Drilling Engineering

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Preface

Drilling engineering is a challenging discipline in the oil patch. It goes beyond what is found in textbooks. The technological advances in the past two decades have been very significant. These advances have allowed the oil industry worldwide to economically and successfully exploit oil and gas fields that may have not been possible before.

The fundamentals of fluid mechanics and solid mechanics, along with the basic scientific concepts of chemistry, form the basis of drilling engineering. The rewards and successes of drilling projects are predicated on the ability of the drilling engineer who fully understands all the engineering aspects and equipment required to drill a usable hole at the lowest dollar per foot ($/ft), in vertical well drilling, or at the highest equivalent barrel of oil per foot (bbl/ft) in horizontal/multilateral well drilling.

In the oil industry, it is common practice to assume that problems may be encountered during the drilling process of a well and can differ from one well to the other, even in the same area. The drilling engineer has the responsibility to be able to think beyond simply the engineering equations in combating some of these problems. He or she must anticipate drilling problems, devise solutions, and choose the best alternatives. They must be intuitive, must have common sense, and be able to think quickly and decisively. In this book, the authors have prepared illustrative examples and supplementary problems that hopefully will encourage the students to cultivate their creative thinking, develop confidence in reaching independently for what is needed to solve problems, and above all, energize their common sense to make wise decisions.

The book is written for educating students in drilling engineering in a two-semester course series: Drilling I and Drilling II. It is also intended to serve as a reference to engineers in field operations. It is suggested that Drilling I cover the following chapters: chapter 1—Rotary Drilling for Oil and Natural Gas, Chapter 2—Drilling Fluids, chapter 3—Fluid Flow and Associated Pressures in the Rotary Rig Circulating System, chapter 4—Drill Bit Hydraulics, chapter 5—Transport of Drilled Cuttings, and chapter 6—Prevention and Control Mechanics of Well Blowouts; where Drilling II covers: chapter 7—Directional and Horizontal Well Drilling, chapter 8—Drill Bit Mechanics, chapter 9—Drill String Design, chapter 10—Drilling Problems and Solutions, chapter 11—Casing and Cementing Design, and Chapter 12—Well Planning in Drilling Engineering.

It is recommended that non-conventional drilling techniques, which is not included in this text, such as under-balance drilling, slim hole drilling, coiled-tubing drilling, casing drilling, etc., be given to students in Drilling II as special topics assignments.

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Rotary Drilling for Oil and Natural Gas

Introduction

Drilling for oil and natural gas requires two major constituents: manpower and hardware systems. The manpower encompasses a drilling-engineering group and a rig-operations group. The first group provides engineering support for optimum drilling operations, including rig selection and design of the mud program, casing and cementing programs, the hydraulic program, the drill bit program, the drill string program, and the well control program. After drilling begins, the daily operations are handled by the second group, which consists of a tool pusher and several drilling crews (derrick and motor personnel, drillers, etc.). The hardware systems that make up a rotary drilling rig are

1. A power generation system
2. A hoisting system
3. A drilling fluid circulating system
4. A rotary system
5. Well blowout control systems
6. A drilling data acquisition and monitoring system

This chapter will primarily address the form and functions of these systems and their various components.

The Process of Rotary Drilling

Whether drilling a *vertical hole* or a *directional hole* (fig. 1–1) for the purpose of producing oil and/or natural gas, several elements are needed to drill the hole successfully and economically (illustrated in fig. 1–2), including

- A force acting downward on a drill bit
- Rotation of the drill bit
- Circulation of fluid, called drilling fluid (liquid, gas, or gasified liquid), from the surface through the tubular, called the drill string, and back to the surface through the annular space, the area between the hole wall and the outside wall of the drill string

This method neglects the effect of buoyancy and the weight of the block and hook. In straight holes, buoyancy can be assumed to be offset by pipe drag. In directional holes, drag has to be considered.

Hoisting engines should have a horsepower rating for intermittent service equal to the required drawworks horsepower rating divided by 85% efficiency. Drawworks also have a rating of line pull efficiency; this factor depends on the number of lines strung between the crown block and the traveling block. (See table 1–1.)

Table 1–1. Line pull efficiency factor

Number of Lines	Efficiency Factor
6	0.874
8	0.841
10	0.81
12	0.77
14	0.74

Example 1–4 (Line pull calculation)

What line pull is required to handle a 500,000 lb casing load with 10 lines strung?

Solution:

$$\frac{500{,}000}{(10)\ (0.810)} = 61{,}800 \text{ lbs}$$

Fluid circulating system

The function of the fluid circulating system in rotary drilling is to allow the movement of a drilling fluid from the surface to the hole bottom and back to surface again. The main components of the system include

- Mud pumps/air compressors
- High-pressure surface connections
- Drill string
- Drill bit
- Return annulus
- Mud pits
- Mud treatment equipment

Figure 1–8 shows a schematic of the system.

the annulus when no pipe is present are called blind rams. These rams, if activated while the drill string is in the hole, will not shut in the annulus. Rams that are designed to shear off drill pipe while string is in hole are referred to as shear rams. These kind of rams are activated only if all other preventers fail to shut the well.

Annular preventers. *Annular preventers* are well control devices that employ a ring of reinforced synthetic rubber as a packing unit that surround the drill string to cause the shutoff. In the full open position, the inside diameter (ID) of the packing unit is equal to the diameter of the preventer bore. These preventers will close and shut in the well regardless of the shape or diameter of the conduit that might be in the hole.

Drilling spools. *Drilling spools* are drill-through–type fittings that are placed in the BOP stack assembly to provide space between two consecutive pipe rams for temporary storage of tool joints during stripping operations and to allow attachment of the kill and choke lines.

Data Acquisition and Monitoring System

The data acquisition and monitoring system of a rotary drilling rig consists of all the devices used to monitor, analyze, display, record, and retrieve information regarding drilling operations. The parameters that are of prime concern are the following:

- Drilling rate
- Hook load
- Hole depth
- Pump pressure
- Flow rate
- Torque
- Rotary speed
- Mud density, temperature, salinity, and flow properties
- Mud tank level
- Pump strokes
- Weight on bit
- Hoisting speed

Drilling problems, such as lost circulation, well kicks, and pipe sticking, can be easily detected by the monitoring equipment. Drilling breaks, which are easily seen on the drilling rate chart, can provide information on changes of lithology and formation pressures. Excessive torques may indicate a bit bearing failure or an extremely high concentration of drilled cuttings in the wellbore annulus. A drastic increase in hook load or decrease in mud returning to the surface could indicate that a lost circulation zone has been encountered. A sudden increase in pit level indicates that formation fluids are entering the wellbore and, hence, that blowout is eminent. The proper maintenance of rotary speed, weight on bit, mud properties, and flow rates is of utmost importance for achieving optimum drilling conditions.

In conclusion, the monitoring system is the functional pulse for the entire drilling process. With the advent of personal computers and downhole measuring devices, the monitoring, recording, analysis, storage, and retrieval of drilling data has become a routine part of the process of drilling operations.

- Casing program
- Makeup water
- Potential corrosion
- Environmental impact
- Availability of products in international operations

A discussion of each of these considerations follows.

Well type. Drilling may be classified as development or wildcat drilling: In areas where drilling has been conducted previously and the geological conditions are known, additional wells to be drilled are referred to as development wells. Otherwise, it is a wildcat well, commonly referred to as an exploratory well. In the latter, the drilling fluid must be chosen so that all geological information can be obtained easily and safely. Also, the drilling fluid must be of such composition to allow quick changes to yield a fluid system suited for whatever unexpected problems are encountered. By contrast, in development wells, the drilling-fluid program is selected and the mud systems are designed along with other programs (hydraulic, drill bit, casing, etc.) to meet the criterion of minimum overall drilling cost.

Problem formations. If either the formation that is being drilled or the fluid that is being used to drill it is affected, directly or indirectly, by the other, then the formation is classified as a problem formation. Examples are

- Shale formations—water sensitive (heaving and swelling) or pressured (caving and sloughing)
- Anhydrite formations (lime or gypsum)
- Salt formation
- High-temperature formation
- Abnormal pressure formation
- Inherently fractured formation (loss circulation zones)

Shale intervals. The problems associated with the drilling of shale intervals (depending on the type of shale) are

- Mechanical pipe sticking
- High torque/drag
- Annular hole–cleaning difficulties
- Logging difficulties
- Mud contamination

Depending on the severity of the problem, adjustments to the properties of the drilling fluid may control the shale. Otherwise, very careful and specific design requirements of the drilling fluid may have to be implemented.

Anhydrite intervals. When bentonite-treated freshwater muds are used to drill anhydrite formations, the calcium ions released into the mud system will retard bentonite hydration and flocculate the mud that has been hydrated, thus affecting mud viscosity and fluid loss. Depending on the massiveness of the intervals, either the calcium ions are treated out of the system or the mud is converted to an inhibitive one (e.g., a gypsum- or lime-treated

Equivalent circulating density. In small-diameter holes, those of 9⅞ in. or less, friction pressure loss in the annulus becomes an important factor that must be taken into consideration. This pressure can cause a further, significant increase in mud weight as compared to the increase due to cuttings accumulations under low drilling rates.

The effect of friction loss is expressed in terms of mud weight and is called the *equivalent circulating density* (ECD) or the equivalent mud weight (EMW) and can be expressed as follows:

$$\mathrm{ECD} = \gamma_m + \frac{P_f}{0.052D} \tag{2.16}$$

where

γ_m is the mud weight, in lbs/gal, as measured on surface
P_f is the annulus friction loss, in psi
D is the depth, in ft, at which the ECD is being calculated

Fluid loss

Fluid loss is defined as the loss of a mud filtrate (liquid phase) into a permeable formation that is being drilled. Because of positive differential pressure (i.e., the pressure difference between the mud pressure in the wellbore and the formation pore pressure), the mud filtrate tends to flow into the formation; this results in the buildup of mud solids deposited on the wellbore walls, thus forming what is commonly referred to as mud cake (filter cake). The term *spurt loss* is used to characterize the initial loss of filtrate to formation at time practically equal to zero. After a mud cake is formed, the loss of filtrate from then on is referred to as the continuous fluid loss.

It has been pointed out in the literature that high spurt loss is advantageous, while high continuous loss is detrimental. It is the general consensus that the rate and amount of high continuous fluid loss into a formation can adversely affect the rate of penetration, water-sensitive and sloughing shale, and the producing formation and can cause differential-pressure pipe sticking. Any or all of these can occur in the field. Therefore, emphasis is placed on specifying and controlling the mud fluid loss property. However, the general tendency is to specify fluid losses much lower than necessary. This can result in drilling problems and, therefore, higher well cost. The best solution, so as not to over- or underspecify fluid loss properties, is to obtain information from offset wells in the same area.

Fluid loss tests. There are two types of tests for fluid loss measurement:

- API static filtration test (standard low pressure and temperature and high pressure and temperature)
- Dynamic filtration test

The static filtration test includes the standard API test at room temperature and 100 psi differential pressure and is the *field test* for fluid loss measurement. The high-pressure, high-temperature test is a laboratory test and is conducted at a differential pressure of 500 psi and a temperature of 300°F. The static tests are indicative of the loss of fluid and the buildup of the filter cake when the fluid is not moving.

The dynamic test represents the loss of fluid and the filter cake buildup while the drilling mud is being circulated. Dynamic tests are strictly laboratory conducted tests.

For a non-Newtonian fluid,
– Using the Bingham plastic model ($\tau = \tau_y + \mu_p \gamma$),

$$\mu_p = 300\,\frac{\theta_N}{N} - \frac{300\tau_y}{N} \tag{2.34}$$

For $N = 300$, 600 rpm,

$$\mu_p = \theta_{600} - \theta_{300} \tag{2.35a}$$

$$\tau_y = 2\theta_{300} - \theta_{600} \tag{2.35b}$$

where
μ_p = is the PV
θ_{600}, θ_{300} are the viscometer dial readings at $N = 600$ rpm and $N = 300$ rpm, respectively
τ_y is the YP in lbs/100 ft
τ_g is the gel strength in lbs/100 ft taken after mud has been thoroughly stirred and then kept undisturbed for 10 s and 10 min time at a rotational speed of three rpm.

– Using the power law fluid model ($\tau = K\gamma^n$),

$$n = 3.32\log_{10}\frac{\theta_{2N}}{\theta_N}$$

$$K = \frac{\theta_N}{\gamma_N^n} \tag{2.36}$$

where
n is the power law index
K is the consistency index

– Using the yield power law fluid model ($\tau = \tau_y + K\gamma^n$),

$$n = 3.32\log_{10}\frac{(\theta_{2N} - \theta_0)}{(\theta_N - \theta_0)} \tag{2.37}$$

$$K = \frac{(\theta_N - \theta_0)}{\gamma_N^n} \tag{2.38}$$

where θ_0 denotes zero gel (lbs/100 ft).

The shear rate, γ (in s^{-1}), imparted to a sample of drilling mud by a variable speed viscometer is commonly expressed in terms of the rotational speed, N (in rpm), of the rotating sleeve (rotor). Based on the geometry of these viscometers, the rotational speed can be converted to shear rate by the following equation:

$$\gamma = 1.7N \tag{2.39}$$

Problem 2–14. List the following:

(a) Seven criteria used in the selection of drilling fluids.
(b) The three basic types of drilling fluids.
(c) Functions of dry-air drilling fluids.
(d) The composition of drilling muds.

Problem 2–15. A kick was taken at the indicated depth for the well shown in figure 2–19 while drilling with 12 lbs/gal mud The recorded shut-in casing and shut-in drill pipe pressures were 600 psi and 800 psi, respectively. How much barite must be added to bring the well under control and maintain a 400 psi differential pressure while drilling the interval?

Nomenclature

A	Filtration area
D	Depth
D_h	Hole diameter
d_p	Particle diameter of largest dimension
D_p	Outer pipe diameter
F	Force
f_{vc}	Volume fraction of solids in cake
f_{vf}	Volume fraction of low specific gravity solids in final mixture
f_{vo}	Volume fraction of low specific gravity solids in original liquid
f_w	Volume percent of water, expressed as a fraction
h	Cake thickness
k	Cake permeability
K	Consistency index
n	Power law index
P_{df}	Drilling-fluid pressure
P_f	Annulus friction loss, in psi
P_{ff}	Formation fluid pressure
P_h	Hydrostatic pressure
Q	Flow rate, in gpm
Q_f	Amount of filtrate volume
Q_m	Total volume of mud filtered
Q_s	Volume of solids deposited in mud cake
ΔP	Differential pressure
R	Penetration rate (ROP)
t	Filtration time
v_a	Annular fluid velocity
V_a	Added material weight
V_f	Final mixture volume
V_o	Original liquid volume
v_{sp}	Particle settling velocity
W_a	Added material weight

These forces are located at r and $r + \Delta r$ in the radial direction and at L and $L + \Delta L$ along the wellbore axis, as shown in figure 3–6.

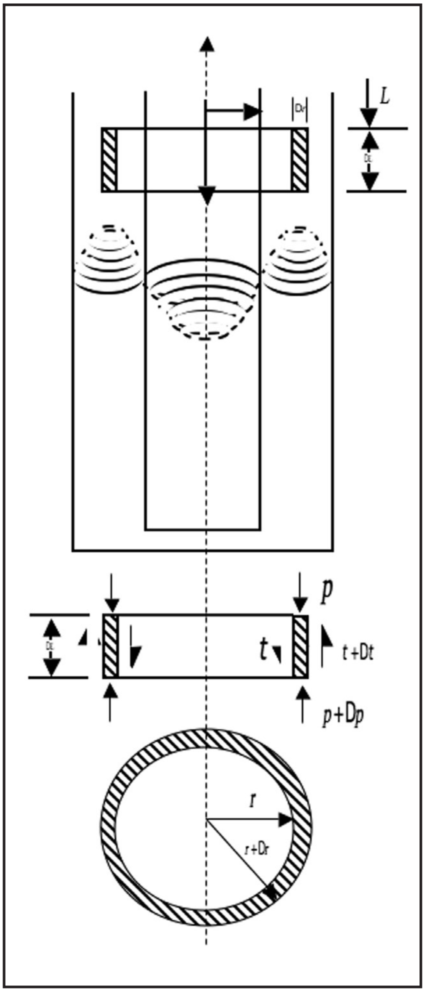

Fig. 3–6. Elements of flowing fluid

Using Newton's law of motion, $\sum \vec{F} = m\vec{a}$, where m denotes mass and a denotes acceleration. Alternatively, for a nonaccelerating fluid, as is the case here, $\sum \vec{F} = 0$.

Thus, summation of forces induced on the isolated layer of fluid owing to the fluid motion yields

$$(P_f + \Delta P_f)(2\pi r)\Delta r - P_f(2\pi r)\Delta r + (\tau + \Delta\tau)[2\pi(r + \Delta r)\Delta L] - \tau(2\pi r)\Delta L = 0 \qquad (3.23)$$