Drilling Engineering Workbook

A Distributed Learning Course

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Baker Hughes INTEQ
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Drilling Engineering - A Distributed Learning Course

FORWARD

The *Drilling Engineering Workbook* is a correspondence (distributed learning) course which covers the important elements of drilling a well. The emphasis is on the theory behind these drilling elements in order to develop a greater understanding of the principles involved in drilling a well.

This is a lesson-by-lesson distributed learning course. Individuals should study each section and then answer the related questions at the end of the section. Supplementary reading is suggested throughout the text. This workbook, along with the related supplementary reading, should provide a sound basis for anyone involved in those services involved in drilling a well.

Comments or questions, regarding any of the course material, should be directed to the technical training department, either in Houston or Aberdeen.

PREFACE

At Baker Hughes INTEQ, we pride ourselves on our people and their level of professionalism, experience, responsiveness and adaptability at the wellsite, where time, money and effective operations depends on rapid, reliable information management. The INTEQ Field Advancement and Career Training System (IN-FACTS), is a system for training, developing and providing professional advancement for field operations personnel. It is the method behind these applications.

The IN-FACTS program provides a standardized career development path which utilizes a progression of both formal and hands-on learning, to turn potential into fully developed expertise. IN-FACTS is the tool that enables Baker Hughes INTEQ personnel to embark on, and develop successful careers within INTEQ, Baker Hughes, and the oil industry.

IN-FACTS is structured to provide an easily understood, orderly flow of learning experiences. These may or may not be in the same specialty, and allow our personnel to concentrate in one area, or to branch out into other disciplines. Movement through the IN-FACTS career progression is determined by industry experience, skills, and knowledge acquired through rigsite work and a variety of formal and informal training programs.

The training programs are modular, and are composed of formal course work, self-paced distributed learning packages, and on-the-job training.

Requirements for further advancement in our wellsite services includes increased knowledge and understanding of the various subjects involved in “wellbore construction and maintenance”. This distributive learning package will focus on these topics.

INSTRUCTIONS ON COMPLETING THIS WORKBOOK

The aim of this distributive learning workbook is to provide you with the information on various drilling engineering topics that can best be studied outside a classroom. It is not the intention of the Training Department that you complete all the assignments as soon as possible. This workbook project should allow you to spend enough time on each particular subject in order to thoroughly understand those aspects of drilling engineering as they apply to every day wellsite operations. This workbook includes:

- Drilling Fluids and Hydraulics
- Casing and Cementing
- Bit Technology
- Drillstring Basics
- Directional Drilling
- Horizontal Wells
- Stuck Pipe
- Well Control
- Cost Analysis
- Technical Writing

At the end of each chapter there will be “Self-Check” exercises, which are designed to assist you in understanding the information covered in the chapter. It is recommended that you do not proceed until you are confident that you fully understand the concepts, calculations, and applications of the chapter's subject matter. Direct any questions you may have to the Technical Training Department or a local technical expert.

When you have completed the workbook, there will be a “Return” assignment (Appendix A). This is to be completed and returned to the regional/area Training Department or local administrator. Using this assignment, the training administrators will be able to assist you in the next step.

Upon satisfactory completion of the “Return” assignment, an “End-of-Project” test will be necessary to comply with IN-FACTS requirements. Passing requirement for this test is 70%. This test can be provided and administrated by the training department or the local administrator.

Summary

This workbook is designed to review those engineering principles that are unique to drilling a well and to increase your knowledge and understanding of how those principles apply to wellsite operations.

There is a lot to learn, and remember, the learning process will never end. There are no real shortcuts. You will be required to learn for yourself, with guidance and assistance from experienced field personnel, local experts and the Technical Training Department.

The aim of the training you receive at Baker Hughes INTEQ is to develop your individual skills and knowledge to make you a fully competent, reliable professional within the oil industry. IN-FACTS is designed to assist you in this.

Comments

The Technical Training staff at Baker Hughes INTEQ is interested in your comments and suggestions concerning this distributed learning workbook. We want to constantly improve our products and with your help, the improvements will be even better. Please take the time to contact us with your comments.

If possible, use the electronic mail system, E-Mail, to contact us. This way we can route the E-Mail to the appropriate department and get back to you more quickly. However, we will accept any type of communications.

We have enclosed a Comment form. If E-Mail is not available to you, please make copies of this form, add your comments and mail or fax it to us.

When you send us your comments, please ensure the page and paragraph references and the following information is included in your transmittal.

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Drilling Engineering Workbook

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Drilling Engineering Workbook

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Chapter 1

Drilling Fluids And Hydraulics

Upon completion of this chapter, you should be able to:

- Recognize the components in the various types of drilling fluids.
- Explain the advantages and disadvantages of the most common types of drilling fluids.
- Provide an explanation of mud properties as they are reported on a “morning report”.
- Calculate barite and water volumes when changes are made to a pre-existing mud system.
- Calculate PV and YP from Fann viscometer readings.
- Perform hydraulic optimization using the Power Law Model.

Additional Review/Reading Material

EXLOG, *MS-3026 Theory And Applications Of Drilling Fluid Hydraulics*

Baker Hughes INTEQ, *Drilling Fluids Manual*, 1991

API, *The Rheology of Oil-Well Drilling Fluids*, Bulletin 13D,2nd Edition, May 1985

API, *Recommended Practice for Drilling Mud Report Form*, Report 13G, 2nd Edition, May 1982

Chilingarian, G.V. and Vorabutr, P., *Drilling and Drilling Fluids*, Elsevier Science Publishers, 1983

Bourgoyne Jr., Adam, et al; *Applied Drilling Engineering*, SPE Textbook Series, Vol. 2, 1986

Moore, Preston; *Drilling Practices Manual*, 2nd Edition, PennWell Publishing Co.; Tulsa; 1986

Rogers, Walter F., *Composition and Properties of Oil Well Drilling Fluids*, Gulf Publishing Company, 1963

Drilling Fluids

A drilling fluid is any fluid which is circulated through a well in order to remove cuttings from a wellbore. This section will discuss fluids which have water or oil as their continuous phase. Air, mist and foam, which can be used as drilling fluids, will not be discussed at this time.

A drilling fluid must fulfill many functions in order for a well to be drilled successfully, safely, and economically. The most important functions are:

1. Remove drilled cuttings from under the bit
2. Carry those cuttings out of the hole
3. Suspend cuttings in the fluid when circulation is stopped
4. Release cuttings when processed by surface equipment
5. Allow cuttings to settle out at the surface
6. Provide enough hydrostatic pressure to balance formation pore pressures
7. Prevent the bore hole from collapsing or caving in
8. Protect producing formations from damage which could impair production
9. Clean, cool, and lubricate the drill bit

Occasionally, these functions require the drilling fluid to act in conflicting ways. It can be seen that items #1-3 are best served if the drilling fluid has a high viscosity, whereas items #4-5 are best accomplished with a low viscosity. Items #6 & 8 are often mutually exclusive because drilled solids will tend to pack into the pore spaces of a producing formation.

Make-up of a Drilling Fluid

In its most basic form a drilling fluid is composed of a liquid (either water or oil) and some sort of viscosifying agent. If nothing else is added, whenever the hydrostatic pressure is greater than the formation pore pressure (and the formation is porous and permeable) a portion of the fluid will be flushed into the formation. Since excessive filtrate can cause borehole problems, some sort of filtration control additive is generally added. In order to provide enough hydrostatic pressure to balance abnormal pore pressures, the density of the drilling fluid is increased by adding a weight material (generally barite).

In summary, a drilling fluid consists of:

The Base Liquid

- Water - fresh or saline
- Oil - diesel or crude
- Mineral Oil or other synthetic fluids

Dispersed Solids

- Colloidal particles, which are suspended particles of various sizes

Dissolved Solids

- Usually salts, and their effects on colloids most is important

All drilling fluids have essentially the same properties, only the magnitude varies. These properties include density, viscosity, gel strength, filter cake, water loss, and electrical resistance.

Normal Drilling Fluids

Though this type of drilling fluid is easy to describe, it is hard to define and even more difficult to find. In the field, a normal fluid generally means there is little effort expended to control the range of properties. As such, it is simple to make and control. General rules include:

1. It is used where no unexpected conditions occur
2. The mud will stabilize, so its properties are in the range required to control hole conditions
3. The chief problem is viscosity control

Formations usually drilled with this type of mud are shales and sands. Since viscosity is the major problem, the amount and condition of the colloidal clay is important. To do this, two general types of treatment are used:

1. Water soluble polyphosphates

   (a) they reduce viscosity

   (b) can be used alone or with tannins

   (c) if filter cake and filtration control is required
   - add colloidal clay to system

2. Caustic Soda and Tannins

   (a) they also reduce viscosity

   (b) used under more severe conditions than phosphate treatment

The upper portions of most wells can use “normal” muds

1. Care must be taken not to add chemicals which may hinder the making of special muds later on
2. Native clays used to make the mud are usually adequate

Special Drilling Fluids

These drilling fluids are made to combat particular abnormal hole conditions or to accomplish specific objectives. These are:

1. Special Objectives

   (a) faster penetration rates

   (b) greater protection to producing zones

2. Abnormal Hole Conditions

   (a) long salt sections

   (b) high formation pressures

Lime Base Muds

1. Water base mud
2. Treated with large amounts of caustic soda, quebracho, and lime. Added in that order
3. Ratio of 2 lb caustic soda, 1.5 lb quebracho and 5 lb lime per 1 barrel of mud
4. Will go through a highly viscous stage, but will become stable at a low viscosity
5. Good points

   (a) can tolerate large amounts of contaminating salts

   (b) remains fluid when solids content gets high

6. Weakness - it has a tendency to solidify when subjected to high bottom-hole temperatures

Lime-Treated Muds

1. Similar to lime based mud - differ only in degree
2. A compromise attempt at overcoming the high temperature gelation problem

    (a) use less lime than lime-base mud

    (b) not nearly so resistant to salt contamination

Emulsion Muds - Oil in Water

1. Oil can be added to any of the normal or special muds with good results
2. No special properties necessary
3. Natural or special emulsifying agents hold oil in tight suspension after mixing
4. Oils used are:

    (a) Crude oils

    (b) Diesel

    (c) any oil with an API gravity between 25 and 50

5. Oil content in mud may be 1% to 40%
6. Advantages are:

    (a) very stable properties

    (b) easily maintained

    (c) low filtration and thin filter cake

    (d) faster penetration rates

    (e) reduces down-hole friction

7. Major objection is that the oil in the mud may mask any oil from the formations

Inhibited Muds

1. Muds with inhibited filtrates
2. Large amounts of dissolved salts added to the mud
3. High pH usually necessary for best results
4. Designed to reduce the amount of formation swelling caused by filtrate - inhibit clay hydration

5. Disadvantages

   (a) need specialized electric logs

   (b) requires much special attention

   (c) low mud weights cannot be maintained without oil

   (d) hard to increase viscosity

   (e) salt destroys natural filter cake building properties of clays

Gypsum Base Muds

1. A specialized inhibited mud

   (a) contained large amounts of calcium sulfate

   (b) add 2 lb/bbl gypsum to mud system

   (c) filtration controlled by organic colloids

2. Advantages

   (a) mud is stable

   (b) economical to maintain

   (c) filtrate does not hydrate clays

   (d) high gel strength

3. Disadvantages

   (a) fine abrasives remain in mud

   (b) retains gas in mud

Oil Based Muds

1. Oil instead of water used as the dispersant
2. Additives must be oil soluble
3. Generally pre-mixed and taken to the wellsite
4. To increase aniline value, blown asphalt and unslaked lime may be added
5. Advantages

   (a) will not hydrate clays

   (b) good lubricating properties

   (c) normally higher drill rates

6. Disadvantages

   (a) expensive

   (b) dirty to work with

   (c) requires special electric logs

   (d) viscosity varies with temperature

Inverted Emulsions

1. Water in oil emulsion. Oil largest component, then water added. Order of addition is important
2. Have some of the advantages of oil muds, but cheaper. Somewhat less stable

Salt Water Muds

1. Can be used either completely or partly saturated
2. Weight can vary up to 10 lb/gal when saturated
3. No filter cake building properties, easily lost to porous formations

Silicate Muds

1. Composed of sodium silicate and saturated salt water
2. Has a pickling effect on shales which prevents heaving or sloughing
3. Will be 12 lb/gal or higher
4. Corrosive, expensive and gives poor electric log results

Low Solids Muds

1. Keeps amounts of clays in the mud at a minimum, which promotes faster and safer drilling
2. Three ways to remove solids from mud

   (a) water dilution

   (b) centrifuging

   (c) circulate through large surface area pits

3. When clays are removed, a minimum of viscosity control chemicals are needed

4. When viscosity and gel strength become too low, clay solids are replaced by organic or suspended material - polymers
5. Other advantages

   (a) good for drilling with large pumps and high mud volumes

   (b) always give faster drilling
6. Problems

   (a) excessive dilution a problem

   (b) can become expensive

Drilling Fluid Classification Systems

Non-Dispersed System

This mud system consists of spud muds, “natural” muds, and other lightly treated systems. Generally used in the shallower portions of a well.

Dispersed Mud Systems

These mud systems are “dispersed” with deflocculants and filtrate reducers. Normally used on deeper wells or where problems with viscosity occur. The main dispersed mud is a “lignosulfonate” system, though other products are used. Lignite and other chemicals are added to maintain specific mud properties.

Calcium-Treated Mud Systems

This mud system uses calcium and magnesium to inhibit the hydration of formation clays/shales. Hydrated lime, gypsum and calcium chloride are the main components of this type of system.

Polymer Mud Systems

Polymers are long-chained, high molecular-weight compounds, which are used to increase the viscosity, flocculate clays, reduce filtrate and stabilize the borehole. Bio-polymers and cross-linked polymers, which have good shear-thinning properties, are also used.

Low Solids Mud System

This type of mud system controls the solids content and type. Total solids should not be higher than 6% to 10%. Clay content should not be greater than 3%. Drilled solids to bentonite ratio should be less than 2:1.

Saturated Salt Mud Systems

A saturated salt system will have a chloride content of 189,000 ppm. In saltwater systems, the chloride content can range from 6,000 to 189,000 ppm. Those at the lower end are normally called “seawater” systems.

These muds can be prepared with fresh or salt water, then sodium chloride or other salts (potassium, etc.) are added. Attapulgite clay, CMC or starch is added to maintain viscosity.

Oil-Based Mud Systems

There are two types of systems: 1) invert emulsion, where water is the dispersed phase and oil the continuous phase (water-in-oil mud), and 2) emulsion muds, where oil is the dispersed phase and water is the continuous phase (oil-in-water mud). Emulsifiers are added to control the rheological properties (water increases viscosity, oil decreases viscosity).

Air, Mist, Foam-Based Mud Systems

These “lower than hydrostatic pressure” systems are of four types: 1) dry air or gas is injected into the borehole to remove cuttings and can be used until appreciable amounts of water are encountered, 2) mist drilling is then used, which involves injecting a foaming agent into the air stream, 3) foam drilling is used when large amounts of water is encountered, which uses chemical detergents and polymers to form the foam, and 4) aerated fluids is a mud system injected with air to reduce the hydrostatic pressure.

Workover Mud Systems

Also called completion fluids, these are specialized systems designed to 1) minimize formation damage, 2) be compatible with acidizing and fracturing fluids, and 3) reduce clay/shale hydration. They are usually highly treated brines and blended salt fluids.

Drilling Fluid Additives

Many substances, both reactive and inert, are added to drilling fluids to perform specialized functions. The most common functions are:

Alkalinity and pH Control

Designed to control the degree of acidity or alkalinity of the drilling fluid. Most common are lime, caustic soda and bicarbonate of soda.

Bactericides

Used to reduce the bacteria count. Paraformaldehyde, caustic soda, lime and starch preservatives are the most common.

Calcium Reducers

These are used to prevent, reduce and overcome the contamination effects of calcium sulfates (anhydrite and gypsum). The most common are caustic soda, soda ash, bicarbonate of soda and certain polyphosphates.

Corrosion Inhibitors

Used to control the effects of oxygen and hydrogen sulfide corrosion. Hydrated lime and amine salts are often added to check this type of corrosion. Oil-based muds have excellent corrosion inhibition properties.

Defoamers

These are used to reduce the foaming action in salt and saturated saltwater mud systems, by reducing the surface tension.

Emulsifiers

Added to a mud system to create a homogeneous mixture of two liquids (oil and water). The most common are modified lignosulfonates, fatty acids and amine derivatives.

Filtrate Reducers

These are used to reduce the amount of water lost to the formations. The most common are bentonite clays, CMC (sodium carboxymethylcellulose) and pre-gelatinized starch.

Flocculants

These are used to cause the colloidal particles in suspension to form into bunches, causing solids to settle out. The most common are salt, hydrated lime, gypsum and sodium tetraphosphates.

Foaming Agents

Most commonly used in air drilling operations. They act as surfactants, to foam in the presence of water.

Lost Circulation Materials

These inert solids are used to plug large openings in the formations, to prevent the loss of whole drilling fluid. Nut plug (nut shells), and mica flakes are commonly used.

Lubricants

These are used to reduce torque at the bit by reducing the coefficient of friction. Certain oils and soaps are commonly used.

Pipe-Freeing Agents

Used as spotting fluids in areas of stuck pipe to reduce friction, increase lubricity and inhibit formation hydration. Commonly used are oils, detergents, surfactants and soaps.

Shale-Control Inhibitors

These are used to control the hydration, caving and disintegration of clay/shale formations. Commonly used are gypsum, sodium silicate and calcium lignosulfonates.

Surfactants

These are used to reduce the interfacial tension between contacting surfaces (oil/water, water/solids, water/air, etc.).

Weighting Agents

Used to provide a weighted fluid higher than the fluids specific gravity. Materials are barite, hematite, calcium carbonate and galena.

Material Balance Equations

Material balance equations are used for calculating volumes and densities when two or more insoluble materials are mixed together.

The Material Balance Equation is:

$$V_1W_1 + V_2W_2 \ldots\ldots = V_FW_F \quad \text{where:} \quad V_1 + V_2 \ldots\ldots = V_F$$

where:
- V_1 = Volume of first material to be mixed together
- W_1 = Density of first material
- V_2 = Volume of second material to be mixed together
- W_2 = Density of second material
- V_F = Total or sum of all volumes mixed together
- W_F = Density of total mixture. Proportional average of all volumes mixed together

The most commonly used variables in material balance equations are:

Barite

1. Weight of a barrel of barite ($BaSO_4$) s.g. = 4.2 g/cc

   42 gal/bbl x 8.33 lb/gal x 4.2 = 1470 lb/bbl

   * since barite comes in 100 lb sacks, one barrel contains 14.70 sacks

2. Weight of a gallon of barite

   8.33 lb/gal x 4.2 = 34.9 lb/gal

Hematite

1. Weight of a barrel of hematite (Fe_2O_3) s.g. = 5.0 g/cc

   42 gal/bbl x 8.33 lb/gal x 5.0 = 1749 lb/bbl

2. Weight of a gallon of hematite

   8.33 lb/gal x 5.0 = 41.65 lb/gal

Light Oil

1. Example - (41° API Gravity) s.g. = 0.82 g/cc

2. Weight of a gallon of oil

   8.33 lb/gal x 0.82 = 6.8 lb/gal

Example Problem #1-1:

Calculate how many sacks of barite are required to increase the density of an 800 barrel mud system from 12.7 lb/gal to 14.5 lb/gal.

Using: $V_1W_1 + V_2W_2 = V_FW_F$

where: V_1 = 800 bbls
W_1 = 12.7 lb/gal
V_2 = unknown volume of barite
W_2 = 34.9 lb/gal (density of barite)
V_F = $V_1 + V_2$ (or $800 + V_2$)
W_F = 14.5 lb/gal

therefore: $800(12.7) + V_2(34.9) = (800 + V_2) \times 14.5$

$10{,}160 + 34.9V_2 = 11{,}600 + 14.5V_2$

$20.4V_2 = 1440$

$V_2 =$ 70.6 bbls of barite

70.6 bbls x 14.7 sk/bbl = 1038 sacks of barite

Example Problem #1-2:

Calculate how much water and barite are required to make 800 barrels of a 10.5 lb/gal water-based drilling mud.

Using: $V_1W_1 + V_2W_2 = V_FW_F$

where: V_1 = unknown volume of water
W_1 = 8.33 lb/gal
V_2 = unknown volume of barite or $(800 - V_1)$
W_2 = 34.9 lb/gal
V_F = 800 bbls
W_F = 10.5 lb/gal

therefore: $V_1(8.33) + (800 - V_1)34.9 = 800(10.5)$

$8.33V_1 + 27920 - 34.9V_1 = 8400$

$-26.57V_1 = -19520$

$V_1 =$ 735 bbls of water

V_2 = 800 bbls - 735 bbls = 65 bbls of barite @ 14.7 sk/bbl or 956 sacks

Oil-Based Drilling Fluids

These fluids, because of their special nature of being a mixture of two immiscible liquids (oil and water), require special treatments and testing procedures.

Dispersed Phase: The liquid present in the form of finely divided droplets.

Continuous Phase: The liquid present in the form of the matrix in which the droplets are suspended.

To keep these liquids stabilized (i.e. to keep the dispersed phase from coalescing and settling out of the mixture), an emulsifier is added to form an interfacial film around the dispersed phase which causes them to repel each other, so they remain dispersed.

The effectiveness of an emulsifier depends on the alkalinity and electrolytes (chloride content) of the water phase, and the temperature of the drilling fluid.

Electrical Stability

The electrical stability (E.S.) of an oil-based drilling fluid is the stability of the emulsions of water in oil, or the amount of current required to break the emulsifier down and allow the saline water to coalesce.

1. An electrical probe is inserted into the drilling fluid and the voltage increased until the emulsion breaks down
   a. the measure of emulsion breakdown is indicated by current flow
   b. relative stability is recorded as the amount of voltage at the breakdown point
2. E.S. is recorded as the voltage reading and temperature of the drilling fluid sample
   a. adding emulsifier will raise the E.S. readings
   b. normal “fresh” mud is about 300 or higher
   c. during drilling, the E.S. can increase to 800 or higher

Oil: Water Ratio

The Oil: Water Ratio is defined as the percent oil in the liquid phase and the percent water in the liquid phase. The percentages can be determined from a retort analysis of the drilling fluid.

Example Problem: #1-3

Determine the oil: water ratio from the following retort analysis:

oil = 54%   water = 36%   solids = 10%

$$oil\% = \frac{54}{54+36} \times 100 \qquad water = \frac{36}{54+36} \times 100$$

The oil: water ratio is 60:40

To change the oil: water ratio requires the additions of oil to increase the ratio, and water to decrease the ratio. For example, the oil required to increase the oil: water ratio can be calculated using:

$$\left(\frac{\%V_{iw}}{\%V_{fw}} - \frac{\%V_t}{100} \right) \times V_m$$

where:
$\%V_{iw}$ = initial % of water by volume (%)
$\%V_{fw}$ = final % of water in liquid phase (%)
$\%V_t$ = initial total liquid volume (%)
V_m = total mud volume (bbls)

The water required to reduce the oil: water ratio can be calculated using:

$$\left(\frac{\%V_{io}}{\%V_{fo}} - \frac{\%V_t}{100} \right) \times V_m$$

where:
$\%V_{io}$ = initial % of oil by volume (%)
$\%V_{fo}$ = final % of oil in liquid phase

Aniline Point

Another common term used when dealing with oil-based drilling fluids is the aniline point of that fluid. The aniline point is the temperature below which an oil containing 50% by volume aniline (C_6H_5-NH_2) becomes cloudy. The solvent powers for rubber are related to the solvent power for aniline. Oils having an aniline point above 140^{o}F are considered acceptable to use.

Drilling Fluid Economics

Table 1: Typical Composition/Costs - Unweighted Drilling Fluid
(Barrels or pounds necessary to mix one barrel)

Component	Volume	Cost($) Unit	Cost($) Component
Low Colloid Oil-Based Drilling Fluid			
Diesel Oil	0.8 bbl	l42.00	33.60
Emulsifier/Wetting Agent	6.0 lbs	1.50	9.00
Water	0.14 bbl	-	-
Gel	5.0 lbs	1.20	6.00
Calcium Chloride	20.0 lbs	0.20	4.00
Lime	3.0 lbs	0.10	0.30

Total Cost (1 bbl)			52.90
Fresh-Water Dispersed Drilling Fluid			
Bentonite	25.0 lbs	0.07	1.75
Chrome Lignosulfonate	6.0 lbs	0.50	3.00
Lignite	4.0 lbs	0.30	1.20
Caustic Soda	3.0 lbs	0.40	1.20
Water	1.0 bbl	-	-

Total Cost (1 bbl)			7.15
KCl Polymer Drilling Fluid			
Bentonite (pre-mixed w/ H_2O)	5.0 lbs	0.07	0.35
Chrome Lignosulfonate	1.0 lbs	0.50	0.50
Caustic Soda	0.3 lbs	0.40	0.12
Potassium Chloride	35.0 lbs	0.20	7.00
Polyanionic Cellulose	2.0 lbs	3.00	6.00
Potassium Hydroxide	0.3 lbs	0.80	0.24

Total Cost (1 bbl)			14.21

Table 2: Typical Composition/Costs - 17.5 ppg Drilling Fluid (Barrels or pounds necessary to mix one barrel)

Component	Volume	Cost($) Unit	Cost($) Component
Low Colloid Oil-Based Drilling Fluid			
Diesel Oil	0.55 bbl	42.00	23.10
Emulsifier/Wetting Agent	8.0 lbs	1.50	12.00
Water	0.09 bbl	-	-
Gel	4.0 lbs	1.20	4.80
Calcium Chloride	15.0 lbs	0.20	3.00
Lime	3.0 lbs	0.10	0.30
Barite	500.0 lbs	0.07	35.00

Total Cost (1 bbl)			78.20
Fresh-Water Dispersed Drilling Fluid			
Bentonite	20.0 lbs	0.07	1.40
Chrome Lignosulfonate	9.0 lbs	0.50	4.50
Lignite	6.0 lbs	0.30	1.80
Caustic Soda	4.0 lbs	0.40	1.60
Barite	450.0 lbs	0.07	31.50
Water	1.0 bbl	-	-

Total Cost (1 bbl)			40.80
KCl Polymer Drilling Fluid			
Bentonite (pre-mixed w/ H_2O)	5.0 lbs	0.07	0.35
Chrome Lignosulfonate	1.0 lbs	0.50	0.50
Caustic Soda	0.3 lbs	0.40	0.12
Potassium Chloride	24.0 lbs	0.20	4.80
Polyinosinic Cellulose	3.0 lbs	3.00	9.00
Modified Starch	5.0 lbs	1.00	5.00
Potassium Hydroxide	0.3 lbs	0.80	0.24
Barite	400.0 lbs	0.07	28.00

Total Cost (1 bbl)			43.01

Table 3: Drilling Fluid Selection Guide

Drilling Conditions													
High Angle Hole (>30)			x	x	x	x			x	x	x		x
Very Reactive Shales		x	x	x	x	x	x	x	x	x	x		x
Sticking Problems	x			x		x	x	x	x	x	x		
Lost Circulation	x	x	x		x		x				x		
Mud Weights (>16ppg)	x	x			x	x		x	x			x	x
Temperatures (>325F)						x		x	x			x	x
Gas Hydrates				x		x					x		
Recommended Mud Type													
Oil-Based						1		1	1	1	2	1	1
Lignosulfonate	1	2					1	2				2	
Polymer			2	1			2	3		2	1		3
Potassium Lime		1	1		1		3			3			2

To use this chart: If the well was a high angle well with possible reactive shales and the possibility of differential sticking, drilling fluid choices (in order of preference) are: (1) oil-base, (2) polymer and (3) potassium lime

Drilling Fluid Properties

For those working at wellsites, a basic knowledge of “fluid” properties is required, especially those properties that distinguish fluids from solids. Fluids can be either a gas or a liquid, where gases are highly compressible and its volume being dependent upon pressure and temperature. Liquids, on the other hand, are only slightly compressible, and their volume being only slightly dependent upon temperature.

We shall be dealing with only liquids in this text. Since drilling muds are commonly referred to as drilling fluids, the term “fluid” will be used throughout the text. The effects of temperature and pressure on a volume of drilling fluid will be ignored.

A cube of water measuring 1 foot along each edge weighs 62.4 lbs. The density or “specific weight” is then 62.4 lb/ft^3. Specific weight divided by the gravitational constant is known as “mass density” or just density. This same cube of water exerts a hydrostatic pressure of 62.4 lbs distributed evenly over its bottom surface of 1 ft^2 or 0.433 psi (62.4lbs ÷ 144 in^2).

Hydrostatic pressure of a column of fluid is thus determined by:

$$H_p = (Dv - Fl) \times MD \times g$$

where:
H_p = hydrostatic pressure.
Dv = vertical depth.
Fl = flowline depth.
MD = fluid density.
g = gravitational constant.

Note that this is dependent upon vertical depth and fluid density.

In oilfield units the fluid density will be the “mud density”, with a conversion factor 0.0519. The conversion factor is derived from:

There are 7.48 gallons in 1 cu/ft and 144 sq inches in 1 sq/ft

because: lb/gal x 7.48 gal/ft^3 x 1/144 ft^2/in^2 = psi/ft

and: 7.48/144 = psi/ft/lb/gal

therefore: 0.0519 = psi/ft/lb/gal

A drilling fluid of 8.34 lb/gal exerts a pressure of;

8.34 x 0.0519 = 0.4328 psi/ft

In SI units the conversion factor is 0.0098, therefore:

Hp (kPa) = MD (kg/m^3) x Dv(m) x 0.0098

Pressure

Pressure is defined as the force acting on a unit area. In the oil field, pressure is commonly measured in pounds per square inch (psi).

At the wellsite, we are typically concerned with the pressures throughout the circulating system. We may need to know the pressure at a particular point in the wellbore (such as the casing shoe or a lost circulation zone) or we may want to know the total pressure required to pump a certain mud volume at a given rate. Various types of pressures exist due to different mechanisms, and are classified as either **hydrostatic**, **hydraulic**, or **imposed**. All of these pressures result in a force acting on a unit area, even though their origins may differ.

Note: *The pressure at any given point in the circulating system is the sum of the hydrostatic, hydraulic, and imposed pressures which exist at that point.*

Hydrostatic Pressure

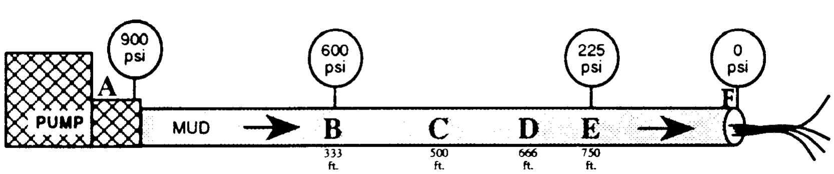
As mentioned earlier, this is the pressure created by a column of fluid due to its density and vertical height. This type of pressure always exists and may be calculated whether the fluid is static or flowing. It can be calculated using:

$$Hp(psi) = MW \times 0.0519 \times TVD(ft)$$

Hydraulic Pressure

This is the pressure created (or needed) to move drilling fluid through pipe. In oil field terms, it is the pressure generated by the mud pump in order to move the drilling fluid from the mud pump around the system and back to the flowline. In this section, the terms **Pump Pressure** and **Hydraulic Pressure** will be used interchangeably. This type of pressure can be calculated at any point in the circulating system.

Pressure drop or pressure loss is the amount of pressure needed to move the fluid over a given distance, for example,



the hydraulic pressure (pump pressure) remaining at point B in the figure is 600 psi. However, the system pressure loss at point B is 300 psi. That is, 300 psi is needed to pump the mud from point A to point B.

The hydraulic pressure (pump pressure) remaining at point E in the figure is 225 psi. However, the system pressure loss at point E is 675 psi. That is, 675 psi is required to move the mud from point A to point E. (300 psi from A to B and 375 psi from B to E.)

Exercise 1-4: How much hydraulic pressure is being exerted at points C and D?

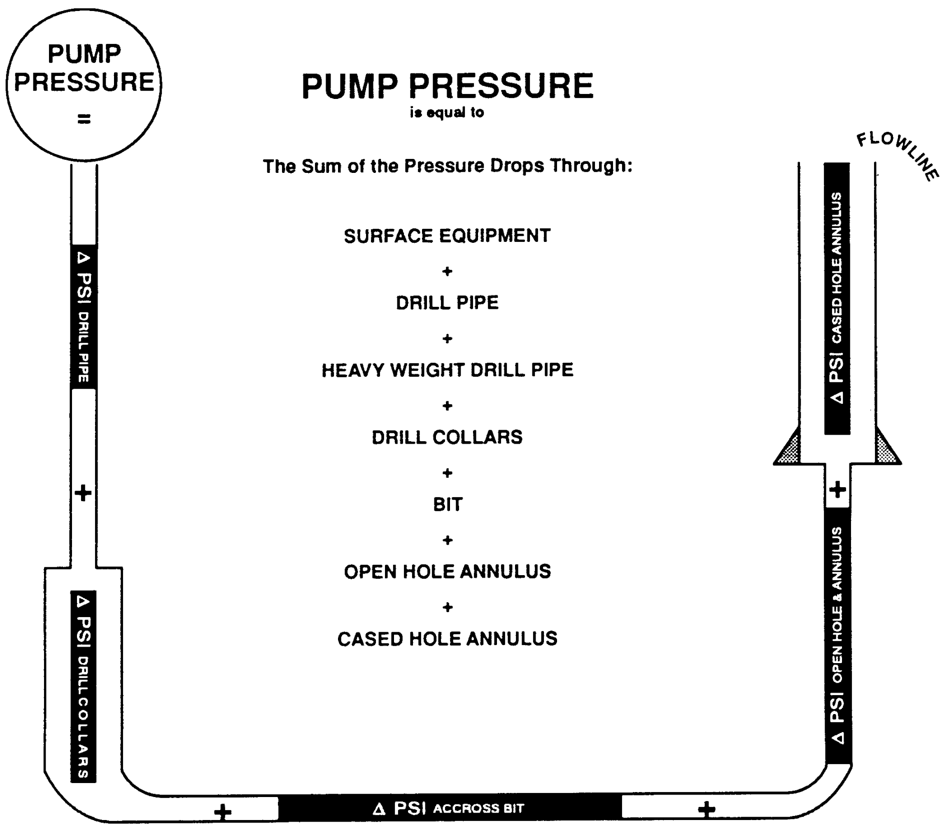
Point C _______ psi Point D _______ psi

Exercise 1-5: What is the pressure drop (loss) between the following points?

A to C _______ psi B to C _______ psi

B to D _______ psi D to F _______ psi

The total system pressure loss in the drawing (A to F) is 900 psi.



Note: *The pressure at any given point in the circulating system is the sum of the hydrostatic, hydraulic, and imposed pressures which exist at that point.*

Typically, hydraulic pressures will be calculated in order to:

- Determine the total pressure being exerted at the casing shoe (generally the weakest point in the circulating system); the bottom of the hole; or any other point (such as a lost circulation zone). After this pressure is determined, it is often converted into a mud density equivalent and reported as the E.C.D. (Equivalent Circulating Density) for that depth.
- Determine the anticipated pump pressure, using:
  - mud properties
  - drill string configuration
  - bit size
  - total flow area for the bit
  - flow rate
- Determine the nozzle size for a bit, using:
  - maximum pump pressure allowed
  - mud properties
  - drill string configuration
  - bit size
  - flow rate

Imposed Pressure

These are external pressures which are "imposed" into the well. Since the well is open to the atmosphere, the well must be "shut-in" for there to be an imposed pressure. This type of pressure will always be felt uniformly throughout the shut-in well. Imposed pressures originate from:

1. the pumps (i.e. when testing a casing shoe)
2. the formation (i.e. when the well kicks)

Pressure Imposed By The Pump

Assume that the well in Exercise #1-4 on page 1-21 is shut in (annular preventer & choke are closed) and a small amount of mud is pumped into the well using the cementing unit. The pressure will begin to increase immediately. This pressure is an **imposed pressure**, and is felt uniformly throughout the well bore.

As an example: Pumping is stopped and 900 psi is held on the pump. This pressure (900 psi) is felt inside the BOP stack, inside the drill string, at the bottom of the hole, at the casing shoe, and everywhere else in the circulating system.

Such procedures are usually done after each casing string. It is referred to as testing the casing shoe and is done in order to determine the amount of pressure the formation at the shoe can withstand. Under normal conditions, the formation fracture pressure will increase with depth. This means that formations normally get stronger, and therefore harder to fracture, as depth increases.

Note: *Under normal conditions, the weakest point in the annulus will be at the casing shoe.*

It is possible to conduct three different types of casing shoe tests:

- Leak-Off Test: Pumping into the shut-in well continues until mud is lost to the formation. It is noted by a non-linear relationship between volume pumped and pressure increase.
- Pressure Integrity Test: Pumping proceeds until a predetermined imposed (pump) pressure is obtained — without any loss of mud into the formation.
- Fracture Test: Pumping proceeds until the formation is fractured. Although this type of test is occasionally done, it is not a normal way of conducting a shoe test.

Exercise 1-6: After setting 13-3/8 inch casing, at 8,500 feet, the casing shoe was drilled out and a casing shoe test was run. Leak-off pressure was determined to be 1,100 psi. The test was conducted with a mud density of 12.8 ppg in the hole. Calculate the following:

Pressure @ Shoe = _______ psi
Gradient @ Shoe = _______ psi/ft
EQMD @ Shoe = _______ ppg

Exercise 1-7: After running the leak-off test in the previous exercise, drilling proceeded to 11,000 ft during which time the mud density was increased to 14.4 ppg. Another leak-off test was conducted. The leak-off pressure was 393 psi. Calculate the following:

Pressure @ Shoe = _______ psi Pressure @ 9,000 ft. = _______ psi

Gradient @ Shoe = _______ psi/ft Gradient @ 9,000 ft. = _______ psi/ft

EQMD @ Shoe = _______ ppg EQMD @ 9,000 ft = _______ ppg

Pressure @ 10,000 ft = _______ psi Pressure @ 11,000 ft. = _______ psi

Gradient @ 10,000 ft. = _______ psi/ftGradient @ 11,000 ft = _______ psi/ft

EQMD @ 10,000 ft = = _______ ppg EQMD @ 11,000 ft = _______ ppg

Exercise 1-8: If while drilling at 10,500 ft with a mud density of 14.4 ppg, a leak-off test had been conducted, what would the leak-off pressure (pump pressure) have been? Assume the formation at the casing shoe began taking fluid when it experienced the experienced the exact same pressure as in the previous exercise.

Leak-Off pressure = _______ psi

If the formation at the shoe is the weakest point in the borehole at what depth did the formation take mud during this leak-off test? _______ ft. (Hint: compare the values of EQMD at each depth calculated.)

Pressure Imposed By The Formation

Imposed pressures can also originate from a formation. If formation pressure exceeds hydrostatic pressure, and the well is shut-in, the pressure differential between the hydrostatic of the drilling fluid and the formation pressure, will be imposed throughout the system. This pressure can be read at the surface. At the surface, two different readings will be noted. These will be the drillpipe (pump) pressure and the casing (choke) pressure.

- If no influx of formation fluid occurs, then the hydrostatic pressure in the drill string, and in the annulus, will be the same; resulting in equal drillpipe and casing pressures.
- Usually, any formation fluid influx will have a density less than the drilling fluid, and will only go into the annulus. In this case, the total hydrostatic pressure in the annulus will be less than the hydrostatic pressure in the drill string. Since the formation pressure is constant for the bottom of the hole (both under the drill string and the annulus) the resulting pressures on the drill pipe and casing will differ. The surface drillpipe pressure will be less than the annular pressure since its hydrostatic is greater.

Exercise 1-9: While drilling at 11,000 ft., with a mud density of 14.4 ppg, the well kicked. It was immediately shut in. After the system stabilized, the drill pipe pressure was 250 psi. (No influx entered the drill string)

What is the pore pressure of the kicking formation? _______ psi

What mud density would be required to balance the kicking formation? _______ ppg

Exercise 1-10: The formation fluid from the kick has an average density of 6.8 ppg. The influx covers the bottom 200 feet of the annulus.

What is the surface casing pressure? _______ psi

What is the pressure on the casing shoe? _______ psi

Depending on the situation, one or more of these types of pressures may exist in the well at any given time. If a type of pressure exists in the well bore, it exists everywhere in the system. However, it’s magnitude may vary throughout the system.

Pascal's Law

“The pressure at any point in a static fluid is the same in all directions. Any pressure applied to a fluid is transmitted undiminished throughout the fluid.”

The consequences of this law when applied to drilling practices are important. When a well is shut in during a kick, the pressure is exerted throughout the fluid column. Which means formations uphole experience the same pressures as those downhole.

Drilling Fluid Report

One of the most important reports at the wellsite is the daily drilling fluid report, or “mud report”. In addition to containing basic well and rig information, chemical inventory and mud system costs, the mud report will contain a list of the fluid properties of the mud system. To maintain the required properties, certain tests are conducted on the drilling fluid. The most important are listed below.

Density pounds/gallon (lb/gal)

The density of the drilling fluid is important to maintaining well control. As mentioned earlier, fresh water has a density of 8.34 lb/gal, with a corresponding gradient of 0.433 psi/ft. As long as the formations have the same gradient, fresh water will “balance” the formation pressures.

Since this is generally not the case, some weight material must be added to the fluid, the most common being barite and hematite.

The drilling fluids density is measured using a “mud balance”. This balance contains a mud cup on one end of a beam with a fixed counter weight on the other end of the beam. The beam is inscribed with a graduated scale, contains a level bubble and a movable rider.

When the cup is filled with fresh water, steel shot is added to the counter weight container until the beam is level, with the rider pointing at the 8.34 scribe line.

During wellsite operations, the mud’s density is checked by filling the cup with drilling fluid and moving the rider until the level bubble indicates the beam is balanced. The density is then read using the position of the rider.

Plastic Viscosity centipoise (cps)

The plastic viscosity (PV) is calculated by measuring the shear rate and stress of the fluid. These values are derived by using a Fann viscometer, which is a rotating-sleeve viscometer, and may be a simple hand operated two speed model or a more complex variable speed electric model. The two speed model operates at 300 and 600 rpm.

The Fann viscometer consists of an outer rotating sleeve and an inner bob. When the outer sleeve is rotated at a known speed, torque is transmitted through the mud to the bob. The bob is connected to a spring and dial, where the torque is measured. The shear rate is the rotational speed of the sleeve and the shear stress is the stress (torque) applied to the bob, measured as deflection units on the instrument dial. These measurement values are not true units and need to be converted.

Shear rate is the rate of change as the fluid layers move past one another per unit distance, and is measured in reciprocal seconds (i.e. (ft/sec)/ft) and is usually written as $seconds^{-1}$. To convert the dial reading to shear stress, the dial reading is multiplied by 1.067 to give a reading in $lb/100ft^2$.

The units of viscosity are poise or centipoise (1/100 poise) and is derived as follows:

Viscosity (poise) = (F/A) / (V/H)

where: F = Force (dynes)

A = Area (cm^2)

V = Velocity (cm/cc)

H = Distance (cm)

This produces viscosity as Dynes (sec/cm^2) or poise.

The Fann viscometer reading is therefore multiplied by 1.067 to obtain shear stress in $lb/100ft^2$; or multiplied by 478.8, and divided by the shear rate in $second^{-1}$ to get $Dynes/cm^2$.

Viscosity then becomes:

511 x dial reading / shear rate (sec^{-1})

since 511 sec^{-1} = 300 rpm

or (300 x dial reading) / Fann shear rpm

The viscometer is designed to give the viscosity of a Newtonian fluid when used at 300 rpm.

For Non-Newtonian fluids, the ratio of shear-stress to shear-rate is not constant and varies for each shear rate. With a Bingham plastic fluid, a finite force is required to initiate a constant rate of increase of shear-stress with shear-rate. To obtain a value for this constant rate of increase, readings are taken with a viscometer at 511 sec^{-1} and 1022 sec^{-1} (300 and 600 rpm). The 600 dial reading minus the 300 dial reading gives the slope of the shear-stress/shear-rate curve. This is the **Plastic Viscosity**. The “apparent viscosity” is given by the 600 reading divided by 2. This is a measure of that part of resistance to flow caused by mechanical friction between solids in the mud, solids and liquids and the shearing layers of the mud itself.

We can see that control of the solids will give us control over our PV! This leads to “Why are we controlling the solids?” Since the viscosity of the mud is one of the principal factors contributing to the carrying capacity of the mud, the suspension of weighting materials, and pressure surges applied to the formation through frictional pressures in the annulus, it is obvious that increased solids will increase these annular pressures (and may increase the mud density), so a balance must be found in which the correct mud density and carrying capacity are maintained without exerting unnecessary pressures on the annulus.

In the mud system, we have solids that are an integral part of the mud (bentonite, starch, CMC, etc.) and solids that are undesirable (sand, limestone, dolomite, etc.). As the mud density is increased, by the addition of barite or hematite (more solids), the PV will automatically increase. The PV is also a function of the viscosity of the fluid phase of the mud (as temperature rises, the viscosity of water decreases, and the PV will decrease).

Several methods of lowering the solids content of the mud are available, all of which will lower the plastic viscosity and apparent viscosity, as well.

1. **Dilution**; add water and lower the concentration of solids.
2. **Shaker Screens**; using the finest screens possible without “blinding” to remove solids. Avoid hosing water on the screens as this washes fine solids through the screens.
3. **Centrifuge**; these separate the solids by size and mass, reducing total solids concentration.
4. **Desander/Desilter**; these mechanically remove the sand/silt sized particles from the mud.

To increase the viscosity of a mud system, various “mud chemicals” can be added. These are mostly types of bentonite, but attapulgite clays, asbestos and gums (Guar or Xanthan) are also used.

The polymer viscosities such as XC polymer, consist of these gums. Most polymers provide a mud with a shear thinning effect. This is desirable as it allows viscosity to be maintained while circulating pressures are reduced.

Yield Point lbs/100 sqft

This parameter is also obtained from the viscometer. The yield point (YP), as mentioned earlier, is a measure of the electro-chemical attractive forces within the mud under flowing conditions. These forces are the result of positive and negative charges located near or on the particle’s surfaces. With this in mind, the yield point is then a function of the surface properties of the mud solids, the volume concentration of the solids, and the concentration and type of ions within the fluid phase.

The yield point is the shear stress at zero shear rate, and is measured in the field by either;

YP = 300 rpm reading - PV

or YP = (2 x 300 rpm reading) - 600 rpm reading

This gives a Bingham yield point, which is generally higher than the actual or true yield.

As stated earlier, at low shear rates, the Bingham model does not give particularly good readings.

High viscosity, resulting from a high yield point is caused by:

1. Introduction of soluble contaminants such as salt, cement, anhydrite, or gypsum, which neutralize negative charges of the clay particles, resulting in flocculation.
2. The breaking of clay particles by the grinding action of the bit and pipe, which creates “broken bond valences” on the edges of the particles, causing the particles to pull together.
3. Introduction of inert solids causes the particles to be closer together into disorganized form or flocks.
4. Drilling of hydratable clays introduces active solids into the system, increasing the attractive forces by increasing the number of charges and by bringing the particles closer together.
5. Both insufficient or over-treatment of the mud with chemicals will increase the attractive forces of the mud.

Treatment for increased yield point may be controlled by chemical action, but reduction of the yield point will also decrease the apparent viscosity.

Yield point may be lowered by the following:

1. Broken bond valences may be neutralized by adsorption of certain negative ions at the edge of the clay particles. These residual valences are almost totally satisfied by chemicals such as tannins, lignins, lignosulfonates and complex phosphates. The attractive forces are satisfied by chemicals, and the clay's natural negative charge remains, so that the particles repel each other.
2. If calcium or magnesium contamination occurs, the ion is removed as an insoluble precipitate, thus decreasing the attractive forces and hence the yield point.
3. Water can be used if the solid content is very high, but it is generally ineffective and may alter other properties drastically (i.e., mud density).

As mentioned earlier, the chemicals that are added to deflocculate the mud and act as “thinners” are commonly lignosulfonates and tannins. These also have a secondary function of acting as filtration agents.

Gel Strength lbs/100 ft^2 (10 sec/10min)

This is a measurement that denotes the thixotropic properties of the mud and is a measurement of the attractive forces of the mud while at rest or under static conditions. As this and yield point are both measures of flocculation, they will tend to increase and decrease together, however a low yield point does not necessarily mean 0/0 gels!

Gel strength is measured with the viscometer by stirring the mud at high speeds for about 15 seconds and then turning the viscometer off or putting it into neutral (low gear if it's a lab model) and waiting the desired period, (i.e., 10 seconds or 10 minutes). If the viscometer is a simple field model, the “gel strength” knob is turned counter clockwise slowly and steadily. The maximum dial deflection before the gel breaks is then recorded in lb/100 ft^2. With a lab model, the procedure is the same except a low speed is used. After a wait, the second gel can be taken in a similar manner.

Gels are described as progressive/strong or fragile/weak. For a drilling fluid, the fragile gel is more desirable. In this case, the gel is initially quite high but builds up with time only slightly. This type of gel is usually easily broken and would require a lower pump pressure to break circulation.

pH

Drilling muds are always treated to be alkaline (i.e., a pH > 7). The pH will affect viscosity, bentonite is least affected if the pH is in the range of 7 to 9.5. Above this, the viscosity will increase and may give viscosities that are out of proportion for good drilling properties. For minimizing shale problems, a pH of 8.5 to 9.5 appears to give the best hole stability and control over mud properties. A high pH (10+) appears to cause shale problems.

The corrosion of metal is increased if it comes into contact with an acidic fluid. From this point of view, the higher pH would be desirable to protect pipe and casing.

Carbon Dioxide corrosion can cause severe pitting and cracks in fatigue areas. If moisture is present, CO_2 dissolves and forms carbonic acid.

$$CO_2 + H_2O = H_2CO_3$$

This causes a reduction in the pH, which makes the water more corrosive to steel.

$$Fe + H_2CO_3 = FeCO_3 \text{ (iron carbonate scale)}$$

If a high pH is maintained, the water will tend to be less corrosive.

Standard treatments for CO_2 are:

1. Kill the source of CO_2 (if it is a kick, then circulate out the gas through the degasser).
2. Re-establish proper alkalinity and pH by additions of lime and/or caustic soda.

While a high pH will combat corrosion, it may be necessary to add chemicals to remove the scale as well.

H_2S as a gas is not particularly corrosive, however if moisture is present it will become corrosive and in the presence of CO_2 or $O_{2,}$ it becomes extremely corrosive. Since H_2S is soluble in drilling muds, as the pH increases, the total amount of sulfides existing as H_2S is reduced. The pH should be maintained above 10 if known H_2S bearing formations are to be drilled. A scavenger should also be added to remove sulfides. The most common scavengers are zinc carbonate, zinc chromate, zinc oxide, ironite sponge (Fe_30_4) and copper carbonate. The pH will have to be treated as scavengers are added.

pH is commonly measured with pHydrion paper. This paper is impregnated with dyes that render a color which is pH dependent. The paper is placed on the surface of the mud which wets the paper. When the color has stabilized, it is compared with a color chart. An electronic pH meter may also be used.

Filtrate/Water Loss ml/30 min
Filter Cake Thickness 1/32 inch

These two properties shall be dealt with together, as it is the filtration of mud that causes the build up of filter cake. Loss of fluid (usually water and soluble chemicals) from the mud to the formation occurs when the permeability is such that it allows fluid to pass through the pore spaces. As fluid is lost, a build up of mud solids occurs on the face of the wellbore. This is the filter cake.

Two types of filtration occur; **dynamic**, while circulating and **static**, while the mud is at rest. Dynamic filtration reaches a constant rate when the rate of erosion of the filter cake due to circulating matches the rate of deposition of the filter cake. Static filtration will cause the cake to grow thicker with time, which results in a decrease in loss of fluids with time.

Mud measurements are confined to the static filtration. Filtration characteristics of a mud are determined by means of a filter press. The test consists of monitoring the rate at which fluid is forced from a filter press under specific conditions of time, temperature and pressure, then measuring the thickness of the residue deposited upon the filter paper.

Excessive filtration and thick filter cake build up are likely to cause the following problems:

1. Tight hole, causing excessive drag.
2. Increased pressure surges, due to reduced hole diameter.
3. Differential sticking, due to an increased pipe contact in filter cake.
4. Excessive formation damage and evaluation problems with wireline logs.

Most of these problems are caused by the filter cake and not the amount of filtration because the aim is to deposit a thin, impermeable filter cake. A low water loss may not do this, as the cake is also dependent upon solids size and distribution.

The standard fluid loss test is conducted over 30 minutes. The amount of filtrate increases with direct proportion to the square root of the time. This can be expressed by the following;

$$Q2 = (Q1 \times T2)/T1$$

Where: Q2 is the unknown filtrate volume at time T2

Q1 is the known filtrate volume at time T1

Pressure also affects filtration by compressing the filter cake, reducing its permeability and therefore reducing the filtrate. Small plate-like particles act as the best filter cake builders and bentonite meets these requirements.

Increased temperature has the effect of reducing the viscosity of the liquid phase and hence increasing filtration. With all other factors being constant, the amount of filtrate will vary with the square root of time.

Proper dispersion of the colloidal clays in the mud gives a good overlap of particles, thus giving good filtration control. A flocculated mud, which has aggregates of particles, allows fluid to pass through easily. The addition of chemicals to act as dispersants will increase the efficiency of the filter cake.

The standard test is conducted at surface temperature at 100 psi and is recorded as the number of ml's of fluid lost in 30 minutes. An API high pressure/high temperature (Hp/Ht) test is conducted at 300° F and 500 psi. The tests may be conducted using a portable filter press that uses CO_2 cartridges or using a compressed air supply.

The high pressure and high temperature test is conducted to simulate downhole conditions, since the degree of filtration may vary, depending upon the compressibility of the filter cake. A mud sample may be tested at standard temperatures and pressures, increased temperature and 100 psi, or at high temperatures and pressures. Increased pressure will indicate if the filter cake is compressible.

The primary fluid loss agent in most water based muds are the clays. These solids should have a size variation with a large percentage being under 1 micron. This will produce a filter cake with low porosity and permeability. The use of centrifuges or cyclone solids removal equipment may cause filtration problems by removing the small size solids. Starch is also used as a fluid loss agent, the starch being treated is so that it will easily gelatinize and swell. Water soluble polymers are commonly used as viscosifiers, acting on the fluid phase which also reduces fluid loss.

Sodium Carboxyl-Methyl Cellulose (CMC) is an organic colloid with a long chain structure that can be polymerized into different lengths or grades. It is thought to act by either the long chains plugging narrow openings in the filter cake, curling into balls to act as plugs, or by coating the clay particles with a film. It will however, lose its effectiveness as salt concentrations rise above 50,000 ppm. A polyanoinic cellulose is used as the fluid loss agent in high salt concentration, low solids drilling fluids.

Alkalinity, Mud Pm
Alkalinity, Filtrate Pf/Mf

Alkalinity or acidity of a mud is indicated by the pH. The pH scale is logarithmic and hence a high pH mud may vary considerably without a noticeable change in pH. The filtrate and mud can both be measured to show the phenolphthalein alkalinity.

The test for filtrate is carried out by putting 1 or more milliliters of filtrate into a titration dish and adding 2 or 3 drops of phenolphthalein indicator solution. Drops of 0.02 normal nitric or sulfuric acid solution are then added until the pink coloration just disappears. The alkalinity is measured as the number of milliliters of acid per milliliter of filtrate. The test for mud is similar except that to one milliliter of mud, 25 to 50 milliliters of water are added for dilution and 4 or 5 drops of phenolphthalein are added. The result is measured the same as for the filtrate.

Salt/Chlorides ppm or gpg

The salt or chlorides concentration of the mud is monitored as an indicator of contamination. The salt contamination may come from water used to make mud, salt beds or from saline formation waters. The test is conducted on mud filtrate.

One or more milliliters of filtrate is added to a titration dish and 2 or 3 drops of phenolphthalein solution is added. Drops of 0.02 nitric or sulfuric acid solution are then added while stirring to remove the pinkish color. One gram of pure calcium carbonate is then added and stirred. Next, 25 - 50 ml of distilled water and 5 - 10 drops of potassium chromate solution are added. This mixture is stirred continuously while drops of silver nitrate solution are added until the color changes from yellow to orange red and persists for 30 seconds. The number of milliliters of silver nitrate used to reach the end-point are recorded. This is then used in the equation:

Chlorides(ppm) = (ml of silver nitrate x 1000) / ml filtrate

This can be converted to salt (NaCl) ppm by multiplying the chlorides by 1.65, or to grains per gallon by multiplying the salt ppm by 0.0583.

Calcium ppm

If water contains a lot of calcium or magnesium salts, it is referred to as “hard water”. The harder the water, the more difficult it is to get bentonite to yield, thus requiring more bentonite to make a good gel. Excess calcium contamination may cause abnormally high water loss and fast gel rates.

Sand Content % vol

This is measured by use of a 200 mesh sand screen set. A measuring tube is filled with mud and water and shaken vigorously. The mixture is then poured over the 200 mesh sieve and washed clean with water. The sand is then washed into the measuring tube and measured in percent. This will give an indication as to the effectiveness of the mechanical solids control equipment.

Solids Content % vol
Water Content % vol
Oil Content % vol

A retort is used to determine the quantity of liquids and solids in a drilling fluid. A measured sample of fluid is heated until the liquid portion is vaporized. The vapors are passed through a condenser and measured as a percentage by volume. The solids are then calculated by subtracting the total from 100.

Funnel Viscosity sec/qt

The Marsh Funnel is the field instrument used to measure viscosity. It is graduated so that one quart (946 cc) of water will flow through the funnel in 26 seconds. To run a test, the bottom orifice is covered and drilling fluid is poured over a screen until the funnel is full. When the bottom is uncovered, the time required to fill one quart is recorded (in seconds) along with the temperature.

Funnel viscosity is a rapid, simple test, but because it is a one point measurement it does not provide information as to why the viscosity has changed, only that it has changed.

Hydraulics

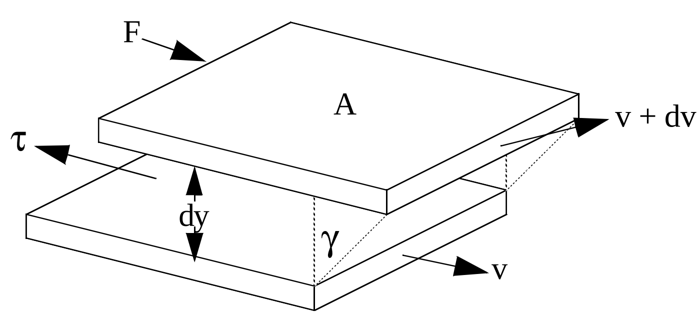
The concept that a fluid cannot maintain a rigid shape is a basic, but important characteristic, which means that fluids cannot sustain a shear-stress (a tangential force applied to the surface). Any tangential force will cause the fluid to deform and continuous deformation is known as “flow”. Fluid flow is always considered to take place within a conductor. A conductor may be the annulus created by casing for drilling fluid or a volcano’s slope and the atmosphere, in the case of a lava flow.

Generally, fluid flow can be considered the result of parallel fluid layers sliding past one another. The layers adjacent to the conductor adhere to the surface and each successive layer slides past its neighbor with increasing velocity. This orderly flow pattern is known as **laminar flow**. At higher velocities, these layers lose their order and crash randomly into one another with an orderly flow occurring only adjacent to the conductor. This flow pattern is known as **turbulent flow**.

Laminar Flow is usually found in the annulus during drilling operations. This type of flow is generally desired in the annulus since it does not lead to hole erosion and does not produce excessive pressure drops. These pressure drop calculations can be mathematically derived according to the type of flow behavior.

Turbulent Flow is the type of flow regime found inside the drill string during drilling operations. Since high mud velocities are required to achieve turbulent flow, this results in high pressure drops. This type of flow is generally not desired in the annulus due to its tendency to cause excessive hole erosion and high “equivalent circulating densities”. However, turbulent flow can move the mud like a plug, causing the mud to move at approximately the same rate. This provides for better hole cleaning and is sometimes required on high angle holes. Pressure drop calculations for turbulent flow are empirical rather than mathematically derived.

When a force is applied to a static fluid, the layers slide past one another and the frictional drag that occurs between the layers (which offers resistance to flow) is known as “**shear-stress**”.



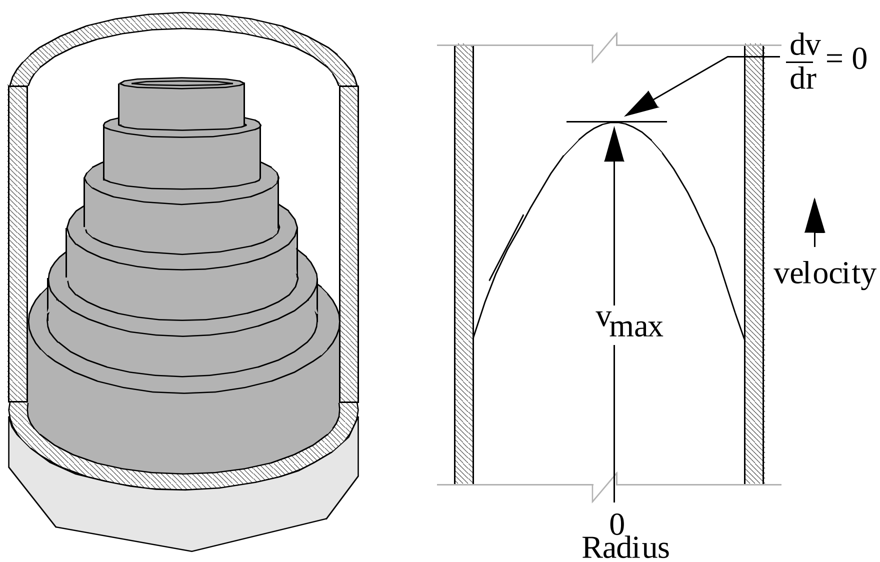
Deformation of a Fluid by Simple Shear

The magnitude of shear between the layers is represented by the **shear-rate**, which is defined as the difference in the velocities between the layers, divided by the distance of separation. It is this relationship between the shear-stress and shear-rate that defines the behavior of the fluid.

For some fluids the relationship is linear (i.e., if the shear-stress is doubled then the shear-rate will also double, or if the circulation rate is doubled then the pressure required to pump the fluid will double). Fluids such as this are known as “Newtonian fluids”. Examples of Newtonian fluids are water, glycerine and diesel. The Newtonian fluid model is defined by the following relationship:

Shear-Stress = Absolute Viscosity x Shear-Rate

The slope of the flow curve in the diagram is given by the absolute viscosity, this is the shear stress divided by the shear rate. A typical flow profile for a Newtonian fluid in a cylindrical pipe is a parabola, with a maximum shear-rate at the wall and a minimum (0) at the center.



Drilling fluids are generally Non-Newtonian in behavior, and are defined by more complex relationships between shear-stress and shear-rate. When fluids contains colloidal particles (or clays), these particles tend to increase the shear-stress or force necessary to maintain a given flow rate. This is due to electrical attraction between particles and to them physically “bumping” into each other. Long particles, randomly oriented in a flow stream, will display high interparticle interference. However, as shear-rate is increased, the particles will tend to develop an orderly orientation and this interaction will decrease.

In the center of a pipe, the shear-rate will be low and hence particle interaction high, giving it a flattened flow profile. This profile has an improved sweep efficiency and an increased carrying capacity for larger particles.

As can be seen from the previous examples, the ratio of shear-stress to shear-rate is not constant but will vary with each shear-rate.

Various "oilfield" models have been proposed to describe this non-Newtonian shear-rate/shear-stress curve. In order to arrived at "standard" variables, these models require the measurement of shear-stress at two or more shear-rates to define the curve.

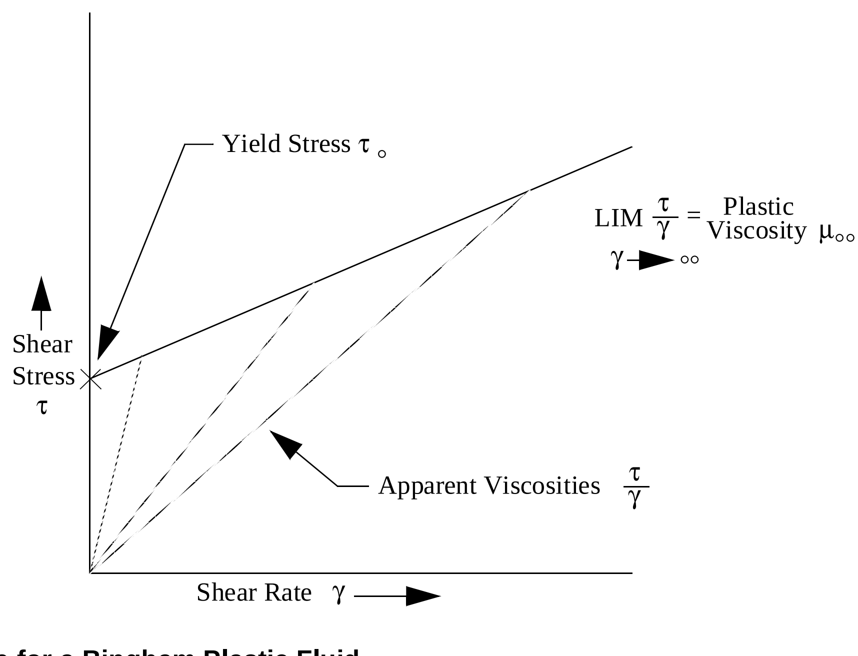
The two most common models used at the wellsite are the Bingham Plastic Model and the Power Law Model.

Bingham Plastic Model

The Bingham model is defined by the relationship;

Shear Stress = Yield Stress + (Plastic Viscosity x Shear Rate)

The major difference between this and Newtonian fluids is the presence of a Yield Stress or "Yield Point" (which is a measure of the electronic attractive forces in the fluid under flowing conditions). No bulk movement of the fluid occurs until this yield stress is overcome. Once the yield stress is exceeded, equal increments of shear stress produce equal increments of shear rate.



Flow Curve for a Bingham Plastic Fluid

Note that the apparent viscosity decreases with increased shear rate. This phenomenon is known as "shear thinning". As shear rates approach infinity, the apparent viscosity reaches a limit known as the Plastic Viscosity. This viscosity is the slope of the Bingham plastic line. The commonly used Fann V-G meter was specifically designed to measure viscosities for this model. As can be seen in the above illustration, this model does not accurately represent drilling fluids at low shear rates.

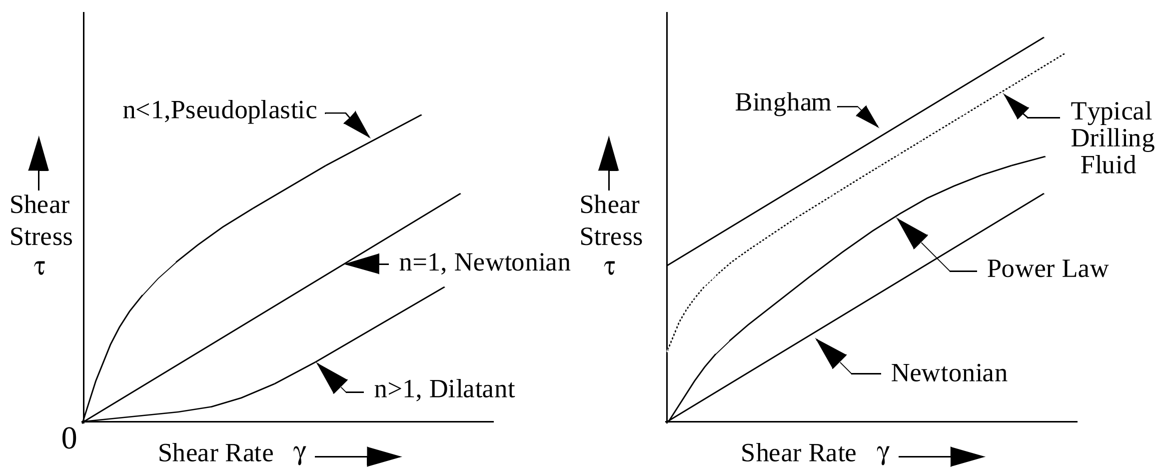
Power Law Model

This model is defined by the relationship:

Shear Stress = Consistency Factor x Shear Rate $^{\text{flow behavior index}}$

It describes the thickness or pumpability of the fluid, and is somewhat analogous to the apparent viscosity. The **flow behavior index (n)** indicates the degree of non-Newtonian characteristics of the fluid. As the fluid becomes more viscous, the **consistency factors (k)** increases; as a fluid becomes more shear thinning "n" decreases. When "n" is 1 the fluid is Newtonian. If "n" is greater than 1, the fluid is classed as Dilatant (the apparent viscosity increases as the shear rate increases). If "n" is between zero and 1 the fluid is classified as Pseudoplastic, exhibiting shear-thinning; (i.e., the apparent viscosity decreases as the shear rate increases). For drilling fluids, this is a desirable property and most drilling fluids are pseudoplastics.

While the Power Law Model is more accurate then the Bingham Model at low shear rates, it does not include a yield stress. This results in poor results at extremely low shear rates.

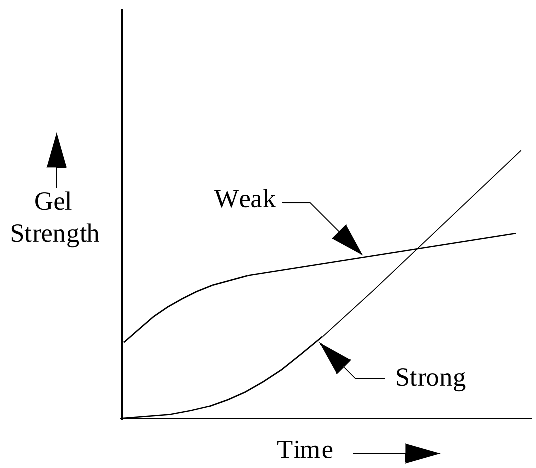


A modification to the Power Law Model, the **OXY Model**, was proposed for use in oil-based muds. The major difference is the viscometer readings used to determine the "k" and "n" values. Power Law uses the 300 and 600 rpm readings, the OXY Model uses the 6 and 100 rpm readings. In addition, other models have been proposed that tend to exhibit behavior between the Bingham and Power Law models at low shear rates.

Non-Newtonian fluids may show a degree of time-dependent behavior. (For example, the apparent viscosity for a fixed shear rate does not remain constant, but varies to some maximum or minimum with the duration of shear.) If the apparent viscosity decreases with flow time, the fluid is termed “Thixotropic”. Once flow has ceased, a thixotropic fluid will show an increase in apparent viscosity. When apparent viscosity increases with flow time, the fluid is “Rheopectic”.

The shear stress developed in most drilling fluids is dependent upon the duration of shear. A time lag exists between an adjustment of shear rate and the stabilization of shear stress. This is due to the breaking up of clay particles at high shear rates and the aggregation of clay particles when shear rate is decreased, both occurrences take a noticeable length of time.

“Gel strength” is used to measure this time dependent behavior. This gel strength measures the attractive forces of a fluid while under static conditions. If the gel strength increases steadily with time, the gel strength is classed strong or progressive. If it increases slowly with time, it is classed as weak or fragile.



When strong gels occur, excessive pressures may be required to break circulation.

Hydraulic Calculations

In the "*Advanced Logging Procedures Workbook*" (P/N 80269H), an introduction to hydraulics illustrates the Bingham method for hydraulic optimization. The second, and more commonly used method is the Power Law Model.

This model fits the actual flow properties more closely, although at low shear rates, it will predict slightly low shear stresses. The model describes a fluid in which the shear stress increases as a function of shear rate, raised to some power. As mentioned earlier, the equation for the Power Law model is:

Shear Stress = k x Shear rate^n

"k" is known as the "consistency index", and is indicative of the pumpability of the fluid. "n" is the power index, denoting the degree of how "non-Newtonian" the fluid is.

Both parameters can be determined from the Fann VG meter. "k" is defined as the viscosity of a fluid at a shear rate of 1 sec^{-1}. When "n" equals 1, the fluid is Newtonian. As the fluid becomes more shear thinning, the "n" value decreases.

$$k = (1 + 0.067n) \times \frac{300_{rpm}}{511^n} \qquad n = 3.32\log\left(\frac{600_{rpm}}{300_{rpm}}\right)$$

where: 300_{rpm} = Fann VG meter dial reading at 300 rpm's
600_{rpm} = Fann VG meter dial reading at 600 rpm's

If the Fann VG meter dial readings are not available, both "k" and "n" can be determined using the Plastic Viscosity and Yield Point.

$$k = 1.067 \times \frac{(PV + YP)}{511^n} \qquad n = \log\left(\frac{(2PV + YP)}{(PV + YP)}\right) \Big/ \log 2$$

where: PV = Plastic Viscosity (cps)
YP = Yield Point (lb/100ft^2)

Once these values have been determined, they are used in calculating the pressure losses throughout the circulating system. This section will describe the pressure losses, using the Power Law Model, in the surface system, the drillstring, and the annulus.

Surface Pressure Losses

System pressure loss calculations begin with the determination of the type/class of surface circulating equipment. These include the standpipe, rotary hose, swivel, and kelly (if present). Though hardly ever consistent, four types/classes have been recognized by the IADC as the most common. They are:

Class #1 (Coefficient 19)	Class #2 (Coefficient 7)
40 ft & 3 in. I.D. Standpipe	40 ft & 3.5 in. I.D. Standpipe
45 ft & 2 in. I.D. Hose	55 ft & 2.5 in. I.D. Hose
4 ft & 2 in. I.D. Swivel	5 ft & 2.5 in. I.D. Swivel
40 ft & 2.25 in I.D. Kelly	40 ft & 3.25 in. I.D. Kelly

Class #3 (Coefficient 4)	Class #4 (Coefficient 3)
5 ft & 2.5 in. I.D. Swivel	6 ft & 3 in. I.D. Swivel
45 ft & 4 in. I.D. Standpipe	45 ft & 4 in. I.D. Standpipe
40 ft & 3.25 in. I.D. Kelly	40 ft & 4 in. I.D. Kelly
55 ft & 3 in. I.D. Hose	55 ft & 3 in. I.D. Hose

When calculating surface pressure losses, choose the class which is closest to the present rig equipment; if necessary, extrapolate. Most modern rigs will have a surface pressure coefficient between 2 and 10. The coefficient is then used in the following formula:

$$P_{ls} = 10^{-5} \times k_s \times MD \times Q^{1.86}$$

where:
P_{ls} = Surface Pressure Loss (psi)
k_s = Surface Pressure Coefficient
MD = Mud Density (lb/gal)
Q = Flow Rate (gal/min)

When extrapolating, bear in mind that increased lengths will increase the coefficient, while increased I.D.'s will decrease the coefficient.

Pressure Loss in the Drillstring

Once passed the surface equipment, the fluid will flow through the drillstring. In hydraulic calculations, these parts of the circulating system are considered circular pipes. In typical field operations, fluid velocities are in the order of 1000 ft/min (300 m/min). At such velocities, the fluid is in turbulent flow.

The pressure required to circulate fluid in turbulent flow varies by approximately 1.8 power of the flowrate. Doubling the flowrate would increase the pressure drop in the drillstring by approximately 3.5 times. Typically, the pressure losses in the drillstring are about 35 percent of the total pump pressure.

With this in mind, it will be necessary to know how much pressure will be required to pump the fluid through the drillstring, at a given rate.

Drillstring Pressure Losses

All pressure losses, at first, assume a laminar flow regime. Power Law Model calculations begin with:

$$P_{lf} = \frac{L \times k}{300 \times d} \times \left(\frac{1.6 \times V_P}{d} \times \frac{(3n + 1)}{4n} \right)^n$$

where: P_{lf} = Pressure Loss in Laminar Flow (psi)
L = Length of Section (feet)
V_P = Velocity in Section of drill string (ft/min)
d = Inside Diameter of drillstring (inches)
k = Consistency Index
n = Power Index

Fluid velocity in the drillstring can be determined by using:

$$V_p = \frac{24.51 \times Q}{d_1^2}$$

where: Q = Pump flow rate (gpm)
d_1 = pipe I.D. (inches)

The equivalent viscosity (μ) is then determined, using:

$$\mu = \frac{90000 \times Pl_f \times d^2}{L \times V}$$

Which, in turn, is used to determine the Reynolds Number.

$$Re = \frac{15.46 \times MD \times V_P \times d}{\mu}$$

Flow behavior, with the Power Law Model, will vary depending on the "n" value of the fluid. The critical Reynolds Number (Rec) is found using:

3470 - 1370n (from laminar to transitional)

4270 - 1370n (from transitional to turbulent)

If: Re < Rec flow is laminar

Re is between laminar and turbulent, flow is transitional

Re > Rec flow is turbulent

If the flow is determined to be turbulent, the pressure losses will have to be re-calculated using turbulent flow. This will also require a friction factor (f) to be included:

$$f = \frac{(\log n + 3.93)}{50} \times Re^{\left(\frac{\log n - 1.75}{7}\right)}$$

Pressure losses are then determined, using:

$$P_{tf} = \frac{f \times L \times MD \times V_P^2}{92894 \times d}$$

Annular Pressure Losses

Hydraulic calculations continue with a determination of the amount of pressure lost in the annulus. Assuming laminar flow, the Power Law Model "pressure loss" equation is:

$$Pl_a = \frac{k \times L}{300(d_1 - d_2)} \times \left(\frac{1.6 \times V \times G}{(d_1 - d_2)}\right)^n$$

where:
- k = Consistency index
- L = Length of section (feet)
- d_1 = Hole or Casing I.D. (inches)
- d_2 = Pipe or Collar O.D. (inches)
- V = Annular Velocity in Section (ft/min)
- n = Power Index
- G = Geometric Factor

Fluid velocity in the annulus is determined by using:

$$\frac{24.51 \times Q}{D_1^2 - D_2^2}$$

where:
- D_1 = hole or casing I.D. (inches)
- D_2 = pipe or collar O.D. (inches)

A "geometric factor" is used to take into account the friction factor (a ratio of the actual shear stress imposed on the borehole wall to the dynamic pressure imposed on the system) and is determined by calculating two dimensionless variables (y and z).

$$y = 0.37n^{-0.14} \qquad z = 1 - \left(1 - \left(\frac{d2}{d1}\right)^y\right)^{1/y}$$

"G" can then be calculated:

$$G = \left(1 + \frac{z}{2}\right) \times \left(\frac{(3 - z) \times n + 1}{(4 - z) \times n}\right)$$

If flow in the annulus is transitional, common in the drill collar/open hole annulus, then the pressure losses are determined using a friction factor (f), calculated using:

$$f = \frac{16}{Rec} + \frac{(Re - Rec)}{800} \times \left(\frac{(3.93 + \log n)}{50} \times Rec^{\left(\frac{\log n - 1.75}{7}\right) - \frac{16}{Rec}}\right)$$

Pressure losses are then determined:

$$P_{trf} = \frac{f \times L \times MD \times V^2}{92894 \times (d_1 - d_2)}$$

Reynolds Number and Critical Velocity

The Reynolds Number, used in the annular Power Law Model calculations is calculated using equivalent viscosity (μ):

$$\mu = \frac{90000 \times Pl_a \times (d_1 - d_2)^2}{L \times V}$$

Reynolds Number is then:

$$Re = \frac{15.47 \times MD \times V \times (d_1 - d_2)}{\mu}$$

The fluid velocity that will produce the critical Reynolds Number for given fluid properties and pipe configuration is found using:

$$V_c = 60 \times \left[\frac{Re_L \times k}{185.6 \times MD} \times \left(\frac{96 \times G}{d_1 - d_2}\right)^n\right]^{\frac{1}{(2 - n)}}$$

where: Re_L = Laminar/Transitional Reynolds Number (3470-1370n).

Cuttings Transport

One of the primary functions of a drilling fluid is to bring the drilled cuttings to the surface. Inadequate hole cleaning can lead to a number of problems, including hole fill, packing off, stuck pipe, and excessive hydrostatic pressure. The ability of a drilling fluid to lift cuttings is affected by many factors, and there is no universally accepted theory which can account for all observed phenomena. Some of the parameters which affect cuttings transport are the fluids density and viscosity, annular size and eccentricity, annular velocity and flow regime, pipe rotation, cuttings density, and the size and shape of the cuttings.

If the cuttings are of irregular shape (and most are) they are subjected to a torque caused by the shearing of the mud. If the drillpipe is rotating, a centrifugal effect causes the cuttings to move towards the outer wall of the annulus. The process is further complicated because the viscosity of non-Newtonian fluids varies according to the shear rate, and therefore the velocity of the cutting changes with radial position. Finally, transport rates are strongly dependent on cutting size and shape, which as stated above, are both irregular and variable.

The only practical way to estimate the slip velocity (or relative sinking velocity) of cuttings, is to develop empirical correlations based on experimental data. Even with this approach, there is a wide disparity in the results obtained by different authors.

Cuttings Slip Velocity

A cutting, traveling up the annulus, experiences a positive upward force due to the drilling fluid velocity, density and viscosity, and a negative downward force due to gravity. The rate at which a cutting falls is known as its “slip velocity”.

Several studies have enabled the following generalizations to be made:

1. The most important factors controlling adequate cuttings transport are annular velocity and rheological properties
2. Annular velocities of 50 ft/min provide adequate cuttings transport in typical muds
3. Cuttings transport efficiency increases as fluid velocity increases
4. The slippage of cuttings as they are transported induces shear thinning of the mud around the cutting reducing the expected transport efficiency
5. Cutting size and mud density have a moderate influence on cuttings transport

6. Hole size, string rpm, and drill rate have slight effects on cuttings transport.

Those who have observed a solids tracer emerging over the shale shaker will realize the large spread of “cuttings” that occurs. Therefore, any calculated estimation of slip velocity will only be an approximation. The reason for this “spread” of solids is the particles ability to be carried by the drilling fluid. It is a function of its position in the mud stream and the size of the particle.

Cuttings will travel up the annulus more efficiently if they travel flat and horizontally. If the cutting turns on its edge, it will slip more easily. Smaller cuttings are more prone to do this. Rotation of the drillpipe will result in a helical motion of the fluid, which will aid transport for those cuttings nearest the pipe.

The rheological properties of the drilling fluid will affect cuttings transport, in as much as they affect the flow profile. Lowering the “n” value or an increases in the YP/PV ratio will generally flatten the flow profile and increase carrying capacity.

The slip velocity of a cutting in turbulent flow may be estimated using:

$$Vs = 113.4 \times \left(\frac{d_p(pp - MD)}{CD \times MD}\right)^{0.5}$$

where: Vs = Slip Velocity (ft/min)
d_p = Particle Diameter (inches)
pp = Particle density (lb/gal)
MD = Mud Density (lb/gal)
CD = Drag Coefficient

For these calculations, the particle density is found by multiplying the cuttings density (gm/cc) by the density of fresh water (8.34). The drag coefficient is the frictional drag between the fluid and the particle.

In turbulent flow, the drag coefficient is 1.5.

In laminar flow, the equivalent viscosity (μ) will effect the slip velocity. In this case the slip velocity is:

$$Vs = 175.2 \times d_p \times \left(\frac{(pp - MD)^2}{\mu \times MD}\right)^{0.333}$$

Equivalent viscosity is calculated as mentioned earlier.

Bit Hydraulics And Optimization

Jet Nozzles

Jet Nozzles were introduced into the oilfield in 1948. These were necessary to increase bottom hole cleaning in deep wells. Prior to jet nozzles, the fluid course in bits was a hole bored into the center of the bit and the drilling fluid went from the drillstring directly into the annulus.

These “conventional water courses” did not have the power necessary to lift the cuttings and assist in the drilling process.

Both roller cone bits and PDC bits have recesses to install different size jet nozzles in order to obtain proper hydraulics. Most roller cone bits use three or four jet nozzles, while PDC bits usually contain six to nine. The flow area of all jets must be determined separately, then added together. For example, suppose four size 9 jets were being used:

$$\text{Each Jet Area} = \frac{\text{Jet Size}^2}{64} \times \pi$$

$$= \frac{9^2}{64} \times \pi$$

$$= 0.0621 \text{ sq. in.}$$

There are four jets so the total flow area is 0.0621 x 4 or 0.2486 in^2.

Jet nozzles increase the speed of the drilling leaving the bit to around 225 ft/sec, and on many occasions the velocity is much greater. Because nozzle velocity is so important in hydraulic optimization, it should be calculated when the jets are installed in a bit. The formula is:

$$V_n = \frac{418.3 \times Q}{\Sigma d_j{}^2}$$

where: V_n = Nozzle Velocity (ft/sec)

Q = Flow Rate (gal/min)

d_j = Nozzle Size (32nds)

Note: *It is ($11^2 + 12^2 + 13^2$), not $(11 + 12 + 13)^2$*

As mentioned in the previous section, the rate of penetration can be improved if the cuttings are removed from beneath the bit. In soft formations, the hole is generated by the jetting action of the drilling fluid, and the drill rate is limited by connection time, undesirable deviations, and the loading of the annulus with cuttings. In hard formations, the drill rate should be proportional to the weight-on-bit, if hole cleaning is adequate.

Surface Horsepower

In order to maximize a hydraulics program, all aspects concerning drilling fluids and the associated equipment must be considered.

The first component in any hydraulic design is the surface equipment and the hydraulic horsepower available from them. There are two limiting factors on the surface hydraulic horsepower.

The first is the **flow rate range**. As discussed earlier, the flow pattern in the annulus should be laminar, therefore the upper limit for the flow rate is a Reynolds Number of 2000. The highest velocity in the annulus will be around the collars, and this velocity can be determined by calculating the "critical velocity" over that section. In addition, running the pumps at that upper range is not always advisable because there will be more wear and tear on the pumps and much more fuel consumption.

The lower limit is a range where there is sufficient hole cleaning. This is determined by using the velocity around the drillpipe and the largest annular section (normally the upper hole section or drillpipe/riser section). A normal range is around 50 ft/min.

The second factor is the **operating pressure** of the mud pumps. Most mud pumps can produce the required pressure with little problem. However, because of the various components associated with the surface system (standpipe, rotary hose, pulsation dampener, etc.) the maximum surface pressure is usually limited to some value less than the maximum rated pump pressure.

The available "surface horsepower" is then determined by:

$$H_{ps} = \frac{P \times Q}{1714}$$

where: H_{ps} = Surface Horsepower

P = Pump Pressure (psi)

Q = Pump Flow Rate (gal/min)

Once the surface horsepower has been determined, the horsepower distributions can be made:

$$H_{ps} = H_{pc} + H_{pb}$$

where: H_{pc} = Circulation Horsepower

H_{pb} = Bit Horsepower

Bottom Hole Horsepower

Determination of the amount of Bottom Hole Cleaning necessary to maximize the drill rate is based upon:

1. Hydraulic (Jet) Impact Force
2. Hydraulic Horsepower

Maximizing H_{pb} involves minimizing H_{pc}, or in other words, the lowest flow rate and the highest pump pressure will result in the highest H_{pb}. However, the "lowest flow rate" will usually result in inadequate bottom hole cleaning. To compensate for this, bottom hole pressure can be increased by using smaller jet nozzles.

Hydraulic Horsepower

Hydraulic horsepower is based on the theory that cuttings are best removed from beneath the bit by delivering the most power to the bottom of the hole.

The amount of pressure lost at the bit, or bit pressure drop, is essential in determining the hydraulic horsepower. Bit pressure drop is determined by:

$$P_b = \frac{MD \times (V_n)^2}{1120}$$

where: MD = Mud Density (lb/gal)

V_n = Nozzle Velocity (ft/sec)

From the bit pressure loss, hydraulic horsepower can be calculated:

$$H_{hh} = \frac{P_b \times Q}{1714}$$

To optimize Bottom Hole Cleaning and Bit Hydraulic Horsepower, it is necessary to select a circulation rate and nozzle sizes which will cause 65% of the pump pressure to be expended forcing the fluid through the jet nozzles of the bit.

$$H_{hh} = 0.65 \times H_{ps}$$

Hydraulic Impact Force

Hydraulic (Jet) Impact Force is based on the theory that cuttings are best removed from beneath the bit when the force of the fluid leaving the jet nozzles and striking the bottom of the hole is the greatest. Impact Force is determined by:

$$H_{if} = \frac{MD \times Q \times V_n}{1930}$$

where: MD = Mud Density (lb/gal)

Q = Flow Rate (gal/min)

V_n = Nozzle Velocity (ft/sec)

As can be seen, Impact Force depends on maximizing flow rate and nozzle velocity rather than pressure. Therefore, higher flow rates are required. The emphasis is on a large volume of fluid impacting with moderate force, rather than a small volume impacting at a high pressure.

This condition is optimized when circulating rates and bit nozzle sizes are chosen which will cause 48% of the pump pressure to be used to force fluid through the jet nozzles.

$$H_{if} = 0.48 \times H_{ps}$$

Fixed Cutter Bit Hydraulics

The hydraulics for fixed cutter bits is based on the drilling fluids ability to remove cuttings beneath the cutters and to cool the bit. Fluid volume is critical to PDC bit performance. Fluid volume and fluid velocity is critical to diamond bit performance.

The major components of fixed cutter bit hydraulics are:

1. flow rate - Q (gal/min) and V (ft/min)
2. drilling fluid characteristics - MD (lb/gal), YP (lbs/100ft^2) and PV (cps)
3. pressure loss - across the bit face (diamond bit) or through the jet nozzles (PDC bit)
4. the Total Flow Area (TFA) - instead of nozzle sizes

A very important parameter in fixed cutter bits is “Hydraulic Power Per Square Inch” or HSI. It is calculated using H_{hp} (hydraulic horsepower):

$$HSI = \frac{H_{hp}}{A}$$

where: H_{hp} = Hydraulic Horsepower

A = Bit Area (square inches)*

* If the area of the bit is not given, it can be calculated using:

$$A = \pi\frac{d^2}{4}$$

where: d = bit diameter (inches)

The hydraulic horsepower equation is the same (P_b x Q/1714), however in fixed cutter bits, resistance to fluid flow is created by the diamonds, nozzles, flow area restrictions, cuttings and the uneven hole pattern. Pressure losses at the bit are calculated using:

$$P_b = \frac{MD \times Q^2}{10858 \times TFA^2}$$

PDC Bit Hydraulics

Since PDC bits are formation specific (best used in plastic formations), the formation characteristics will determine the hydraulic energy required. The drilling fluid will dictate the HSI, for water-based drilling fluids it will be between 2.5 and 4.5, while for oil-based drilling fluids it will be between 1.5 and 3.0.

The HSI, calculated at the jet nozzle orifices, will have several characteristics which will directly affect hydraulic energy:

1. the fluid velocity decreases rapidly once it leaves the nozzles
2. high vertical velocity and low horizontal velocities are achieved across the bit face
3. for higher volumes of fluid pumped, horizontal velocities will increase, but not necessarily HSI

The increased horizontal velocities provide better cuttings removal, better cooling, and possibly better drill rates.

Nozzle velocity is calculated in the same manner as with rollercone bits.

Diamond Bit Hydraulics

The horizontal fluid velocity is the key element in diamond bit life and bit performance. It can be determined using:

$$Vel = \frac{0.32 \times Q}{TFA}$$

The fluid courses assist this by directing the drilling fluid across the bit to cool the diamonds and to remove the cuttings.

The diamond bit “Total Flow Area” consists of two components:

1. **Fluid Course Area** - is the area of all fluid courses on the bit. They are cast into the bit body.
2. **Diamond Exposure Area** - is the area between the bit face and formation, produced by the diamond exposure.

The desired TFA is calculated and designed into the bit by varying the diamond exposure, and the width and depth of the fluid courses.

Another phenomenon which occurs with natural diamond bits is called hydraulic pump-off. The hydrodynamic pressure of the mud at the bit acts over the bit face area (between the cutting face of the bit and the formation) and tends to lift the bit off the bottom of the hole. For example, the pump-off force on a 8-1/2 inch radial flow diamond bit (having a pressure drop of 900 psi) would be approximately 8600 pounds. It will require at least this much bit weight to keep the face of the bit in contact with the bottom of the hole.

Diamond Bit Flow Patterns

There are two main flow patterns in diamond bits:

1. Cross Pad Flow System (feeder/collector system)

   a) the fluid travels along the high pressure “primary fluid courses” (those which connect to the crowfoot), to a point where “low pressure collectors” draw the fluid across the diamond pad

   b) this ensures that the diamonds towards the outside diameter are cleaned and cooled

   c) The HSI should be between 1.5 and 2.5.

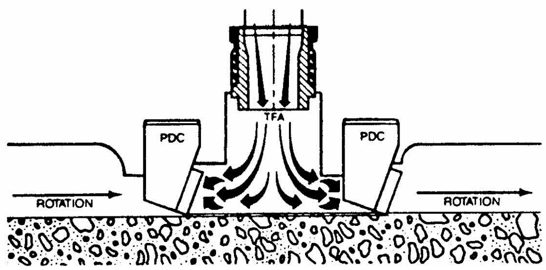
2. Radial Flow System

   a) provides a “high pressure primary fluid course” for each diamond row

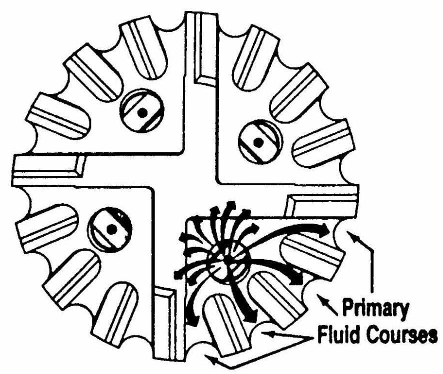
   b) permits fluid to travel in front of, and behind each diamond pad to facilitate cuttings removal and cooling

   c) maintains uniform horizontal fluid velocity by tapering fluid course depth as they approach the outside diameter

   d) The HSI should be between 2.0 to 3.0.



PDC TFA (Total Flow Area) determined by nozzle area times number of nozzles.



CONTROLLED RADIAL FLOW WITH NOZZLES

Jet Nozzle Flow Area (inches)

Jet Size	TFA of 1 Jet	TFA of 2 Jets	TFA of 3 Jets	TFA of 4 Jets	TFA of 5 Jets	TFA of 6 Jets	TFA of 7 Jets	TFA of 8 Jets	TFA of 9 Jets
7/32	.038	.075	.113	.150	.188	.226	.263	.301	.338
8/32	.049	.098	.147	.196	.245	.295	.344	.393	.442
9/32	.062	.124	.186	.249	.311	.373	.435	.397	.559
10/32	.077	.153	.230	.307	.384	.460	.537	.614	.690
11/32	.093	.186	.278	.371	.464	.557	.650	.742	.835
12/32	.110	.221	.331	.442	.552	.663	.773	.884	.994
13/32	.130	.259	.389	.519	.648	.778	.907	1.037	1.167
14/32	.150	.301	.451	.601	.752	.902	1.052	1.203	1.353
15/32	.173	.345	.518	.690	.863	1.035	1.208	1.381	1.553
16/32	.196	.393	.589	.785	.982	1.178	1.374	1.571	1.767

Figure 1-1: Nozzle Flow Area

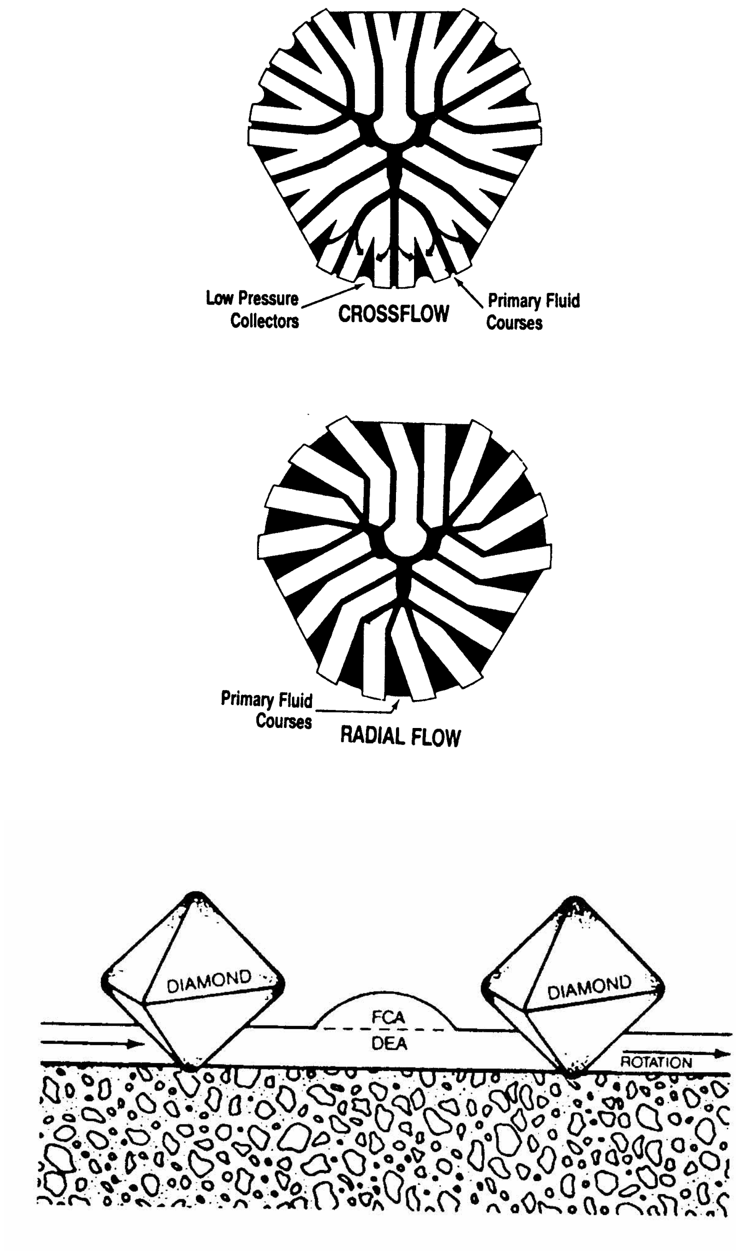

Low Pressure Collectors
CROSSFLOW
Primary Fluid Courses
Primary Fluid Courses
RADIAL FLOW
DIAMOND
DIAMOND
FCA
DEA
ROTATION

Figure 1-2

Swab And Surge Pressures

Both swab and surge pressures are caused by moving the drillstring axially, and can be calculated using a method similar for calculating annular pressure losses. The greatest difficulty is determining the fluid flow velocity in the annulus when the pipe is opened-ended, because the distribution of flow between the drillstring and annulus cannot be determined by a simple method.

Two approaches have been proposed.

The first assumes that fluid levels in the annulus and drillstring remain equal at all times. Annular fluid velocity then becomes:

$$V_a = -V_p \times \frac{(d^2 - d_1{}^2)}{(D^2 - d^2 + d_i{}^2)}$$

where:

V_a = Average velocity (ft/min)

V_p = Drillstring velocity (ft/min)

D = Borehole Diameter (inches)

d = Drillstring Outside Diameter (inches)

d_i = Drillstring Inside Diameter (inches)

The minus sign is in the equation because the drillstring velocity is in the opposite direction to the fluid velocity.

This average velocity equation remains valid even when hole geometry changes. This method is easy to apply and is in widespread use in the oilfield. Its basic premise, that fluid levels in the drillstring and annulus remain equal, is rarely justified. Because of the greater restrictions to flow, caused by the bit nozzles and pipe bore, actual flow in the annulus will nearly always exceed that calculated by this method. Calculated swab and surge pressures are therefore usually too low.

An alternative procedure considers the drillstring and the annulus as a “U-Tube”, as shown in the following figure. It is clear that the sum of hydrostatic and frictional pressures in the pipe bore and through the bit should equal the sum of hydrostatic and frictional pressures in the annulus. Both sums represent the pressure prevailing immediately below the bit.

There is only one flow distribution that will fulfill this criterion, and it can be found by trial and error through the use of the pressure loss equations.

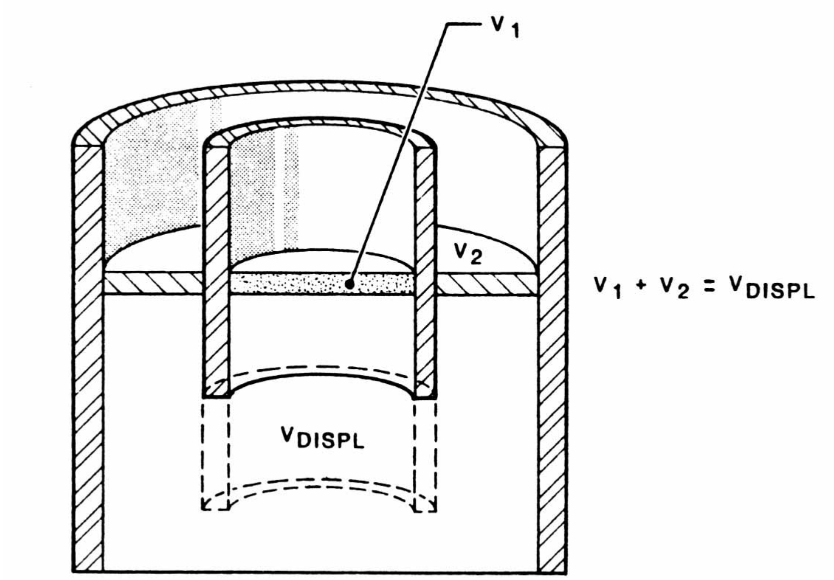


Figure 1-3: Equal Level Displacement

When tripping out of the hole, it may be assumed that both drillstring and annulus are kept full of fluid. The required distribution of flow is that which gives equal frictional losses in the pipe bore and annulus. When tripping into the hole, the fluid level inside the drillstring can drop well below that in the annulus, if small bit nozzles are present. This effect is usually seen as a pit volume being higher than expected, string weight lower than expected, and a considerable volume being pumped before standpipe pressure builds up while breaking circulation.

When the fluid level in the drillstring is below that of the annulus, a greater hydrostatic pressure will exist in the annulus, and fluid will tend to flow from the annulus up the drillstring. In this case, calculating flow distribution by equating frictional losses gives a calculated annular flow and surge pressure slightly higher than actually exists. Because this error is small and conservative, and because at present there is no reliable way of measuring the fluid level within the pipe, the practice of calculating flow distribution by equating internal and external pressure losses is generally accepted.

If the pipe is closed, or contains a float sub, it is easy to calculate flow in the annulus, because all of the fluid displaced by the drillstring passes up the annulus.

$$V_a = -V_p \times \frac{d^2}{(D^2 - d^2)}$$

Calculating the pressure drop in the annulus is complicated by the motion of the inner wall of the drillstring. This motion is in the opposite direction to the displaced fluid, so the pressure drop will be greater than that for the same flowrate in a stationary annulus (see Figure 1-4). Equations describing the system can be formulated, but solutions are usually too complicated for wellsite use.

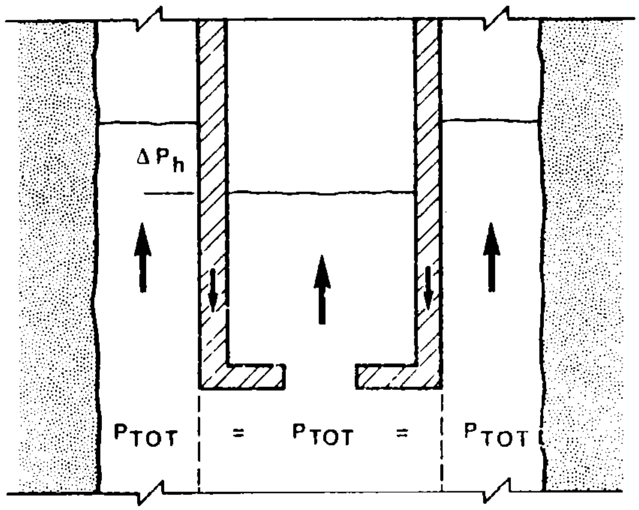


Figure 1-4: U-Tube Analogy for Equal Pressure Displacement

The problem can be solved for a Newtonian fluid in laminar flow, using:

$$\frac{8\mu L}{\Delta P R^2}\left[V_a + \frac{v_p}{2ln\alpha} + \frac{v_p \times \alpha^2}{(1-\alpha^2)}\right] = 1 + \alpha^2 + \frac{(1-\alpha^2)}{ln\alpha}$$

where: v_p = pipe velocity

α = d/D

The analog with the stationary annulus solution is clear. The stationary annulus solution can be used if an effective fluid velocity is substituted:

$$V_{eff} = V_a + v_p\left[\frac{1}{2ln\alpha} + \frac{\alpha^2}{(1-\alpha^2)}\right]$$

The term:

$$\frac{1}{2ln\alpha} + \frac{\alpha^2}{(1-\alpha^2)}$$

is known as the *clinging constant (K_C)*. It represents the proportion of pipe velocity which must be added to fluid velocity in order to find the equivalent or effective velocity, which must be used in the stationary annulus calculation. The effective velocity is numerically greater than the actual fluid velocity, because V_a and v_p are opposite signs and the clinging constant is negative.

For Newtonian fluids, the clinging constant depends only on the annulus diameter ratio. This is not the case for non-Newtonian fluids, in which the clinging constant is also a function of the drilling fluids properties, and of fluid and pipe velocity. Calculation of clinging constants for non-Newtonian fluids is very tedious. Some representative values for Bingham fluids and Power Law fluids are shown in Figures 1-5 and 1-6.

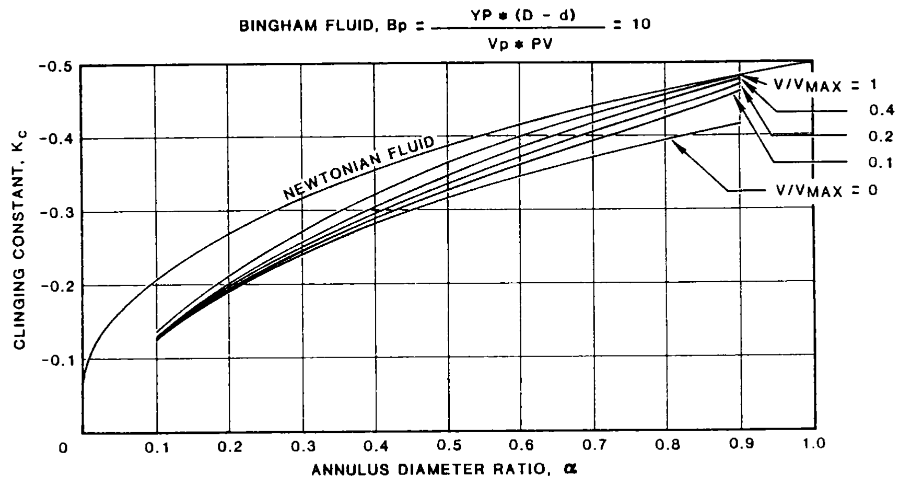


Figure 1-5: Clinging Constants for Bingham Fluid

It is common oilfield practice to assume a clinging constant of -0.45. The two graphs, however, show how much in error this can be. Baker Hughes INTEQ prefers a more exact calculation.

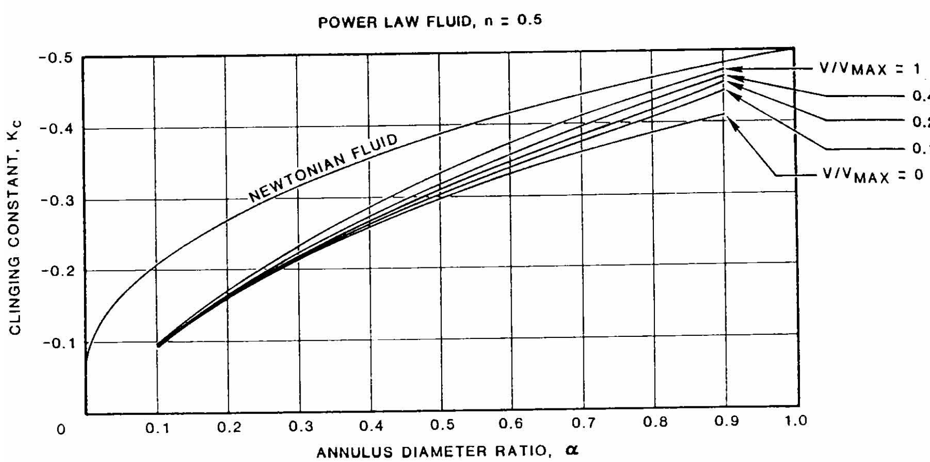


Figure 1-6: Clinging Constants for Power Law Fluid

The possibility of turbulent flow in the annulus must be considered in swab and surge calculations. Assuming that the velocity profile in turbulent flow is flat, the resultant pressure drop can be estimated by summing the pressure drops caused by the velocity at the outer wall and the relative velocity (V_a - v_p) at the inner wall, because V_a and v_p are of opposite signs. With a closed pipe, the turbulent flow clinging constant can be approximated by:

$$K_t \approx \frac{\alpha^2 - \left[\frac{\alpha^4 + \alpha}{1 + \alpha}\right]^{0.5}}{1 - \alpha^2}$$

This function is graphed in Figure 1-7. It is an approximation for closed pipe and it appears to be similar to turbulent flow clinging constants derived by other authors.

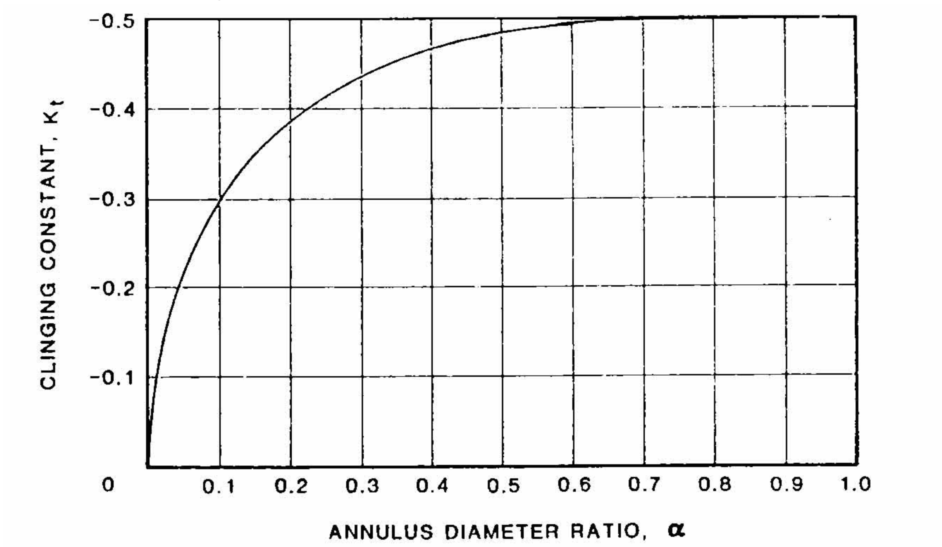


Figure 1-7: Clinging Constants for Turbulent Flow

The point at which transition occurs from laminar to turbulent flow is difficult to determine theoretically, and experimental data is lacking. It is therefore recommended that, for swab and surge pressure calculations, both laminar and turbulent pressure drops be calculated. The flow regime giving the greater pressure drop may then be considered to be correct. This procedure is conservative in that it will give a pressure equal to or exceeding the true swab or surge pressure.

Finally, when calculating swab or surge pressures for Power Law fluids, the calculated pressure loss should be checked against the pressure required to break the gels strength. For each annular section, the gel breaking pressure is:

$$P_g = \frac{4L\tau_g}{(D-d)}$$

where: P_g = Pressure to break gel strength (psi)

L = Section length (feet)

τ_g = Gel strength ($lbs/100ft^2$)

D = Outer diameter (inches)

d = Inner diameter (inches)

If the calculated swab or surge pressure is less than the sum of the gel breaking pressures, the gel breaking pressure should be used. This check is not required if the fluid model incorporates a yield stress.

Swab and Surge Analysis Report

Open Pipe

Input Data

Depth	12000.0 ft.	Mud Density	10.00 lb/gal
Casing Depth	10000.0 ft.	PV	20.000 cP
Leak Off EQMD	15.10 lb/gal	YP	15.00 lb/cft^2
Pore Pressure	9.00 lb/gal	Average Stand	93.0 ft.

Swab and Surge Analysis

Pipe Velocity			Bit at Total Depth			Bit at Casing Shoe		
Stand Time	Average	Maximum	Pressure Drop	Swab EQMD	Surge EQMD	Pressure Drop	Swab EQMD	Surge EQMD
sec/stand	ft/sec	ft/sec	psi	lb/gal	lb/gal	psi	lb/gal	lb/gal
200	0.46	0.70	4	99.9	10.01	3	9.99	10.01
180	0.52	0.77	4	9.99	10.01	5	9.99	10.01
160	0.58	0.87	7	9.99	10.01	4	9.99	10.01
140	0.66	1.00	5	99.9	10.01	4	9.99	10.01
120	0.78	1.16	6	9.99	10.01	5	9.99	10.01
100	0.93	1.39	6	9.99	10.01	5	9.99	10.01
80	1.16	1.74	7	9.99	10.01	6	9.99	10.01
60	1.55	2.33	9	9.99	10.01	8	9.99	10.01
40	2.32	3.49	12	9.98	10.02	10	9.98	10.02
20	4.65	6.97	18	9.97	10.03	15	9.97	10.03
10	9.30	13.95	28	9.95	10.05	24	9.95	10.05
9	10.33	15.50	30	9.95	10.05	26	9.95	10.05
8	11.62	17.44	33	9.95	10.05	28	9.95	10.05
7	13.29	19.93	36	9.994	10.06	31	9.94	10.06
6	15.50	23.25	40	9.94	10.06	34	9.93	10.07
5	18.60	29.90	45	9.93	10.07	38	9.93	10.07
4	23.25	34.87	52	9.92	10.08	44	9.92	10.08
3	31.00	46.50	62	9.90	10.10	53	9.90	10.10
2	46.50	69.75	81	9.87	10.13	69	9.87	10.13
1	93.00	139.50	128	9.80	10.20	109	9.79	10.21

While Bit is in Open Hole
Recommended Maximum Running Speed:0.67 sec/stand
Maximum Surge EQMD: 10.20 lb/gal
Recommended Maximum Pulling Speed:0.67 sec/stand
Maximum Swab EQMD: 9.80 lb/gal

While Bit is in Cased Hole
Recommended Maximum Running Speed:0.67 sec/stand
Maximum Surge EQMD: 10.21 lb/gal
Recommended Maximum Pulling Speed:0.67 sec/stand
Maximum Swab EQMD: 9.79 lb/gal

Mud Hydraulics Analysis Report

Input Data					
Depth	12000.0 ft	Mud Density	12.00 lb/gal	Cuttings Density	2.30 gm/cc
Vertical Depth	12000.0 ft	PV	20.000 cP	Bit Jets	12/12/12 1/32 in
Pump Rate	107 str/min	YP	15.00 lb/cft^2		
Flow Rate	450 gal/min	Power Law k	0.6217	Total Flow Area	0.3313 in^2
Pump Pressure	3300 psi	Power Law n	0.6521		
Average ROP	20.0 ft/hr				

Table of Results - Power Law Fluid Model @ 450 gal/min

Section		**Section Hole**		**Pipe**		**Volumes & Capacities**			**Pressure Loss**		**Mud Velocity**			**Reynolds Number Flow**		
From	To	Length	Diam	OD	ID	Hole	Pipe	Annulus	Pipe	Annulus	Pipe	Annulus	Critical	Annulus	Critical	Reg
ft	ft	ft	in	in	in	bbls	bbls	bbls	psi	psi	ft/sec	ft/sec	ft/sec			
5.0	500.0	495.0	20.000	5.000	4.276	192	9	180	32	0	603.2	29.4	85.0	423	1769	Laminar
500.0	10000.0	9500.0	12.416	5.000	4.276	1423	169	1176	617	25	603.2	85.4	118.1	1124	1741	Laminar
10000.0	11500.0	1500.0	12.250	5.000	4.276	219	27	180	97	4	603.2	88.2	119.4	1157	1740	Laminar
11500.0	12000.0	500.0	12.250	8.000	2.750	73	4	42	230	4	1458.4	128.2	153.4	1352	1723	Laminar

Volume Summary

	bbls	Stroke	Minutes	
Annular Capacity	1578	15948	148	<- Lag Time
Pipe Capacity	208	2103	20	<- Down Time
Circulating Volume	1785	18051	168	<- Circulating Time
Pipe Displacement	122			
Total Hole Volume				

Hydraulics Results Using Power Law Fluid Model

Flow Rate	90	162	234	306	378	450	522	594	666	738	810	gal/ min
Pump Rate	21	39	56	73	90	107	124	141	158	175	193	str/min
Total Flow Area	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	0.3313	in^2
Jet Velocity	87.1	156.9	226.6	296.3	366	435	505.4	575.2	644.9	714.6	784.3	ft/sec
Impact Force	48.8	158.0	329.6	563.6	860	1218.9	1640.1	2123.8	2669.8	3278.3	3949.1	lbf
Hydraulic Power	4.3	25.3	76.3	170.5	321	542.4	846.6	1247.5	1758.3	2392.5	3163.3	Hp
Pipe Loss	85	150	337	521	735	976	1242	1533	1847	2183	2540	psi
Bit Loss	82	264	551	942	1438	2038	2742	3551	4464	5482	6603	psi
Percentage of Total	19.1	46.4	54.8	60.3	63.6	65.8	67.5	68.8	69.8	70.7	71.5	%
Annular Loss	12	18	22	27	31	34	38	42	48	57	65	psi
Cutting Loss	249	138	96	73	59	50	43	38	34	30	28	psi
Total Loss	427	570	1006	1563	2263	3098	4065	5163	6392	7751	9235	psi
Hydrostatic Pressure	7478	7478	7478	7478	7478	7478	7478	7478	7478	7478	7478	psi
Circulating Pressure	7738	7634	7596	7578	7568	7562	7558	7557	7559	7565	7570	psi
ECD @ Vertical Depth	12.02	12.03	12.04	12.04	12.05	12.06	12.06	12.07	12.08	12.09	12.10	lb/gal
ECD with Cuttings	12.42	12.25	12.19	12.16	12.14	12.13	12.13	12.13	12.13	12.14	12.15	lb/gal

Minimum Recommended Flow is 539 gal/min to maintain laminar flow in section with Diameter 12.250 and Pipe OD 8.00 in
Minimum Recommended Flow is 382 gal/min to maintain cuttings transport in section with Diameter 20.000 and Pipe OD 5.000 in

Bit Hydraulics Optimization Report - Input Data

Previous Bit			
Nozzle A diameter	12 1/32 in	Mud Density	12.00 lb/gal
Nozzle B diameter	12 1/32 in	PV	20.000 cP
Nozzle C diameter	12 1/32 in	YP	15.00 lb/cft^2
		Flow Rate	450 gal/min
Total Flow Area	0.3313 in ^2	Pump Pressure	3300 psi

Optimization Limits	**Maximum**		**Minimum**
Flow Rate	800 gal/min		300 gal/min
Pump Pressure	3000 psi		

Calculated From Previous Bit

Jet Velocity	435.7 ft/sec
Parasitic Pressure	1262 psi
Bit Pressure Drop	2038 psi
Parasitic Exponent	1.6271

Calculated Optimum Bit Hydraulics

	Hydraulic Power	Impact Force
Parasitic Pressure	1142 psi	1654 psi
Bit Pressure Drop	1858 psi	1346 psi
Optimum Flow Rate	423 gal/min	531 gal/min
Flow Rate Used	423 gal/min	531 gal/min
Hydraulic Power	465.0 Hp	423.0 Hp
Impact Force	1094.5 lbf	1169.7 lbf
Jet Velocity	416.0 ft/sec	354.1 ft/sec
Total Flow Area	0.3263 in^2	0.4815 in^2
Recommended Bit Nozzles	11/12/12 1/32 in	14/14/15 1/32 in

Self-Check Exercises

1. What are the three basic components of a drilling fluid?

   a____

   b____

   c____

2. What are three major advantages of oil based muds?

   a____

   b____

   c____

3. What material is used to maintain a continuous oil phase in an invert emulsion oil mud?

   ____

4. What criteria is used to express the stability of an oil-based mud's emulsion strength?

   ____

5. The frictional drag that occurs when parallel layers of a flowing fluid slide past each other is known as:

   ____

6. Bingham's Plastic Model defining the relationship of shear stress and shear rate includes an additional feature to differ from the Newtonian Model. What is that feature?

   ____

7. If a gel strength increases slowly over time, what is it's classification?

   ____

8. What methods are used to lower a mud's solid content?

____

____

____

____

9. What type of gel strength is desirable for drilling fluids?

____

10. What two gases can cause changes in the mud's pH?

a_______________________________________

b_______________________________________

11. What is the material balance equation?

____

12. Calculate the amount of Barite needed and the resulting volume increase if you raise 100 bbls of mud from 8.6 ppg to 14.0 ppg. Give this answer in sacks and barrels.

Given:	Gallon of Barite = 35.5 lbs
	Barrel of Barite = 1490 lbs
	sacks/bbl = 14.9

answer____________________________________

13. Calculate slip velocity using the following information.

Given:	Drilling Lithology:	Shale @ 2.4 g/cc
	Particle Size:	1/2” by 1/2”
	Viscosity:	55 cps
	Annular Velocity:	150 ft/min
	Gravity:	32.2 ft/sec^2
	Flow Regime:	Laminar

answer____________________________________

14. Calculate the PV and YP using the following readings from the Fann Meter.

Given: $RPM_{600} = 40$, $RPM_{300} = 30$

answer____

15. From the data in question #14, calculate n and k.

answer____

16. In hard formations, what must be efficient for the drill rate to be proportional to weight-on-bit?

____

17. What two factors must be taken into account when determining surface hydraulic horsepower?

a____

b____

18. What would be the available surface horsepower, with a pump pressure of 3200 psi and a flow rate of 850 gal/min?

____

19. Using 3200 psi, what would be the optimum pressure loss for hydraulic horsepower and jet impact force?

Hhh = ____

Hif = ____

20. What factors of fluid hydraulics are critical to PDC and diamond bits?

PDC Bits: ____

Diamond Bits: ____

21. What are the optimum HSI's for PDC bit hydraulics in the following drilling fluid systems?

    Water-Based Drilling Fluids: ______________________________

    Oil-Based Drilling Fluids: ________________________________

22. What two components comprise a diamond bits TFA?

    a____

    b____

23. What are the two types of diamond bit flow patterns?

    a____

    b____

24. Turbulent flow has greater cuttings cleaning and carrying capacity than laminar flow. Why is it not normally the flow regime of choice?

    ____

    ____

•Notes•

Chapter **2**

Casing And Cementing

Upon completion of this chapter, you should be able to:

- Understand the limitations of various casing strings.
- Calculate the material requirements for a cementing operation.
- Calculate cement slurry volumes, job times, and mud returns.
- Trouble-shoot problems that may occur during cementing operations.

Additional Review/Reading Material

Petroleum Extension Service AV #178, *Primary Cementing*, The University of Texas at Austin

Bourgoyne Jr., Adam, et al, *Applied Drilling Engineering*, SPE Textbook Series, Vol. 2, 1986

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Rabia, Hussain, *Oilwell Drilling Engineering: Principles and Practice*, Graham & Trotman Limited, 1985

Casing

Casing has several important functions during the drilling and completing of a well. It is used to prevent the borehole from caving in during the drilling of the well, to provide a means of controlling fluids encountered while drilling, to prevent contamination of fluids to be produced, and to protect or isolate certain formations during the course of a well. Casing is also one of the most expensive parts of a well, around 20% of the cost of a completed well.

Casing is usually divided into five basic types.

Conductor Casing

Conductor pipe or drive pipe if it is hammer-driven to depth, is the first string of casing to be used. The setting depth can vary from 10 ft to around 300 ft. The normal size range for conductor pipe is from 16 to 36 inches (outside diameter). The conductor pipe must be large enough to allow the other casing strings to be run through it. Purposes of conductor pipe are to:

- raise the level of circulating fluid so that fluid returns are possible
- prevent washouts in the near surface, normally unconsolidated formations

Surface Casing

The amount of surface casing used will depend on the depth of the unconsolidated formations. Surface casing is usually set in the first competent formation. Normal size for surface casing is between 20 inch and 13-3/8 inch (outside diameter). Since temperature, pressure and corrosive fluids tend to increase with depth, different grades of casing will be required to handle the different well conditions. Purposes of surface casing are to:

- protect fresh water formations
- seal off unconsolidated formations and lost circulation zones
- provide a place to install the B.O.P.'s
- protect “build” sections on deviated wells
- provide for a sufficient “leak-off” test to be conducted

Intermediate Casing

Intermediate casing is set after surface casing, normally to seal off a problem formation. The size of intermediate casing, will depend on the size of the surface casing and the grade required to withstand the subsurface conditions. Normal sizes are between 9 5/8 and 13 3/8 inch (outside diameter).

Production Casing

Production casing is usually the last full string of pipe set in a well. These strings are run to isolate producing formations and provide for selective production in multi-zone production areas. The size of production casing will depend on the expected production rate, the higher the barrel per day production rate, the larger the inside diameter of the pipe. Common sizes are between 3 and 7 inch (outside diameter).

Liner

A liner is a string of casing that does not reach the surface. They are usually "hung" (attached to the intermediate casing using an arrangement of packers and slips) from the base of the intermediate casing and reach to the bottom of the hole. The major advantage of a liner is the cost of the string is reduced, as are running and cementing times. During the course of the well, if the liner has to be extended to the surface (making it another string of casing), the string attaching the liner to the surface is known as a "tie-back" string.

Casing Standards

The American Petroleum Institute (API) has developed certain standards and specifications for oil-field related casing and tubing. One of the more common standards is weight per unit length. There are three "weights" used:

- Nominal Weight: Based on the theoretical calculated weight per foot for a 20 ft length of threaded and coupled casing joint.
- Plain End Weight: The weight of the joint of casing without the threads and couplings.
- Threaded and Coupled Weight: The weight of a casing joint with threads on both ends and a coupling at one end.

The Plain End Weight, and the Threaded and Coupled Weight are calculated using API formulas. These can be found in API Bulletin 5C3.

API standards include three length ranges, which are:

- R-1: Joint length must be within the range of 16 to 25 feet, and 95% must have lengths greater than 18 feet
- R-2: Joint length must be within the range of 25 to 34 feet, and 95% must have lengths greater than 28 feet

- R-3: Joint length must be over 34 feet, and 95% must have lengths greater than 36 feet.

The API grade of casing denotes the steel properties of the casing. The grade has a letter, which designates the grade, and a number, which designates the minimum yield strength in thousands of psi. A table of API casing grades and properties are listed below:

Table 2-1:

API Grade	Yield Strength (min), psi	Tensile Strength (min), psi
H-40	40,000	60,000
J-55	55,000	75,000
K-55	55,000	95,000
C-75	75,000	95,000
L-80	80,000	100,000
N-80	80,000	100,000
C-90	90,000	105,000
C-95	95,000	105,000
P-110	110,000	125,000

Casing properties are defined as:

- Yield Strength: The tensile stress required to produce a total elongation of 0.5% per unit length
- Collapse Strength: The maximum external pressure or force required to collapse the casing joint
- Burst Strength: The maximum internal pressure required to cause a casing joint to yield

Casing dimensions are specified by its outside diameter (OD) and nominal wall thickness. Normal wellsite conventions specify casing by its OD and weight per foot. As stated earlier, one should specify which weight one is referring to, though most often it is the nominal weight.

Casing Couplings

Couplings are short pieces of casing used to connect the individual joints. They are normally made of the same grade of steel as the casing. Through their strength can be different than the casing. The API has specifications for four types of couplings.

- Short round threads and couplings (CSG)
- Long round threads and couplings (LCSG)
- Buttress threads and couplings (BCSG)
- Extremeline threads (XCSG)

The CSG and LCSG have the same basic thread design. The threads have a rounded shape, with eight threads per inch. These threads are generally referred to as API 8-round. The only difference between the two is that the LCSG has a longer thread run-out, which offers more strength for the connection. LCSG are very common couplings.

Buttress (BCSG) threads are more square, with five threads per inch. They are also longer couplings, with corresponding longer thread run-out.

The XCSG (Extremeline) couplings are different from the other three connectors in that they are integral connectors, meaning the coupling has both box and pin ends.

Coupling threads are cut on a taper, causing stress to build up as the threads are made up. A loose connection can result in a leaking joint. An over-tight connection will result in galling, which again, will cause leaking. Proper make-up is monitored using torque make-up tables and the number of required turns.

A special thread compound (pipe dope) is used on casing couplings, each type of coupling having its own special compound.

Many companies have their own couplings, in addition to the API standards, which offer additional features not available on the API couplings.

Cementing

Introduction

Oil well cementing is the process of mixing and displacing a slurry down the casing and up the annulus, behind the casing, where is allowed to “set”, thus bonding the casing to the formation. Some additional functions of cementing include:

- Protecting producing formations
- Providing support for the casing
- Protecting the casing from corrosion
- Sealing off troublesome zones
- Protecting the borehole in the event of problems

The main ingredient in most cements is “Portland” cement, a mixture of limestone and clay. This name comes from the solid mixture resembling the rocks quarried on the Isle of Portland, off the coast of England.

All cement is manufactured in essentially the same way. Calcareous and argillaceous materials (containing iron and aluminum oxides) are finely ground and mixed in correct proportions, either in a dry condition (dry processing) or with water (water processing). The mixture is then fed into the upper end of a sloping kiln at a uniform rate. The kiln is heated to temperatures from 2600^o to 3000^{o}F. As the mixture falls to the lower end, the mixture melts and chemical reactions occur between the raw materials. When the mixture cools, it is called “clinker”. The clinker is then ground with a controlled amount of gypsum (1.5 to 3.0% by weight), to form portland cement.

The principle compounds resulting from the burning process are Tricalcium Silicate (C3S), Dicalcium Silicate (C2S), Tricalcium Aluminate(C3A), and Tetracalcium Aluminoferrite(C4AF). Table 2-2 contains more information on the properties of these compounds. These materials are in an anhydrous form. When water is added, they convert to their hydrous form, which is then called a “cement slurry”.

The American Petroleum Institute (API) has established a classification system for the various types of cements, which must meet specified chemical and physical requirements. Table 2-3 lists nine classifications and their applications to depths of 16,000 ft. (4880 m), under various temperature and pressure conditions.

Cement Slurries

Water is added to dry cement to cause hydration and to make a pumpable slurry. To be used correctly, several properties must be known: the yield per unit (cubic feet per sack), the amount of water required (gallons per sack), and its density (pounds per gallon).

Another important parameter is the cements “absolute volume”. This is the actual volume occupied by the material (the bulk volume includes the open spaces between the cement particles). For example, one sack (94 lbs) of cement has a bulk volume of 1 ft^3, but if all the open spaces between the particles were removed, the absolute volume would be 0.478 ft^3.

With dry materials (cement and additives), the absolute volume is used along with the water requirements to determine the slurry. For example, the absolute volume of one sack of cement (0.478 ft^3) plus the water volume (5.18 gal/sk or 0.693 ft^3) yields a slurry volume of 1.171 ft^3 (0.478 + 0.693).

The absolute volume of the cement's components are normally found in tables (see Table 2-4), but may be calculated using:

$$AbsoluteVolume(gal/\mathrm{lb}) = \frac{1}{8.34 lb/\mathrm{gal} \times SG\ of\ component}$$

For components that dissolve in water (sodium chloride, etc.), since they do not occupy as much space as the specific gravities would indicate, the absolute volume is determined from experimental data and placed in reference tables (see Table 2-5).

Slurry density is also determined. Since one sack of cement weighs 94 lbs, and 0.693 ft^3 of water weighs 43.2 lbs, when mixed they yield 137.2 lbs of slurry. The slurry's density is then calculated by dividing slurry weight by slurry volume, 137.2 lbs / 1.171 ft^3 equals 117.1 lbs/ft^3 (15.7 ppg).

Yield is converted to cubic feet per sack by using the constant 7.4805 (62.4 lbs/ft^3 / 8.34 lbs/gal).

Fly ash, a synthetic pozzolan, is another major constituent of cements. A fly ash/cement mixture is designated as the ratio of fly ash to cement (expressed as 50:50 or 60:40, etc.) with the total always equaling 100. The first number is the percentage of fly ash (74 lbs/sack), the second number is cement (94 lbs/sack). A sack of fly ash and a sack of cement have the same absolute volume.

If other additives are included (gel, accelerators, retarders, etc.), the mixture is expressed as a percentage of weight of both cement and fly ash. The slurry is then expressed: 50:50:2% gel

Example problem:

Using the information below, determine the water requirement.

Cement Blend:

35: 65 : 2% GEL Class H at 13.5 ppg

	Bulk Weight lbs/ft^3	**Absolute Volume gal/lb**
Class H	94	0.0382
Fly Ash	74	0.0487
Gel (Bentonite)	60	0.0453
Water	X	0.1199

Material	lb/ft3		gal/lb		gal/ft^3
Class H	61.1	x	0.0382	=	2.33 (65% of 94)
Fly Ash	25.9	x	0.0487	=	1.26 (35% of 74)
Subtotal	87.0				3.59
Gel	1.74	x	0.0453	=	0.08 (2% of 87)
Water	X	x	0.1199	=	0.1199X

$$88.74 + X = 13.5(3.67 + 0.1199X)$$

$$88.74 + X = 49.545 + 1.61865X$$

$$39.195 = 0.61865X$$

$$63.35 = X$$

Water = 63.35 lb/ft^3 x 0.1199 gal/lb = 7.60 gal/sack

Yield = (3.67 gal/ft^3 + 7.60 gal/sk)/7.4805 gal/ft^3 = 1.52 ft^3/sk

Typical Field Calculations

The amount of cement slurry used is determined by calculating the annular volume between the casing and open hole, and expressing this value in cubic feet. To this value, the volume of cement in the casing below the plugs must be added.

The annular volume (in bbls) is easily determined (d_1^2 - d_2^2 x 0.000971 x L) and the conversion from barrels to cubic feet is: bbls x 5.6146 = cubic feet.

From carbide data or borehole caliper, hole enlargements can be estimated. If it isn't known, then a "percent excess" is attached to the volume (anywhere between 25% to 100% of the annular volume). Once the annular volume is determined, then a minimum excess factor is applied (normally 10% to 15%) to the total.

This quantity will be pumped into the annulus between the formations and casing.

Example Field Calculation:

Well Information:

13 3/8" casing (54.50 lb/ft.), 12.615-inch ID, to 1700 feet
12 1/4" open hole to 4950 feet

9 5/8" casing (36 lb/ft.), ID 8.921", to be run to TD
Float Collar 42 feet above shoe
Cement to fill 300 feet into previous casing

Slurry: Class G (25% excess) neat, with 1.3% FL-50 at 14.2 ppg
20 bbl spacer (weighted mud sweep) ahead of cement

High Pressure mixing at 2.5 bbl/min
10 minutes for plug dropping
Displacement Rate: 8 bbl/min

Volume Calculations:

Volume 1: Between 9 5/8" and 13 3/8" casing

$(12.615^2 - 9.625^2) \times 0.000971 \times 300 = 19.37$ bbls
$19.37 \times 5.6146 = 108.8$ ft^3

Volume 2: Between 9 5/8" casing and 12 1/4" open hole w/25% excess

$(12.25^2 - 9.625^2) \times 0.000971 \times 3250 \times 1.25 = 226.51$ bbls
$226.51 \times 5.6146 = 1271.8$ ft^3

Volume 3: Inside 9 5/8" casing

$(8.921^2) \times 0.000971 \times 42 = 3.25$ bbls
$3.78 \times 5.6146 = 18.22$ ft^3

Total Slurry Volume: 108.8 + 1271.8 + 18.22 = 1399 ft^3

Cement and Water Requirements:

Material	lbs/ft^3		gal/lb		gal/ft^3
Class G	94	x	0.0382	=	3.5908
FL-50 (1.3%)	1.23	x	0.0895	=	0.1108
Water	X	x	0.1199	=	0.1199X

$$\begin{aligned} 95.23 + X &= 14.2(3.7016 + 0.1199X) \\ 95.23 + X &= 52.5627 + 1.7026X \\ 42.6673 &= 0.7026X \\ 60.73 &= X \end{aligned}$$

Water = 60.73 lbs/ft^3 x 0.1199 gal/lb = 7.28 gal/sack

Yield = (3.7016 gal/ft^3 + 7.28 gal/sk)/7.4805 gal/ft^3 = 1.47 ft^3/sack

Sacks of Cement: 1399 ft^3/1.47 ft^3/sack = 952 sacks
Mix Water Required: (7.28 gal/sk x 954 sks)/42 gal/bbl = 165 bbls
Total Water: 165 bbls + 20 bbl spacer = 185 bbls
Amount of FL-50: 1.3% of 952 sacks = 12.4 sacks

Weight: 952 sks of Class G(94 lbs/sk) = 89388.0 lbs
12.4 sks of FL-50(35 lbs/sk) = 434.0 lbs
Total Weight = 89922.0 lbs

Displacement Volume: (8.921^2) x 0.000971 x 4908 = 379.3 bbls

Job Time:

Pumping of Pre-flush	= 20 bbls @ 2.5 bbl/min	= 8 min
High Pressure Mixing	= 165 bbls @ 2.5 bbl/min	= 66.0 min
Displacement Time	= 379.3 bbls @ 8 bbl/min	= 47.4 min
Time to Drop Plugs	= 10 minutes	

Total Time = 132 minutes or 2.3 hours

Mud Returns: Steel Volume + Pre-Flush + Slurry Volume

(9.625^2 - 8.921^2) x 0.000971 x 4950	= 63 bbls
Pre-Flush	= 20 bbls
Slurry Volume	= 250 bbls

Mud Returns = 333 bbls

Removal of the Drilling Fluid

For cementing operations to be successful, all annular spaces must be filled with cement, and the cement properly bonded to the previous casing and formation. In order for this to occur, all the drilling fluid must be displaced by the cement slurry. This is not always an easy matter, because there are several factors which affect the removal of the drilling fluid:

- washouts in the open hole, making it difficult to remove drilling fluid and filter cake
- crooked holes, making casing centralization difficult and drilling fluid not being removed from the low side
- poorly treated drilling fluids having high fluid losses

Good drilling practices will not assure a good cement job, but they may help prevent a failure. The ideal drilling fluid for cementing operations should have:

- a low gel strength, with low PV and low YP
- a low density
- a low fluid loss
- a chemical make-up similar to the cement

Since these conditions are very seldom met, fluid washes and spacers are usually pumped ahead of the cement to remove as much drilling fluid as possible.

Cementing Nomenclature

Casing Centralizers

Centralizers assist in the removal of filter cake and displacement of drilling fluid by providing a more uniform flow path for the cement slurry. Close scrutiny of the mudlog and wireline logs will help in the placement of centralizers. Zones of increased permeability, doglegs and areas of key seating, should have centralizers placed around the casing

Wall Scratchers

These are most useful when running casing through a high fluid-loss drilling fluid. There are two types of wall scratchers, rotating scratchers used when the casing can be rotated (normally in vertical wells), and reciprocating scratchers used when the pipe is reciprocated (moved up and down). When these scratchers are placed in 15 to 20 foot intervals, overlapping cleaning occurs.

Wiper Plugs

Both top and bottom plugs are used during cementing operations. They are used to separate the various fluids from one another.

The red bottom plug has a shallow top, is made of rubber, and has a hollow core. It is used ahead of the cement slurry to prevent cement/drilling fluid contamination and to clean the casing wall of filter cake. After the bottom plug comes into contact with the float valve, sufficient pressure (150 to 350 psi) causes the top diaphragm to rupture, allowing the cement slurry to flow through it.

The black top plug has a deep cup on its top and has a solid, molded rubber core. It is dropped after the cement slurry has been pumped, to prevent contamination with the displacement fluid. The top plug also signals the end of displacement by forming a seal on top of the bottom plug, causing a pressure increase.

Chemical Washes

Chemical washes are fluids containing surfactants and mud thinners, designed to thin and disperse the drilling fluid so that it can be removed from the casing and borehole. Washes are available for water-based and oil-based drilling fluids. They are designed to be used in turbulent flow conditions.

Spacers

Spacers are fluids of controlled viscosity, density and gel strength used to form a buffer between the cement and drilling fluid. They also help in the removal of drilling fluid during cementing.

Cement Additives

Accelerators

An accelerator is a chemical additive used to speed up the normal rate of reaction between cement and water which shortens the thickening time of the cement, increase the early strength of cement, and saves time on the drilling rig. Cement slurries used opposite shallow, low-temperature formations require accelerators to shorten the time for "waiting-on-cement". Most operators wait on cement to reach a minimum compressive strength of 500 psi before resuming drilling operations. When using accelerators, this strength can be developed in 4 hours. It is a good practice to use accelerators with basic cements because at temperatures below 100^{o}F, neat cement may require 1 or 2 days to develop a 500 psi compressive strength.

Common accelerators are sodium metasilicate, sodium chloride, sea water, anhydrous calcium chloride, potassium chloride and gypsum.

Retarders

Neat cement slurries set quickly at a BHT greater than 110^{o}F. A retarder is an additive used to increase the thickening time of cements. Besides extending the pumping time of cements, most retarders affect the viscosity to some degree. The governing factors for the use of retarders are temperature and depth.

Common retarders are lignosulfonates, modified cellulose, organic acids, organic materials and borax.

Extenders

Extended cement slurries are used to reduce the hydrostatic pressure on weak formations and to decrease the cost of slurries. Extenders work by allowing the addition of more water to the slurry to lighten the mixture and to keep the solids from separating. These additives change the thickening times, compressive strengths and water loss.

Common extenders are fly ash, bentonite, and diatomaceous earth.

Pozzolans

Pozzolans are natural or artificial siliceous materials added to portland cement to reduce slurry density and viscosity. The material may be either a volcanic ash or a clay high in silica. The silica in the pozzolans combines with the free lime in dry cement, which means a soluble constituent is removed from the cement and the new cement is made more resistive.

Common pozzolans are diatomaceous earth and fly ash.

Table 2-2:

PRINCIPLE COMPOUNDS IN PORTLAND CEMENT
Tricalcium Silicate - $3CaO{:}SiO_2$ - C_3S 1. The major compound in Portland cement 2. Contributes to strength development, especially during the first 28 days 3. Hydration equation: $2(3CaO{:}SiO_2) + 6H_2O \text{--->} 3CaO{:}2SiO_2{:}3H_2O + 3Ca(OH)_2$
Dicalcium Silicate - $2CaO{:}SiO_2$ - C_2S 1. A much slower hydrating compound than tricalcium silicate 2. Contributes to a slower, gradual increase in strength, over an extended period of time 3. Hydration equation: $2(2CaO{:}SiO_2) + 4H_2O \text{--->} 3CaO{:}2SiO_2{:}3H_2O + Ca(OH)_2$
Tricalcium Aluminate - $3CaO{:}Al_2O_3$ - C_3A 1. Promotes rapid hydration of cement 2. Controls the setting time of cement 3. Regulates the cements resistance to sulfate attack (HSR - High Sulfate Resistance) 4. Gypsum usually added to control hydration and flash setting 5. Produces most of the heat observed over first few days 6. Hydration equation: $3CaO{:}Al_2O_3 + 12H_2O + Ca(OH)_2 \text{--->} 3CaO{:}Al_2O_3{:}Ca(OH)_2{:}12H_2O$ $3CaO{:}Al_2O_3 + 10H_2O + CaSO_4{:}2H_2O \text{--->} 3CaO{:}Al_2O_3{:}CaSO_4{:}12H_2O$
Tetracalcium Aluminoferrite - $4CaO{:}Al_2O_3{:}Fe_2O_3$ - C_4AF 1. Promotes low heat of hydration in cement 2. Hydration equation: $4CaO{:}Al_2O_3{:}Fe_2O_3 + 10H_2O + 2Ca(OH)_2 \text{--->} 6CaO{:}Al_2O_3{:}Fe_2O_3{:}12H_2O$

Table 2-3:

API Class	Application
A Neat	- Used at depth ranges of 0 to 6000 ft. - Used at temperatures up to 170°F - Used when special properties are not required - Used when well conditions permit - Economical when compared to premium cements * Normal Slurry Weight is 15.6 ppg * Normal Mixing Water Requirement - 46% (5.19 gal/sk & 0.693 ft^3/sk) * Normal Slurry Yield - 1.17 ft^3/sk
B Neat	- Used at depth ranges of 0 to 6000 ft. - Used at temperatures up to 170°F - Used when moderate to high sulfate resistance is required - Used when well conditions permit - Economical when compared to premium cements * Normal Slurry Weight is 15.6 ppg * Normal Mixing Water Requirement - 46% (5.19 gal/sk & 0.693 ft^3/sk) * Normal Slurry Yield - 1.17 ft^3/sk
C Neat	- Used at depth ranges of 0 to 6000 ft. - Used at temperatures up to 170°F - Used when high early-strength is required - Used when its special properties are required - High in tricalcium silicate * Normal Slurry Weight is 14.8 ppg * Normal Mixing Water Requirement - 56% (6.31 gal/sk & 0.844 ft^3/sk) * Normal Slurry Yield - 1.32 ft^3/sk
D,E Neat	- Class D used at depths from 6000 to 10000 ft. and at temperatures from 170 - 260°F - Class E used at depth from 10000 to 14000 ft. and at temperatures from 170 - 290°F - Both used at moderately high temperatures and high pressures - Both available in types that exhibit regular and high resistance to sulfate - Both are retarded with an organic compound, chemical composition and grind - Both are more expensive than Portland cement * Normal Slurry Weight - 16.5 ppg * Normal Mixing Water Requirement - 38% (4.28 gal/sk & 0.572 ft^3/sk) * Normal Slurry Yield - 4.29 ft^3/sk

Table 2-3: continued

API Class	Application
F Neat	- Used at depth ranges of 10000 to 16000 ft. - Used at temperatures from 230 - 320^oF - Used when extremely high temperatures and pressures are encountered - Available in types that exhibit moderate and high resistance to sulfate - Retarded with an organic additive, chemical composition and grind * Normal Slurry Weight - 16.5 ppg * Normal Mixing Water Requirement - 38% (4.28 gal/sk & 0.572 ft^3/sk) * Normal Slurry Yield - 1.05 ft^3/sk
G,H Neat	- Used at depth ranges from 0 to 8000 ft. - Used at temperatures up to 200^oF without modifiers - A basic cement compatible with accelerators or retarders - Usable over the complete ranges of A to E with additives - Additives can be blended at bulk station or at well site - Class H is a coarser grind than Class G * Class G slurry weight is 15.8 ppg * Class G mixing water requirement - 44% (4.96 gal/sk & 0.663 ft^3/sk) * Class G slurry yield - 1.14 ft^3/sk * Class H slurry weight is 15.6 (shallow) to 16.4 (deep) ppg * Class H API water requirement - 46% (5.2 gal/sk & 0.69 ft^3/sk) to 38% (4.3 gal/sk & 0.57 ft^3/sk) * Class H slurry yield - 1.17 ft^3/sk (shallow) to 1.05 ft^3/sk (deep)
J	- Used at depth ranges from 12000 to 16000 ft. - Used for conditions of extreme temperature and pressure: 170 - 320^oF (unmodified) - Usable with accelerators and retarders - Will not set at temperatures less than 150^oF when used as a neat slurry * Water requirements set by manufacturer

Table 2-4: Physical Properties of Cement Additives

Material	Bulk Weight. lbs/ft^3	Specific Gravity g/cc	Absolute Volume gal/lb	ft^3/lb
Sodium Chloride	71.0	2.17	0.0553	0.0074
Calcium Chloride	56.0	1.96	0.0612	0.0082
Potassium Chloride	64.9	1.984	0.0604	0.0081
Gypsum	75	2.7	0.0444	0.0059
Cement	94	3.14	0.0382	0.0051
Attapulgite	40	2.89	0.0415	0.0053
Barite	135	4.23	0.0284	0.0038
Hematite	193	5.02	0.0239	0.0032
Diatomaceous Earth	16.7	2.1	0.0572	0.0076
Pozzolan	40	2.43	0.0493	0.0066
Diesel Oil (1)	51.1	0.82	0.1457	0.0195
Diesel Oil (2)	53.0	0.85	0.1411	0.0189
Fly Ash	74	2.46	0.0487	0.0065
Bentonite	60	2.65	0.0453	0.0060
Gilsonite	50	1.07	0.1122	0.0150
Nut Plug	48	1.28	0.0938	0.0125
Silica Flour	70	2.63	0.0456	0.0061
Sand	100	2.63	0.0456	0.0061
Water (fresh)	62.4	1.00	0.1200	0.0160
Water (Sea)	63.96	1.025	0.1169	0.0153
Lignosulphonate	35.1	1.36	0.0882	0.0118
Polymer (FL-50)	35	1.34	0.0895	0.0119

Table 2-5: Absolute Volume of NaCl (Dissolved)

%NaCl	gal/lb
2	0.0371
5	0.0381
8	0.0390
10	0.0394
12	0.0399
15	0.0405
17	0.04095
20	0.0412
23	0.0422
25	0.0426
28	0.0430
30	0.0433
33	0.04375
35	0.0440
37	0.0442

Table 2-6: General Problems Encountered During A Cementing Operation

PROBLEM	PROBABLE CAUSE	CORRECTION
Cannot receive fluid from the rig	a. Valve closed or broken b. Hooked to wrong line c. Supply tank empty d. Obstruction in line	a. Check out valves b. Trace out supply lines and tank c. Check tank d. Back-flush lines
Cannot pump out of displacement tank	a. Valve closed or broken b. Obstruction in suction c. No air pressure on the unit d. Air lock in pumps	a. Check out valves b. Flush suction line c. Check air system d. Prime pumps
Leaks or break in discharge line	a. Seal lost from union b. Damaged union face c. Improperly made up d. Washed-out pipe	a. Take apart, inspect and repair or replace b. Take apart, inspect and repair or replace c. Take apart, inspect and repair or replace d. Take apart, inspect and replace
Cannot pump through cement mixer	a. Mixing pump disengaged b. Valve closed or broken c. Obstruction in suction d. Screen or jet plugged e. Obstruction in mixer tube	a. Check pump for rotation b. Check out valves c. Back-flush d. Check out screen, jet and tube e. Check out screen, jet and tube
Cannot obtain proper slurry or control the density	a. Starving mixing pump b. Obstruction in jet, bypass or mixer tube c. Air leak in mixer bowl	a. Check out pump, jet, bypass, bowl or hopper b. Check out pump, jet, bypass, tube, bowl or hopper c. Check out pump, jet, bypass, tube, bowl or hopper

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
No cement returns to surface	a. Washed-out hole b. Loss to formation c. Wrong volume d. Not completely displaced from pipe	a. Use excess slurry b. Use lost-circulation material c. Recalculate job d. Recalculate job
Sudden pressure drop while displacing	a. Pumps lost prime b. Split pipe c. Lost circulation d. Packer failure e. Communication between perforations	a. Check fluid source and re-prime pumps b. Recalculate volume, locate hole in pipe and squeeze c. Check well returns d. Check annulus pressure. Reverse out and reset packer e. Check annulus pressure. Reverse out and reset packer
	a. Differential pressure too great b. Hole caved in.	a. Slow pump rate. Use low density slurry. Displace with a heavy fluid. Open bleeder valve and allow pipe to settle back in place. Chain down pipe b. Slow pump rate. Use low density slurry. Displace with a heavy fluid. Open bleeder valve and allow pipe to settle back in place. Chain down pipe

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Find no cement in the shoe joint	a. Mud cake scraped off pipe wall by top plug b. Fluid siphoned from pump unit ahead of top plug. c. Last of cement too thin	a. Run bottom plug Run pre-flush b. Close discharge valve after mixing c. Keep thin slurry out of the pipe
Top plug does not bump	a. Shoe joint off or casing weight quoted wrong. b. Plug still in head c. Plug failed to seal d. Mud compression	a. Recheck calculations and weight of casing. Check with measuring line b. Check cement head. Check with measuring line c. Stop pumping; check with measuring line d. Allow for compression in mud. Check with measuring line
Top plug bumps but pressure fails	a. Surface leak b. Shoe joint off c. Baffle broken d. Plug failed to seal e. Surface leak	a. Check for surface leaks b. Stop pumping; check float c. Stop pumping check float d. Stop pumping; check float e. Check leak
Cement plug in place; pipe on a vacuum	a. Underdisplaced b. Formation broke down c. Oversized hole	a. Recheck calculations b. Recheck calculations; allow to equalize c. Recheck calculations; allow to equalize
Cement plug in place; pressure on pipe	a. Overdisplaced b. Undersized hole c. Well fluid out of balance d. Pre-flush and after-flush not in balance e. Slurry lighter than well fluid	a. Recheck calculations b. Allow to equalize c. Circulate fluid to condition before cementing d. Pull it wet e. Overdisplaced

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Cement plug in place; cannot pull pipe	a. Cement set b. BOP closed c. Key-seat in bore hole d. Hole caved in	a. Check cement additives for proper percentages b. Check BOP c. Rotate pipe d. Circulate or reverse-circulate cement out
Cannot locate cement plug or plug too low	a. Cement not set b. Hole washed out c. Lost to formation d. Moved downhole	a. Use mud decontaminate b. Use excess slurry c. Use low density slurry d. Use wall scratchers
Location of cement plug too high	a. Overdisplaced b. Hole undersized c. Well heaved d. Swabbed up the hole while pulling pipe e. Bottom joints of tubing off. f. Not enough pipe run in	a. Recheck calculations b. Pull pipe slowly; condition mud density c. Pull pipe slowly; condition mud density d. Pull pipe slowly; condition mud density e. Pull pipe slowly; condition mud density f. Pull pipe slowly; condition mud density
Plugging for lost circulation	a. Weak zone, fractures or caverns	a. Select cementing materials for gel strength. Use granular or flake materials to bridge. Low density. Keep fluid head low while cement sets

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Squeeze cementing or treating below packer; sudden flow or pressure rise in annulus	a. Circulating sub open b. Packer unseated c. Communication outside casing through upper perforations d. Drill pipe leak e. Squeeze manifold leak to annulus	a. Check downhole tool. Check lines and valve to annulus b. Check downhole tool. Check lines and valve to annulus c. Check lines and valve to annulus Set packer above upper perforations d. Pull drill pipe e. Isolate and pressure test manifold
Squeeze cementing or treating below packer. Sudden pressure loss in the annulus	a. Casing split above or perforations above packer b. BOP leaking	a. Keep inside pressure to safe limits. Reverse out or pull pipe b. Check BOP
Displacing cement to packer setting depth, lost count on displacing fluid	a. Not reading stroke counting properly b. Taking on mud while pumping out of same tank	a. Reverse out Reverse slurry back to top of tubing; then measure displacement back down b. Reverse out. Reverse slurry back to top of tubing; then measure displacement back down
Squeeze cement in place; packer stuck	a. Cement above packer b. Tail pipe below packer in set cement c. Casing collapsed above packer d. BOP closed e. Pressured differential across packer too high	a. Reverse-circulate b. Reverse-circulate c. Not enough pressure was held on back side; go fishing d. Check BOP e. Relieve pressure differential

Table 2-6: continued

PROBLEM	PROBABLE CAUSE	CORRECTION
Zone to be squeezed accepts well fluid but not cement slurry	a. Tight formation b. Pressure limitation too low c. Water-sensitive zone	a. Spot acid or other break-down fluid b. Spot acid or other break-down fluid c. Use salt slurry
Mixing cement, bulk delivery fails and cannot be fixed in time to finish	a. Any reason	a. Calculate volume of slurry mixed If sufficient for proper job, continue. If not, circulate out and start over
Slurry mixed; then pumping unit becomes inoperable	a. Any reason	a. Displace with the rig pump
Operator complains of trouble drilling up top rubber plug in large- diameter casing	a. Plug turns with bit	a. Place a few sacks of cement on top of the plug

Casing and Cementing Analysis Report

Depth 14500.0 ft.
Casing Shoe Depth 14036.8 ft.

Volumes and Capacities

From	Section To	Length	Hole Diam	Casing Section	Average Joint	Casing OD	Casing ID	Steel Total	Displ. Joint	Casing Total	Capacity Joint	Annulus Volume	Annulus Volume
ft	ft	ft	in		ft	in	in	bbls	bbls	bbls	bbls	bbls	bbl/ft
5.0	500.0	495.0	20.000	3	94.7	5.000	4.000	4	0.828	8	1.472	180	1.195
500.0	762.8	262.8	12.416	3	94.7	5.000	4.000	2	0.828	4	1.472	33	0.412
762.8	8707.9	7945.2	12.416	2	38.9	9.625	8.835	113	0.552	602	2.953	475	0.196
8707.9	10000.0	1292.1	12.416	1	39.2	9.625	8.921	16	0.497	100	3.029	77	0.196
10000.0	14036.8	40360.8	12.250	1	39.2	9.625	8.921	51	0.497	312	3.029	225	0.183
14036.8	14500.0	463.2	12.250	<									

Summary

Total Steel Displacement	187 bbls
Total Casing Capacity	1026 bbls
Total Casing Displacement	1213 bbls
Total Annular Volume	990 bbls
Total Hole Volume	2271 bbls

Weights and Hookload

								Casing Hook Load		
Casing Section	Length	Number of Joints	Average Joint	Casing OD	ID	Casing Weight Steel Per Joint		In Air	In Mud Empty	Full
	ft	ft	ft	in	in	lb/ft	klb	klb	klb	klb
1	5328.8	136	39.2	9.625	8.921	36.00	0.14	19.56	1.08	16.96
2	7945.2	204	38.9	9.625	8.835	36.00	0.14	29.17	1.61	24.83
3	757.8	8	95.3	5.000	4.000	76.80	0.75	5.97	5.26	5.72
	-----.-	-----						---.---	--.---	---.--
	14031.8	348						54.70	7.95	47.50

Hookload Summary

Block and Hook Weight	99.00 klb
Empty Casing in Air	153.70 klb
Empty Casing in Mud	106.95 klb
Full Casing in Mud	146.50 klb

Cementing Analysis Cement Pump Capacity 0.119 bbl/stk

Cementing Operation	Circulating Depth	Cement Top	Position Base	Length Cement	Mud Density	Cement Density	Volume Cement		Mud Volume to Position Cement		Cement Back Pressure
	ft	ft	ft	ft	lb/gal	lb/gal	bbl	str	bbls	str	psi
1	14030.0	11000.0	14030.0	3030.0	9.00	12.00	169	85219	1026	517153	472
2	8900.0	7000.0	8000.0	1000.0	9.00	11.50	60	30130	606	305372	130
3	5000.0	3000.0	4500.0	1500.0	9.00	11.00	90	45196	363	183002	156

Self-Check Exercises

1. What do the "threaded and coupled weight" standards refer to?

    ____

    ____

    ____

2. Three common API grades of casing and their associated tensile strengths are:

    a.____

    b____

    c.____

3. After the initial calcareous and argillaceous cement materials are mixed and baked in a kiln at 2800^{o} F, the resulting mixture is known as:

    ____

4. What formula is used to calculate the absolute volume of cementing materials?

    ____

5. An example of a slurry mixture is 60:40:2. What do these three numbers refer to?

    60:____

    40:____

    2:____

6. What are the ideal properties of a drilling fluid that should be used during cementing operations?

    ____

    ____

    ____

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____

7. Most operators wait on cement to reach a minimum compressive strength of ____________ before resuming drilling operations.

8. Why are Pozzolans added to Portland cement?

____

____

9. Given the following information, calculate the slurry volume with an excess factor of 1.75.

Diameters and Lengths	Material	Specific Gravities
Casing OD = 13 3/8”	Class A Cement	3.14
Casing ID = 12.415"	Bentonite	2.65
Casing Shoe = 40’	$CaCl_2$	1.0329
Hole Size = 17"	Seawater	1.0279

Objective: Place a 500 foot column of high-strength slurry at the bottom of the casing. Place a low-density slurry in the upper 2000 feet of annulus.

Tail Slurry: Class A cement 2% $CaCl_2$ flake (by weight of cement) and a water/cement ratio of 5.2 gal/sk.

Lead Slurry: Class H cement mixed with 16% Bentonite and 5% NaCl (by weight of cement) and a water/cement ratio of 13 gal/sk.

answer____

10. What is a casing coupling?

____

____

____

•Notes•

Chapter **3**

Bit Technology

Upon completion of this chapter, you should be able to:

- Describe the components of roller cone and fixed cutter bits and understand why these variations are advantageous in certain situations.
- Determine the appropriate type of bit for a future bit run, given the previous bit performances.
- Describe the various types of fixed cuter bits.
- Explain why running procedures are different for fixed cutter bits.

Additional Review/Reading Material

Rabia, Hussain, *Oilwell Drilling Engineering: Principles and Practice*, Graham & Trotman, 1985

SPE, *Applied Drilling Engineering*, SPE Textbook Series, Vol 2, 1986

Moore, Preston, *Drilling Practices Manual, 2nd Edition*, Pennwell Publishing Company, 1986

Hughes Tool Co.; Video Tape, *Tri-Cone Bit Design*

Hughes Tool Co.; Video Tape, *Bit Action On Bottom*

Hughes Tool Co.; Video Tape, *Dull Bit Grading*

Hughes Tool Co.; Video Tape, *Introduction To PDC Bits*

Bit Technology

The *Advanced Logging Procedures* workbook contains information on drill bits, IADC classifications and bit grading, and should be reviewed before beginning this chapter.

Rolling Cutter Rock Bits

The first successful rolling cutter rock bit was introduced into the oil field by Howard Hughes Sr. in 1909. Over the next fifteen years, the rolling cutter bit was used primarily in hard formation areas. This rolling cutter bit was a two-cone bit with cones that did not mesh, consequently, the bit had a tendency to "balled-up" in soft shales. The bit was redesigned with meshing teeth (self-cleaning) in the 1920s and in the early 1930's, the tri-cone bit was introduced with cutters designed for hard and soft formations.

The primary drilling mechanism of the rolling cutter bits is intrusion, which means that the teeth are forced into the rock by the weight-on-bit, and pulled through the rock by the rotary action. For this reason, the cones and teeth of rolling cuttings rock bits are made from specially, case hardened steel.

One advantage of a rolling cutter bits is the three bearing design located around the journal of the bit. Heel bearings are roller bearings, which carry most of the load and receive most of the wear. Middle bearings are ball bearings, which hold the cone on the journal and resist thrust in either direction. The nose bearing consists of a special case hardened bushing pressed into the nose of the cone and a male piece, hard faced with a special material, to resist seizure and wear.

Although rock bits have been continually improved upon over the years, three developments remains outstanding: (1) the change in water course design and the development of the "jet" bit, (2) the introduction of the tungsten carbide insert cutting structure, and (3) the development of sealed journal bearings.

Journal Angle

One of the basic design fundamentals of rolling cutter rock bits is the journal angle. Though this angle may vary from one rock bit type to the next, in each bit the three journal angles are all identical.

The journal angle (Figure 3-1) is the angle at which the journal is mounted, relative to a horizontal plane. This mounting moves the cutting elements (cones) outside the support members. The journal angle also controls the cutter profile or pattern it drills, and it affects the amount of cutter action on the bottom of the hole.

Journal angles are different for each "type" of formation:

Soft Formations

Journal angle (33°) - this allows a cutter profile which accentuates cutter action and permits greater tooth depth.

Medium Formations

Journal angle (34° to 36°), to decrease cutter action.

Hard Formations

Uses a large journal angle (39°), to minimize cutter action.

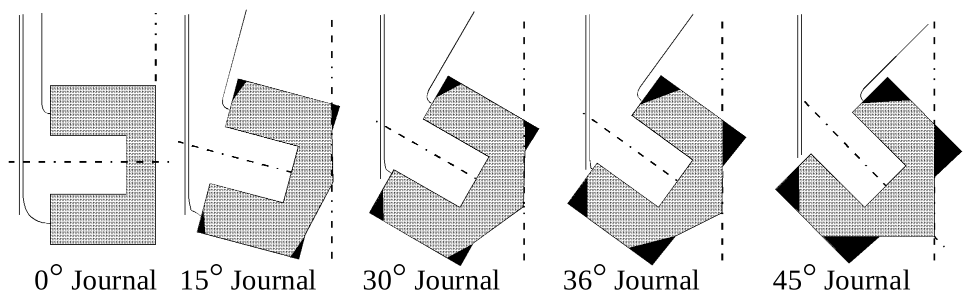


Figure 3-1: Journal Angles in Roller Cone Bits

Interfitting Teeth and Cone Offset

The idea of interfitting teeth (Figure 3-2a), makes it possible to have large bit parts, and allows the inner row of teeth to cut new formation on each rotation. Interfitting also offers some degree of self-cleaning. One result of this interfitting is that each of the three cones are different.

Cone offset (Figure 3-2b), is caused by the journal centerline not intersecting the bit centerline (or bit center of rotation). The distance that the journal centerline misses the bit centerline (measured perpendicular to the journal centerline at the center of rotation) is the offset.

The skew point is an arbitrary point along the journal centerline and is the angle formed by the offset, the centerline of the journal, and a line from the bit center to the skew point.

The skew direction is always "positive", or in the direction of rotation. This permits the tips of the teeth to "ream" the hole to full gauge. "Negative" skew would have the gauge face rubbing the hole wall, increasing gauge wear.

As with the journal angle, the offset will be different in each type of formation. In soft formation bits, the maximum offset (3° skew angle) is used to increase the gouging, scraping action. Medium formation bits add a limited offset (2° skew angle) to develop cutter action. While hard formation bits have no offset, to minimize gouging and scraping.

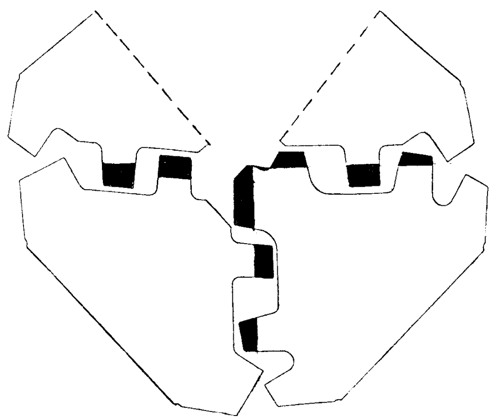


Figure 3-2a:Interfitting Teeth

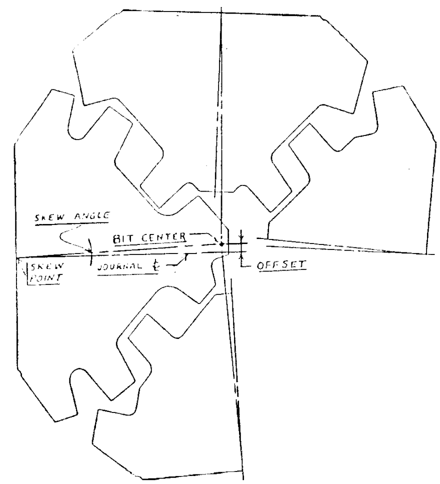


Figure 3-2b:Cutter Offset Skew Angle

Circulation Systems

The first hydraulic features incorporated into drilling tools dated back to the original use of hollow drillpipe with direct circulation of drilling fluids. As the first fishtail bits became popular, around the turn of the century, circulation though water courses was used for the first time. The first rolling cutter rock bits of 1909 introduced a central water course system which directed fluid discharge towards the cutters.

In 1942, rock bits with jet nozzles were introduced to the oil industry. The “jet bit” concept is considered to be the major hydraulic design improvement in drill bits and remains state-of-the-art.

Further improvements in the circulation systems include extended nozzle bits, seven to twelve nozzles in PDC bits, and the various water courses in diamond bits.

Regular Circulation Bits

Regular circulation bits (Figure 3-3a), have one to three holes drilled in the dome of the bit. Drilling fluid passes through the bore of the bit, through the drilled holes, over the cutters, and then to the bottom of the hole, to flush away the drill cuttings.

Jet Circulation Bits

Jet circulation bits (Figure 3-3b), are manufactured with smooth, streamlined, fluid passageways in the dome of the bit. Drilling fluid passes through the bore of the bit at high velocities with minimum pressure losses, through the jet nozzles, and then to the hole bottom to flush cuttings away from the bit and up the hole. Excess fluid that impinges on the hole bottom flows up and around the cutters for cutter cleaning.

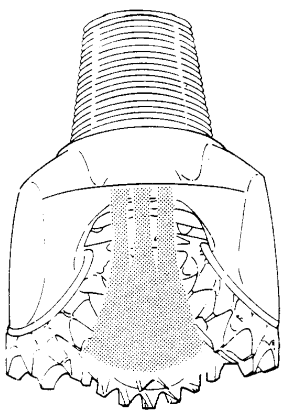


Figure 3-3a: Regular Circulation

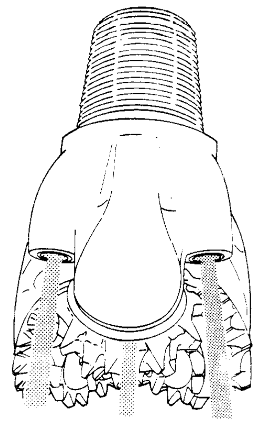


Figure 3-3b: Jet Nozzle Circulation

Air or Gas Circulation Bits

A third type of circulation medium is compressed air or gas, and can be used with either regular or jet circulation bits. Bits manufactured for air or gas circulation have special passageways from the bore of the bit to the bearings, through which a portion of the air or gas is diverted to keep the bearings cool and purged of dust or cuttings. From the special passageways to the bearings, the air or gas passes through a number of strategically located ports or holes in the bearing journal, flows through the bearing structure and exhausts at the shirttail and gauge of the bit, to flow up the annulus.

Jet Nozzles

There are essentially three types of jet nozzles used in tri-cone bits. Shrouded nozzle jets provide maximum protection against retainer ring erosion, excessive turbulence or extended drilling periods. Standard jet nozzles are easier to install and are recommended for situations where erosion is not a problem. Air jet nozzles (see above) are used on bits designated for drilling with air or gas.

Nozzle sizes play an important role in bit hydraulics. The benefits of the correct selection include effective hole cleaning and cuttings removal, faster drill rates and thus lower drilling costs.

Orifice sizes are stated in 1/32 inch increments, with the most common being between 10/32 to 14/32 sizes. Directional bit jets are available in sizes from 18/32 to 28/32.

Cutting Structures

In 1909, when roller cone bits were introduced into the oilfield, the drag bit was replaced by the roller cone's steel tooth cutting structure. These steel (milled) teeth have undergone changes in height, number per cone, and thickness, to accommodate the various types of formations.

When harder formations tended to "eat up" the steel teeth, a different cutting structure was needed, and in 1949 the first insert bit was used. Introduced by Hughes Tool Company and nicknamed the "The Chert Bit", it brought on-bottom drilling hours up from 5 hours to 30 hours or more. Many of the design features in the milled tooth bits were incorporated into insert bits.

Steel Tooth Cutting Structures

There are three basic design features incorporated in steel tooth cutting structures, teeth spacing, tooth hardfacing, and tooth angle (Figure 3-4). Using variations of these parameters, bits are separated into formation types.

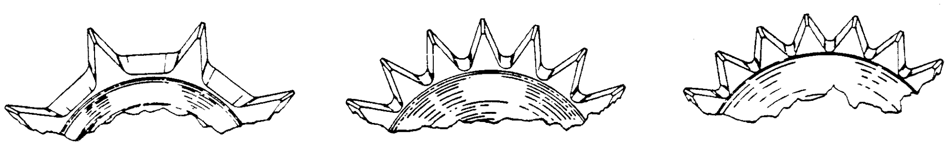


Figure 3-4: Tooth Spacing on Milled-Tooth Bits

Soft Formation Cutting Structures

Teeth on this type of bit are few in number, widely spaced, and placed in a few broad rows. They tend to be slender, with small tooth angles (39° to 42°). They are dressed with hard metal.

Medium Formation Cutting Structures

Teeth on medium formation bits are fairly numerous, with moderate spacing and depth. The teeth are strong, and are a compromise between hard and soft bits, with tooth angles of 43° to 46°. The inner rows as well as the gauge rows are hardfaced.

Hard Formation Cutting Structures

There are many teeth on this type of bit. They are closely spaced and are short and blunt. There are many narrow rows with tooth angles of 46^o to 50^o. The inner rows have no hardfacing, while the gauge row is hardfaced.

Tungsten Carbide Cutting Structures

Since most of the basic design features of the mill tooth cuttings structures have been incorporated into insert bits, the main variations occur in insert shape (Figure 3-5).

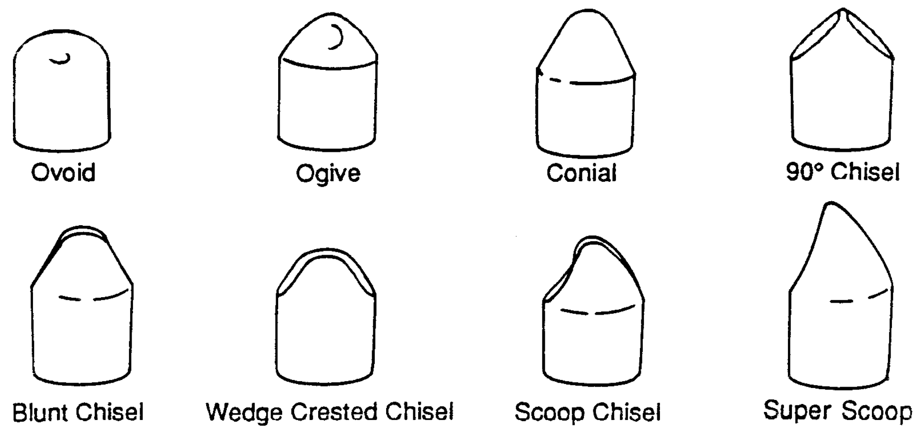


Figure 3-5: Tungsten Carbide Tooth Shapes

Historical shapes of milled teeth have built up a mystique about insert tooth shape. Many people in the oil field thought that chisel shaped teeth significantly affected the drill rate in all formations. This was because early drilling practices used light bit weights, causing the relatively sharp chisel shaped inserts to have a higher unit loading on the formation, hence faster drill rates. When heavier bit weights are used, it tends to nullify the advantage of the chisel shape. Even the steel milled teeth break down under heavy weights. In fact, most bits drill 75% of the hole in a 1/2 to 3/4 dull condition. With this in mind, many "blunt" insert tooth designs were made, and seem to drill efficiently. Nowadays, most insert teeth have this blunt, conical shape.

Gauge Protection

Protection of the gauge surface is vital to the effectiveness of any bit. The gauge surfaces constantly ream the hole, and thus are subject to continuous abrasive wear.

Applying tungsten carbide in a steel matrix through a welding process, called "hardfacing", provides the best resistance to this type of wear. Gauge protection is improved as the amount of hardfaced surface area increases.

The configuration of the gauge teeth determines the available surface area. The “A” type teeth are standard for soft formation bits, resulting in minimum gauge protection for drilling medium-hard formations. The “T” type teeth provides the greatest amount of surface area for the application of hard metal, and are used for abrasive formation bit types.

For work in very hard formations, a flat-top tungsten carbide insert is pressed into the gauge surface for additional protection.

Gauge protection is specified in roller cone bits by adding a “G” to the IADC code.

Bearing Systems

The first type of bearing system used with roller cone bits was a non-sealed, roller-ball-friction bearing arrangement, utilizing rollers on the heel of the journal. The primary load, or stress was exerted on these rollers, and drilling fluid was used to lubricate the bearings. Bearing size was maximized, since room for a seal was not required. The bearing surfaces were machined and ground to very close tolerances to ensure dependable service. This type of bearing system is also available with modifications for air circulation and for use with a percussion hammer (Figure 3-6a).

The next generation of bearing systems was a sealed roller bearing system, having a sealed grease reservoir to lubricate the bearings. The bearing system is composed of: 1) a roller-ball-friction or roller-ball-roller bearings 2) the seal, which retains the lubricant and prevents drilling fluid and abrasive cuttings from entering the bearing cavities, 3) the shirttail is designed and hardfaced to protect the seal, 4) a lubricant, an elasto-hydrodynamic type, is used to ensure minimum friction and wear, 5) the reservoir, which stores and supplies the lubricant to the bearings, and 6) the vented breather plug, which transfers downhole fluid pressure against the lubricant-filled flexible diaphragm to equalize pressures surrounding the bearing seal (Figure 3-6b).

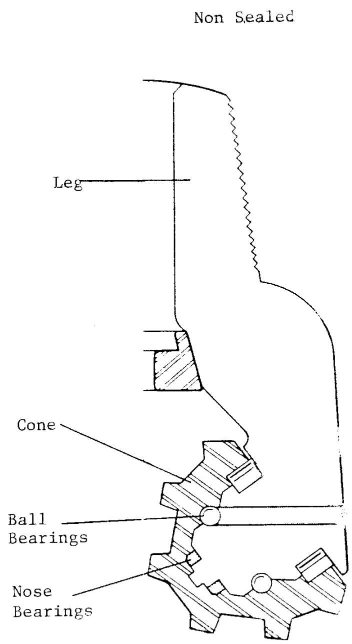


Figure 3-6a

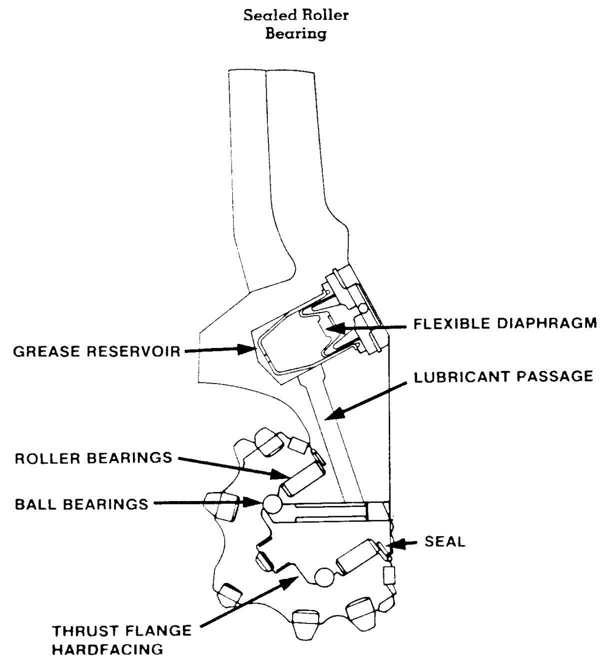


Figure 3-6b

There is, however, one serious drawback to the roller-ball-roller bearing system. The primary cause of roller bearing failure is journal spalling, which causes destruction of the rollers and the locking of the cone.

To remedy this, instead of the standard roller bearing assembly, the “journal bearing” system utilizes solid metal bushings for direct cone to journal contact. This offers a distinct mechanical advantage over roller arrangements in that it presents a larger contact area at the load bearing point. This distribution of the load eliminated the chief cause of roller bearing assembly failure - spalling in the load portion of the bearing face.

Journal bearing systems in the tungsten carbide insert bits features a metal bearing surface combined with a hardfaced journal and a lubricant. Specialized seals and reliable pressure equalization systems keeps the drilling fluid and formation contaminants out of bearings, and positively seals the graphite-based lubricant inside the bearing. Precision fit of the journal and cone distributes contact loading evenly throughout a near-perfect arc. Bearing surfaces are finished to a carefully controlled surface texture to ensure optimum lubrication.

The manufacturing of the journal bearing system consists of having the journals either milled, grooved or pressed (depending on the bit company) to accommodate the bushing. Then the bushings are inlaid on the journal. Once the cone is fitted with teeth and gauge protection, the journal is then machine-pressed into the cone. To complete the seal between the cone and the journal, special rings (seals) have been developed.

Seals

The first and still most popular seal is the radial seal (used mainly on the sealed roller bearing bits). The radial seal is a circular steel spring encased in rubber, which seals against the face of the shank and the face of the cone. The newer “O” ring seal is considered the most effective seal. The major problem confronting the “O” ring is tolerance, which must be precise in order to maintain an effective seal.

An understanding of lubricants and lubricating systems is necessary for successful drilling operations. The lubricating systems are essentially the same, and are composed of an external equalizer located under the bit or on back of the shanks, a grease reservoir with some sort of expandable diaphragm to distribute the grease, and some sort of distribution system to the bearings. In addition, there is a pressure relief valve to release any trapped pressure, which might otherwise rupture the seals.

Pressure surges can be detrimental to these sealed systems. As pressure and temperature increase, the viscosity of the lubricant increases. As a result, the system cannot instantaneously compensate for abrupt changes in pressure due to surges (going into the hole, making connections, etc.) and small quantities of mud invade the system. With the close tolerance necessary for effective sealing, mud solids can be damaging.

Adequate cleaning is even more important with sealed bearing bits. If drilled cuttings are allowed to build up around the shirttail, seal damage and premature bearing failure may result. Gauge protection is also important to seal and bearing life, because seal damage can occur from shirttail wear caused by inadequate gauge protection.

Any time a sealed bearing bit is rerun, the seals and shirttail should be carefully checked for excessive wear or grooving.

To complete the journal-cone assembly, a positive seal is required to keep drilling fluid out, while allowing the graphite lubricant in, which keeps the bearings from overheating. The positive seal requires a relief valve to allow escape of excess pressure, which can overload the seal and cause seal failure.

Material Requirements

The rock bit must be stronger than the rock it is to drill. The measurement of hard steel is measured on the “Rockwell” hardness tester scale (Rc). The tester uses a diamond pyramid indenter with a load of 150 kilograms. The deeper the indentation in the steel, the softer it is.

The degree of hardness that can be produced in steel is determined by its carbon content, the higher the percentage of carbon (up to 0.7%), the harder the steel. By heat treating properly, it can be made up to about 65 Rc. Alloying elements improve the hardening potential in thick sections and cause the steel to have a more uniform response to heat treating. The steel must also be ductile (resistance to crack propagation). This ductility or “toughness” of metals is inversely related to hardness (the harder a metal, the less ductile. The softer the steel, the more ductile). Alloying elements improve the ductility of steels and toughness, and resistance to failure from impact loads.

Heat Treating

The desired metallurgical properties and physical strengths are developed through heat treating. As mentioned above, the strength is improved by increasing the carbon content at the surface by carbonizing, commonly known as “case hardening”. This is essential for the teeth on milled tooth bits, and necessary for strength and wear resistance on the bearing surfaces. Toughness (resistance to impact and crack propagation) is attained by leaving the inner part or the “core steel” unchanged.

The overall physical properties that are needed (strength and toughness) are achieved by heating the parts to a high temperature, then quenching them in oil. The maximum surface hardness of the carbonized section gets about 60 - 64 Rc (the hardness of a file). The core hardness will be about 25 - 40 Rc, remaining tough and ductile.

Mill Tooth Bit Teeth

The teeth on a mill tooth bit are sometimes “hard-faced” using tungsten carbide. This hard-facing can be on the gauge teeth (for hard formations), the inner teeth (for soft formations), or on both rows. Hard-facing is applied in such a way so that, as the teeth dull, the hard-facing causes a self-sharpening of the tooth.

Insert Bits

Over the past ten years, most of the progress in rolling cutter bits has been made in the design of insert bits. Although the merits of tugsten carbide bits has long been accepted, it was not until recently that bit manufacturers obtained enough experience with the carbide material and design to make it possible to consider this type of bit for application in virtually all formations - soft, medium and hard.

The chief advantage of this concept is that there is virtually no change in the configuration of the cutting structure due to wear. In addition, any bit often finds good application in a variety of formations. Thus, the limiting factor on performance is usually the life of the bearing assembly (providing formation changes do not cut short the bit run).

The basic principles governing insert-type bit designs are the same as those applied to milled tooth design, desired depth of tooth interfit, insert extension, cone shell thickness, cone diameter, and gauge requirements.

Of primary importance is the proper grade of carbide material used in the inserts. Much has been learned in this respect since the initial model was placed on the market. Experience has shown the need for carbide materials of various grades, dictated largely by the design purpose of the cutting structure.

At present, the manner in which insert bits now function closely parallels the mechanics of the three major categories of milled tooth bits, soft (gouging/spading), medium (chipping plus limited penetration), and hard (crushing/fracturing). For this reason, the composition as well as the configuration of the insert material is being subjected to constant evaluation and improvement. To date, the ultimate in both areas has not been determined.

Polycrystalline Diamond Compact Bits

In the early days of oilwell drilling, fishtail/drag bits were used extensively throughout the oilfields. Around 1909, it was realized that these drag bits would not penetrate many of the formations which overlay deeper oil and gas reservoirs, and were eventually replaced by roller cone bits.

General Electric, recognizing that drag bits had advantages (most notably the absence of moving parts and the efficiency of shear cutting) began in the early 70's the testing of new cutting structures for these drag bits. Since their introduction into the oilfields in 1976, the cutting structure of the polycrystalline diamond compact (PDC) has made the drag bit competitive with the conventional roller cone and diamond bits.

PDC Drill Blanks

These drill blanks consist of a layer of synthetic polycrystalline diamond bonded to a layer of cemented tugsten carbide using a high-temperature, high-pressure bonding technique. The resulting blank has the hardness and wear resistance of diamond which is complemented by the strength and impact resistance of tungsten carbide.

PDC blanks are self-sharpening in the sense that small, sharp crystals are repeatedly exposed as each blank wears, and because they are polycrystalline these blanks have no inherently weak cleavage planes, which can result in massive fractures as in the large, single crystal diamonds in the diamond bits.

The blanks are then bonded to tungsten carbide studs, which are then press-fitted into holes on the steel or matrix head of the bit. The cutters are positioned in a helical pattern on the bit face so as to have a negative rake, an equal distribution of weight-on-bit, and a redundant shearing action. The result being an optimal rate of penetration.

The bit body is forged from the same high strength steel used in the cones of tri-cone bits, and the face is then coated with a layer of tungsten carbide, to resist fluid erosion.

Bit Design

PDC bits feature a steel or matrix head, which is advantageous because there are no bearings to wear out or broken cones to have to fish out of the hole. The bit has a long, extended gauge with cemented tugsten carbide wear pads to help maintain gauge. There is also inherent stabilization in the bits extended gauge.

The face of the bit is concave, permitting several gauge and nose cutters to attack the rock simultaneously, increasing stabilization while decreasing the potential for deviation.

Jet nozzles vary in size and number, are interchangeable, and are strategically located for maximum cleaning action of the cutters and the bottom of the hole.

The cutters are arranged in one of three patterns:

- an open face, helical pattern on the face of the bit
- a ribbed pattern, with the cutters on ribs less that one-inch above the bit face
- a bladed patters, with the cutters on blades, more than one-inch from the bit face

All three types provide complete cutter coverage for a consistent bottomhole pattern. One bottomhole pattern, known as kerfing, uses a combination of scribe and round cutters to enhance the scraping and shearing action of the bit.

Without moving parts, the bit shears the rock rather than gouging or crushing as do the roller cone bits.

PDC Bit Operating Parameters

PDC bits do not have the benefit of the self fluid-cleaning action between rows of teeth like roller cone bits, so they must rely on the bit’s hydraulics to flush the cuttings from under the bit to prevent balling. This is accomplished with strategically positioned converging-diverging nozzles which maximize cleaning while minimizing erosion of the body near the nozzle area. Optimum hydraulic range is between 2.0 to 4.0 hydraulic horsepower per square inch. The interchangeable jet nozzles come in standard sizes from 8/32’s to 14/32’s.

Bit life is controlled by the cutting structure. As stated earlier, the PDC cutting elements provide a self-sharpening edge with the wear resistance of diamonds. This combination is very effective in soft to medium formations such as shale, chalks, limestones, clays, salts and anhydrite. These formations have been drilled at excellent penetration rates with weights between 1000 and 2500 pounds per inch of bit diameter and rotary speeds of 85 to 140 rpm. Economic performance has also been achieved with rotary speeds of 750 rpm and weights of 1000 pounds per inch of bit diameter using downhole motors.

High rotary speeds provide better drill rates and reduce the chances of deviation. Optimum rotary speed varies with formation hardness. A soft, plastic formation would require higher rpm; a hard formation, lower rpm. Most applications require rotary speeds less than 120 rpm.

Lighter weight-on-bit means lower stress on the drill string, with increased string life as a result. There's less drag in directional holes because fewer drill collars are required, reducing the potential for stuck pipe.

These bits have made economical runs in both oil and water base muds. Oil base muds and the addition of lubricants to water base muds will enhance PDC bit performance in formations that tend to be somewhat plastic and sticky.

Formations which should be avoided with PDC bits are soft sticky shales and clays, abrasive sands, and those formations which are very hard. In sticky formations, PDC bits have a tendency to ball up; in abrasive formations or hard formations, cutter wear and breakage occur rapidly. PDC bits cannot drill as broad a range of formations as roller cone bits, but have shown to be competitive with diamond bits. Thus, care must be taken when selecting bits for various applications. When properly applied, most PDC bits can be run in more than one well.

PDC bits cost between $10,000 to $25,000, and savings are measured in terms of trip time saved, longer bit life, improved rates of penetration, and fewer rig hours required to drill a well.

PDC Bit Drilling Parameters

Even though PDC bits have achieved recognition as a viable tool for improved drilling, certain precautions and drilling parameters should be met in order that the bit run be as efficient and economical as possible.

1. When the prior bit is removed, it should be inspected for any damage. If junk was left in the hole, do not run a PDC bit until the hole is cleaned.
2. When picking-up a PDC bit, take all the precautions normally taken when handling a diamond bit, and some additional ones:
    a. When removing the bit from its box, handle it carefully. Do not roll it out on the rig floor. If the bit is dumped on the floor and some of the cutters are chipped, the bits life will be reduced.
    b. The interior of the bit should be inspected to make sure no debris is left inside.
    c. The proper bit breaker should be used to make up the bit.
3. The bit is one solid piece and does not have the limited flexibility of roller cone bits. Hitting ledges or running through tight spots can damage the gauge cutters.

4. If it is necessary to ream when going into the hole, pick up the kelly and run the maximum flow rate. The rotary speed should be about 60, and go through the tight spot slowly.

5. When near bottom, the last joint should be washed down slowly at full flow and 40-50 rpm, to avoid plugging the bit with any fill.

   a. To locate the bottom of the hole, observe the torque and weight indicators. Because of the type of cutting structure on PDC bits, it is common that the first on-bottom indication is a sudden increase in torque.

   b. After the bottom of the hole has been reached, the bit should be lifted a foot or two off bottom, then circulate and rotate slowly for about five minutes to make certain the bottom of the hole is cleaned.

6. When ready to start drilling, bring the rotary speed up to 60 and approach bottom. Light weight should be used in order to cut a new hole pattern.

   a. At least 1 foot of new hole should be cut in this manner before looking for optimum weight and rotary speed for drilling.

   b. In soft formations, the bit will drill quickly with light weight, and the rotary speed should be increased until the bit is drilling at its fastest rate (usually between 100-150 rpm).

   c. In hard formations, it will take much longer to drill the one foot. Adding weight too quickly will damage the cutters. Once the bottom hole pattern is established and weight is added, watch the torque indicator for possible problems.

7. There is no limit to rotary speed, use as much as possible without damaging the rest of the drillstring.

8. The on-bottom torque should approach what is experienced with roller cone bits. If there is no torque buildup, or the penetration rate does not increase with added weight, the formation may not be suitable for PDC bits.

9. After making a connection, the bit should be washed back down to bottom. Dropping and then stopping the drillstring suddenly can cause the bit to hit bottom and be damaged due to pipe stretch.

10. PDC bits respond dramatically to changing formations, if the rate of penetration suddenly decreases or the bit starts torquing, a change in the weight-on-bit and rotary speed should help.

11. When the cutters wear to a point where they will not drill, the bit should be pulled. If the wear is primarily on the outside, there

will be a sudden decrease in the penetration rate and torque, and an increase in standpipe pressure. If the wear is on the gauge portion, there will be very high on-bottom torque with little weight-on-bit and a decrease in the penetration rate.

Diamond Bits

Diamond core bits were introduced into the oilfield in the early 1920's and were used to core extremely hard formations. These early diamond bits were very expensive, costing about twenty times the price of the roller bits. Since performance was barely economical for coring, very little consideration was given to diamond bits as a drilling tool.

By the 1940's, a much improved technique had been developed for the manufacture of diamond bits. The diamonds were cast in a matrix of tungsten carbide powder bonded together with a copper and nickel binder. This change permitted the use of more complex bit designs and diamond setting patterns. These changes resulted in the improved performance of diamond bits, and reduced the cost of the diamond bits as compared to roller cone bits. However, they still were ten to fifteen times the cost of roller bits, and therefore limited to a “last resort” item.

Regardless of reputation, many drilling engineers were attracted to diamond bits because of the ability of being able to stay on the bottom and drill for longer periods of time. During the late 1950's several major oil companies began research programs on diamond bits, and these studies provided a much better understanding of the mechanics of diamond bit drilling and the influence of hydraulics on the penetration rate. This, plus subsequent developments of more erosion resistant matrix materials, led to performance levels in the 1970's which provided cost savings on a regular basis.

The Diamonds

There are three classifications of diamonds used on diamond bits:

1. Single Crystal (West African-Bortz): These diamonds are generally translucent, shiny and come in geometrically regular shapes, such as octahedrons, dodecahedrons, and other shapes tending towards spheres.
2. Coated (Congo): These diamonds have a heavy surface coating or skin which is usually greenish or grayish in color, and does not permit the transmission of light. They are balas (rounded) in shape.
3. Carbonado (Black Diamond): So termed because the majority are black in color and do not transmit light. The majority of these diamonds have a non-crystalline or amorphous structure.

Diamonds used in oilfield bits are of natural origin and range from as small as 15 stones per carat to as large as seven carats per stone. Diamonds are resistant to abrasion, extremely high in compressive strength (the hardest material known) but are low in tensile strength and have high thermal capacity. The low tensile strength reduces its ability to withstand impacts.

The terminology used to describe diamond quality is quite varied, and "quality" is roughly defined by the following factors:

1. Surface Condition: A glossy, smooth surface denotes a surface of better quality.
2. Translucence: In crystalline diamonds, the ability to transmit light is indicative of higher quality. This is not necessarily true when non-crystalline diamonds and coated diamonds are being evaluated.
3. Internal Structure: The absence of large internal fractures, inclusions, and growth structures are indicative of high quality.
4. External Shape: A block-shape or nearly spherical diamond is stronger and hence of higher quality.

The Diamond Bit

A diamond bit (either for drilling or coring) is composed of three parts: diamonds, matrix and shank. The diamonds are held in place by the matrix which is bonded to the steel shank. The matrix is principally powdered tungsten carbide infiltrated with a metal bonding material. The tungsten carbide is used for its abrasive wear and erosion resistant properties (but far from a diamond in this respect). The shank of steel affords structural strength and makes a suitable means to attach the bit to the drill string.

Diamond bits are sold by the carat weight (1 carat = 0.2 grams) of the diamonds in the bit, plus a setting charge. The price will vary depending upon classification (or quality) and size. The setting charge is to cover the manufacturing cost of the bit. A used bit is generally returned to salvage the diamonds and to receive credit for the reusable stones (which materially decreases the bit cost). This credit is frequently as much as 50% of the original bit cost.

Uses of Diamond Bits

As with any bit selection, the decision to run a diamond bit should be based on a detailed cost analysis. There are, however, certain drilling situations which indicate the likelihood of an economical application for diamond bits.

- Very short roller cone bit life: If roller cone bit life is very short due to bearing failure, tooth wear, or tooth breakage, a diamond bit can increase on-bottom time dramatically. Diamond bits have no bearings and each diamond has a compressive strength of 1,261,000 psi (approximately 1.5 times that of sintered tungsten carbide). The relative wear resistance is approximately 100 times that of tungsten carbide.

- Low penetration rates with roller cone bits: Frequently, when roller cone bits drill at slow rates (especially 5 ft/hr or less), due to high mud weights or limited rig hydraulics, diamond bits can provide a savings. The “plowing” type cutting action of diamond bits generally produces higher penetration rates when using heavy muds. Since the drilling fluid is distributed between the bit face and the formation in a smooth uniform sheet, it takes less hydraulic horsepower per square inch to clean under a diamond bit than under the same size roller cone bit.
- Deep, small holes: Roller cone bits that are 6-inch and smaller have limited life due to the space limitations on the bearing, cone shell thickness, etc. Diamond bits being one solid piece often last much longer in very small boreholes.
- Directional drilling: Diamond side tracking bits are designed to drill “sideways” making it a natural choice for “kicking off” in directional drilling situations.
- Limited bit weight: Diamond bits drill at higher rates of penetration with less weight than normally required for roller cone bits in the same size range.
- Downhole motor applications: Roller cone bits generally have bearing failures on motor applications due to high rotary speeds. Diamond bits will have a very long life under these conditions.
- Cutting casing windows: Window cutting through casing using diamond bits is now an effective, field-proven method for re-entering older wells to increase production, to apply directional drilling techniques, or to sidetrack. Using permanent casing whipstocks and specially designed diamond bits, wider and longer windows are cut when sidetracking.
- Coring: The use of diamond bits for coring operations is essential for smooth, whole cores. Longer cores are possible with increased on-bottom time and cores “look better” because of the cutting action of diamond bits as compared to those of roller cone bits.

There are some drilling situations **which should be avoided** when using diamond bits:

- Very hard broken formations: Broken formations can cause severe shock loading on diamond bits resulting in diamond breakage and a short bit life.
- Formations containing chert or pyrite: Chert and pyrite tend to break apart in large pieces and “roll” under a diamond bit, causing diamond damage.

- Reaming long sections in hard formations: Since the “nozzles” of a diamond bit are formed by the formation on one side and the bit matrix on the other side, hydraulic cooling and cleaning are extremely poor during reaming. This can result in diamond “burning” or breakage in the gauge area.

Diamond Bit Operating Parameters

Hydraulics

Hydraulic programs for diamond bits must consider circulation rate and pressure loss. There should be sufficient fluid and pressure to cool and clean under the bit. Rig hydraulics do not require modification, but a good optimum flow rate in the range of 4.5 to 7.0 gallons per minute per square inch of hole area is necessary. It may be more or less if the hole or operating conditions dictate and if the bit is designed for such conditions.

Each diamond on the bit is continually on bottom, continually doing work, therefore the entire area must be continually cleaned and cooled. The bit must be kept clean to prevent balling up, and to keep formations exposed to the cutting action of the diamonds. The bit must be kept cool; excessive heat is one of the diamond's worst enemies. Because of the diamond's cutting action, heat is always being generated and a damage can only be prevented with adequate flow rates. Other factors being equal, better performance may be expected with higher rates of fluid flow.

Pressure is required to force the fluid over the face of the bit at velocities high enough to provide adequate cooling and cleaning. When the bit is off bottom, the fluid has a nearly unrestricted flow, but on bottom, the fluid must pass through a small area made up of fluid courses in the bit and the hole itself (clearance is the space between the bit matrix and the formation). This results in an off-on bottom pressure difference in a range of 100 to 1,000 psi depending on the total fluid area and operating conditions (mud density, bit weight, pump pressure, etc.).

Weight-on-Bit

The weight on diamond bits should be somewhat less than for roller cone bits. A good average weight is between 350 to 750 pounds per square inch of bit area.

Hole conditions may make it necessary to slack off more weight, but caution should be used in this respect since excessive weight-on-bit will shorten its life. Formations which drill by a chipping action produce an impact load against the diamonds. Drilling weight should be increased in increments of 2,000 pounds until increases in weight does not show a comparable increase in the penetration rate. When this occurs, the weight should be decreased to the lowest weight at which the best penetration rate was obtained.

Rotary Speed

Rotary speed should be relatively high, with 100 rpm being average, although 200 to 1000 rpm is not uncommon when downhole motors are used. Penetration rate should increase at high speeds if hydraulics are good and no roughness in drilling occurs.

Drill rate, with good hydraulics, is nearly a straight line function of rotary speed. Drilling rate will, therefore, continue to increase as rotary speed is increased. The limits are usually imposed by safety considerations for the drill pipe.

Torque

Torque indications are very useful as a check on smooth operation. No absolute values have been set up, but a steady torque is an indication that the previous three factors are well coordinated.

Bit Stabilization

A diamond is extremely strong in compression, but relatively weak in shear, and needs constant cooling when on bottom. The bit is designed and the rake of the diamonds set, so that a constant vertical load on the bit keeps an even compressive load on the diamonds, and even distribution of coolant fluid over the bit face. If there is lateral movement or tilting of the bit, an uneven shear load can be put on the diamonds with coolant leakage on the opposite side of the bit.

Any of the standard “stiff-hookup” or packed hole assemblies are suitable for stabilization when running diamond bits. It is recommended that full gauge stabilizers be run near the bit, and at 10 feet and 40 feet from the bottom.

General Diamond Bit Drilling Practices

Prior to running a diamond bit, clean the hole by running a junk basket on the last roller cone bit.

Running a Diamond Bit into the Hole

Place the bit in the bit breaker and makeup with tongs on the collar, to the same torque as used on the collar connection.

Use care going in the hole. Avoid striking ledges and pushing through tight places which could damage the gauge diamonds.

Although diamond bits may be used to ream short intervals, care must be taken, especially the first time a diamond bit is run. Remember, diamond bits are solidly constructed and have no “give” as do roller cone bits. In a reaming situation, most of the drilling fluid escapes through the junk slots on the diamond bit and the mud cannot effectively cool the diamonds in the gauge zone. During reaming, these diamonds absorb all applied weight and may become overloaded.

When reaming, the bit weight of about 2,000 to 5,000 pounds maximum should be used to avoid fracturing or burning the diamonds, and the rotary speed should be moderate (40-60 rpm). If considerable reaming in hard, abrasive formations is going to be necessary, the diamond bit should be pulled and replaced with a diamond bit specifically designed for reaming.

Starting a Diamond Drill Bit

It is recommended that circulation be started prior to reaching bottom and that extreme care be used to find bottom. The bit should be rotated slowly to bottom, or if possible establish bottom with zero rotation. Then circulate with full volume and rotate slowly at a point about one foot or less off bottom for a period of at least five minutes to clean the bottom of the hole.

After circulating, use extreme care to find bottom. Within the minimum bit weight and full fluid volume, drill enough hole to form a new bottom hole contour. This is important since a diamond bit does not get proper cleaning and cooling action until the bottom of the hole exactly fits the bit profile.

Under some conditions, procedures may dictate touching bottom with full pump force but no rotation in order to try to crush any irregular large foreign particles on the bottom of the hole, with minimum of bit damage. This procedure, when appropriate, should be used several times before rotating the drill string.

Drilling

After the bit has been started, rotary speed should be increased to the practical limit indicated by rig equipment. The drill pipe, hole condition, and depth should also be taken into consideration.

Weight should be added as smoothly as possible in 2000 pound increments. Observations of penetration rate after each weight increase should be made to avoid overloading. As long as the penetration rate continues to increase with weight, then weight should be increased. However, if additional weight does not increase the penetration rate, then the weight should be reduced back 2000 to 3000 pounds, to avoid packing and balling-up of the space between the diamonds. Drilling should be continued at this reduced weight.

After making a connection, be sure to circulate just off bottom for at least five minutes, as cuttings in the hole could damage the bit. The time spent here may lengthen the life of the bit by many hours.

Diamond Bit Selection

Choice of bit style, diamond size and diamond quality can mean the difference between an economical bit run or a costly bit run.

Some formations are more drillable with diamond bits than others, but these formations and their drillability change from area to area. Diamond bits normally perform better in hard formations, because it is easier to keep the bit clean, the cuttings are smaller, and individual diamonds cut with a plowing action rather than by chipping and tearing.

Diamond bits require hydraulics equivalent to, or greater than other bits in order to stay clean and run cooler in softer, stickier formations. The smaller the diamond bit, the better it performs - mainly because of hydraulics. Since the cutting surface of a diamond bit runs very close to the formation, the cuttings move from the center of the hole across the face of the bit to the outside of the borehole. The larger the bit, the greater amount of cuttings to be moved across the face, which may result in partial clogging of the flow area and a decrease in penetration rate unless hydraulics are maintained at high energy levels.

Special Designs

Standard bit styles can be used in most cases. Special designs, or standard bits with special features, are manufactured for unusual applications. For example:

1. Low pressure drop bits for downhole motors
2. Flat bottom, shallow cone designs for sidetracking with downhole motors
3. Deep cone, short gauge bit design for whipstock jobs or sidetracking
4. Core ejectors can be built into most styles where cone wear is a problem or where larger cuttings are desired
5. Deep cones having a 70° apex angle are normally used to give built-in stability and greater diamond concentration at the cone apex. In certain formations, a deep cone could fracture the formation horizontally, leaving a plug in the bit cone. Thereafter, the formation plug would be ground and splintered away beneath the bit face, inducing diamond breakage and premature failure. In fracturing type formations, a shallower cone angle of about 90° or 100° may be used.

Selection Guideline

Because formations of the same age and composition change in character, with depth, and drill differently, no universal bit selection guide can be prepared. However, general guidelines include:

Soft formations

Sand, shale, salt, anhydrite or limestone require a bit with a radial fluid course set with large diamonds. Stones of 1-5 carats each are used, depending on formation hardness. This type of bit should be set with a single row of diamonds on each rib and designed to handle mud velocities ranging from 300-400 fps to prevent balling.

Medium formations

Sand, shale, anhydite or limestone require a radial style bit with double rows of diamonds on each blade or rib. Diamond sizes range from 2-3 stones per carat. Mud should be circulated through these bits at a high velocity. Good penetration rates can be expected in interbedded sand and shale formations.

Hard, dense formations

Mudstone, siltstone or sandstone usually require a crowsfoot fluid course design. This provides sufficient cross-pad cleaning and cooling and allows a higher concentration of diamonds on the wide pads. Diamond sizes average about 8 stones per carat.

Extremely hard, abrasive or fractured formations

Schist, chert, volcanic rock, sandstone or quartzite require a bit set with small diamonds and a crowsfoot fluid course to permit a high concentration of diamonds. The diamonds (about 12 per carat) are set in concentric “metal protected” ridges for perfect stone alignment, diamond exposure and protection from impact damage.

Diamond Bit Salvage

When returning a bit for salvage, it is helpful to furnish a performance report on the bit. The manufacturer can then inspect the bit with a better understanding of how it was used in conjunction with its condition.

Salvage, or recovery of the stones in a diamond bit is done by electrolysis. The binder material is plated out of the matrix, which allows the tungsten carbide particles and the diamonds to drop out. The diamonds are screened out of the resulting sludge, then chemically cleaned.

When brought to the sorting room, the diamonds are screened for sizing, then each stone is inspected and graded under a magnifier by an expert.

Self-Check Exercises

1. What are the types of bearings used on all roller cone bits?

   a.____

   b. ____

   c.____

2. The “skew” direction of a roller cone bit should always be in a ___________ direction to permit the teeth to ream the hole to full gauge.

3. What tooth angles are used on mill-toothed roller cone bits for these types of formation hardness?

   Hard Formation Bits: ______________________________

   Medium Formation Bits: ___________________________

   Soft Formation Bits:________________________________

4. Steel milled teeth break down under heavy bit weights. In fact, most roller cone bits drill _______ of the hole in a _______ to _______ condition.

5. What type of teeth on a roller cone bit provides the greatest amount of surface area and are used in abrasive formations?

   ____

6. In mill toothed bits, the journal bearing has a distinct advantage in that it utilizes __________ that present a larger contact area at the load bearing point.

7. Insert drill bits have a distinct advantage in that there is virtually no change in ___________ due to wear.

8. What are three advantages of PDC bits with regard to its steel head feature?

   a.____

   b. ____

   c.____

9. PDC bits are sensitive to the amount of RPM used to optimize the drill rate. A soft, plastic formation would require a ________ RPM, while a harder formation would require a ________ RPM.

10. What three types of natural diamonds are used in diamond bits?

    a.____

    b. ____

    c.____

•Notes•

Chapter 4

Drillstring Basics

Upon completion of this section you will be able to:

- Explain how drill pipe grades define the yield strength and tensile strength of steel.
- Explain how drill pipe is classified.
- Calculate total yield strength for a specific grade/class of drill pipe.
- Explain the effects of buoyancy on the drillstring.
- Calculate the buoyed weight (or hookload) in a vertical hole.
- Explain the causes of varying hookload during the drilling process.
- Explain overpull and calculate the maximum permitted pull.
- Calculate required BHA air weight for applications where drill pipe is to be run in compression.
- Calculate critical buckling force and explain the factors involved when running drill pipe in compression.
- Explain causes and effects of sinusoidal and helical buckling.
- Explain neutral point and calculate the approximate location of the neutral point in a rotary drillstring.
- Explain the relationship between cyclic bending stress and drill pipe fatigue.
- Describe some of the factors affecting axial drag and torque, and the effect of drag on weight on bit.

Tubulars

Introduction

Drill pipe and collars are designed to satisfy certain operational requirements. In general, downhole tubulars must have the capability to withstand the maximum expected hookload, torque, bending stresses, internal pressure, and external collapse pressure. Operational capabilities of different sizes and grades of drill pipe and collars are tabulated in the API RP 7G to assist the drilling engineer in selection of pipe and collars for a given drilling situation. Other concerns, such as the presence of H_2S, must also be considered in the selection process.

Drill Pipe Yield Strength and Tensile Strength

If drill pipe is stretched, it will initially go through a region of elastic deformation. In this region, if the stretching force is removed, the drill pipe will return to its original dimensions. The upper limit of this elastic deformation is called the **Yield Strength**, which can be measured in psi. Beyond this, there exists a region of plastic deformation. In this region, the drill pipe becomes permanently elongated, even when the stretching force is removed. The upper limit of plastic deformation is called the **Tensile Strength**. If the tensile strength is exceeded, the drill pipe will fail.

Tension failures generally occur while pulling on stuck drill pipe. As the pull exceeds the yield strength, the metal distorts with a characteristic thinning in the weakest area of the drill pipe (or the smallest cross sectional area). If the pull is increased and exceeds the tensile strength, the drillstring will part. Such failures will normally occur near the top of the drillstring, because the top of the string is subjected to the upward pulling force as well as the downward weight of the drillstring.

Drill Pipe Grades

There are four common grades of drill pipe which define the yield strength and tensile strength of the steel being used.

Grade

	E	**X-95**	**G-105**	**S-135**
Minimum Yield Strength (psi)	75,000	95,000	105,000	135,000
Minimum Tensile Strength (psi)	100,000	105,000	115,000	145,000

Grade E, composed of a lower grade of steel, is sometimes referred to as "mild" steel, because it has the lowest yield strength per unit area. As such, mild steel is generally defined as steel with a yield strength of less than 80,000 psi. As can be seen, Grade E drill pipe has a lower yield strength in psi than the high strength drill pipe grades, however once the yield strength is exceeded, it can withstand a greater percentage of stretch or "strain" prior to parting. Lower grades of steel such as Grade E are also more resistant to corrosion and cracking. Grade E has been utilized in medium depth wells (10,000 to 15,000 feet).

In the 1980's, as horizontal drilling, high inclination extended reach wells and deep hole drilling applications increased, so has the demand for high strength drill pipe. It is common in deep hole applications for high strength drill pipe to be utilized in the upper portion of the string to keep the tension load within the capabilities of the steel. In high dogleg environments, such as those encountered in medium and short radius horizontal wells, high strength drill pipe can withstand the associated bending stresses. In high inclination and horizontal wells, high strength drill pipe is also commonly run in compression. One drawback of higher grades of steel is that they are generally less resistant to corrosion, like that caused by hydrogen sulfide (H_2S). Limited availability also contributes to the higher cost.

The yield and tensile strengths are in "pounds per square inch of the cross sectional area" of the drill pipe. In order to calculate yield strength in pounds, this cross sectional area must be known. This leads to a discussion of drill pipe classes.

Drill Pipe Classification

Drill pipe class defines the physical condition of the drill pipe in terms of dimension, surface damage, and corrosion. Drill pipe class is indicated by paint bands on the drill pipe according to the following code:

CLASS	# and COLOR of BANDS
1 (New)	One White
Premium	Two White
2	One Yellow
3	One Orange
4	One Green
Scrap	One Red

Class 1 drill pipe is **New** and therefore the strongest. As pipe is used, the wall thickness will be gradually reduced. This reduction of the drill pipe cross sectional area results in a lower **Total Yield Strength** in pounds. This yield strength in pounds can be calculated using the following formula:

YIELD STRENGTH = Yield Strength x $\pi/4$ ($OD^2 - ID^2$)
(in pounds)(in psi)

Example 4.1

5" grade G-105, class 1 (new) drill pipe has a nominal weight of 19.5 Ib/ft and an ID of 4.276” ...therefore:

Minimum Yield Strength in pounds= 105,000 x $\pi/4$ x (5^2 - 4.276^2)
= 553,833 lbs.

This same information can be found in the **API RP 7G**. This publication contains data on the properties of drill pipe and tool joints for all common sizes in classes 1 (New), Premium, 2 and 3 in the four common grades. Of interest is information listed in “New Drill Pipe Torsional and Tensile Data” (Table 2.2). The data on torsional yield states the maximum twisting force (torque) in foot pounds the drill pipe can withstand before permanent damage can occur. Data on tensile yield refers to the maximum stretch force (yield strength) in pounds that the pipe can withstand before plastic or permanent deformation occurs.

Tool Joints

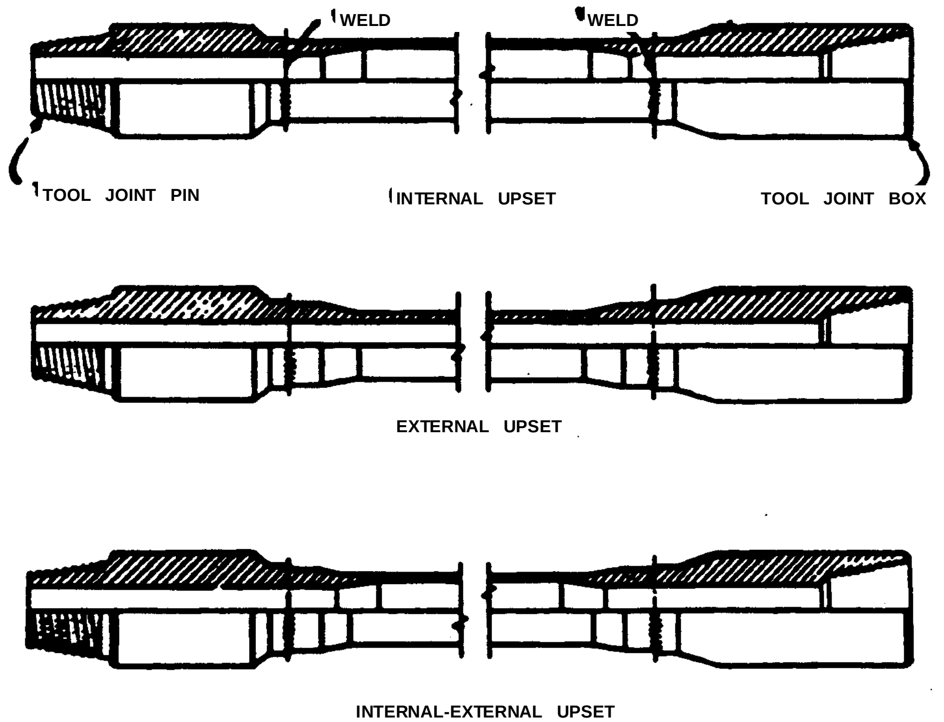
Tool joints are short sections of pipe that are attached to the tubing portion of drill pipe by means of using a flash welding process. The internally threaded tool joint is called a “box”, while the externally threaded tool joint if the “pin”.

API specifications also apply to tool joints:

- Minimum Yield Strength = 120,000 psi
- Minimum Tensile Strength = 140,000 psi

Because tool joints are added to drillpipe, the weight of given to pipe in many tables is the “nominal weight”. The exact weight will require adding the weight of the tool joints to the tubing portion. Since two joints do not weigh the same, it is difficult to determine the weight of a joint of drillpipe and so an “approximate weight” is used in many calculations.

The tool joints on drill pipe may contain internal and/or external upsets. An upset is a decrease in the ID and/or an increase in the OD of the pipe which is used to strengthen the weld between the pipe and the tool joint. It is important to note that under tension, the tool joint is stronger than the tubular.



Make-Up Torque

Part of the strength of the drillstring and the seal for the fluid conduit are both contained in the tool joints. It is very important therefore, that the correct make-up torque is applied to the tool joints. If a tool joint is not torqued enough, bending between the box and pin could cause premature failure. Also, the shoulder seal may not be properly seated, resulting in mud leaking through the tool joint, causing a washout. Exceeding the torsional yield strength of the connection by applying too much torque to the tool joint could cause the shoulders to bevel outward or the pin to break off the box. Recommended make up torques for drill pipe and tool joints are listed in the API RP 7G.

Buoyancy & Hookload

Introduction

Drillstrings weigh less in weighted fluids than in air due to a fluid property known as buoyancy. Therefore, what is seen as the hookload is actually the buoyed weight of the drillstring. Archimedes's principle states that the buoy force is equal to the weight of the fluid displaced. Another way of saying this is that a buoy force is equal to the pressure at the bottom of the string multiplied by the cross sectional area of the tubular. This is due to the fact that the force of buoyancy is not a body force such as gravity, but a surface force.

For example, the buoy force exerted on 7.5-inch x 2-inch drill collars in a 700 ft vertical hole with 12 ppg mud would be 17,925 pounds.

Buoy Force = Pressure x Area

Hydrostatic Pressure = 0.0519 x MW x TVD
= 0.0519 x (12) x (700)
= 436.8 psi

Cross Sectional Area = $\pi/4$ x (OD^2 - ID^2)
= $\pi/4$ x (7.5^2 - 2^2)
= $\pi/4$ x (56.25 - 4)
= 41.04 in^2

Buoy Force = 436.8 x 41.04
= 17,924.99 pounds

By looking at the API RP 7G it can be determined that the air weight of these 7.5-inch drill collars is 139 pounds per foot. If we have 700 feet of collars, the total air weight would be 97,300 pounds.

Total Air Weight = weight per foot x length
= 139 x 700
= 97,300 pounds

The buoyed weight of the collars, or the **Hookload**, is equal to the air weight minus the buoy force.

Hookload = Air Weight - Buoy Force
= 97,300- 17,925
= 79,375 pounds

This method for determining the buoyed weight is not normally used. Instead, the following formula, which incorporates a buoyancy factor, is used and recommended by the API.

$$\text{Buoyancy Factor} = 1 - \frac{MW}{65.5}$$

$$= 1 - \frac{12}{65.5}$$

$$= 0.817$$

MW=Mud Density (ppg)

Hookload = Air Weight x Buoyancy Factor
= 97,300 x 0.817
= 79,494 pounds

Buoyancy Factors rounded off to three places can also be found in the API RP 7G (Table 2.13).

> **Note:** *The formula above for hookload does not take into account axial drag. Hookload, as determined in the formula above is the approximate static surface hookload that would be displayed by the weight indicator in a vertical hole with no drag, excluding the weight of the traveling block, drill line etc.*

In practice, hookload will vary due to motion and hole drag. Pick-Up Load refers to the hookload when pulling the drillstring upwards. The highest hookload normally encountered will be when attempting to pick up the string. Slack-Off Load refers to the hookload when lowering the drillstring. Drag Load refers to the hookload when drilling in the oriented mode. Other references to hookload are Rotating Off-Bottom Load and (rotary) Drilling Load.

Overpull

In tight holes or stuck pipe situations, the operator must know how much additional tension, or pull, can be applied to the string before exceeding the yield strength of the drill pipe. This is known as **Overpull**, since it is the pull force over the weight of the string. For example, in a vertical hole with 12 ppg mud, a drillstring consists of 600 feet of 7.25-inch x 2.25-inch drill collars and 6,000 ft of 5-inch, New Grade E drill pipe with a nominal weight of 19.5 lbs/ft and an approximate weight of 20.89 lbs/ft.

First, the hookload is determined

Hookload = Air Weight x Buoyancy Factor

= [(6,000 x 20.89) + (600 x 127)] 0.817

= 164,658 pounds

Referring to the API RP 7G, the yield strength in pounds for this grade, class, size and nominal weight of drill pipe is 395,595 pounds. Therefore:

Maximum Overpull = Yield Strength In Pounds - Hookload

= 395,595 - 164,658

= 230,937 pounds

The operator can pull 230,937 pounds over the hookload before reaching the limit of elastic deformation (yield strength). Obviously, as depth increases, hookload increases, at a certain depth the hookload will equal the yield strength (in pounds) for the drill pipe in use. This depth can be thought of as the maximum depth that can be reached without causing permanent elongation of the drill pipe (disregarding hole drag as a consideration). Practically, an operator would never intend to reach this limit. A considerable safety factor is always included to allow for overpull caused by expected hole drag, tight hole conditions or a stuck drillstring.

In practice, selection of the drill pipe grade is based upon predicted values of pick-up load. For a directional well, the prediction of pick-up load is best obtained using a Torque and Drag program, as well as including the capacity for overpull. Some operators include an additional safety factor by basing their calculations on 90% of the yield strength values quoted in API RP7G.

Example 4.2

For a horizontal well proposal, the maximum tensile loads have been calculated using a Torque and Drag program assuming that 5-inch drill pipe will be used. In the 8.5-inch hole section, the anticipated loads at the end of the build and at TD of the horizontal section are:

8.5-inch Hole Section	Pick-Up Load (lbs)
TD Curve	178,991
TD Horizontal	188,916

Using 90% of the yield strengths quoted in RP7G and including a margin of 100,000 lbs overpull, the maximum tensile loads which can be applied to 5-inch, 19.5 lbs/ft, API class 2 drill pipe (worst case) are:

Drill Pipe Grade	**E75**	**X95**	**G105**	**S135**
RP7G	270,432	342,548	378,605	486,778
90% of RP7G Value	243,389	308,293	340,745	438,100
less 100,000 lbs.	143,389	208,293	249,745	338,100

In this worst case scenario, it can be seen that E75 drill pipe has a low tensile yield strength for both the curve and the horizontal sections. The recommendation made to the client would be that X95, 19.5 lbs/ft, 5-inch drill pipe of premium class should be used.

Maximum Hookload When Two Grades Of Drill Pipe Are Used

When two grades of drill pipe are used, the higher grade (i.e. the pipe with the higher load capacity) is placed above the lower grade pipe. The maximum tension to which the top joint can be subjected is based on the yield strength of the higher grade of pipe. Calculations similar to those already dealt with may be used to determine the maximum length of both grades of pipe.

Another consideration is the maximum hookload which can be applied when only a few stands of the higher grade pipe have been added. Provided the higher grade pipe is in the vertical section, maximum hookload (pick-up load) is calculated as the yield strength of the lower grade of pipe PLUS the “air weight” of the higher grade pipe. This is because the surface hookload includes the weight of the higher grade pipe; but that weight (since it is supported from the surface) does not act on the top joint of lower grade pipe.

$$\text{Maximum Hookload} = \underset{\text{Of Lower Grade Pipe}}{\text{Yield Strength}} + \underset{\text{Of Higher Grade Pipe}}{\text{Weight}}$$

When a sufficient length of higher grade pipe has been added, the limiting condition will become the yield strength of the higher grade pipe.

The air weight of the higher grade pipe is used because the buoy force acting on the drillstring is acting on the bit and components of the BHA. The hydrostatic pressure which the mud exerts on the drill pipe in the upper (vertical) section of the hole does not create a resultant force acting upwards.

Example 4.3

A directional well has been drilled vertically to the kick-off point at 3,000 ft. Premium class, 5-inch grade E drill pipe (nominal weight 19.5 lbs/ft) is used until a certain depth is reached, and from that point the pipe used is premium class 5-inch grade X95, nominal weight 19.5 lbs/ft.

Calculate the maximum permitted hookload when all the pipe above the kick-off point is X95.

Solution

From API RP7G, the actual weight of 5-inch NC50 grade X95 pipe (nominal weight 19.5 lbs/ft) is 21.92 lbs./ft.

Weight of 3,000 ft of X95 pipe	= 65,760 lbs
Yield strength of 5 grade E pipe	= 311,535 lbs
90% of yield strength	= 280,380

∴ maximum permitted hookload= (280,380 + 65,760) lbs
i.e. approx. = 346,000 lbs

(For comparison, the yield strength of the X95 pipe is 394,612 lbs. and 90% of that value is approximately 355,000 lbs.)

Higher Grade Pipe In The Inclined Section Of The Well

The previous discussion was restricted to the simple case when the higher grade pipe is totally in the vertical portion of the well. If the higher grade pipe is used through a build-up section, the calculation becomes more difficult. A rough approximation could be obtained by treating each stand length as a straight section of hole and using the average inclination of that course length. The weight this exerts along the borehole is found from:

Weight acting along borehole = weight of stand x cos (ave. inc.)

This, however, ignores drag which may be significant.

Similarly, for an inclined section of the well where the inclination is constant, the weight acting along hole will be the air-weight of the pipe multiplied by the cosine of the average inclination. Notice again that in this particular calculation we do not use a buoyancy factor. This is because although the entire drillstring is subject to a buoyancy force, that force is acting on the lower portion of the string and affects the weight pulling down on the top joint of lower grade pipe from below, but not the weight of the joints of higher grade pipe at the top of the string.

It must be emphasized that if a higher grade pipe extends below the vertical part of the well, then an accurate analysis of the axial stresses requires the use of “Torque and Drag” programs.

BHA Weight & Weight-On-Bit

One important consideration in designing the BHA is determining the number of drill collars and heavy-weight pipe required to provide the desired weight-on-bit. When drilling vertical wells, standard practice is to avoid putting ordinary drill pipe into compression (recommended by Lubinski in 1950). This is achieved by making sure that the "buoyed weight" of the drill collars and heavy-weight pipe exceed the maximum weight-on-bit. This practice has also been adopted on low inclination, directionally drilled wells.

In other types of directional wells, it must be remembered that since gravity acts vertically, only the weight of the "along-hole" component of the BHA elements will contribute to the weight-on-bit. The problem this creates is that if high WOB is required when drilling a high inclination borehole, a long (and expensive) BHA would be needed to prevent putting the drillpipe into compression. However, for these high inclination wells, it is common practice to use about the same BHA weight as used on low inclination wells.

On highly deviated wells, operators have been running drillpipe in compression for years. Analysis of drillpipe buckling in inclined wells, by a number of researchers (most notably Dawson and Paslay), has shown that drillpipe can tolerate significant levels of compression in small diameter, high inclination boreholes. This is because of the support provided by the "low-side" of the borehole.

Drillpipe is always run in compression in horizontal wells, without apparently causing damage to the drillpipe.

Required BHA Weight For Rotary Assemblies

When two contacting surfaces (i.e drillpipe and the borehole wall) are in relative motion, the direction of the frictional sliding force on each surface will act along a line of relative motion and in the opposite direction to its motion. Therefore, when a BHA is rotated, most of the frictional forces will act circumferentially to oppose rotation (torque), with only a small component acting along the borehole (drag).

Measurements of downhole WOB by MWD tools has confirmed that when the BHA is rotated there is only a small reduction in WOB due to drag. This reduction is usually compensated for by using a "safety factor".

Consider a short element of the BHA which has a weight "W" (see following figure). Neglecting drag in the hole:

Effective weight in mud = W (BF)

Component of weight acting along borehole = W (BF) cosθ
... where Θ is the borehole inclination

Extending this discussion to the whole BHA,

$$W_{BIT} = W_{BHA} \text{ (BF) } \cos\theta$$

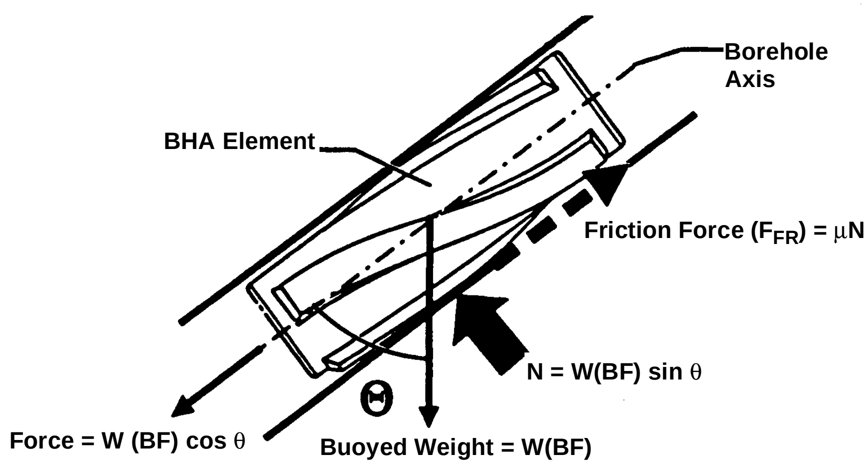
... where W_{BHA} is the total air weight of the BHA and W_{BIT} is the weight on bit.

Therefore, if **no** drill pipe is to be run in compression

$$\text{Required air weight of BHA} = \frac{\text{Maximum WOB x safety factor}}{\textit{buoyancy} \text{ factor x } \cos\theta}$$

$$\text{where the safety factor} = 1 + \frac{\text{percentage safety margin}}{100}$$

For example, to allow a 10% safety margin the safety factor in the formula would be 1.1



Example 4.4

A. Drilling 17.5-inch hole with a roller cone bit, we want to use 45,000 lbs WOB in the tangent section at 30° inclination. What air weight of BHA is required to avoid running any drill pipe in compression? The mud density is 10 ppg. Use a 10% safety margin.

$$\text{Required air weight of BHA} = \frac{45,000 \times 1.1}{0.847 \times \cos 30°} = 67,500 lbs$$

B. Suppose we have 180' of 9.5-inch tubulars weighing 220 lbs per foot, a 9.5-inch MWD tool weighing 3,400 lbs and 90 ft of 8-inch tubulars weighing 154 lbs per foot. How many joints of 5-inch HWDP would be required to meet the criteria in Example 4.4A.

Total weight of drill collar
section = (180 x 220) + 3,400 + (90 x 154) = 56,860 lbs.

Required air weight of HWDP = 67,5001bs - 56,860 lbs = 10,640 lbs.

Weight of one 30 ft joint of 5-inch HWDP = 1,480 lbs

$$\text{Therefore, number of joints of HWDP required} = \frac{10,640}{1,480} = 7.2$$

Therefore a minimum of 8 joints of HWDP are required.

Running Drill Pipe In Compression

Example 4.5

Prior to drilling a 12.25-inch tangent section in a hard formation using an insert bit, the directional driller estimates that they expect to use 50,000 lbs WOB. The hole inclination is 60° and the mud density is 11 ppg.

What air weight of BHA is required if we are to avoid running any drill pipe in compression? Use a 15% safety margin.

$$\text{Required BHA weight} = \frac{50,000 \times 1.15}{0.832 \times \cos 60°} = 138,200 lbs$$

This is roughly the weight of ten stands of 8-inch drill collars, or attentively, six stands of 8-inch collars plus 44 joints of HWDP!

This is just not practical! It would be a long, stiff and expensive BHA.

Critical Buckling Force

Dawson and Paslay developed the following formula for critical buckling force in drill pipe.

$$F_{CR} = 2\sqrt{\frac{\mathrm{EIW}\sin\theta}{r}}$$

where **E** is Young's modulus.
I is axial moment of inertia.
W is buoyed weight per unit length.

θ is borehole inclination.
r is radial clearance between the pipe tool joint and the borehole wall.

If the compressive load reaches the F_{CR}, then sinusoidal buckling occurs.

This sinusoidal buckling formula can be used to develop graphs and tables (see pages 4-18 through 4-23). If the compressive load at a given inclination lies below the graph, then the drill pipe will not buckle. The reason that pipe in an inclined hole is so resistant to buckling is that the hole is supporting and constraining the pipe throughout its length. The low side of the hole tends to form a trough that resists even a slight displacement of the pipe from its initial straight configuration.

The graphs and tables provided in this section are for specific pipe/hole configurations and may be used to look up the critical buckling force. The following example illustrates how to calculate the critical buckling load.

Calculating Critical Buckling Force

Calculate the critical buckling load for 4.5-inch grade E drill pipe with a nominal weight of 16.6 lb/ft (approximate weight 17.98 lb/ft; tool joint OD 6.375 inches: from API RP7G, Table 2.10) in an 8.5-inch hole at 50° inclination.

1. Young's modulus, E, for steel is 29 x 10 psi

2. $I = \frac{\pi}{64}(OD^4 - ID^4)$

4.5-inch drill pipe with a nominal weight of 16.6 lbs/ft has an ID of 3.826 inches. This information can be found under *"New Drill Pipe Dimensional Data"* in the API RP-7G. (Table 2.1)

$$I = \frac{\pi}{64}(4.5^4 - 3.826^4) = 9.61 in^4$$

3. The approximate air weights for different sizes of drill pipe can also be found in the API RP-7G.

   Air weight = 17.98 lb/ft = 1.498 lb/in

$$\text{Buoyancy factor for 14 ppg mud} = 1 - \frac{14}{65.5} = 0.786$$

W = 1.498 x 0.786 = 1.178 lb/in

4. SIN 50° = **0.766**
5. Radial clearance = 1/2 (8.5" - 6.375") = 1.0625"

Note: *The values obtained in steps 1 through 5 may now be substituted in the formula below.*

$$FCR = 2\sqrt{\frac{29 \times 10^6 \times 9.61 \times 1.178 \times 0.766}{1.0625}}$$

Critical Buckling Force = 30,769 lbs

Calculating BHA Weight With Drill Pipe In Compression

This means that on high-angle wells in small hole sizes, a fraction of the weight on bit can safely be provided by having drill pipe in compression. It is suggested that 90% of the critical buckling force be used as the maximum contribution to the weight on bit from ordinary drill pipe.

Denoting the total air weight of the BHA by W_{BHA} the weight on bit by W_{BIT} and the critical buckling load by F_{CR}, we have:

$$W_{BIT}\ (SF) = W_{BHA}\ (BF)\ COS\theta + 0.9F_{CR}$$

Therefore,

$$W_{BHA} = \frac{W_{BIT}(SF) - 0.9F_{CR}}{(BF)\cos\Theta}$$

Note: *This formula does NOT take account of drag.*

Continuing example 4.5, recalculate the weight of the BHA required (assuming some drill pipe is to be run in compression).

Suppose we are using New 5-inch Grade E drill pipe with 4.5-inch IF connections.

Referring to the table for 5-inch drill pipe in a 12.25-inch hole, we see that the critical buckling load at 60° inclination is approximately 26,000 lbs.

Our formula then gives:

$$W_{BHA} = \frac{50,000 \times 1.15 - 0.9 \times 26,000}{0.832 \times 0.5}$$

W_{BHA} 82,000 lbs (approx).

Thus, a total air weight of 82,000 lbs is required. This is much more feasible than the value of 138,000 lbs which was previously calculated.

BHA Requirements When The Drillstring Is Not Rotated

As stated earlier, when the drillstring is rotated, the component of sliding friction (drag) is small and may be compensated for by using a safety factor in BHA weight calculations. Drillstring friction for rotary assemblies will mainly affect torque values. When the drillstring is not rotated (a steerable motor system in the oriented mode) axial drag can become very significant and drillstring friction should be evaluated.

A proper analysis of drillstring friction is more complex and must take into account a number of factors, including wellbore curvature.

BHA Weight For Steerable Motor Assemblies

In practice, BHA weight for steerable assemblies on typical directional wells is not a problem for the following reasons.

- The WOB is usually fairly low, especially when a PDC bit is used.
- When the drillstring is not rotated, the drill pipe is not subjected to the cyclical stresses which occur during rotary drilling. Therefore, sinusoidal buckling can be tolerated when there is no rotation of the drillstring. Helical buckling however, must be avoided.

Helical buckling occurs at 1.41 F_{CR}, where F_{CR} is the compressive force at which sinusoidal buckling occurs.

Therefore, if BHA weight requirements are evaluated as for rotary drilling, the results should be valid for steerable systems in the oriented mode except for unusual well paths which create exceptionally high values of axial drag.

The standard practice of minimizing BHA length and weight for steerable assemblies has not created any noticeable increase in the incidence of drillstring failure, even when long sections are drilled in the oriented mode.

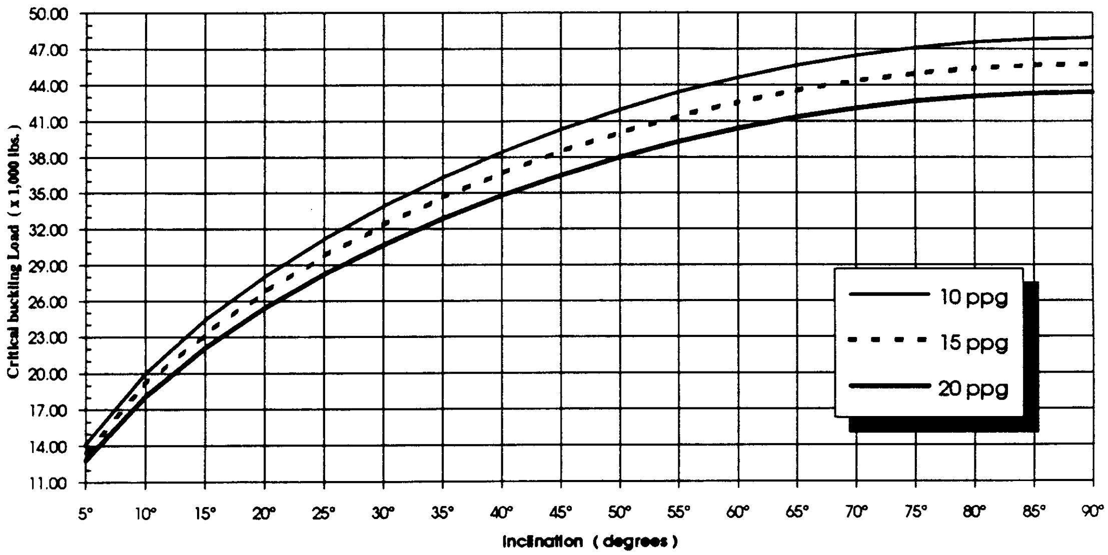
Summary

- When drilling vertical wells, ordinary drill pipe must NEVER be run in compression, in any hole size. Therefore, sufficient BHA weight must be used to provide all the desired weight on bit with an acceptable safety margin, except at higher inclinations.
- In large hole sizes (16-inch or greater) drill pipe should not be run in compression.
- In smaller hole sizes on high-angle wells (over 45°), drill pipe may be run in compression to contribute to the weight on bit, provided the maximum compressive load is less than the critical buckling force. This critical buckling force is the minimum compressive force which will cause sinusoidal buckling of the drill pipe.
- A safety margin of at least 10% should be used in the calculation to allow for some drag (friction) in the hole. However, axial drag *is* not a major factor when assemblies are rotated.

  The majority of the preceding discussion concerned rotary assemblies. However, it would also apply to steerable motor systems used in the rotary mode, with only minimal oriented drilling anticipated, the required BHA weight could be calculated the same way. If a significant amount of oriented drilling was likely, then the drag in the hole should be evaluated using Torque and Drag computer programs. In this type of situation, a proper engineering analysis of BHA weight requirements is advised.

NEW 5" GRADE E DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
8½" HOLE

lbf



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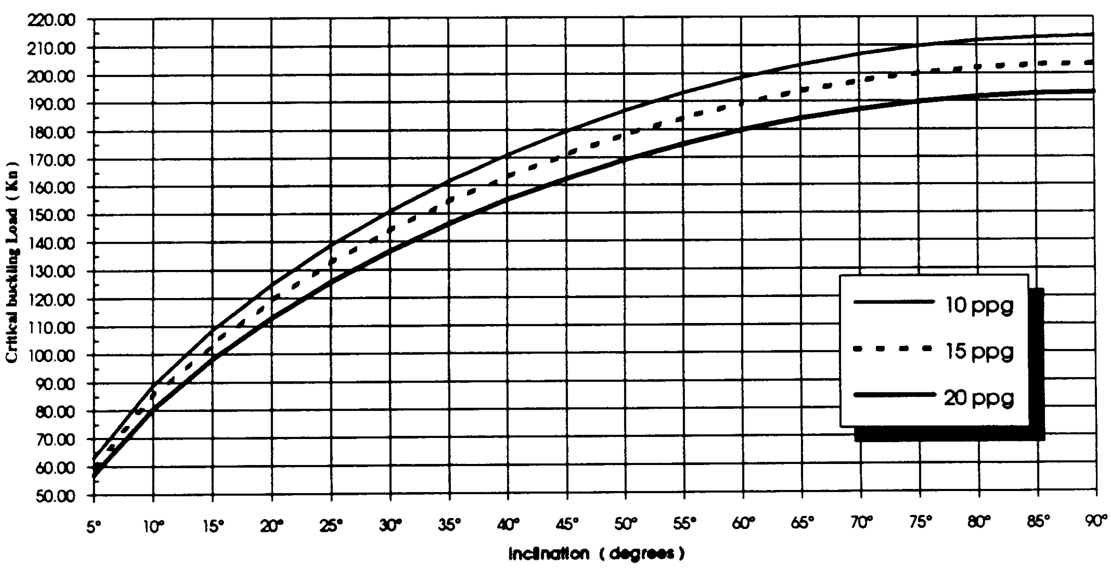
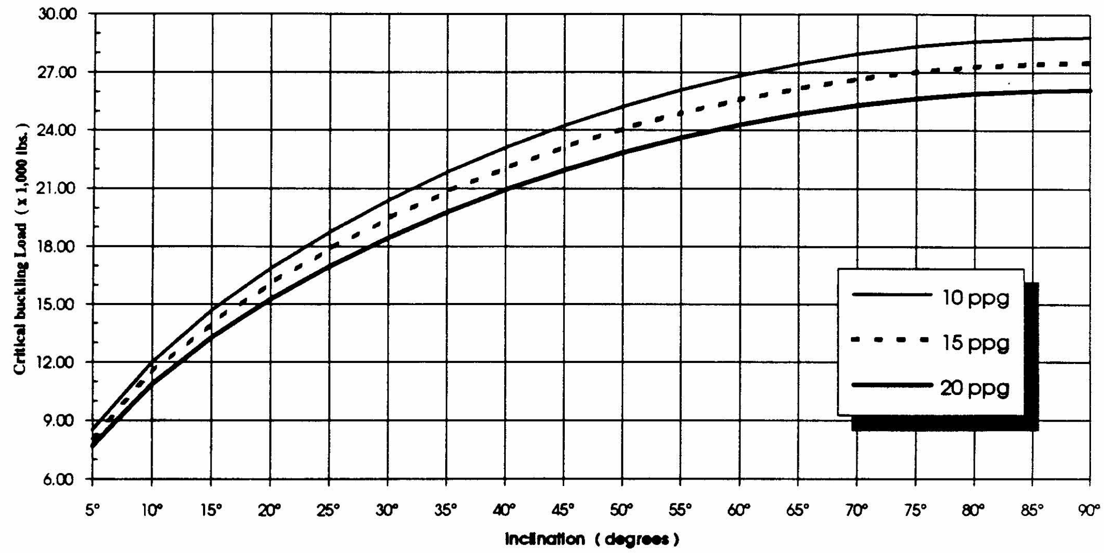


NEW 5" GRADE E DRILL PIPE

Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS

12¼" HOLE

lbf



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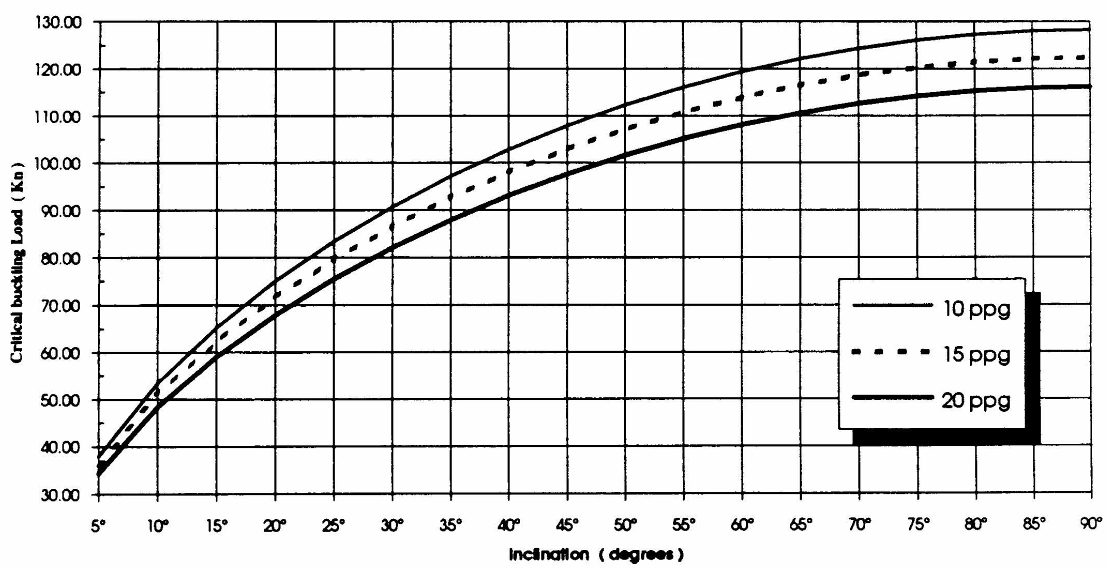
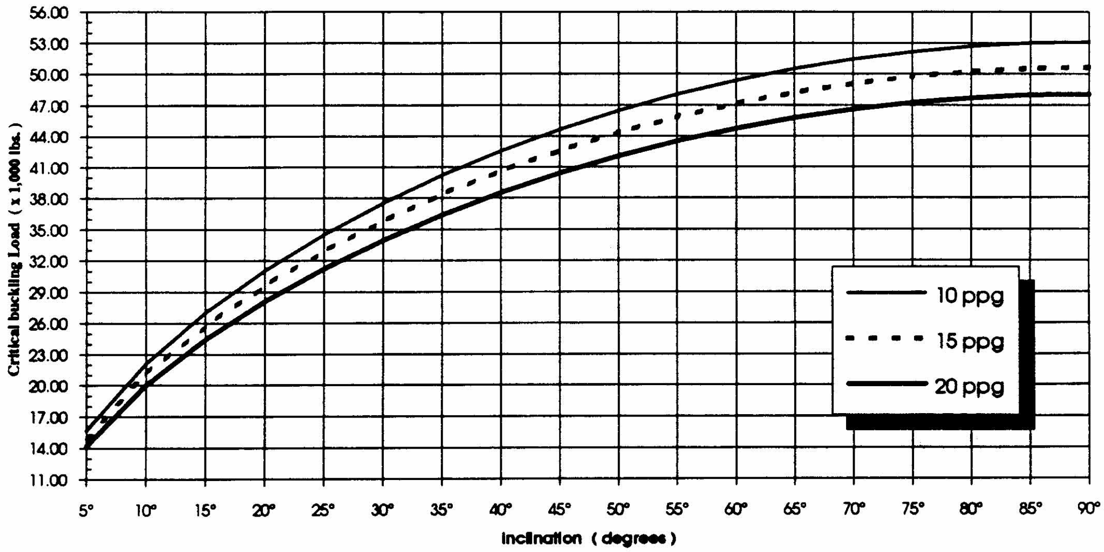


NEW 5" GRADE S-135 DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
8½" HOLE

lbf



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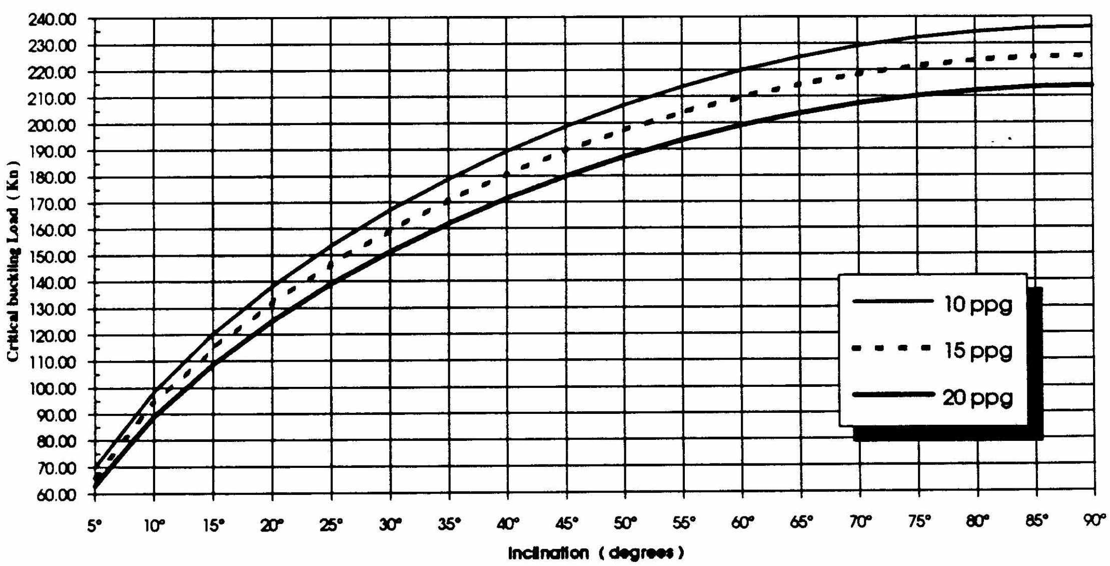
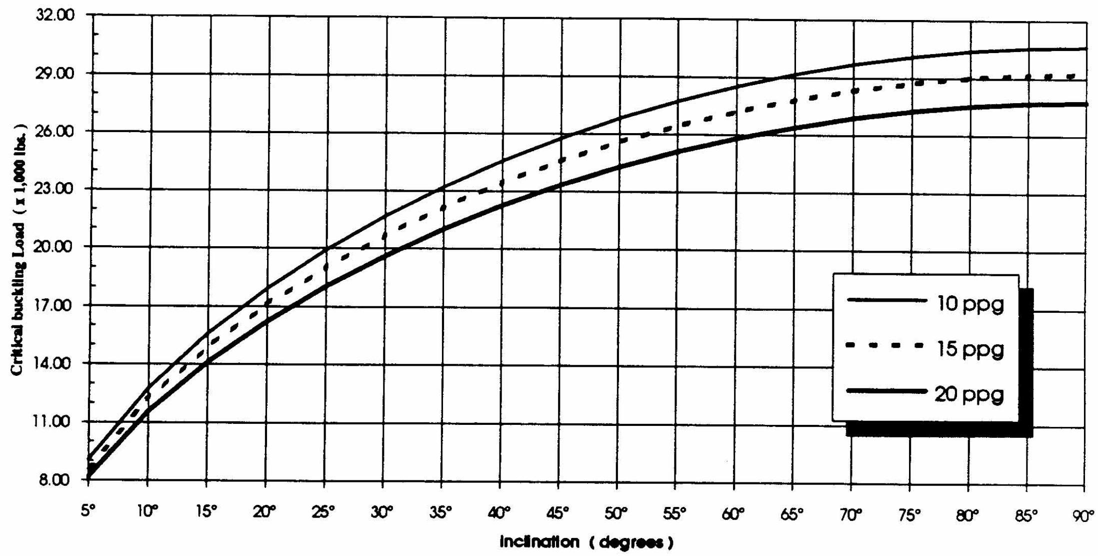


NEW 5" GRADE S-135 DRILL PIPE
Nom wt. 19.5 lb/ft - 4½" IF CONNECTIONS
12¼" HOLE

lbf



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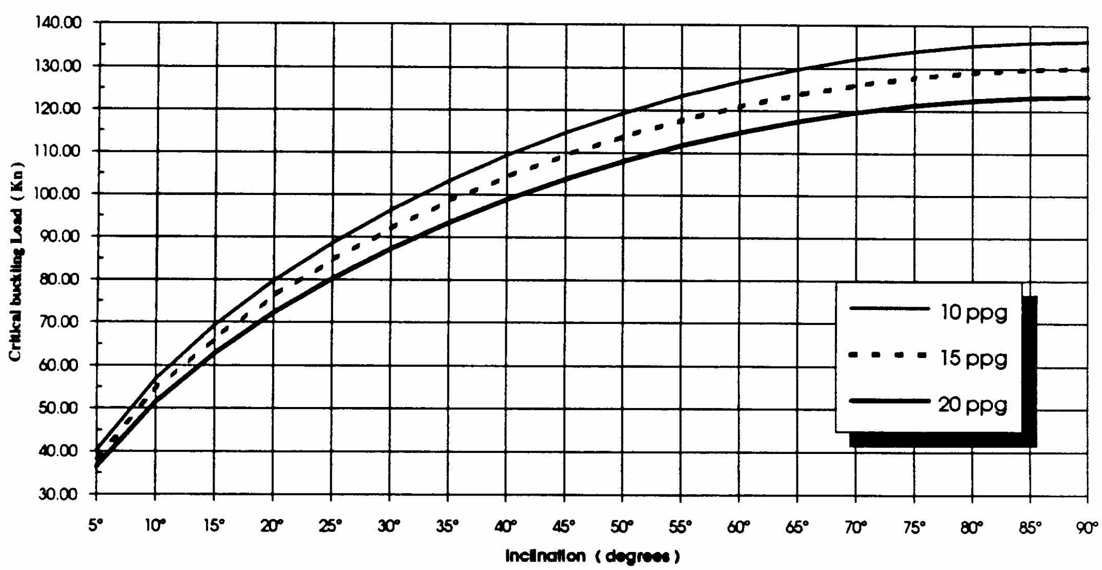
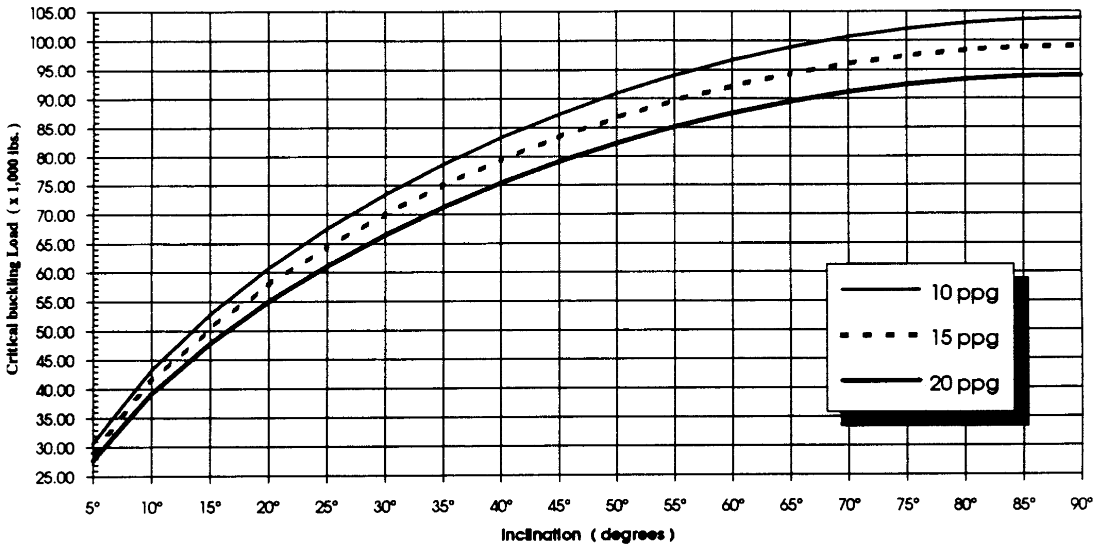


NEW 5" HWDP DRILL PIPE
49.3 lb/ft - 4½" IF CONNECTIONS
8½" HOLE

lbf



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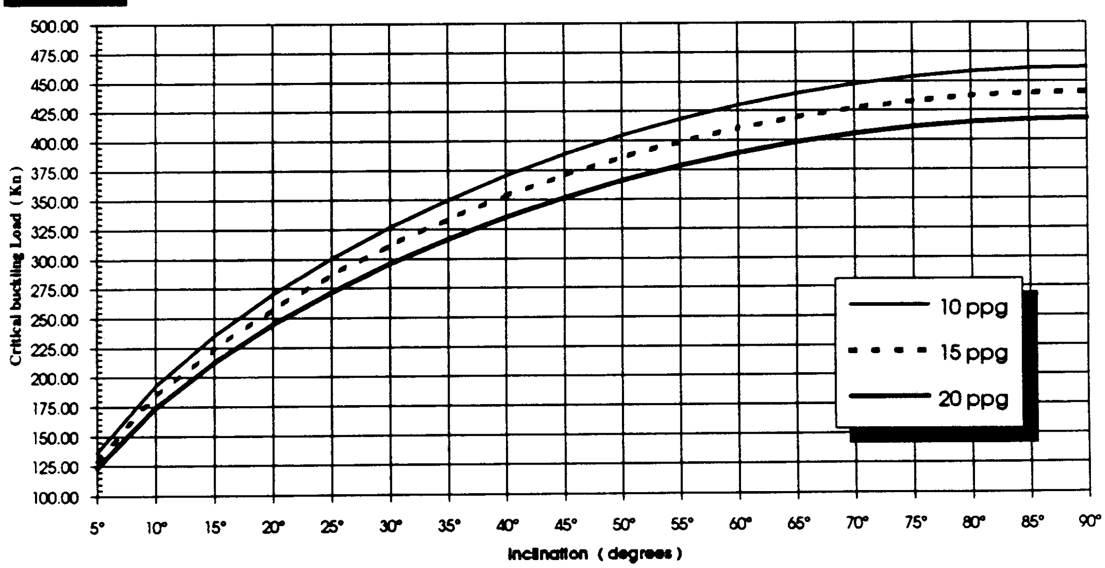
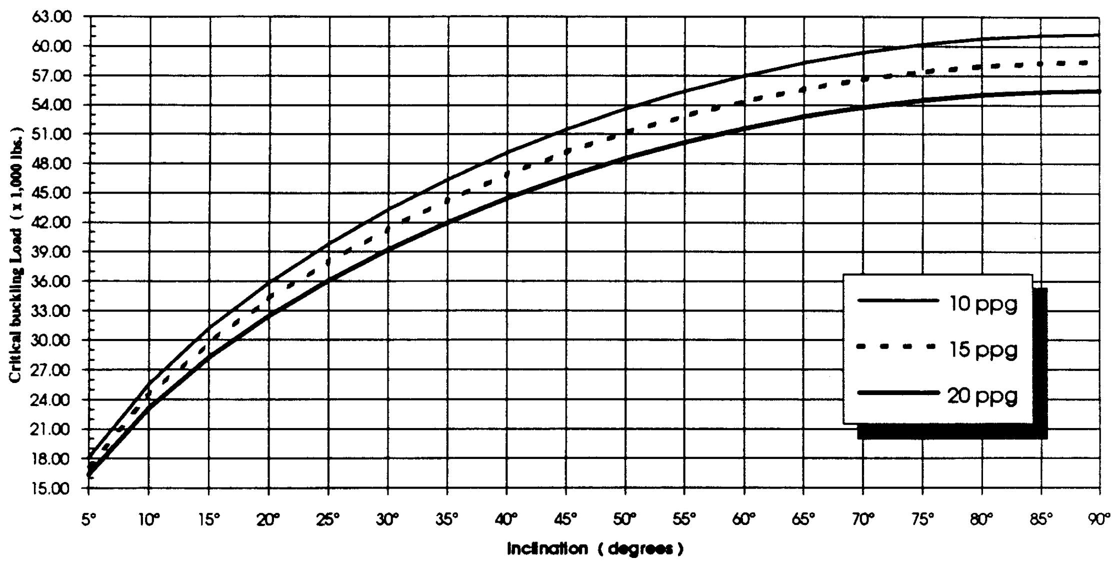


NEW 5" HWDP DRILL PIPE
49.3 lb/ft - 4½" IF CONNECTIONS
12¼" HOLE

lbf



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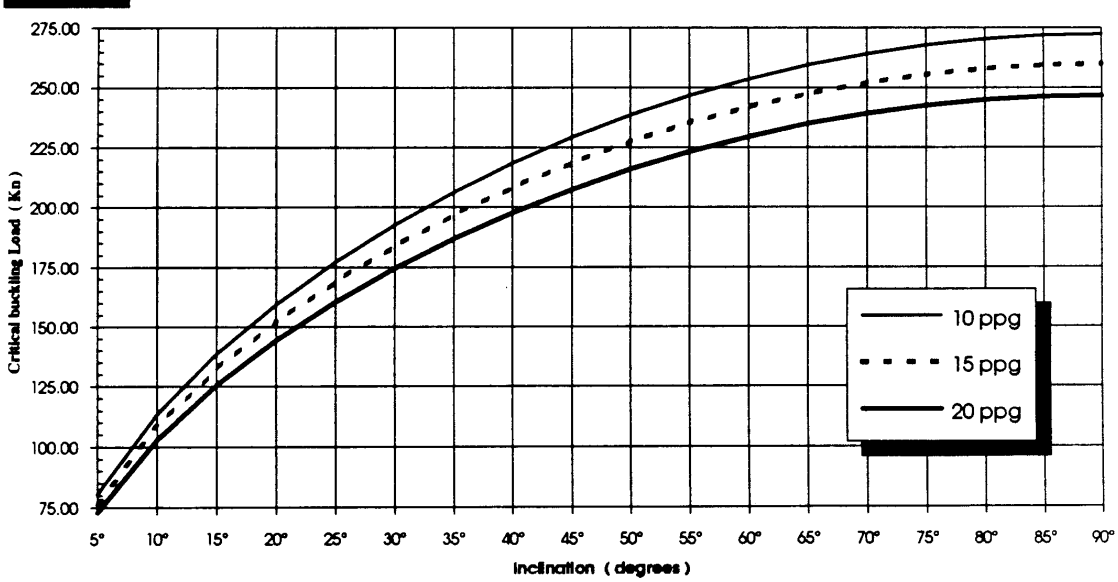


Neutral Point

The neutral point is usually defined as the point in the drillstring where the axial stress changes from compression to tension. The location of this neutral point depends on the weight-on-bit and the buoyancy factor of the drilling fluid. In practice, since the WOB fluctuates, the position of the neutral point changes. It is therefore quite common to refer to a “transition zone” as the section where axial stress changes from compression to tension.

Drillstring components located in this “transition zone” may, therefore, alternately experience compression and tension. These cyclic oscillations can damage downhole tools. A prime example is drilling jars, whose life may be drastically shortened if the jars are located in the transition zone. It is also important, as previously explained, to know if any drill pipe is being run in compression. Therefore it is important to know the location of the neutral point.

Calculation of Neutral Point

Case 1: Vertical Well, Neutral Point in the drill collars

$$L_{np} = \frac{WOB}{W_{DC}(BF)}$$

where:

L_{np} is the distance from the bit to the neutral point.

W_{DC} is the weight per foot of the drill collars

BF is the buoyancy factor of the drilling mud.

Example: Determine the neutral point in 7.25-inch x 2.25-inch collars if the weight-on0bit is 30,000 lbs and mud density is 11 ppg.

$$L_{np} = \frac{30,000}{127 \times 0.832} = 284ft$$

therefore:

L_{np} is 284 feet up into the collars.

Case 2: Vertical Well, Neutral Point in the heavy weight drill pipe

If drill collars and heavy weight are both being used, calculating the location of the neutral point becomes a little harder. First, you should use the previous formula to see if the neutral point is in the collars. If L_{np} is less than the length of the collars, then the neutral point is in the collars. If L_{np} is more than the length of the collars, the following formula should be used to determine how far up in the heavy weight the neutral point is located.

$$L_{nphw} = \frac{WOB - W_{DC}L_{DC}(BF)}{W_{hw}(BF)}$$

where:

L_{nphw} is the distance from the bottom of heavy weight to neutral point

WOB is weight on bit

W_{DC} is weight per foot of the collars

L_{DC} is length of the collars

W_{hw} is weight per foot of the heavy weight

BF is Buoyancy Factor

Example: Determine the location of the neutral point for the following.

Mud density = 13 ppg

Weight-on-Bit = 40,000 lbs

400 of 7-inch x 2.25-inch drill collars

600 of 5-inch heavy weight weighing 50 lbs/ft

$$L_{np} = \frac{WOB}{W_{DC}(BF)}$$

$$= \frac{40,000}{117 \times 0.802}$$

$$= 426.28 feet$$

Since L_{np} is 426 feet and we only have 400 feet of drill collar, the neutral point must be located in the heavy weight.

$$L_{nphw} = \frac{WOB - W_{DC}L_{DC}(BF)}{W_{hw}(BF)}$$

$$= \frac{40,000 - (117 \times 400 \times 0.802)}{50 \times 0.802}$$

$$= 61.51\text{feet}$$

Thus, the neutral point is 62 feet up from the bottom of the heavy weight drill pipe.

Case 3: Directional Well, Neutral Point in the drill collars

When the neutral point is in the drill collar section and the collars are all of one diameter, the following formula should be used:

$$L_{np} = \frac{WOB}{W_{DC}(BF)\cos I}$$

where:

L_{np} = distance from bit to neutral point in feet

W_{DC} = weight per foot of the drill collars

BF = Buoyancy Factor

WOB = weight on bit

I = borehole inclination

Case 4: Directional Well, Neutral Point in the heavy weight drill pipe

When the neutral point is in the HWDP but all the drill collars are of the same diameter, the following formula should be used:

$$L_{nphw} = \frac{WOB - W_{DC}L_{DC}(BF)\cos I}{W_{hw}(BF)\cos I}$$

where:

L_{nphw} is the distance from the bottom of the HWDP to the neutral point.

L_{DC} is the total length of the drill collar section.

W_{hw} is the weight per foot of the HWDP

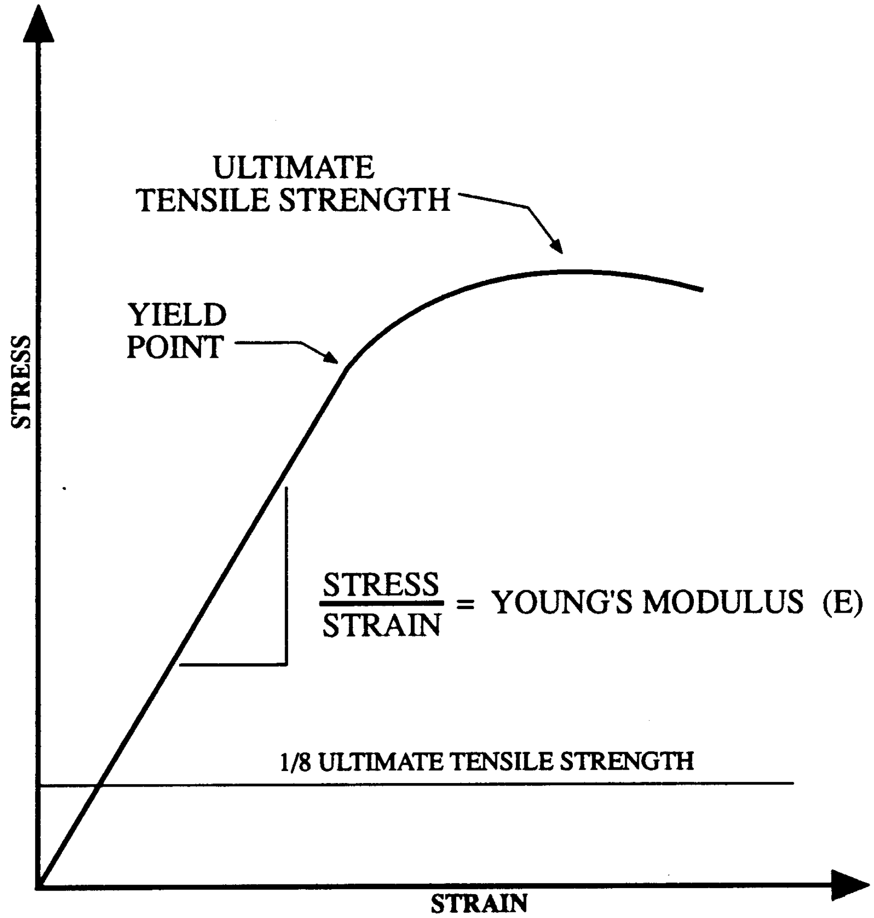
General Formula for Directional Wells

The last formula can be expanded in the case of a "tapered" BHA with drill collars of more than one diameter. For example, if there were two sizes of drill collars but the neutral point was in the heavy weight, the formula would become:

$$L_{nphw} = \frac{WOB - (BF)\cos I(W_{DC1}L_{DC1} + W_{DC2}L_{DC2})}{W_{hw}(BF)\cos I}$$

where W_{DC1} and L_{DCI} are the weight per foot and total length of the first size of drill collar and W_{DC2} and L_{DC2} are the weight per foot and total length of the second size of drill collar.

Drillpipe Fatigue and Failure



Bending Stress

$$SIGMA\beta = \frac{ED}{2R}$$

where **E** is Young's modulus (psi)

D is Diameter of tubular (inches)

R is Radius of curvature (inches)

Pipe Grade	SIGMA Ultimate	SIGMA Min Tensile Yield
E	100,000 psi	75,000 psi
X	120,000 psi	95,000 psi
G	130,000 psi	105,000 psi
S-135	160,000 psi	135,000 psi
S-165	175,000 psi	165,000 psi

Fatigue Damage

Note: *Fatigue damage will ultimately lead to pipe failure.*

Case 1

Sigma β < 1/8 Sigma Ultimate

- Fatigue damage should not occur.
- Life should be infinite.

Case 2

1/8 Sigma Ultimate < Sigma β < 1/4 Sigma Ultimate

- Fatigue damage may occur.
- Life may be as low as 1,000,000 cycles or be infinite.

Case 3

1/4 Sigma Ultimate < Sigma β < 0.42 Sigma Ultimate

- Fatigue damage will occur.
- Life will be less than 1,000,000 cycles.

Case 4

Sigma β > 0.42 Sigma Ultimate

- Fatigue damage will occur.
- Do not rotate.

Torque & Drag

Several factors affect hole drag, including hole inclination, dogleg severity, hole condition, mud properties, hole size, and drillstring component types, sizes and placement. However, as mentioned earlier, in drilling situations where the drillstring is not rotated (as when a steerable system is used in the oriented mode) axial drag can become very significant and should be evaluated using a Torque and Drag computer program. Torque and Drag programs can be found in ***EC*Track*** and ***DrillByte***.

Along Hole Components of Force

Consider a short element of a BHA which has a weight W.

Effective weight in drilling mud = W(BF)

Component of weight acting along borehole = $W(BF)\cos\theta$

If the BHA is not rotated, *the force of friction,* F_{FR} acting up the borehole on the BHA element is given by:

$$F_{FR} = \mu N$$

...where μ is the coefficient of friction,

N is the normal reaction force between the BHA element and the borehole wall. If this normal reaction is due only to the weight of the BHA element itself, then:

$N = W(BF)\sin\theta$ and hence

$$F_{FR} = \mu W(BF)\sin\theta$$

The net contribution to the WOB from this BHA element is therefore

$$W_{BIT} = W\,(BF)\,(\cos\theta - \mu\sin\theta)$$

Computer Models of Drillstring Friction

Proper evaluation of drillstring friction requires the use of a computer program. These programs analyze drillstring friction for rotary drilling as well as drilling with no drillstring rotation.

These mathematical models make a number of simplifying assumptions and consider the drillstring as composed of discrete elements. Using these models, it is possible to solve equations for the normal force of drillstring/ well bore contact at the bottom drillstring element, the friction force deriving from that normal contact force, and the load condition at the upper end of the drillstring element. Such methods, repeated for each drillstring element over the length of the drillstring, yield the following information:

- Surface hookload and rotary torque

- Normal forces of drillstring/well bore contact at each drillstring element
- Average torsional and tensile load acting upon each drillstring element

The E*C TRAK Torque and Drag Module

This program, developed at the Drilling Research Center in Celle, Germany, is used to calculate torque and drag when a friction factor (coefficient of sliding friction) is known or estimated. It will calculate the friction factor when either torque or hookload is known.

Software accuracy has been verified against actual field data, with inputs and outputs handled in user selected units.

General Uses

The program may be used to:

- Optimize well path design for minimum torque and drag
- Analyze problems either current or post-well
- Determine drillstring design limitations
- Determine rig size requirements

Inputs Required

- Drillstring component data (OD, ID, tool joint, and material composition)
- Survey data (actual or planned)
- Friction factor(s) or actual hookload or torque values (for friction factor calculation)

Outputs

Information concerning loads, torques and stresses are calculated for discrete points in the drillstring from rotary table to the bit. These values are output in both tabular (summary or detailed) and graphical formats:

- Drag load (pick-up or slack-off)
- Pick up load
- Slack off load
- Rotating off bottom load
- Drilling load

- Rotating off bottom torque
- Rotary torque (drilling and off-bottom)
- Maximum allowable hook load (at minimum yield)
- Drillstring weight (in air)
- Bit to neutral point distance drillstring twist
- Drillstring twist
- Axial stress
- Torsional stress
- Bending stress
- Total equivalent stress

Typical Drillstring - Wellbore Friction Factors

Well Environment	Mud Type Water Base	Mud Type Oil Base
Casing	0.17 - 0.28	0.10 - 0.16
Open Hole	0.23 - 0.44	0.13 - 0.26

Use Of Torque & Drag Programs For BHA Weight Evaluation

These programs have a wide range of applications, but have mainly been used to evaluate drillstring design integrity and alternative well plans for horizontal wells or complex**,** unusual directional wells. However, the program can be used to check BHA weight calculations for normal directional wells. The program will calculate axial drag for a non-rotated assembly and also calculates the position of the neutral point in the drillstring. In addition, the program calculates the forces on the drill pipe and will “flag” any values of compressive load which exceed the critical buckling force for the drill pipe.

Self-Check Exercises

1. Determine the static hookload of a drillstring consisting of 9,000 ft of 4.5-inch new, Grade E drill pipe with a nominal weight of 16.6 lbs/ft (approximate weight of 17.1 lbs/ft) plus 600 feet of 5 inch heavy-weight drill pipe weighing 49.3 lbs/ft and 120 feet of eight 2.5-inch collars in a vertical hole with 12 ppg mud. Disregard effects of hole drag and assume that the drillstring is full of fluid

   A. What is the air weight of the drillstring

   B. What is the buoyed weight of the drillstring or hookload

   C. What is the net buoyant force acting on the drillstring

2. Allowing for a safety factor of 100,000 pound overpull before reaching the drill pipe yield strength, what is the deepest that can be drilled with the drill pipe and BHA in Exercise 1.

3. In all the following examples, assume that **no** drill pipe is to be run in compression and ignore drag in the calculation. Find the air weight required to get the desired weight on the bit.

   A. Desired weight 40,000 lbs; mud density 13 ppg; hole angle 20°; safety margin 10%. AIR WEIGHT REQUIRED =

   ____

   B. Desired weight 40,000 lbs; mud weight 13 ppg; hole angle 20°; safety margin 15%. AIR WEIGHT REQUIRED =

   ____

   C. Find the number of joints needed to get the air weight. 62,000 lbs air weight needed; six 7-inch OD, 2-inch ID drill collars are available. How many joints of 4.5-inch heavy weight are needed (joint of HWDP=1230 lbs)?

   ____

4. Calculate the critical buckling load for the drill pipe specified in the following case.

   A. 3.5-inch new, high strength drill pipe (2.764 inch ID) with an approximate weight of 14.7 lb/ft (5-inch OD tool joint) in a 6 inch hole with 80° inclination and a mud density of 11 ppg.

5. In the following examples, assume that drill pipe may be run in compression but the compressive force must not exceed 90% of the critical buckling force. In all cases assume 5-inch new, S-135 drill pipe with 4.5-inch IF connections is being used. Find the BHA air weight required.

   A. Desired maximum WOB = 50,000 lbs;
   Borehole Inclination = 55°;
   Mud Density = 13ppg;
   Hole Size = 12.25-inch.
   Use a safety factor of 10%.

   B. Suppose you have 100 feet of 8-inch tubulars weighing 150 lbs/ft and 93 feet of 6.5-inch tubulars weighing 99 lbs/ft. How many joints of 5-inch HWDP are required?

Drill Collar Weights
(pounds per foot)

OD/ID	1”	1-1/4”	1-1/2”	1-3/4”	2”	2-1/4”	2-1/2”	2-13/16	3”	3-1/4”	3-1/2”	3-3/4”
3” OD	21	20	18									
3-1/8”	22	22	20									
3-1/4”	26	24	22									
3-1/2”	30	29	27									
3-3/4”	35	33	32									
4” OD	40	39	37	35	32	29						
4-1/8”	43	41	39	37	35	32						
4-1/4”	46	44	42	40	38	35						
4-1/2”	51	50	48	46	43	41						
4-3/4”			54	52	50	47	44					
5” OD			61	59	56	53	50					
5-1/4”			68	65	63	60	57					
5-1/2”			75	73	70	67	64	60				
5-3/4”			82	80	78	75	72	67	64	60		
6” OD			90	88	85	83	79	75	72	68		
6-1/4”			98	96	94	91	88	83	80	76	72	
6-1/2”			107	105	102	99	96	91	89	85	80	
6-3/4”			116	114	111	108	105	100	98	93	89	
7” OD			125	123	120	117	114	110	107	103	98	93
7-1/4”			134	132	130	127	124	119	116	112	108	103
7-1/2”			144	142	139	137	133	129	126	122	117	113
7-3/4”			154	152	150	147	144	139	136	132	128	123
8” OD			165	163	160	157	154	150	147	143	138	133
8-1/4”			176	174	171	168	165	160	158	154	149	144
8-1/2”			187	185	182	179	176	172	169	165	160	155
9” OD			210	208	206	203	200	195	192	188	184	179
9-1/2”			234	232	230	227	224	220	216	212	209	206
9-3/4”			248	245	243	240	237	232	229	225	221	216

Heavy Weight Drill Pipe - Range II

Nominal Size (in)	ID (in)	Connection Type & OD (in)	Approximate Weight/foot (lb)	Make-Up Torque (ft/lb)	Capacity bbl/100ft	Displacement (bbl/100ft)
3-1/2”	2-1/16”	N.C.38 (3-1/2 I.F.) / 4-3/4	25.3	9,900	0.421	0.921
4”	2-9/16”	N.C.40 (4 F.H.) / 5-1/4”	29.7	13,250	0.645	1.082
4-1/2”	2-3/4”	N.C.46 (4 I.F.) / 6-1/4”	41.0	21,800	0.743	1.493
5”	3”	N.C.50 (4-1/2 I.F.) / 6-1/2”	49.3	29,400	0.883	1.796

Chapter 5

Directional Drilling

Upon completion of this chapter, you should be able to:

- Describe the general aspects involved in well planning.
- Describe the main features of the common well patterns and list the applications and disadvantages of each.
- State the two basic types of downhole motor and give a simple explanation of the operating principles of each.
- Explain what is meant by “reactive torque” and the importance of this in directional drilling.
- List the main deflection tools available and state the advantages and disadvantages of each.
- Explain what is meant by the “toolface” of a deflection tool.
- Define and explain the terms “Tool Face Orientation”, “High Side Tool Face”, and “Magnetic Tool Face”.
- List the main factors which affect the directional behavior of rotary assemblies.
- Explain the Fulcrum, Stabilization and Pendulum principles.
- Explain what is meant by the terms “steerable motor” and “Navigation Drilling System”.
- Explain the concept of “three-point geometry” and calculate the “Theoretical Geometric Dogleg Severity” (TGDS) of a Navigation System.
- Explain the differences between “Conventional” and “Navigational” drilling systems

Additional Review/Reading Material

Baker Hughes INTEQ, *DrillByte Operations Manual*, P/N 80319H

Baker Hughes INTEQ, *Directional Drilling Manual*,

Bourgoyne Jr., Adam, et al, *Applied Drilling Engineering*, SPE Textbook Series, Vol. 2, 1986

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Applications Of Directional Drilling

Definition of Directional Drilling

Directional drilling can generally be defined as the science of directing a wellbore along a predetermined trajectory to intersect a designated sub-surface target.

Applications

Multiple wells from offshore structures

The most common application of directional drilling techniques is in offshore drilling. Many oil and gas deposits are situated well beyond the reach of land based rigs. Drilling a large number of vertical wells from individual platforms is both impractical and uneconomical. The obvious approach for a large oilfield is to install a fixed platform on the seabed, from which many directional boreholes can be drilled. The bottomhole locations of these wells are carefully spaced for optimum recovery.

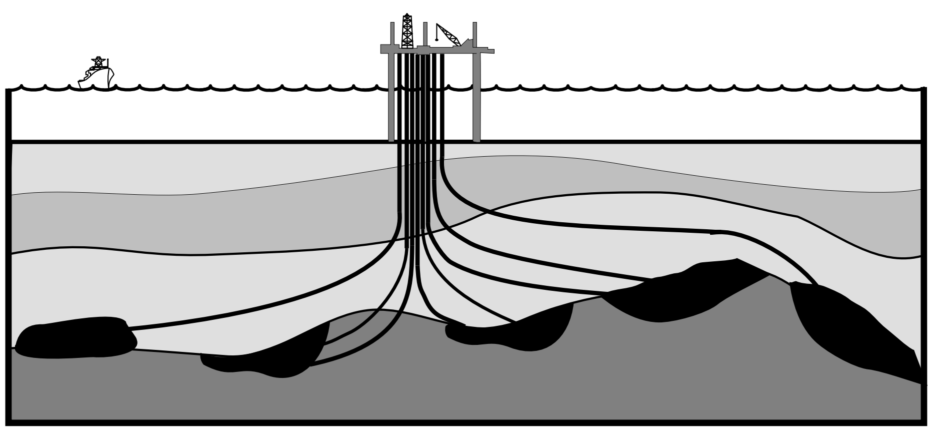


Figure 5-1: Multiple wells from offshore structures.

In conventional development, wells cannot be drilled until the platform has been constructed and installed. This can mean a delay of several years before production begins. Such delay scan be considerably reduced by pre-drilling some of the wells through a subsea template while the platform is being constructed. These wells are directionally drilled from a semi-submersible rig and tied back to the platform once it has been installed.

Relief Wells

Directional techniques are used to drill relief wells in order to “kill” blowouts. Relief wells are deviated to pass as close as possible to the uncontrolled well. Heavy mud is pumped into the reservoir to overcome the pressure and bring the wild well under control.

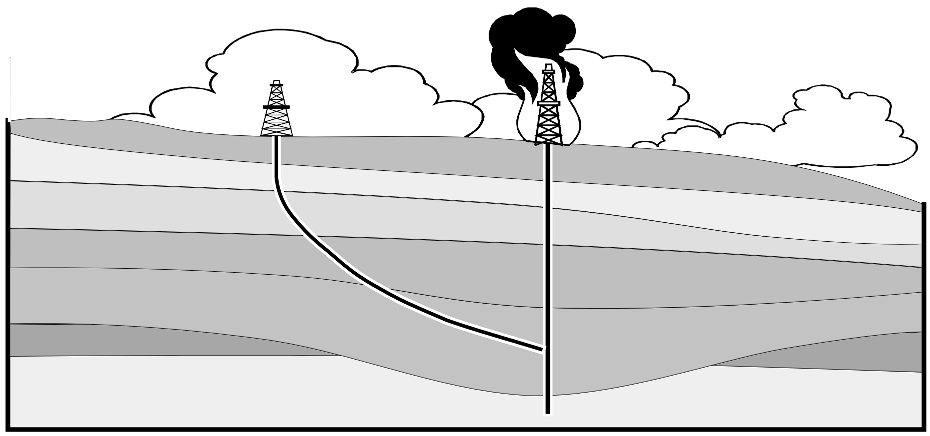


Figure 5-2: Relief wells.

Controlling Vertical Wells

Directional techniques are used to “straighten crooked holes”. When deviation occurs in a well which is supposed to be vertical, various techniques can be used to bring the well back to vertical. This was one of the earliest applications of directional drilling.

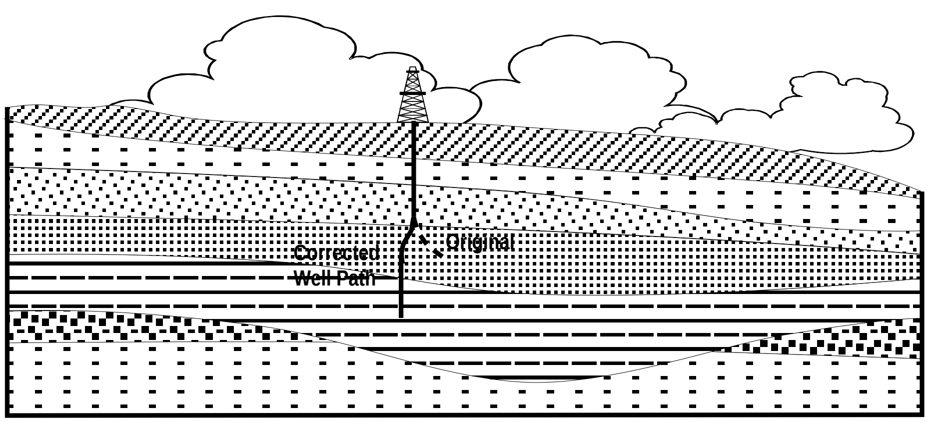


Figure 5-3: Controlling vertical wells.

Sidetracking

Sidetracking out of an existing wellbore is another application of directional drilling. This is done to bypass an obstruction (“fish”) in the original wellbore, to explore the extent of a producing zone in a certain sector of a field, or to sidetrack a dry hole to a more promising target. Wells are also sidetracked to access more reservoir by drilling a horizontal hole section from the existing well bore.

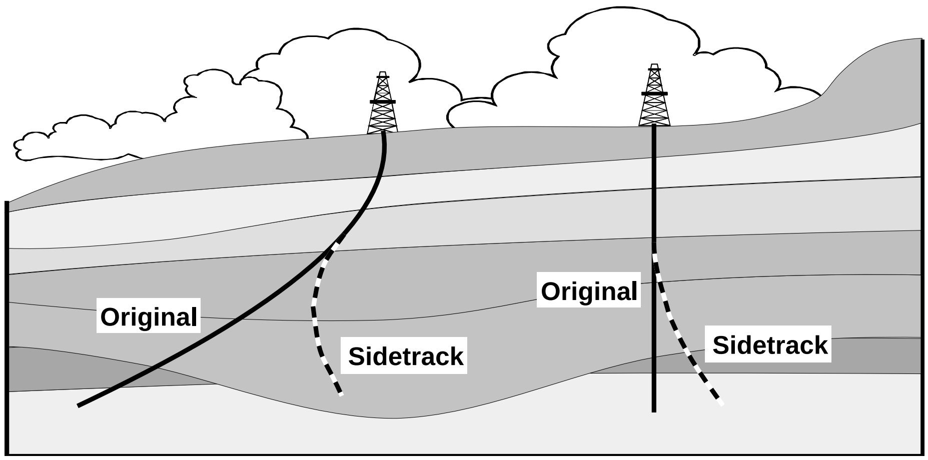


Figure 5-4: Sidetracking.

Inaccessible locations

Directional wells are often drilled because the surface location directly above the reservoir is inaccessible, either because of natural or man-made obstacles.

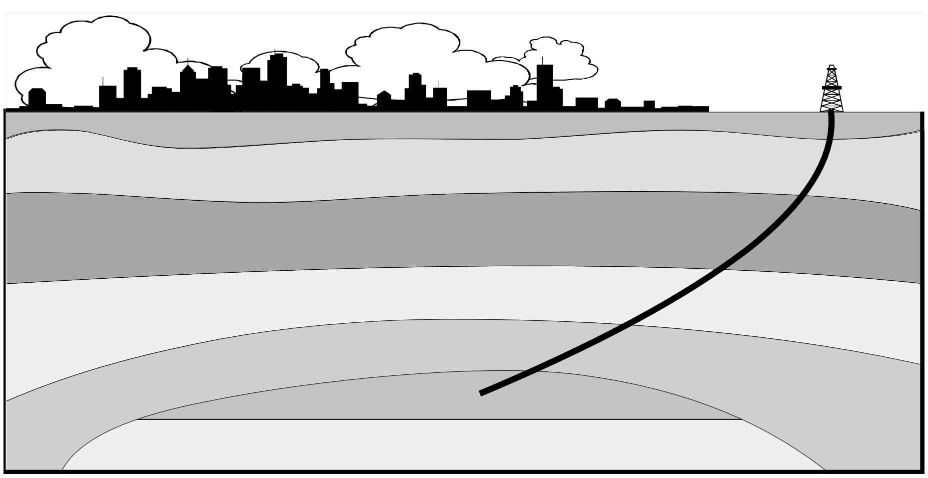


Figure 5-5: Inaccessible locations.

Fault Drilling

Directional wells are also drilled to avoid drilling a vertical well through a steeply inclined fault plane which could slip and shear the casing.

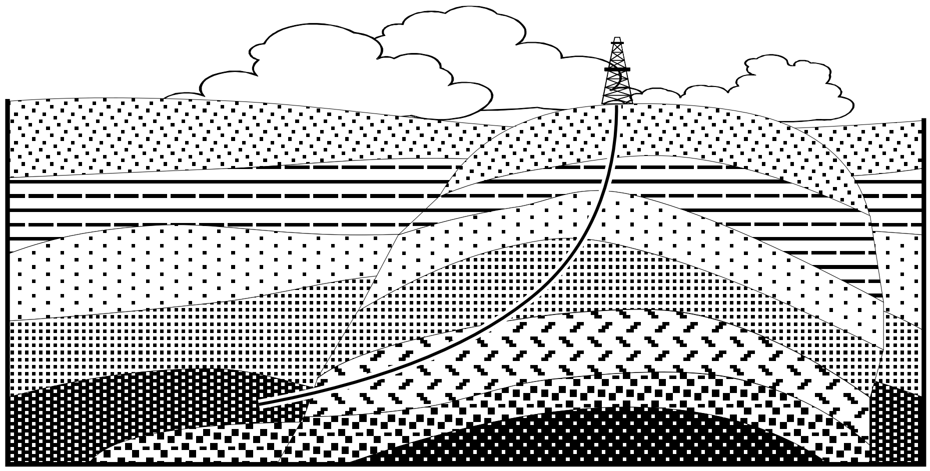


Figure 5-6: Fault drilling.

Salt Dome Drilling

Directional drilling programs are sometimes used to overcome the problems of drilling near salt domes. Instead of drilling through the salt, the well is drilled at one side of the dome and is then deviated around and underneath the overhanging cap.

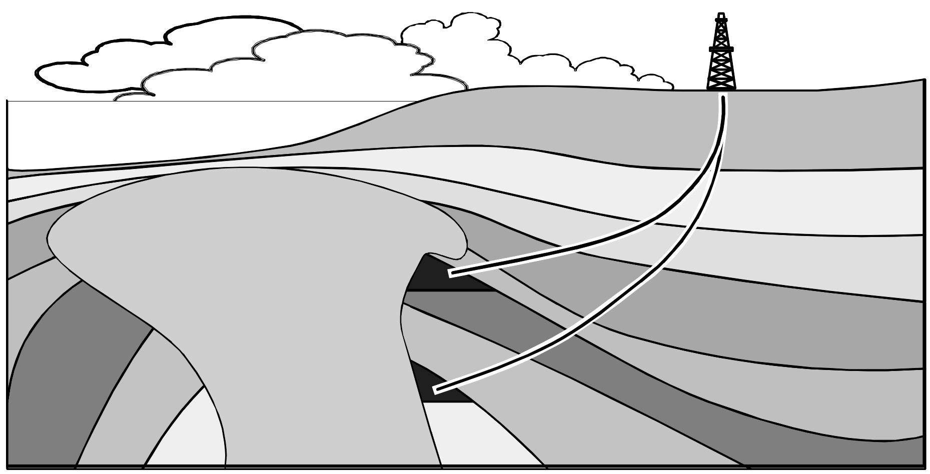


Figure 5-7: Salt dome drilling.

Shoreline Drilling.

In the case where a reservoir lies offshore but quite close to land, the most economical way to exploit the reservoir may be to drill directional wells from a land rig on the coast.

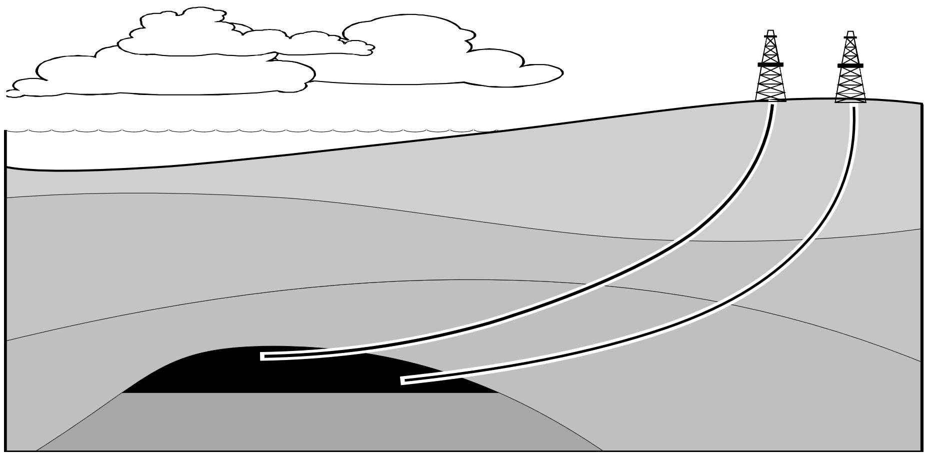


Figure 5-8: Shoreline drilling.

These are only some of the many applications of directional drilling. Although it is not a new concept, one type of directional drilling, horizontal drilling, is the fastest growing branch of drilling, with major advances occurring in tools and techniques. As with directional drilling, there are numerous specific applications for horizontal drilling.

Well Planning

Introduction

There are many aspects involved in well planning, and many individuals from various companies and disciplines are involved in designing various programs for the well (mud program, casing program, drill string design, bit program, etc). A novel approach to well planning is one where the service contractors become equally involved in their area of expertise.

This section will concentrate on those aspects of well planning which have always been the province of directional drilling companies.

Reference Systems and Coordinates.

With the exception of Inertial Navigation Systems, all survey systems measure inclination and azimuth at a particular measured depth (depths measured “along hole”). These measurements are tied to fixed reference systems so that the course of the borehole can be calculated and recorded. These reference systems include:

- Depth references
- Inclination references
- Azimuth references

Depth References

During the course of a directional well, there are two kinds of depths:

- Measured Depth (MD) is the distance measured along the actual course of the borehole from the surface reference point to the survey point. This depth is always measured in some way, for example, pipe tally, wireline depth counter, or mud loggers depth counter.
- True Vertical Depth (TVD) is the vertical distance from the depth reference level to a point on the borehole course. This depth is always calculated from the deviation survey data.

In most drilling operations the rotary table elevation is used as the working depth reference. The abbreviation BRT (below rotary table) and RKB (rotary kelly bushing) are used to indicate depths measured from the rotary table. This can also be referred to as derrick floor elevation. For floating drilling rigs the rotary table elevation is not fixed and hence a mean rotary table elevation has to be used.

In order to compare individual wells within the same field, a common depth reference must be defined and referred to (e.g. When drilling a relief well into a blow-out well, the difference in elevation between the wellheads has to be accurately known). Offshore, mean sea level (MSL) is sometimes used. Variations in actual sea level from MSL can be read from tide tables or can be measured.

Inclination References

The inclination of a well-bore is the angle (in degrees) between the vertical and the well bore axis at a particular point. The vertical reference is the direction of the local gravity vector and could be indicated by a plumb bob.

Azimuth Reference Systems

For directional surveying there are three azimuth reference systems:

- Magnetic North
- True (Geographic) North
- Grid North

All “magnetic-type” tools give an azimuth (hole direction) referenced to Magnetic North. However, the final calculated coordinates are always referenced to either True North or Grid North.

True (Geographic) North

This is the direction of the geographic North Pole which lies on the Earth’s axis of rotation. Direction is shown on maps using meridians of longitude.

Grid North

Drilling operations occur on a curved surface (i.e, the surface of the Earth) but when calculating horizontal plane coordinates a flat surface is assumed. Since it is not possible to exactly represent part of the surface of a sphere on a flat well plan, corrections must be applied to the measurements. To do this, different projection systems which can be used.

UTM System

One example of a grid system is the Universal Transverse Mercator (UTM) System. In transverse mercator projection, the surface of the spheroid chosen to represent the Earth is wrapped in a cylinder which touches the spheroid along a chosen meridian. (A meridian is a circle running around the Earth passing through both North and South geographic poles.)

These meridians of longitude converge towards the North Pole and do not produce a rectangular grid system. The grid lines on a map form the rectangular grid system, the Northerly direction of which is determined by one specified meridian of longitude. This “Grid North” direction will only be identical to “True North” on a specified meridian.

The relationship between True North and Grid North is indicated by the angles 'a' in Figure 5-9. Convergence is the angle difference between grid north and true north for the location being considered.

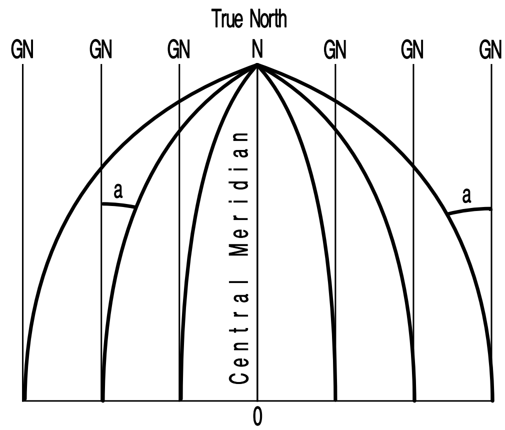


Figure 5-9: Relationship between True North and Grid North

The reference meridians are 6 degrees apart, starting at the Greenwich meridian, which means the world is divided into 60 zones. The zones are numbered 0 to 60 with zone 31 having the 0 degree meridian (Greenwich) on the left and the 6 degree East on the right. Each zone is then further divided into grid sectors - a grid sector covering 8 degrees latitude starting from the equator and ranging from 80° South to 80° North. The sectors are given letters ranging from C to X (excluding I and O).

Therefore, each sector is uniquely identified by a number from 0 to 60 (zone number) and a letter. For example, sector 31U shown in Figure 5-10, is the Southern North Sea.

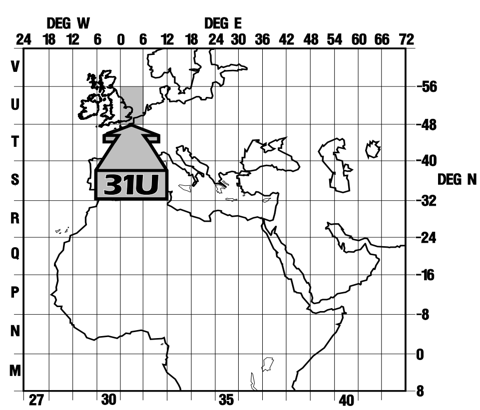


Figure 5-10: Sector Identification

Coordinates in the UTM system are measured in meters. North coordinates being measured from the equator. For the Northern hemisphere, the equator is taken as 0.00m North whereas for the Southern hemisphere the equator is 10,000,000m North (to avoid negative numbers). East coordinates for each sector are measured from a line 500,000m west of the central meridian for that sector. In other words, the central meridian for each zone is arbitrarily given the coordinate 500,000m East. Again, this avoids negative numbers.

So UTM coordinates are always Northings and Eastings, and are always positive numbers.

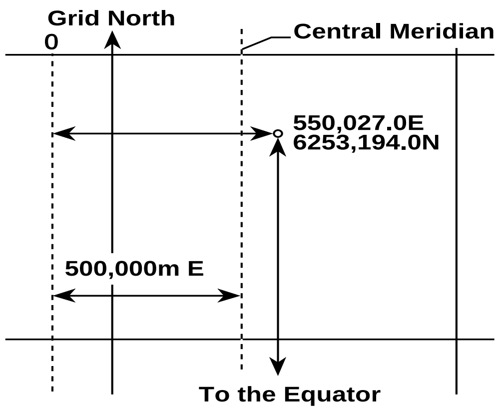


Figure 5-11: Northings and Eastings

Lambert Projection.

Another projection system, used in some parts of the world, is the conical projection or LAMBERT system. A cone as opposed to a cylinder covers the spheroid under consideration. This produces a representation with meridians as convergent lines and parallels as arcs of circles.

Further discussion of the coordinate systems and map projections is beyond the scope of this text.

Field Coordinates

Although the coordinates of points on a wellpath could be expressed as UTM coordinates, it is not normal practice. Instead, a reference point on the platform or rig is chosen as the local origin and given the coordinates 0,0. On offshore platforms this point is usually the center of the platform. The Northings and Eastings points on the wells drilled from the platform are referenced to this single origin. This is important when comparing positions of wells, in particular for anti-collision analysis.

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:

Azimuth.

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

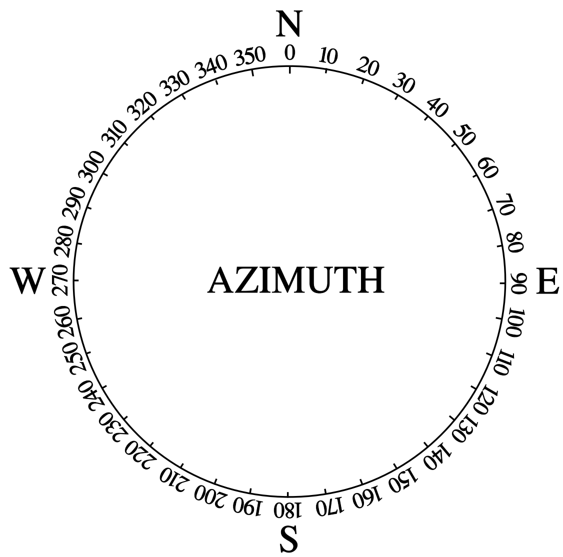


Figure 5-12: The Azimuth System

Quadrant Bearings

In the quadrant system (Figure 5-13), the directions are expressed as angles from 0°-90° measured from North in the two Northern quadrants and from

South in the Southern quadrants. The diagram in Figure 5-14 illustrates how to convert from the quadrant system to azimuth, and vice versa.

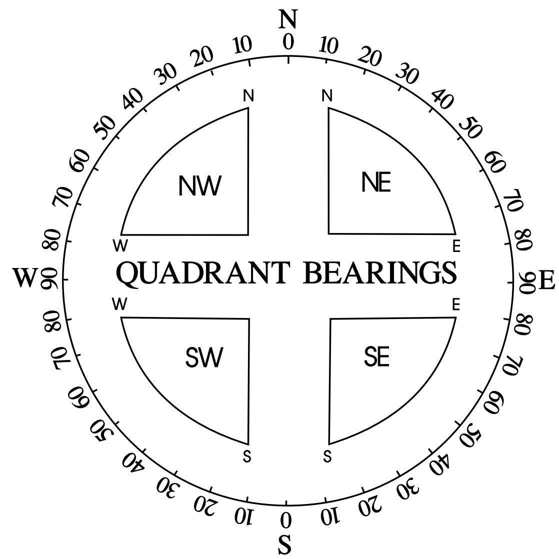


Figure 5-13: The Quadrant System

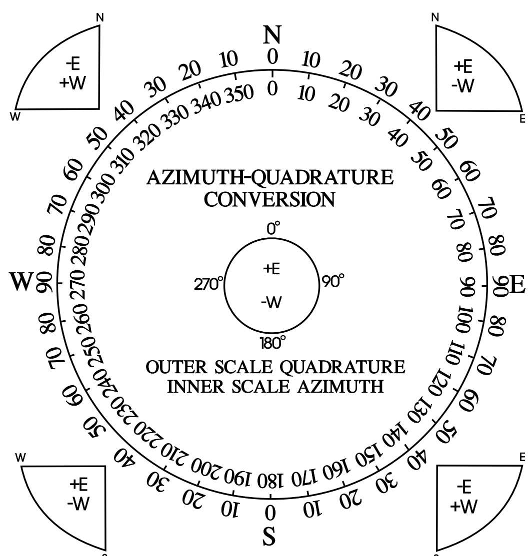


Figure 5-14: Conversion from Quadrant to Azimuth Systems

Planning The Well Trajectory

One area of well planning in which directional companies are closely involved is the planning of the well trajectory. 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.

The Target

The target is usually specified by the geologist, who will not merely define a certain point as the target but also specify the acceptable tolerance (e.g. a circle of radius 100 feet having the exact target as its center). Target zones should be selected as large as possible to achieve the objective. If multiple zones are to be penetrated, they should be selected so that the planned pattern is reasonable and can be achieved without causing drilling problems.

Types of Directional Patterns

The advent of steerable systems has resulted in wells that are planned and drilled with complex paths involving 3-dimensional turns. This is particularly true in the case of re-drills, where old wells are sidetracked and drilled to new targets.

These complex well paths are harder to drill and the old adage that “the simplest method is usually the best” holds true. Therefore, most directional wells are still planned using traditional patterns which have been in use for many years. Common patterns for vertical projections are shown on the following pages:

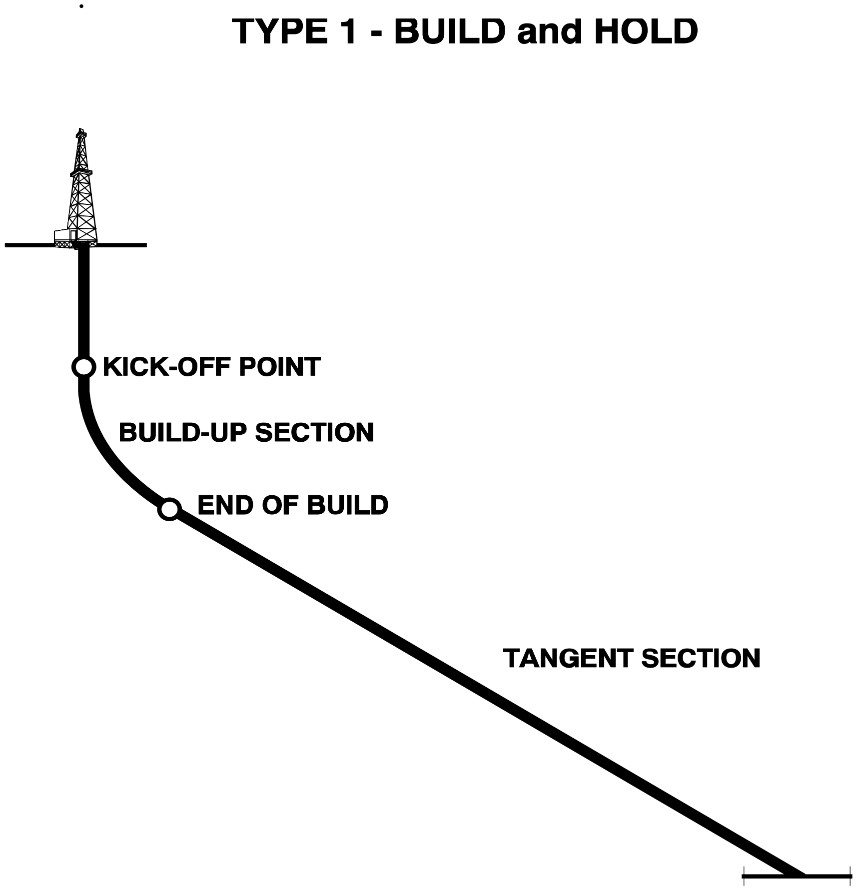


Figure 5-15: Type 1 (Build and Hold)

Features:·

Shallow kick-off point (KOP)

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

Tangent section

Applications:

Deep wells with large horizontal displacements

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

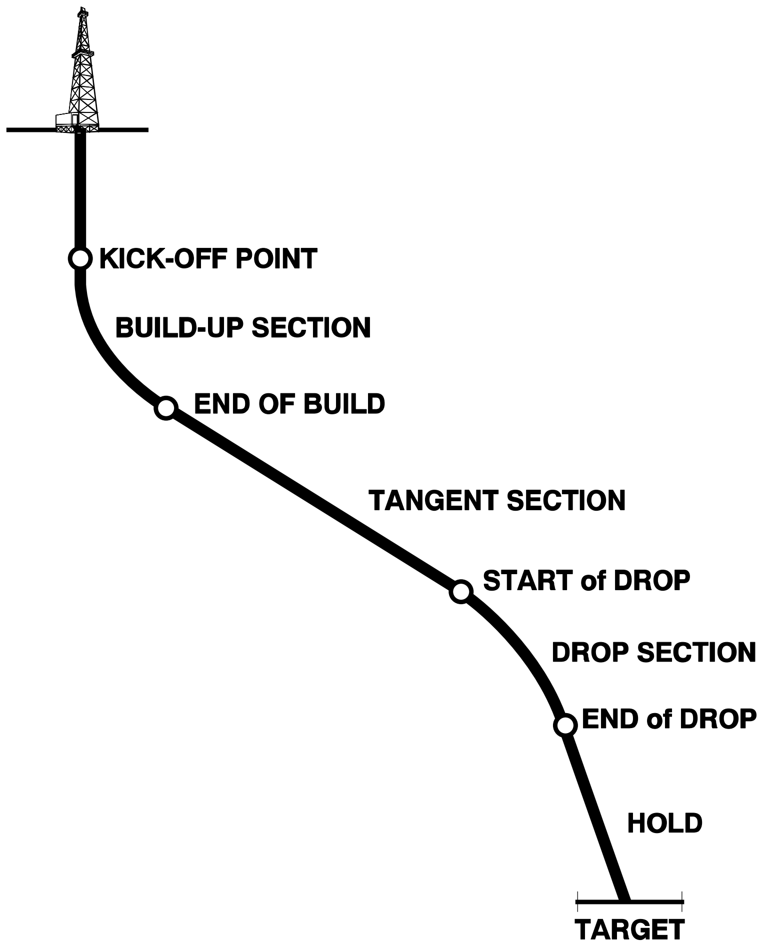


Figure 5-16: Type 2 (S Type Well)

Features:	**There are several variations:**
Shallow KOP	- Build, hold & drop back to vertical
Build-up section	- Build, hold, drop & hold (illustrated above)
Tangent section	- Build, hold & continuous drop through reservoir
Drop-off section	

Applications:	**Disadvantages:**
Multiple pay zones	- Increased torque & drag
Reduces final angle in reservoir	- Risk of keyseating
Lease or target limitations	- Logging problems due to inclination
Well spacing requirements	
Deep wells with small horizontal displacements	

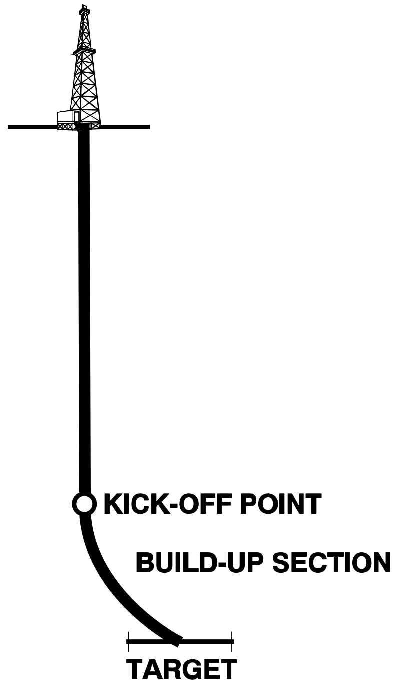


Figure 5-17: Type 3 (Deep Kickoff and Build)

Features:

Deep KOP

Build-up section

Short tangent section (optional)

Applications:

Appraisal wells to assess the extent of a newly discovered reservoir

Repositioning of the bottom part of the hole or re-drilling

Salt dome drilling

Disadvantages:

Formations are harder so the initial deflection may be more difficult to achieve

Harder to achieve desired tool face orientation with downhole motor deflection assemblies (more reactive torque)

Longer trip time for any BHA changes required

On multi-well platforms, only a few wells are given deep kick-off points, because of the small slot separation and the difficulty of keeping wells vertical in firmer formation. Most wells are given shallow kick-off points to reduce congestion below the platform and to minimize the risk of collisions.

Catenary Curve Well Plan

One suggestion for an efficient well path for directional wells would be to plan the well as a continuous smooth curve, all the way from KOP to target. This is the catenary method. A catenary curve is the natural curve that a cable, chain or any other line of uniform weight assumes when suspended between two points. A similar suspension of drill string would also form a catenary curve.

Proponents of the catenary method argue that it results in a smoother drilled wellbore, that drag and torque are reduced and that there is less chance of key seating and differential sticking. However, in practice it is hard to pick BHAs which will continuously give the required gradual rate of build. It is in reality no easier to follow a catenary curve well plan than a traditional well plan. Also, the catenary curve method produces a higher maximum inclination than would result from the build and hold or S type patterns.

Although the catenary method has been tried, with some success, it is not widely used and it **IS NOT** Baker Hughes INTEQ policy to recommend this type of well profile.

Horizontal wells

For many applications, the best well profile is one in which the inclination is built to 90° or even higher.

Allocation of slots to targets

Even this is not always a simple task. From a directional driller's viewpoint, slots on the North East side of the platform or pad should be used for wells whose targets are in a North Easterly direction. Unfortunately there are other considerations (e.g. water injection wells may have to be grouped together for manifolding requirements). Also, as more wells are drilled and the reservoir model is upgraded, targets can be changed or modified.

Inner slots are used to drill to the innermost targets (i.e. targets with the smallest horizontal distances from the platform) and these wells will be given slightly deeper kick-off points. The outer slots are used to drill to targets which are furthest from the platform. These wells will be given shallow kick-off points and higher build-up rates to keep the maximum inclination as low as possible.

Kick-off Point and Build-Up Rate

The selection of both the kick-off point and the build-up rate depends on many factors. Several being hole pattern, casing program, mud program, required horizontal displacement and maximum tolerable inclination. Choice of kick-off points can be limited by requirements to keep the well path at a safe distance from existing wells. The shallower the KOP and the higher the build-up rate used, the lower the maximum inclination.

Build-up rates are usually in the range 1.5°/100' M.D. to 4.0°/100' M.D. for normal directional wells. Maximum permissible dogleg severity must be considered when choosing the appropriate rate.

In practice, well trajectory can be calculated for several KOPs and build-up rates and the results compared. The optimum choice is one which gives a safe clearance from all existing wells, keeps the maximum inclination within desired limits and avoids unnecessarily high dogleg severities.

Tangent Section

During the eighties, a number of extended reach projects were successfully completed. If wells are drilled at inclinations (up to 80°), the area which can be covered from a single platform is approximately 8 times that covered when maximum inclination of the wells is limited to 60°. However, high inclination angles can result in excessive torque and drag on the drill string and present hole cleaning, logging, casing, cementing and production problems. These can generally be avoided with current technology.

Experience over the years has shown that directional control problems are aggravated when tangent inclinations are less than 15°. This is because there is more tendency for the bit to walk (i.e. change in azimuth) so more time is spent keeping the well on course. As such, most run-of-the-mill directional wells are still planned with inclinations in the range 15° - 60°.

Drop-off section

On S-type wells, the rate of drop off is selected to ease casing problems and avoidance of completion and production problems. It is much less critical to drilling because there is less tension in the drill pipe that is run through deeper doglegs and less time spent rotating below the dogleg.

The horizontal projection

On many well plans, horizontal projection is just a straight line drawn from the slot to the target. On multi-well platforms however, it is sometimes necessary to start the well in a different direction to avoid other wells. Once clear of these, the well is turned to aim at the target. This is a 3-dimensional turn, but on the horizontal plan it would typically look like Figure 5-18.

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The path of the drilled well is plotted on the horizontal projection by plotting total North/South coordinates (Northings) versus total East/West coordinates (Eastings). These coordinates are calculated from surveys.

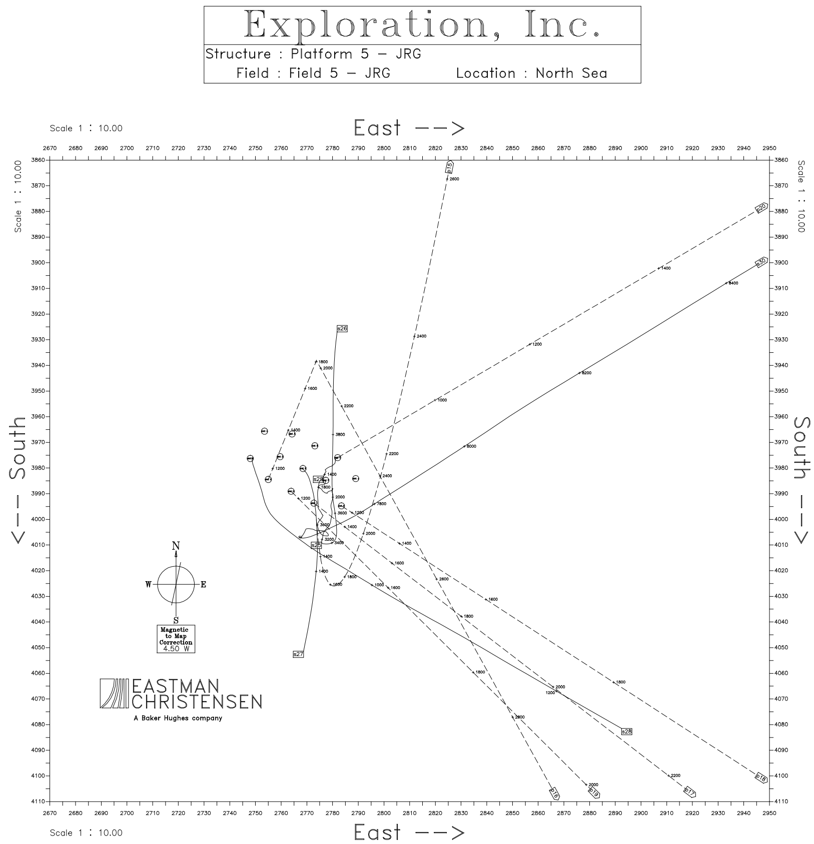

Figure 5-18: This is a 3-dimensional turn on the horizontal plan.

Lead angle

In the old days (pre 1985) it was normal practice to allow a "lead angle" when kicking off. Since roller cone bits used with rotary assemblies tend to "walk to the right", the wells were generally kicked off in a direction several degrees to the left of the target direction. In extreme cases the lead angles could be as large as 20°.

The greatly increased use of steerable motors and PDC bits for rotary drilling have drastically reduced the need for wells to be given a "lead angle". Many wells today are deliberately kicked off with no lead angle (i.e. in the target direction).

Nudging

The technique of "nudging" is used on platforms in order to "spread out" conductors and surface casings, which minimizes the chance of a collision.

Basically, when the hole for surface casing is drilled, some angle is built at a low rate (e.g. 1°/100') in the chosen direction.

In addition to “spreading things out”, other reasons for “nudging” are:

- to drill from a slot located on the opposite side of the platform from the target, when there are other wells in between
- to keep wells drilled in the same general direction as far apart as possible
- if the required horizontal displacement of a well is large compared to the total vertical depth, then it is necessary to build angle right below the surface conductor to avoid having to use a high build rate

Techniques for “nudging”

When formations are suitable (soft), jetting is the best technique to use. The most common method is to use a mud motor of 9.5" OD or greater with a 17.5" bit and a 1.5° bent sub. Using a 1.5° bent sub gives low build rates and hence a low dogleg severity. The hole is then opened to the required size after the mud motor run. Occasionally the job is performed with a large mud motor and a 26" bit from the start. In this case either a 1.5°or 2° bent sub might be used.

Planning a nudge program

The directions in which the wells are “nudged" should be chosen to achieve maximum separation. Wells may not necessarily be nudged in their target directions.

Nudges will not only be shown on the individual well plans for each well, but a structure plot will also be drawn which will show well positions at the surface casing point after the nudge.

Proximity (anti-collision) analysis

On multi-well projects (particularly offshore) there are small distances between slots. To eliminate the risk of collisions directly beneath the platform, the proposed well path is compared to existing and other proposed wells. The distances between the other wells and the proposal are calculated at frequent intervals in critical sections. These calculations can be performed using the EC*TRAK software (BHI) or COMPASS.

Survey uncertainty must also be computed for both the proposed well and the existing wells. All major operating companies have established criteria for the minimum acceptable separation of wells, which are usually linked to “cone of error” or “ellipse of uncertainty” calculations.

Downhole Motors

The idea of using downhole motors to directly turn the bit is not a new one. One of the first commercial motors was turbine driven. The first patent for a turbodrill existed in 1873. The USSR focused efforts in developing downhole motors as far back as the 1920's and has continued to use motors extensively in their drilling activity. After 1945, the West focused efforts more on rotary drilling, but field applications for downhole motors has increased spectacularly from the 1980's onwards.

A turbine consists of a multistage vane-type rotor and stator section, a bearing section, a drive shaft and a bit rotating sub. A "stage" consists of a rotor and stator of identical profile. The stators are stationary, locked to the turbine body, and deflect the flow of drilling mud onto the rotors which are locked to the drive shaft. As the rotors are forced to turn, the drive shaft is also forced to turn, causing the bit sub and the bit to rotate

Positive Displacement Motors

A positive displacement motor (PDM) is a hydraulically driven downhole motor that uses the Moineau principle to rotate the bit, independent of drill string rotation. The PDM is made up of several sections:

- By-pass valve or dump sub.
- Motor section.
- Universal joint or connecting rod section.
- Bearing section with drive sub.

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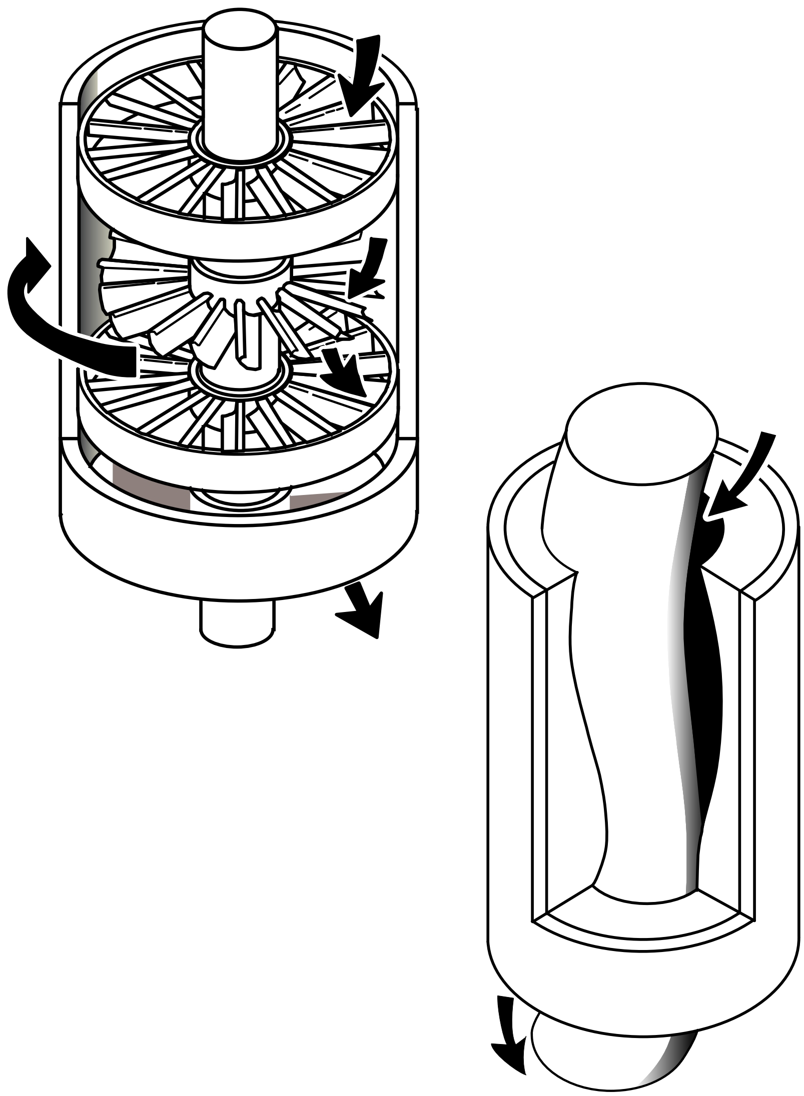


Figure 5-19: Differences between the turbine motor (left) and positive displacement motor (right) designs.

By-Pass Valve

The by-pass valve allows fluid to fill the drill string while tripping in the hole and to drain while tripping out. When mud is pumped, the valve closes causing fluid to move through the tool. Most valves are of a spring piston type which closes under pressure to seal off ports to the annulus. When there is no downward pressure, the spring forces the piston up so fluid can channel through the ports to the annulus. (Figure 5-20).

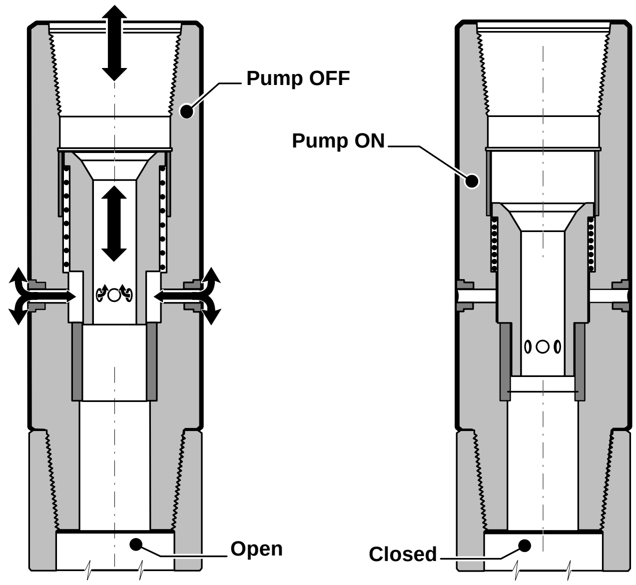


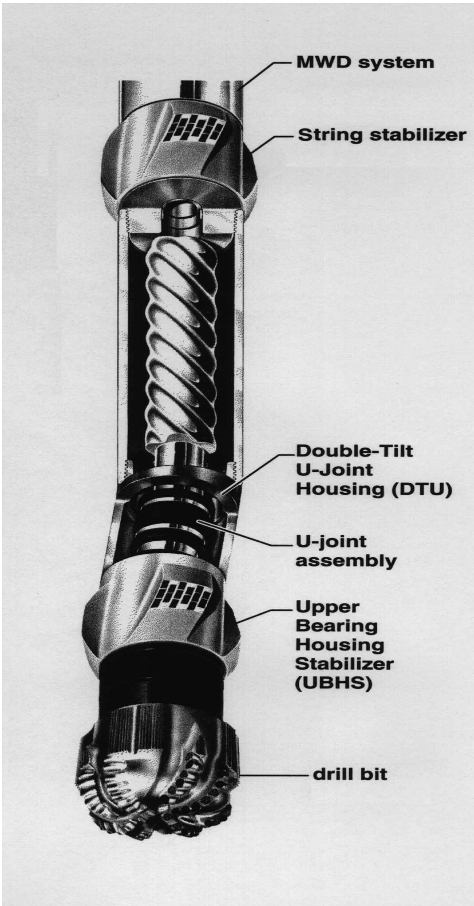
Figure 5-20: Bypass Valve.

Motor Section

This is a reverse application of Rene Moineau’s pump principle. The motor section consists of a rubber stator and steel rotor. The simple type is a helical rotor which is continuous and round. This is the single lobe type. The stator is molded inside the outer steel housing and is an elastometer compound. The stator will always have one more lobe than the rotor. Hence motors will be described as 1/2, 3/4, 5/6 or 9/10 motors.

Both rotor and stator have certain pitch lengths and the ratio of the pitch length is equal to the ratio of the number of lobes on the rotor to the number of lobes on the stator.

As mud is pumped through the motor, it fills the cavities between the dissimilar shapes of the rotor and stator. The rotor is forced to give way by turning or, in other words, is displaced (hence the name). It is the rotation of the rotor shaft which is eventually transmitted to the bit.



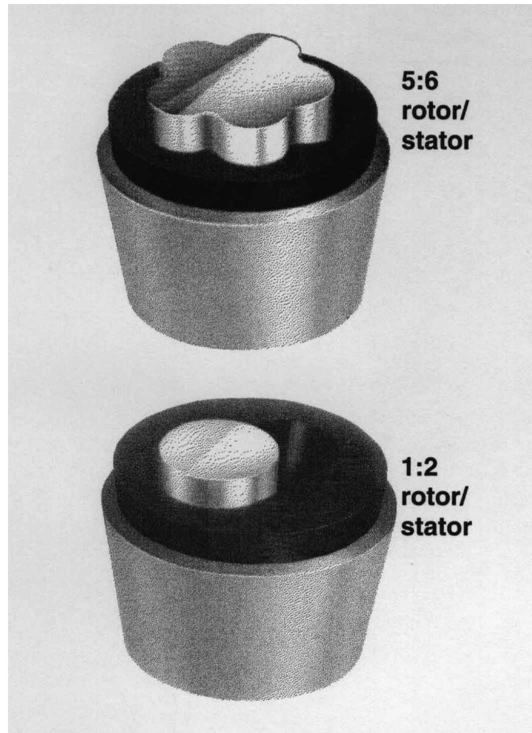


Figure 5-21: Parts of Downhole Motors

Connecting rod assemblies

Since the rotor is spiral shaped, it does not rotate concentrically, rather it traces a back and forth motion. This motion must be converted to a concentric motion to be transmitted to the bit via the drive sub. This is achieved by a connecting rod assembly. There are several types.

Universal-joint

U-joint assemblies (Figure 5-22a) have been utilized by the industry and are still used in most positive displacement motors. The assembly consists of two universal joints, each grease filled, and sealed with oil-resistant reinforced rubber sleeves to protect them from drill fluid contamination. A drawback of the U-joint assembly is the lack of sufficient strength for higher torque applications, such as those encountered with recent generations of high torque PDM's, particularly when used with PDC bits.

This inherent weakness is a result of the manufacturing process whereby the U-joint is “flame-cut” rather than machined.

Flex rod

A recent development in connecting rod assembly technology has been the utilization of flexible steel or titanium “flex rods” (Figure 5-22b). While flex rods are limited by the degree of allowable lateral bending, they have the advantage of low maintenance, since they do not require lubricants or rubber sleeves. Flex rods are now standard on most smaller Navi-Drills. One recent approach has been to mount the flex rod inside the hollow rotor of a short, high torque steerable PDM, rather than connecting it to the bottom of the rotor. By connecting a long flex rod to the inside of the top end of the rotor and extending it through the rotor, to connect to the top of the drive sub assembly, the overall rate of bend is decreased due to its increased length.

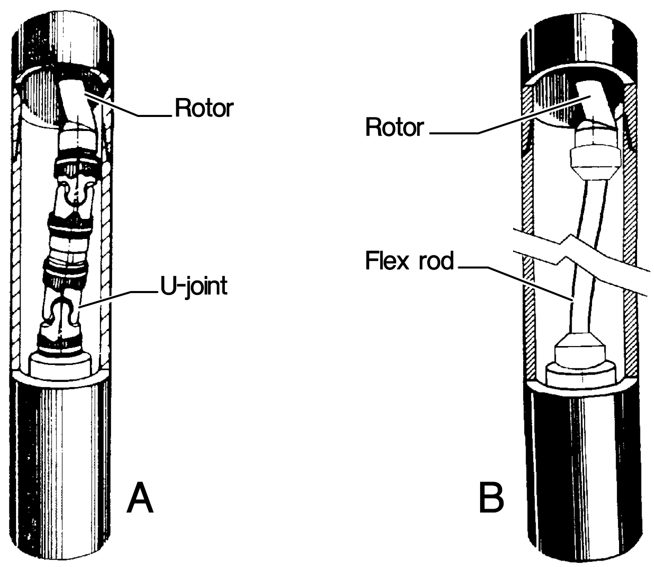


Figure 5-22: Type of Connecting Rod Assemblies

Bearing Section

A typical positive displacement motor utilizes three sets of bearings attached to a drive shaft. There are two sets of radial bearings (“upper” and “lower”) with one set of axial thrust bearings.

The axial thrust bearing section supports the on and off bottom loading and hydraulic thrust. It consists of a series of ball bearings stacked one on top of the other, each set being contained in its own race (groove). The number of these bearings will vary, depending on the size of the tool.

The upper and lower radial bearings are lined with tungsten carbide inserts. These bearings support the concentrically rotating drive shaft against lateral loads. The inherent design of the upper radial bearing limits the amount of fluid flow diverted to cool and lubricate the bearing package. This diversion of flow is typically 2 - 10%, depending on motor and bit pressure drop. The major portion of the drilling fluid is collected by ports in the drive shaft and exits through the bit. In some motors, diamond bearings are used, which need up to 20% of the flow to be diverted, depending upon conditions. Figure 5-23 illustrates typical bearing sections found in PDMs.

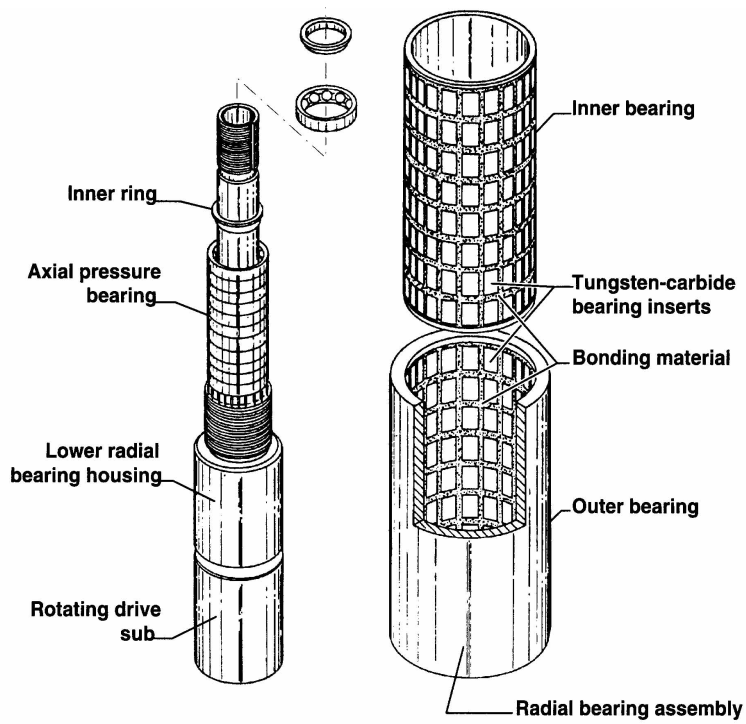


Figure 5-23: Various bearings in PDMs.

Types of Positive Displacement Motors

PDMs come in various configurations. As has been mentioned previously, the stator will have one more lobe than the rotor. The first types of PDMs, and the simplest, are 1/2 motors. These generally give medium to low torque output and medium to high rotary speed. Torque output is directly proportional to pressure drop across the motor. The
1/2 motors have good applications in performance drilling with a PDC, diamond, or TSP-type bits. Some shorter models are used for directional purposes.

Multi-lobe motors have high torque output and relatively slow speed. Therefore, they have good applications with roller cone bits and for coring. Such motors are also suitable for use with PDC bits, especially the large cutter types which require a good torque output to be efficient. These tools, being fairly short, also have good directional applications with bent subs as the deflection device. Multi-lobe motors may be constructed with a hollow rotor and a nozzle or blank placed in a holding device at the top. The nozzle allows for high flow rates to be accommodated by by-passing the excess flow from the motor section and the fluid will exit through the bit.

PDM Observations

- Motor stall will be obvious due to an increase in surface pressure. Motor stalling should be avoided as it erodes the service life of the motor.
- LCM can be pumped safely, though care should be taken that the material is added slowly and evenly dispersed. The system should not be slugged.
- Sand content in the drilling fluid should be kept to a minimum.
- Temperature limits are around 270°F to 130ºC, but higher temperature stators have been developed.
- Pressure drop through the tool while working is typically around 50 psi to 800 psi.
- Allowable wear on bearings is of the order of 1mm - 8mm, depending upon tool size.
- The tool should be flushed out with water prior to laying down.

In general, drilling fluids with a low aniline point can damage the rubber stator. As a rule, the nailine point in oil based muds should be around 150°F (60°C). Usually, this is related to the aromatic content which should be equal to or less than 10%. Contact the local supplier if there is any doubt.

If a by-pass nozzle is fitted to a multi-lobe rotor, then it must be sized very carefully to allow the motor section to develop the necessary power. Any variation in flow for which the nozzle was inserted will compromise the motor’s performance.

Characteristics

- Torque is directly proportional to the motor’s differential pressure. This makes the tool a very simple to operate.
- RPM is directly proportional to flow rate, through somewhat affected by torque output.

- Hydraulic horsepower consumed = {(P x Q) ÷ 1714}, where P is the pressure drop (psi) across the motor and Q is flow rate (gpm).

Navi-Drill Mach 1C

The Mach 1C is a positive-displacement motor that develops high torque at the bit at relatively low speed ranges (80-340 rpm). This makes it ideal for directional applications, drilling with high weight-on-bit, navigation drilling with roller cone or large cutter PDC bits, and coring operations.

The motor has a multi-lobe (5/6) rotor/stator configuration, which generates higher torque than the 1/2 lobe motors, permitting more weight-on-bit and increasing the drill rate. Because the motor develops its power at low speeds, it can improve bit performance without accelerating wear on the bearings or cones.

A unique bearing assembly and improved elastomer compounds in the stator have increased the Mach 1C’s hydraulic horsepower and extended operating life. It also has a new rotor nozzling system that allows the motor to be run at 50-100% over its maximum recommended flow rate without exceeding maximum recommended motor speed. The additional mud passes through the motor’s rotor, and flow rate can be adjusted by interchanging nozzles. Higher rates offer improved hole cleaning and bit hydraulics.

Although primarily a directional performance drilling motor, the Mach 1C can also be used for straight-hole drilling.

Tables 5-1 and 5-2 detail the Mach 1C specifications.

Table 5-1: Mach 1C Specifications (US Standard)

Tool Size (OD) (in)	**3¾**	**4¾**	**6¾**	**8**	**9½**	**11¼**
Length (ft)	16.1	17.4	19.8	22.9	24.6	26.5
Weight (lbs)	440	710	1720	2430	4080	6070
Recommended Hole Size (in)	4¼ - 5 7/8	6 - 7 7/8	8- 9 7/8	9½ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (gpm) **minimum** **maximum**	 65 185	 80 185	 185 475	 315 685	 395 740	 525 1135
Bit Speed Range (rpm)	120 - 340	100-300	100-260	85-190	100-190	80-170
Operating Diff.Pres. (psi)	800	725	725	580	800	655
Operating Torque (ft/lbs)	890	1180	2800	4500	6870	9770
Maximum Torque ** (ft/lbs)	1420	1890	4480	7200	10,970	15,570
Horsepower Range (hp)	20-58	22-67	53-139	73-163	131-249	149-316
Efficiency (max%)	67	68	70	70	72	73 5/8
Thread Connection						
By-Pass Valve Box-Up	2 7/8” Reg	3 ½” Reg	4 ½” Reg	6 5/8” Reg*	7 5/8” Reg	7 5/8” Reg
Bit Sub Box Down	2 7/8” Reg	3 ½” Reg	4 ½” Reg	6 5/8” Reg	7 5/8” Reg	6 5/8” Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**.

Table 5-2: Mach 1C Specifications (Metric)

Tool Size (OD) (in)	3¾	4¾	6¾	8	9½	11¼
Length (m)	5.1	5.3	6.1	7.0	7.5	8.1
Weight (kgs)	200	320	781	1100	1850	2750
Recommended Hole Size (in)	4¼ - 5 7/8	6 - 7 7/8	8- 9 7/8	9½ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (lpm) minimum maximum	 250 700	 300 900	 700 1800	 1200 2600	 1500 2800	 2000 4300
Bit Speed Range (rpm)	120 - 340	100-300	100-260	85-190	100-190	80-170
Operating Diff.Pres. (bar)	55	50	50	40	55	45
Operating Torque (Nm)	1200	1600	3800	6100	9300	13,200
Maximum Torque ** (Nm)	1920	2560	6080	9760	14,880	21,120
Horsepower Range (kW)	15-43	17-50	40-103	54-121	97-185	109-235
Efficiency (max%)	67	68	70	70	72	73 5/8
Thread Connection						
By-Pass Valve Box-Up	2 7/8” Reg	3 ½” Reg	4 ½” Reg	6 5/8” Reg*	7 5/8” Reg	7 5/8” Reg
Bit Sub Box Down	2 7/8” Reg	3 ½” Reg	4 ½” Reg	6 5/8” Reg	7 5/8” Reg	6 5/8” Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**

Navi-Drill Mach 2

The Navi-Drill Mach 2 is a positive-displacement motor that can improve drill rates in both straight-hole and directional applications.

The Mach 2 has a multi-stage, 1/2 rotor/stator configuration, which generates low to medium torque at medium speeds for higher penetration rates with less weight-on-bit. This makes it a good choice for drilling straight and directional holes in difficult formations. The motor is particularly suited for long-interval performance drilling with natural diamond, TSP, or PDC bits.

Mach 2 motors also come in 1-3/4”, 2-5/8” and 4-3/4” ODs for slimhole applications.

Tables 5-3 and 5-4 list the Mach 2 specifications.

.

Table 5-3: Mach 2 Specifications (US Standard)

Tool Size (OD) (in)	**1¾**	**2 5/8**	**3¾**	**4¾**	**6¾**	**8**	**9½**	**11¼**
Length (ft)	8.9	13.1	21.5	17.4	26.7	26.5	33.0	32.1
Weight (lbs)	49	180	840	710	2160	2810	5220	7300
Recommended Hole Size (in)	17/8 - 2¾	27/8 - 3½	4¼ - 5 7/8	6 - 7 7/8	8- 9 7/8	9½ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (gpm) **minimum** **maximum**	 20 50	 25 80	 65 210	 80 265	 185 530	 240 685	 395 790	 525 1135
Bit Speed Range (rpm)	830-2100	550-1650	250 - 800	195-650	190-550	155-450	200-400	156-330
Operating Diff.Pres. (psi)	580	870	725	725	725	580	870	580
Operating Torque (ft/lbs)	30	95	480	740	1840	2400	4750	5530
Maximum Torque ** (ft/lbs)	49	153	770	1180	2950	3830	7610	8850
Horsepower Range (hp)	4.7-12	10-30	23-73	27-92	67-193	71-206	181-262	163-347
Efficiency (max%)	71	10	83	83	86	88	90	90
Thread Connection **By-Pass Valve Box-Up** **Bit Sub Box Down**	 AW Rod AW Rod	 BWRod BW Rod	 2 7/8” Reg 2 7/8” Reg	 3 ½” Reg 3 ½” Reg	 4 ½” Reg 4 ½” Reg	 6 5/8” Reg* 6 5/8” Reg	 7 5/8” Reg 7 5/8” Reg	 7 5/8” Reg 6 5/8” Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**.

Table 5-4: Mach 2 Specifications (Metric)

Tool Size (OD) (in)	1¾	2 5/8	3¾	4¾	6¾	8	9½	11¼
Length (m)	2.7	4.0	6.3	6.5	8.1	8.1	10.0	9.8
Weight (kgs)	21	80	210	380	980	1270	2360	3310
Recommended Hole Size (in)	17/8 - 2¾	27/8 - 3½	4¼ - 5 7/8	6 - 7 7/8	8- 9 7/8	9½ - 12¼	12¼ - 17½	17½ - 26
Pump Rate (lpm) minimum maximum	75 190	100 300	250 800	300 1000	700 2000	900 2600	1500 3000	2000 4300
Bit Speed Range (rpm)	830-2100	550-1650	250 - 800	195-3650	190-550	155-450	200-400	156-330
Operating Diff.Pres. (bar)	40	60	50	50	50	40	60	40
Operating Torque (Nm)	41	130	650	1000	2500	3250	6450	7500
Maximum Torque ** (Nm)	66	208	1040	1600	4000	5200	10,320	12,000
Horsepower Range (kW)	3.9-9	7.5-22.5	17-54	20.5-68	50-144	53-153	138-270	122-260
Efficiency (max%)	71	10	83	83	86	88	90	90
Thread Connection By-Pass Valve Box-Up Bit Sub Box Down	AWRod AW Rod	BW Rod BW Rod	2 7/8” Reg 2 7/8” Reg	3 ½” Reg 3 ½” Reg	4 ½” Reg 4 ½” Reg	6 5/8” Reg* 6 5/8” Reg	7 5/8” Reg 7 5/8” Reg	7 5/8” Reg 6 5/8” Reg

*** Available with 5½ Reg in US only.**

**** Operating above this level can shorten tool life**

Navi-Drill Mach 1 P/HF

The Navi-Drill Mach 1 P/HF (High Torque/High Flow) is a positive displacement motor that develops high torque at the bit at relatively low to medium speed range (80-310 RPM). This makes it ideal for directional applications, drilling with high weight-on-bit, or in areas where formations require high torque due to specialized PDC bits.

The Navi-Drill Mach 1 P/HF motor has a multi-lobe rotor/stator configuration which generates more torque than other motors.

A unique bearing assembly and improved elastomer compounds have increased the Mach 1 P/HF’s hydraulic horsepower and extended its operating life. The rotor/stator design allows a larger than normal flow rate to be pumped through the motor, generating the higher torques. There is a rotor nozzling system that allows the motor to run over the higher maximum flow rate without exceeding maximum recommended motor speed. These higher flow rates offer improved hole cleaning and bit hydraulics.

The Navi-Drill Mach 1 P/HF offers the AKO (adjustable kick off sub) which is rig floor adjustable between 0° - 2.75°, giving a BUR up to 12°/100 ft. Included in the design is a unique U-joint assembly which allows the higher torque to be transmitted from the motor section through the bearing assembly and to the bit.

Although primarily a directional performance drilling motor, the Navi-Drill Mach 1 P/HF can also be used for straight-hole drilling.

Table 5-5: Specifications for Mach 1 P/HF

Tool Size (OD) (in)	3¾	4¾	6¾	8	9½
Flow rate (lpm) **minimum** **maximum**	 398 796	 606 1213	 1308 2312	 2008 3411	 2501 4207
Bit Speed Range (rpm)	155-310	130-260	100-180	90-150	80-130
Diff. Pres. (bar)	76	60	50	50	50
Max. Torque (Nm)	1898	2901	6901	11,700	16,690
Power Output (kW)	31-62	38-78	71-130	107-178	135-227
Efficiency (max%)	66	66	68	65	65
Rotor/Stator	7/8	7/8	9/10	9/10	9/10

Navi-Drill Mach 1/AD

The Navi-Drill Mach 1/AD motor is designed specifically for use in holes drilled with air and mist. With an AKO, the steerable motor drilling system combines directional and straight hole drilling capabilities to provide precise directional control. Generally, in one run it can establish the desired direction and inclination for the surface interval of a directional well.

The AKO places the bend close to the bit, and can be adjusted so the motor housing tilt angle can be configured on the rig floor to settings from 0° - 2.5°. The resulting dogleg capability can be as high as 12°/100 ft. The unique AKO design requires no shims to adjust the bent housing angle, so a single motor can achieve a variety of build rates.

This motor, with the AKO, can perform directional work when oriented in a particular direction, and is capable of drilling straight ahead when the drillstring is rotating. This is accomplished by tilting the bit relative to the motor and/or applying a side force at the bit while maintaining a minimum amount of bit offset relative to the axis of the motor.

When an alignment bent sub (ABS) is fitted to the top of the motor and used in conjunction with the AKO, the motor configuration can be used for building angle, as in a fixed angle build motor. Orientation of the motor and drillstring is possible in this configuration, but not rotation. The maximum build rate possible from this configuration is approximately 20°/ 100 ft.

Motor Orientation/Control

All directional wells require steering during initial kick offs, correction runs, sidetracks, and re-drills. Once the desired direction in which the tool should be faced is determined, the next step is to actually face the tool in that direction in order to drill the predetermined course.

For the Mach 1/AD motor, a cartridge data transmission (CDT) system has been developed that allows orientation of the motor in a particular direction, while still allowing drilling with drillstring rotation. This CDT system uses a special heavy duty steering tool which provides continuous surface readout of the drift angle and azimuth, as well as toolface orientation while drilling ahead.

A “hard wire” from the steering tool, through the drillstring to the surface, relays the information to computerized surface equipment. Data transmitted from the steering tool is updated and converted instantly to information which can be used to make any necessary corrections to the motor.

Table 5-6: Specifications for Mach 1/AD

Tool Size OD (in)	4¾	6¾	8
Flow rate (lpm) **minimum** **maximum**	 2100 4200	 3000 6000	 4250 8500
Bit Speed Range (rpm)	110-266	125-250	90-205
Diff. Pres. (bar)	24	24	24
Max. Torque (Nm)	2800	6000	10,600
Power Output (kW)	56-112	78-157	114-229

Turbines

A turbine is made up of several sections:

- Drive stages or motor section.
- Axial thrust bearing assembly and radial bearings.
- Bit drive sub.

As stated earlier, the drive stages, or motor section, consists of a series of stators and rotors of a bladed design. This stator and rotor combination form a stage. Turbines are referred to as 90 stage, 250 stage, etc. The number of stages determines the torque generated. Each stage, theoretically, applies an equal amount of torque to the control shaft and it is the sum of those torques which will be output to the bit.

The drive sub is simply the bit connection and bearing shaft. Radial bearings protect the shaft from lateral loading and the thrust bearings support the downwards hydraulic thrust from mud being pumped through the tool and the upward thrust of weight being applied to the bit. Theoretically, weight on bit should be applied to equalize the hydraulic thrust, which unloads the bearings and prolongs their life.

Drive Section

This will consist of a series of bladed stators, fixed to the outer tool housing and bladed rotors fixed to the central rotating shaft. Mud flow is deflected at a pre-determined angle off the stator blades to hit the rotor blades and cause the shaft to rotate. The angle of the blades will affect the torque and speed output of the turbine (Figure 5-24).

Bearing Section

Usually, thrust bearings are made up of rubber discs (Figure 5-24) which are non-rotating (being fixed to the outer housing of the tool) and rotating steel discs attached to the central rotating shaft. Long bearing sections known as cartridges are used for long life in tangent or straight hole drilling sections. These are changeable at the rigsite. If the bearings wear past the maximum point, considerable damage can be inflicted as the steel rotors will crash into the stators below.

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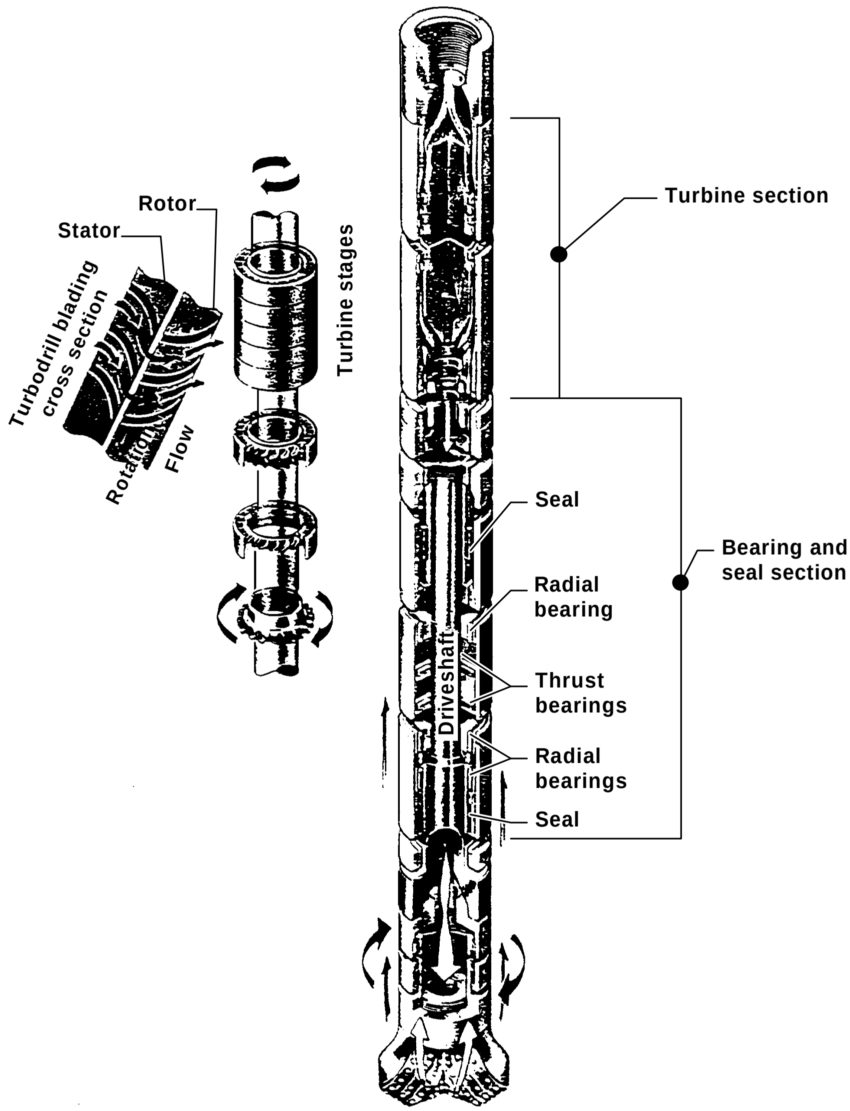

Figure 5-24: Cross-section of a turbine motor

Directional Turbine

This is a short tool which has a set number of stages and its bearing section entirely within one housing. That is, it is not a sectional tool and will be typically less than 30 feet long. It is designed for short runs to kick off or correct a directional well, using a bent sub as the deflection device. Steerable turbodrills do exist and will be discussed later.

Turbine Observations

- There is minimal surface indication of a turbine stalling.
- Turbines do not readily allow the pumping of LCM.
- Sand content of the drilling fluid should be kept to a minimum.
- Due to minimal rubber components, the turbine is able to operate in high temperature wells.
- Pressure drop through the tool is typically high and can be anything from 500 psi to over 2000 psi.
- Turbines do not require a by-pass valve.
- Usually, the maximum allowable bearing wear is of the order of 4mm.

Turbine Characteristics

- Torque and RPM are inversely proportional (i.e. as RPM increases, torque decreases and vice versa).
- RPM is directly proportional to flow rate (at a constant torque).
- Torque is a function of flow rate, mud density, blade angle and the number of stages, and varies if weight-on-bit varies.
- Optimum power output takes place when thrust bearings are balanced.
- Changing the flow rate causes the characteristic curve to shift.
- Off bottom, the turbine RPM will reach “run away speed” and torque is zero.
- On bottom, and just at stall, the turbine achieves maximum torque and RPM is zero.
- Optimum performance is at half the stall torque and at half the runaway speed, the turbine then achieves maximum horsepower.
- A stabilized turbine used in tangent sections will normally cause the hole to “walk” to the left.

Deflection tools and techniques

Whipstocks

The whipstock was the main deflection tool from 1930-1950. A standard whipstock is seldom used nowadays, but it has not disappeared completely. Whipstocks are used in coiled tubing drilling for re-entry work. There are 3 types of whipstock used in conventional directional drilling:

Standard removable Whipstock

The Standard Removable Whipstock is mainly used to kick off wells, but can also be used for sidetracking. It consists of a long inverted steel wedge which is concave on one side to hold and guide the drilling 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. It will usually be used with a drilling assembly consisting of a bit, a spiral stabilizer, and an orientation sub, rigidly attached to the whipstock by means of a shear pin.

The whipstock assembly is lowered to the bottom of the hole and orientated. Weight is applied to set the whipstock and shear the pin. The bit is then drilled down and forced to deflect to one side. A 12 to 16 foot “rat hole” is drilled below the toe of the whipstock and the assembly is then pulled out of hole, taking the whipstock with it. A hole opener is run to open the rat hole out to full gauge. The hole opener assembly is then tripped out and a rapid angle build assembly run in hole to “follow up”the initial deflection. This whole procedure may have to be repeated several times in the kick-off.

It is obvious that the major disadvantage of the standard whipstock is the number of “trips” involved. The other important disadvantage is that the whipstock produced a sudden, sharp deflection - in other words, a severe dogleg - which may give rise to subsequent problems with the hole. The advantages are that it is a fairly simple piece of equipment which requires relatively little maintenance and has no temperature limitations.

Figure 5-25: Standard removable Whipstock.

Circulating Whipstock

The “Circulating Whipstock” is run, set and drilled like the standard whipstock. However, in this case the drilling mud initially flows through a passage to the bottom of the whipstock which permits more efficient cleaning of the bottom of the hole and ensures a clean seat for the tool. It is most efficient for washing out bottom hole fills.

Permanent Casing Whipstock

The “Permanent Casing Whipstock” (Figure 5-26) is designed to remain permanently in the well. It is used where a “window” is to be cut in casing for a sidetrack. The casing whipstock can be set using a Baker Model “D” Packer. A special stinger at the base of the whipstock slips into the packer assembly, and a stainless steel key within the packer locks the whipstock's anchor-seal and prohibits any circular movement during drilling.

The normal procedure is to orientate the system and then set the packer. After this, the starting mill is pinned to the whipstock and the whole assembly run slowly in hole and seated in the packer.

Although the packer has already been orientated, it is good practice to orientate the whipstock in the same manner as the packer. This will ensure that a faster “latch up” will take place without endangering the shear pin.

After the whipstock has been “seated” in the packer, the pin is sheared and circulation and rotation started. The starting mill is used to make an initial cut through the casing and mill approximately 2 feet of the window. The lug that held the starting mill to the whipstock must also be milled off.

This assembly is tripped out and the mill changed. A tungsten carbide or diamond speed mill is used to cut the rest of the window. Once the window has been cut, approximately 5 feet of formation is cut before pulling out of hole. Next, a taper mill is run with a watermelon mill immediately above it. This is done to “clean” the top and the bottom of the window. Finally, another trip is made to change over to the drilling assembly which is used to drill ahead.

The advantage of using this system, instead of the normal method of milling a section and sidetracking, is that the operation usually takes less time. The main disadvantage is that it gives a sharp dogleg, and as such the casing whipstock assembly is not recommended if there is a considerable distance to drill below the sidetrack. This is because problems can occur when trying to pull stabilizers, etc back into the casing through the window. On the other hand, if there is only a short distance to be drilled below the sidetrack point, then the casing whipstock is well worth considering.

In recent years, improvements in the design of the system have eliminated the need for so many trips in and out of the hole

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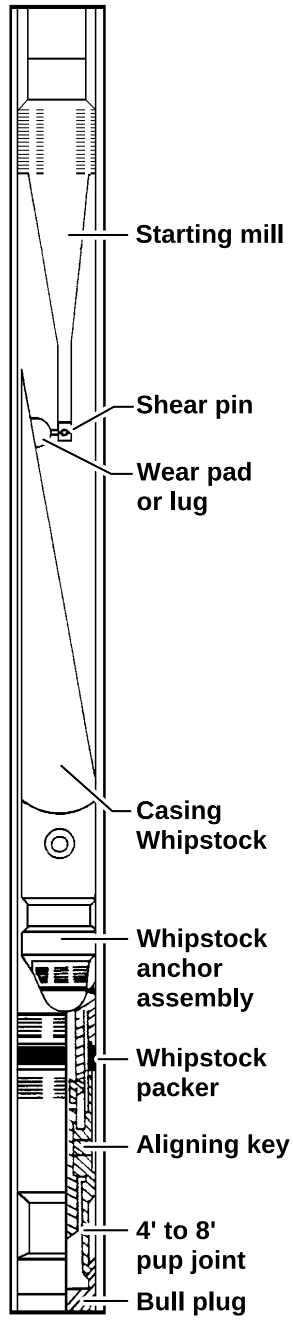

Figure 5-26: Permanent casing Whipstock.

Jetting

Jetting (or badgering) is a technique used to deviate wellbores in soft formations. The technique was developed in the mid 1950s and superseded the use of whipstocks as the primary deflection technique.

Although jetting has subsequently been supplanted by downhole motor deflection assemblies it is still used frequently and offers several advantages which makes it the preferred method in some situations.

A special jet bit may be used, but it is also common practice to use a standard soft formation tri-cone bit, with one very large nozzle and two smaller ones.

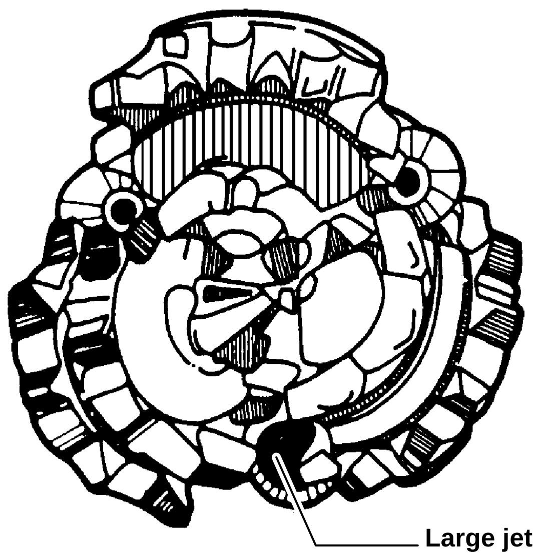

Figure 5-27: Bit set-up for jetting

Requirements for jetting

- The formations must be soft enough to be eroded by the mud exiting the large nozzle. As a rough rule of thumb, if formations cannot be drilled at penetration rates of greater than 80 ft/hr using normal drilling parameters, they are not suitable for jetting. Jetting is most effective in soft, sandy formations, and its effectiveness is reduced as depth increases, since the formations become more compacted.
- Adequate rig hydraulic horsepower must be available. For jetting to be successful there must be adequate hydraulic energy available at the bit to erode the formation. A rule of thumb for jetting is that mud velocity through the large jet should be at least 500 ft/sec.

Jetting Assemblies

A typical jetting assembly used to drill a $12^1/_4$"pilot hole is:

1) $12^1/_4$"jet bit,
2) extension sub,
3) $12^1/_4$"stabilizer,
4) UBHO sub,
5) 3 x 8" Drill Collars,
6) 12-1/4" stabilizer,
7) a Drill Collar,
8) HWDP as required.

This is essentially a strong angle build rotary assembly with a suitable bit for jetting. The upper stabilizer is optional and is often omitted.

Nozzling the Jetting Bit

There are three alternatives:

1. Use a specialized jet bit with a large extended nozzle in place of one of the cones.
2. Fit one large and two small nozzles in a conventional tri-cone bit.
3. Blank off one nozzle of a conventional bit to divert the flow through the other two.

Flow through two jets may be desirable in large hole sizes (e.g. 17-1/2") because of the large washout required to deflect the bit and near bit stabilizer. Both (A) and (B) work well in most hole sizes which are commonly jet drilled. (B) is the most common option because it uses standard bits and nozzles and results in a bit dressed in such a way as to be suitable for both jetting and drilling.

A 12-1/4" bit dressed for jetting would typically have the main nozzle size of 26/32" or 28/32" and the other two 10/32" or 8/32".

Procedure for Jetting

The assembly will be run to bottom, a survey is taken and the large jet nozzle (the "tool face") is orientated in the required direction.

Maximum circulation is established (e.g. 800 gpm in 12-1/4" hole) and a controlled washout is effected.

The drill string may be spudded up and down periodically, but not rotated, until several feet of hole have been made and the bit and near bit stabilizer have been forced into the washed out pocket. The technique is to lift the string 5 to 10 feet off bottom and then let it fall, catching it with the brake so that the stretch of the string causes it to spud on bottom rather than the full weight of the string. Another technique which may improve the effectiveness of jetting involves turning the rotary table a few degrees (15°) right and left while jetting.

Having jetted 3 to 8 feet of hole (the exact distance depending on required build rate and previous results) drilling is started. The circulation rate is now reduced to about 50%. Hole cleaning considerations are ignored while drilling the next 10 feet or so. High weight on bit (40 - 45 Klb) and low rotary speed (60 70 RPM) should be used to bend the assembly and force it to follow through the trend established while jetting. Progress may be difficult at first because of interference between the stabilizer and the irregularly shaped jetted hole.

After approximately 10 feet of hole has been drilled, the pump rate can be increased to perhaps 60% - 70% of the rate originally used while jetting. High WOB and low RPM should be maintained. The hole is drilled down to the next survey point.

A survey is taken to evaluate progress. If the dogleg is too severe the section should be reamed and another survey taken.

At the start of a kick-off, jetting is repeated every single until about 3º of angle has been built. After that, it is normal to jet every “double”. After drilling each section, the jet nozzle has to be re-orientated to the desired tool face setting before jetting again. The operation is repeated until sufficient angle has been built and the well is heading in the desired direction.

The principle is that, during the initial spudding and washing process, a pocket is produced in the formation opposite the jet nozzle. When high WOB is then applied and the drill string rotated, the bit and near bit stabilizer work their way into the pocket (the path of least resistance). The collars above the NB stabilizer bend and contact the low side of the hole. This causes a bending moment about the NB stabilizer which acts as a pivot or fulcrum, and the bit is pushed harder into the pocket (i.e. the direction in which the large jet nozzle was originally orientated).

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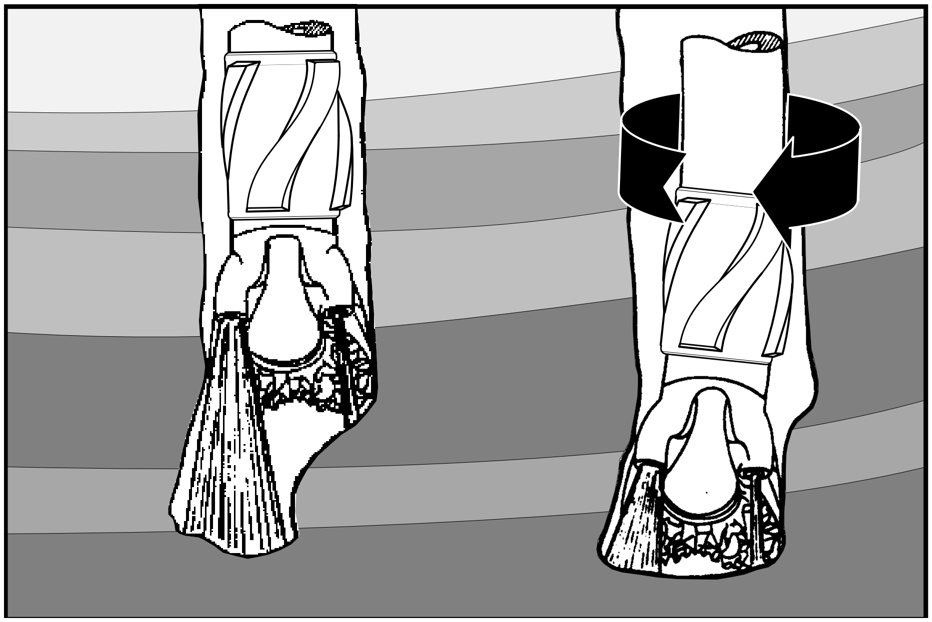


Figure 5-28: Jetting and drilling actions

Advantages of Jetting

- It is a simple and cheap method of deflecting well bores in soft formations. No special equipment is needed.
- Dogleg severity can be partly controlled from surface by varying the number of feet “jetted” each time.
- The survey tool is not far behind the bit, so survey depths are not much less than the corresponding bit depths.
- Orientation of tool face is fairly easy.
- The same assembly can be used for normal rotary drilling.

Disadvantages of Jetting

The technique only works in soft formation and therefore at shallow depths. For this reason, jetting is mainly used to kick wells off at shallow depths.

In jetting, high dogleg severities are often produced. Deviation is produced in a series of sudden changes, rather than a smooth continuous change. For this reason, it is normal practice to jet an undergauge hole and then open it out to full gauge, which smooths off the worst of the doglegs.

Downhole motor and bent sub

A common method of deflecting wellbores is to use a downhole motor and a bent sub. As illustrated in Figure 5-29, the bent sub is placed directly above the motor and the bent sub which makes this a deflection assembly. Its lower thread (on the pin) is inclined 1° - 3° from the axis of the sub body.

The bent sub acts as the pivot of a lever and the bit is pushed sideways as well as downwards. This sideways component of force at the bit gives the motor a tendency to drill a curved path, provided there is no rotation of the drill string. The degree of curvature (dogleg severity) depends on the bent sub angle and the OD of the motor, bent sub and drill collars in relation to the diameter of the hole. It also depends on the length of the motor.

A downhole motor and bent sub assembly may be used for kicking off wells, and for correction runs or for sidetracking.

Notice the absence of any stabilizers in the lower part of this assembly. Usually there would be no stabilizers for at least 90 feet above the bent sub. In fact, it is not uncommon for the entire BHA to be “slick” when a motor and bent sub is used for kicking off at shallow depths.

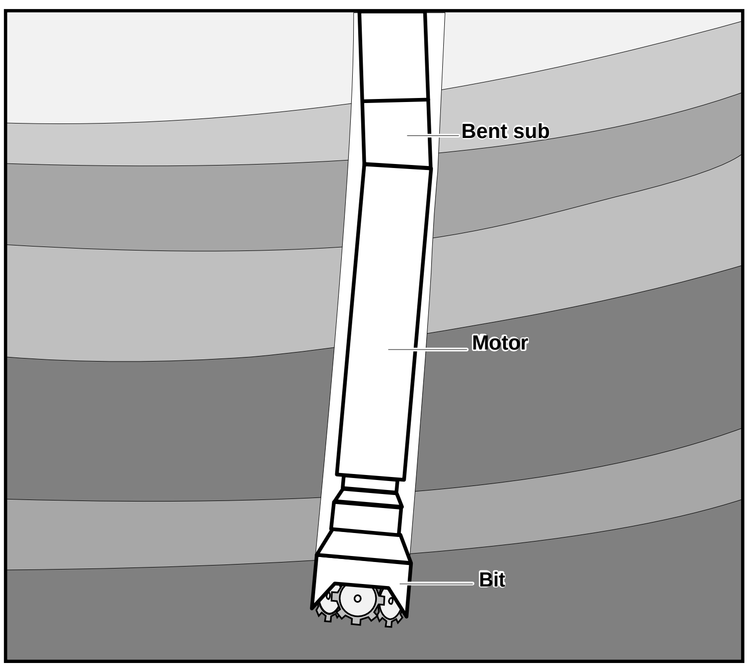


Figure 5-29: Downhole motor and bent sub assembly.

Reactive torque

Reactive torque is created by the drilling fluid pushing against the stator. Since the stator is bonded to the body of the motor, the effect of this force is to twist the motor and BHA anti-clockwise. As weight-on-bit is increased, the drilling torque created by the motor increases, and reactive torque increases in direct proportion. Thus a reasonable, although simplistic, way to view this is that the clockwise drilling torque generated at the bit is the “action” and the counter-clockwise torque on the motor housing is the “reaction”. The reactive torque at the motor is equal to the drilling torque.

Reactive torque causes a problem for directional drillers when they are using a motor and bent sub to deflect the well-bore. The twisting of the BHA caused by reactive torque changes the tool face orientation of the bent sub. If they are obtaining tool face orientation from single shot surveys, the directional driller has to estimate how much turn to the left they will get due to reactive torque. They will set the tool face that number of degrees round to the right of the desired tool face, so that the reactive torque will bring it back to the setting required while drilling.

Drill string design will also affect the extent of “drill string twist.” This concept is important to understand because it can directly affect the tool face orientation of the downhole motor. This twisting becomes more critical at greater depths, especially when using smaller OD drillpipe.

When drilling is in progress, every effort must be made to keep the drilling parameters constant and obtain a constant reactive torque, and a steady tool face setting. Reactive torque occurs with both types of downhole motors. Obviously, high torque motors produce higher reactive torque.

Factors Affecting Reactive Torque

The reactive torque which motors generate will be in direct proportion to the differential pressure across the motor. This in turn is influenced by:·

- Motor characteristics
- Bit characteristics
- Formation drillability
- Weight on bit

Estimation of reactive torque has always been a problem for directional drillers. Several charts and rules of thumb have evolved. One is:

EXPECTED REACTIVE TORQUE = 10° - 20° / 1000 ft M.D.

Note: *Use lower values for low torque motors (Mach 2) and higher values for high torque motors (Mach 1).*

Running Procedures

1. The motor is inspected and tested using standard procedures.
2. Before drilling can begin with a motor and bent sub assembly, the bent sub (tool face) must be orientated in the desired direction.
3. The pipe is worked until string torque is eliminated. Best results are obtained by using a moderately fast up and down pipe movement. It is recommended that the bit be kept a minimum of 5 feet from the bottom of the hole.
4. Make a reference mark on the kelly bushings, lock the rotary table and take a survey to determine tool face orientation.
5. Turn the pipe to achieve the desired tool face orientation. This orientation should include an allowance for the anticipated reactive torque. A rough rule of thumb is to allow 10° /1000' for lower torque motors (Mach 2) and 20° /1000' for higher torque motors (Mach 1), but remember the reactive torque obtained is a function of WOB and differential pressure across the motor.
6. When orienting, turn the pipe to the right unless the turn is less than 90° left of the present setting. Work the string up and down so that the turn reaches the bottomhole assembly.
7. Lock the rotary table before beginning to drill.

PDMs vs Turbines with a Bent Sub

For directional work with a bent sub, PDMs offer several advantages over turbines. When drilling with a PDM, the directional driller can use pump pressure as a weight indicator. If the pump pressure is constant, the differential pressure across the PDM is constant, so torque and WOB are constant. It is also much easier to tell if a PDM has stalled because there will be an immediate increase in surface pressure. PDMs give a longer bit life than turbines because of the slower rotary speed. They can tolerate LCM whereas turbines cannot. Finally, instead of using a bent sub, a PDM with a small bend at the U-joint housing can be used. As this bend is nearer to the bit, a smaller angle of bend will have the same effect as a larger bent sub angle. This reduces the problem of the bit riding the side of the hole while tripping in and out.

The only real advantage of turbines is that they can operate at higher temperatures than PDMs. Also turbines DO NOT have a dump valve. Years ago, short deviation turbines could handle higher flow rates than PDMs, but this is no longer the case. Nowadays, it is quite rare to use a turbine with a bent sub.

Downhole Motor and Bent Sub Combination

A downhole motor and bent sub combination will drill a smooth, continuous curve, which makes dogleg severity more predictable than with other deflection tools. They can be used in most formations. In addition, since there is no rotation from the surface. It is possible to use a wireline “steering tool” for surveying and orientation while drilling. Alternatively, a MWD system can be utilized.

One drawback of this combination is that reactive torque changes the tool face when drilling commences, which may also make it difficult to keep a steady tool face. Also the motors are expensive and require maintenance.

PDM with Kick-Off Subs

An alternative to using a bent sub is to use a PDM with a single bend in the universal joint housing, described as a kick-off sub in the case of a Navi-Drill and a bent housing by some other PDM manufacturers. Historically, these “single tilt” motors were used for difficult deviation jobs such as sidetracking over a short section of hole into hard formation. Since the bend is closer to the bit than when a bent sub is used, a smaller tilt angle can be used but still give a strong deviation tendency.

Nowadays, single tilt motors are frequently used as steerable motors. If the drill string is rotated so that the body of the motor rotates, then a fairly straight path is drilled. However, if the tilt (tool face) is orientated in a desired direction and there is no drill string rotation, then the motor will drill a controlled curve.

Toolface Orientation

The “Toolface” of a deflection tool, or a steerable motor system, is the part (usually marked with a scribe line) which is oriented in a particular direction to make a desired deflection within the wellbore. There are two ways of expressing toolface orientation:

Magnetic or Gyro Toolface is the toolface orientation measured as a direction on the horizontal plane. If measured by a “magnetic” type survey tool, it is called magnetic toolface; whereas if it is measured by a gyroscopic survey device, it is called gyro toolface. Toolface orientation is measured and expressed in this way at low inclinations, generally less than 5°.

High Side Toolface is the toolface orientation measured from the high side of the borehole in a plane perpendicular to the axis of the hole.

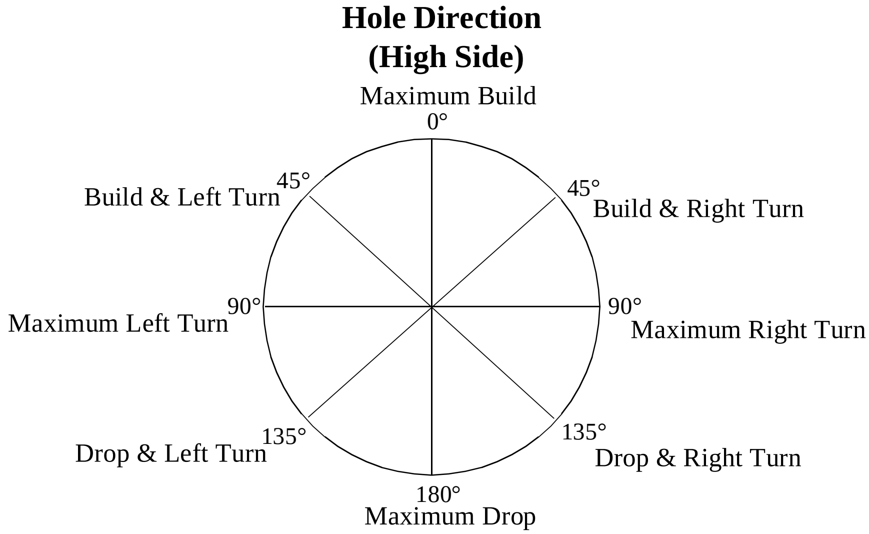
It must be pointed out that the term toolface commonly used is a shortened version of “toolface orientation”. A magnetic or gyro toolface reading can be converted to a high side toolface reading using:

High side toolface = mag/gyro toolface - hole azimuth

A negative answer means the angle is measured anti-clockwise or left of high side. The above formula is based on the fact that the high side direction is the azimuth of the borehole.

The following chart is a rule of thumb which can be used when orienting deflection tools or steerable motors. The chart is applicable to steerable systems in most situations. It may not be applicable to slick motor and bent sub assemblies, used at higher inclinations (over 30^{o}) in soft or medium soft formations.It will give the qualitative changes in inclination and azimuth which should result from drilling with the given tool face settings.

It should be noted that the tool face settings are based on the high side of the hole.



Rule of thumb for orientation of ToolFace (at low inclinations, less than 30°).

Directional Control with Rotary Assemblies

An important aspect of directional drilling is the BHA design which is to drill the planned trajectory. In this section we shall concentrate on the basic principles used in directional control when drilling with rotary assemblies, and the typical assemblies used for each section. The effects of drilling parameters (weight-on-bit) and formation (anisotropy) will be considered.

Historically, it has always been possible to control the angle (inclination) of directional wells during rotary drilling by correct design of the assembly and use of suitable drilling parameters. However, the control of hole direction has traditionally been poor. Roller cone bits usually walk to the right, and directional control was formerly limited to using well-stabilized assemblies to reduce this tendency. Until the eighties it was standard practice to give wells a lead angle to the left of the proposal to compensate for this right hand walk.

Side Force and Tilt Angle

Directional trends are partly related to the direction of the resultant force at the bit. It has also been shown that bit tilt (the angle between the bit axis and the hole axis) influences the direction of drilling. This is because a drill bit is designed to drill parallel to its axis. In rotary assemblies where there is a near bit stabilizer, the bit tilt angle is small causing the magnitude of side force at the bit to be a key factor.

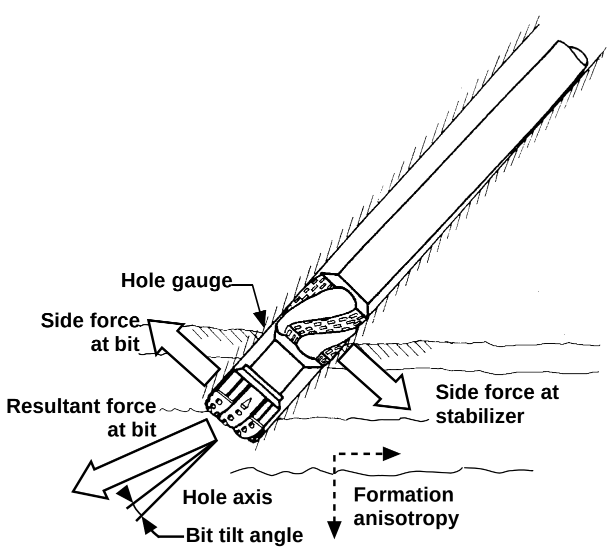


Figure 5-30: Forces acting at the bit which influence the direction of the borehole.

Factors Affecting Bit Trajectory

Factors which can affect the directional behavior of rotary assemblies include:

- Gauge and placement of stabilizers
- Diameter and length of drill collars
- Weight -on-bit
- Rotary speed
- Bit type
- Formation anisotropy and dip angle of the bedding planes
- Formation hardness
- Flow rate
- Rate of penetration

Many of these factors are interrelated.

Basic Directional Control Principles

- The Fulcrum Principle is used to build angle (increase borehole inclination)
- The Stabilization Principle is used to hold (maintain) angle and direction.
- The Pendulum Principle is used to drop (reduce) angle.

The Fulcrum Principle

An assembly with a full gauge near-bit stabilizer, followed by 40 to 120 feet of drill collars, before the first string stabilizer, or no string stabilizer at all, will build angle when weight-on bit is applied.

As illustrated in Figure 5-31, the collars above the near-bit stabilizer bend, partly due to their own weight and partly because of the applied WOB. The near-bit stabilizer acts as the pivot, or fulcrum, of a lever and the bit is pushed to the high side of the hole. The bit therefore drills a path which is gradually curving upwards (the assembly builds angle).

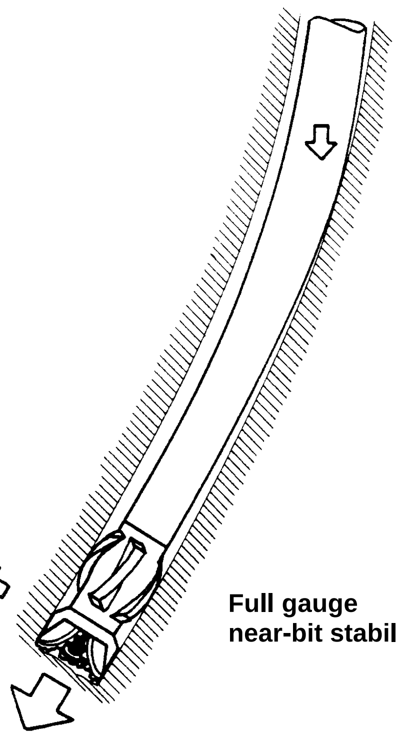


Figure 5-31: BHA using the fulcrum principle.

The rate of build will be **INCREASED** by the following:

- Increasing the distance from the near-bit stabilizer to the first string stabilizer
- Increase in hole inclination
- Reduction of drill collar diameter
- Increase in weight on bit
- Reduction in rotary speed
- Reduction in flow rate (in soft formations)

The distance from the near-bit stabilizer to the first string stabilizer is the main design feature in a fulcrum assembly which will affect the build rate. The build rate increases as this distance is increased, because a longer fulcrum section will bend more, which will increase the fulcrum effect and the side force on high side. There is a limit, however. Once the upper stabilizer is more than 120 feet from the near-bit stabilizer (depending on hole size, collar OD, etc.), the collars are contacting the low side of the hole and any further increase in this distance will have no additional effect on build rate.

The rate of build increases as the inclination increases because there is a larger component of the collars' own weight causing them to bend. The mechanics involved predicts that the rate of build should increase in direct proportion to the sine of the inclination. In reality, the situation and the actual response is more complicated. For example, a strong build assembly which built at a rate of 1.5°/100' when the inclination was only 15° might build at 4°/100' when the inclination was 60°.

Drill Collar Diameter: The stiffness of a drill collar is proportional to the fourth power of its diameter. A small reduction in the OD of the drill collars used in the fulcrum section considerably increases their limberness and hence the rate of build. However, it is not common practice to pick drill collar diameter according to build rate requirements. Usually, standard collar sizes for the given hole size are used.

Weight-on-Bit: Increasing the weight on bit will bend the drill collars behind the near-bit stabilizer more, so the rate of build will increase.

Rotary Speed: A higher rotary speed will tend to `straighten' the drill collars and hence reduce the rate of build. For this reason, low rotary speeds (70 - 100 RPM) are generally used with fulcrum assemblies.

Flow Rate: In soft formations, a high flow rate can lead to washing out the formation ahead of the bit which reduces the build tendency.

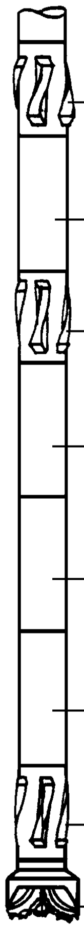


Figure 5-32: 90 ft Build Assembly
17½" bit / 17½" NB stab 3 x 9½ x 30' DCs / 17½" stab / 9½" x 30' DCs as needed / etc. This assembly will build angle rapidly, typically at 2.0° - 3.5°/100', depending on the inclination and the drilling parameters.

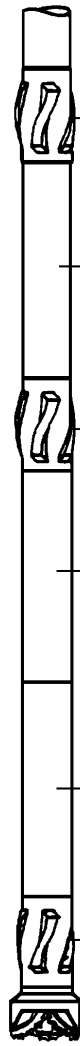


Figure 5-33: 60 ft Build Assembly
17½" bit / 17½" NB stab 2 x 9½ x 30' DCs / 17½" stab / 9½" x 30' DCs as needed / etc. This assembly will build angle at the rate of 1.5° - 2.5°/100', depending on the inclination and the drilling parameters

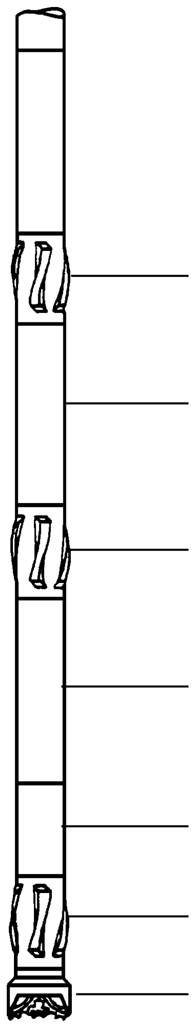


Figure 5-34: Gradual Angle Build Assembly
17½” bit / 17½” NB stab /9½ x 12’ DC / 9½ x 30’ DC / 17½” stab / 9½” x 30’ DCs as needed / etc. This assembly will build typically at 0.5° - 1.5°/100’, depending on the inclination and the drilling parameters

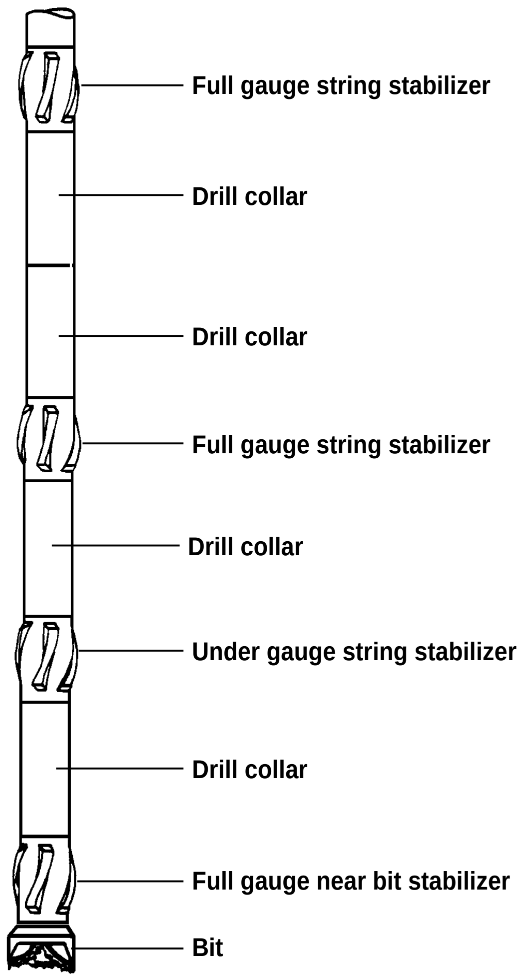


Figure 5-35: Gradual Angle Build Assembly
12¼" bit / 12¼" NB stab / 8" x 30' DC / 12¼" stab / 8" x 30' DCs as needed / etc. This assembly would be used in the tangent section when it was necessary to build angle gradually. It would build typically at 0.5° - 1.0°/100'

The Stabilization (Packed Hole) Principle

This principle states that if there are three stabilizers in quick succession behind the bit separated by short, stiff drill collar sections, then the three stabilizers will resist going around a curve and force the bit to drill a reasonably straight path. The first of the three stabilizers should be immediately behind the bit (a near-bit stabilizer) and should be full gauge.

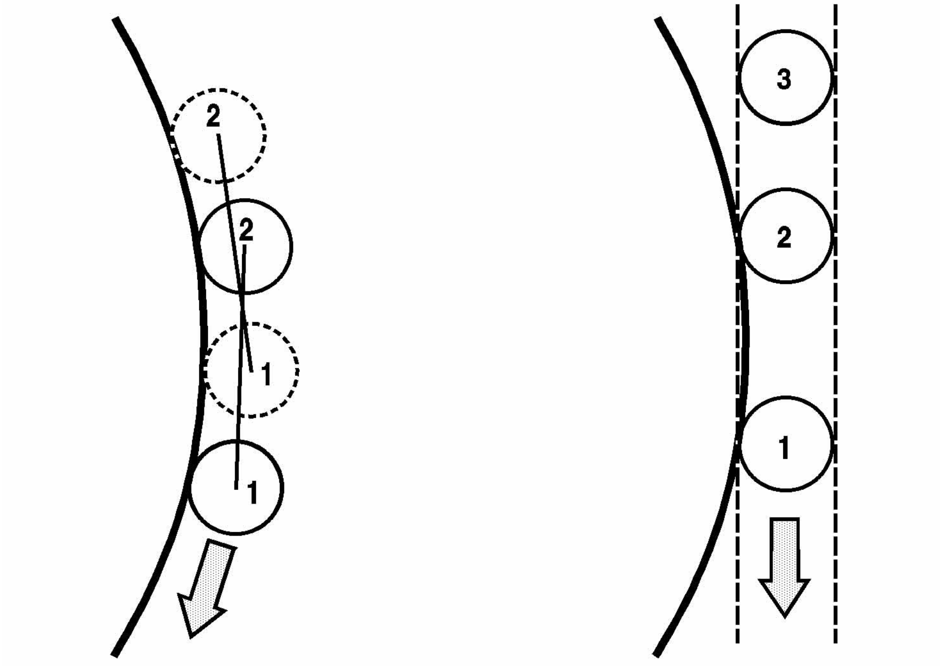


Figure 5-36: Packed Hole (Stabilization) principle

Assemblies which utilize this principle are called packed hole assemblies and are used to drill the tangent sections of directional wells, maintaining angle and direction. High rotary speed (120-160+) will assist the tendency to drill straight.

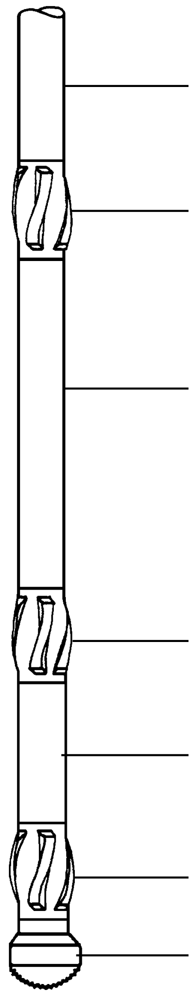


Figure 5-37: Rate equals 0.1° - 0.5°/100’ depending on various factors such as formation characteristics, WOB, RPM, bit type, etc.

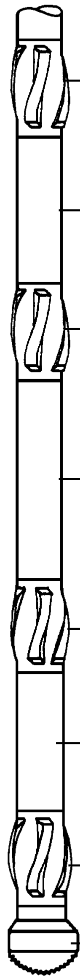


Figure 5-38: This assembly should hold angle depending on the exact gauge of the first string stabilizer.

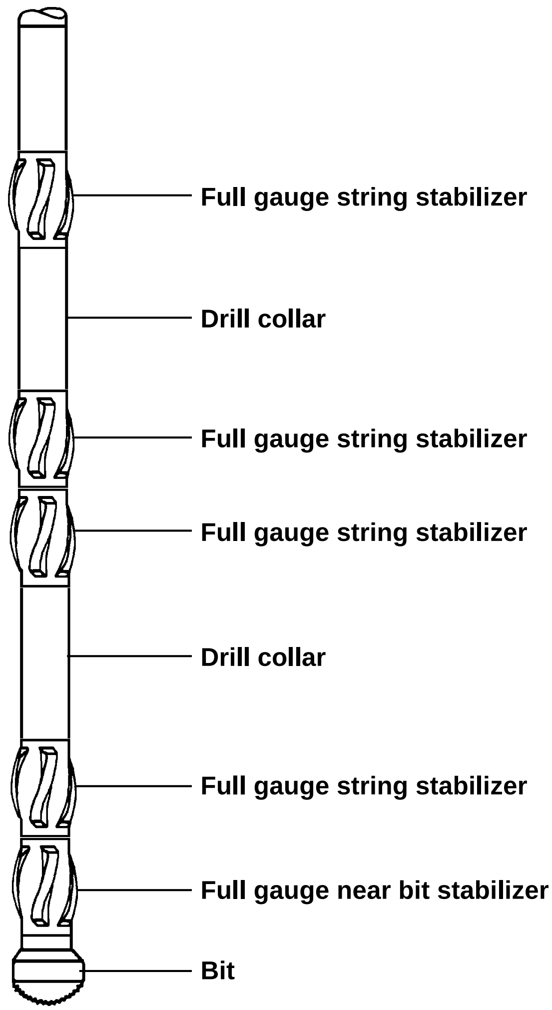


Figure 5-39: The tandem stabilizers make this assembly very rigid. In the past it was more common to use tandem stabilizers to control the bit walk of roller cone bits. Presently, its use is limited to areas where extreme bit walk is common. Rotation of an assembly such as this will generate high rotary torque. Generally, as the number of stabilizers in the BHA increases, so does the possibility of hole sticking.

The Pendulum Principle

This was the first directional control principle to be formulated and was originally analyzed for slick assemblies drilling straight holes. We shall concentrate on pendulum assemblies used in deviated wells.

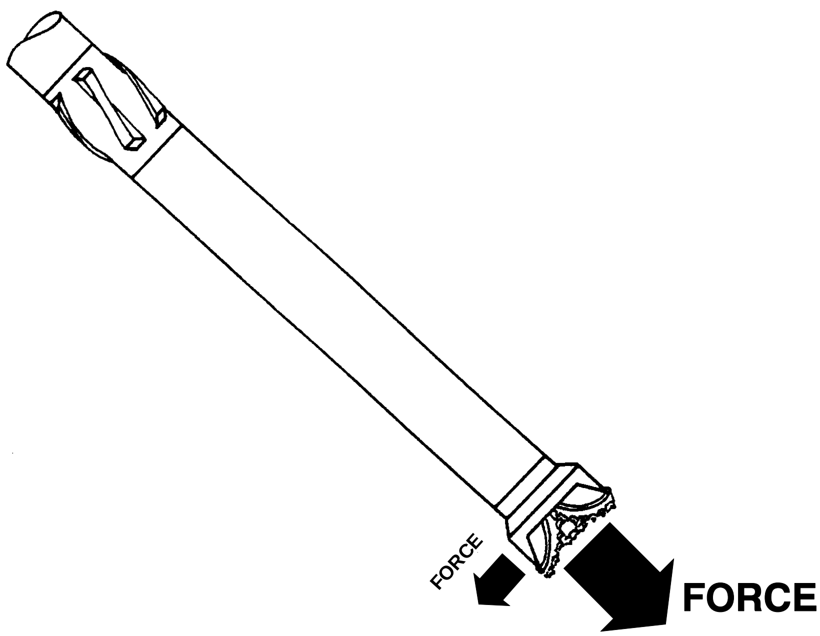


Figure 5-40: The pendulum principle.

The portion of the BHA from the bit to the first string stabilizer hangs like a pendulum and, because of its own weight, presses the bit towards the low side of the hole. The major design feature of a pendulum assembly is that there is either no near-bit stabilizer or an undergauge near- bit stabilizer. In most cases where a pendulum assembly is used, the main factor causing deviation is the force at the bit acting on the low side of the hole. The length of collars from the bit to the first string stabilizer (the "pendulum") must not be allowed to bend too much towards the low side of the hole.

If the collars make contact with low side as shown in the Figure 5-41, then the effective length of the pendulum and the side force on low side are both reduced. This situation is also undesirable because the bit axis has been tilted upwards in relation to the hole axis which will reduce the dropping tendency.

Careful selection of drilling parameters is required to prevent this. High rotary speed (120 - 160+) helps keep the pendulum straight to avoid the above situation. Initially, low weight-on-bit should be used, again to avoid bending the pendulum towards the low side of the hole. Once the dropping trend has been established, moderate weight can be used to achieve a respectable penetration rate.

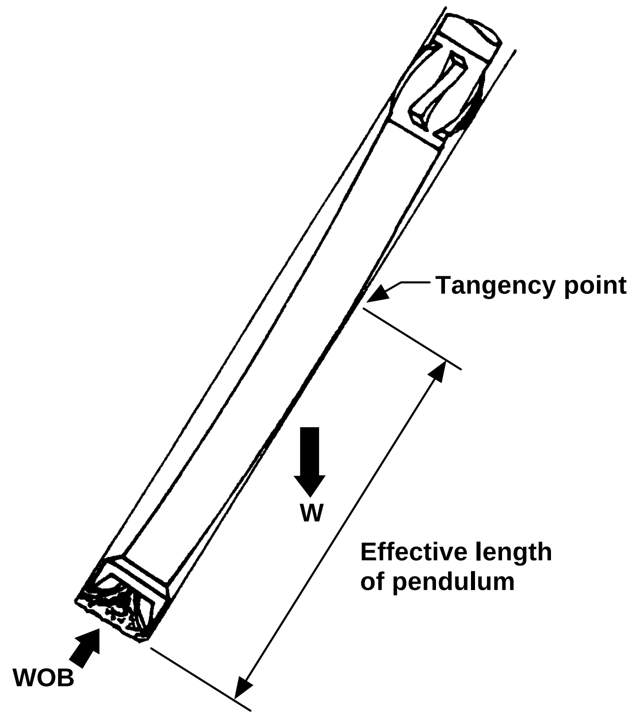


Figure 5-41: Reduction of pendulum force due to wall contact.

Some elementary texts on directional drilling depict the pendulum effect as shown in Figure 5-42. The implication being that part of the dropping tendency is produced by a downward tilt of the bit axis. It is interesting to note that if this picture were true then the dropping tendency would be increased by increasing WOB and reducing rotary speed, the precise opposite of what is recommended.

Figure 5-42 is possible for certain lengths of pendulum when there is no near-bit stabilizer and only one string stabilizer. The collars above the upper stabilizer will sag towards the low side of the hole causing a fulcrum effect about the string stabilizer and tilting the upper portion of the pendulum towards the high side of the hole.Experienced has shown instances of pendulum assemblies dropping faster with high WOB and low rotary speed.

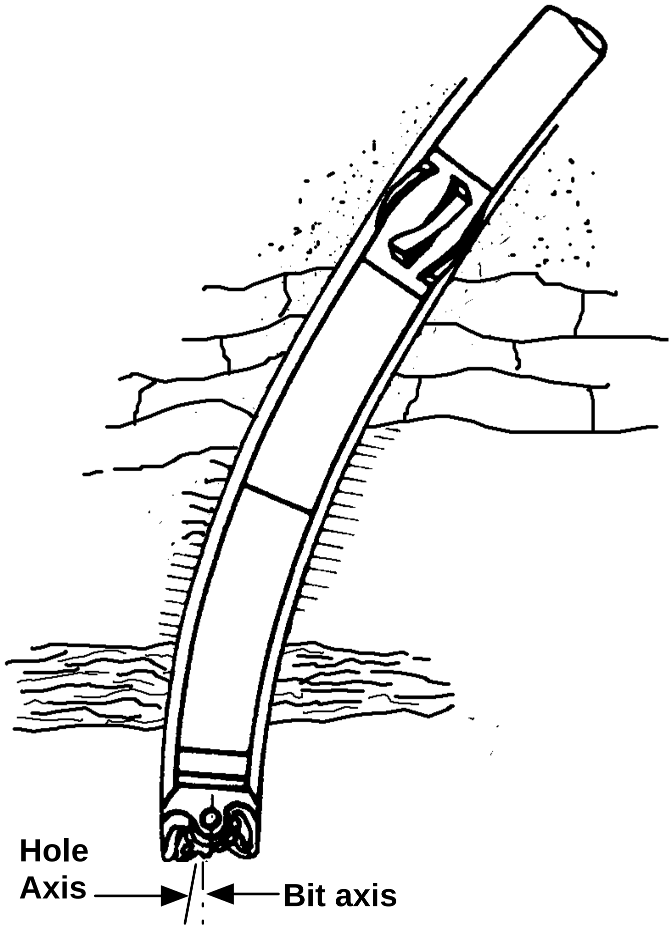


Figure 5-42: One possible interpretation of the pendulum effect.

It must be emphasized, however, that this is not what would normally occur. The gauge of the bit is effectively a point of support, so that most pendulum assemblies, especially longer pendulums, the pendulum section is most likely to bend towards the low side of the hole.

Summary and Recommended Practices.

- The safest approach to designing and using a pendulum assembly is to concentrate on producing a side force at the bit on the low side of the hole. This is achieved by running an assembly where the pendulum portion will be as stiff and straight as possible. It is also desirable that the section immediately above the first string stabilizer be stiff and straight and that a second string stabilizer be within 30 feet of the first.
- Omit the near-bit stabilizer when azimuth control is not a concern or when drilling with a PDC bit. When drilling with a roller cone bit, use

an under-gauge near-bit stabilizer if azimuth control is a consideration. Typically, the near-bit stabilizer need only be 1/4” to 1/2” undergauge in order to produce a dropping tendency.

- The assembly should have two string stabilizers with the second stabilizer not more than 30 feet above the first.
- Initially use low WOB until the dropping tendency is established, then gradually increase bit weight until an acceptable penetration rate is achieved.
- Use high rotary speed, depending on bit type.
- If possible, do not plan drop sections in hard formation.

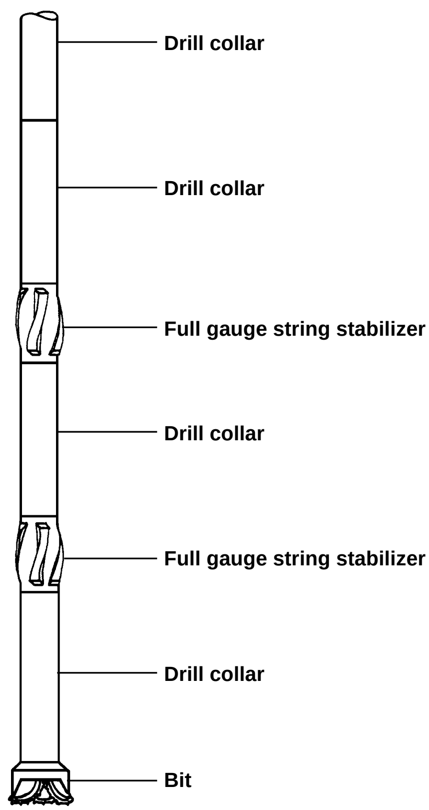


Figure 5-43: 30 foot Pendulum Assembly.
The rate of drop depends on the wellbore inclination and the diameter and weight of the bottom drill collar, as well as the drilling parameters. At 45° inclination, this assembly would typically drop at 1.5° - 2.0°/100’.

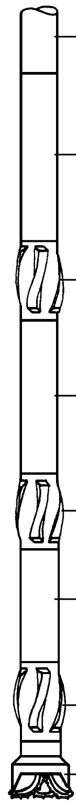


Figure 5-44: 30 foot Pendulum Assembly with under-gauge near bit stabilizer. This will give a slightly lower rate of drop than the previous BHA, but should reduce bit walk and thereby give better azimuth control.

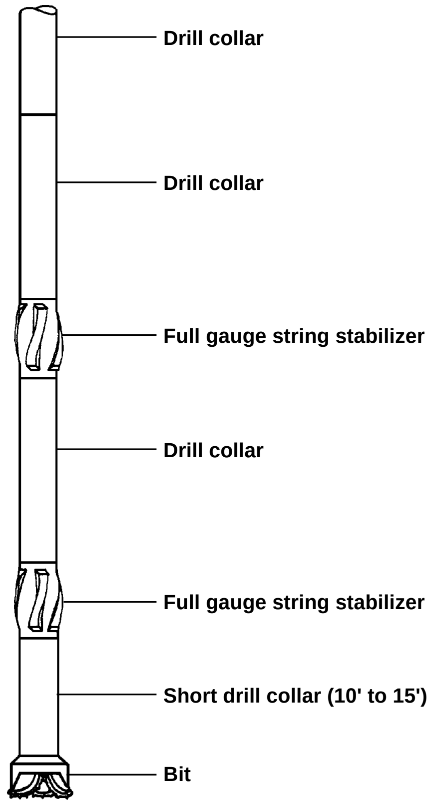


Figure 5-45: Gradual Angle Drop Assembly.
This short pendulum hook-up would give a more gradual drop rate approximately 1°/100’ depending on inclination, etc.

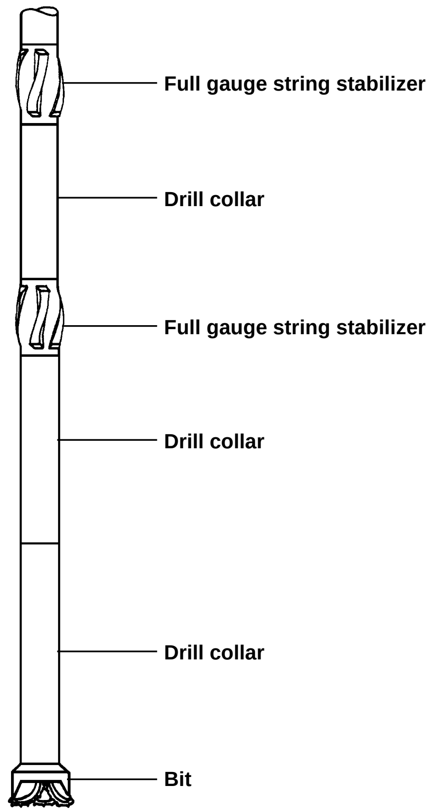


Figure 5-46: 60 foot Pendulum Assembly used to drill vertical wells. This is too strong a dropping assembly to use on directional wells, except perhaps low angle wells. It is commonly used to drill vertical wells through soft to medium hard formations.

Bit Type Effects on Rotary Assemblies

Roller Cone Bits

When rotary drilling with roller cone bits, the type of bit makes very little difference to whether an assembly builds, holds or drops angle. Mainly because directional control is determined by the configuration of stabilizers and collars and by varying the drilling parameters.

However, the type of bit has a significant influence on walk rates. Conventional tri-cone bits cause right-hand walk in normal rotary drilling. Generally speaking, long tooth bits drilling soft to medium hard formations give a greater right walk tendency than short tooth bits drilling a harder formation. This is because soft formation bits have a larger cone offset and cut the rock by a gouging action.

PDC Bits

During the eighties it became common practice to use PDC bits for rotary drilling, with low WOB and high rotary speeds. When rotary drilling with PDC bits, it has been found that almost no walk occurs (the assemblies hold their direction). It has also been found that inclination angle is affected by PDC bits, particularly when an angle drop assembly is used.

The gauge length of a PDC bit can significantly affect the build rate in a rotary assembly. A bit with a short gauge length can result in a build rate greater than that would be expected with a tri-cone bit. On the other hand, a longer gauge stabilizes the bit, which tends to reduce the rate of build. The low WOB typically used with PDC bits can also reduce the build rate, since collar flexure decreases with decreasing WOB. When used with packed assemblies, longer gauged PDC bits seem to aid in maintaining inclination and direction due to the increased stabilization at the bit.

When used with angle drop assemblies, PDC bits can reduce the drop rate previously obtained with a tri-cone bit. Generally, the longer the gauge length, the lower the rate of drop obtained because the bit gauge acts similar to a full gauge near-bit stabilizer. Short gauge length PDCs can be used effectively for dropping angle. When such a suitable PDC bit is used in a rotary pendulum assembly, the low WOB and high RPM, typical to most PDC bit applications, should assist in dropping angle.

Stiffness of drill collars

The behavior of bottom-hole assemblies, particularly fulcrum and pendulum assemblies, is affected considerably by the stiffness of the drill collars used in the lowest portion of the BHA.

It is generally accepted that drill collars are considered as thick walled cylinders. Their stiffness depending on the axial moment of inertia and the modulus of elasticity of the steel.

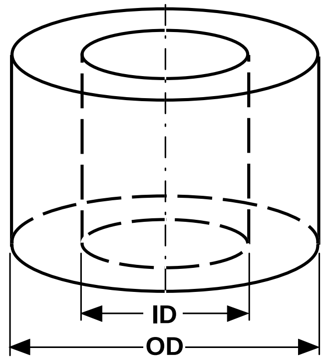


Figure 5-47: Collar strength determination

A collar's axial moment of inertia I, is determined by:

$$I = (\pi \div 64) \times (OD^4 - ID^4)$$

The weight per unit length, W, is calculated from:

$$W = (\pi \div 4)\rho \times (OD^2 - ID^2)$$

where ρ is the density of the steel.

Notice that the stiffness is proportional to the fourth power of the outside diameter, while the collar weight is proportional to the square of the outside diameter. This means that the inside diameter has very little effect on collar stiffness but has a significant effect on collar weight.

Table 5-7: Relative Weights & Inertia of Some Common Drill Collars

Collar OD (in)	Moment of Inertia (in^4)	Weight/Length (lb/ft)
4.75	25	45
6.5	85	100
8.0	200	160
9.5	400	235

For example, the moment of inertia of a 9-1/2" collar is double that of an 8" collar, which in turn is more than double that of a 6-1/2" collar.

The component of weight/unit length tending to bend the drill collars and contributing to the lateral forces at the bit and stabilizers is then:

$$W_x = W\ (BF) \sin \Theta$$

where W = weight/foot of the drill collar in air,
BF = buoyancy factor of the drilling mud
Θ= inclination of the wellbore

For example, if the inclination was 50° and the mud density was 10 ppg then the value of W_x for 8-inch drill collars would be:

$W_x = 160 \times 0.847 \times \sin 50°$

$W_x = 160 \times 0.847 \times 0.766 = 104$ lb/ft

(Buoyancy factor for 10 ppg mud = 0.847)

The following table gives the modulus of elasticity and density for various metals which can be used to manufacture drill collars.

Table 5-8: Modulus of Elasticity and density of Various Metals

Metal	Modulus of Elasticity (10^6 psi)	Density (lb/ft^3)
Steel (low carbon	29.0	491
Stainless Steel	28.0	501
K Monel	26.0	529
Aluminum	10.6	170
Tungsten	51.5	1205

The thing to notice is that most types of steel and monel which are actually used in drill collars have about the same modulus of elasticity and density. So in practice the stiffness of a drill collar depends almost entirely on its outside diameter and is proportional to the fourth power of the OD. However, aluminum drill collars would be more limber than steel drill collars of the same dimensions whereas tungsten collars would be much stiffer.

In general, it is recommended that standard drill collar diameters should be used for each hole size.

Effects of Drill Collar O.D.

When using a fulcrum (build) assembly, reducing the collar OD will dramatically increase the build tendency, because the collars will be more limber and will bend more. Another factor is the clearance between the outside of the drill collars and the wall of the hole. The greater the clearance, the more the collars can bend before they contact the low side of the hole. Once the collars contact the low side of the hole, further increases in WOB will have only a marginal effect on build rate by moving the contact point down the hole.

When using a packed assembly, reducing collar OD may give a slight build tendency because the collars can bend more.

When using a pendulum assembly, it is best that the pendulum portion be as stiff as possible, so it is preferable to use large diameter collars. Reducing collar OD increases the likelihood that the collars will bend towards the low side of the hole, which will reduce the pendulum effect and the rate of drop. Also, reducing the collar OD reduces the weight of the bottom collars which reduces the pendulum force and the rate of drop.

Formation Effects on Bit Trajectory

The nature and hardness of the rock being drilled can have a pronounced influence on directional tendencies, although in many cases the importance may be exaggerated. A main point is whether the rock is isotropic or anisotropic. An isotropic rock is one which has the same properties, or behaves in the same way, regardless of its direction. Most sandstones are isotropic. Conversely, anisotropic rocks, such as shales, do not have the same properties in all directions.

Most oilfield drilling is done in sedimentary rocks. Due to the nature of their deposition, sedimentary rocks have layers or bedding planes, causing most sedimentary rocks to show some degree of anisotropy. Drilling into dipping (tilted) formations has shown that the drill bit is forced towards a preferential direction related to the dip angle and direction of the bedding. The trends are most prevalent in low angle, medium to hard drilling, especially in formations with pronounced structure.

A number of explanations and models have been proposed over the years to explain these effects. In their early work on the pendulum theory, Lubinski and Woods proposed a drillability model which related an index of the rock strength when attacked perpendicular to the bedding planes to rock strength when attacked parallel to the formation. They produced tables of anisotropy indices and formation classes which could be used as a guide in selecting pendulum length, drill collar size or weight on bit.

Another theory proposes that as the bit drills into hard layers, the hard layer will fracture perpendicular to the dip. This creates a miniature whipstock which guides the bit to drill into the dip.

Another explanation, proposed by McLamore and others, is that of preferential chip formation. This considers the mode of chip formation at a single tooth. Anisotropic formations have preferential planes of failure. As it impacts the formation, the bit tooth sets up a compressive stress in a direction perpendicular to the face of the tooth. Shear failure will then occur more readily along the bedding planes. When the bit is drilling an anisotropic rock, larger chips will be cut rapidly on one side of the bit and smaller chips will be cut more slowly on the other. Unequal chip volumes will therefore be generated on each side of a bit tooth.

Using Figure 5-48 as an example, the forces between the bit tooth and the rock will be greater on the right side of the tooth. Therefore, there will be a resultant force on the bit acting to the left. This is Fd, the deviation force. It follows that the deviation force will depend on the angle of dip.

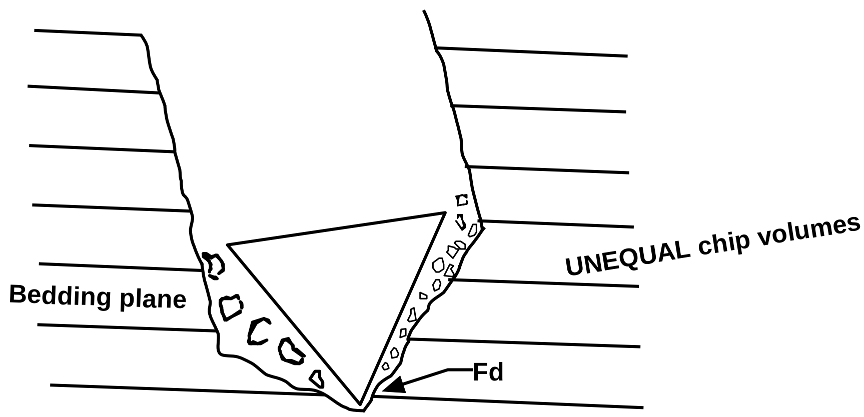


Figure 5-48: Generation of drill cuttings in a directional well

Relationship Between Dip Angle and Deviation Force.

Based on the preferential chip formation theory, the graph shown below has been derived from experimental work.

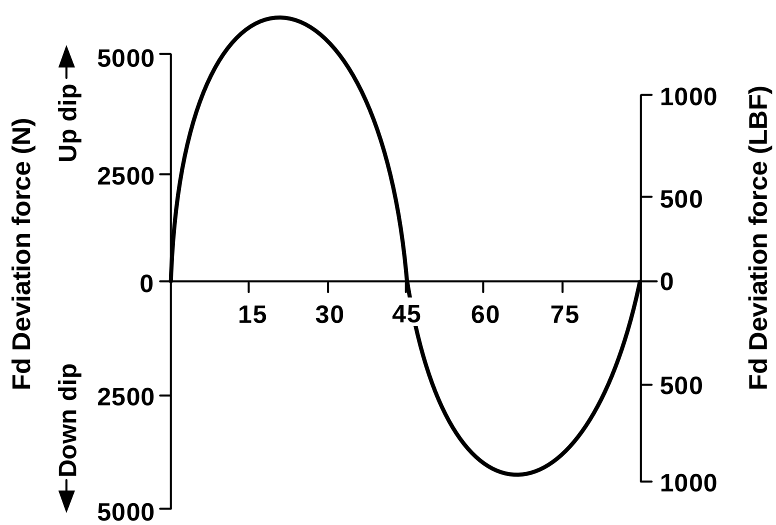


Figure 5-49: Maximum deviation force as a function of formation dip.

The effective dip angle is the angle at which the bit strikes the bedding plane. The graph predicts that when the effective dip angle is less than 45°, the direction of the deviation force is up-dip. When the effective dip angle is greater than 45° the direction of the deviation force is down-dip.

The meaning of up-dip and down-dip is illustrated in Figure 5-50. In practice, it has sometimes been observed that an up-dip tendency is observed at dip angles as high as 60º.

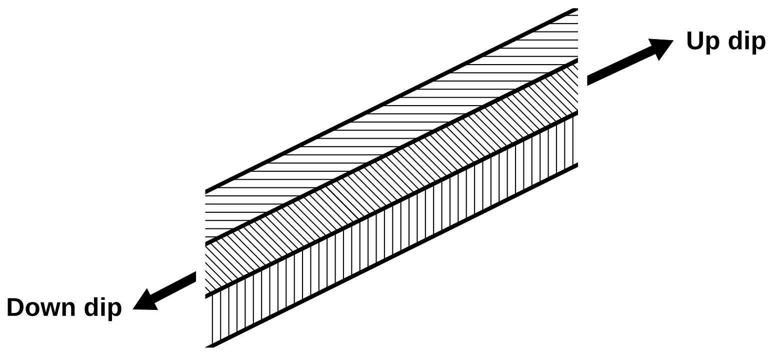


Figure 5-50: Up-dip versus down-dip.

The unwanted deviation in vertical wells has borne out the predictions of the graph shown in Figure 5-49. Drilling through alternately hard and soft formations with low dip angles, using a well stabilized bit and weights high enough to cause collar flexure, usually results in a course perpendicular to the bedding planes.

Figure 5-51 illustrates the tendency of the bit to deviate in the up-dip direction when the formation dip angle is low.

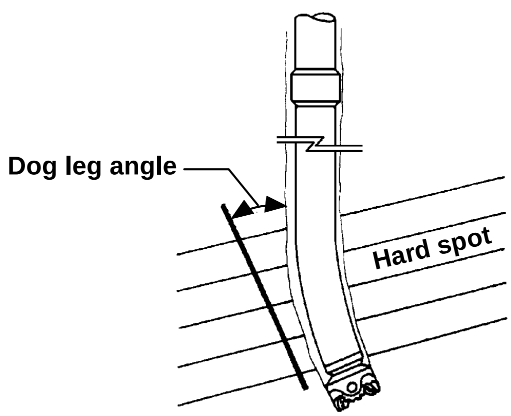


Figure 5-51: At low dip angles, deviation tendency is up-dip.

The formation attitudes will have a similar effect on directional tendencies. For dip angles less than 45°, if the direction is up-dip, the bit will tend to maintain direction, but build angle. If the borehole direction is left of up-dip, the bit may tend to walk to the right; whereas if the direction is right of up-dip the bit tends to walk to the left. Both phenomena are just special cases of the up-dip tendency.

When the formation dip angle is greater than 60°, the usual tendency of the bit is to drill parallel to the bedding plane or down-dip.

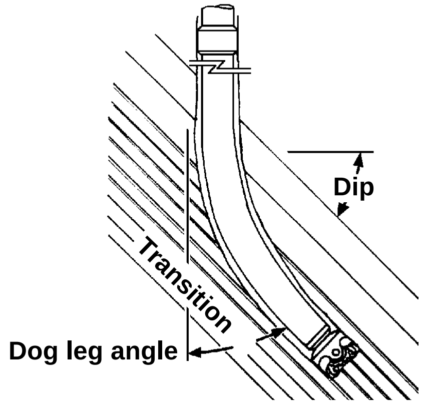


Figure 5-52: At high dip angles, deviation tendency is down-dip.

In cases where the dip angle is greater than 60°, if the hole direction is right of down-dip direction then the bit tends to walk to the left. If the hole direction is left of down-dip direction, the bit tends to walk to the right. Again, these are simply special cases of the down-dip tendency.

There will be no deflection of the bit caused by the formation at 0° or 90° dip. This is because the bit is cutting into a structure that is essentially uniform and is constantly cutting into the same layers at the same time or constantly drilling between layers.

Effective Dip Angle in a Deviated Hole

In a directional well, the effective dip angle is the angle at which the bit strikes the bedding planes.

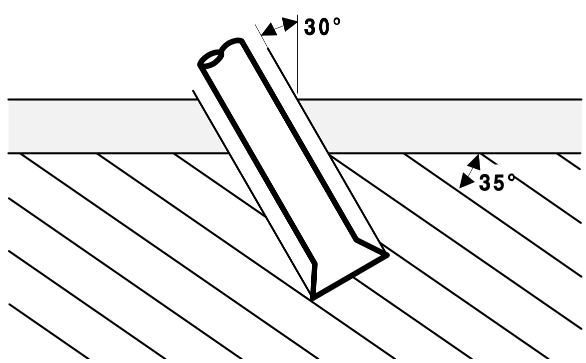


Figure 5-53: Hole inclination = 30°;
Real dip angle = 35°; Effective dip angle = 30° + 35° = 65°;
There will be a down-dip deviation force.

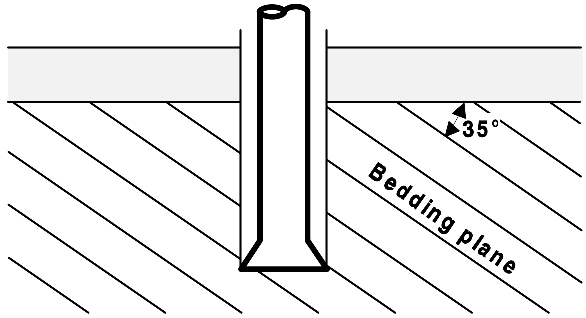


Figure 5-54: Hole inclination = 0°;
Effective angle of dip equals real dip angle (35°);
There will be an up-dip deviation force.

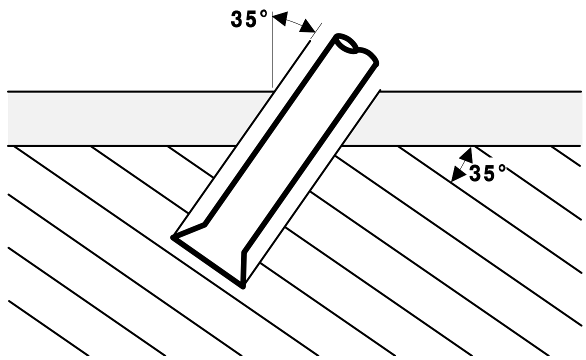


Figure 5-55: Hole inclination = 35°;
Real dip angle = 35°; Effective dip angle = 0;
There will be no deviation force.

Formation Hardness

The preceding discussion has concentrated on the effects of rock anisotropy and changes in hardness between layers. There are a few general points concerning the effect of rock hardness on directional behavior which should be mentioned.

In very soft formations, the formation can be eroded by the drilling fluid exiting from the bit nozzles, creating an overgauge hole. This can make it hard to build angle, even with a strong build assembly. If this problem is anticipated then fairly large nozzles should be fitted into the bit. If it occurs while drilling, the pump rate should be reduced and prior to making each connection, increase the flow rate to clean the hole with the bit one joint off bottom. Hole washing or enlargement in soft formations may also cause packed assemblies to give a dropping tendency at high inclinations.

This can be counteracted by increasing WOB and reducing flow rate. If anticipated beforehand, a possible solution would be to run a mild build assembly.

BHAs tend to respond more closely to their theoretical behavior in harder formations. This is mainly because the hole is more likely to be in gauge. In medium to hard formations, building assemblies are more responsive as maximum bit weight may be applied to produce the required build. The main directional problem encountered in hard formations is getting a pendulum assembly to drop angle. Generally speaking, the harder the formation, the longer it takes a dropping assembly to respond. There may also be a conflict between the need to reduce WOB to get the dropping trend established and the need for high WOB to maintain an acceptable penetration rate. Where possible, it is best to avoid planning a drop section in hard formation. When a drop section must be drilled in hard formation, the use of large diameter, heavy collars is recommended.

Summary of Formation Effects

It should be emphasized that in most formations, the rock properties have a minimal effect on the BHAs directional response.

In soft to medium soft, isotropic formations, the rock has little influence on directional response and the BHA should follow its theoretical behavior.

In medium to hard rocks, which have an appreciable degree of anisotropy, directional tendencies can be significantly affected by formation attitudes and in particular by the effective dip angle of the bedding planes. If the effective dip angle is less than 45° - 60º, the bit tends to drill up-dip. When the effective dip angle is greater than 60°, the bit tends to drill down dip. When the effective dip angle is approximately 0°, there is no tendency to deviate.

Unwanted deviation tendencies caused by the formation can best be reduced by packed assemblies. The use of a full gauge near-bit stabilizer definitely reduces bit walk. In cases where strong formation effects have been observed on previous wells in the same area, the BHA design should be suitably modified to compensate for the anticipated effect.

Navigation Drilling Systems

Most conventional directional drilling operations will require extra trips to change the BHA for directional control. In addition, bit performance can be reduced by those same conventional deflection techniques.

Several methods exist for continuously controlled directional drilling using "steerable downhole motors". These methods are based upon tilting the axis of the bit with respect to the axis of the hole to creating a side force at the bit. If the drill string, and the body of the motor, is rotated at the surface, the bit will tend to drill straight ahead. However, if the drill string is not rotated from surface then bit will drill a curved path determined by the orientation of the side force or the tilt of the bit axis.

Most steerable systems presently being used are based on a positive displacement motor and use the principles of tilting the axis of the bit with respect to the axis of the hole. The majority of directional drilling companies use a single-tilt PDM, with a bend either on the U-joint housing or at the connection between the U-joint housing and the bearing housing. Nowadays this single bend is typically adjustable on the rig floor, enabling the tilt angle to be set at any value between zero and some maximum.

There are also steerable turbines.

Advantages of NDS

- Elimination of trips for directional assembly changes, saving rig time
- More complex well paths can be drilled
- Wells are drilled more closely to the plan at all times
- Smaller directional targets can be hit

Steerable Turbines

Steerable turbines use the side force method by having an eccentric (or offset) stabilizer at the lower end of the bearing section (at the bottom end) of the turbine body, quite close to the bit. The three blade version shown below is the one most commonly used, but a single blade version exists and is used if a lot of drag (friction) is anticipated.

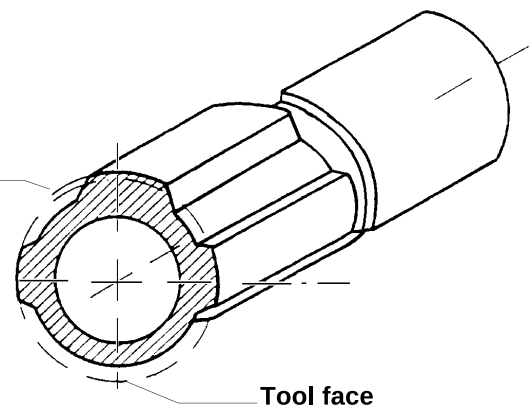


Figure 5-56: Three blade steerable turbine

As illustrated in Figure 5-56, one blade is larger in surface area and is offset by 1/8-inch. When the drill string is rotated, the offset stabilizer has no effect on the well path. When it is desired to deflect the well path, the toolface (the point opposite the center of the offset blade) is orientated using an MWD tool. Drilling continues with no rotation from surface and the turbine drills a curved path.

Steerable turbines have been used to perform various types of deflections including kick-offs. Their most successful applications have been tangent section drilling and performing correction runs as required to keep the well on course.

The DTU Navigation Drilling System

This drilling system consists of the following:

- Suitable drill bit
- Navi-Drill motor with a bearing housing stabilizer and DTU
- Undergauge string stabilizer just above the motor
- Survey system (usually MWD)

Modes of Operation

The capability to drill either oriented or rotary with the same tool is made possible by incorporating a Double-Tilted U-joint housing (DTU) and a longer U-joint assembly on a standard Mach 1 or Mach 2 PDM. The DTU creates a small tilt much closer to the bit than a conventional bent sub assembly, producing a lower bit offset.

Bit tilt and offset allow directional (azimuth and/or inclination) changes to be performed to keep the well bore on target.

The low bit tilt and offset produced by the sub, means the string can be rotated when oriented drilling is not required. Rotation of the drillstring negates the bit tilt effect and the bit will usually drill a straight path.

DTU Basic Components

- Bypass Valve with box connection
- Navi-Drill motor section - Mach 1 or 2
- Double tilted U-joint housing
- Upper bearing housing with stabilizer (UBHS)
- Drive sub with bit box

Only the DTU housing, universal joint, and upper bearing housing components will be discussed; other components are standard Navi-Drill parts. Navi-Drill performance or operating specifications are not altered by the addition of these two special components. The DTU steerable motor is shown in Figure 5-57.

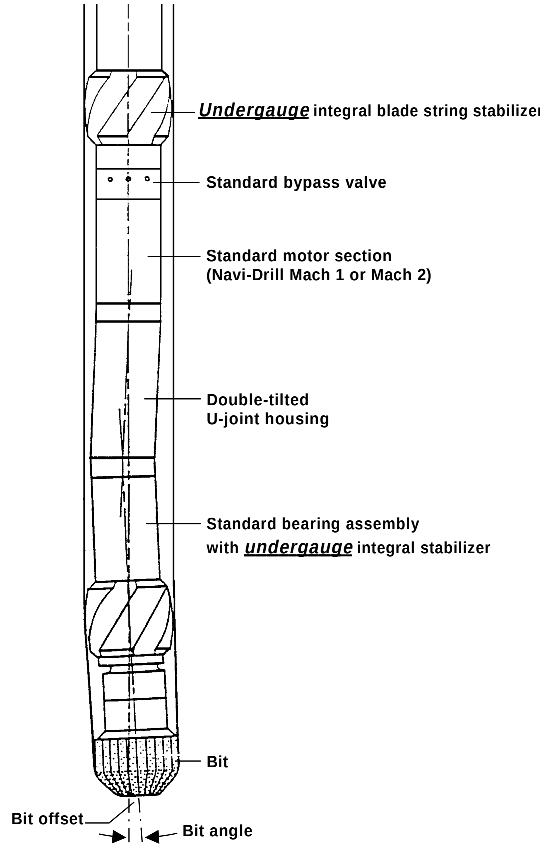


Figure 5-57: DTU Configuration

The double tilted universal joint housing:

- Replaces the straight universal joint housing on a standard Navi-Drill. The universal joint is slightly longer than the straight housing and universal joint.
- Is available in various tilt angles and identified by the tilt angle, which is the mathematical resultant angle computed from the two opposing tilt angles.
- Produces a desired bit tilt angle while reducing actual bit offset.
- Allows for extended rotation of the motor with a low eccentricity as compared to conventional bent sub or bent housing assemblies with comparable dogleg capability. Rotation of the drill string negates the effect of the bit tilt and the assembly theoretically drills a straight, slightly oversize, hole.
- Is available in various diameters ranging from 4-3/4” to 11-1/4”.

With the exceptions of the 8” and the 9-1/2” tools, each diameter has three standard tilt angles designed to provide approximately 2°, 3° and 4° per hundred feet theoretical dogleg rates when configured with a Mach 2 motor. TGDS is theoretically higher when using the shorter Mach 1.

As illustrated in Figure 5-58, the concept behind the double tilt is that by having the two tilts in the same plane but opposed (at 180°) to each other, the bit offset is minimized. Bit offset is the distance from the center of the bit to the axis of the motor section (extrapolated down to the bit).

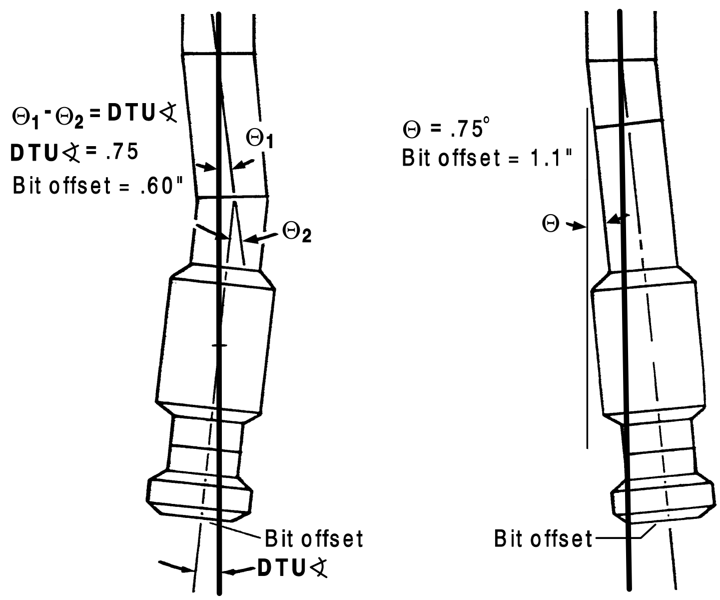


Figure 5-58: DTU and Bit Offset

A stabilizer can be mounted on the upper bearing housing. This stabilizer:

- Is used to centralize the motor and bit in the center of the hole.
- Is usually manufactured as an integral part of the housing and is referred to as the UBHS 9-1/2” and 11-1/4”. Motors are available with either integral or sleeve type stabilizer UBHS.
- Is always undergauge.
- Has a special design to reduce drag between the blade and the wellbore, allowing sliding when the motor is drilling in the oriented mode.

The design of the UBHS includes:

- A double taper or watermelon-shape profile with rounded edges to reduce stabilizer hangup and drag.

- Blade widths of 3 to 4 inches to help prevent a cutting or ploughing action by the blade when drilling in the oriented mode.
- Blade wraps varying from straight ribbed to a maximum of 30º to reduce contact area and make the stabilizer more maneuverable.
- Gauge lengths varying from 4 to 12 inches with recommended length being less than or equal to bit gauge length.
- Three blades at 1/8-inch undergauge for up to 17-1/2” hole sizes, or four blades at ¼-inch undergauge for larger hole sizes.

UBHS with 5 straight blades are now the preferred design.

Theoretical geometric dogleg severity

This angle is defined by three points on a drilled arc:

1. The bit
2. The motor stabilizer or Upper Bearing Housing Stabilizer (UBHS)
3. The first string stabilizer above the motor

TGDS(^{o}/100 ft) = (200 x Tilt Angle) ÷ L

Tilt angle = Bit tilt in degrees

L = length between the bit and string stabilizer = $L_1 + L_2$

> **Note:** *The above formula for calculating Theoretical Geometric Dogleg Severity is based on a system which contains full gauge stabilizers.*

Adjustable Kick-Off (AKO) Motor

This is a single-tilt adjustable motor, which:

- Is powered by a Navi-Drill motor section
- Incorporates a rigsite-adjustable bent housing which can be set to achieve maximum build rates in the medium radius range (8º/30m - 20º/30m), varying with tool size and stabilizer configuration
- Allows a single AKO motor to be used for a variety of build rates
- Allows fewer tools to be transported to and from the rig, a particular advantage for remote locations

Adjustable Kick Off Housing

The NaviDrill Mach 1 or 2, can be configured with an adjustable U-joint housing drilling motor suitable for both performance and general directional drilling applications. Steerable (mixed rotary and oriented mode) operation of the motor is possible for all well paths normally required in conventional or medium radius directional drilling operations.

The tilt angle of the AKO can be adjusted from 0° to the maximum design angle. The maximum tilt angle ranges from 2° to 2.75° depending on tool size (see below). This variable tilt angle is possible because the internal connections of the AKO housing features a tilted pin thread which screws into a tilted box thread. The relative position of the two tilted angles determines the AKO tilt angle and the position of the High Side. The AKO angle is rig floor adjustable.

Maximum Adjustment of AKO Motors

On the adjustable sub kick off housing, the angle is infinitely adjustable from 0° up to the maximum:

- 3-3/4” tool size is 2.2°
- 4-3/4” tool size is 2.5°
- 6-3/4” tool size is 2.75°
- 8” tool size is 2.5°
- 9-1/2” tool size is 2°
- 11-1/4” tool size is 2°

The addition of an alignment bent sub, with a 2° tilt angle, above the motor section allows the tool to achieve build rates up to 24°/100 ft. This is the Double Adjustable Motor (DAM). Major components include:

- Standard NaviDrill bearing and drive sub assembly with short gauge, straight rib, integral blade or sleeve type bearing housing stabilization.

- Rig floor adjustable single tilted U-joint housing.
- Standard Mach 1 or Mach 2 motor section.
- Standard bypass valve.
- String stabilizers with short gauge, straight rib integral blades (optional).

Dogleg Capabilities

The dogleg capability for the AKO is variable and is a function of the adjustable U-joint housing angular offset. The range of AKO U-joint housing adjustment, and corresponding dogleg capability for both oriented-only and steerable (mixed mode) operation, are detailed in the NaviDrill Operations handbook.

Using lower DLS and AKO settings, the motor can be rotated and used as a steerable motor.

The AKO motor can also be used as a:

- partially stabilized system with bearing housing stabilizer
- fully stabilized system with bearing housing and top stabilizer
- slick system (without stabilization) where a wear protection hard-banding ring on the AKO sub is one of the points which supports the tool inside the hole.

Maximum allowable deflection angle on the AKO sub may be limited when contact of the tool with the borehole wall exceeds mechanical limitations. This maximum angle is called “recommended Maximum Angle”.

The NaviDrill AKO is available for medium radius applications in 3-3/4”, 4-3/4”, 6-3/4”, 8”, 9-1/2”,11-1/4” OD sizes for hole sizes from 4-1/2” to 26”. Mechanical operating and performance characteristics for the AKO are identical to those for the standard NaviDrill.

Tilt Angle

The proper tilt angle and steerable motor deflection technique is usually dependent upon the directional requirements and characteristics of the well plan.

When kicking off or sidetracking, high tilt steerable motors are recommended. The tilt angle selected should produce a greater dogleg severity in the oriented mode than the rate of change specified in the well plan.

By getting higher dogleg severities than specified, the directional driller can “get ahead” of the well plan build requirements and begin utilizing the practice of drilling intervals using oriented and rotary modes. The directional driller can reduce a high build up rate increasing the percentage of footage drilled in the rotary mode.

Typically, the rate of penetration will increase when switching from the oriented mode to the rotary mode. As a rule of thumb, the tilt angle selected should theoretically produce a minimum of 1.25 times the maximum dogleg severity required for the well plan. Directional drillers must keep in mind that the TGDS (Theoretical Geometric Dogleg Severity) assumes that tool face orientation is constant. In practice this is difficult to do, especially in high torque applications. As a result of a constantly changing tool face orientation, the actual rate of change could be less than expected.

- When a choice is available, a tool with a higher dogleg capability can increase overall efficiency by reducing oriented drilling requirements.
- When tangent section or straight hole drilling, a lower tilted tool may be more desirable to reduce bit wear and increase ROP. However, this depends on the extent to which orientation may be necessary and the anticipated ease of oriented drilling.

First String Stabilizer

It is normal practice to run a string stabilizer either directly above the motor or with a pony drill collar between the motor and the stabilizer. Reasons for using this include:

- It defines the third point of contact in the NDS assembly
- It produces a predictable directional response
- It centralizes the drill string

Placement

The stabilizer is most commonly run directly above the motor. According to the 3-point geometry, increasing “L” (by moving the first string stabilizer higher in the BHA) reduces the Theoretical Geometric Dogleg Severity. This does not always work in practice. It has been found that moving the stabilizer higher can make it harder to get away from vertical in a kick-off. However, once some inclination has been achieved, the rate of build is often greater than the TGDS. For flat turns or for dropping angle, increasing “L” does reduce the dogleg rate as theory predicts.

Size and Design

The diameter of the first string stabilizer must not be greater than the diameter of the UBHS and is usually less. It should have preferably the same physical design as the UBHS.

First string stabilizer size - oriented mode

If the first string stabilizer diameter is decreased to less than the UBHS and an upward toolface orientation is present, then the oriented dogleg rate is increased. This is true for both AKO and DTU motors.

Figure 5-59: Upward Toolface

If the first string stabilizer diameter is decreased to less than the UBHS and a downward toolface orientation is present, then the oriented dogleg rate is reduced.

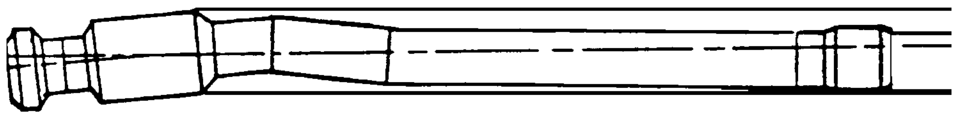


Figure 5-60: Downward Toolface

In either of the above cases, the more undergauge the first string stabilizer, the greater the effect. The same basic effect is seen with both the AKO and the DTU steerable systems.

First string stabilizer size - rotary mode

Field results have shown that an undergauge first string stabilizer is required to produce a holding tendency when NDS is run in the rotary mode. The requirements for the first string stabilizer gauge diameter will be a function of formation trends and hole inclination.

The following table can be used as a general guideline for determining the required diameter for the first string stabilizer so that inclination is maintained.

Table 5-9: Required Diameter for First String Stabilizer

Hole Size (in)	First String Stabilizer Gauge (in)
8½	8 - 8 1/4
9 7/8	9 1/8 - 9 5/8
12¼	11¾ - 12
14¾	14 1/8 - 14½
17½	16 - 17

Table 5-10 can be used as a general guideline for determining first string stabilizer changes in diameter to produce a significant change (minimum of 0.25°/100') in rotary inclination reaction.

Table 5-10: Fine Tuning Gauge of First String Stabilizer

Hole Size (in)	Change Required in Gauge of First String Stabilizer (in)
8½	1/8
12¼	¼
17½	3/8

These guidelines apply to both AKO and DTU steerable systems.

Kicking-Off

Bottomhole Assemblies

During kick-off operations, two basic factors will determine general NDS assembly design:

- Required build up rate
- Expected length of run

The following example assembly for a 17-1/2" hole is designed to have a rotary hold tendency.

- 17-1/2" Rock Bit
- 11-1/4" Mach 1, AKO or DTU, 17-1/4" UBHS
- 16-1/2" First String Stabilizer
- Float Sub
- 9-1/2" NMDC
- 9-1/2" MWD
- 16-1/2" Non-magnetic Stabilizer
- 2 x 9-1/2" NMDC
- Crossover
- 2 x 8" Steel Drill Collars (increase or decrease if required)
- Jars
- 8" Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight on bit)

The following example assembly for a 17-1/2” hole is designed to have a rotary build tendency.

- 17-1/2” PDC Bit
- 11-1/4” Mach 2, AKO or DTU, 17-1/4” UBHS
- Crossover
- 12-1/4” First String Stabilizer
- Float Sub
- 9-1/2” NMDC
- 9-1/2” MWD
- 16-1/2” Non-magnetic Stabilizer
- 2 x 9-1/2” NMDC
- Crossover
- 2 x 8” Steel Drill Collars (increase or decrease if required)
- Jars
- 8” Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight on bit)

This assembly is designed to have a considerable rotary build tendency. A good estimate would be 2°/100’.

The following example assembly for a 12-1/4” hole is designed to have a rotary hold tendency.

- 12-1/4” Bit
- 9-1/2” Mach 1, AKO or DTU, 12-1/8” UBHS
- Crossover
- 12” First String Stabilizer
- 8” NMDC
- 8” MWD
- 12” Non-magnetic Stabilizer
- 2 x 8” NMDC
- Jars
- 8” Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight-on-bit)

The following assembly for a 12-1/4" hole is designed for a rotary build tendency.

- 12-1/4" Rock Bit
- 9-1/2" Mach 1, AKO or DTU, 12-1/8" UBHS
- Crossover
- 11" First String Stabilizer
- 8" NMDC
- 8" MWD
- 11-3/4" Non-magnetic Stabilizer
- 2 x 8" NMDC
- Jars
- 8" Steel Drill Collar
- Crossover
- HWDP (sufficient amount to provide weight-on-bit)

Recommended Guidelines When Kicking Off

- When beginning a kick-off, it is recommended to have the first string stabilizer in open hole and not up in the casing to prevent hanging up or any other anomalous assembly reactions.
- When using a steerable motor assembly in vertical or near vertical holes, the actual dogleg may be less than the calculated TGDS.
- Initially, during a kick-off, observe the actual oriented dogleg severity for the steerable assembly over an interval of at least 60 feet. Constant monitoring of the actual oriented dogleg severity is necessary to plan subsequent oriented/rotary drilling intervals.
- Minimizing rotary speed will slightly increase the fulcrum effect. This practice can reduce oriented drilling intervals.
- During the initial stage of a kick-off from vertical, stabilizer hangup can occur. This problem may exist until the wellbore is inclined and/or the first string stabilizer enters the curved, oriented hole.
- Consider beginning the kick-off early; this can reduce oriented drilling requirements and the maximum inclination of the wellpath.

Interval drilling

An estimate of the required footage to be drilled in oriented mode can be determined using:

% Footage Oriented = [(DL - DLR) ÷ (DLO - DLR)] x 100 where:

DL = required dogleg (°/100’)

DLO = actual dogleg when oriented (°/100’)

DLR = actual dogleg when rotary drilling (°/100’)

Example:

Planned build-up rate = 2.5°/100’

Build-up rate obtained when oriented = 3.5°/100’

Build-up rate obtained during rotary drilling = 0.5°/100’

% Footage Oriented = [(2.5 - 0.5) ÷ (3.5 - 0.5)] x 100 = 67%

Tangent Section Drilling

Tangent or hold sections can prove to be very economical using NDS, although NDS performance drilling will not usually match that of straight motor performance drilling. Long sections of hole can be drilled faster than with conventional rotary assemblies, and corrections can be performed, if required, to keep the well on course. Basic design principles include:

- An undergauge first string stabilizer is required to maintain inclination when rotary drilling with NDS.
- The assembly should be capable of producing an acceptable dogleg rate to allow for shorter corrective oriented intervals.
- Decreasing the diameter of the first string stabilizer versus increasing “L” is preferred because TGDS is affected less. This practice also limits the number of variables to one, the OD of the first string stabilizer.

A typical BHA for drilling a 12-1/4” hole tangent section is:

- 12-1/4” PDC bit
- 9-1/2” Mach 1 motor, AKO or DTU, 12-1/8” UBHS
- Crossover
- 11-3/4” string stabilizer
- 8” NMDC
- 8” MWD tool
- 11-3/4” non-magnetic stabilizer
- 2 x 8” NMDC
- 2 x 8” DC
- Jars
- 8” DC

- Crossover
- HWDP as required

When drilling a tangent or hold section with NDS, the following should be observed:

- After observing NDS directional tendencies over a minimum of 200 ft of rotary drilled interval, a plan for drilling long distances between orientations should be established. This plan should minimize the number of orientation toolsets and maximize penetration rate.
- Oriented drilling intervals should be minimized. Oriented drilling in a tangent or hold section is performed to correct the present wellpath and to compensate for anticipated trends.
- Never let the drilled wellpath get too far from the planned trajectory, because “drilling on the line” can be significantly more expensive. As surveys are obtained, calculate and plot the position on both horizontal and vertical plans. At all times there must be a feasible course to drill from the current location to the intended target.

Drop Sections

When a drop section is drilled, the gauge of the first string stabilizer can be increased to produce more of a dropping tendency in the rotary mode. The recommended diameter is no larger than the UBHS. Increasing the diameter of this stabilizer can increase hole drag and stabilizer hang up.

Typical rotary drop rates are seldom much higher than 1º/100 ft, with 0.5º to 0.75º/100 ft commonly produced when the angle is less than 20º. If higher drop rates are required, then oriented drilling will be mandatory.

The following is a general design for a drop assembly while rotary drilling.

- 12¼” bit
- AKO or DTU motor
- Crossover
- 12" first string stabilizer
- 8" NMDC
- 12" NM stabilizer
- 8" MWD
- Etc.

The following guidelines should be considered when drilling drop sections.

- Except in stringent circumstances, the drilled wellpath can be positioned "ahead" of the planned path. This will usually reduce the oriented drilling requirements.
- In hard to drill or problem formations, oriented toolsets should be minimized or avoided.
- Actual dogleg rate when drilling to drop inclination with an oriented system is usually less than the TGDS.
- The NDS assembly should be designed such that the TGDS is at least 125% of the required drop rate.
- Stabilizers should be selected such that rotary drilling either assists in achieving desired dog-leg, or produces a neutral tendency.

Azimuth Control

Rotary Mode

Rotary drilling with NDS usually exhibits an azimuth hold tendency.

The dip and strike of the formation will affect the tendency of the NDS assembly to walk.

The conventional directional concept of increasing rotary RPM to stiffen an assembly is applicable with NDS.

Oriented Mode

Changes in azimuth are most efficiently performed in oriented mode.

Due to the stabilization of the steerable motor, the toolface can be orientated 90° right or left of high side for maximum turn without dropping inclination (a typical problem with motor and bent sub assemblies in soft formations).

A reduction in TGDS can be expected when oriented for a turn due to the effect of the undergauge first string stabilizer.

Self-Check Exercises

1. List six applications of directional drilling.

(a) ______________________________

(b) ______________________________

(c) ______________________________

(d) ______________________________

(e) ______________________________

(f) ______________________________

2. Define the following terms for “north”.

(i) True North:

____

(ii) Magnetic North:

____

(iii) Grid North:

____

3. Convert the following quadrant bearings into azimuth.

Quadrant Bearing	Azimuth
S64-1/2°E	
N 35°E	
S 88-3/4°W	
N 66.5°W	
S 22.25°E	
N 35.5°W	
S 89°E	
N 71 1/2°E	
S 25.5°W	
N 3-3/4°W	
S 11.5°E	

4. State one advantage and two disadvantages of a standard removable whipstock as a deflection tool.

   Advantage:

   Disadvantages:

   a. ______________________________

   b. ______________________________

5. Explain what is meant by “nudging” and why it is done.

   ____

   ____

   ____

6. What is meant by “multi-lobe” PDM’s?

   ____

   ____

   ____

7. State the relationship between torque and differential pressure in PDM’s

   ____

   ____

8. What is the relationship between flow rate and RPM in turbines?

   ____

   ____

9. Explain what is meant by reactive torque of downhole motors and why it causes problems for directional drillers.

   ____

   ____

10. List three advantages of a motor and bent sub as a deflection tool.

    1. ______________________________

    2. ______________________________

    3. ______________________________

11. How can an estimate of required footage that should be drilled in an oriented mode be determined?

____

____

12. List six factors which affect the rate of build in a fulcrum assembly.

    a. ____

    b. ____

    c. ____

    d. ____

    e. ____

    f. ____

13. Explain the effect of varying WOB and RPM on the drop rate of a pendulum assembly.

____

____

____

____

____

14. What are the guidelines to be followed when kicking off with a NDS?

____

____

____

____

15. Describe how the placement of the first string stabilizer affects the response of an NDS assembly.

____

____

16. How does the diameter of the first string stabilizer affect NDS assemblies when drilling in an oriented mode?

____

____

____

17. What are the guidelines to be followed when drilling the tangent section with a NDS?

____

____

____

•Notes•

Chapter **6**

Horizontal Wells

Upon completion of this chapter, you should be able to:

- Understand the general classifications of horizontal wells and the major factors which dictate a well's profile.
- Appreciate the recent developments that have made horizontal wells feasible and economical.
- Understand the conditions when a horizontal well may be an option and when they indicate a horizontal well may not the ideal option.
- Provide information to the client concerning the effective removal of cuttings.
- Use drilling and formation evaluation information to suggest when the zone of interest has been penetrated and when the bit has left this zone.

Additional Review/Reading Material

AAPG, *Geological Aspects of Horizontal Drilling*, Course Note #33, Tulsa, OK., 1991

World Oil, *Handbook of Horizontal Drilling and Completion Technology*, Gulf Publishing Company, 1991

Brochure:

Oil & Gas Journal - Horizontal Wells- December 30, 1990

Innovative Horizontal Drilling Technology - EC - x-229

Self-Check Exercises

1. What are the typical build rates for the following types of horizontal wells.

   Short Radius: ______________________

   Medium Radius: ______________________

   Long Radius: ______________________

2. What are some of the developments in horizontal drilling that have improved the overall drilling success during the last decade?

   ____

   ____

   ____

   ____

3. What are four major reasons for drilling horizontal wells?

   a. ______________________

   b. ______________________

   c. ______________________

   d. ______________________

4. What are the length of radii for the three types of horizontal wells?

   Short Radius: ______________________

   Medium Radius: ______________________

   Long Radius: ______________________

5. What are three parameters that must be known to successfully remain within a reservoir while drilling horizontally?

   a. ______________________

   b. ______________________

   c. ______________________

6. What are three reasons why drill rate is not a sure indicator of lithology in horizontal holes?

   a. ____

   b. ____

   c. ____

7. Why is it a bad sign when the actual lag is less than the theoretical lag in a horizontal well?

   ____

   ____

   ____

8. What type of carbide substitute do you need for lag in horizontal wells and why is it necessary?

   ____

   ____

   ____

9. When the cuttings are being analyzed in a horizontal reservoir, a large increase in a new rock type means the bit is ________ the reservoir. A small increase likely means the bit is penetrating ________.

Chapter **7**

Stuck Pipe

Upon completion of this chapter, you should be able to:

- Understand the importance of preventing stuck pipe.
- Understand how the various forms of stuck pipe can be prevented.
- Recognize the indications of stuck pipe.
- Calculate the pulling force required to free stuck pipe.
- Calculate the stuck pipe location.
- Understand the remedial actions taken when stuck pipe problems arise.

Additional Review/Reading Material

Adams, Neal, *How to Control Differential Pipe Sticking - 5 Part Series*, Petroleum Engineer, Sept 77 - Feb 78

BP Research, *Guidelines For The Prevention and Cure of Stuck Pipe*, Sudbury Research Centre, Aug 1989

Baker Hughes INTEQ, *Drilling Fluids Manual*, 1991

Kemp, Gore, *Oilwell Fishing Operations: Tools and Techniques*, Gulf Publishing Company, 1986

Moore, Preston, *Drilling Practices Manual, 2nd Edition*, PennWell Publishing Company, 1986

Stuck Pipe Problems

Introduction

Baker Hughes INTEQ personnel can be valuable members of the drilling team in diagnosing potential stuck pipe problems. Having access to the drilling information (via the DrillByte network), the geological data (from the Logging Geologist), and using the right analytical approach, INTEQ personnel can assist the client in keeping stuck pipe problems to a minimum.

Effective communication between the logging unit, company-man, directional driller and mud engineer can prevent many stuck pipe situations.

The types and causes of stuck pipe have been mentioned and described in the "*Advanced Logging Procedures*" workbook (P/N 80269H). This section will center around using the logging unit's analysis of the information available and their response to potential stuck pipe situations.

The following tables illustrate the response that can be made to the many factors that can result in stuck pipe/borehole problems.

DRILLBYTE INSTRUMENTATION	BOREHOLE PROBLEM	LOGGING PERSONNEL RESPONSE
Lithology Identification and Description	a. Formation Related b. Differential Sticking c. Cement Related d. Undergauge Hole e. Poor Hole Cleaning	a. Identification of Rock Types and Characteristics b. Identification of Permeable Sandstones c. Identification of Cement in Cuttings Samples d. Identification of Abrasive Formations e. Amount of Cuttings in Samples
Depth and Drill Rate Recorder	a. Formation Related b. Wellbore Geometry c. Poor Hole Cleaning	a. Identification of borehole problems from drill rate b. Reduced drill rate due to BHA hanging up on ledges c. Reduced drill rate due to poor transfer of WOB
Monitor Calculations	All Types of Borehole Problems	Monitor trends in hole conditions, and relating trends to lithology, hole deviation and BHA configuration
Pump Stroke Counters	Poor Hole Cleaning	Monitoring annular velocities to adequately clean borehole
Pore Pressure Evaluation	a. Geopressure b. Differential Sticking	a. Detecting abnormal or sub-normal pore pressure b. Calculation of ECD and amount of overbalance
Lag Time Determination	Poor Hole Cleaning	Monitoring actual hole volume to determine actual versus theoretical lag time

Table 7-1: Response to Analysis of Borehole Conditions

INDICATOR / CAUSES	Cavings	Dxc	Shale Density	Gas	Flowline Temperature	Shale Swelling	Shale Factor (CEC)
REACTIVE (HYDRATING) FORMATIONS	Large Quantities	No Indication	No Indication	No Indication	No Indication	Good Indication	High Values
GEOPRESSURED FORMATIONS	Large Quantities	Decrease in Trend	Decrease in Value	Increase in Value	Increase in Trend	Some Indication	High Values
FRACTURED & FAULTED FORMATIONS	Not Present	No Indication	No Indication	Increase if Present	No Indication	No Indication	No Indication
MOBILE (SALT) FORMATIONS	Small Quantities	No Indication	No Indication	No Indication	No Indication	No Indication	No Indication
UNCONSOLIDATED FORMATIONS	Not Present	Large Decrease in Trend	No Indication	Increase if Present	No Indication	No Indication	No Indication

Table 7-2: Indicators Available to the Field Personnel.

Recognizing Problem Situations

During the course of a well, many drilling and non-drilling operations can potentially cause stuck pipe. Careful observation of the various parameters monitored by DrillByte can pin-point many troublesome zones. Several of the more common are illustrated below.

During Connections and Surveys

The major indication of a potential problem will be increased drag, when the drillstring is moved.

Questions to Answer	Response
1. Are problem formations exposed?	1. Check lag time
2. Was the borehole adequately cleaned before the connection/survey?	2. Check drill rate before connection/survey
3. Are there indications of sticking?	3. Check lithology
	4. Check annular velocities
	5. Check filter cake thickness
	6. Check hydrostatic overbalance
	7. Check if permeable formations are exposed

Tripping Out

During trips out of the hole, the common indication of stuck pipe problems will be increased drag and overpull.

Questions to Answer	Response
1. Are problem formations exposed above the bit?	1. Review records of previous trips. Is there a trend which can be related to a possible cause?
2. Are high swab pressures resulting in hole instability?	2. Check if the proper lag time was completed when circulating bottoms up?
3. Was the hole adequately cleaned prior to the trip?	3. Check swab pressures, should the trip speed be reduced.
4. Were similar conditions experienced on previous trips? If so, is the hole getting worse?	4. Check the lithology
1. Can the problem be related to deviation or the BHA?	1. Check if overpulls are increasing on each trip
2. Is a keyseat developing?	2. Check the nature of any interbedded sequences.
3. Are there sequences of hard/soft formations which may result in ledges?	3. Relate doglegs to BHA configuration
	4. Check if conditions exists which would encourage keyseating

Reaming Operations (Reaming In & Reaming Out)

During reaming operations, the primary indication of hole problems will be increased torque.

Questions to Answer	Response
1. Are problem formations exposed?	1. Check the BHA configuration. How does it compare to the last assembly?
2. Can the problem be related to deviation and BHA?	2. Check for hard/soft interbedded sequences.
3. Can the problem be related to ledges?	3. Check for problem formations
4. It is possible that a cuttings bed has formed on the low side of the borehole?	4. Correlate trends from previous trips. Is the problem still occurring?
5. Was the hole adequately cleaned?	5. Correlate deviation with BHA configuration.
	6. Check annular velocities during circulation.
	7. Check the drill rate prior to reaming
	8. Check lithology and location of problem formations.

Drilling Operations

Though few stuck pipe problems occur while drilling, it is wise to keep in mind that they can happen. The most commonly monitored drilling parameters which will indicate problems are torque, pump pressure and drill rate. Changes in these parameters, when matched with known data (i.e. cuttings lithology, ECD) can pin-point mechanisms which can result in stuck pipe and other borehole problems.

Several problems, with their drilling parameter correlations are listed in the following table:

INDICATOR PROBLEM	TORQUE	PUMP PRESSURE	DRILL RATE
Poor Hole Cleaning	Increase	Increase	Gradual Increase
High Overbalance & Permeable Sands	Gradual Increase	No Change	Gradual Decrease
Mobile Formations	Gradual Increase	Increase	Gradual Decrease
Fractured and Faulted Formations	Sudden Erratic Increase	May Be Unaffected	Sudden Increase
Geopressured Formations	Increase	Increase	Initial Increase with a Gradual Decrease
Reactive Formations	Gradual Increase	Increase	Gradual Decrease
Unconsolidated Formations	Increase	Increase	Decrease
Junk	Sudden Increase	No Change	Sudden Decrease
Cement Blocks	Sudden Increase	No Change	Sudden Decrease

Table 7-3: Stuck Pipe Indicators During Drilling Operations

Mechanics of Differential Sticking

Even when all precautions are taken, stuck pipe may occur. Should this situation develop, there are still ways in which the INTEQ personnel can be of assistance.

To free a differentially stuck drillstring, the driller must overcome the restraining force of the drilling fluid, which is pushing the drillstring against a permeable formation. The drillstring (drillpipe or collars) will soon become imbedded in the filter cake opposite the permeable zone if corrective action is not taken as soon as the sticking situation is noticed.

The force necessary to free the drillstring will be proportional to the area of contact and pressure differential, and will increase with time because of filter cake build-up. Due to the filter cake build-up, the area of contact can double by the thickening of the filter cake.

The force holding the drillstring against the borehole wall can be calculated very quickly. This force will have to be exceeded to free the drillstring. If the force is greater than the pull of the blocks or the tensile strength of the drillstring, the general practice is to add some compound (i.e. diesel, “black magic”, etc.) to the drilling fluid to reduce the friction between the drillstring and filter cake.

The equation for determining the sticking force is:

$$F_s = \Delta P \text{ x } A \text{ x } f$$

where:

F_s = The sticking force or the total pulling force that would be required to free the pipe (lbs)

ΔP = The pressure differential between the drilling fluid and the formation (psi)

A = The area of contact between the drillstring and filter cake (in^2)

f = The coefficient of friction between the drillstring and filter cake (dimensionless)

Determining the Variables in the Stuck Pipe Equation

Pressure Differential (ΔP)

The pressure differential between the drilling fluid and the permeable formation is determined using the hydrostatic pressure of the drilling fluid (0.0519 x MD x TVD) and the estimated pore pressure of the permeable formation.

Area of Contact (A)

The effective area of contact is the chord length of the imbedded portion of the drillstring multiplied by the thickness of the permeable formation. The most acceptable equation is:

$$A = P_C \text{ x } (T_F \text{ x } 12)$$

where P_C is the chord length or circumference of the pipe stuck against the formation (inches), T_F is the thickness of the formation causing the stuck pipe (feet) and 12 is the conversion from feet to inches.

Coefficient of Friction (f)

Though very seldom quantitatively defined in field operations, “f” will normally vary between 0.07 (for invert emulsion muds) and 0.40 (for low solids native muds). As the mud density increases, the amount of solids (barite, sand, bentonite, etc.) also increases, which increases the coefficient of friction.

The coefficient can be determined using a specialized mud test apparatus called a “stickometer”. This test uses a torque plate which is pushed against a filter cake at 500 psi. After a set time limit, the plate is rotated using a torque wrench and the amount of torque required to rotate the plate is measured.

The coefficient of friction is the ratio of the force necessary to initiate sliding of the plate to the normal force on the plate. The core face of the stickometer is 3.14 inches, the radius of the plate is 1 inch, and the differential pressure used is 500 psi. Because of the geometry of the core face the torque is multiplied by 1.5. The formula then becomes:

$$f = \frac{Torque(in - lb) \times 1.5}{500psi \times 3.14in^2 \times 1inch}$$

Preventing Stuck Pipe

If the driller is unable to free the stuck pipe or the force necessary to free the pipe is greater than the force that can be applied by the blocks, then other remedial measures must be used. Normally a lubricating fluid is “spotted” in the troublesome area and is used to dissolve the filter cake. Spotting procedures and calculations have been mentioned in the “*Advanced Logging Procedures*” manual, under “Additional Volume Calculations”.

These spotting procedures are facilitated by pin-pointing the depth at which the pipe is stuck. The depth (or free point - stuck point location) can be calculated from relatively simple measurements taken on the rig floor. With reference to Figure 7-1, the procedure to determine the variables is as follows:

1. An upward force "F1" is applied to the pipe. This must be greater than the total weight to insure that the entire string is in tension.
2. A reference point is marked on the drillpipe at the surface, normally at the top of the rotary table.
3. A greater upward force "F2" is applied, causing the free portion of the drillstring to stretch by an amount "e". The stretch is measured above the reference point.

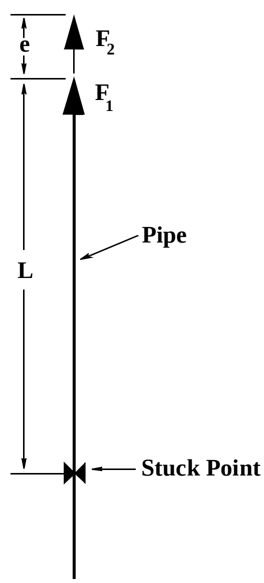


Figure 7-1Determination of Stuck Pipe Variables

Once the measurements have been taken, they are used in the following equation:

$$SPL = (735 \times 10^3) \times \frac{(w) \times (e)}{(F_2 - F_1)}$$

where: SPL = Stuck Pipe Location

735×10^3 = Derivation of Youngs Modulus for steel

w = Drillpipe weight (lbs/ft)

e = Length of stretch (inches)

F_1 = Force applied when pipe is in tension (lbs)

F_2 = Force applied to stretch pipe to "e" (lbs)

The stuck pipe location produced from this equation will be a best guess value for a couple of reasons: (1) Since all boreholes are crooked to some extent, there can be a considerable amount of friction between the borehole and drillpipe, and (2) If the borehole is highly deviated, it will be very difficult to place the drillstring in tension without it coming into contact with the borehole.

However, this calculation is simple to perform and is much better than the industry's nomograms for stuck pipe stretch. The value from the SPL equation will also provide a “near-enough” depth for a starting point when a free-point indicator is lowered into the drillstring.

Preventing Stuck Pipe

During the course of a well, there are many operations or items within those operations which can prevent stuck pipe from occurring. Even when problems are evident, there are generally ways to prevent the drillstring from sticking. This section will list the most common causes of stuck pipe, the most commonly used operations to prevent the drillstring from sticking, and the operations required if preventive measures fail.

Differential Sticking

Much has been said in this section on differential sticking. It should be remembered that this type of sticking will develop if six factors are present; (1) a permeable formation, (2) thick filter cake (due to a high water loss), (3) the drillstring is in contact with that filter cake, (4) an overbalance situation exists, (5) insufficient drillstring movement and, (6) a lack of circulation between the drillstring and the filter cake. Preventive measures include:

1. Moving the drillstring as much as possible
2. Rotate the drillstring on connections
3. Always begin pipe motion in a downward direction
4. Ensure a pit is available for pumping pills
5. Use grooved or spiral drill collars
6. Minimize the length of unstabilized drill collars
7. Minimize the length of the BHA
8. Use undergauge stabilizers when possible
9. Consider placing the jar(s) in the heavy-weight pipe section
10. Use survey methods that are of short duration

There are basically three methods which can be followed if the drillstring becomes differentially stuck. The first operation is to immediately work/jar the drillstring (downwards if possible) and apply right-hand torque. Secondly, reducing the hydrostatic pressure may be an option (well control considerations must be taken into account). The third operation involves spotting a friction reducing fluid within the stuck zone.

If these methods fail, then back-off operations, using a free-point indicator, must be considered. The fish can then be recovered using washover pipe, or a DST tool can be used to reduce the hydrostatic pressure followed by the washover pipe.

Geopressured Formations

These formations have a pore pressure which exceed the hydrostatic pressure of the drilling fluid. If these formations are not permeable (for example, shales), once drilled, these formations will “cave” into the borehole. Preventive measures include:

1. Clean the hole of cuttings when not drilling
2. Observe the cuttings for cavings, some being large and convex/ concave in appearance
3. Increase the mud density if possible
4. Ream on each connection
5. Perform regular wiper trips
6. Monitor pump pressure for annular loading
7. Control the drill rate
8. Minimize the time in the open hole when tripping
9. Recognize overpull, then circulate to clean the hole
10. Monitor the drilling fluid's parameters

If geopressured formations are causing stuck pipe problems, great care must be taken to ensure well control problems do not develop. The first step in correcting the situation is to establish circulation. If possible, pipe movement should be downwards, gradually increasing these applied forces. Once full circulation is established and pipe movement is unrestricted, an increase in the mud density is advisable.

Reactive Formations

These are naturally occurring bentonitic shales, generally known as "gumbo shales". The clays within the shales react with the mud filtrate and hydrate. The hydrated shales will then fall or swell into the borehole. When drilling, the bit tends to "ball-up" with these clays. When tripping, the BHA can become stuck in the smaller diameter (swelled) portions of the borehole. Preventive measures include:

1. Avoid long time periods without circulation
2. Be prepared to stop drilling and circulate
3. Plan to initiate wiper trips whenever necessary
4. Carefully monitor swab/surge pressures
5. Be prepared to ream when tripping
6. Carefully monitor drilling fluid properties

If the drillstring is stuck in reactive formations, circulation must be established. Concentrate on working the drillstring downwards. Rotation may help dislodge the packing-off borehole material. Increasing the mud density, if possible, may also be beneficial.

Unconsolidated Formations

These naturally occurring sand and gravel formations will collapse into the borehole when drilled. When this occurs, they can easily bury the bit or form a bridge around the collars. Preventive measures include:

1. Control the drill rate
2. Use all solids removal equipment
3. Be prepared for shale shaker screen binding
4. Use viscous sweeps before drilling
5. Ream after each connection
6. Avoid excessive swab/surge pressures
7. Avoid excessive circulation opposite those zones

If sticking does occur, establish circulation first. Then concentrate on working the drillstring downwards to disturb the bridge/mound. Once the drillstring is free, ensure the material is circulated out before drilling. Increase the mud density if possible.

Mobile Formations

These are naturally occurring plastic formations. Most commonly shales and salt. When drilled, they will tend to “flow” into the borehole. Preventive measures include:

1. Recognize there is a reaction time associated with these formations
2. Regular wiper trips are normally required
3. Condition the mud prior to drilling those formations
4. Use “eccentric” PDC bits to drill these formations
5. Increase the mud density if possible
6. Minimize open hole time

If the drillstring becomes stuck in a mobile formation, the annulus may become packed-off, so concentration must be placed on establishing circulation. The drillstring should be worked up and down, if possible.

If circulation is possible, in a squeezing salt formation a fresh water pill should be pumped immediately. When oil-based muds are used, a water/detergent spacer should be used ahead of the pill. Repeat the pill procedure every 2 hours until the drillstring is free.

Once the drillstring is freed, an increase in the mud density should be considered.

Fractured/Faulted Formations

These are naturally occurring formations. When the fractured or faulted formation is drilled, there will be a tendency for pieces of the formation to fall into the borehole. The size of the pieces will vary from pebbles to boulders. They will more commonly occur in limestones and shales. Preventive measures include:

1. Clean out excess fill before drilling
2. Minimize surge pressures
3. Place the jar in the heavy-weight pipe section
4. Be prepared to wash/ream when tripping in
5. Design a BHA to minimize the risk of hitting a ledge
6. Use low circulation rates/pressures to clean the hole

If it is determined that faulted/fractured formations are the cause of the sticking, the drillstring should be worked up and down to try and break up the pieces of formation. If limestone is causing the problem, an inhibited acid (HCl) pill can be used to dissolve the limestone. The pill should be spotted with a large water spacer.

Key Seating

Key seats are the result of the drillstring wearing an additional hole into the side of the borehole. This “extra” hole will generally have the I.D. of the drillpipe's tool joints and the drill collars will not pass through this extra hole when tripping out. Preventive measures include:

1. Minimize pipe rotation
2. Use wiper trips often
3. Minimize dogleg severity
4. Carefully design the BHA
5. Minimize the length of rathole below casing
6. Have a surface jar on location
7. If the problem is recognized, cure it before drilling ahead

If the drillstring becomes key seated, the drillstring should be worked upwards gradually, this will depend on how long the key seat is, and if the BHA is not jammed into the key seat. The drillstring should try to be rotated up and out of the key seat with minimum tension.

Borehole Geometry (Profile and Ledges)

The borehole is seldom drilled in a smooth manner. Ledges and washouts are common, especially when alternating hard/soft formations are drilled. Problems with borehole geometry normally occur during tripping operations. Remember, when tripping in, the drillstring is in compression making it more flexible. When tripping out, the drillstring is in tension making it more rigid. Preventive measures include:

1. Minimize doglegs
2. Reduce the number of BHA changes
3. Ream if the BHA configuration is changed
4. Do not run stabilizers above a jar
5. Be prepared to run a hole opener if necessary

If borehole geometry problems are suspected when tripping in, a gradual upwards working force should be applied. If this occurs when tripping out, upwards forces should be applied gradually to prevent the drillstring from further jamming. If a ledge is suspected, then a combination of upward/ downward forces should be used to try and remove the ledge.

Undergauge Borehole

When drilling long sections of abrasive formations, the gauge protection on the bit and stabilizers can become so worn it becomes ineffective. Any additional hole that is drilled will be undergauge. Preventive measures include:

1. Properly gauge the bit and stabilizers after each run
2. Ream back to bottom if an undergauge hole is suspected
3. Never force a new bit to bottom
4. Select bits with good gauge protection (5&7 feature in roller cone bits)
5. Carefully run fixed cutter bits after roller cone bits

If the new bit is run into an undergauge hole, maximum upwards working/ jarring forces should be applied immediately.

Inadequate Hole Cleaning

Inadequate hole cleaning causes overloading of the annulus. In highly deviated or horizontal wells, this results in the formation of a cuttings bed on the low side of the borehole. Preventive measures include:

1. Control the drill rate to ensure the hole is cleaned
2. Circulate bottoms-up until shakers are clean
3. Always check the volume of cuttings coming over the shaker
4. Maintain the correct drilling fluid properties
5. Control the annular velocities
6. Recognize increased overpull
7. Always reciprocate and rotate pipe while circulating
8. Use viscous sweeps
9. Recognize low-side sections of deviated holes
10. Plan to use regular wiper trips
11. On floaters, use the riser booster pumps

If the annulus becomes overloaded, attempts to establish circulation must be attempted. In addition, a downward force should be applied gradually until circulation begins. Once circulation is established, the drillstring should be rotated to further disturb the cuttings.

In low angle holes, a weighted high viscous pill should be used to “float out” the cuttings. In high angle holes, a low viscous pill should be used to disturb the cuttings bed, followed by weighted pills to carry the cuttings out of the hole.

Junk in the Borehole

Junk is a foreign object in the borehole, which is not meant to be there. Since the clearance between casing and collars/stabilizers is not great, even a small piece of junk can stick the drillstring. Preventive measures include:

1. Ensure downhole tools are in good condition
2. Inspect downhole tools regularly
3. Be careful when working around the rotary table
4. Leave the hole covered when the drillstring is out of the borehole
5. Install drillpipe wipers whenever possible

If junk sticking is suspected, upward and downward working and jarring should commence to try and dislodge the obstruction. These forces should be gradually increased until the drillstring is freed.

Cement Blocks

After a leak-off test has been performed and drilling has resumed, the large sized collars or stabilizers can cause blocks of cement to break loose and fall into the borehole. These large blocks can easily jam against the drillstring. Preventive measures include:

1. Minimize the length of rathole below the casing shoe
2. Always ream ratholes or cement plugs before drilling ahead
3. Be careful when tripping back through the casing shoe

If jamming occurs, attempt to dislodge or break up the obstructions by using alternating upward and downward working and jarring. These freeing forces should be gradually increased until the drillstring is freed and, if available, an acid solution can be pumped around to dissolved the cement.

Green Cement

A rare occurrence of stuck pipe is one due to soft or “green” cement. This occurs when the cement is not allowed to set properly, or because of incorrect additives and bottomhole temperature gradients, the cement does not set properly. After the normal time for WOC (Waiting On Cement) and the drillstring is tripped in to drill out the plugs and float equipment, the cement can “flash set” when pressure is applied. Preventive measures include:

1. Pre-treat the drilling fluid if green cement is suspected
2. Know the depth to the top of cement

3. Begin circulation above the top of the cement
4. Monitor cement returns at the shale shaker
5. Realize the weight-on-bit will be inaccurate
6. Restrict the drill rate when drilling out cement

If problems develop, immediate action is required to prevent the cement from setting. Upward working and jarring operations should commence as soon as possible. If circulation is possible, an acid solution can be pumped to try and dissolve the cement.

Self-Check Exercises

1. What should be the response of INTEQ personnel if borehole problems point towards inadequate hole cleaning?

2. How can Shale Factor (CEC) be of assistance in predicting hole problems?

3. What is the most common indication of hole problems when the rig is performing reaming operations?

4. When using the “Stuck Pipe Equation”, how is “ΔP” determined?

5. What piece of mud test equipment is used to measure the “friction coefficient”?

6. What is the first step taken if stuck pipe occurs in geopressured, reactive or unconsolidated formations?

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7. What two operations can be performed if the drillstring becomes stuck in a faulted limestone formation?

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8. What type of pill(s) should be used if stuck pipe occurs in a high angle hole due to inadequate hole cleaning?

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9. What is meant by “green” cement?

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Chapter 8

Well Control

Upon completion of this chapter, you should be able to:

- Understand the causes of kicks and use that knowledge to assist in preventing kick-related problems from occurring.
- Recognize the warning signs of kicks.
- Understand the differences and limitations of the various kill methods on different types of rigs.
- Calculate the necessary kill parameters and follow the proper kill procedures.
- Adapt to the correct kill procedure when special problems occur.

Additional Review/Reading Material

Adams, Neal, *Well Control Problems And Solutions*, Petroleum Publishing Co., Tulsa, 1980

INTEQ Video Tape #3, *Kick And Kill*

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Rabia, Hussain, *Oilwell Drilling: Principles and Practice*, Graham & Trotman Limited, 1985

Petroleum Extension Service AV #112, *Causes And Prevention Of Blowouts, Part I. Causes*, The University of Texas at Austin

Petroleum Extension Service AV #113, *Causes And Prevention Of Blowouts, Part II. Prevention*, The University of Texas at Austin

Petroleum Extension Service AV #106, *Causes And Prevention Of Blowouts, Part III. Equipment*, The University of Texas at Austin

Introduction

A kick is defined as an undesirable influx of formation fluid into the borehole. If left unattended a kick can develop into a blowout (an uncontrolled influx of formation fluid into the borehole).

While kicks are a problem, they are not too common. However, the penalty for failing to control a kick can be the loss of the well, and quite possibly the loss of the rig and the lives of the crew.

Well control procedures vary slightly from rig to rig, and company to company, but four simultaneous operations are normally considered.

Rig Control: This includes the BOP's, pumps, drawworks and other rig equipment. This is the responsibility of the driller, and any blowout control procedures should assign these operations to the driller.

Mud Control: This involves the addition of weighting material (most commonly barite) to the mud to increase its density, but also includes the correct operation of the mixing system and chemical additions. These are generally the responsibility of the mud engineer and derrickman.

Choke Control: This includes the correct calculation of pressures and time relationships, as well as operating the choke and monitoring the pump rate. The choke operator should be the best trained man on the rig in kick control. He will be required to give guidance during the kill operations.

Supervision: This is the final element of control. This task will normally be assigned to the rig superintendent or toolpusher. They will supervise the previous three elements of well control operations.

Decisions made under kick situations depend upon the knowledge, attitude and judgement of the supervisor. These can be confused by crew change problems and the divided responsibilities between the rig superintendent/ toolpusher and the oil company representative/drilling engineer. One of the most important elements of a well control program is the establishment of policies and procedures outlined in detail. This procedure must be made known to Baker Hughes INTEQ personnel. It is the responsibility of the senior person or Field Supervisor to obtain this information as soon as possible.

Kicks

Causes of Kicks

There are 5 major reasons why kicks occur:

Failure To Keep The Hole Full: The majority of kicks occur when the bit is off bottom, while tripping. When the pumps are shut down prior to tripping, there is a pressure reduction in the borehole equal to the annular pressure losses. If the equivalent circulating density and the pore pressure are nearly equal, flow may occur when circulation stops. As pipe is removed, the mud-level in the borehole falls, causing a reduction in hydrostatic pressure. Pipe displacement volume must be converted into pump strokes so the correct number of strokes to fill the bore-hole is known.

Swabbing of Formation Fluids Into the Borehole: When pipe is pulled it acts like a piston, more so below than above the bit. Both gel strength and viscosity of the mud have a large effect on swabbing. Swabbing is further increased if the mud cake is thick, the bit is balled-up, the nozzles are blocked, or a back-pressure valve is in the drillstring. The speed at which pipe is pulled also has a great effect on swabbing.

In INTEQ logging units, a DrillByte EAP program provides a range of pipe pulling speeds and their corresponding swab and surge pressures. If swabbing does occur, the pipe should be run back to bottom and the invading fluid circulated out. Surge pressures, when running into the hole (pipe or casing), may be sufficient to exceed the fracture pressure of a weak formation. The swab/surge pressure printout should be consulted, and the pipe run at a speed that produces surge pressures below the minimum fracture pressure. It is important to remember that this is necessary anywhere in borehole, as pressures are transmitted to the open hole even when the bit is inside the casing.

Insufficient Mud Density: Fewer kicks result from too low a mud density than the previous two causes. If a kick occurs while drilling, due to insufficient mud density, it is possible that an oversight has occurred or that poor engineering practices were employed. In any event, pressure trends and plots will have to be re-evaluated. Penetration into a geopressured formation without prior indication may have occurred, or a fault or unconformity may have been crossed. Also changes in lithology or drilling practices may have masked a transition zone.

Poor Well Planning: Both mud and casing programs have a great bearing on well control. These programs must be flexible enough to allow progressively deeper casing strings to be set; otherwise a situation may arise where it is not possible to control kicks or lost circulation. Well control is an important part of well planning, but it should not be overstated to the point that overall drilling effectiveness is reduced.

Lost Circulation: Raising the mud density to a value that exceeds the lowest fracture pressure, for fear of a kick, is not nearly as prevalent as it was in the 40's or 50's. A kick may still occur during drilling, but it is more likely to be due to fracturing a formation of lower pore pressure than an abnormally pressured zone. Rather than setting casing after drilling through a geopressured zone, the mud density is kept high to balance these formations. If the pore pressure decreases significantly, those lower pressured formations become susceptible to fracturing. If fracturing occurs, the fluid level in the annulus may drop due to lost circulation and the resulting loss in hydrostatic pressure may allow an influx of formation fluids, resulting in a kick. The existence of an abnormally pore pressured zone and a lost circulation zone in the same hole section are ingredients for a kick. The utmost care combined with diligent observation are necessary to successfully drill this type of well.

Recognition of Kicks

The only time a kick can occur without warning is when drilling offshore and there is no annular connection between the wellhead and the rig. However, there is never a lack of indications that a kick or blowout is occurring. In the majority of situations the borehole and mud pits are a closed circulating system, the addition of any fluid from the formation will result in a change in return flow and a change in the active pit volume.

One rare occurrence when surface recognition may be delayed is during lost circulation. The annulus is not full and cannot be filled. When the rate of loss is greater than the rate at which fluid can be pumped into the hole, it is not possible to monitor the fluid levels. A major influx may occur and it will not be detected at the surface. If such an event occurs, the well should be shut in, and the shut-in pressures monitored. Pipe movement can be made by stripping through the BOP's and the hole can be filled using the choke and kill lines.

Sequence of Events

In most cases, the following distinct series of events can lead to a kick while drilling. Some indications may not occur while others may be accentuated. Recognition of the changing trends at an early stage will allow remedial action to be taken, thus minimizing the potential hazards and costs.

1. The first indication is a drilling break. The fast drill-rate need not necessarily indicate an increase in porosity, permeability and pressure, but it is prudent to assume that it does. The magnitude of the drilling break will vary, based on the formation

characteristics. Regardless of the increase, any significant drilling break should be checked for flow.

This is done by: (1) picking up the kelly so the kelly bushings are about 10 ft above the rig floor, (2) stopping the pumps, and (3) observing the fluid level in the annulus to see if the well is flowing. This may be difficult on floating rigs as the level will fluctuate with the heave of the rig. In these instances the flowcheck should continue for at least 5 minutes, or be conducted by circulating through the trip tank and the trip tank volume observed for a gain. If the well is flowing, it should be shut-in and any resultant pressures checked.

2. The second indication of a kick, or the first confirmation that a kick is taking place, is an increase in return flowrate at the flowline. Flow of formation fluid into the wellbore will cause the return flowrate to increase, which will occur concurrently with, or shortly after the drill break. The invading fluid is normally lighter than the mud, so continual influx will lighten the mud column and further reduce bottomhole pressure. This, in turn, allows the influx rate to increase. Once flow begins, the rate of increase will be proportional to the depth of penetration into the formation.

3. Hookload may be seen to increase as a result of the lower density invading fluid and fluid-cut mud. If the mass flow of invading fluid is great enough, it may result in a decrease in hookload, as the drillstring is lifted by the invading fluid.

4. An increase in pit volume may be the result of two separate mechanisms: (1) the increased flow rate translates into an increase in mud volume, and (2) if the kick contains gas, its expansion in the annulus will increase the flow rate and pit volume.

5. A pump pressure decrease, along with a pump stroke rate increase becomes noticeable only when the kick fluid has been displaced some distance up the annulus.

6. A reduction in flowline mud density occurs as the invading fluids reach the surface. This reduction is severe with a gas kick, but may be large or unnoticeable with a water kick (depending on the mud density). Large amounts of gas can be dissolved in the kick fluids and as the kick fluid reach the surface, high gas shows will occur.

During drilling operations, it is important that alarms be set on as many sensors as possible. However, since there are sufficient exceptions, it is unwise to depend on only one factor in these sequence of events. For example, continual mud mixing in the active system may mask a volume increase, or partial returns may mask the effects of flowrate and volume increases, which will make kick detection very difficult.

During Connections

When drilling close to balance (between equivalent circulating density and pore pressure), flow into the annulus may occur when the pumps are shut off. This is caused by the removal of the annular pressure loss, which increases the bottomhole pressure while circulating. When the kelly is lifted, swab pressures can further reduce bottomhole pressure. An increase in hookload may indicate that a lighter fluid has invaded the hole as the less dense invading fluid reduces the buoyancy effect on the drillstring, hence the higher hookload.

A kick taken during a connection is signaled by a sequence of events much the same as while drilling.

1. The well may flow when the pumps are first shut off. This can be monitored by the return flow sensor and a PVT (Pit Volume Totalizer).
2. An increase in pit volume may be noticed only after the connection. Usually, when the pumps are shut off, some of the mud from the surface equipment will flow back into the active pit. When the levels have stabilized, after the pumps are restarted, an increase in level prior to the connection indicates that a flow has occurred. The volume of mud from the surface equipment should be established at the start of each new job and re-established periodically as the well progresses (e.g. a 2 bbl increase on a connection may be normal, while a 3 bbl increase may be significant).
3. Pump pressure and rate changes similar to those experienced while drilling may be noted after successive connections. However, the flow will increase during each connection.
4. Mud density reductions may be similar to those while drilling.

Recognition of kicks during connections requires careful monitoring of the return flow sensor. After the pumps have been shut down, the flow sensor should indicate an absolute **“no flow”** condition. However, on some rigs a long sloping flowline may cause mud to slowly trickle down after the pumps have been shut down. If this is the case, an increase above this slow trickle will indicate a kick. Also, a record of flowline mud density will disclose small mud cuts caused after connections, and may be accompanied by connection gases, but connection gases alone are not an indication of a kick during a connection.

While Tripping

Since kick control procedures are greatly simplified when the bit is near the bottom of the hole, as such kicks during tripping operations have the greatest potential danger. With the pipe standing on the rig floor, it is impossible to get heavy mud to the bottom of the hole. During trips, the same annular pressure drop occurs as when the pumps are shut off.

When the drill pipe is being removed, the hole must be topped off with mud regularly. If the hole does not take the same volume of mud to replace the volume of pipe withdrawn, it is an indication that formation fluid is displacing mud near the bottom of the hole and the well is kicking. It is common while drilling offshore to continually circulate through a trip tank while tripping out. Careful monitoring of the decrease in trip tank volume, against the calculated pipe displacement is required so discrepancies can be noticed. In INTEQ logging units, the trip monitor program provides comparison volumes for every stand pulled. Alternatively, a “trip condition log” provides a summary of hole conditions and fill-up during trips.

Older rigs may not have a trip tank, so reliance for volume checks is placed on monitoring one of the active pits and pump strokes. PVT monitoring provides a necessary cross-check, but because of the large surface area of the active pits, precision may be limited. The mud pumps are a reasonably efficient displacement monitor at low pressures and stroke-rates, and pump strokes are often used to measure the amount of fluid displaced, while tripping out. It is normal for the hole to take slightly more mud than the volume of the pipe removed, due to static filtration into the formation.

If a kick occurs when the bit is not on bottom, every effort must be made to run back in the hole. Modern BOP's are designed for stripping through the annular preventer or ram sets, enabling the bit to be run back to TD.

Kick Tolerance

Kick tolerance is defined as the maximum Pore Pressure Gradient that may be encountered if a kick is taken at the present depth, with the present mud density and the well is shut-in, without downhole fracturing occurring.

During drilling, kick tolerance must not be exceeded because if a kick occurs there is a considerable chance that an underground blowout will occur when the well is shut-in.

A complete description of kick tolerance, with the relevant equations and calculations can be found in the “*Formation Pressure Evaluation*” manual (P/N 80824H).

Kick Control

Within the oil industry, there are three recognized kick control procedures. 1) Driller’s, 2) Weight, and 3) Concurrent. The selection of which to use will depend upon the amount and type of kick fluids that have entered the well, the rig's equipment capabilities, the minimum fracture pressure in the open hole, and the drilling and operating companies well control policies. Determination of the most suitable and safest method (assuming their company policy allows flexibility of procedures determined by the demands of the situation) involves several important considerations:

- The time required to execute any complex kill procedures
- Surface pressures that will arise from circulating out the kick fluids
- Downhole stresses are applied to formations during kill operation
- The complexity of the procedure itself relative to the implementation, rig capability and rig crew experience

It is the responsibility of the tool pusher or operator's representative to decide which method will be used to kill the well. Under no circumstance should INTEQ personnel become involved in this decision.

Each of the previous points must be assessed and their relative importance to the kick situation evaluated before implementing the selected kill method. In the following paragraphs, elaboration of these points will illustrate the reasoning behind the importance of individual situations.

The Time Factor

The total amount of time taken to implement and complete kill procedures is important, especially if the kick is gas. This is because the “gas bubble” will percolate up the annulus, increasing annular pressures.

There may also be a danger of the pipe sticking, especially if a fresh water mud system is in use. Invading saline pore water may cause the mud cake to flocculate, so the bit, stabilizers and collars would be in danger of sticking.

Considerable time is involved in weighting up the mud, but more importantly is the time for the kill operation to be completed. The strains and pressures on the well, surface equipment and personnel should be minimized in the interests of safety and cost. Therefore, depending on the kick situation, the decision as to which method to use must be based on these priorities.

The kill procedures that involve the least amount of initial waiting time are the two circulation method (or driller's method) and the concurrent method. In both of these procedures, pumping begins immediately after the shut-in pressures are recorded. However, if the time taken to weight-up the mud is less than one circulation then the engineers, or one circulation, method may be preferred. In certain situations the extra time required for the two circulation method may be seriously detrimental to hole stability or may cause excessive BOP wear.

Surface Pressures

If a gas kick is taken, annular pressures may become alarmingly high during the course of the kill operation. This is due to gas expansion as it nears the surface. This is normal. If expansion is not allowed to occur, severe pressures will be placed on the annulus and surface equipment. For this reason, the most reliable well killing procedures utilize a constant drillpipe pressure and a variable annular pressure (through a variable choke) during circulation.

The kill procedure that involves the least surface pressures must be used if the kick tolerance is minimal. Figure 8-1 shows the different surface pressure requirements for the two different kick situations, using the one and two circulation methods.

The first difference is noted immediately after the drillpipe is displaced with kill mud. When keeping the drillpipe pressure constant (with the constant pump rate) the casing pressure begins to decrease as a result of the kill mud hydrostatic pressure in the one circulation procedure.

This initial decrease is not seen in the two circulation method, since the mud density has not changed, and as can be seen, the casing pressure increases as the gas expansion displaces mud from the hole. The second pressure difference is noted when the gas approaches the surface. The two circulation method, again, has the higher pressures which is the result of circulating the original mud density during the first circulation.

Also, after one complete circulation has been made, the one circulation method has killed the well, resulting in zero surface pressure, whereas the two circulation method still has pressure on the casing, equal to that of the shut in drillpipe pressure (SIDP).

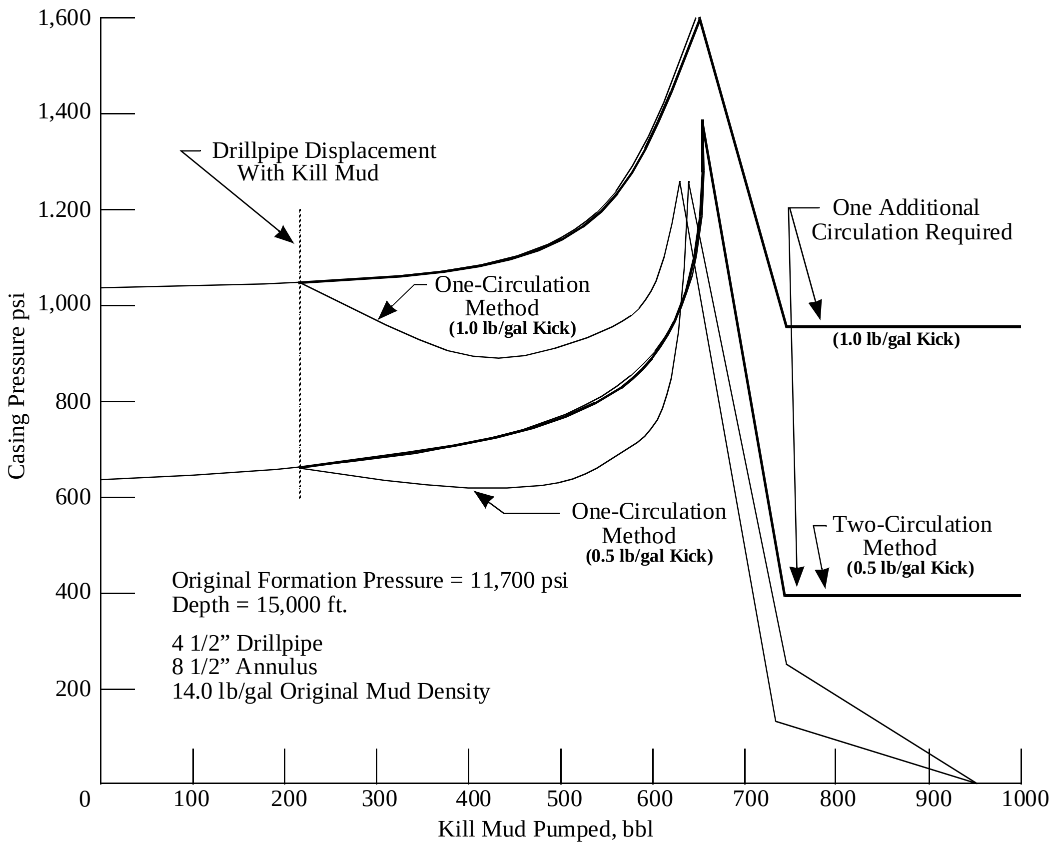


Figure 0-1Different surface pressures produced during the one and two circulation kill methods

Downhole Stresses

Downhole stresses are prime concern during kill operations. If the extra stresses imposed by the kick are greater than the minimum fracture pressure in the open hole, fracturing occurs.

Similarly, procedures which through its implementation, places high stresses on the wellbore should not be used in preference to others which impose lower stresses on the wellbore. Reference to the above points illustrates that the one circulation method places the minimum stresses on both the wellbore and surface equipment. When a kick is circulated out the maximum stresses occur very early in the circulation - particularly in deep wells with higher pressures. At any point in the borehole, the maximum stress is imposed on the formation when the top of the kick fluid reaches that point.

Generally, if fracturing and lost circulation does not occur on initial shut-in, they will not occur throughout the kill process (if the correct procedure is chosen and implemented).

Formulas that enable most of the relevant pressures to be calculated and predicted are presented in Table 8-1.

Procedural Complexity

The suitability of any process is dependent on the ease with which it may be reliably executed. If a kill procedure is difficult to comprehend and implement, its reliability is negated.

The one and two circulation methods are simple in both theory and execution. Choice between the two is dependent upon the other points (time factor, surface pressures, downhole stresses, and so forth), and any other limitations caused by the situation. The concurrent kill method is relatively complex in operation and its reliability may be reduced through its intricacy. Because of this, many operators have discontinued its use.

It is important to realize that all pressures calculated on deviated wells must use vertical depth and not measured depth. Measured lengths are used for ECD calculations, so that the resultant pressure losses can be added to the hydrostatic pressure (calculated from the vertical depths).

Situations may arise when the casing pressure causes downhole stresses approaching or slightly exceeding the actual or estimated minimum fracture pressure. In this case the well cannot be shut-in, and an alternate method of kill control must be attempted. Maximum pressure at the surface are determined by three factors:

1. The maximum pressure the wellhead will hold
2. The maximum pressure the casing will hold (burst pressure)
3. The maximum pressure the formation will hold

Table 1: Formulas Used In Kick And Kill Procedures

Hydrostatic Pressure (psi): MW x TVD x 0.0519

where: MW = Mud Density (lb/gal)
TVD = True Vertical Depth (ft)

Circulating Pressure (psi): (MW x TVD x 0.0519) + P_{la}

where: P_{la} = Annular Pressure Loss (psi)

Initial Circulating Pressure (psi): SPR + SIDP

where: SPR = System pressure loss at kill rate (psi)
SIDP= Shut-in Drillpipe Pressure (psi)

Final Circulating Pressure (psi): (KMW / MW) x SPR

where: KMW = Kill Mud Density (lb/gal)

Kill Mud Weight (lb/gal): MW + (SIDP / (TVD x 0.0519))

Formation Pressure (psi): SIDP + (MW x TVD x 0.0519)

Density of influx (ppg): MW - [(SICP - SIDP)/(L x 0.0519)]

where: SICP= Shut in casing pressure (psi)
L = Length of influx (ft)

Length of kick around drill collars (ft):

Pit Gain (bbls)/ Annular Volume around collars (bbls/ft)

Length of kick, drill collars and drill pipe (ft):

Collar Length + [(Pit Gain - Collar Annular Volume) / (D_1^2 - D_2^2 x 0.000971)]

where: D_1 = hole diameter (inches)
D_2 = drillpipe diameter (inches)

Gas bubble migration rate (psi/hr): ΔPa / (0.0519 x MW)

where: ΔPa = pressure change over time interval / time interval (hr)

Barite required (sk/100 bbls mud):

1490 x (KMW - MW) / (35.8 - KMW)

Volume increase caused by weighting up:

100 x (KMW - MW) / (35.8 - KMW)

The drill pipe pressure can be used as a downhole pressure gauge, while the casing pressure is affected by the type and amount of fluid influx. When the density of the kick fluid is known, the composition may be estimated;

Influx Density (psi/ft)	Influx Type
0.05 - 0.2	gas
0.2 - 0.4	combination of gas/oil and or seawater
0.4 - 0.5	oil or seawater

Kick Control Methods

All kill procedures require data concerning drillstring geometry, hole geometry, mud density, pump rates, pressure losses, and fracture pressure. Important data that is required prior to initiating kill procedures include:

1. Circulating pressure at kill rate
2. Surface to bit time at kill rate (in strokes and minutes)
3. Bit to surface time at kill rate (in strokes and minutes)
4. Maximum allowable annular pressure
5. Formula for calculating the kill mud density
6. Formula for calculating the change in circulating pressure due to the effect of the heavier mud

7. The clients policies on safety factors and trip margins

For a well to be killed successfully, the pressure in the formation must be kept under control during the entire kill operation. The only exception is in cases when the maximum allowable annular pressure will be exceeded. The simplest method of doing this is to control the drillpipe pressure by running the kill pump at a constant rate and controlling the pressure by regulating the choke on the choke line.

The three main kill methods are:

1. The Driller's Method (two circulations)
2. The Wait and Weight (Engineers) method (one circulation)
3. The Concurrent Method

The EAP Kick and Kill Analysis and DrillByte Kill Monitor programs provides printouts of the data required in these procedures and plots a record of progress during kill operations.

The Driller's Method

When a kick occurs, the normal procedures is as follows:

1. Pick up the kelly and note the position of tool joints in relation to the drilling spools.
2. Stop the pumps.
3. Open the choke line.
4. Close the annular preventer or ram preventers.
5. Close the choke.
6. Record the pit gain.
7. Record the SIDP and SICP when they stabilize.

Once the well is shut-in, it is necessary to calculate the kill mud density, initial and final circulating pressures, and the kick fluid gradient. If the kick fluid is gas, the bubble may start to percolate up the annulus. (this will cause a slow rise in the pressures on both drillpipe and casing). If the pressures begin to rise, a small amount of fluid can be bled from the choke, to release this “trapped pressure”. This process should be repeated until the drillpipe pressure has stabilized.

The first circulation of the Driller’s Method is performed using the original mud. The choke is opened slightly, at the same time the pumps are started up to the kill rate. When the pumps have reached kill rate, the choke is manipulated to maintain the Initial Circulating Pressure (ICP) on the drillpipe. As the kick fluids approach the surface, the annular pressure will rise drastically if the kick is gas. If the kick is saltwater the annular pressure will drop slightly.

When the influx has been circulated out, the pumps are stopped and the choke closed. At this time, the two surface pressures (SIDP & SICP) should be the same.

During the first circulation, the mud density in the pits is raised to the kill mud density. When the kill mud volume has been achieved, the kill mud is circulated. As with the first circulation, the choke is opened and the pump speed increased to the kill rate (with the annulus pressure kept constant). The annular pressure is kept constant by manipulating the choke until the kill mud has reached the bit. As kill mud begins to fill the system, the drillpipe pressure will decrease from the initial circulating pressure to the final circulating pressure (see Figure 8-2).

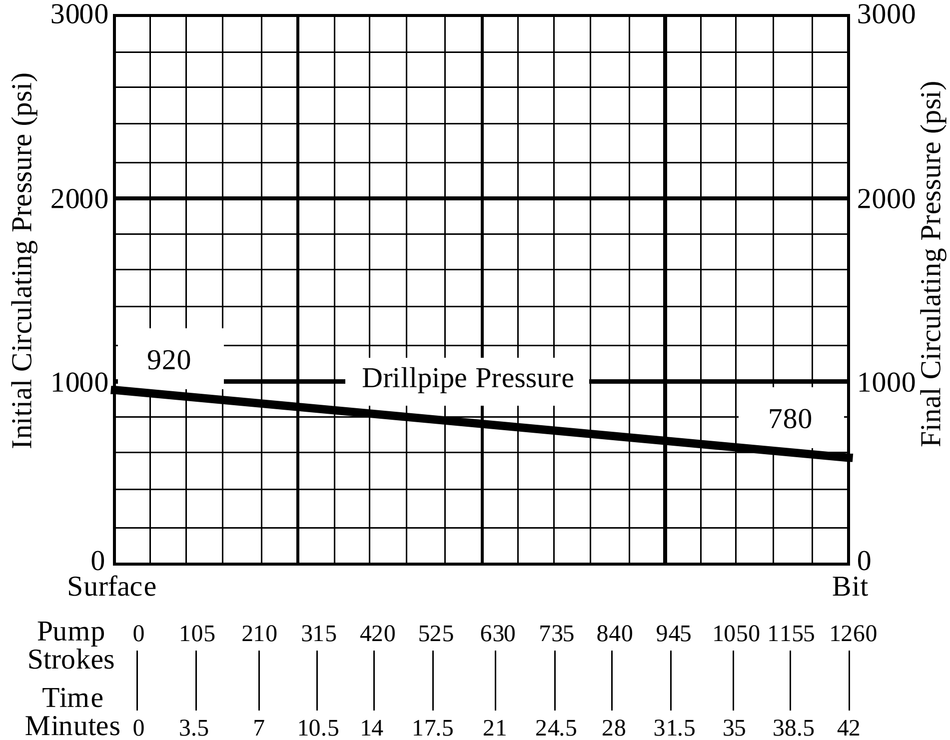


Figure 0-2Drillpipe/pressure plot of kill mud being pumped down the drillpipe

When kill mud reaches the bit, it is good practice to shut-in the well. The drillpipe pressure should fall to zero; if it doesn't, a few more barrels should be pumped to ensure that the kill mud has reached the bit. If the drillpipe pressure is still greater than zero when the pump is stopped and the choke closed, the kick control figures should be rechecked. When satisfied, pumping is restarted, but now the drillpipe pressure is kept constant as the kill mud displaces the mud in the annulus. When the kick fluids and original mud have been displaced, the choke should be wide open. The pump should be shut down and both SIDP & SICP should read zero. If so, the well should then be observed for flow. The kick is now killed and mud should be circulated to condition the hole, and at the same time the trip margin (if any) should be added.

Figures 8-3 & 8-4 illustrate how the pressures behavior as the first and second circulations are performed.

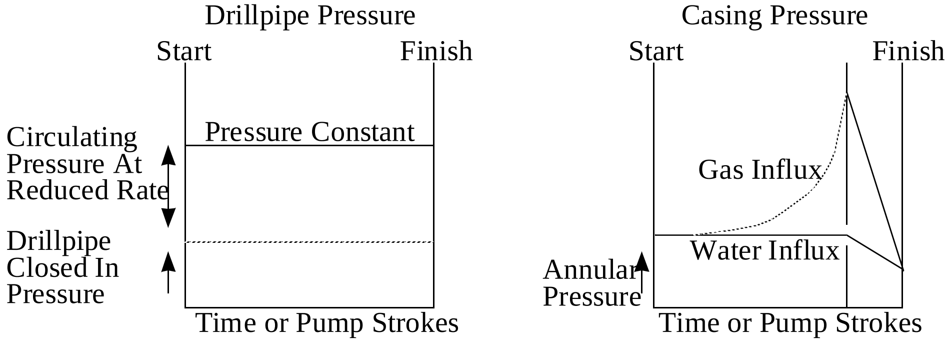


Figure 0-3First circulation pressures during the drillers method.

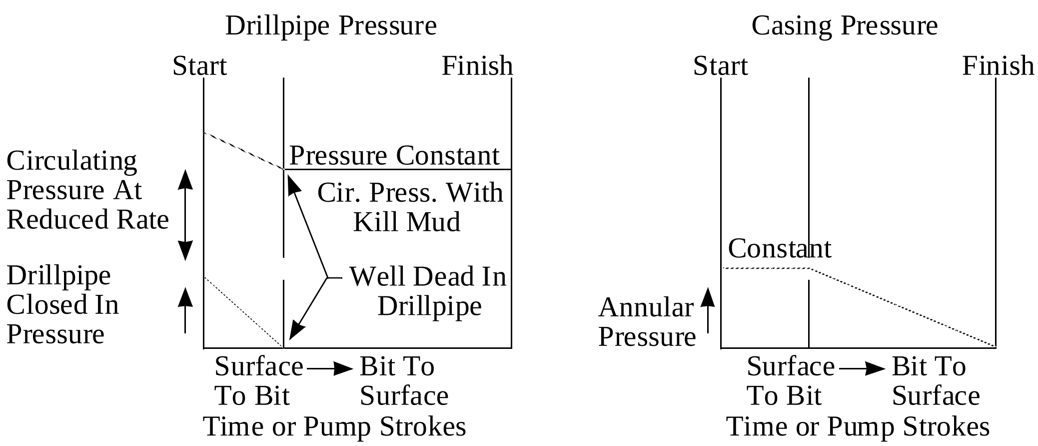


Figure 0-4Second circulation during the drillers method.

The Engineer's Method

This is usually a more effective method of killing a kick than the driller's method, if time is not a prime concern (Figure 8-5). Kill mud is pumped into the drillpipe as soon as it is ready, which tends to reduce the high annular pressures associated with gas kicks. The same shut-in procedures are used as outlined in the previous section.

When all the calculations have been performed, the mud density is raised immediately to the calculated kill mud density. When the kill mud volume is ready, the pumps are started and the choke slowly opened, while keeping the annular pressure constant until the pump has reached kill rate. The choke is then regulated in such a way as to decrease the drillpipe pressure until the kill mud reaches the bit, at which point the final circulating pressure is reached.

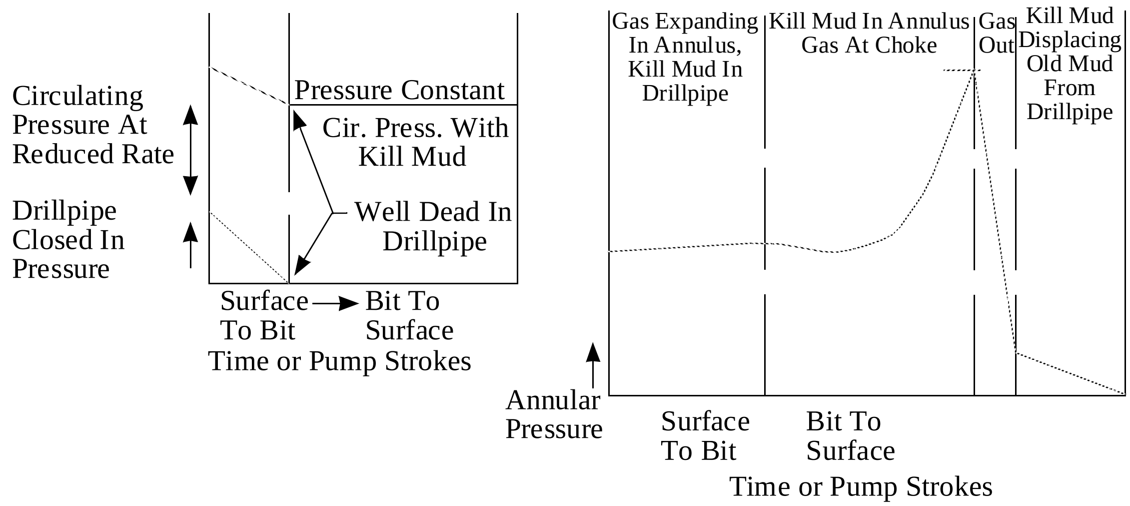


Figure 0-5Drillpipe and annular pressure curves during the engineer's kill method

Pumping is continued, holding the drillpipe pressure constant by adjusting the choke. When the kick fluids have been displaced, and further volume has been displaced equal to the pipe volume, the SIDP should be zero. The kick should be killed and the well checked for flow. Further circulations can be performed to condition the hole and to add any trip margin. Figure 8-6 shows the variations in drillpipe and casing pressures as the kill procedure is implemented.

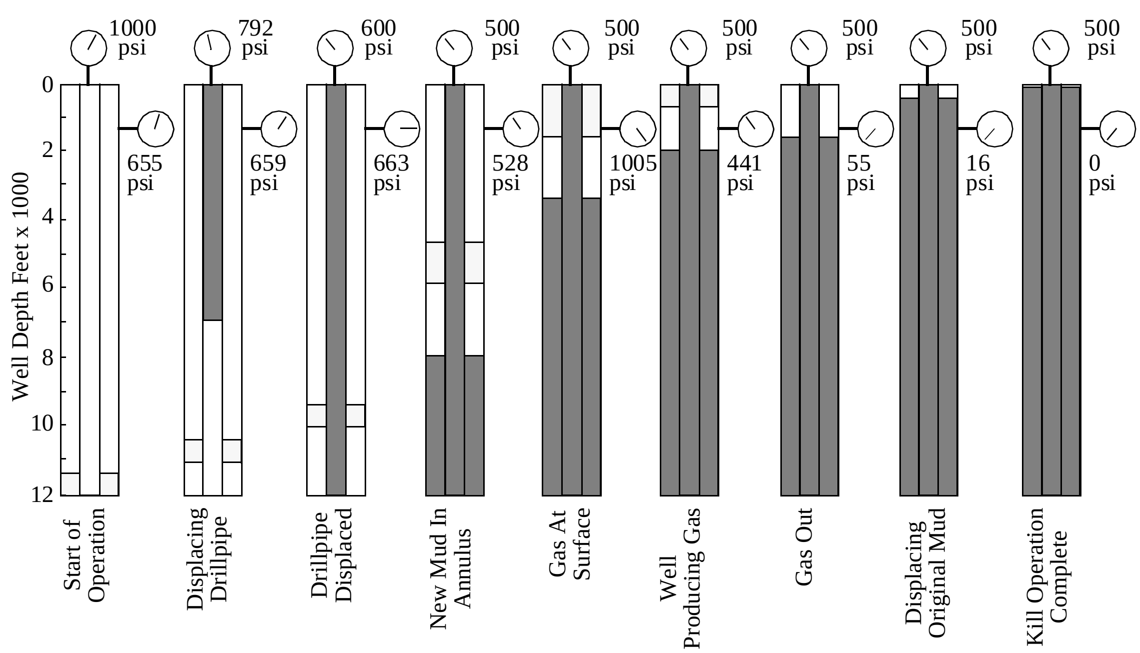


Figure 0-6Shows diagrammatically the displacement of the original mud with kill mud, with example pressures, using the engineers method.

The Concurrent Method

This is the most complicated and unpredictable method of the three. Its main value lies in the fact that it combines the driller's and engineer's methods, so that kill operation may be initiated immediately upon receipt of the shut-in pressures. Instead of waiting until all the surface mud has been weighted up, pumping begins immediately at the kill rate and the mud is pumped down as the density is increased. The rate at which the mud density is raised is dependent upon the mixing facilities available and the capability of the crew. The main complication of this method is that the drillpipe can be filled with muds of different densities, making calculation of the bottomhole hydrostatic pressure (and drillpipe pressure) difficult.

Provided there is adequate supervision and communication, and the method is completely understood, this can be a very effective way of killing a kick. Figure 8-7 illustrates the irregularities in drillpipe pressure with kill mud volume, caused by the different densities of the mud. The shut-in procedure is the same as that outlined previously. When all the kick information has been recorded the pumps are activated slowly until the initial circulating pressure has been reached at the designated kill rate. The mud should be weighted up as fast as possible, and, as the mud density changes in the suction pit, the choke operator is informed. The total pump strokes are checked on the drillpipe pressure chart when the new density is pumped and the choke is adjusted to suit the new drillpipe conditions.

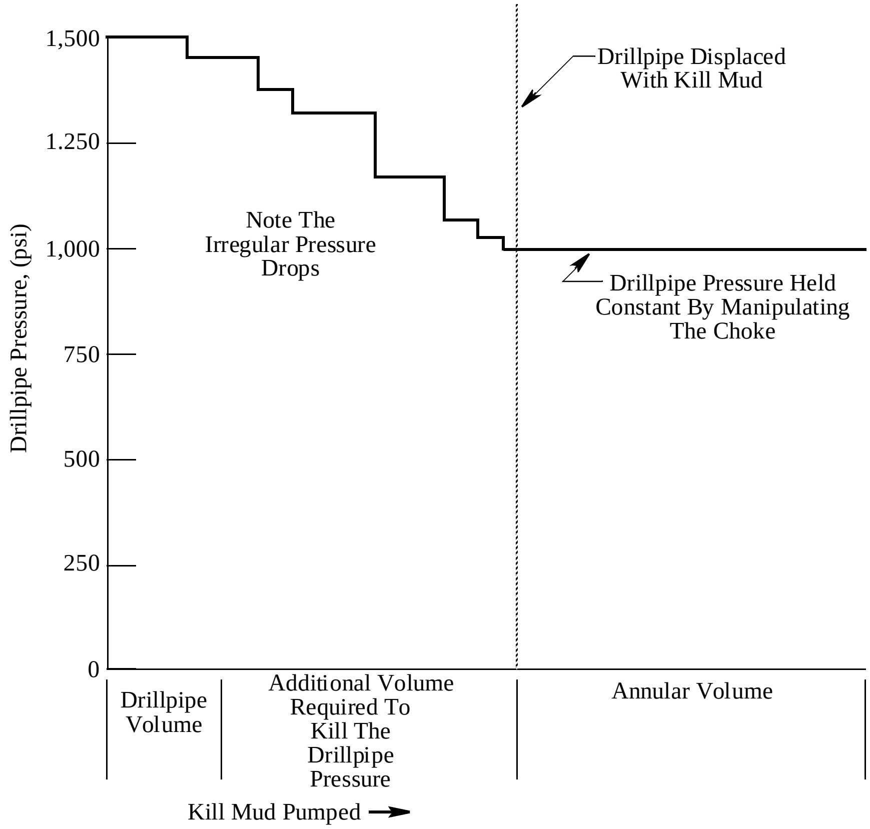


Figure 0-7Typical irregular drillpipe pressure reductions during concurrent method

When the final kill mud reaches the bit, the final circulating pressure will be reached and from this point on the drillpipe pressure should be kept constant until the operation is completed.

Pressure Control Theory

Shut-in Procedures

As mentioned earlier, as soon as indications of a kick are noticed, steps should be taken to shut-in the well. If tripping, under no circumstances should the pipe be run back to bottom with the annular preventer open and the well flowing. The primary concern is to kill the well, any concerns about stuck pipe or other well problems should be secondary. Two types of shut-in are possible:

Hard Shut-In: The annular preventer is closed immediately when the pumps are shut off.

Soft Shut-In: The choke is opened prior to shutting the annular preventers. The choke is then closed.

One argument for using a soft shut-in is that it reduces the water-hammer effect of abruptly stopping fluid flow, and it provides an alternative means of well control should the casing pressure become excessive. The primary argument against the soft shut-in is that a continuous influx occurs while the shut-in procedures are executed.

Within the industry, there is still disagreement as to which shut-in method should be used. Some authorities suggest that the water-hammer effect has no has not been proven and the low choke method is unreliable. In any case, it is the **oil company's** decision as to what method should be used.

Shut-in procedures will vary from rig type to rig type and between well site operations. The main variations in procedures are dependent upon whether the rig is floating or fixed. The following is a summary of the various shut-in procedures.

Drilling on a fixed rig:

These include land rigs, barges, jack-ups, platforms.

1. Once the warning signs of a kick have been observed, the kelly should be raised until one tool joint is above the rotary table. This allows a safety valve at the base of the kelly to be closed. The annular preventer also develops a better seal around drillpipe than around the kelly.
2. The pumps are shut off.
3. The annular preventer is closed.
4. Record the SIDP, SICP and pit volume gain.

Tripping on a fixed rig:

Once the warning signs of a kick have been observed, the top tool joint should be set in the slips.

1. An open, full-opening safety valve should be installed onto the pipe. This is easier to install than a float valve, because any flow up the pipe will tend to close the float during installation (a float valve can always be added to the string later to allow stripping back to bottom).
2. The safety valve should be closed, then the annular preventer is closed.
3. Pick up, and make up the kelly.
4. Open the safety valve.
5. Record the SIDP, SICP and pit gain.

Drilling on a floating rig:

These are semi-submersibles and drill ships.

The major difference with these rigs is that the BOP stack is on the seafloor and pipe movement relative to the drill floor can occur (even with a motion compensator). To solve this problem, a tool joint is lowered onto a set of closed rams and the weight of the drillstring is hung on these rams. With the BOP stack so far from the drill floor, the problem of a tool joint interfering with the closing of the preventers always exists. To compensate for this problem, a spacing out procedure is performed prior to the possibility of taking a kick. The rams are closed and the drill string lowered until a tool joint contacts the ram. The position of the kelly is then recorded.

1-3 These are similar to those on a fixed rig.

4. Close the upper set of pipe rams.
5. Reduce the hydraulic pressure on the annular preventer.
6. Lower the drillpipe until the pipe is supported entirely by the rams.
7. Record the SIDP, SICP and pit gain.

Tripping on a floating rig:

1-4. These are similar to those for tripping on a fixed rig.

5. Open the safety valve.
6. Close the upper set of rams.
7. Reduce the hydraulic pressure on the annular preventer.

8. Lower the drillpipe until the pipe is supported by the rams.
9. Record the SIDP, SICP and the pit gain.

Diverter procedures for all rigs:

During initial spudding and early drilling, a shallow underground blowout is difficult to control and may easily result in the loss of the rig, hence, an effort must be made to divert the flow away from the rig. Care must be taken to ensure that the well is not shut in until the diverter lines are opened.

1. As soon as a warning of a kick occurs, raise the kelly until a tool joint is above the rotary table.
2. Shut down the pumps.
3. Open the diverter lines.
4. Close the diverter bag (annular preventer).
5. Start pumping at a fast rate.

When kicks occur with the drillstring off bottom, it sometimes becomes necessary to lower the string into the well while maintaining the proper surface pressures to prevent further influx of formation fluids. The correct procedure is to either strip or snub into the well with the BOP closed.

The difference between the two is based on the relationship between the string weight and the formation pressure acting upon it. If the resultant upward force exerted by the kick acting on the string is greater than the weight of the string, the pipe will have to be snubbed into the hole. That is, pressure will have to be applied to the string to run it in. If the string weight is greater than the upward forces, the string is stripped in.

Drillpipe Float Valves:

If a kick occurs while a float valve is installed in the drillstring, both fluid and pressure movement up the string will be prevented. It is therefore impossible to read the SIDP when the well is shut-in.

If the slow circulation rate (SCR) is known, it is possible to obtain the SIDP as follows:

1. Shut in the well and record the SICP.
2. Start the pumps and maintain them at the SCR.
3. As the pumps are started, adjust the choke to regulate the SICP at the same pressure that was recorded at shut-in.
4. After the pumps are running at the kill rate and the casing pressure regulated as at shut-in, the pressure on the drillpipe while circulating should be recorded.

5. The pumps should then be shut down.

SIDP = Circulating pressure - SCR pressure.

If the SCR is not known, the SIDP can be obtained as follows:

1. Shut in the well.
2. Line up a low volume, high pressure reciprocating pump on the stand pipe.
3. Start pumping and fill up all the lines.
4. Gradually increase the torque on the pumps until the pumps begin to move fluid down the drill pipe.
5. The SIDP is the amount of pressure required to initiate the fluid movement. It is assumed that this is the amount needed to overcome the pressure acting on the lower side of the valve.

Floater Operations:

In shallow water operations (300 - 500 ft.), well control is very similar to that on land, with respect to the circulating pressure. As water depths increases, it becomes increasingly difficult to maintain the desired drillpipe pressures (initial circulating pressure and final circulating pressure) due to the small choke line ID from the subsea BOP stack to the rig floor. A thorough understanding of choke line pressure drop (frictional pressure loss) is an important aspect of subsea well control.

Choke line friction pressure (Figures 8-8a through 8-8c):

The choke line friction pressure can be measured by pumping down the choke and up the riser at the chosen slow circulating rate (Figure 8-8a).

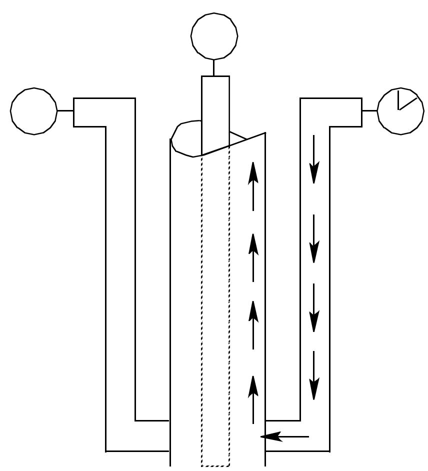


Figure 8-8a

The choke line friction pressure may also be calculated by comparing the circulating pressures recorded while circulating down the drillpipe and up the choke and circulating down the drillpipe and up the riser (Figures 8-8b and 8-8c).

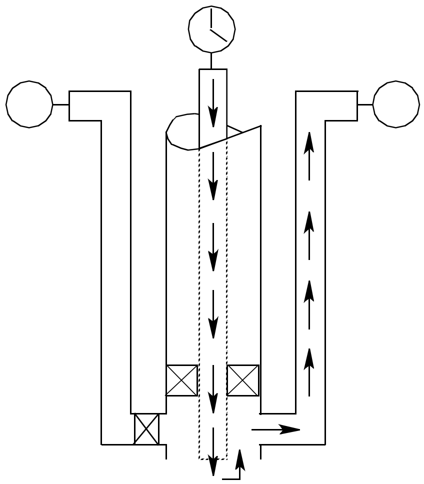


Figure 8-8b

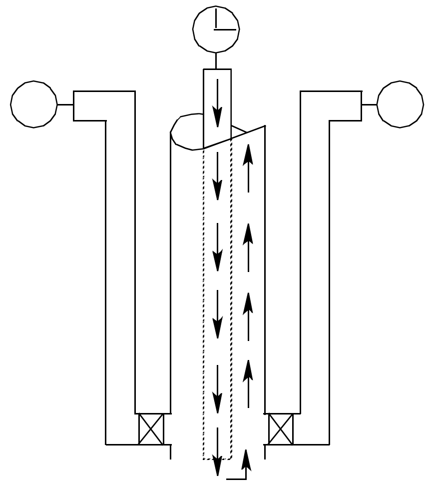


Figure 8-8c

The difference between these two is the choke line friction pressure.

Having calculated the pressure losses for circulating up both the riser and choke line, it is necessary to decide which to use in calculating the initial and final circulating pressures. Although the circulating of a kick will be done through the choke, the pressure used to establish the ICP and FCP is that derived from the slow circulation up the riser, not the choke!

It is important to establish the choke line friction because this pressure is imposed on all portions of the hole below the BOP stack, even back up to the drillpipe pressure gauge.

With a surface stack, the slow circulating rate pressure is the sum of the pressure losses in the system. These include:

1. Pressure loss through the surface system
2. Pressure loss through the drill pipe
3. Pressure loss through the drill collars
4. Pressure loss through the bit
5. Pressure loss through the annulus

The annular pressure loss is the only pressure exerted on the formation. When killing a well from a floater, the annular pressure loss will include the choke line friction pressure, because the well must be killed using the choke and the additional pressure loss must be added to the list:

6. Pressure loss through the choke line.

The deeper the water, the greater this choke line friction pressure loss, and the more significant it becomes.

In summary, the choke line pressure loss is always added to the annular pressure loss whenever circulation is from the bottom of the hole to the surface, through the choke line.

For example:

Using a slow circulating pressure through the choke of 1300 psi, and a slow circulating pressure of 1000 psi up the riser, the choke line pressure loss can be calculated to be 300 psi. Assuming a kick is taken and the following pressures are recorded;

SIDP = 200 psi   SICP = 300 psi

All of the necessary kill calculations are made prior to circulating. If the standard procedure for a surface stack is followed, the pump will be brought up to speed, maintaining the casing pressure constant; the gauge would read 300 psi.

However, this will impose excessive pressures on the entire well system. The 300 psi read on the casing pressure gauge is only valid while shut-in. Once fluid movement occurs, this gauge is reading choke pressure - not casing pressure. To read casing pressure while circulating, the kill line must be used as a casing monitor. In this example, an extra 300 psi would have been imposed on the drillpipe side and the casing side.

What should happen (as the pumps are brought up to speed) is that the choke should be opened to allow the choke line pressure to drop to zero. The casing pressure at the wellhead will still read 300 psi and the drillpipe pressure will be maintained at the desired ICP. The choke line friction pressure drop of 300 psi has been substituted for the SICP of 300 psi.

In another example, the following pressures are used (Figure 5-9):

SIDP = 200 psi   SICP = 400 psi

Choke line pressure drop = 300 psi

The casing pressure must be held constant while the pumps are brought up to speed. The desired pressure on the casing side is 400 psi minus 300 psi, or 100 psi while pumping. The choke would be opened up and adjusted to 100 psi, the choke line friction remains at 300 psi and the casing side will retain the 400 psi initially recorded. Figures 8-9a and 8-9b show the shut-in and initial circulating pressures.

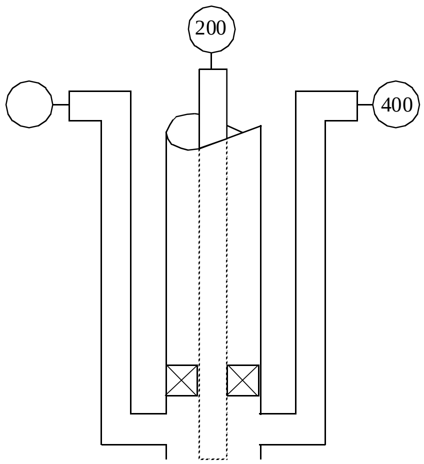


Figure 8-9a

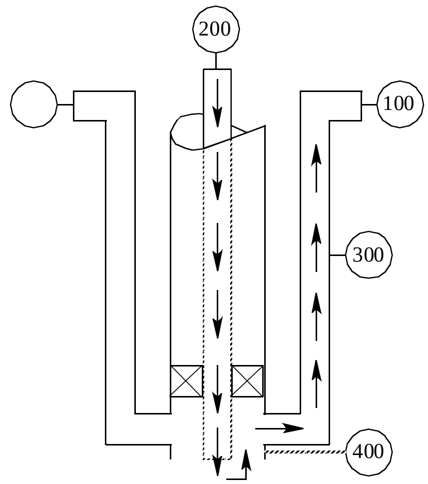


Figure 8-9b

As the water depth increases, the pressure drop through the choke line increases. For example:

SIDP = 200 psi   SICP = 300 psi

Choke line pressure drop = 400 psi

Note that the choke line pressure drop is greater than the SICP. In this instance, it is impossible to open the choke to substitute all of the choke pressure loss for the casing pressure. The surface choke pressure will read zero but 100 psi would still be imposed below the BOP stack. This is in effect an “overkill” of 100 psi. This will result in the drillpipe pressure increasing by 100 psi also. This cannot be adjusted to the desired pressure as the choke is still already open. Figures 8-9c through 8-9e illustrate this overkill. To reduce the “overkill”, the choke line pressure drop must be

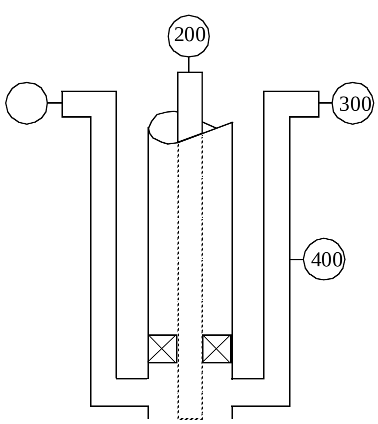


Figure 8-9c

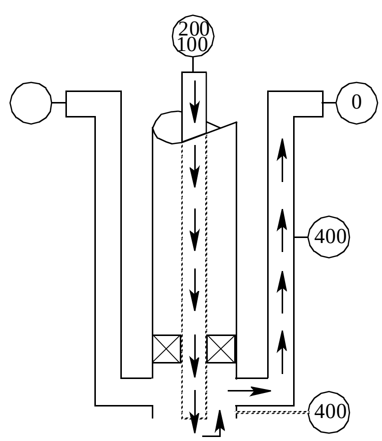


Figure 8-9d

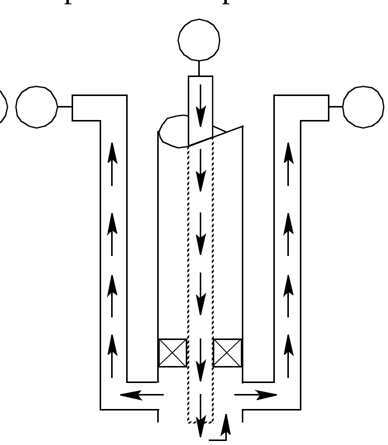


Figure 8-9e

reduced. This is accomplished by either reducing the slow circulating rate or by circulating up both the choke and kill lines. Figure 8-9c, illustrates circulating with both the choke and kill lines open.

If the SICP is greater than the choke line friction pressure loss, it is possible to circulate out the kick with conventional techniques and not worry about the choke friction pressure loss. However, when the old mud is in the choke line, the pressure loss will be equal to that as measured by the slow circulating rate. As the kill mud reaches the choke line, the choke line friction pressure loss will increase by the ratio of the kill mud density to the original mud. For example:

Slow circulating pressure through choke 1300 psi.

Slow circulating pressure through the riser 1000 psi.

This gives a choke line friction pressure loss of 300 psi. If the old mud density was 10 ppg, and the kill mud required is 11 ppg, the choke friction pressure loss will become:

$$300 \times 11/10 = 330 \text{ psi}$$

This will occur when the kill mud reaches the choke line. Yet again, this pressure can be reduced by circulating at a slower rate or by using both the choke and kill lines. If the slow circulation rate was taken using the lowest optimum rate with the rig pumps, it may be necessary to use the cementing pump to circulate at a lower rate. Obviously, a slow circulation rate must be taken with the cementing unit prior to this!

As stated earlier, kicks occurring while drilling from a floating rig will usually give higher surface pressures due to the length of choke line. Also, only a small portion of kick fluid will be required to completely fill the choke line and because the surface pressure is then dependent upon the length of the kick, it becomes increasingly important to detect kicks as rapidly as possible in deepwater drilling. It is vitally important that return flow sensors be as accurate as possible to provide this earliest warning.

In deep water subsea well control:

1. It is almost impossible to maintain a constant bottomhole pressure.
2. The margin between leak-off and mud weight decreases with water depth.
3. “Gas to surface” pressures increase with water depth.
4. The kick size that can be controlled decreases with depth.
5. Circulation through both choke and kill lines may be necessary.
6. Slow circulation pressures should be taken through the riser, choke line and choke and kill lines, using the mud pumps and the cementing pump.

7. Formation breakdown is likely, as kill mud enters the choke line.
8. Diverter use is discouraged except when displacing the riser with mud.

Well Control Equipment

The flow of fluid from the well caused by a kick is stopped by using the Blowout Preventers. Multiple blowout preventers used in a series is referred to as the BOP Stack. BOP stacks should be capable of terminating flow under all conditions.

A BOP stack comprises various types of preventer elements, including ram preventers, spools, and an annular preventer.

Annular preventer:

Commonly referred to as a bag type or spherical preventer, it is designed to stop flow from the well using a steel-ribbed packing element that contracts around the drill pipe. The packer will conform to the shape of the pipe that is in the bore hole. It is operated hydraulically, utilizing a piston acting on the packer. Once closed they utilize the upward well pressure to maintain their closed position. These preventers are available for a variety of working pressures, ranging from 2,000 to 10,000 psi. While these preventers can be used without pipe in the hole, the life of the packing element will be reduced by the stress of closing upon itself.

The initial recommended hydraulic pressure for closing most types of annular preventers is 1,500 psi. Once the packer is closed, the pressure should be reduced slightly to reduce damage to the rubber portion of the packer. One special feature of the annular preventer is that it will allow stripping operations to be carried out while maintaining pressure as the tool joints pass through the preventer. When stripping-in, the tool joints should be moved slowly through the preventer to avoid damage to the packing element.

Some of the most commonly used annular preventers are manufactured by Hydril. These possess different packing elements for different applications:

Packing Type	Color Code	Usage
Natural rubber	black	water based mud, < 5% oil, temperature greater than -30^{o}F
Synthetic rubber	red	Oil base mud w/ aniline points between 165^o and 245^{o}F, operating temperatures >20^{o}F
Neoprene	green	Oil based mud, operating temperatures between 20^{o}F and -30^{o}F

All of the above are suitable for H_2S use.

Both NL Schaffer and Cameron Iron Works also make annular preventers.

Ram Preventers:

Ram type preventers have two opposing packing elements that are closed by moving them together. Rubber packing elements again, form the seal. A major difference between these and the annular preventer is that they are designed for specific applications. Rams are designed for a certain size of pipe and will only work on that type of pipe. Also, most ram type preventers are designed to seal in only one direction. They will only hold a pressure exerted from the lower side. Thus they will not function if installed upside down and will not pressure test from above. Ram pistons are universal in that they may accept any of the following types of ram elements.

Pipe rams: These have semi-circular openings that match the diameter of the pipe being used. A drillstring comprising different pipe sizes, such as 3-inch and 5-inch drill pipe, would require two sets of pipe rams to accommodate both sizes of pipe. These are also operated hydraulically, and close around the tubing portion of drill pipe when used.

Blind rams: These are designed to close off the hole when no pipe is in the hole. If they are shut on drill pipe, they will flatten the pipe, but not necessarily stem the flow.

Shear rams: These are a form of blind rams that are designed to cut drill pipe when closed. This will result in the dropping of the drillstring below the BOP stack unless the stack is designed in such a way as to have a set of pipe rams below the shear rams on which a tool joint can be supported. They will stop the flow from the well. Shear rams are usually only used as a last resort when all other rams and the annular preventer have failed.

The ram preventers will have a manual screw-type locking device that can be used in the event of a hydraulic failure.

Other Components:
In addition to the annular and ram type components, the BOP stack must contain some mud access line, and a drilling spool will be inserted into the stack to allow for the connection of these choke and kill lines.

The BOP stack will be attached to the casing string via a “casing head”. This casing/BOP connection will have a pressure rating similar to the rest of the BOP components.

In certain cases, it may be necessary to allow the well to blowout in a controlled manner rather than be shut-in. This is common in shallow sections due to insufficient casing to contain a kick. In these circumstances, a **diverter system** will be used. This is a relatively low pressure system, often using the annular preventer to seal off the annulus below the flow line. The diverter line will then be opened below the annular preventer to allow the flow to be directed away from the rig.

The BOP stack can only be used to stop the flow of fluids from the annulus. Additional valves are used to stop the flow within the drillstring. These valves include kelly cock valves and internal blowout preventers.

Kelly cocks are generally placed at the top and bottom of the kelly. These valves may be installed as a permanent part of the drillstring or just when a kick occurs. They can be automatic or manually controlled and they consist of subs with valves that may be of a spring loaded ball type, a flapper valve type, or dart type. The dart acts as a one way valve, with pressure from below closing the valve, and pressure from above, opening it. The drawback of these valves is that while preventing a blowout up the string they prevent the shut-in drillpipe pressure from being monitored.

A manual valve, more commonly referred to as a “full opening safety valve”, is usually installed onto the drillpipe after a kick occurs. They usually contain a movable ball and when in one position allows flow through a hole in the ball, but after turning 90^o, shuts off flow completely. Rotating the ball is performed with a wrench. These have the advantage that wireline tools can be passed through them.

Control of the kick and kill fluids during kill operations is accomplished using a **choke manifold**. This manifold must be able to work under a variety of conditions, such as high pressure, with oil, gas, mud and water, and be capable of withstanding the effects of abrasive solids (sand and shale) in the kick fluids. The manifold should be capable of controlling the well using one of several chokes and be able to divert flow to one of several areas, such as reserve pits, burn pits, or degassers. Since vibrations occur during kill operations, the manifold must be securely anchored down, with as few bends as possible to prevent washouts under high pressure flow conditions.

The system used for closing the BOP's is a high pressure hydraulic fluid **accumulator**. Hydraulic fluid is stored under pressure, the pressure being provided by stored nitrogen. When hydraulic oil is forced into the accumulator by a small volume, high pressure pump, the nitrogen is compressed, storing potential energy. When the BOP's are activated the pressured oil is released, either opening or closing the BOP's. Hydraulic pumps replenish the accumulator with the same amount of fluid that was used to operate the BOP. The accumulator must also be equipped to allow varying pressures. When stripping pipe through an annular preventer, a constant pressure must be maintained as the tool joints pass through the packing element. Accumulators commonly have minimum working pressures of 1200 psi and maximum working pressures of between 1500 and 3000 psi.

Special Kick Problems And Procedures

The majority of problems which occur during well control operations are caused by equipment failure, formation breakdown or improper operating procedures.

Excessive Casing Pressure

Mechanical failure or formation breakdown can occur if excessive casing pressure is allowed to build up. Mechanical failure at the surface can be catastrophic, while formation breakdown can lead to lost circulation, an underground blowout and/or possible surface fracturing. A “maximum allowable casing pressure” must be determined and if casing pressure rises to this maximum level during the initial closing of the well, a decision must be made whether or not to shut-in the well.

If excessive casing pressures occur, the following alternatives may be considered:

1. The “Low Choke” procedure
2. Turn the well loose
3. Close in the well and consider bullheading

With the correct casing design, equipment selection and frequent testing of the surface equipment, the chances of mechanical failure are greatly reduced.

Formation breakdown can also be catastrophic, especially if the last casing shoe is shallow, with the possibility of fractures reaching the surface.

If the maximum casing pressure is reached while circulating out a kick, the decision must be made whether to:

1. Controlled circulation of the kick with drillpipe pressure while allowing the casing pressure to increase. This can lead to mechanical failure of the casing and/or formation breakdown.
2. Adjust the choke to hold the maximum allowable casing pressure and follow the low choke procedure until the well can be shut-in. However, the control of a high volume gas flow using the low choke method is extremely difficult.
3. Close in the well and bullhead the kick back down the annulus to reduce casing pressure or spot a pill of heavy mud or cement. This may also cause formation breakdown.

If the casing pressure is likely to exceed that of the surface equipment, or if the possibility of surface fracturing due to casing or formation failure exists, the well cannot be shut-in. As stated earlier, if these conditions exist the alternatives include using the low choke pressure procedure, pumping a barite pill, pumping cement, or allowing the well to flow until pressure is reduced. If the surface equipment rating will not be exceeded and fracturing to the surface is not likely, consideration can be given to shutting in the well and allowing formation breakdown to occur.

The Low Choke procedure consists of circulating and weighting up the mud at its maximum density, while maintaining the maximum allowable casing pressure on the choke. The influx will continue to flow into the well until the mud has been sufficiently weighted and this may take several circulations. The required kill mud density will not be known as the drillpipe pressure is not allowed to stabilize upon initial closure. After some heavier fluid has been circulated, the well may be shut-in and an estimate of the required kill mud density can be made.

When using the Low Choke method, the weight material should be added to the mud system as rapidly as possible, while applying the maximum allowable casing pressure, because the annular pressure drop will aid this method. The highest possible circulation rates possible should be used (except in the case of subsea BOP stacks where the choke line friction will be excessive. In these cases, the returns should be circulated up both the choke and kill lines, and circulation carried out at the maximum rate that will not cause shoe breakdown due to the imposed choke and kill line friction pressures).

Low Choke Pressure Procedure:

1. Circulate using the maximum pump rate.
2. Start weighting up the mud to the “estimated” kill mud density.
3. Begin circulating, while holding the maximum allowable casing pressure by adjusting the choke. Care must be taken, and observe for lost circulation.
4. Circulate out the kick fluid until it reduces the choke opening in order to maintain the maximum allowable casing pressure.
5. Shut-in the well and record the shut-in drill pipe and shut-in casing pressures. The wait and weight (engineers) method or the concurrent kill method can now be used.

   To obtain the initial circulating pressure, multiply the prerecorded kill rate pressure by the ratio of the present fluid density to the drilling fluid density used to obtain the kill rate and add it to the shut-in drill pipe pressure.
6. If the casing pressure cannot be reduced sufficiently for the well to be safely shut-in, or the well cannot be killed, preparations must be made for either a barite or cement plug to seal the kicking formation.

Kick Occurs While Running Casing or Liner

Running liner:

Kicks that occur while running liner can be handled in a similar manner to a kick that occurs while drilling. If the liner is near bottom, an attempt should be made to strip into the hole. The kick can then be circulated out, the hole conditioned and the liner cemented in place. In some cases it may be necessary to strip the liner back into the casing shoe to prevent the liner from sticking. The annular pressure can be reduced by bullheading heavy drilling fluid into the well to overbalance the kick pressure, but when running of more liner into the hole, it may displace some of the heavy fluid and may start the well flowing again. In addition, pumping high density fluid into the annulus may result in lost circulation problems. Once the kick is killed, the liner should be tripped out and the hole conditioned for rerunning the liner. If the liner has not been run to the shoe, an attempt should be made to strip to the shoe, but not into the open hole.

Running casing:

A kick that occurs while running casing can lead to extreme problems. Stripping the casing to bottom should only be attempted if the guide shoe is within a few joints of bottom. If only a short section of casing is in the hole, the annular pressure will tend to force it upwards, in which case the casing will need to be tied down and filled with drilling fluid immediately. With a long section of casing, it becomes more likely that the combination of tensional forces, the annulus pressure, and the pressure exerted by the BOP's (in subsea wells) will collapse the casing. If it is possible, annular preventers should be closed slowly with the choke wide open. Due to the small annulus around the relatively large casing, pump rates will tend to be slower and the fill up of the casing with kill fluid will take much longer. Gas entering the bore hole and casing can continue migrating and may complicate pressure calculations. The dangers of lost circulation and an underground blowout are increased due to the small annulus. As a last resort to gain control, a barite plug may be used or the casing cemented (if not at bottom) at the present depth.

Parted or Washed-Out Drillstring

If the drill string develops a washout, every consideration should be given to preventing washout-hole enlargement. Circulation, rotation and pipe movement should be performed carefully to minimize the chances of the string parting. The procedures are the same for a parted string, a washed out string, or with the bit off bottom that cannot be stripped back to bottom. The following procedures are recommended:

1. Locate the point where the string is parted or washed out.

2. Observe the SIDP and SICP. If the SIDP is not significantly lower than the SICP the influx is still below the washout or bit (if the bit is off bottom).

3. If the influx is below the washout (or bit) it must be allowed to percolate upwards. Circulating above the influx serves no purpose in removal of the influx. As the gas percolates upwards it will expand and the excess pressure must be bled off carefully to prevent further influx.

4. When the influx rises above the washout (or bit) the SICP will be higher than the SIDP. The influx may then be circulated out conventionally and the density of the kill fluid can be calculated using the following equation:

KMD (ppg) = SIDP / TVD (of washout/bit/end of string) x 0.0519

The well will not have been successfully killed until the drillstring is run back to bottom and all influx fluids are displaced and replaced with a suitable drilling fluid to maintain control.

Stuck Pipe

An influx of formation fluid or increase in annular pressure may cause the drillstring to become deferentially stuck. Pipe movement (if possible) should be made carefully. In the event of a kick, the well must be controlled first. Only after the well is brought under control should drillstring recovery operations be initiated.

Plugged or Packed-Off Bit

If one or more bit jets become plugged, the SIDP will increase suddenly while a constant pump rate is maintained. The choke should not be opened to maintain a constant drillpipe pressure, as this will allow the influx of more fluid. The pump should be stopped and the well shut in. The SPR should be redetermined and this new pressure maintained as the pumps are brought up to the new slow circulating rate, without encountering excessive drill pipe pressures. These new pressures should be used to continue the kill operation.

If the bit becomes completely plugged, drillpipe pressure cannot be used to maintain a constant bottomhole pressure and the casing pressure will increase slowly as gas percolates up the annulus. The casing pressure should be allowed to rise 100 psi above the initial SICP and small amounts of fluid should be bled off into a tank to monitor fluid volume. The procedures for a migrating gas bubble are then followed. Consideration may be given to running a string shot or perforating to regain circulation.

Underground Blowout

This is an uncontrolled flow of formation fluids from a high pressure zone into a lower pressure zone. The loss of drill pipe pressure with changes in annular pressure, the loss of large volumes of drilling fluid, or the total loss of drilling fluid returns, characterizes underground blowouts. A common cause is the fracturing of formations below the casing shoe by excessive annular pressures. If the flow is not too severe, it may be possible to pump LCM in a light fluid, or a "gunk squeeze" down the annulus while killing the high pressure zone down the drillpipe with heavy mud.

The direction of fluid flow is an important concern when choosing a control procedure. The cause of the blowout will often indicate the direction of flow. If the cause is thought to be the fracturing of a formation due to shutting in a kick, the direction of fluid flow will generally be upward (assuming that shallow zones are more likely to fracture than deeper zones and that the initial kick zone is the primary source of formation fluid).

If, however, a zone of lost circulation is encountered at the bit, the flow may be from a shallower zone to a deeper zone. The loss of hydrostatic head may induce an upper zone to kick. While the flow will generally be to the zone of lost returns, this is not always the case.

One method of killing an underground blowout is:

1. As soon as the symptoms are recognized;
    a. Request or rig up a logging unit for a temperature log and noise log
    b. Start increasing the mud density in the pits
    c. Kill the drill pipe side with the heavy mud
    d. Continue to pump a few barrels of mud every 30 minutes to keep the bit from plugging
    e. If the drillpipe sticks, pull and stretch the pipe to prevent buckling above the free point.
2. Rig up the wireline logging unit and run the temperature log going down the drillpipe and the noise log while pulling out.
    a. Determine the point of fluid entry and fluid exit
    b. Calculate the mud density required to kill the well between the point of entry and the point of exit. The calculated mud density may exceed 20 ppg. In this case, use the highest mud density that can be mixed and pumped.

3. Mix a minimum of 3 times the hole volume of either the required mud density or the maximum pumpable density.

Simultaneously;

   a. Ensure pumps are in good condition

   b. Obtain high volume mixing equipment

   c. Blow the jets out of the bit and/or perforate above the bit to maximize the flow through the drill string

4. Pump the mud at a high rate until all the mud has been pumped. DO NOT STOP UNTIL 3 TIMES THE ESTIMATED HOLE VOLUME OF HEAVY MUD HAS BEEN PUMPED.

5. Run the temperature/noise logs to determine if the well is dead. If it is dead, bleed off any casing pressure and rerun the logs.

This procedure is known as a “running kill”. Even though the pumped mud will be cut, the annular density will increase as more mud is pumped. As the annular density increases, so will the back pressure on the formation, resulting in a decreased kick flow rate. A kill can be accomplished with a limited volume of mud if the mud is MUCH heavier, and pumping is fast and continuous. A running kill of an underground blowout cannot be accomplished if the mud weight is only 1 to 2 ppg heavier than the estimated bottomhole pressure.

Lost Circulation

Loss of fluid returns will lower the hydrostatic head of the drilling fluid in the wellbore, thereby inducing a kick. The influx fluid will then flow to the surface or into the zone of lower pressure. Lost circulation can occur in naturally occurring fractured, vuggy, cavernous, sub-normally pressured or pressure depleted formations. Induced losses can occur from mechanical fracturing due to pressure surges while breaking circulation. In all cases of lost circulation, attempts should be made to keep the hole full. The hole can be filled with either light drilling fluid or water. A record of the amount of fluid pumped should be made.

Loss of returns while trying to kill a kick can develop in underground blowouts. If a kick is impending or an underground blowout has started, a barite plug may be effective in isolating the thief zone from the kick. In addition, fine sealing material may be used to control slow losses (coarse material that may plug the bit, choke valve or choke line should not be used). Occasionally, a coarse sealing fluid may be used when bullheading down the annulus. Normally, the lost circulation zone should be sealed once the loss zone has been isolated from the influx zone.

Weighted Plugs

In the case of an underground blowout, lost circulation, or situations requiring the low choke pressure control, it may become necessary to attempt well control using a weighted settling plug. These are deflocculated slurries of weight material in water or oil, weighing between 18 and 26 ppg, which bridge the hole as a result of high water loss and the rapid settling of the weight material once circulation is stopped. Hematite is recommended if slurry densities over 22 ppg are required and/or if the influx contains H_2S, because hematite can act as a secondary scavenger (removing the gas by absorption).

If circulation has not been lost, the weight plug must be run under a back pressure and the influx must be held by casing pressure or hydrostatic pressure to allow the plug time to settle.

Bullheading

This is defined as pumping fluid into the well without circulation back to the surface. The fluid can be pumped down the drillpipe, down the annulus, or both. In most instances this will result in formation fracturing. This will occur at the weakest point, which is usually the formation near the last casing shoe. Obviously, in underground blowouts or wells with lost circulation, bullheading can prove useful since the fracture or loss zone already exists.

Wells with short open hole sections and zones of high permeability respond better to bullheading than wells with long open hole sections and low permeability zones.

The quicker the flow can be reversed, the less amount of drilling fluid has to be pumped to force the influx back into the formation. Any gas in the kick will migrate up the hole at a rate dependent upon the drilling fluid's density and viscosity.

There are no specific rates at which bullheading should be performed. At slow rates (the pressures are within the boundaries of casing burst pressure) the pump rate can be increased until the higher pressure will become detrimental to the operation. The higher pump rates are desirable to pump the influx away as soon as possible, and to overcome any gas migration.

Once the influx has been pumped away, normal circulation should be resumed to establish a balanced fluid column. The circulation of kill fluid should be at a rate that does not break down the formation any further. If, during bullheading a formation is fractured, it may heal with time. If not, further steps will have to be taken to heal the zone. In areas where H_2S is present as a possible kick component, bullheading provides a useful means of limiting the amount of gas that has to be dealt with at the surface.

Bullheading has many advantages, but also many disadvantages that must be considered:

Advantages

1. Prevents Hydrogen Sulfide from reaching the surface
2. Keeps formation gas away from rig floor
3. Lower surface pressures are commonly used
4. Useful when underground blowouts occur
5. Can be used with or without pipe in the hole
6. Can be used to kill liner-top leaks

Disadvantages

1. Fractures formations
2. Can burst the casing
3. May break liner top
4. Can plug drillpipe
5. Will lose mud to formations (may therefore be expensive)
6. May pressure up formations, causing a back-flow when circulation is stopped

Kick and Kill Analysis

Input Data

Depth	12000.0 ft.	Pump Rate	30 str/min
V. Depth	11980.0 ft.	Flow Rate	126 gal/min
Inclination	2.00 deg	Pressure	250 psi
Mud Density	10.00 lb/gal		
Leak Off EQMD	15.10 lb/gal		

Influx Data	
Kick Volume	10 bbls
Shut In Casing Pressure	450 psi
Shut In Drillpipe Pressure	400 psi

Calculated Results

Volumes	bbls	Strokes	Minutes
Pipe Capacity	208	2085	69
Hole Annular Volume	1398	14027	466
Riser Annular Volume	180	1801	60
Choke Volume	6	61	2

Total Volumes	bbls	Strokes	Minutes
Circulating through Riser	1785	17913	595
Circulating through Choke	1612	16173	537

Kill Data	Units
Pore Pressure at TD	6624. psi
Kill Mud Density	10.81 lb/gal
Maximum Allowable Annular Pressure	2649. psi
Initial Circulating Pressure	650. psi
Final Circulating Pressure	270. psi
Length of Influx	119.6 ft.
Vertical Length of Influx	119.5 ft.
Estimated Influx Density	1.95 lb/gal
Influx Fluid Type	Gas

Self-Check Exercises

1. List five major causes of kicks.

   a. ______________________________

   b. ______________________________

   c. ______________________________

   d. ______________________________

   e. ______________________________

2. What is the typical sequence of events that may be observed if a kick is taken during a connection?

   ____

   ____

   ____

   ____

3. Which of the kill methods results in the lowest pressures during the killing procedure?

   (Circle one) Drillers Method Engineers Method

4. What information is required prior to initiating kill procedures?

   ____

   ____

   ____

5. While killing a well with the “Driller's Method”, the first circulation is used to ________________ and the second circulation is used to ________________.

6. Why is the “concurrent method” usually not chosen to kill a well?

   ____

   ____

   ____

7. When the drill pipe must be run into the hole while the annular preventers are closed, what is the difference between striping and snubbing the pipe?

____

____

____

____

8. How do pipe rams differ from shear rams?

____

____

____

9. What are the disadvantages of “bullheading”?

____

____

____

10. Calculate the kill mud density (no safety factor).

SIDP	=	600 psi	MD	=	10.0 ppg
SICP	=	900 psi	Depth	=	10,000 ft.

answer: ____

11. If the following data is known, what fluid type has entered the well bore (assume no collars).

SIDP	=	800 psi	MD	=	15.0 ppg
SICP	=	1400 psi	Pipe	=	3.5 inch
Pit Gain		= 20 bbl	Hole	=	6.0 inch

answer: ____

Chapter **9**

Cost Analysis

Upon completion of this chapter, you should be able to:

- Understand the limitations and inaccuracies of using older methods of analyzing drilling costs.
- Appreciate the variables in the “cost-per-foot” analysis equation and be able to perform relevant calculations.
- Draw a cost per foot curve and explain how it can be used in economics evaluations.
- Perform a graphical “breakeven” analysis and determine when a bit is no longer cost-effective.
- Suggest the proper type of bit and drilling variables to obtain the most cost-effective bit for the following run.
- Describe the best methods to optimize the drilling process.

Additional Review/Reading Material

Baker Hughes INTEQ, *DrillByte Operations Manual*, P/N 80319H

Bourgoyne Jr., Adam, et al, *Applied Drilling Engineering*, SPE Textbook Series, Vol. 2, 1986

Moore, Preston, *Drilling Practices Manual*, PennWell Publishing Co., Tulsa, 1986

Whittaker, Alun, *Mud Logging Handbook*, Prentice-Hall, 1991

Introduction

The value of accurate drilling data cannot be over-emphasized. Reliable, factual data is the foundation of post-well project evaluation and review. All information collected becomes extremely useful, from the moment it is analyzed until the time it can be relied upon as a planning tool. Wellsite information is used by all levels within the industry, from the morning tour driller through the drilling engineering sections of the operator and service companies.

Computers are playing an ever-increasing role in drilling operations and the old adage is still true, if the data fed into computers is erroneous, then the final “print out” will not be reliable.

At the field level, the Bit Data Record (Figure 9-1) can be one of the well planners most valid tools. Much of the data required to complete this standard form is already documented and readily available on the rig.

Dull bit evaluation can be valuable information, when the grading is objectively performed. It can, at times, reveal erroneous entries in other parts of the form, such as gross errors in weight-on-bit, rotary speed, or rotating time.

The recent trend towards deeper and costlier wells has led to the development of rock bits which will stay in the hole longer, drill more footage, and eliminate expensive rig-time and excessive trips. As a result, ever-increasing numbers of rock bits types have become available, including may styles of roller cone and fixed cutter bits.

With these changes in the rock bit product line and the variances in bit cost and/or performance, common comparative factors such as total rotating hours, penetration rate and total footage drilled, have lost their significance. One factor that has retained its validity is cost comparison.

To make the most efficient use of these newer bits will require that much more emphasis be placed on cost-per-foot analysis as a basis of drilling performance.

Cost-Per-Foot Analysis

The introduction of advanced drill bit designs has not always had the effect of obsoleting existing designs. Instead, the availability of new designs has increased the number of types of bits available from the various bit manufacturers.

Selection of the bit best suited for a specific use is further complicated by the variable performances and prices of the many types of bits. Thus, the question which needs to be answered is: How can the correct bit be selected for a given application?

The decision concerning which bit to use often based on some performance criteria, such as total rotating hours, total footage, or maximum penetration rate. Other times, the least expensive bit is chosen. This approach may be satisfactory in areas where practices and costs are constants but it may not be satisfactory where drilling costs are changing, and drilling practices and bit selection vary.

A realistic approach to bit selection is to base the final decision on the minimum cost-per-foot. In this way, it is possible to achieve an optimum relationship between penetration rate, bit footage, rig cost, trip time and bit cost.

Cost-per-foot as related to these variables can be determined by the equation:

$$\text{cost/foot} = \frac{\text{Hourly Rig Cost(Trip Time + Drilling Time) + Bit Cost}}{\text{Footage Drilled}}$$

Note: *This is "on-bottom" drilling time. Since these calculations are made to compare bit runs, time spent circulating off-bottom, waiting on weather, making connections, and so forth, is ignored in the calculations.*

The example below illustrates how this formula evaluates the performance of two different bits. From the bit record, 15 and 16 are evaluated. Bit number 15 is a journal-bearing milled-tooth bit. Bit number 16 is a journal-bearing insert bit.

Bit No.	Bit Cost	Depth Out (ft)	Footage	Rotating Hours	Penetration (ft/hr)	Cost/foot
15	$950	7,547	264	18.5	14.3	$42.99
16	$3145	8,510	963	76.0	12.7	$38.36

Rig Cost = \$400/hour Trip Time = 1 hr/1000 feet

$$Bit\#15\ \text{cost/ft} = \frac{\$400/\text{hr} \times (7.5\ hr + 18.5\ hr) + \$950}{264\ \text{feet}} = \$42.99/\text{ft}$$

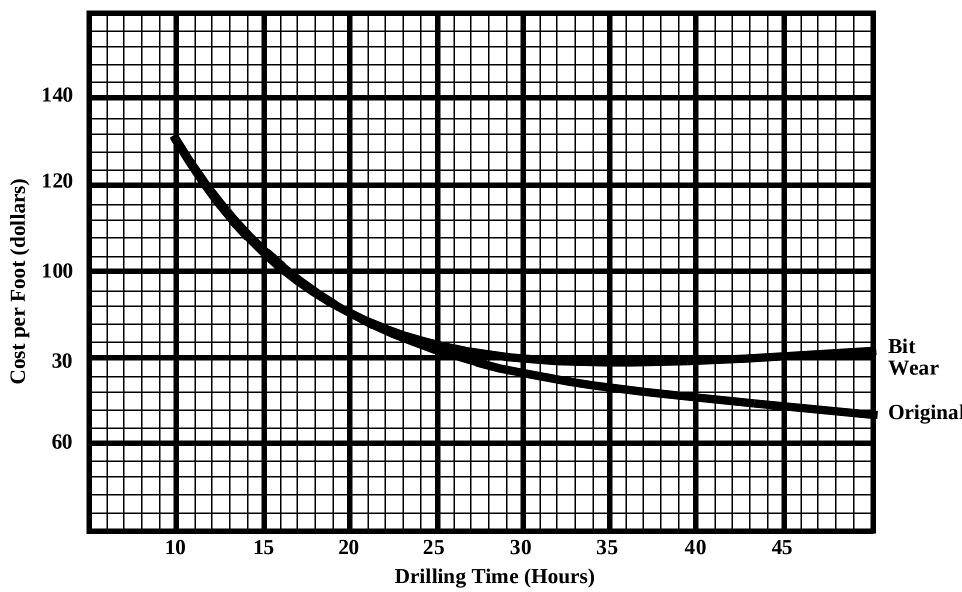
$$Bit\#16\ \text{cost/ft} = \frac{\$400/\text{hr} \times (8.5\ \text{hr} + 76\ hr) + 3145}{963\ \text{feet}} = \$38.36/\text{ft}$$

If performance is based on using penetration rate as the criteria, bit #15 would appear to be superior. Referring to the cost-per-foot comparison, bit #16 gave the best performance, at \$4.63/ft cheaper than bit #15.

It has been demonstrated that by using this cost-per-foot formula, a bit can be pulled when it no longer becomes economical to drill. When the drilling time-per-foot begins to increase, and the footage drilled-per-time decreases, the cost-per-foot will begin to increase. When that increase is first noticed, it would be economical to pull the bit.

This analysis can also be represented graphically (see below). As drilling begins, the cost-per-foot will decrease rapidly. The longer the bit is in the hole, the more straight the curve becomes. When the curve begins to increase, it becomes necessary to pull the bit.

Cost Curve



INTEQ COMPANY: Kinghurst Exploration Company WELL: Training Well #1 SHEET NO. 1

BIT DATA RECORD

RUN #	BIT DATA						BIT RUN								
	BIT #	MFR	TYPE	SIZE	IADC CODE	JET SIZES	START DEPTH	DRILLED Feet	DRILLED HOURS	AVERAGE ROP	WOB	RPM	PUMP PRESSURE	SPM/GPM	IADC BIT CONDITION
1	1	Smith	DSJ	26.0	111S	3 x 16	1976	280			Spud Bit				
2	2	Smith	SDS	12.25	114E	4 x 12	2259	513		Drilled Pilot Hole					
3	RR1	Smith	DSJ	26.0	111S	3 x 24	2259	829		Wash Out & Drill Hole for Surface Casing					
4	3	Reed	Y11	15.0	111S	3 x 15	2956	1088	15.4	80-90	2-20	130-145	2900-3050	150/680	T4B5I
5	4	Reed	Y11	15.0	111S	15/15/12	4044	492	5.6	80-100	10-25	150-155	2970-3200	150/740	T2B1I
6	RR2	Smith	SDS	12.25	114E	4 x 12	4532			Pulled to Squeeze Cement					
7	RR2	Smith	SDS	12.25	114E	4 x 12	4532		6.2		Drilled Cement				
8	5	Chrst	C-201	8.50	T4X8	0.50 TFA	4538	30	3.8	8-12	1-5	45-55	1000-1500	50/350	T2I
			Cored Top of Austin Chalk - Recovered 100% Minor Burn Wear on Diamonds												
9	6	Sndvk	PD-21	12.25	S744	0.44 TFA	4568	492	7.5	50-60	22-30	80-100	3000-3200	155/700	T1I BT
10	7	Reed	CS16FD	8.50	0350	0.50 TFA	5060	60	2.2	37-40	15-18	45-50	700-1500	50/300	T1I
			Cored Woodbine and Top of Eagleford - Recovered 100% Run in with Junk Basket Prior to Coring												
11	8	HTC	J1	12.25	116G	13/13/OP	5120	1296	27.4	35-47	30-40	100-110	3000-3250	144/675	T3SEI
12	RR8	HTC	J1	12.25	116G	13/13/12	6417	598	22.7	26-32	45-47	100-105	3000-3100	125/630	T6SEI
13	9	Sec	S88F	12.25	547X	3 x 12	7051	290	12.9	20-22	40-45	110-115	3400-3480	170/780	T5SEI
14	10	Reed	HP53A	12.25	537Y	12/12/13	7305	466	26.5	15-18	50-55	100-110	3250-3300	165/780	T3SQI
15	11	HTC	ATJ11	12.25	517X	3 x 12	8119	984	53.6	15-20	60-80	60-70	3500-3550	150/680	T8SFI
			Lost Cone #1 in hole, and 12 teeth from Cones 2 and 3: Bearings Locked Up												
NB	Mill	Bowen	Junk	12.25			9103	5		Mill on Junk from last Bit Run					
16	12	Smith	SDS	8.50	114G	3 x 12		Trip in after casing with casing scratcher - Wiper Trip							
17	13	HTC	J2	8.50	126G	3 x 12	8985	Drill Cement							

EL P/N 18430 MAY 1980

Figure 9-1Bit Data Record

Cost Per Foot Calculations Including Downhole Motors

When downhole motors are used and charged at an hourly rate, they can be included in the cost equation:

$$C = \frac{C_{Rig}(t_D + t_f) + C_{Bit} + C_{Motor}t_D}{d}$$

Where:

Where:	C	is the cost/ft for drilling the section of hole
	C_{Rig}	is the rig cost per hour
	C_{Bit}	is the bit cost (each)
	C_{Motor}	is the cost per hour of drilling
	d	is the distance drilled
	t_D	is the hours spend drilling
	t_f	is the hours spend tripping

The following example is a case history. The above equation was used to qualify the savings to an operator in the North Sea when drilling a very hard conglomerate formation with an impregnated diamond bit and a turbine. Calculations were made based on all the bit runs through the conglomerate formation on five different wells.

The following values were used for the calculations:

C_{Rig} = £ 2,000 per hour
t_t = 1,000 ft/hr (trip time)
C_{Bit} = £ 4,000 per insert bit
= £ 19,000 per fixed cutter bit
C_{Motor} = £ 200 per hour

In the following table, the client's cost per foot for drilling the conglomerate section has been calculated for all the insert bit runs, for two PDC bit runs and for one run with a diamond bit.

In this exercise calculate the client's cost per foot for drilling with the impregnated diamond bit.

Well No.	Bit Style	C (rig) (£/hr)	$t_{(t)}$ (hrs)	$t_{(d)}$ (hrs)	C (bit) (£)	C (mtr) (£/hr)	d (ft)	Cost (ttl) (£/ft)
1	Insert Bit	2,000	13.2	16.0	4,000	-	68	917.60
	Insert Bit	2,000	13.8	13.0	4,000	-	26	2,215.40
	Insert Bit	2,000	13.8	26.5	4,000	-	65	1,301.50
	Insert Bit	2,000	13.9	30.0	4,000	-	93	987.10
	PDC Bit	2,000	14.0	24.5	19,000	-	52	1,846.20
	PDC Bit	2,000	14.1	13.0	19,000	-	63	1,161.90
	PDC Bit	2,000	14.2	30.0	4,000	-	101	914.90
	Insert Bit	2,000	14.3	29.0	4,000	-	117	774.40
	Insert Bit	2,000	14.4	18.0	4,000	-	60	1,146.70
	Insert Bit	2,000	14.5	23.0	19,000	200	134	735.80
	Insert Bit							
	Insert Bit							
	PDC Bit							
2	Insert Bit	2,000	13.4	41.3	4,000	-	125	907.20
	Insert Bit	2,000	13.8	19.4	4,000	-	67	1,050.70
	Insert Bit	2,000	13.9	13.4	4,000	-	53	1,105.70
	Insert Bit	2,000	14.0	9.2	4,000	-	32	157.50
	Insert Bit	2,000	14.0	28.9	4,000	-	152	590.80
3	Insert Bit	2,000	12.6	2.4	4,000	-	23	1,478.00
	Insert Bit	2,000	12.8	23.0	4,000	-	212	356.80
	Insert Bit	2,000	12.9	3.0	4,000	-	18	1,988.90
	Insert Bit	2,000	12.9	19.2	4,000	-	120	568.30
4	Impregnated Bit	2,000	15.1	58.5	19,000	200	495	
	Impregnated Bit	2,000	14.2	39.5	19,000	200	403	
	Impregnated Bit	2,000	15.4	39.5	19,000	200	317	
	Impregnated Bit	2,000	15.7	42.0	19,000	200	358	
5	Impregnated Bit	2,000	14.2	57.5	19,000	200	540	
	Impregnated Bit	2,000	14.2	68.5	19,000	200	283	

These calculated values of cost per foot were used to determine the average cost per foot for each type of bit. The following table shows the results.

Bit Type	No. of Bit Runs	Average Cost (£/ft)	Cost for 1,500 ft Section of Conglomerate (£)
Insert Bits	16	1,117.40	1,676,100
PDC Bits	2	1,504.00	2,256,000
PDC Bits (turbine)	1	735.80	1,103,700
Impregnated Bits	6	424.10	636,150

For drilling the 1,500 ft section of conglomerate on one well, the use of the impregnated bits saved £ 1,039,950 compared to the cost of using insert bits and £ 1,619,850 compared to PDC bits.

Target Cost Per Foot and Target ROP

Cost per foot calculations can also be used in generating performance proposals for clients. A target cost per foot can be calculated based on information from offset well performance that used competitor products. This target cost per foot is underwritten by Baker Hughes INTEQ by applying a sliding-scale hourly rate for motor operations. If the target is met or exceeded, the motor is charged at normal list price; if it is not, then the hourly rate is adjusted downwards (to an agreed minimum) until the target figure is reached. This type of proposal has been used several times to persuade clients to run INTEQ motors.

Before we can propose a target cost per foot to the operator, we should be reasonably sure that we will be able to achieve a minimum ROP. This ROP is the required drill rate needed to meet both the proposed cost per foot figure, and our pricing structure. After calculating this target ROP, it must be determined whether it is attainable.

Note: *All terms in the following formulas are our targets. For example, C is the target cost per foot agreed upon with the client. ROP is the target ROP necessary, and so forth.*

$$ROP = \frac{d}{t_D}$$

Since:

$$C = \frac{C_{Rig}(t_D + t_t) + C_{Bit} + C_{Motor}t_D}{d}$$

then:

$$t_D = \frac{C\,\mathrm{d} - C_{Bit} - C_{Rig}t_t}{C_{Rig} + C_{Motor}}$$

Example 1, Baker Hughes INTEQ Proposal

Offset-well cost /ft

Rig Cost	=	£ 2,083 per hour
Bit Cost	=	£ 95,600 (8 bits)
Section Length	=	3,056 feet
Drilling Time	=	361.8 hours
Trip Time	=	101 hours (1,000 ft/hr round trip)

$$\text{Cost per foot} = \frac{2,083(361.8 + 101) + 95,900}{3,056}$$

Offset well cost per foot = £ 346.73 /ft

Baker Hughes INTEQ then proposes a performance deal based on a 15% reduction in the cost per foot, for example:

Target cost/ft = £ 294.72

The performance proposal calls for two bit runs (2 HCC PDC bits) using a Mach 1C Navi-Drill. The section length is established at 3,753 feet.

Calculation of Target ROP

Rig Cost	=	£ 2,083 per hour
Bit Cost	=	£ 48,500 (2 bits)
Motor Cost	=	£ 225 per hour
Section length	=	3,753 feet
Trip Time	=	21.8 hours (2 round trips)
Target cost per foot	=	£ 294.72

Target cost of drilling interval = **£ 1,106,092** (294.72 x 3,753 feet)

Cost of trip time	=	£ 2,083 x 21.8 = £ 45,409
Bit Costs	=	£ 48,500

Target cost of drilling time = **£ 1,012,183** [1,106,092 - (45,409 + 48,500)]

Total cost per hour of drilling time = **£ 2,308/hr** (2,083 + 225)

$$\text{Target drilling hours} = \frac{\text{target cost of drilling time}}{\text{hourly cost of drilling}}$$

$$\text{Target drilling hours} = \frac{1,012,183}{2308} = 438.6 \text{ hrs.}$$

$$\text{Target ROP} = \frac{3,753 \text{ ft}}{438.6 \text{ hrs}} = 8.6 \text{ ft/hr}$$

Provided the section is drilled with two bit runs and the average ROP is at least 8.6 ft/hr, then the target cost per foot will be achieved and full list prices will be charged to the client.

Example 2, Calculation of Target Cost per foot, and Target ROP with a Motor.

In this case, the operator does not have good offset well data and no realistic value of cost per foot is available. The operator's engineers agree that the interval is PDC drillable, and it will be economical to run PDC bits provided no more than two bits are required to drill the section and provided an average ROP of 16 ft/hr can be achieved. The proposed well is vertical and they are not persuaded that running a downhole motor will be cost effective.

Calculations of Target Cost per foot for rotary drilling

Rig cost	=	£ 2,000/hr
Bit cost	=	£ 50,900 (2 PDC bits)
Section length	=	4,550 ft (10,400' to 14,950')
Trip time	=	26 hours (2 round trips)
Target ROP	=	16 ft/hr

If we are to drill 4,550 feet at an average ROP of 16 ft/hr, then

$$\text{Target drilling hours} = \frac{4,550}{16} = 284.4$$

$$\text{Target cost per foot} = \frac{2,000(284.4 + 26) + 50,900}{4,550}$$

Target cost per foot = £ 147.62 /ft

Target ROP with a Downhole Motor

The Baker Hughes INTEQ engineer decides the only way to persuade the client to use a motor is to offer a performance deal based on the cost per foot calculated above. The target ROP is calculated as follows.

Standard hourly rate for motor = £ 220/hr (including engineer)

Target cost for interval = 4,550 ft x 147.62 £/ft

or, £ 671,650

Target drilling costs = £ 671,650 - £ (2000 x 26 + 50,900)
or, £ 568,750

$$\text{Target drilling hours} = \frac{\text{target drilling cost}}{\text{hourly rate for (rig + motor)}}$$

$$\text{Target drilling hours} = \frac{568.750}{2,000 + 220} = 256.2$$

$$\text{Target ROP} = \frac{4,550}{256.2} = 17.8 ft/\text{hr}$$

After consulting database records, the INTEQ engineer is confident that an average ROP of 18 ft/hr is attainable. He therefore offers the client the following terms:

1. If a target cost per foot, estimated at £ 147.62, is achieved, the specified motor will be charged at the standard hourly rate.
2. If the cost per foot exceeds the target figure, the hourly charge for the motor will be scaled down until the target is achieved. The minimum hourly rate for the motor will be 60% of list price.
3. If trips are required that are not related to motor or bit performance, the trip times will not be included in the cost per foot calculation.
4. Drilling time will be calculated on the basis of on-bottom drilling hours (i.e. excluding connections).
5. The cost per foot calculations will be mutually agreed between the oil company and Baker Hughes INTEQ before the job starts.
6. Normal rates for personnel, standby and maintenance apply.

Summary

There are various ways of using cost per foot calculations to evaluate bit runs. We have considered only some of the possibilities. However, all the methods are simply variations of the basic cost per foot equation.

Breakeven Cost Analysis

Before deciding to run the more expensive bits (insert, PDC, or diamond) through a zone previously drilled with a lower priced bit (mill tooth). It is frequently desirable to define, as precisely as possible, the required performance of the next bit. This analysis may range from a simple cost-per-foot comparison, to more complicated and detailed investigations involving drilling fluids, required operating conditions and other variables. Since the ultimate goal of the drilling operation is to make a profit, any comparison should be tied to total drilling cost or to drilling cost per foot of hole.

The standard cost-per-foot formula makes no allowance for the variations in operating costs when comparing runs of greatly different lengths. These variations stem from safety factors (working hazards are greater during trips), time for rig maintenance, need for additional mud treatment prior to trips, severity of operating conditions (more WOB requires more collars), and hole conditions which may be aggravated during trips. Nevertheless, it is the best approach we have for a generalized comparison, and lends itself well to the need for a prior analysis to determine when to run a higher priced bit. Those factors not included in the formula invariably favor using the bit which makes the most hole.

A breakeven chart makes use of this cost-per-foot formula in determining just how long a higher priced bit must run and how fast it must drill to provide a drilling cost equal to that of less expensive bits.

The first step in making a breakeven analysis is to determine the various costs of previous wells. Using the standard formula and considering the bit (or series of bits) used to drill the zone under consideration, a “target” cost-per-foot is determined. (In this example three 8 3/4 inch steel tooth bits drilled 850 feet in 103 hours. Rig cost was $250/hr, with trip time of 7 hours. The calculated $53.45/ft is the target which must be equaled or bettered to provide an economical run.)

On the graph, point “A” is located on the horizontal scale left of zero, which is a distance equal to the combined bit cost (expressed in rig hours and trip time). In our example, it is assumed that an 8 3/4 inch insert bit costing $3,317 will be used and that a trip will still require 7 hours. The bit is now worth approximately 14 rig hours, making the combined bit and trip value 21 hours. Point “A” is 21 hours left of zero.

The cost of the bit and trip is the converted into feet of hole at the “target” cost and plotted vertically as point “B”. (In this example, combined bit cost of $3,317 and trip cost of $1750 (7 x $250) is $5,067. This divided by $53.45 is 95 feet).

Finally, a line is drawn through points "A" and "B" and projected through the grid to represent performance which will give the breakeven drilling cost. Any combination of feet and hours on the line equals the "target" cost, a combination under the line is more expensive and above the line is cheaper. In this example, the breakeven line represents $53.45/ft. Some combinations, (for instance of 400 feet in 80 hours), would exceed this cost; if a bit drilled 500 feet in 60 hours, it would be less expensive.

Based on local drilling conditions and the expertise of wellsite personnel, it is possible to estimate with reasonable accuracy either the hours which can be expected or the probable penetration rate. If probable hours are estimated, this value can be found along the breakeven line and a horizontal reading on the footage scale indicates the required footage to breakeven.

If it is known how many feet are to be drilled in the zone, a vertical reading from the intersection of this value with the breakeven line will indicate the required hours. If the best guess which can be made is penetration rate, a line may be constructed from the "zero" point at this rate and its intersection with the breakeven line provides readings of both footage and hours. In this example, it is assumed that a 600 foot section will be drilled, and the chart indicates the run will be economical if it takes 92 hours or less.

This chart can be used when comparing expected bit runs of any price, and is just as useful in evaluating use of diamond, PDC, TSP, or insert bits against less expensive steel tooth bits.

Example 3: Break Even Analysis

Offset Data

Rig Cost/Hr	$250
Trip Time, Hrs	8 Bits @ 7 hr. each = 56 hrs.
Total Footage	850
Total Rotating Hrs.	103
Total # Bits	8 @ $710 = $5680
Avg. Cost/Ft	$53.45

$$C = \frac{B + R(T + t)}{\mathrm{F}}$$

$$C = \frac{5680 + 250(103 + 56)}{850} = \$53.45 \text{ per feet "target" cost}$$

Breakeven Performance

1. $$\text{trip hrs} + \frac{\text{Insert Bit Cost}}{\text{Rig Cost/Hr}} = \text{Hours*}$$

$$7 + \frac{3317}{250} = 21\text{hrs}$$

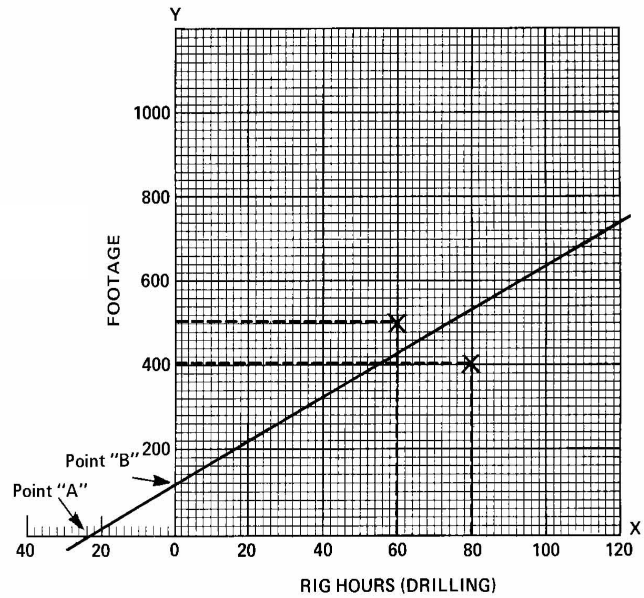
* Plot to left of zero on 'X' (horizontal) axis

2. $$\frac{\text{Insert Bit Cost + Trip Cost}}{\text{Offset Cost/Ft}} = \text{Footage **}$$

$$\frac{\$3317 + \$1750}{53.45} = 95$$

** Plot footage on 'Y' (vertical) axis

3. Draw a straight line extending through points "A" and "B"



Any footage and hour combination on this line is a breakeven point; above the line is the lower cost/ft, below is the higher cost/ft.

Diamond Bit Cost Per Foot Comparison & Breakeven Performance

Comparison Drilling Cost Per Foot

Item	Description	Roller Bit/s	Diamond Bit
A	Bit Size	6-5/8”	6-5/8”
B	Number of bits to be compared	6	1
C	Total trip time all bits being compared (of B)	48 Hrs.	8 Hrs.
D	Rig cost per hour	$100.00	$100.00
E	Total trip cost all bits being compared (of B) C X D	$4,800.00	$800.00
F	Total footage drilled all bits being compared (of B)	554 Ft.	1350 Ft.
G	Total rotating hours all bits being compared (of B)	72 Hrs.	165 Hrs.
H	Total bit cost all bits being compared (of B)	$1,100.00	$3,350.00
I	Drilling cost per foot	$23.65	$15.30

Breakeven Performance Diamond Bit

$$J = Rig \text{ Hours} = C(\text{ Diamond Bit}) + \frac{H(\text{Diamond Bit})}{D(\text{ Diamond Bit})} = 8 \quad + \frac{3350}{100} = 41.5$$

$$K = Footage = \frac{H(\text{ Diamond Bit}) + E(\text{ Diamond Bit})}{I(\text{ Roller Bits})} = \frac{3350 + 800}{23.65} = 175.48$$

Directions for use of graph

1. Plot “J” value to left of zero on “X” (Horizontal) axis.
2. Plot “K” value on “Y” (vertical) axis.
3. Draw a straight line extending through points “J” and “K”.
4. Any footage and hour combination on this line is the breakeven point for the diamond bit. Any point above the line extending through “J” and “K” indicates a cheaper cost per foot. Any point below the line indicates higher cost per foot for the diamond bit.

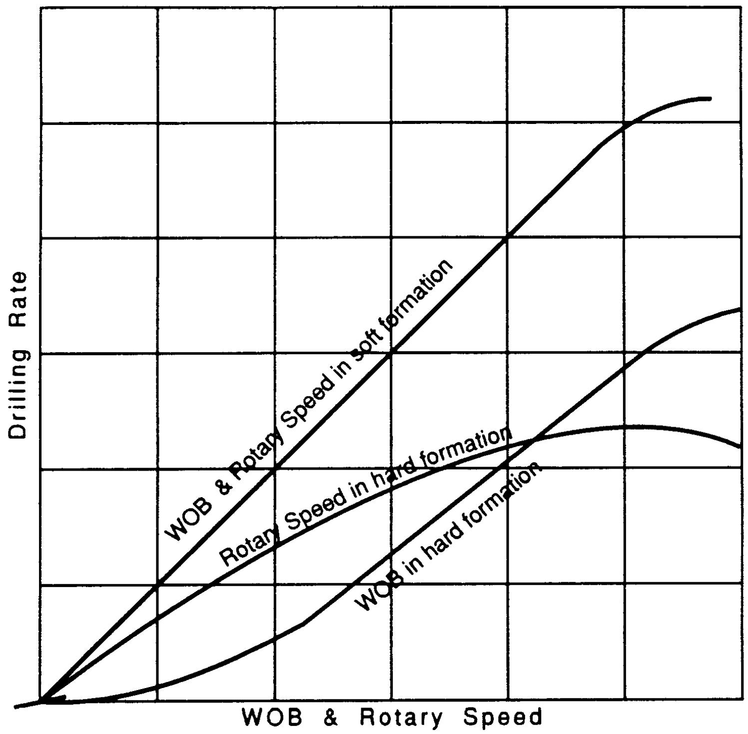
Drilling Optimization

One of the primary parameters which directly affects cost analysis is the efficiency of the drilling operation, or the optimization of the drilling variables. Those operating variables must be varied to achieve the best drill rate for each drill bit, each application, and each formation. The two primary variables which can be manipulated are the weight-on-bit (WOB) and the rotary speed (RPM). Bit hydraulics may have to be manipulated, but this should have been accomplished before the bit was tripped into the borehole.

Many tests have been performed to optimize the drill rate by varying the WOB and RPM, and below are some general results:

1. <u>Soft Formations</u>: Increasing the rotary speed can improve the penetration rate with little effect on bit cutter wear. Relatively low WOB is recommended.
2. <u>Medium Formations</u>: Increased RPM will not have the same result as in soft formations. Moderate RPM with moderate WOB should maximize the drill rate and reduce bit wear. As the cutters begin to wear, the WOB should be increased to maintain the drill rate.
3. <u>Hard Formations</u>: Increased WOB is more important than increased RPM. Moderately high WOB with minimum RPM yields the most optimum drill rates.

The relationship between penetration rate and WOB, and between penetration rate and rotary speed, are illustrated below.



Additional WOB and RPM considerations must be kept in mind. A very high rotary speed can drastically reduce the life of many roller cone bits, thereby increasing their cost per foot (because of the cost of extra bits and extra trips). Similarly, running excessively high weight-on-bit may buckle the drill pipe as well as damage the bit, and will almost certainly cause problems because of excessive drilling torque. It would be best, therefore, to use values of WOB and rotary speed corresponding to the top end of the linear portions of the previous graph. The actual values of WOB and RPM at the point at which the graph departs from linearity depends on the type of bit and the hardness of the formation (as well as on the efficiency of the hydraulics in cleaning the bit and the bottom of the hole).

Drill-Off Tests

A drill-off test is designed to determine the most appropriate WOB and RPM, using the above listed considerations. This test is a step by step process to achieve the maximum drill rate.

Preliminary Steps

1. Before starting test, make sure the bit is properly seated (i.e. has the proper bottomhole pattern).

2. Driller and logging personnel should communicate before the start of the test - logging unit to collect data in one second intervals.

3. Lift bit off bottom approximately one foot, stop pumps and rotary speed - wait ten seconds.

4. Start pumps - wait ten seconds

5. Start rotary speed - wait ten seconds

6. Start drill-off test

Example Drill-Off Test Parameters

1. Maintain each WOB for 60 seconds

2. Flow rate: 520 gpm

3. Bit Type: 126S

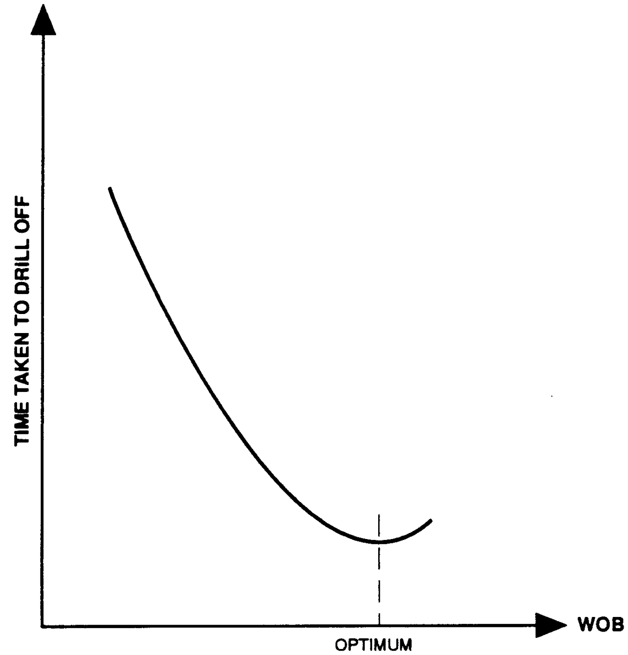
Test #1: RPM 120
WOB 48, 36, 24, 18 klbs

Test #2: RPM 60
WOB 48, 36, 24, 18 klbs

Test #3: RPM 90
WOB 48, 36, 24, 18 klbs

Test #4: RPM 90
WOB 24, 36, 48 klbs

After the completion of the drill-off test, select the RPM and WOB which provided the best penetration rate. A graph like that shown below should be obtained if the time taken to drill off each decrement is plotted against the average WOB in each case.



The lowest point on the graph indicates the optimum WOB. A variation of the drill off test is to mark off the kelly in one inch segments and (with the brake locked) measure the time and weight for each inch drilled off.

As shown above, the test is repeated for several different values of rotary speed in order to find the optimum rotary speed also.

Surface Indicators

Once the drill rate has been optimized and drilling has commenced, there are several surface variables which should be monitored to ensure this drill rate remains optimized and problems are avoided. Usually, problems with the drill rate and well bore will show up on several surface indicators, and cross-referencing will help to determine the cause.

As mentioned earlier, WOB and RPM are the most important drilling parameters, and should be monitored constantly. Their interaction with the following indicators should be noted.

Torque

Torque is usually measured in foot pounds. When diesel or SCR rigs are being used, torque will be measured in amperes (amps), which is the amount of electrical power required by the motors to rotate the drillstring.

Torque is a function of the RPM and hole conditions and will be induced into the drillstem when the pipe is rotated. Some of the torque comes from the bit, the rest from the BHA and drillpipe interaction with the borehole.

There is no “baseline” value for torque, but deviations from an established baseline which is constant for that particular bit run.

Constant Torque

In soft formations, the value will be relatively low. The harder the formation, the higher the torque values.

Irregular Torque

Changes from the constant value(s) may indicate:

- Interbedded Formations
- Stabilizers hanging up
- Keyseats or doglegs
- Excessive WOB
- The bit is becoming undergauged
- Junk in the hole

Increases in Torque may be due to:

- A formation change
- Increasing hole inclination
- Increasing filter cake
- The bit becoming undergauge

Decreases in Torque may be due to:

- A formation change
- Decreasing hole inclination
- Decreasing filter cake
- Bit balling

Pump Pressure

Pump Pressure is measured in pounds per square inch (psi), with readings being taken at the mud pumps or standpipe.

Constant Pump Pressure

This should be the norm, once the recommended pressure is reached.

Irregular Pump Pressure

Changes from the recommended value could mean:

- A nodular or broken formation
- The BHA is hanging-up

Increases in Pump Pressure may indicate:

- The annulus is packing-off
- The bit is balling
- Inadequate hole cleaning
- A plugged fluid passageway or nozzle

Decreases in Pump Pressure may indicate:

- A washout in the nozzles or drillstring
- Losing circulation
- Aerated drilling fluid

Pump Strokes

The pistons on the mud pumps stroke forward and backward to push the drilling fluid through the system. The stroke rate is measured in strokes per minute (spm). A set number of strokes per minute are necessary to circulate at the predetermined flow rate and pressure. With the pump pressure constant variations in the stroke rate can indicate problems.

Increased Pump Strokes can indicate:

- A washout
- Losing circulation
- Aerated drilling fluid

Decreased Pump Strokes indicates:

- An annular restriction
- A plugged bit
- The bit is balling up

Pulling the Drill Bit

All the optimization in the world will not make a bit last for the entire well. Pulling a worn bit is necessary to make the drilling operations more efficient. Four parameters to keep in mind when determining when to pull the bit are:

Cost-per-Foot

This value, mentioned earlier, is a reliable guide in predicting when to pull a bit. The cost per foot should continue to decrease. When the cumulative cost per foot value begins to increase, it may be necessary to put a new bit into the hole.

Breakeven Analysis

This value can be calculated prior to a bit run. If the calculated value is not being met, then a new (or cheaper) bit may have to be run.

Drill Rate

A gradual decrease in the drill rate in a consistent formation generally indicates a worn bit.

Drilling Parameter Change

A sudden change in one of the surface indicators, or a value beyond acceptable limits, may point to a worn bit or some other type of borehole problem which may require the bit to be pulled.

Summary

Wellsite personnel have the responsibility for monitoring the efficiency of the drilling operation and recommending ways to optimize the drill rate. Monitoring the cost per foot curve and watching the surface drilling parameters will make INTEQ personnel much more effective members of the drilling team.

DRILLING COST ANALYSIS

Bit Number24.0 Bit Cost24000.00 $
Bit Start Depth6578.0 ftRig Cost/hr1000.00 $
Average Trip Speed9.80 ft/min

Record No	Depth ft	Interval ft	Bit Time min	Interval min	Average ROP ft/hr	Instantaneous Cost $/ft	Cumulative Cost $/ft
0	6580.0	2.0	10.0	10.0	12.0	83.37	23273.84
1	6585.0	5.0	16.0	6.0	50.0	20.01	666.39
2	6590.0	5.0	21.0	5.0	60.0	16.67	3897.09
3	6595.0	5.0	27.0	6.0	50.0	20.01	2757.77
4.	6600.0	5.0	37.0	10.0	30.0	33.35	2139.36
5	6605.0	5.0	46.5	9.5	31.6	31.68	1749.68
6	6610.0	5.0	58.0	11.5	26.1	38.35	1482.81
7	6615.0	5.0	71.0	13.0	23.1	43.35	1288.75
8	6620.0	5.0	81.0	10.0	30.0	33.35	1139.70
9	6625.0	5.0	870	6.0	50.0	20.01	1020.95
10	6630.0	5.0	96.0	9.0	33.3	30.01	925.99
11	6635.0	5.0	109.0	13.0	23.1	43.35	848.87
12	6640.0	5.0	125.0	16.0	18.7	53.35	784.99
13	6645.0	5.0	139.0	14.0	21.4	46.69	730.14
14	6650.0	5.0	151.0	12.0	25.0	40.02	682.45
15	6655.0	5.0	167.0	16.0	18.7	53.35	641.82
16	6660.0	5.0	197.0	30.0	10.0	100.04	609.00
17	6665.0	5.0	230.0	33.0	9.1	110.04	580.52
18	6670.0	5.0	272.0	42.0	7.1	140.06	556.76
19	6675.0	5.0	323.0	51.0	5.9	170.07	537.01
20	6680.0	5.0	370.0	47.0	6.4	156.73	518.53
21	6685.0	5.0	422.0	52.0	5.8	173.40	502.56
22	6690.0	5.0	488.0	66.0	4.5	220.09	490.10
23	6695.0	5.0	560.0	72.0	4.2	240.10	479.57
24	6700.0	5.0	645.0	85.0	3.5	283.45	471.67
25	6705.0	5.0	779.0	134.0	2.2	446.85	470.82
26	6710.0	5.0	933.0	154.0	1.9	513.54	472.57
27	6715.0	5.0	1087.0	154.0	1.9	513.54	474.19
28	6720.0	5.0	1255.0	168.0	1.8	560.22	477.34
29	6730.0	10.0	1480.0	255.0	2.7	375.15	470.84
30	6735.0	5.0	1680.0	200.0	1.5	666.93	477.19
31	6740.0	5.0	1710.0	30.0	10.0	100.04	465.66
32	6745.0	5.0	1760.0	50.0	6.0	166.73	456.81
33	6750.0	5.0	1835.0	75.0	4.0	250.10	450.90
34	6735.0	5.0	1965.0	130.0	2.3	433.51	450.50
35	6760.0	5.0	2105.0	140.0	2.1	466.85	451.05
36	67865.0	5.0	2225.0	120.0	2.5	400.16	449.78
37	6770.0	5.0	2355.0	130.0	2.3	433.51	449.44
38	6775.0	5.0	2470.0	115.0	2.6	383.49	447.85
39	6780.0	5.0	2635.0	165.0	1.8	550.22	450.47
40	6785.0	5.0	2867.0	232.0	1.3	773.64	458.36

Self-Check Exercises

1. The least expensive type of bit may be the proper choice when practices and costs ________.

2. Since the ultimate goal is to make a profit, any cost comparison should be tied to ________ or ________.

3. Those factors not included in the cost-per-foot formula invariably favor ________.

4. What is the first step in making a breakdown analysis?

   ____

   ____

   ____

5. Which of the following bits would be the most economical?

Bit No.	Bit Cost	Depth Out	Footage	Rotating Hours	ROP
3	10000	12100	500	20.5	24.3
4	12600	12700	600	18.3	32.7

Rig Cost = $1000/hr

Trip Time = 1.2 hr/1000 ft

6. Determine which series of bits was most economical for the operator, then graph the breakeven analysis.

		Case #1	**Case #2**
A	Bit size	8.5"	8.5
B	# of bits to be compared	5	3
C	Total trip time all bits being compared (of B)	90 Hrs.	45 Hrs.
D	Rig cost per hour	$1250	$1250
E	Total trip cost all bits being compared (of B) C X D	$112500	$56250
F	Total footage drilled all bits being compared (of B)	1000 ft	900 ft
G	Total rotating hours all bits being compared (of B)	100 hrs	70 hrs
H	Total bit cost all bits being compared (of B)	$25000	$35000

Graph:

Technical Writing

Upon completion of this chapter, you should know how to:

- Follow correct procedures for organizing and writing engineering sections of technical reports.
- Proof technical reports to ensure the contents are accurate, complete, and relevant to the client's requirements.
- Correctly use technical writing skills in the preparation of Baker Hughes INTEQ technical reports.
- Include all the relevant information for each major topic within the Drilling and Engineering section of the wellsite “Final Well Report.

Additional Review/Reading Material

Hicks, G., and C. Valore Sr., *Handbook Of Effective Technical Communications*, McGraw-Hill Book Co., New York, 1989

Houp, K., and T. Pearsall, *Reporting Technical Information*, McMillan Publishing Co., New York, 1984

Murray, Melba, *Engineered Report Writing*, PennWell Publishing Co., Tulsa, 1969

Shipley Associates, *Writing In The World Of Work*, Boutiful, Utah, 1985

The American Geological Institute, *Dictionary Of Geological Terms*, Anchor Press/Doubleday, New York, 1960

Watkins, F, et al., *Practical English Handbook*, Houghton Miffin Co., Boston, 1978

Technical Writing Techniques

The most efficient, and easiest, way to produce good written material is to follow a proven procedure. Until you have enough experience to develop the procedure that suits your, and Baker Hughes INTEQ's, particular requirements, you must use the experience of other writers. The checklist presented below summarizes the steps used by technical writers from around the world. This list will be useful whether you are just beginning to write technical reports or have written them for many years. By following this checklist, you will be able to prepare for any technical writing task.

Checklist For Technical Writing

1. *Before beginning, classify the technical writing task:* The Final Well Report (FWR), and in particular the Drilling and Engineering section, is an “engineering report”.
2. *Determine the desired length of the written work:* The length of the FWR is determined by company recommendations, modified by the amount of data/information to be presented.
3. *Define the reason for writing the piece:* The FWR is used to report findings, conclusions and recommendations concerning the well that was drilled. Additional reasons for the FWR are to persuade the client to continue to use our services and to publicize our new products and services.
4. *Classify the typical readers of the work:* The typical readers of The FWR will be between 25 and 50 years of age and probably have at least a Masters degree. They will probably be an engineer or geologist with good reading skills, and will use the FWR for business reasons.
5. *Collect data you will need for your writing:* Most of the data will come from the logging unit’s data collection devices (i.e. computers, chart recorders, etc.). Additional data will come from the logging geologists and DrillByte operators working at the wellsite.
6. *Get additional data from other sources:* During the course of the well much information can be collected from discussions with others at the wellsite, by observing equipment and/or operations as they are in progress, by studying the well prognosis, and visiting the Baker Hughes INTEQ or clients office for discussions.

7. *Determine what specifications govern the writing:* There is an FWR format and it usually uses a “canned” selection of questions/statements which are to be answered.

8. *Determine deadlines for each stage of the writing task:* Normally, rough drafts of the FWR are required after each casing point and at the end of the well. These deadlines also include when the final version of the report is due, when the illustrations or plots/prints are due, and when all are to be delivered to the client.

9. *Estimate the writing time and cost:* This includes how long it will take to prepare the rough draft of the report, the final draft, running the plots/prints, and office time required. Costs are incurred for copying, revising and correcting errors in the report.

10. *Establish contact with specialists:* Within Baker Hughes INTEQ, there are technical specialists in charge of FWR review, preparing the final draft and plots, and delivery to the client. They should be able to answer any questions you may have during the preparation of your FWR report.

11. *Assemble your data:* Use the FWR capabilities of the computer/ workstation. Use the technical library of the region/area office. The unit diary will prove invaluable. The logs and plots which are produced during the well will be necessary. During the course of the well, sort the data and keep only what is useful.

12. *Prepare a rough outline:* During the course of the well, assign temporary headings for the various subjects that will be discussed (i.e. hole sections, casing operations, surveys, borehole problems, etc.).

13. *List the available data in random order:* This will include; types of bits, casing types and weights, drillstring configurations, drilling problems and remedies, survey calculations, drilling parameters and modifications. These, and other data, should be entered under the headings in the rough outline.

14. *Regroup the data under “Introduction”, “Body”, and “Conclusion”:* This format will be used whether it pertains to a specific hole section or to the entire Drilling Engineering section.

15. *Prepare the final outline from the regrouped data:* Using the proper format, decide on the order of data presentation, based on; order of importance, order of events, etc. Baker Hughes INTEQ usually uses an order-of-events arrangement to present the data in chronological order. Use only short clauses, sentences or phrases in this outline. Indicate where any plots/illustrations will be referenced.

16. *Have the outline checked by the pertinent technical specialists:* Again, the regional/business unit technical specialists who routinely check the FWR's can provide meaningful input and recommendations to your outline. Then make the appropriate changes.

17. *Collect and evaluate the plots/prints for the report:* Study these plots/prints and be certain they are helpful to the reader, also do they illustrate what you want to say, and are they labeled properly. Indicate in the outline the size of each plot (i.e. 8.5 x 11, 8.5 x 17, etc.). Recheck the number of plots/prints in the report; are there too many, not enough, located in the wrong part of the section, etc.

18. *Begin your writing - take care to write convincingly:*

    a. Be certain your statements are exact.

    b. Be sure you know what you are writing about.

    c. Write for your readers.

    d. Use words that will build the readers interest.

    e. Try to use short sentences (the average sentence length should not exceed 20 words).

    f. Alternate short and long sentences and paragraphs.

    g. Define any words your readers will not comprehend.

    h. Be specific, avoid vaguely worded facts

       1. Use exact names/abbreviations of equipment, tools, etc.

       2. Provide paragraph or section numbers when referring to previously presented material

       3. Refer to plots and tables by their numbers

       4. Use clear language

       5. Be brief

    i. Write out the captions for the plots, prints, and tables

    j. Write the conclusion, summary, table of contents, etc.

19. *Finish the writing - then review the text:* Allow some time to elapse between the completion of the writing and the start of the review. Read the text for clarity, conciseness and comprehensiveness. Then;

    a. Check the technical content

    b. Check all main and secondary headings

c. Evaluate the summary for clarity

d. Check the proportions of the entire written piece - is any portion too long or too short

e. See that all plots and table references are correct

f. Check the plot captions. It is best, at this point, to have someone else read the report for errors in grammar and usage.

20. *Ensure that your report is finalized properly:* Make sure the report is typed and assembled according to business unit/ regional/Baker Hughes INTEQ requirements. Has it been bound and copied to the clients specifications. Maintain a file copy.

If you use this checklist regularly when preparing your Final Well Report, you will find that you will produce better reports in less time. Most technical writers spend approximately 80% of their time preparing to write (i.e. collecting data. organizing the outline, etc.) and only 20% of their time doing the actual writing. If you can reduce the preparation time, you will have more time to devote to the writing.

Grammar Review

You need not memorize the meaning of sentence, subject, verb, and the like. But read the definitions in this special glossary, whenever you have a chance. After a few readings you will know the meaning of most of these thirty-five key terms. Then, if you begin to misuse one of the parts of speech, a phrase, or clause, your mind will become more alert and you'll correct the error before it occurs. The terms selected for this glossary are those you'll need most often in technical writing. The definitions are short and easy to understand and use. Study this glossary and see how useful grammar can be.

Active Voice Form of verb used when the subject of the sentence acts. (This form is preferred for direct, personalized expression.)

The mud pump *discharges* 300 gal/min.

The borehole *collapsed* during a trip.

Adjust the chromatograph's timing once a month.

Adjective Word that modifies a noun or pronoun; used to describe, tell or number.

The *large noisy* helicopter took off quickly.
(Two adjectives, both modifying *helicopter*.)

Business was *good* during the *last* month of the year.

Three rigs sank off the reef.

Adjective Clause
Subordinate clause used as an adjective; describes or limits noun or pronoun.

He is the engineer *whom we met in Texas*.

They use chromatographs *that have automatic cycles*.

Adverb Modifies verb, adjective, or other adverbs; shows manner, degree, time, or place.

The burner ignited *quickly*. (Manner)

There is *only* one petroleum engineer. (Degree)

Begin your writing *now*. (Time)

The logging unit will be placed *here*. (Place)

Adverbial Clause

Subordinate clause used as an adverb; answers a question of how, why, when, where, how much.

The rig will be built *as the engineers specified.* (How)

A fire started *after the motor failed.* (When)

Antecedent Word or group of words to which a pronoun refers.

The *motor* that failed was new.
(*Motor* is antecedent of the relative pronoun *that.*)

Article Either definite (*the*) or indefinite (*a, an*); used as adjectives.

Auxiliary Verb used to form other verbs; *will, shall, can, may, have, be, do, must,* and *ought* are typical auxiliaries.

The report *had been* reviewed by the supervisor.

She *will* design the plot format.

Clause Group of words containing subject and verb, used as part of a sentence. May be independent (a sentence) or dependent (as subject and predicate but does not express a complete thought).

The collar fell but *it didn't injure anyone.*
(Two independent clauses; each is a simple sentence.)

When the company-man was fired, the crew cheered.
(Dependent clause; has subject and very, but does not express a complete thought.)

Complex Sentence

Contains one independent and one or more dependent clauses.

The helicopter crashed *while it was approaching the rig.*

Compound Sentence

Contains two or more independent clauses and no dependent clauses.

The well was tested and *it went into production.*

Conjunction Word used to connect clauses, phrases, or words. *And, but, or, for, nor, so, yet* (coordinating conjunctions) connect clauses, phrases, or words of equal importance.

She went to the logging unit *but* she returned immediately.

After, although, as (not like), because, if, since, that, unless, when, while (subordinating conjunctions) connect subordinate (dependent) clauses to independent clauses.

The report will be read *if* it is acceptable

Either...or, neither...nor, both...and, etc. (correlative conjunctions) are used in pairs.

Either the Field Supervisor *or* his assistant will write the report.

Dependent Clause
Contains subject and verb but does not express a complete thought.

Ellipsis Omission of words from a sentence or clause without affecting the clarity of the expression.

Use gas detectors when (it is) necessary.

Mercury is heavier than lead (is heavy).

Gerund Noun formed by adding *ing* to a verb. Used like a noun but can take an object or an adverbial modifier.

Writing a FWR is good mental discipline.

Good *logging* requires skill and training.

Independent Clause
Contains subject and verb, and states a complete thought; can be a simple sentence; may be introduced by a coordinating conjunction.

All geologists can write. But not all geologists are good writers.

Infinitive Verb preceded by *to* or by another verb form; the simple form of the verb. Can be used as a noun, adverb, or part of a verb.

His greatest desire is to *design* logging units.

To *plan* the job, he worked late.

This helicopter can *carry* 20 passengers.

Modifier Word or group of words used as an adjective or adverb to qualify, limit, or describe another word or group of words.

The *engineer* wrote the *report* at his office.

A *logger* collided with a roughneck in the galley.

Object Word or words (noun, pronoun, phrase, or clause used as a noun) which receives the action of a verb or is governed by a preposition.

They placed the *samples* on the helicopter *pad.*
(*Samples* is the object of the verb;
pad is the object of the preposition *on.)*

Participle Word derived from a verb but having the characteristics of both verb and adjective. Present participle ends in *ing;* past participle can end in *ed, en, t, n, d.*

The *rising* pressure caused a head loss.

The *recorded* pressure was 20 psi.

Parts of Speech
Names of the words used in a sentence. There are eight parts of speech-noun, pronoun, verb, adjective, adverb, preposition, conjunction, and interjection. The interjection is probably the least used in technical writing.

Passive Voice Verb form which indicates the subject is being acted upon.

The report *was written* by the logger.
(The same thought expressed in active voice would be:
The logger *wrote* the report.)

Person Relation between the verb and subject showing whether a person is speaking (first person), spoken to (second person), or spoken of (third person).

I *am* a technical writer.

You are a technical writer.

He (or *she*) *is* a technical writer.

Phrase Group of related words without a subject or predicate; used as a part of speech.

Hurried writing of *Final Well Reports* causes confusion. *(Of Final Well Reports* is a participle phrase used as a noun.)

Predicate Word or words in a sentence or clause that make a statement about the subject.

The engineer *surveyed the wellsite.*

Most well-written technical books *follow a logical line of thought from the known to the unknown.*

Preposition Relation word that connects a noun or pronoun to some other element in the sentence.

The work-boat crashed *into* the rig.

Make an outline *of every* proposed report.

Pronoun Word used in place of a noun. The six types of pronouns are: (1) personal (*I, we, you, he, she, it, they);* (2) interrogative *(who, which, what);* (3) relative *(who, which, that);* (4) demonstrative *(this, that, these, those);* (5) indefinite *(one, nobody, someone, anything, etc.)* (6) reflexive *(myself, yourselves, himself, etc.).*

Sentence Group of words expressing a complete thought; contains a subject and a predicate.

He *logged*. (Subject is *he;* predicate is *logged.*)

Mad-Dog, the driller, smiled broadly as he began to chew the tobacco. (Subject in italic; predicate in roman.)

Subject Word or group of words naming the person or thing about which something is said in a sentence.

Some *engineers* in industry write their own reports. (Simple subject)

Some engineers in industry write their own reports. (Complete subject)

Some engineers and geologists write their own reports. (Compound subject)

Tense Change in verb form to show the time of the action. The English language has six tenses: present, past, future, present perfect, past perfect, future perfect.

Verb Word or group of words expressing action or a state of being.

Technical writing *is* a new profession.

He *wrote* the paper for a geological society.

Note: *A verb should always agree with its subject in number and person. Examples: I am; You are.*

Verbal Having the nature of or derived from a verb, but used as a noun or adjective. In the English language, infinitives, gerunds, and participles are verbals.

Voice Form of a verb that shows whether the subject acts or is acted upon.

The logging geologist *opened* the sample bag. (Active voice)

The sample bag *was opened* by the logging geologist. (Passive voice)

Final Well Report

Information Collection

During the course of a well, there is a tremendous amount of engineering data which must be collected to ensure an accurate and comprehensive Final Well Report. Make use of this information when writing the Drilling and Engineering section of the FWR. This type of information is best suited for Tables and Plots, which can be used as references at the end of the section or included as appendices at the end of the report.

Drillstring/BHA Make-up

Drill Bit - type, name and size

Drill Collars - type, size (OD & ID) and number

Specialized Tools - Stabilizers, X/O's, PDM, Turbine, MWD, Jars, etc.

Heavyweight - size (OD & ID), number

Drillpipe - size (OD & ID)

Reasons for Using - Location of Neutral Point, Build/Hold/Drop Assembly, Packed or Inverted Assembly, etc.

Casing Program

Hole Size - areas of washout, tight spots, caliper size

Casing Size - Grade, OD's and ID's, Weight per foot

Casing Shoe Depths - Measured and True Vertical

Accessories - float collar, centralizers, scratchers, liner hanger

Possible Plots: casing running speeds (surge pressures) make-up torque picture of casing, depths, location of accessories

Cementing Program

Cement Class - Lead and Tail slurries

Washes and Spacers - pre-flush type, volumes

Additives - types, amounts

Cement Volume Requirements - sacks, ft^3, weight, yield

Mixing Water Requirements - gallons per sack

Displacement rate, pumping time and setting time

Possible Plots: Displacement Rate and Pumping Time

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Drilling Fluid Program

Type of Mud System - depth changed or modified

Additives - depth when additions are made, why added

Mud Rheology - depth changed, reasons changed

Possible Plots: Pressure Losses (Flow rates, annular velocity)
Rheology Changes and Property Changes

Bit Program

Type of Bits - Size, IADC code and Manufacturer name

Bit Operating Parameters - Weight-on-Bit, Rotary Speed, Pump Pressure

Bit Hydraulics - Pressure Losses, Nozzle Velocity, Nozzle/TFA Size

Bit Grading - IADC Format

Possible Plots: Cost-per-Foot vs Instantaneous Cost
Break Even Analysis
Number of Bit Runs vs Depth
Nozzle Selection

Directional Drilling Program

Location - Coordinates, Block, Area

Drillstring Assemblies - Building, Holding, Dropping

Type of Well - Vertical, Directional, Horizontal

Survey Data and Calculations

Type of Survey - Single-shot, MWD, Gyro

Borehole Trajectory - Build-and-Hold, Build-Hold-and-Drop, Modified

Target Location(s)

Well Problems

Stuck Pipe - Type, Causes, Location, Remedial Measures, Results

Fishing Operations - Tools used, techniques

Lost Circulation - Type, Causes, Location, Remedial Measures, Results

Well Kicks - Pressures, Pit Gain, Kill Procedures, Results

Twist-Off - Causes, Location, Remedial Measures, Results

Shale Problems - Type, Location, Remedial Measures, Results

Brochure

General Catalog EC - 1990-1991

Self-Check Exercises

1. Who is the typical reader of the drilling and engineering section of the Final Well Report?

   ____

   ____

   ____

2. What determines the length of the FWR?

   ____

   ____

3. What data can be integrated into the FWR, in addition to that available from the logging unit, and where can it be obtained?

   ____

   ____

4. List several rules that should be followed to ensure that the client will have a readable, useful FWR.

   ____

   ____

   ____

5. Once the FWR text is read for clarity and conciseness, what is the next step to follow?

   ____

   ____

6. What type of cementing information should be included in the FWR?

   ____

   ____

   ____

7. What are some deadlines that should be used when preparing the FWR?

____

____

____

8. Once the available data for the FWR has been listed in a random order, it should be regrouped under three general headings. What are these headings?

   a. ____

   b. ____

   c. ____

End Of Manual Return Exercises

1. Name the classifications of drilling fluid systems.

2. Excess filter cake can lead to four basic problems. Name them.

3. Give the generalizations that have been made concerning cuttings transport.

4. Compute the volume and density of a mud composed of 25 lb of bentonite, 60 lb of barite, and 1 bbl of fresh water.

   Where: Density of Clay = 910 lb/bbl
   Density of Barite = 1470 lb/bbl
   Density of Water = 350 lb/bbl

5. There are 500 barrels of an 18.0 lb/gal mud with the following composition: Oil = 51%, Water = 9%, Solids = 40%

   Determine:

   1) The oil/water ratio.

   2) The fluid type and amount to increase the oil ratio to 90/10.

   3) The fluid type and amount to decrease the oil ratio to 80/20.

6. What is the velocity (ft/min and ft/sec) of the mud inside drill collars with an I.D. of 2 inches and a pump rate of 300 gpm?

7. Assume a flow rate of 920 gpm in a 17.5-inch hole with 4.5-inch drill pipe. What is the annular velocity (ft/min and ft/sec) of the mud?

8. If the borehole contains a drilling mud of 15.0 ppg to a depth of 8000 ft and 10.0 ppg to TD of 10,500 ft, what is the effective mud density at the bottom of the hole?

9. What is the casing standard called “burst strength”?

10. What three important properties of cement that must be known when water is added for hydration?

11. What is the bulk volume and absolute volume of one sack of cement (94 lb)?

12. Determine the water requirement and yield for the following cement slurry 30:70:3% gel at 15.0 ppg.

13. Calculate the absolute volume, mixing water, yield, density, and mixing water per sack for the following class H cement:

Cement: 70: 30: 4%(fly ash / cement / gel)

Given:

	Bulk Vol.	**Abs. Vol**	**Abs. Vol/lb**	**Water Needed**
Fly Ash	74	0.478	0.00646	40% of ash
Cement	94	0.478	0.0051	46% of cmt
Gel	94	0.650	0.00691	530% of gel

14. Describe the circumstances when a casing whipstock could be used.

15. What nozzles sizes would you fit into a 12.25-inch tri-cone bit for jetting purposes?

16. List a possible BHA you would use to jet drill a 12.25 pilot hole starting from vertical.

17. You are going to perform a kick-off in a 17.5-inch hole with a Navi-drill and a bent sub. The required build-up is $2.5^{o}/100$ ft. List the BHA you would use.

18. Design two specific NDS assemblies to drill the two well sections defined by the plan below.

Well Section	Build Rate	Hole Size	Bit Type
1,500' to 7,000' M.D.	2.0°/100'	171/2"	Rock
7,000' to 11,000' M.D.	-1.0°/100'	121/4"	PDC

19. What is the sequence of events that normally leads to a kick being detected during the drilling process?

20. What are four major considerations when deciding upon the best manner to kill a kick?

21. What three factors determine the maximum casing pressure that can be allowed during the killing process?

22. What general procedures should be followed to shut-in an onshore well once a kick has been recognized?

23. Why is the choke opened prior to closing the annular preventer or pipe rams?

24. How can you obtain the SIDP when a float valve is in the drillstring (assume the slow circulation rate pressure is known)?

25. What options are available if the maximum casing pressure is reached while circulating out a kick?

26. Calculate the hydrostatic pressure reduction when pulling ten, 93 ft stands of drill pipe from the hole without filling the hole.

    Given:

Hole Size	=	8.5 inches
Drillpipe	=	4.5-inch x 3.74-inch
Collars	=	7-inch x 2.5-inch
Mud Density	=	15.0 lb/gal

27. Determine:

    A) The maximum shut-in pressure without fracturing the shoe.

    B) The reservoir pressure.

    C) The initial circulating pressure.

    D) The final circulating pressure

    E) The length of the kick.

    F) The density and type of the influx fluids.

    Given:

Depth	=	12000ft
MW	=	12.2 ppg
Hole Size	=	9 7/8”
Collars	=	8" x 500ft
Pipe	=	5.0 inches
Leak Off	=	14.5 ppg
SCP	=	200 psi
SIDP	=	300 psi
SICP	=	400 psi
Pit Gain	=	10 bbl

28. Journal angles in tri-cone bits vary with depending on the relative hardness of the formation. What are approximate angles that are used with soft, medium, and hard lithologies?

29. Discuss the three types of jet nozzles used in tri-cone bits.

30. What are the six components of the bearing structure in a sealed roller bearing bit?

31. What are the drilling mechanisms for soft, medium and hard formation bits?

32. When using PDC bits, there are many precautions and drilling parameters that should be considered so the bit will run as efficiently and economical as possible. List seven:

33. What are the four criteria used to describe diamond quality in diamond bits?

34. What are the five major operating parameters that must be considered when deciding run a diamond bit?

35. What will cause the cost per foot to increase?

36. The standard cost-per-foot formula makes no allowance for miscellaneous variations in operating costs. List four items that are included in these variations:

37. A recommended bit program is being prepared for a new well using bit performance records from nearby wells. Drilling performance records for three bits are shown for a thick limestone formation at 9,000 ft. Determine which bit would be the best choice.

Rig Cost = $400/hr

Bit	**Cost Bit ($)**	**Drilling Time**	**Trip Time**	**Feet Drilled**
A	800	14.8	7.0	204.2
B	4900	57.7	7.0	727.0
C	4500	95.8	7.0	977.2

38. What are four disadvantages of long-radius horizontal wells?

39. What are six characteristics of an ideal reservoir for a horizontal drilling?.

40. Why is torque not a good indicator of lithology changes in horizontal wells?

41. Find the air weight required to get the desired weight on the bit.

    a Desired WOB 40,000 lbs; mud density 16 ppg; hole angle 20°; safety factor 10%.
    Air Weight Required = ____________________

    b Desired WOB 40,000 lbs; mud density 13 ppg; hole angle 48°; safety factor 10%.
    Air Weight Required = ____________________

    c Desired WOB 20,000 lbs; mud density 13 ppg; hole angle 20°; safety factor 10%.
    Air Weight Required = ____________________

42. Find the number of joints required for the following air weights:

    a 62,000 lbs air weight needed; 30 joints of 4.5-inch heavy weight are to be used. How many 7-1/4 inch O.D., 2-1/2 inch I.D. drill collars are needed?

    b 35,000 lbs air weight needed; two 7-1/2 inch O.D., 2 inch I.D. drill collars, three 6 inch O.D., 2-1/2 inch I.D. drill collars are available. How many joints of 3-1/2 inch heavy weight are needed?

43. Calculate the critical buckling load for the drill pipe:

    a 4-1/2 inch New, grade E drill pipe (ID = 3.826-inch, tool joint = 6.5-inch) with an approximate weight of 18.37 lb/ft in a 8-1/2 inch hole with 60° inclination and a mud density of 11.5 ppg.

44. A well has been kicked off by jetting and the angle built to 15°. The hole has been opened to 17½” diameter. It is now planned to run a conventional angle-build rotary BHA to increase the inclination to 62.0°, which is the planned inclination angle of the tangent section. The build up section will all be in 17½” hole. The planned build-up rate is 3.0°/100’; the well is “on the line” on the vertical plan. Design a suitable rotary BHA using a soft formation tri-cone bit and incorporating an MWD tool. State the actual gauge of stabilizers to be used and suggest possible drilling parameters.

45. Write down a packed assembly which could be used to hold angle in the tangent section of a directional well. Assume the inclination angle is in the range 45° - 50° and that the 12¼” hole section is being drilled. Indicate the gauge of all stabilizers. Suggest possible drilling parameters, assuming you are drilling medium hardness formation. State whether a PDC or roller cone bit is to be used.

Drill Collar Weights
(pounds per foot)

OD/ID	1”	1-1/4”	1-1/2”	1-3/4”	2”	2-1/4”	2-1/2”	2-13/16	3”	3-1/4”	3-1/2”	3-3/4”
3” OD	21	20	18									
3-1/8”	22	22	20									
3-1/4”	26	24	22									
3-1/2”	30	29	27									
3-3/4”	35	33	32									
4” OD	40	39	37	35	32	29						
4-1/8”	43	41	39	37	35	32						
4-1/4”	46	44	42	40	38	35						
4-1/2”	51	50	48	46	43	41						
4-3/4”			54	52	50	47	44					
5” OD			61	59	56	53	50					
5-1/4”			68	65	63	60	57					
5-1/2”			75	73	70	67	64	60				
5-3/4”			82	80	78	75	72	67	64	60		
6” OD			90	88	85	83	79	75	72	68		
6-1/4”			98	96	94	91	88	83	80	76	72	
6-1/2”			107	105	102	99	96	91	89	85	80	
6-3/4”			116	114	111	108	105	100	98	93	89	
7” OD			125	123	120	117	114	110	107	103	98	93
7-1/4”			134	132	130	127	124	119	116	112	108	103
7-1/2”			144	142	139	137	133	129	126	122	117	113
7-3/4”			154	152	150	147	144	139	136	132	128	123
8” OD			165	163	160	157	154	150	147	143	138	133
8-1/4”			176	174	171	168	165	160	158	154	149	144
8-1/2”			187	185	182	179	176	172	169	165	160	155
9” OD			210	208	206	203	200	195	192	188	184	179
9-1/2”			234	232	230	227	224	220	216	212	209	206
9-3/4”			248	245	243	240	237	232	229	225	221	216

Answers to Self-Help Exercises
Chapter 1 - Drilling Fluids And Fluid Hydraulics

1. a) Base Liquid
   b) Dispersed Solids
   c) Dissolved Solids

2. a) Will not hydrate clays
   b) Good lubricating properties
   c) Normally, higher drill rates

3. Emulsifier

4. Electrical Stability

5. Shear Stress

6. Yield Stress

7. Weak

8. a) Dilution
   b) Shaker Screens
   c) Centrifuge
   d) DeSander or DeSilter

9. Weak

10. H_2S and CO_2

11. $V_1W_1 + V_2W_2 .... = V_FW_F$

12. Total lb = 37400 lb (Or, 374 sacks)

    Volume Increase = 25.1 bbl barite

13. V_s = 1.56 ft/sec

14. PV = 10
    YP = 20

15. n = 0.4148
    k = 2.40

16. Hole Cleaning

17. a) Flow Rate Range

    b) Operating Pressure

18. 1587 hhp

19. Hhp = 2080 psi
    Hif = 1536 psi

20. PDC Bits: Fluid Volume
    Diamond Bits: Fluid Volume and Fluid Velocity

21. Water-Based: 2.5 to 4.5 HSI
    Oil-Based: 1.5 to 3.0 HSI

22. a) Fluid Course Area

    b) Diamond Exposure Area

23. a) Cross Pad Flow System
    b) Radial Flow System

24. It damages the face of the borehole, causing “washouts” and creates higher pressure loss.

Chapter 2 - Casing and Cementing

1. The weight of a casing joint with threads on both ends and a coupling at one end.

2. a.) P-110 / 125k psi

   b.) N-80 / 100k psi

   c.) H-40 / 60k psi

3. Clinker

4. $$AbloluteVolume(gal/\mathrm{lb}) = \frac{1}{8.34lb/\mathrm{gal}*\ \mathrm{S.G.}ofcomponent}$$

5. 60: fly ash
   40: cement
    2: additives

6. a) Low gel strength, low PV and YP

   b) Low density

   c) Low fluid loss

   d) Chemical make-up similar to the cement

7. 500 psi

8. Reduce slurry density and viscosity

9. The total slurry volume:

   2102 ft^3 + 559.2 ft^3 = 2661.2 ft^3

   The total sacks:

   901 sks + 473 sks = 1374 sks

10. Short pieces of casing used to connect the individual casing joints.

Chapter 3 - Bit Technology

1. a.) Heel bearings are roller bearings which carry most of the load and receive most of the wear.

   b.) Middle bearings are ball bearings, which hold the cone on the journal and resist thrust on longitudinal loads in either direction.

   c.) Nose bearings consist of a special case hardened bushing pressed into the nose of the cone and a male piece, and are hard faced with a special material.

2. Positive

3. a.) Soft Formations = 39 to 42^o

   b.) Medium Formations= 43 to 46^o

   c.) Hard Formations = 46 to 50^o

4. 75%, 1/2 to 3/4 dull

5. "T" type teeth

6. Solid metal bushings or direct cone to journal contact.

7. The cutting configuration

8. a.) No bearings to wear out.

   b.) No matrix to come apart.

   c.) No broken cones to fish out of the hole.

9. a.) Higher

   b.) Lower

10. a.) Single crystal

    b.) Coated

    c.) Carbonado

Chapter 4 - Drillstring Basics

1. a.) 201, 960 lbs
   b.) 165,000 lbs
   c.) 36,960 lbs

2. 14,412 feet

3. a. 58,386 lbs
   b.) 61,040 lbs
   c.) 33 joints

4. 32,400 lbs

5. a.) 66,739 lbs
   b.) 29 joints

Chapter 5- Directional Drilling

1. a. Multiple wells from offshore platforms
   b. Relief wells
   c. Controlling vertical wells
   d. Sidetracking
   e. Inaccessible locations
   f. Fault drilling
   g. Salt dome drilling
   h. Shoreline drilling

2. True North - this is the direction of the geographic north pole, which lies on the Earth's axis of rotation

   Magnetic North - This is the direction of the magnetic north pole, which lies in northern Canada.

   Grid North - the northern direction as depicted on a flat surface (i.e. a map)

3.

   S64.75E = 115.25

   N35E = 35

   S88.75W = 268.75

   N66.5W = 293.5

   S22.25E = 157.75

   N35.5W = 324.5

   S89E = 91

   N71.5E = 71.5

   S25.5W = 205.5

   N3.75W = 356.25

   S11.5E = 168.5

4. Advantage: Simple piece of equipment with little maintenance and no temperature limitations

   Disadvantages:

   a. A large number of trips are involved to complete the kick off

   b. It produces a sudden, sharp deflection in the borehole

5. Nudging is used on platforms to “spread out” the surface and conductor casings to minimize the chance of collisions.

6. This is a positive displacement motor based on the reverse of the Moineau principal. It employs a power section which consists of a rotor and stator. The stator will have one more lobe than the rotor.

7. Torque output is directional proportional to the motor's differential pressure.

8. There is no direct relationship. However, RPM is directly proportional to flow rate (at a constant torque.)

9. Reactive torque is created by the drilling fluid pushing against the stator, which forces the motor and BHA to twist counter-clockwise (turn to the left). This twisting effect changes the tool face orientation of bent subs and other directional drilling tools.

10. a. They drill a smooth, continuous curve, which minimizes doglegs and makes them more predictable.

    b. They can be used in most formations

    c. There is no rotation from the surface, allowing the use of wireline steering tools. MWD tools may also be used.

11. % Footage in Oriented Mode = [(DL - DLR) / (DLO - DLR)] x 100

    where: DL = required dogleg (°/100')
    DLO = actual dogleg when oriented (°/100')
    DLR = actual dogleg when rotary drilling (°/100')

12. a. Increasing the distance from the near-bit stabilizer to the first string stabilizer

    b. Increase in hole inclination

    c. Reduction of drill collar diameter

    d. Increase in weight-on-bit

    e. Reduction in rotary speed

    f. Reduction in flow rate (in soft formation)

13. Initially, low WOB is recommended to avoid bending the BHA towards the low side of the hole, when the drop trend is established, increase WOB until an acceptable ROP is achieved. Use high RPM (based on bit type).

14. a. When beginning a kick-off, it is recommended to have the first string stabilizer in open hole and not up in the casing to prevent hanging up or any other anomalous assembly reactions.

    b. When using a steerable motor assembly in vertical or near vertical holes, the actual dogleg may be less than the calculated TGDS.

    c. Initially, during a kick-off, observe the actual oriented dogleg severity for the steerable assembly over an interval of at least 60 feet. Constant monitoring of the actual oriented dogleg severity is necessary to plan subsequent oriented/rotary drilling intervals.

    d. Minimizing rotary speed will slightly increase the fulcrum effect. This practice can reduce oriented drilling intervals.

    e. During the initial stage of a kick-off from vertical, stabilizer hang-up can occur. This problem may exist until the wellbore is inclined and/or the first string stabilizer enters the curved, oriented hole.

    f. Consider beginning the kick-off early; this can reduce oriented drilling requirements and the maximum inclination of the wellpath.

15. By moving the placement higher up in the BHA will make it harder to get away from vertical in a kick-off, however, once an initial inclination is achieved, the rate of build is often greater than the TGDS. For flat turns or for dropping angle, increasing the distance from the motor to the first string stabilizer will reduce the dogleg.

16. If the first string stabilizer diameter is decreased to less than the UBHS, 1) in an upward toolface orientation, the oriented dogleg will be increased, 2) in a downward orientation, the oriented dogleg is reduced.

17. a. After observing NDS directional tendencies over a minimum of 200 ft of rotary drilled interval, a plan for drilling long distances between orientations should be established. This plan should minimize the number of orientation toolsets and maximize penetration rate.

    b. Oriented drilling intervals should be minimized. Oriented drilling in a tangent or hold section is performed to correct the present wellpath and to compensate for anticipated trends.

    c. Never let the drilled wellpath get too far from the planned trajectory, because “drilling on the line” can be significantly more expensive. As surveys are obtained, calculate and plot the position on both horizontal and vertical plans. At all times there must be a feasible course to drill from the current location to the intended target.

Chapter 6 - Horizontal Wells

1. Short Radius: 100^{o} / 100 ft

   Medium Radius: 10 to 50^{o} / 100 ft

   Long Radius: Less than 10^{o} / 100 ft

2. a.) Downhole tools now permit deviation and azimuth measurements while drilling.

   b.) Downhole motors are now steerable and have extended lives.

   c.) Drilling fluids can be tailored to meet most hole cleaning or formation stabilization requirements.

   d.) Bending stresses and buckling forces that act on drill pipe in horizontal holes can be pre-calculated and designed for.

   e.) Evacuation of cuttings from horizontal holes is now achieved through appropriate annular velocities.

   f.) Horizontal holes are now routinely logged, cased, perforated, and selectively treated.

3. a.) Accelerated field production.

   b.) Increased ultimate recovery over a longer well life.

   c.) Reduced drilling infrastructure costs.

   d.) Improved reservoir knowledge.

4. Short Radius: 40 to 20 ft

   Medium Radius: 700 to 125 ft

   Long Radius: 3000 to 1000 ft

5. a.) The hole's vertical location in the reservoir.

   b.) The location of the gas/oil/water contacts.

   c.) The presence of lateral geologic changes.

6. a.) Bit rotary speeds vary widely (rotary vs steering modes)

   b.) Bit weights vary widely (as above)

   c.) Surface weight on bit may not reflect bottom hole WOB.

7. It may indicate that the cuttings are not being successfully circulated past the build section.

8. You need a solid tracer with properties similar to cuttings. The cuttings will take longer to reach the surface because they will roll along the borehole “low side” in the build and horizontal sections.

9. Leaving; stringers

Chapter 7 - Stuck Pipe

1. a.) Monitor the drill rate for changes
   b.) Compare the amount of cuttings with previous samples
   c.) Check the borehole's deviation
   d.) Monitor annular velocities
   e.) Determine the actual hole volume/size

2. High CEC values can assist in pin-pointing reactive shales and geopressured zones.

3. Increased torque is the most common indicator during reaming.

4. The difference between the mud's hydrostatic pressure and the formation's pore pressure.

5. A stickometer

6. The first step is to establish circulation.

7. a.) work the drillstring to break up the pieces of formation
   b.) pump down an inhibited HCl pill to dissolve the rock

8. A low viscous pill is used to disturb the cuttings bed, followed by a high viscous pill to carry out the cuttings.

9. Soft cement or cement which has not hardened

Chapter 8 - Well Control

1. a.) Failure to keep the hole full.
   b.) Swabbing.
   c.) Insufficient mud density.
   d.) Poor well planning.
   e.) Lost circulation.

2. a.) The well may flow when the pumps are first shut off.
   b.) An increase in pit volume may be noticed only after the connection.
   c.) Similar pump pressure and rate changes to those experienced while drilling may be noticed after successive connections. However, the flow rate will increase during each connection.
   d.) Mud density reductions may be noticed when the mud associated with the connection period is circulated to the surface.

3. The Engineer's Method

4. a.) The circulating pressure at the kill rate.
   b.) The surface to bit time at the kill rate.
   c.) The bit to surface time at the kill rate.
   d.) The maximum allowable surface annular pressure.
   e.) The formulas used for calculating the kill mud density.
   f.) Formulas for calculating the change in circulating pressure due to the effect of the heavier mud weight.
   g.) The client's policies on safety factors and trip margins.

5. To circulate out the kick fluids; to circulate around the proper mud weight to kill the well.

6. It is the most complicated and unpredictable of the three types of killing procedures.

7. Snubbing means that downward force must be applied to counteract the upward force exerted by the kick. If the kick is not exerting upward force greater than the string weight, the weight of the drill string can be used to “strip” into the hole.

8. Pipe rams have a hemispherical cutout to seal the hole around the drillpipe. Shear rams “shear” the drillpipe and seal against themselves.

9. a.) It can fracture formations.
   b.) It can burst the casing.
   c.) It may break the seal at a liner top.
   d.) It can plug the drillpipe.
   e.) It can be expensive through lost mud.
   f.) It may pressure up the formation, resulting in back-flow when circulation has stopped.

10. $MW_{kill} = 11.16$ ppg

11. $D_{kick} = 0.0865$ psi/ft, gas

Chapter 9 - Cost Analysis

1. Are constants

2. Total drilling cost; drilling cost-per-foot.

3. The use of a bit making the most hole.

4. Determining the costs of prior wells.

5. Bit #4 is more economical.

6. Case #2 was more economical.

Chapter 10 - Technical Writing

1. a.) Between 25 and 50 years old.
   b.) Probably has a masters degree.
   c.) Geologist or engineer with good reading skills.
   d.) Will use the FWR for business purposes.

2. The company recommendations, modified by the amount of data/ information to be presented.

3. a.) Discussions with non-INTEQ personnel at the wellsite.
   b.) Observing equipment and/or operations as they are in progress.
   c.) By studying the well prognosis.
   d.) Visiting the INTEQ or client's office for discussions.

4. a.) Be certain your statements are exact.
   b.) Be sure you know what you are writing about.
   c.) Write for your readers.
   d.) Use words that will build the readers interest.
   e.) Try to avoid excessively long sentences.
   f.) Alternate long and short sentences and paragraphs.
   g.) Define any words that your readers may not understand.
   h.) Be specific; avoid vaguely worded facts.

5. a.) Check the technical content.
   b.) Check all the main and secondary headings.
   c.) Evaluate the summary for clarity.
   d.) Check to see if any portion of the report is too long or too short.
   e.) Be sure that all plots and table references are correct.
   f.) Check the plot captions and titles.

6. a.) Cement Class - Lead and Tail Slurries
   b.) Washes and Spacers - pre-flush type, volumes
   c.) Additives
   d.) Cement Volume Requirements - sacks, ft^3, weight, yield
   e.) Mixing water requirements - gallons per sack
   f.) Displacement rate, pumping time, and setting time

7. a.) Rough drafts at each casing point.
   b.) When the final version of the text is due.
   c.) When the illustrations or plots/prints are due.
   d.) When the client should be getting the final product.

8. a.) Introduction
   b.) Body
   c.) Conclusion