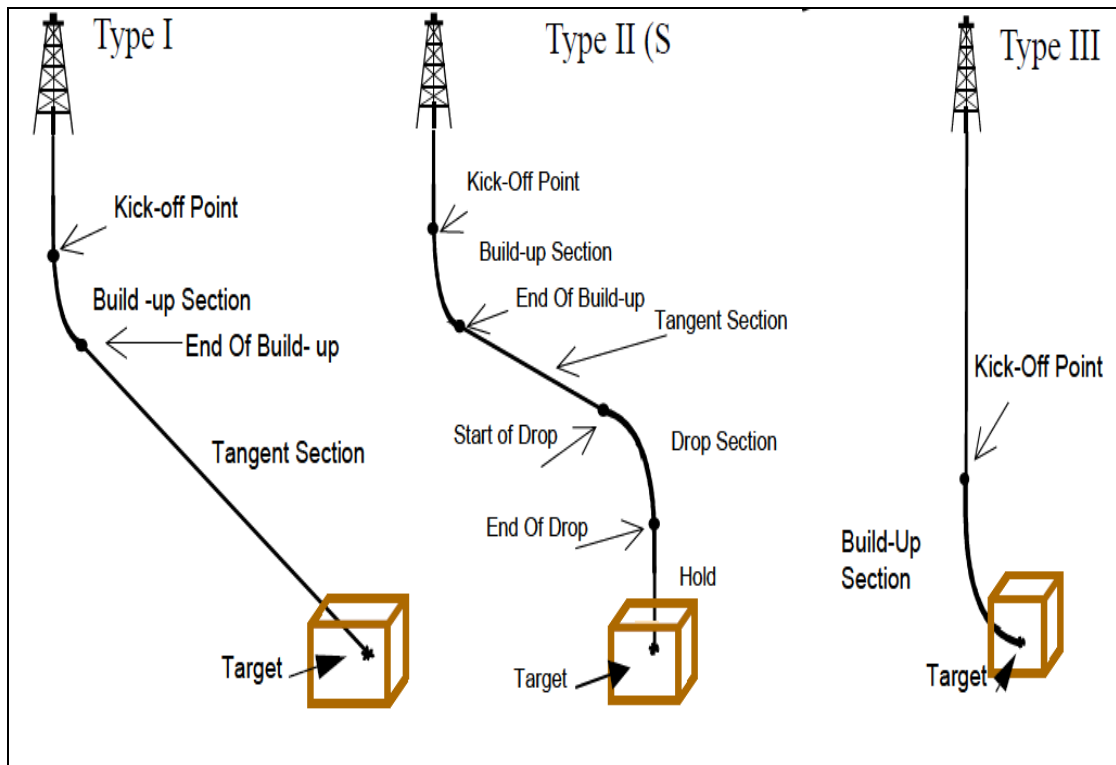

Fig (2.1): Types of Well Profiles (Rabia H).

There are three basic well profiles which include the design of most directional wells:

1. Type one: Build and hold trajectory. This is made up of a kick off point, one build up section and a tangent section to target, see Fig.**2.1**.

2. Type two: S-Shape trajectory. This is made up of a vertical section, kick-off point, build-up section, tangent section, drop-off section and a hold section to target, see Fig.**2.1**.

3. Type three: Deep kick off trajectory. This is made up of a vertical section, a deep kick off and a build up to target, see Fig.**2.1**.

2.2.2.2 Build-Up & Hold Design:

To carry out the geometric planning for a Type I well, Fig.**2.2**, the following information is required (Rabia H):

• Surface Co-ordinates

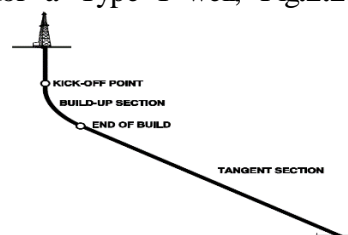• Target Co-ordinates

• TVD of target

• TVD to KOP

Fig (2.2): Build-up &hold (Baker Hughes,1995).

• Build-up rate

Features: -

- Shallow kick-off point (KOP).

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

- Tangent section.

➢ **Applications: -**

- Deep wells with large horizontal displacements.

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

➢ **Calculation: -**
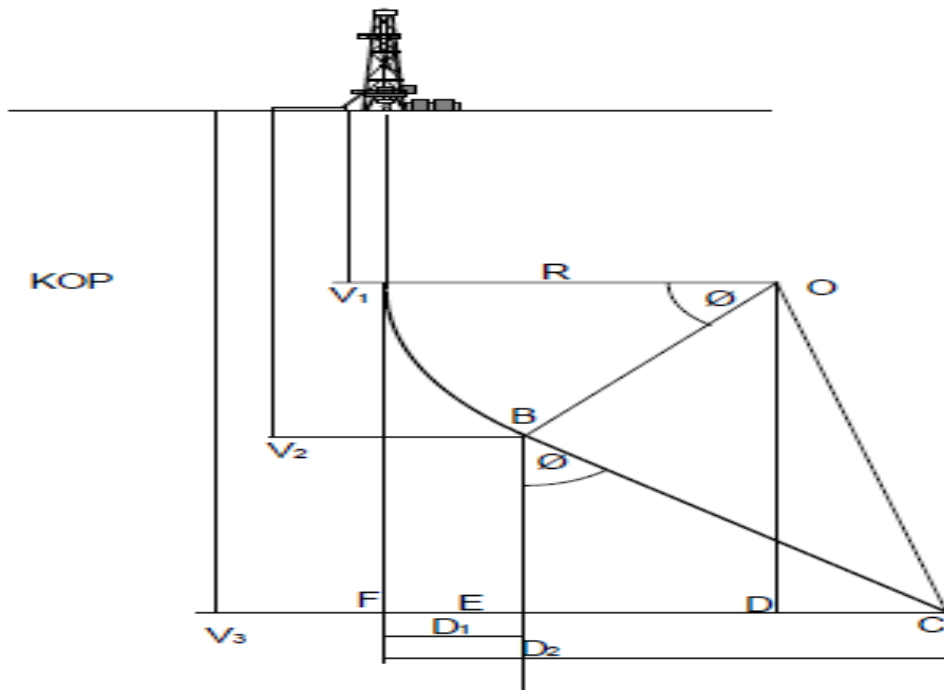
- **First Case $R < D_2$:**

Fig (2.3): Build-up & Hold Type Well; R < Total Target Displacement (Directional Drilling Training Manual, 1996).

Given:

- Wellhead coordinates.

- Target coordinates.

- Target TVD, V_3.

To determine:

- KOP vertical depth, V_1.

- Build up rate, BUR.

- KOP Kick-off point.

- V_1 TVD of straight section/surface to KOP.

- V_2 TVD of end of buildup.

- V_2 - V_1 TVD of buildup section with BUR corresponding to radius of curvature R.

- V_3 - V_2 TVD of Tangent section to total depth.

- D_1 Displacement at end of buildup.

- D_2 Total horizontal displacement of target.

- Maximum inclination of well.

The maximum inclination angle α_{max} is given by:

$$\alpha_{max} = 180 - \arctan\left(\frac{v_3-v_1}{D_2-R}\right) - \arccos\left(\left(\frac{R}{v_3-v_1}\right)\sin\left[\arctan\left(\frac{v_3-v_1}{D_2-R}\right)\right]\right) \quad\text{.................} (2.3)$$

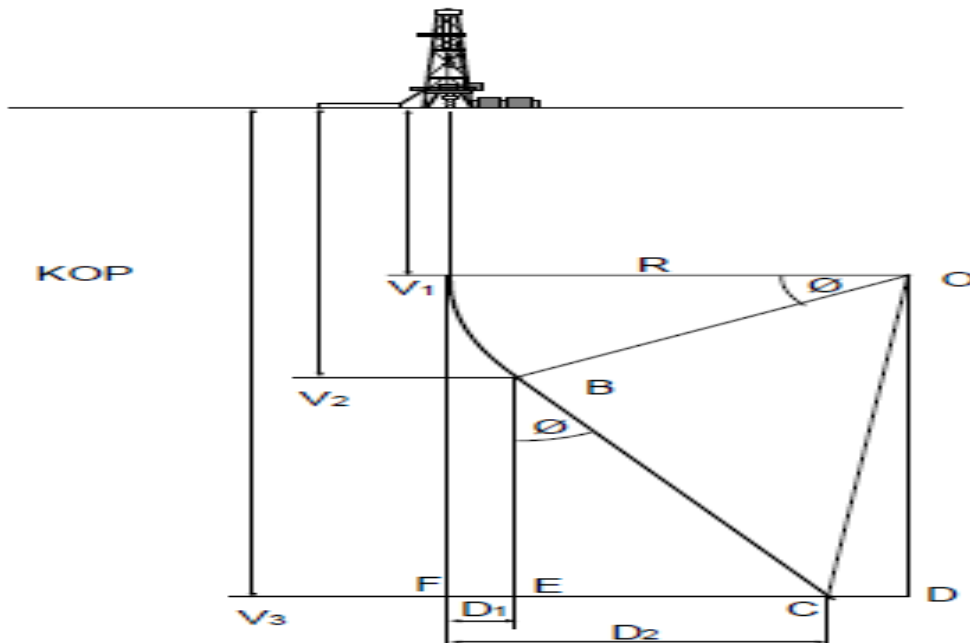- **Second Case R > D₂:**

Fig (2.4): Build-up &Hold Type Well; R >Total Target Displacement (Directional Drilling Training Manual,1996).

Given:

- Wellhead coordinates.

- Target coordinates.

- Target TVD, V_3.

To determine:

- KOP vertical depth, V_1

- Build up rate, BUR

- KOP Kick-off point.

- V_1 TVD of straight section/surface to KOP.

- V_2 TVD of end of buildup.

- $V_2 - V_1$ TVD of buildup section with BUR corresponding to radius of curvature R.

- $V_3 - V_2$ TVD of Tangent section to total depth.

- D_1 Displacement at end of buildup.

- D_2 Total horizontal displacement of target.

- Maximum inclination of well.

The maximum inclination angle α_{max} for type I trajectory is given by:

$$\alpha_{max} = arc\tan\left[\frac{v_3 - v_1}{R - D2}\right] - \arccos\left(\left(\frac{R}{v_3 - v_1}\right) \times \sin\left[\arctan\left(\frac{v_3 - v_1}{R - D}\right)\right]\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots (2.4)$$

> **Build-up Section: -**

1. Radius of curvature (R) of build-up section:

$$R = \frac{360 \times 100}{2 \times \pi \times BUR} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.5)$$

   Where BUR = build-up rate, degrees/100ft

2. Measured length of build-up section:

$$MD_2 = \frac{\alpha_1 \times 100}{BUR} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.6)$$

   Where α= maximum inclination angle at end of buildup section

3. Vertical length of build-up section:

$$V_2 - V_1 = R_1 x \sin \alpha \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.7)$$

4. Horizontal displacement (departure) at end of build-up section:

$$D_1 = R_1 x (1 - \cos\alpha) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.8)$$

> **Tangent Section: -**

5. Measured length of tangent section:

$$MD_3 = \frac{v_3 - v_2}{\cos \alpha} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.9)$$

6. Vertical length of tangent section:

$$V_3 - V_2 = MD_3 x \cos \alpha \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.10)$$

7. Horizontal displacement at end of tangent section:

$$D_2 = D_1 + MD_3 \text{ x } \sin \alpha\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .... (2.11)$$

8. Total measured depth for type I wells:

$$TMD= MD_1 + MD_2 + MD_3\ldots\ldots\ldots..\ldots\ldots\ldots\ldots\ldots\ldots........(2.12)$$

2.2.3 Deflection Tools:

The wellbore can be deflected from its current position using one of the following tools (Rabia H):

- Whipstocks.
- Jetting action.
- Downhole motors and bent sub.
- Steerable positive displacement motor.
- Rotary steerable systems.

2.2.3.1 Whipstocks:

The whipstock is widely used as a deflecting medium for drilling multilateral wells. It consists of a long inverted steel wedge (Shute) which is concave on one side to hold and guide a deflecting drilling or milling assembly. It is also provided with a chisel point at the bottom to prevent the tool from turning, and a heavy collar at the top to withdraw the tool from the hole, Fig.**2.5**.

Today, whipstocks are mainly used to mill casing windows for sidetracking existing wells.

There are two main types of Whipstocks:

- The standard removable Whipstock which is used to kick off wells and for sidetracking. The Whipstock is used with a drilling assembly consisting of a bit, a spiral stabilizer, and an orientation sub, rigidly attached to the
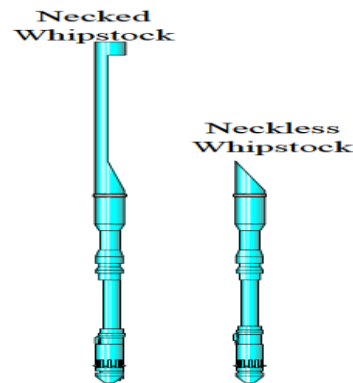

Fig (2.5): Whipstock (Rabia H).

Whipstock by means of a shear pin. To deflect the well, the whipstock and Kick off assembly is run in hole and oriented in the required direction. Weight is then applied to shear the pin and allow the drilling bit to slide down the Shute and drill in the set direction.

- The Permanent Casing Whipstock is designed to remain permanently in the well.
- Thru tubing whipstock.

2.2.3.2 Jetting:

This is an old technique which is rarely used today. It relies on hydraulics to deviate the wellbore and is therefore only effective in soft formations. A special jet bit, is often used, but it is possible to use a normal soft formation bit, using one very large nozzle and 2 small jet nozzles. The large jet nozzle is the "tool face". The fluid coming out from the large nozzle causes the maximum formation erosion and allows the well to be, effectively, deflected in the direction of the jet coming out of the big nozzle. Jetting usually causes high dogleg severities.

2.2.3.3 Downhole Motors with Bent Subs:

A downhole motor with a bent sub, Fig.**2.6**, was a common method for deflecting wells until replaced by steerable motors. The bent sub is run directly above the motor and its pin is offset at an angle of 1-3 degrees. The bent sub has a scribe line cut on its outside body (casing) above the pin offset. This scribe line is used to orient the BHA in the required direction. The orienting sub (Fig.**2.6**) allows single shot surveys to be taken to confirm the orientation of the BHA.
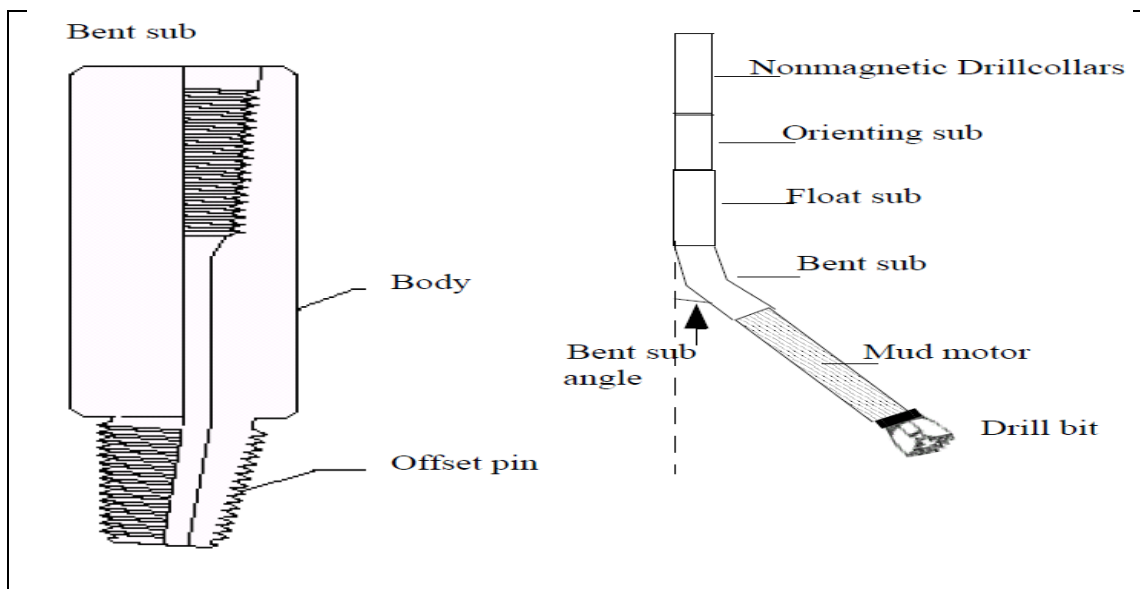

Fig (2.6): PDM BHA with Bent Sub (Rabia H).

Deflection of the wellbore occurs when drilling is carried out with no surface rotation to the drillstring. The drillbit is forced to follow the curve of the bent sub. The degree of curvature depends largely on the bent sub offset angle and the OD of the motor.

When the required angles (inclination and/or azimuth) are obtained, this BHA is tripped out and replaced with a rotary assembly.

2.2.3.4 Steerable Positive Displacement Motors:

The motor is designed with an in-built bent housing below the motor section; usually the connecting rod housing. The bent housing angle is usually 0.25-1.5 degrees and is designed to tilt the axis of the bit relative to the axis of the hole. The reader should note that having only a small bit offset will create a considerable bit side force (deflecting force).

A steerable motor can be used in oriented mode (sliding) or rotary mode. In the sliding mode, the drillstring remains stationary (rotary table or top-drive is locked) while the drillbit is rotated by the motor. The course of the well is only changed when drilling in sliding mode as the drillbit will now follow the curvature of the motor bent housing. In rotary mode, the steerable motor becomes "locked" with respect to trajectory and the hole direction and inclination are maintained while drilling. The use of steerable motors with the correct drillbit and BHA reduces the number of round trips required to produce the desired inclination/azimuth.

2.2.4 Bottom Hole Assemblies (BHA):

The bottom hole assembly refers to the HWDP, drill collars, stabilizers and other accessories used in the drillstring. All wells whether vertical or deviated require careful design of the bottom hole assembly (BHA) to control the direction of the well in order to achieve the target objectives. Stabilizers and drill collars are the main components used to control hole inclination (Directional Drilling Training Manual,1996).

2.2.4.1 Heavy Weight Drill Pipe (HWDP):

This is an intermediate-weight drill string member with drill pipe dimensions for easier handling. Its heavy wall tube is attached to special extra-length tool joints. These provide ample space for recutting the connections and reduce the rate of wear on the OD.

HWDP is less rigid than DCs and has much less wall contact. Chances of differential sticking are reduced. Its three-point wall contact feature solves two serious problems in directional drilling. Today, the trend in BHA design is to minimize the number of

DCs in the BHA and use HWDP to comprise a major portion of available weight on bit HWDP is normally provided by the drilling contractor.

2.2.4.2 Drilling Jars:

These are designed to deliver an impact either upwards or downwards. Jars are run in deviated wells so that the string can be jarred free in case of tight hole or stuck pipe. Jarscan be either mechanical, hydraulic or hydro-mechanical design.

2.2.4.3 Drill Collar (DC):

Drill collars are heavy, stiff steel tubulars. They are used at the bottom of a BHA to provide weight on bit and rigidity. Flush or spiral drill collars are available. In directional drilling, spiral drill collars are preferable Fig.**2.7**. The spiral grooves machined in the collar reduce the wall contact area by 40% for a reduction in weight of only 4%. The chances of differential sticking are greatly reduced. Spiral drill collars usually have slip and elevator recesses. Stress-relief groove pins and bore back boxes are optional. The drill collars (various sizes) are normally owned by the drilling contractor.
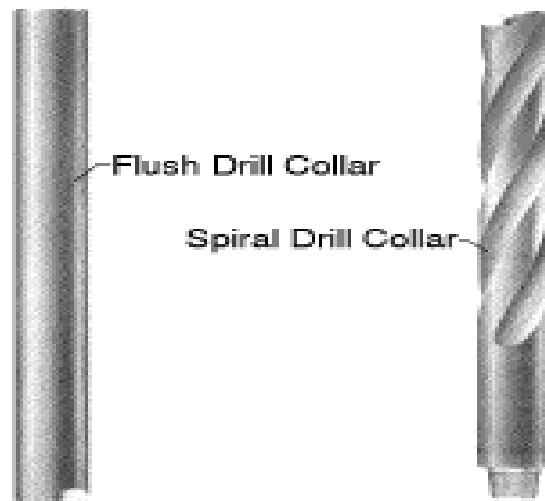

Fig (2.7): Flush and Spiral Drill Collars (Directional Drilling Training Manual,1996).

Features of All Our Drill Collars:

- The bores of our drill collars are machined to close tolerance by precision drilling methods and are drifted to API specifications. The surface is "as rolled", which is the original mill finish.
- All connections are chemically treated to prevent galling.
- Thread roots are cold-worked to provide longer fatigue life.

• All drill collars are shipped with thread protectors.

2.2.4.4 Non-Magnetic Drill Collar (NMDC):

Non-magnetic drill collars are usually flush (non-spiral). They are manufactured from high-quality, corrosion-resistant, austenitic stainless steel. Magnetic survey instruments run in the hole need to be located in a non-magnetic drill collar of sufficient length to allow the measurement of the earth's magnetic field without magnetic interference. Survey instruments are isolated from magnetic disturbance caused by steel components

in the BHA and drillpipe. ANADRILL's M1 MWD tool and its successors are fixed inside their own special MWD non-magnetic drill collars. SLIM-1, however, is run inside a standard NMDC. Stress-relief groove pins and bore back boxes are optional.

2.2.4.5 Float Sub:

This is a PIN x BOX sub which is bored out to take a float valve. It is often run above a mud motor. In conventional rotary BHAs, a float valve is inserted either in the bit sub (in the case of a pendulum BHA) or in the bored-out near-bit stabilizer. Poppet and flapper designs of float valve are available. Note that some clients may not allow the use of a float valve (because of kick-control problems). The DD should check the client's regulations on arrival at the rig. The float sub is usually provided by the DD company. The float valve is usually provided by the drilling contractor.

2.2.4.6 Section Mill:

This tool is used to mill a section of casing (usually prior to a cased-hole sidetrack). The Servco K-mill (Figure) is the most common in ANADRILL. It operates on a similar principle to the under reamer. It includes six triangular cutters which are dressed with tungsten carbide. On reaching the depth of the top of the section, pump pressure is applied. Three of the cutter arms expand and begin the cut-out. When the casing cut-out is complete, the second set of three arms expands into the milling position. The Flo-Tel feature gives a positive surface indication of casing cut-out. All six cutter arms are then seated squarely on top of the casing and milling of the section proceeds.

2.2.4.7 Diamond Bits:

Diamond has been used as a material for cutting rock for many years. The hardness and wear resistance of diamond made it an obvious material to be used for a drilling bit. The diamond bit is really a type of drag bit.

A new generation of diamond bits known as **polycrystalline diamond compact (PDC) bits** was introduced in the 1980's. PDC bits have been run very successfully in many areas around the world.

The PDC drill bits were introduced to the drilling industry in 1967. A PDC cutter consists of a stud covered by an artificial diamond layer bonded in a high pressure/high temperature sintering process.

The ability of the PDC bits to drill different formations with excellent efficiency was proven to the industry (Millheim,1986). The main advantages of the PDC bits are:

- Longer life (Better wear resistance).
- Higher average ROP.
- Better drilling economics ($/m).

2.2.5 Cuttings Transport:

Efficient removal of cuttings from wellbore is considered as an essential for the success of the overall drilling operation. Insufficient hole cleaning results that the cuttings may deposit and accumulate in the annulus and causes several drilling problems that include (Ozbayoglu et al,2010):

- Increase in drilling string torque and drag.
- Poor hole condition can lead to slow rate of penetration.
- Stuck pipe.
- Difficulty when running and cementing casing (reason for channeling...) (Mesfin et al,2014).

To avoid such problems, it is very crucial to handle this situation properly during planning phase in order to achieve sufficient hole cleaning. Failure to remove drilled cuttings can ultimately result such as stuck pipe incidents that can lead to the loss of a well. This only accident may cost over 1 $ million USD which will increase the operational cost for the industry. The major factors affecting transportation of cuttings

in the annulus can be categorized into three groups (Ozbayoglu et al,2010) (Mesfin et al,2014):

- Fluid parameters.
- Cutting parameter and.
- Operational parameters.

Several factors affecting the carrying capacity of drilling fluid is listed on the following Table.**2.1**.

Table (2.1): Factors affecting the carrying capacity of drilling fluid

Fluid Parameters	Cutting parameter	Wellbore configuration + operational parameters
Mud density	Cutting density	Angle of inclination
Rheology	Cutting size	Pipe rotation
	Shape	Rate of penetration
	Cutting concentration	Eccentricity of the hole
	Bed porosity	Flow rate
	Angle of repose	Depth, hole size/casing well inside diameter

Inadequate hole cleaning and cutting transport problems are so common in directional and horizontal drilling. As seen in Fig.**2.8**, the formation of cutting bed is relatively at higher angles from vertical and also cutting bed would slide down in intermediate angle (Ozbayoglu et al,2010) (Mesfin et al,2014).
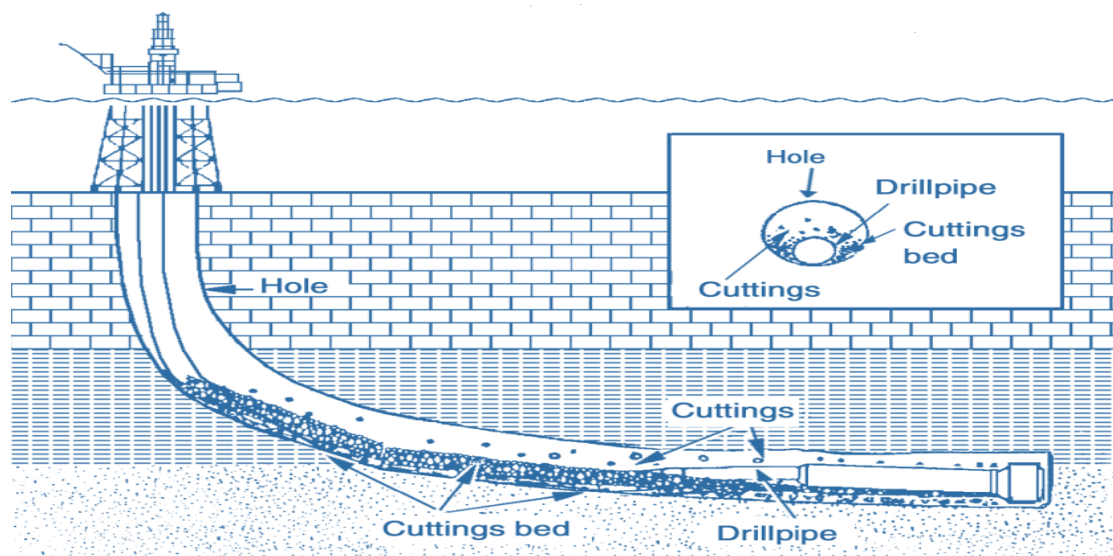

Fig (2.8): Deposition of Cuttings in Inclined Well (Ozbayoglu et al,2010) (Mesfin et al,2014).

Efficient removal of cuttings from a wellbore is an essential for conducting a successful drilling operation. Therefore, using the Hydraulic module in wellplan software will help to examine the minimum flow rate and determine the minimum flow rate to transport cutting and bed height simulation by using flow rate lower than the minimum allowable flow rate.

2.2.6 Surge and Swab:

The movement of the drill string when pulling out of the hole will cause the pressure caused by the drilling fluid on the bottom of the hole to decrease. This caused by the friction between the movement of the pipe and the stationary drilling mud. This is referred to as swab pressure, P_{sw}.

The reverse is also true, running in the hole the pressure will increase due to the pipe movement, this is called surge pressure, P_{surge}.

The swab and surge pressure need to be control so the well does not form a kick or break down the formation.

2.2.7 Wellbore Stability:

Unexpected or unknown behavior of rock is often the cause of drilling problems, resulting in an expensive loss of time, sometimes in a loss of part or even whole borehole. Borehole stability is a continuing problem which results insubstantial yearly expenditures by the petroleum industry (Bradley, 1978, Awal et al., 2001). As result, a major concern of the drilling engineers is keeping the borehole wall from falling in or breaking down. Detailed attention is paid to drilling fluid programs, casing programs, and operating procedures in drilling a well to minimize these costly problems.

Wellbore instability is one of the main problems that engineers meet during drilling. The causes of wellbore instability are often classified into either mechanical (for example, failure of the rock around the hole because of high stresses, low rock strength, or inappropriate drilling practice) or chemical effects which arise from damaging interaction between the rock, generally shale, and the drilling fluid. Often, field instances of instability are a result of a combination of both chemical and mechanical (Zagreb, 2007).

- **The Mechanism of Wellbore Stability:**

Wellbore formation broke the equilibrium situ stress, the stress redistribution in the rock surrounding the well, causing stress concentration. When the well's mud column pressure is too high, the formation is fractured leading to extend the original crack open fissures or form a new system. Mud column pressure at this time is called the formation fracture pressure. The size of the fracture pressure of the formation is closely related to the size of in-situ stress, formation strength and porosity, the degree of development of micro-cracks. From the mechanical point of view, when the tensile stress exceeds the tensile strength, formation will rupture. Formation tensile strength is zero for high degree of development of micro-cracks. Therefore, we must first study the stress state around the well.

1) The Stress State Around the Well

On the infinite plane, a round hole with uniform internal pressure, at the same time in the plane infinity have the effect of the two horizontal in-situ stresses with the vertical direction by the overlying pressure. Considering rock for small deformation elastic body, then the linear superposition principle is applicable. Therefore, the total stress state can obtain firstly through the study of the stress components of borehole stress contribution, and then through the superposition method.
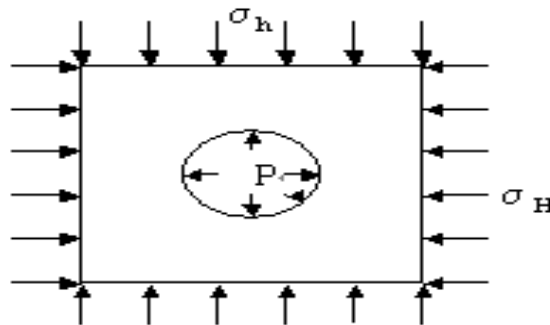

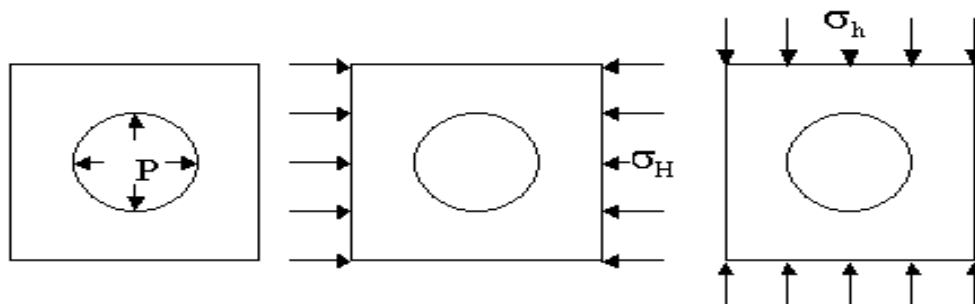**Fig (2.9):** Stress State Around the Well.

Fig (2.10): Wellbore Stress State Decomposition.

2) Wall Fracture Pressure Model

Tensile stress criterion is used to study formation fracture usually. That believes the rock brittle fracture and the initial formation of cracks when effective tensile stress exceeds the tensile strength of the rock. Tensile strength of the rock can be obtained from laboratory tests, also that there is an original wall rock fissures, so the zero tensile strength values.

When P is increased, σ_θ becomes smaller; when P is increased to a certain extent, σ_θ becomes negative, which means rock circumferential stress suffered by the compression becomes stretched. When this tensile force is large enough to overcome the tensile strength of rock, formations generate rupture which causes well leakage.

3) Borehole Collapse Pressure Model

From the mechanical point of view, the cause of the collapse of the wall is mainly due to the lower wells column pressure, making the rock wall surrounding the stress exceeds the strength of the rock itself, and damage caused by shearing. In this case, the formation of brittle generates collapse and hole enlargement. And the formation of the plastic generates plastic deformation and sinking.

2.2.8 Torque:

Torque or moment is rotational force and generally defined as a result of force multiplied by an arm. It is the moment required to rotate the pipe and the rotational force should overcome the frictional in the well and on the bit with the formation during drilling. Torque is mathematically expressed as:

$$\text{Torque= Force x Distance} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (2.13)$$

High torque and high drag forces are normally associated with each other. In drilling application, an ideal vertical well the torque loss would be zero, except for a small loss due to viscous force resulted by mud. However, if is in a deviated well the torque loss may be significant, especially in long complex or extended reach well. In drilling operation, torque loss is a major limiting factor to how long drilling can be continued. Torque is dependent to the radius of which rotation occurs and the friction coefficient and the normal force over pipe. The increment torque calculation is (Bernt Aadnoy,2006):

$$\Delta T = \mu N i r \, \Delta S \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (2.14)$$

In conditions when both buckled and non-buckled string the torque loss per unit length is represented as

$$T_{i+1} = T_i + \sum_{i-1}^{n} \mu r_i N_i (S_{i+1} - S_i) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2.15)$$

2.2.9 Friction Factor:

Friction Factor also known as friction coefficient plays an important role in drilling operations and in the solid mechanics calculations due to torque and drag as well as hydraulic calculations, including surge, swab and hook load estimation during cementing. One of the challenges during drilling, running casing and completion is to minimize torque, drag and stress in drillstrings. As we drill deeper or inclined wells, friction increases because of the increased contact area between the drillstring and the wellbore wall. Therefore, the friction force must be considered when the work string is tripped out/in or rotated on/off bottom. The simulation of drilling operation with the friction force is very complex due to some uncertainties that affect the friction term (Robello Samuel,2010).

Friction factor is not really pure friction factor at all but more of a "fudge factor". Because there are several issues to be considered in addition to friction. They include (K & M Technology Group):

• Mud system lubricity.
• Hole cleaning (Cuttings bed).
• Pipe stiffness and key seats.
• Dogleg severity and wellbore tortuosity.
• Stabilizer and centralizer interaction.
• Consideration to the type of operation (e.g. rotating or sliding).

Furthermore, it should be noted that Slack-off, pick-up and torque friction factors might appear to be same in the nature but in reality, they are different. The industry will usually only allow a single friction factor for a given hole section. For instance, in our simulation study it is essential at the beginning of the project to establish a database for cased hole and open hole friction factors for the mud type used. However, in order to model torque and drag accurately, it is important to note that separate friction factors are required for pick-up, slack-off and torque. Table.**2.2** shows the typical coefficient of friction to different types of fluid (K & M Technology Group).

Table (2.2): Range of Friction Factors (K & M Technology Group).

Fluid type	Friction Factors	
	Cased Hole	Open Hole
Oil-based	0.16-0.20	0.17-0.25
Water-based	0.25-0.35	0.25-0.40
Brine	0.30-0.40	0.30-0.4
Polymer-based	0.15-0.22	0.2-0.30
Synthetic-based	0.12-0.18	0.15-0.25
Foam	0.30-0.40	0.35-0.55
Air	0.35-0.55	0.40-0.60

In most torque and drag analysis models, the friction coefficients are calibrated to enable adjusting the mud weight as well as the string weight and consequently, enables to match the calculated pick up, slack off and torque values to the actual value measured on the rig. The friction factor back calculated for pick-up and slack-off is usually different than one used for the torque. The discrepancy between the friction factors may be due to the type of either soft string or stiff string model used. Some discrepancy may also exist between the pick-up and slack-off friction coefficients. This could be due to the different borehole conditions or due to the compression force in tubulars incorrectly modeled with the type of model used during this operation. Friction coefficients are mainly dependent on mud type and lubricity, open hole and cased hole and contact force. However, the friction coefficient is not depend the tortuosity of the well path since is usually masked behind friction factor that are falsely higher than it should be (Menand et al,2006).