ROTARY DRILLING

Making Hole

Third Edition, Rev.

UNIT II • LESSON 1

ROTARY DRILLING SERIES

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Units of Measurement

Throughout the world, two systems of measurement dominate: the English system and the metric system. Today, the United States is one of only a few countries that employ the English system.

The English system uses the pound as the unit of weight, the foot as the unit of length, and the gallon as the unit of capacity. In the English system, for example, 1 foot equals 12 inches, 1 yard equals 36 inches, and 1 mile equals 5,280 feet or 1,760 yards.

The metric system uses the gram as the unit of weight, the metre as the unit of length, and the litre as the unit of capacity. In the metric system, 1 metre equals 10 decimetres, 100 centimetres, or 1,000 millimetres. A kilometre equals 1,000 metres. The metric system, unlike the English system, uses a base of 10; thus, it is easy to convert from one unit to another. To convert from one unit to another in the English system, you must memorize or look up the values.

In the late 1970s, the Eleventh General Conference on Weights and Measures described and adopted the Systeme International (SI) d'Unites. Conference participants based the SI system on the metric system and designed it as an international standard of measurement.

The Rotary Drilling Series gives both English and SI units. And because the SI system employs the British spelling of many of the terms, the book follows those spelling rules as well. The unit of length, for example, is metre, not meter. (Note, however, that the unit of weight is gram, not gramme.)

To aid U.S. readers in making and understanding the conversion system, we include the table on the next page.

English-Units-to-SI-Units Conversion Factors

Quantity or Property	English Units	Multiply English Units By	To Obtain These SI Units
Length, depth, or height	inches (in.)	25.4	millimetres (mm)
		2.54	centimetres (cm)
	feet (ft)	0.3048	metres (m)
	yards (yd)	0.9144	metres (m)
	miles (mi)	1609.344	metres (m)
		1.61	kilometres (km)
Hole and pipe diameters, bit size	inches (in.)	25.4	millimetres (mm)
Drilling rate	feet per hour (ft/h)	0.3048	metres per hour (m/h)
Weight on bit	pounds (lb)	0.445	decanewtons (dN)
Nozzle size	32nds of an inch	0.8	millimetres (mm)
Volume	barrels (bbl)	0.159	cubic metres (m^3)
		159	litres (L)
	gallons per stroke (gal/stroke)	0.00379	cubic metres per stroke (m^3/stroke)
	ounces (oz)	29.57	millilitres (mL)
	cubic inches ($in.^3$)	16.387	cubic centimetres (cm^3)
	cubic feet (ft^3)	28.3169	litres (L)
		0.0283	cubic metres (m^3)
	quarts (qt)	0.9464	litres (L)
	gallons (gal)	3.7854	litres (L)
	gallons (gal)	0.00379	cubic metres (m^3)
	pounds per barrel (lb/bbl)	2.895	kilograms per cubic metre (kg/m^3)
	barrels per ton (bbl/tn)	0.175	cubic metres per tonne (m^3/t)
Pump output and flow rate	gallons per minute (gpm)	0.00379	cubic metres per minute (m^3/min)
	gallons per hour (gph)	0.00379	cubic metres per hour (m^3/h)
	barrels per stroke (bbl/stroke)	0.159	cubic metres per stroke (m^3/stroke)
	barrels per minute (bbl/min)	0.159	cubic metres per minute (m^3/min)
Pressure	pounds per square inch (psi)	6.895	kilopascals (kPa)
		0.006895	megapascals (MPa)
Temperature	degrees Fahrenheit (°F)	$\frac{^\circ F - 32}{1.8}$	degrees Celsius (°C)
Mass (weight)	ounces (oz)	28.35	grams (g)
	pounds (lb)	453.59	grams (g)
		0.4536	kilograms (kg)
	tons (tn)	0.9072	tonnes (t)
	pounds per foot (lb/ft)	1.488	kilograms per metre (kg/m)
Mud weight	pounds per gallon (ppg)	119.82	kilograms per cubic metre (kg/m^3)
	pounds per cubic foot (lb/ft^3)	16.0	kilograms per cubic metre (kg/m^3)
Pressure gradient	pounds per square inch per foot (psi/ft)	22.621	kilopascals per metre (kPa/m)
Funnel viscosity	seconds per quart (s/qt)	1.057	seconds per litre (s/L)
Yield point	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Gel strength	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Filter cake thickness	32nds of an inch	0.8	millimetres (mm)
Power	horsepower (hp)	0.75	kilowatts (kW)
Area	square inches ($in.^2$)	6.45	square centimetres (cm^2)
	square feet (ft^2)	0.0929	square metres (m^2)
	square yards (yd^2)	0.8361	square metres (m^2)
	square miles (mi^2)	2.59	square kilometres (km^2)
	acre (ac)	0.40	hectare (ha)
Drilling line wear	ton-miles (tn•mi)	14.317	megajoules (MJ)
		1.459	tonne-kilometres (t•km)
Torque	foot-pounds (ft•lb)	1.3558	newton metres (N•m)

Introduction

In this chapter:

- Drilling project considerations
- Drilling contracts
- Cost per foot (metre) drilled
- Rate of penetration

It's true: to drill a hole you put the bit on the bottom and turn it to the right. In simple terms, that's how you "make hole"; but, of course, the whole story is more complicated. What type of bit do you put on bottom? How much weight do you put on the bit? Do you rotate the bit rapidly or slowly? What about mud properties? What should pump pressure be? All these questions, and more, are related and critical to drilling progress. Thus, if one factor changes, it can result in unforeseen difficulties unless the crew makes other adjustments as drilling proceeds.

A drilling contractor's goal: follow operator specifications and drill a usable hole for the least possible cost.

Drilling situations vary widely throughout the world. A successful drilling program in South Louisiana could be wrong for a contractor in Oklahoma's hard-rock country. A well plan for drilling the deep overpressured gas zones of West Texas could not be used in California's shallow tar sands. A wildcat well only a few miles from a producing field can encounter vastly different conditions. The field may be in flat-lying beds, for instance, while the wildcat may encounter steeply dipping beds. Further, not all wells are drilled vertically. The operator may specify that a deviated or a horizontal hole be kicked off at a certain depth.

To safely operate in such widely divergent conditions, every drilling operation must be carefully planned. Whatever the conditions, the drilling contractor's goal is the same: to drill a usable hole to the operator's specifications for the least possible cost. Indeed, the contractor's survival depends on meeting that goal. The contractor must usually accomplish the objectives set out in the drilling contract (fig. 1) in the shortest

Drill Bits

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In this chapter:

- Reasons for selecting a bit
- Types of bits
- Classification of bits
- Evaluation of dull bits

Bit Selection

The ideal bit is always the one that does the job for the least overall cost, but the great variety of available bits complicates the bit selection process. Manufacturers make bits for virtually every drilling need. Given reasonable time, bit manufacturers can deliver custom-designed bits for any given drilling situation. A bit supplier can review all previous drilling records in an area and deliver a customized, recommended bit program to customers (fig. 4).

Figure 4. A recommended bit or well program

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RECOMMENDED BIT PROGRAM

GEOGRAPHIC LOCATION	OPERATOR	CONTRACTOR / RIG	PREPARED FOR
Gulfo de Paria Oeste	Conoco Venezuela	Mallard 76	E. J. GILBERT
FIELD / AREA	LOCATION / WELL NUMBER	SALES REPRESENTATIVE	DATE
	Esmeralda	Raul Salazar	AUGUST 7, 1998

No.	SIZE (in)	BIT TYPE	DEPTH OUT (ft)	DIST DRLD (ft)	DRLG TIME (hrs)	ROP (ft/hr)	ACC TIME (hrs)	WOB (klb)	RPM	MUD WT (ppg)	DAYS	REMARKS
1	26	GTX-CG1	2000	2000	25.0	80.0	25.0	2 15	100 160		1.2	GT TECHNOLOGY
		Set 20 in. casing. 1.5 Days.									2.7	
2	16	GTX-CG1	4800	2800	21.0	133.3	46.0	5 30	100 160		3.8	STH / CENTER JET
3	16	GTX-CG1	7300	2500	19.5	128.2	65.5	5 30	100 180		4.7	GT TECHNOLOGY
4	16	GTX-CG1	9000	1700	14.0	121.4	79.5	5 30	100 200		5.4	
		Set 13-3/8 in. casing. 2 Days.									7.4	
5	12-1/4	GTX-C1	9100	100	5.0	20.0	84.5	5 30	100 160		7.6	DRILL OUT FLOAT EQUIP.
6	14	14RWD512	12400	3300	100.0	33.0	185	4 12	60 180		14.5	RWD OPENS HOLE TO 14"
7	8-1/2	R526U4	12401	1	1.0	1.0	186	4 12	60 180		16.6	3/4" PDC CUTTERS
		Set 11-3/4 in. casing. 2 Days.									18.6	
8	10-5/8	GT-1	12500	99	5.0	19.8	191	5 30	100 160		18.8	DRILL OUT FLOAT EQUIP.
9	12-1/4	12.25RWD51	14500	2000	90.0	22.2	281	4 12	60 180		23.0	RWD OPENS HOLE TO 12.25
10	8-1/2	R526U4	14501	1	1.0	1.0	282	4 12	60 180		25.1	3/4" PDC CUTTERS RERUN BIT
		Set 9-5/8 in. casing. 2 Days.									27.1	
11	8-1/2	R526U4	18500	3999	170.0	23.5	452	5 20	60 180		33.9	3/4" PDC CUTTERS

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Drilling Performance Records

In this chapter:

- Bit records
- Daily drilling reports
- Measurement-while-drilling systems
- Information networks

Accurate drilling performance records are of great value. They directly influence the selection of bits and help determine proper operating procedures that impact total drilling costs.

Bit records show many critical facts about the operation (fig. 44). The most important statistics describe each bit run, including bit type, drilling hours, footage drilled, nozzle size, reason pulled, and dull condition. Other information shown on the bit record includes the rotary weight and speed, circulation system, and deviation, all of which affect cost calculations.

Bit records include:
- Description of each bit
- Number of hours used
- Footage drilled
- Reason bit was pulled
- Condition after use

The *daily drilling report* is another important performance record (fig. 45). The report is a 24-hour record of the drilling operation and provides a complete and accurate account of the drilling progress by each tour. The driller signs and is responsible for the report on his tour. The daily drilling report helps achieve consistency in the drilling process because each driller can refer to the progress made by the last tour. Continuity of operations is assured because the report sets out the current conditions or problems assumed by the new crew, including bit performance, mud program, drilling assembly, and time required for various rig operations or mechanical problems. The operator will usually extract information from the rig's daily report and condense it for office use (fig. 46).

Weight on Bit and Rotary Speed

In this chapter:

- Relationship between weight on bit and rotary speed
- Automatic driller technology
- Factors affecting weight on bit and rotary speed

The mechanical factors of bit weight and rotary speed must be coordinated with bit selection to achieve optimal drilling rates. Generally, an increase in either weight or rpm increases the rate of penetration, provided the right bit is in place and bottomhole cleaning is attained through proper bit hydraulics. However, weight and rpm cannot be increased indiscriminately without considering other factors. The extra wear imposed on the bit bearings and cutting structures must be considered. For instance, drill string failure is more common at high rotary speed. The increase in shock loads can shatter bit teeth, especially if the formation contains both soft and hard layers. One extra trip can exceed the costs of a few hours of slower penetration. Hole deviation may also become a problem with increased weight unless the drill string is not stiff and well stabilized. Also, as the bit becomes dull, hole deviation tends to increase. When all factors are considered, simply increasing the weight or rotary speed will not always result in least-cost drilling.

With automatic driller technology, it is possible to maintain a steady weight on the bit. This technology enhances penetration rates significantly and increases both the bit life and number of reusable bits. Drilling with automatic drillers can control weight, differential pressure, or rotary amps (torque), all of which contribute to lower drilling costs per foot.

Increases in bit weight and rotary speed must consider:
- How much the bit will be impacted
- How much the hole might be deviated

Special Considerations

In this chapter:

- The effects of drill collars on bit weight and rotary speed
- The effects of deviations and doglegs
- The effects of a rig's power system
- Slant and horizontal drilling
- Downhole motors

Specific contract requirements, the rig's capability, and other factors must be considered when calculating the appropriate bit weight and rotary speed.

For example, additional, or heavier, drill collars may be needed to provide the added weight or stiffness. If more and heavier drill collars are required, one question the rig owner must ask is, "Can the derrick safely handle the heavier load?" Other considerations include costs. Drill collars are expensive to buy, or rent, and to maintain. They are hard to handle and require safety clamps and lifting subs that add to the trip time. If ten stands (30 collars) are used, it may require several hours to break out and make up the collars in a round trip.

Another consideration is that deviation and doglegs tend to develop when the bit weight is changed (fig. 49). If the drilling contract imposes strict deviation controls, or if dipping formations are present, increasing the bit weight to attain faster penetration may be ill-advised.

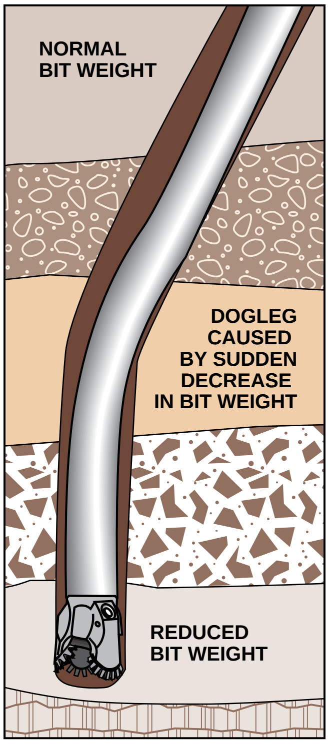

Figure 49. Dogleg produced by reduced weight

Rate of Penetration Control

In this chapter:

- Changes in drilling rate
- Evaluating drilling rate
- Drill-off tests

Variations in the drilling rate are normal. Changes can indicate bit wear, change in formation, weight, rotary speed, or hydraulics. The driller must evaluate all these possibilities before taking corrective action.

An unworn bit matched to the right formation, and properly run, will drill faster than a worn bit or a bit not matched to the formation. A driller can use this fact to determine the optimum weight to maintain by measuring how much time is required to drill a certain distance—1 ft, 10 ft (1 m, 10 m), or a kelly length. This time measurement is then converted to ft/h or m/h (the usual basis for comparing bit performance) or minutes (min) per ft or m. The rig's drilling rate recorder (Geolograph™) allows a quick visual evaluation of the drilling rate (fig. 58). Computers tied directly to the rig instruments are also used to collect such data. If automatic devices are not available, the driller can determine drilling rate by marking the kelly, maintaining a constant speed and bit weight, and then measuring the time it takes to drill one foot. This provides a rough estimate of bit performance under that particular weight and speed.

A driller can estimate drilling rate by marking the kelly and determining how long it takes to drill one foot.

Drilling Mud

In this chapter:

- The basic functions of drilling mud
- Three components of drilling mud
- Mud characteristics that affect penetration rate
- Mud costs

Drilling mud properties impact the penetration rate by performing functions vital to cost-effective drilling (fig. 60). The basic functions of drilling mud are to:

- Clean the bit teeth and the bottom of the hole
- Transport formation cuttings to the surface
- Prevent formation fluids from entering the wellbore causing a kick or blowout
- Protect and support the walls of the wellbore
- Cool and lubricate the bit and drill string
- Provide hydraulic power for downhole motors or turbines (see figs. 52 and 53)
- Help detect the presence of oil, gas, or saltwater in formations

Drilling mud contains:
- A liquid (water, oil, or mixture)
- A solid reactive with liquid
- A solid nonreactive with liquid

Drilling mud contains three types of material—one liquid and two solid. The liquid component may be water (water base) or oil (oil base), or a mixture of both.

One type of solid is reactive with liquid. The main reactive solids in most drilling muds are clays. Clays swell in water and thicken the mud. The other type of solids is nonreactive which means they do not react with the liquid phase of the mud. Nonreactive solids include formation cuttings of all sizes. Solids are generally undesirable because they add weight to the mud and are abrasive to equipment. One common nonreactive solid is barite, which is purposely added to the mud to increase the weight as needed to control formation pressure.

Air or Gas Drilling

In this chapter:

- The advantages of air or gas drilling
- The disadvantages of air or gas drilling
- Air drilling equipment
- Procedure for converting rotary rig from mud to air drilling
- Variables that must be controlled in air or gas drilling

In certain areas, use of air or gas rather than mud as the circulating fluid permits much lower-cost drilling. Generally, air or gas drilling is used in areas where the subsurface formations are older, hard rocks, and where soft, sloughing shale is not a problem. Moreover, formation water production cannot exceed 50 barrels per hour (bbl/h) or 8 m^3/h. These requirements virtually eliminate the Gulf Coast and offshore for the application of air or gas drilling.

Where conditions are favorable, air or gas drilling can offer advantages:

- Penetration rates are faster than drilling with mud because air or gas is the least-dense circulation medium available. An air or gas column does not create a hold-down effect because it holds very little hydrostatic pressure on the rock. Air removes the cuttings instantly so there is no redrilling of loose chips and less dulling of the bit.
- Air or gas does an excellent job of cooling the bit. As air or gas leaves the bit, it expands and cools. Effective cooling reduces bit bearing wear, which means that bits last longer.
- Formation changes are instantly recognized by changes at the blooey line—the line out of which the air or gas and cuttings blow to the surface. Rock type can be easily identified.
- Shows of water, gas, or oil are quickly evident. Formation evaluation is thus accomplished while drilling, negating the need for expensive testing operations.

Air or gas drilling can increase–
- Penetration rate
- Ease with which bit is cooled
- Ability to recognize formation changes
- Speed with which water, gas, or oil are evident

Bit Hydraulics

In this chapter:

- Hydraulic horsepower
- Pressure losses
- Calculating variable related to hydraulics
- Bit nozzles

At the bit, the hydraulic horsepower must be high enough to remove the cuttings quickly and effectively.

Hydraulics deals with the behavior of a liquid in motion. Bit hydraulics concerns the circulating pressure available at the bit to clean the bottom of the hole. The hydraulic horsepower of the circulating fluid at the bit is critical to the penetration rate because this horsepower removes the cuttings from the bottom of the hole. Hydraulic horsepower at the bit must be sufficient to efficiently remove the cuttings. If the cuttings are not removed quickly, the bit merely regrinds them instead of deepening the hole. Increasing the weight and rotary speed does not increase the rate of penetration if the hole is not cleared of cuttings.

Hydraulic horsepower is determined by pump output, which is usually measured in gallons per minute or cubic metres per minute (gpm or m^3/min), and circulating pressure in psi or kPa. A change in either output or pressure directly affects hydraulic horsepower at the bit. The mud pumps generate hydraulic pressure and transmit it down the drill string, out of the bit, and up the annulus to the surface. When the mud reaches the surface, all its pressure is used up. The mud may leave the pump under thousands of pounds of pressure but at every point in the system pressure losses occur (fig. 70). Substantial pressure is lost as the mud travels through the surface equipment and down the drill string because the inside of the pipes is rough.

Formation Properties

In this chapter:

- Formation characteristics that affect drilling
- Well prognoses
- Drilling breaks
- The effects of different types of rocks on drilling
- Formation dip

The nature of the formation being drilled greatly influences the drilling rate and other important aspects of the overall drilling operation. Petroleum geologists gather information from nearby wells and predict formation depths (tops), rock character, and geological hazards. A geologist prepares a well prognosis setting out this information and the rig manager or drilling superintendent will usually have access to it. The bit program may be based in part on the information in the prognosis. A geologist will often be on site to examine well cuttings, call formation tops, help pick casing, logging, and coring points, as well as the total depth. The operator may also engage a mud logging company to provide full time, continuous monitoring of the mud stream for shows of oil and gas and to identify the formations being drilled.

In general, porous and permeable formations drill faster than impermeable formations. If the bit is drilling an impermeable zone and it enters a permeable zone, a *drilling break* may occur. A drilling break is an increase in the rate of penetration. If a drilling break occurs in a possible pay horizon, drilling may be stopped and the cuttings, along with any shows of hydrocarbons in the mud, circulated to the surface. Formation testing may be conducted at that point or an evaluation may be deferred until logs are run.

Sudden increases in a bit's ROP—called drilling breaks—often occur when drilling an impermeable zone and then entering a permeable zone.

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