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DRILLING ENGINEERING (Well Planning)

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well planning

The well planning process requires the coordinated effort of many individuals with various responsibilities.

Tasks & Responsibilities

Effective well planning requires good communication among the technical personnel responsible for it's development and implementation. This section outlines the roles, responsibilities, and objectives of the following personnel:

- Geophysicist;
- Geologist;
- Drilling Engineer;
- Production Engineer;
- Reservoir Engineer;
- Drilling Manager;
- Drilling Superintendent;
- Drilling Supervisor;
- Logistics Coordinator;
- Loss Prevention and Safety Specialist;
- Environmental and Regulatory Specialist;
- Purchasing Specialist.

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Geophysicist

The geophysicist's role is to identify potential hydrocarbon-bearing structures from seismic data. Responsibilities include:

- ❑ processing and interpreting seismic data to identify potential reservoir structures;
- ❑ Assisting in prospect evaluation, based on structure size and seismic reflection interpretation;
- ❑ Reporting formation thickness, structure tops, and bed orientation to engineers preparing the drilling program;
- ❑ Identifying critical anomalies that indicate potential drilling difficulties (e.g. shallow gas hazards, bedded salt, abnormal pressures, and fault crossings); estimating depths for these anomalies;
- ❑ Assisting in development of a logging program;
- ❑ Working with operations personnel to select a rig location;
- ❑ Specifying velocity survey and checkshot intervals.

The geophysicist's goals are to:

- ❑ Identify substantial hydrocarbon-bearing structures
- ❑ Interpret seismic data to help the drilling engineers anticipate potential problems

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Geologist

The geologist's role is to predict the lithologic sequence of formations in proposed wells, and to identify formations as they are penetrated by interpreting cuttings samples, log measurements, and other geological indicators. Responsibilities include:

- Conducting surface geology studies to identify lithology sequences from outcrops;
- Identifying gross surface features from aerial surveys to establish the possibility of subsurface trapping mechanisms;
- Reviewing offset well histories for use in interpreting seismic maps to develop a stratigraphic column;
- Conducting or monitoring source-rock studies;
- Assisting in thermal maturation studies;
- Preparing AFE cost request forms that provide a geological prognosis for the expected lithologic sequence;
- Helping planning logging, coring, and testing programs;
- Identifying potential hole problems, specifying formation and expected depth whenever possible;
- Providing onsite formation evaluation expertise.

The goals of the geologist include:

- Identifying potential reservoirs and predicting formation types and thicknesses of the zones of interest;
- Accurately interpreting the expected lithology in the planned well.

Drilling Engineer

The drilling engineer plays a number of roles in the well planning process. During initial evaluation of a prospect, he or she conducts preliminary studies and estimates well-costs. Once well AFEs are approved, the drilling engineer becomes the designer, coordinator, and monitor of the overall well program. The responsibilities of the drilling engineer include:

- gathering and reviewing available data on previous drilling activity in the proposed areas of operation;
- preparing initial cost estimates;
- preparing specific well-cost estimates for Authorization for Expenditure packages
- conducting an initial planning meeting with others involved in specific well projects to establish objectives for the well;
- estimating expected formation pressures and fracture gradients;
- anticipating and addressing the most likely drilling problems;
- selecting casing sizes and setting depths;
- providing the data necessary for submitting an application for a drilling permit;

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Drilling Engineer

- resolving directional drilling requirements;
- developing the drilling mud program;
- designing casing strings;
- preparing a hydraulics program;
- recommending bottomhole assemblies and bits;
- preparing cementing recommendations;
- preparing step-by-step procedures for drilling operations;
- preparing rig specifications prior to rig bid requests to assist in rig selection;
- identifying necessary mud-processing and solids-control equipment;
- preparing drilling-cost and drilling-time curves to plot predicted performance;
- coordinating the well-planning activities of geoscience, purchasing, operations, environmental and regulatory, and other engineering groups to ensure that all aspect of well program development will meet schedule commitments.

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Drilling Engineer

The goals of the drilling engineer include:

· providing accurate cost estimates;
· designing well programs that satisfy well objectives;
· reducing cost through the selection of high-efficiency equipment, systems, and practices;
· ensuring safety through the recommendation of sound practices and thorough contingency planning;

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Reservoir Engineer

The reservoir engineer's role is to provide engineering analysis and support in all phases of reservoir evaluation. Responsibilities include:

· assisting the geologist and geophysicist in interpreting reservoir size, characteristics, and potential reserves of the prospect;
· assisting economic calculations based on prospect size, estimated reserves, production rates, and well cost;
· assisting in the design of logging, coring, and testing programs;
· assisting in the evaluation of data collected during drilling.

The goals of the reservoir engineer include:

· accurately evaluating prospect potential;
· maximizing the quantity and quality of reservoir data gathered during the drilling, testing, and completion of the well.

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Production/Completion Engineer

The production/completion engineer defines the testing, stimulation, and completion requirements for the well. Responsibilities include:

- predicting formation pressures and estimating production rates to assist drilling engineers in designing production casing;
- preparing testing and completion programs for the subject well;
- ensuring that formation testing is done according to the program, and supervising the testing;
- providing the drilling engineer with a completion design;
- providing the drilling engineer with an early outline of the potential stimulation design, including the maximum expected stimulation pressures;
- helping the drilling engineer estimate testing, stimulation, and completion costs and time during AFE preparation;

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Production/Completion Engineer

- providing the drilling engineer with a list of required completion and wellhead equipment necessary while the drilling rig is on location;
- indicating corrosion-protection measures, if warranted;
- identifying potential formation sensitivity to assist the drilling engineer in selecting the best mud program.

The goals of the production/completion engineer are to

- maximize data collection during drilling to improve evaluation of potential production zones;
- design a completion program that will most efficiently drain reservoir hydrocarbons.

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Drilling Manager

The drilling manager must review the well plan closely, approve it, and assist the rig supervisors in its implementation. He or she is ultimately responsible for operations conducted at the rig site. The drilling manager's responsibilities include:

· maintaining an approved drilling contractor list;;
· supervising the compilation of rig bid specifications, rig bid requests, and bid evaluations;
· supervising company rig supervisors on ongoing drilling operations;
· communicating drilling-operations status to higher management, as required;
· advising the drilling engineer regarding recommended drilling practices pertinent to the area of operations;
· reviewing well plan procedures, practices, and equipment specifications;
· making critical decisions concerning rig problems, based in part on the advice and support of the drilling engineers.

The goals of the drilling manager include:

· drilling the well to targeted objectives safely and cost effectively;
· coordinating the well plan implementation among engineers, rig supervisors, and contractors.

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Drilling Superintendent

The drilling superintendent provides mid-level management support to the drilling manager and rig supervisor for ongoing drilling operations. Responsibilities include:

· reviewing the daily drilling reports from assigned rigs, and providing advice and assistance concerning rig operations, as required;
· advising drilling engineers on well plan preparation according to field experience in the area;
· assisting the drilling manager in organizing schedules for rig assignment, time off, and training for rig supervisors;
· reviewing regulatory requirements, and ensuring that company and contractor personnel at the rig are observing these requirements;
· providing onsite inspection and support as required;
· inspecting proposed drilling rigs and equipment for compliance with specifications.

The goal of the drilling superintendent is to ensure efficiency, safety, and cost control in all rig-site activity.

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Drilling Supervisor

The drilling supervisor is responsible for the day-to-day operation of his or her assigned drilling rig. Responsibilities include

- making day-to-day decisions on rig operations as the well is drilled;
- supervising contractors and service company personnel on location;
- following the recommended practices and procedures listed in the well plan as closely as possible, and providing feedback to the supervisors and engineers if problems with plan implementation occur;
- conducting safety and well-control drills;
- ensuring that contractor and service company personnel comply with regulatory stipulations;
- maintaining accurate records of operations and cost;
- providing daily reports detailing drilling progress, costs, current operation, mud properties, materials used and in inventory, hole deviation, etc.;
- reviewing and signing all invoices for services and materials used at the rig;

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Drilling Supervisor

- placing orders for materials, equipment, and service company personnel with allowance of sufficient lead time;
- communicating with drilling engineers for support in drilling optimization and in critical operations such as cementing, testing, completion, etc.;
- supervising location construction, rig move-in, and stockpiling of material at the beginning of new well activity;
- providing feedback as to potential location problems;
- supervising location cleanup after the well is completed or abandoned.

The goal of the drilling supervisor is to conduct well operations safely and efficiently.

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Logistics Coordinator

The logistics coordinator provides support to the rig in the form of materials, equipment, transportation, communications, and invoicing. This role is especially critical in remote or overseas operations where supplies, communication, and regulations require additional planning and lead time. Listing specific responsibilities is inappropriate because of the variable nature of remote operations. They do involve the following support activities, often from an intermediate support facility between the office and the rig. The logistics coordinator must:

- maintain equipment and material supplies by ordering with sufficient lead time;
- maintain the communications system to ensure operation according to the well plan;
- coordinate normal and emergency transportation to and from the rig;
- coordinate customs clearances and official inspections to ensure regulatory compliance;
- assist in maintaining and forwarding rig invoices, operations reports, etc. between the rig and the main office accounting department.

The goal of the logistics coordinator is to provide remote operations with the support needed to keep the rig running according to the well plan.

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Loss Prevention/Safety Advisor

The safety advisor is a specialist staff support function. The safety advisor should provide input to the team in all areas of site selection, rig selection, operational safety considerations, personnel safety training, and rig safety. The safety professional's role includes serving as a liaison with governmental and industry agencies relative to safety, and ensuring compliance with all applicable codes, standards, rules, laws, and regulations as they apply to drilling activities.

As a staff support function, the safety advisor is responsible for providing management with professional, technical support to ensure compliance with applicable laws, codes, standards, and regulations. Responsibilities include:

- determining the environmental and safety impact of the rig-site location on the surrounding properties;

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Loss Prevention/Safety Advisor

- investigating the drilling contractor's past safety and accident performance record;
- reviewing all drilling contracts to ensure that the contractor's safety responsibilities are clearly defined;
- reviewing (with regard to safety) the layout of mud pits, choke and blooey lines, high-pressure hoses and lines, BOP control panel location, etc.;
- reviewing the contractor's plans with regard to rig electrical safety prior to spud to ensure compliance with applicable laws and standards;
- reviewing all piping diagrams and equipment specifications for rig fire protection;
- reviewing material safety data bulletins (or equivalent) for all chemicals to be used on the rig; and ensuring that (if acids and/or caustics are to be used) an adequate clear water source is provided for eyewash/emergency showers;
- identifying specific hazards, and specifying personal protective equipment to be provided (e.g., breathing apparatus in a potential H_2S atmosphere; survival suits in cold environments);
- reviewing all contingency plans, station bills, and emergency shutdown systems;

Loss Prevention/Safety Advisor

- reviewing safety programming (e.g., safety meetings, accident investigations, hot work permits), and outlining contractor safety training for all employees, including rig management, to ensure consistency with modern safety management concepts; this includes reviewing the contractor's safety manual.
- reviewing plans for onsite potable water treatment, cooking and eating facilities, and noise-level documentation, to ensure compliance with applicable regulations;
- attending the pre-spud meeting to ensure that all pressure tests have been completed, equipment (chains, wireline, etc.) has been inspected, fuel transfer and personnel transfer procedures are in place, and pit drills, etc. have been completed.

The ultimate goal of any loss-prevention effort is to minimize risk to personnel and property. The safety advisor should ensure that the standards and procedures outlined in the planning stage are strictly followed through the completion of the well.

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Environmental and Regulatory Advisor

The environmental and regulatory advisor identifies, gathers, and submits the necessary permits and reports required by state and/or federal agencies for approval of a permit to drill the subject well. The responsibilities include

- reviewing stipulations of lease sale and permit agreements and preparing copies of these stipulations for drilling engineers and operations personnel;
- gather information from exploration and engineering groups for preparation of the exploration plan (if necessary) and the application for permit-to-drill documentation;
- coordinating externally prepared documents such as the Rig Discharge (NPDES) permit, the Environmental Report, the Oil Spill Containment Plan, the Environmental Training Report, and the Hazard and Biological Survey;
- providing the drilling engineer with a timetable of permit application and approval.

The goals of the environmental and regulatory advisor include:

- providing support for timely preparation of required pre-spud permits and reports;
- assisting the drilling engineers and operations personnel in identifying and complying with stipulations of lease and permit agreements.

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Purchasing/Materials Coordinator

The purchasing/materials coordinator's primary role during the planning stages of a well is to give functional guidance with regard to obtaining critical materials. Primary responsibilities include:

- supplying drilling engineers with information regarding availability, sourcing, lead time, and pricing of materials required for the well;
- serving as a liaison between E&P groups to facilitate inventory and stock sharing during material shortages;
- coordinating supplier selection for common items required by several units of organization to ensure supply and economic advantage;
- coordinating material acquisition, delivery, and payment;
- forecasting price and supply variations for general planning purposes;
- assisting in quality-control programs, operation audits, claim handling, and task force procurement activity as requested by operating units;

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Purchasing/Materials Coordinator

- working with engineers to secure competitive quotations on bid services and materials within specification;
- reviewing requisitions and maintaining accurate records of procurement activities.

The goals of the purchasing/materials coordinator include:

- providing timely support in the selection and procurement of required materials;
- providing commercial support in procurement activity;
- providing market intelligence as to which manufacturers offer the most competitive combination of material quality, service, price, delivery, and operating costs.

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well planning

The well planning process flow chart illustrates the extensiveness of the effort.

The major activities can be outlined as follows:

I. Well Selection
II. Authorization for Expenditure (AFE) Preparation
III. Organizing and Data Gathering
IV. Well Design
VI. Rig Design
VII. Procedures
VIII. Contract
IX. Cost Estimate

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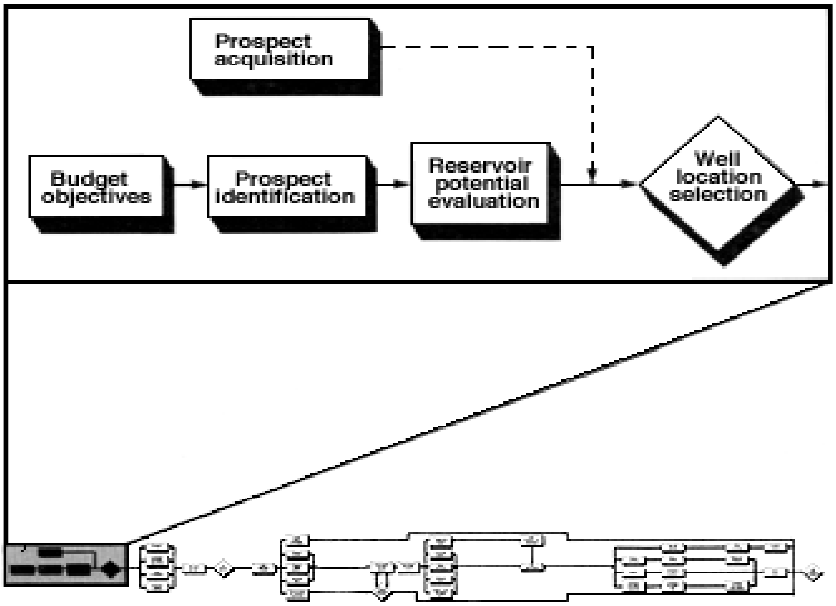
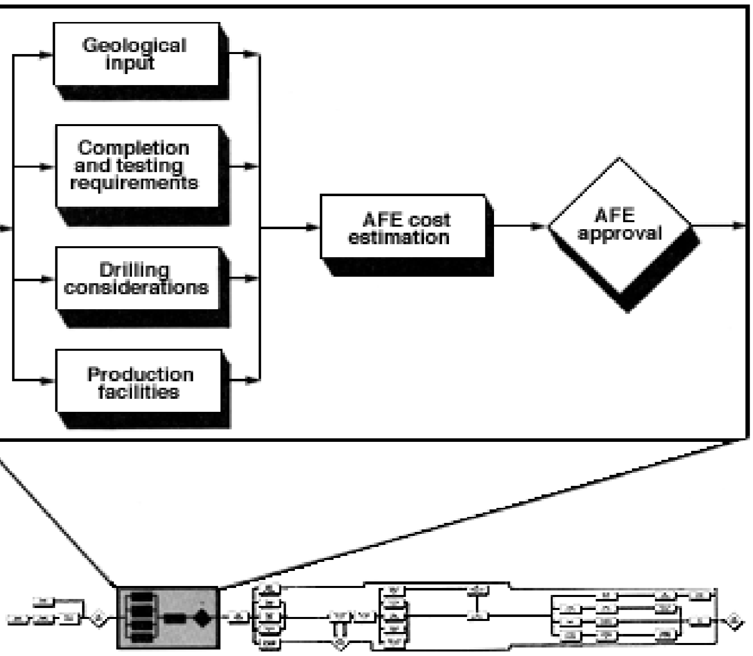
Well Selection

Well Selection



Authorization for Expenditure (AFE) Preparation

AFE Preparation



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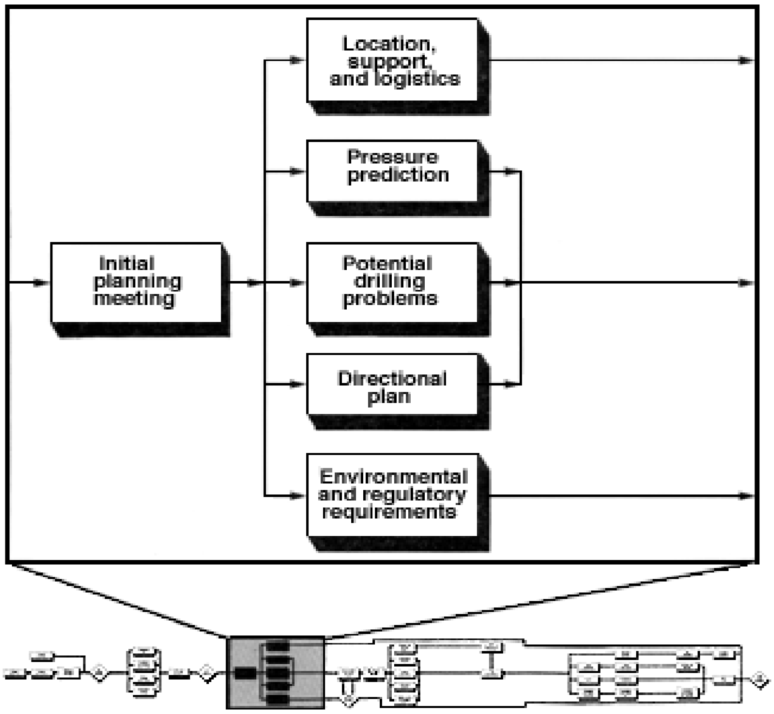
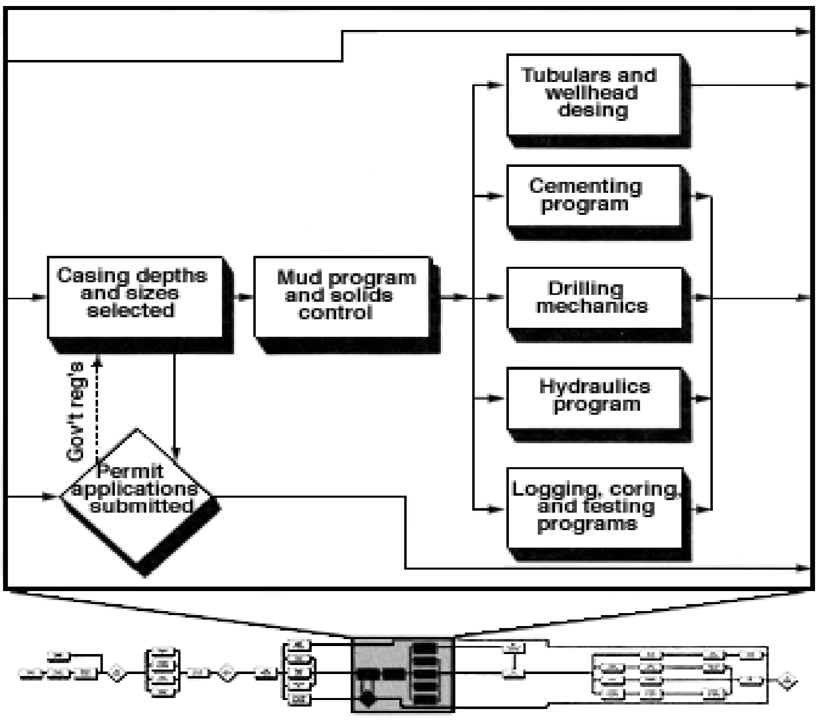
Organizing and Data Gathering

Organizing and Data Gathering



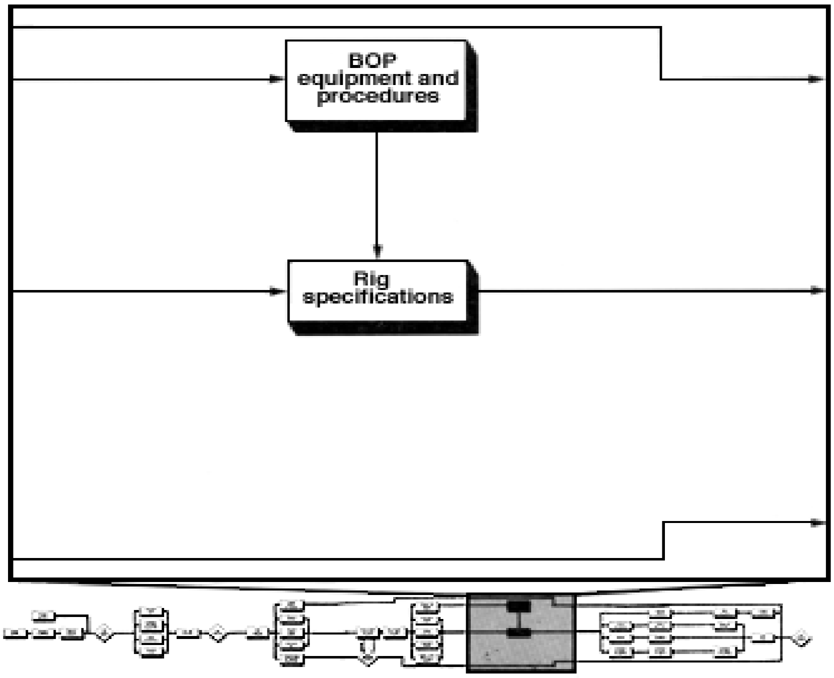
Well Design

Well Design



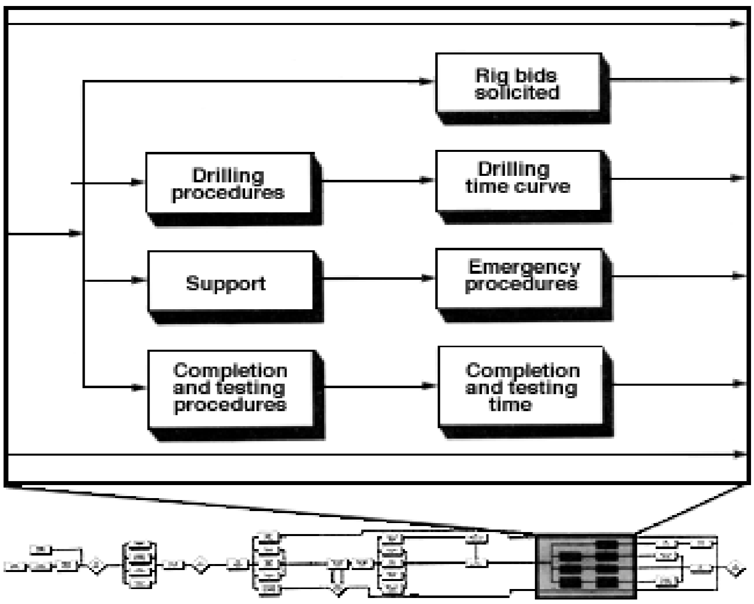
Rig Design

Rig Design



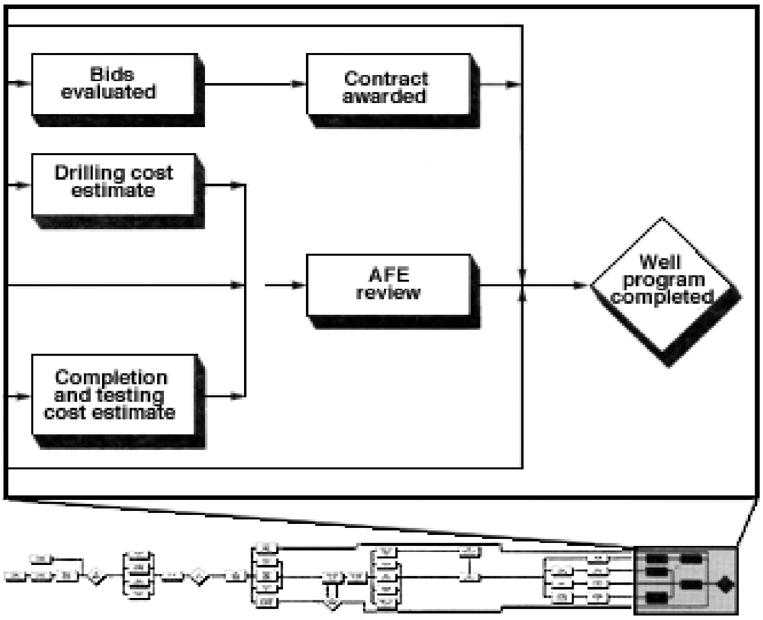
Procedures

Procedures



Contract/Cost Estimate

Cost Review



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DRILLING ENGINEERING OPTIMIZATION

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DRILLING OBJECTIVES

✓The goals of any drilling venture are safety, minimized cost and a usable completion.

✓Companies may have different ideas of how best to attain these goals, and drilling practices may vary according to location, rig type, hole conditions or other factors.

✓The goals themselves, however, remain the same.

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well plan

Data sources may include:

- bit records
- mud records
- mud logs
- IADC drilling reports ("tour sheets")
- scout tickets
- log headers
- production histories
- seismic studies
- well surveys
- geologic contours
- databases or service company files productivity index

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Drilling Optimization

- Drilling optimization involves using available resources to minimize overall cost, subject to safety and well completion requirements. Part of this, of course, entails preventing or successfully solving hole problems. But optimization efforts also encompass "normal" operations. The key measure of performance in this area is the cost to drill a given interval.

To optimize drilling operations, we must do three things:

- Establish criteria for evaluating drilling performance.
- Identify the variables that affect this performance.
- Determine how to control these variables to our advantage.

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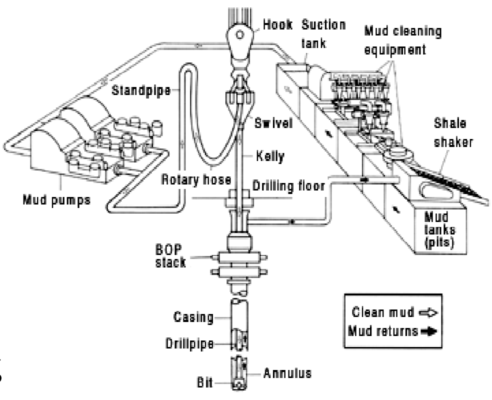
DRILLING HYDRAULICS

- When hole problems occur when we are trying to optimize drilling performance we should look first to the drilling mud and the circulating system. This makes sense when we consider that the mud functions include:
- controlling subsurface pressures
- stabilizing the wellbore
- supporting part of the drill string and casing weight
- removing and transporting drilled cuttings
- suspending cuttings in the annulus when the pumps are shut down
- transmitting hydraulic energy to the bit
- cooling and lubricating the bit and drill string
- minimizing formation damage
- collecting formation data



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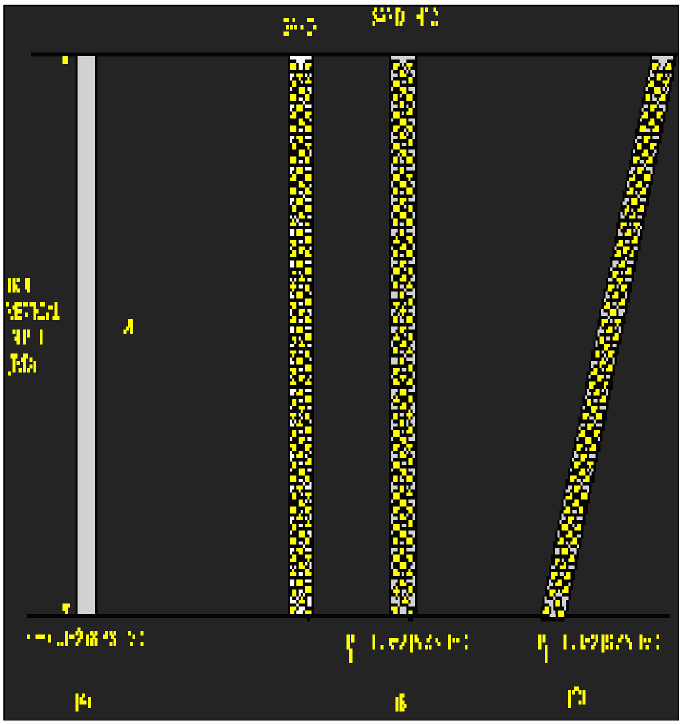
Wellbore and Formation Pressure

$$P = 0.052 \times MW \times TVD$$

where:

- P = pressure, psi
- MW = mud weight or density, lbm/gal (U.S.)
- TVD = true vertical depth, ft
- When expressed in SI units (with pressure given in kPa), 0.052 becomes 0.00980.



Wellbore and Formation Pressure

- **This equation is adequate for determining the pressure of a static, homogeneous mud column.**
- **In many instances, however, the mud is not static; circulation and pipe movement can significantly affect wellbore pressure. Nor is the mud column necessarily homogeneous; during cementing operations or mud changeovers, for example, the well contains fluids of different densities.**
- **To determine the actual wellbore pressure, we have to account for these variables. We can simplify our task by defining equivalent mud weight (EMW) or equivalent circulating density (ECD):**

Equivalent mud weight (EMW)
Equivalent circulating density (ECD)

$$EMW = \frac{P_{well}}{0.052 \times TVD}$$

$$ECD = MW + \frac{\Delta P_{ann}}{0.052 \times TVD}$$

where EMW = equivalent mud weight, lbm/gal (U.S.)

ECD = equivalent circulating density, lbm/gal (U.S.)

Pwell = sum of hydrostatic and applied pressures, psi

DPann = the frictional pressure loss in the annulus. This corresponds to the pump pressure minus the pressure losses through the surface equipment, drill string and drill bit.

TVD = True vertical depth, ft

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Example : Equivalent Circulating Density

Determine:

Equivalent Circulating Density and the effective wellbore pressure for the following conditions:

- Mud weight = 12.5 lbm/gal
- TVD =11,300 ft
- Calculated annular pressure loss = 150 psi

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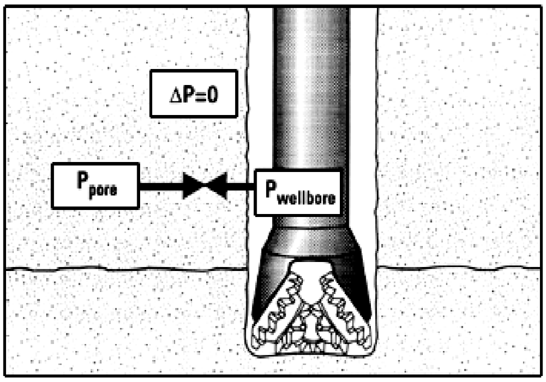
Differential pressure

- *Differential pressure* (DP) is simply the difference between wellbore and formation pressure:
- When the wellbore and formation pressures are approximately equal, DP is zero. We refer to this condition as balanced.



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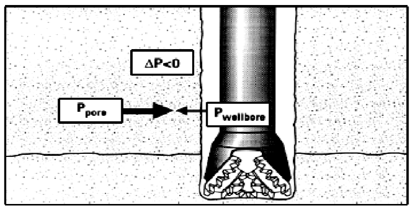
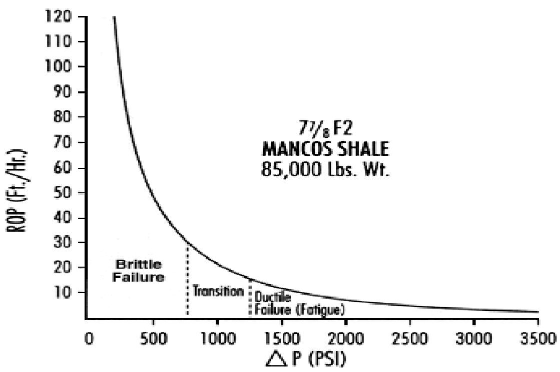
Under balanced Drilling

Balanced drilling with an unweighted mud system is a viable option in areas or depth intervals having well-established pressure trends and little blowout risk. In low-permeability, high-strength formations, operators may even drill under balanced (DP<0) using air, gas, foam or low-density liquids (*under balanced conditions; wellbore pressure is less than pore pressure*).





(courtesy Smith International)

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Formation fracture gradient

Formation fracture gradients define our upper wellbore pressure limit. Exceeding this limit can cause lost circulation, resulting in formation damage and induced fractures. Severe fracturing can cause the wellbore fluid level to drop, thereby creating a blowout risk.

Formation fracture gradient

Fracture pressure is related to overburden stress, which is equal to the rock matrix pressure plus the pore pressure:

$$\boxed{S = \sigma + P_{pore}}$$

Where: S = overburden stress

σ = matrix stress at depth of interest

P pore = pore pressure at depth of interest

Determining fracture gradients

Matthews and Kelly (1967), building on the landmark work of Hubbert and Willis (1957), developed the following relationship for sedimentary rocks:

$$\gamma_{frac} = \left(\frac{P_{pore} + K_i \sigma}{D} \right) \times S = \sigma + P_{pore}$$

where: γfrac = fracture gradient, psi/ft [k Pa/m]

D = depth, ft [m]

K i = matrix stress coefficient for the depth at which the value of s would be the normal matrix stress (dimensionless)

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Determining fracture gradients

Matthews and Kelly’s procedure for determining the fracture gradient is as follows:

1.Determine the pore pressure (based on seismic measurements, well log anlaysis or drilling data correlations).

2.Assume a gradient of 1.0 psi/ft for the overburden, and calculate the matrix stress s.

3.Determine the depth (Di) at which s would have a normal value, assuming that S=1.0 psi/ft and the normal stress gradient equals 0.535 psi/ft. Therefore,

$$0.535 \times D_i = \sigma$$

4.Using Figure (*Matrix stress coefficients of Matthews and Kelly, basd on data from U.S. Gulf Coast Sands*), determine Ki and calculate γfrac from the pervious equation (note that Figure is empirically generated from field data).

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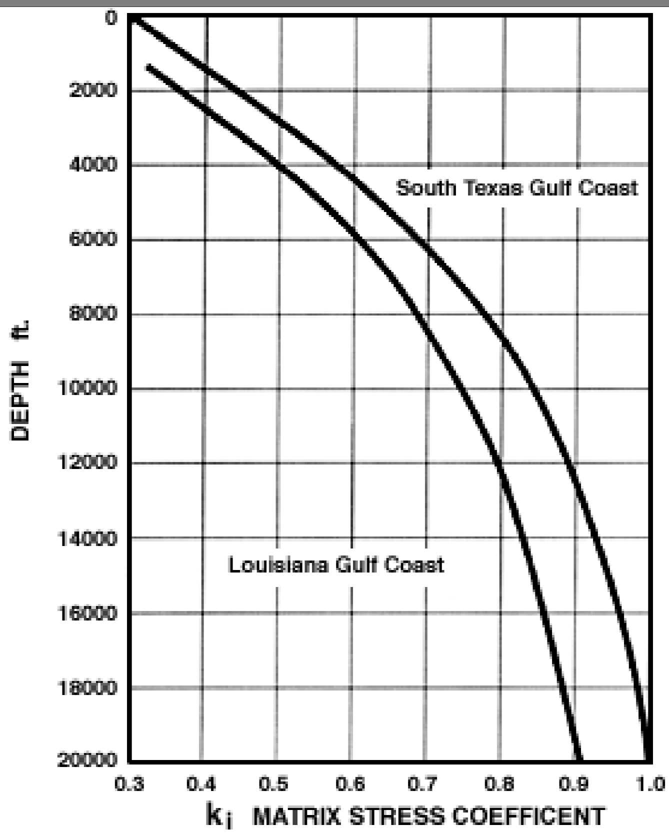

(courtesy Pennwell Publishing Co.)

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Example: Determining fracture gradient

Using the Matthews and Kelly procedure, determine the fracture gradient just below the casing seat for the following Louisiana Gulf Coast well.

Casing set at 6,650 ft TVD

Formation pressure = 3,300 psi

Solution:

$$\sigma = S - P = (1.0 \times 6{,}650) - 3{,}300 = 3{,}350 \text{ psi}$$

$$D_i = \frac{\sigma}{0.535} = \frac{3{,}350}{0.535} = 6{,}262 \text{ ft}$$

$$\gamma_{frac} = \frac{P_{pore} + K_i \sigma}{D} = \frac{3{,}300 + (0.63 \times 3{,}350)}{6{,}650} = 0.814 \text{ psi/ft}$$

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Leak-off test

In the field, we can estimate the minimum fracture gradient at each new casing point by performing a leak-off test as follows:

1. Close the blowout preventer and apply pressure down the drill pipe in small increments, using a low-volume pump.
2. Continue pumping small volumes of mud until the formation begins to take fluid, or until the pressure reaches a pre-set test limit.
3. Plot pressure versus the pumped volume to determine the initial fracture pressure.

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Example : Leak-off test-- calculating fracture gradient

Determine the fracture gradient at a well's casing point (6,750 ft. TVD), given the information in **Table** below (mud weight = 12.5 lbm/gal).

Table: *Results of leak-off test.*

Volume pumped, bbl	**Pressure, psi**
0	0
1	4
1.5	100
2.0	190
2.5	280
3.0	370
3.5	460
4.0	550
4.5	640
5.0	730
5.5	820
6.0	850
6.5	880

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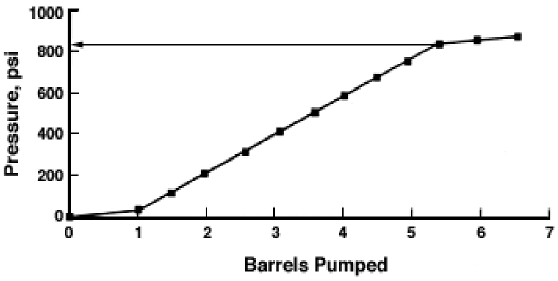
Example : Leak-off test-- calculating fracture gradient

Solution:

Figure indicates that the formation begins to fracture at an applied pressure of about 820 psi. The fracture pressure is equal to this applied pressure plus the hydrostatic wellbore pressure:

$$P_{frac} = 820 + (0.052 \times 12.5 \times 6{,}750) = 5{,}208 \text{ psi}$$

$$\gamma_{frac} = \frac{5{,}208}{6{,}750} = 0.772 \text{ psi/ft}$$



(after Adams, 1985)

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Buoyancy

- An object immersed in fluid is subject to an upward-acting buoyant force, which equals the weight of the fluid the object displaces (i.e., the product of the fluid volume and density). The net effect of buoyant force is that an object submerged in liquid weighs less than it would in air.

- In practical terms, this means that a string of pipe in a mud-filled wellbore weighs less than it would if suspended in air, by an amount that corresponds to the weight of the displaced mud. It is important to account for buoyancy effects when calculating hook loads, bit weights, drill collar requirements, casing specifications, rig capacity and other weight-related parameters.

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Buoyancy

The weight of pipe in a well is equal to its weight in air multiplied by a buoyancy factor (BF):

$$\boxed{W_{fluid} = W_{air} \times BF}$$

The buoyancy factor is a function of the fluid density, and for steel pipe is equal to

$$\boxed{BF = 1 - \frac{MW}{r_{steel}}}$$

where MW is the mud weight and r steel is the density of steel, which equals 65.5 lbm/gal [7860 kg/m3].

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Example: Buoyancy effects

Determine the maximum weight-on-bit provided by 450 ft of 7 3/4-inch OD., 144 lb/ft drill collars for both of the following mud weights. (Assume that all of the drill string compression is in the drill collars.)

- 9.5 lbm/gal
- 16.0 lbm/gal

Solution:

$$W_{air} = 450 \text{ ft} \times 144 \text{ lb/ft} = 64{,}800 \text{lb}$$

$$MW = 9.5 \text{ lb}_m\text{/gal}; \quad BF = 0.855$$

$$\Rightarrow W_{fluid} = 64{,}800 \times 0.855 \cong 55{,}400 \; lb$$

$$MW = 16.0 \text{ lb}_m\text{/gal}; \quad BF = 0.756$$

$$\Rightarrow W_{fluid} = 64{,}800 \times 0.756 \cong 49{,}000 \; lb$$

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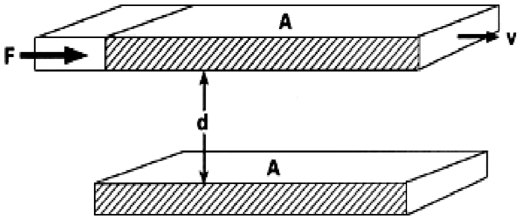
Rheological Models

- Rheology, a term often used in drilling engineering, is the study of the flow or deformation of matter. We generally describe flow or deformation in terms of shear stress and shear rate.
- We may best understand these concepts by considering a fluid located between two parallel plates separated by a distance *d*. If we apply a force to the upper plate while holding the lower plate stationary, the upper plate attains a constant velocity (v), which depends on the applied force (F), the distance between the plates, the surface area (A) and the fluid viscosity (μ):

$$\frac{F}{A} = \frac{\mu \times v}{d}$$



$$\tau = \frac{F}{A} \qquad \gamma = \frac{v}{d}$$

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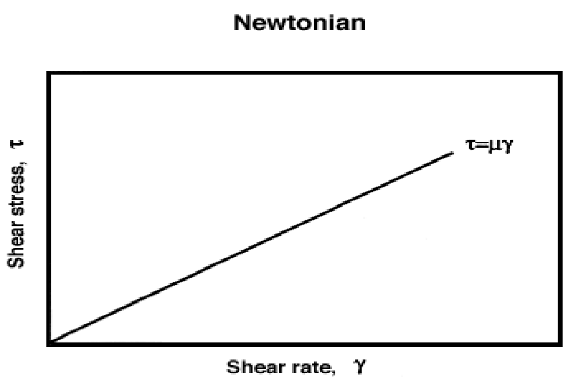
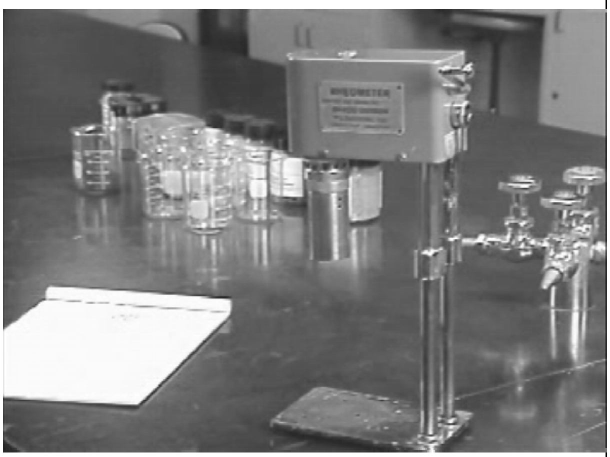
Newtonian fluids

Newtonian fluids exhibit direct proportionality between shear stress and shear rate.





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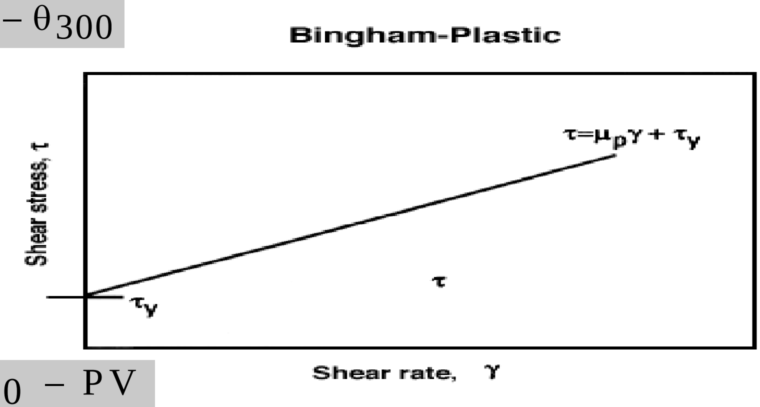
Bingham-Plastic model

$$\tau = \mu_p \gamma + \tau_y$$

Where: μp = plastic viscosity (PV), cp

τy = yield stress or yield point (YP), lbf /100 ft 2
(1.0 cp = 0.001 Pa-s; 1 lbf /100 ft 2 = 0.4788 Pa)

$$PV = \theta_{600} - \theta_{300}$$



$$YP = \theta_{300} - PV$$

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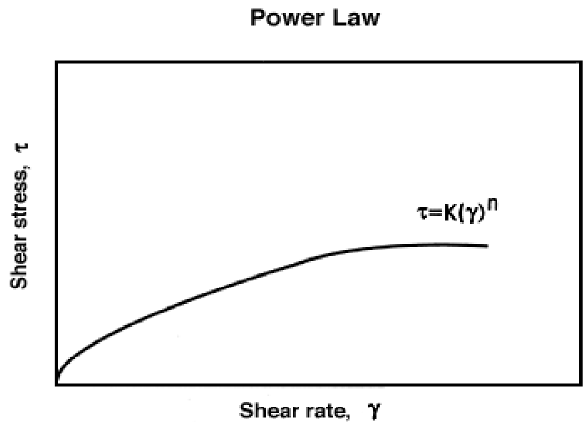
Power Law model

The *Power Law* model is a non-linear relationship, which is more descriptive of real drilling fluid behavior.

$$\tau = K(\gamma)^n$$

$$K = \text{consistency index} = \frac{\theta_{300}}{511^n}$$

$$n = \text{flow behavior index} = 3.32 \times \log\left(\frac{\theta_{600}}{\theta_{300}}\right)$$



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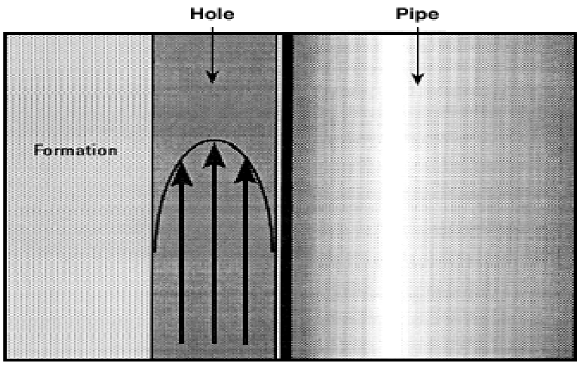
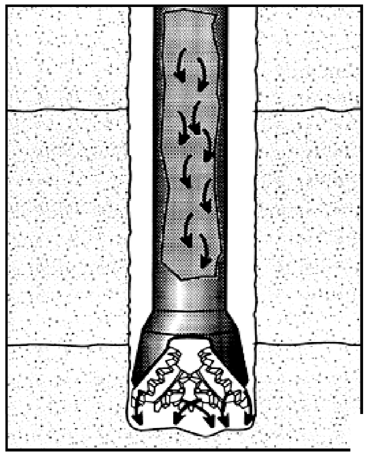
Flow Regimes

The flow regimes most commonly encountered in drilling are *laminar*, *turbulent* and *transitional*.





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Determining a fluid's flow regime

The most common method for determining a fluid's flow regime is to calculate its Reynolds number. In its simplest form (i.e., for the case of a Newtonian, non-elastic liquid inside pipe) we may define the Reynolds number as

$$N_{Re} = \frac{\rho\, vd}{\mu}$$

$$v = \frac{\text{flow rate}}{\text{area}} = \frac{q}{\left(\frac{\pi}{4}\right)d^2} = \frac{q}{0.7854d^2}$$

For annular flow, the Reynolds number becomes:

$$N_{Re} = 0.816 \times \frac{\rho v\left(d_2 - d_1\right)}{\mu} \qquad v = \frac{q}{0.7854\left(d_2^{\,2} - d_1^{\,2}\right)}$$

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Determining a fluid's flow regime

In field units (where ρ is given in lbm/gal, v in ft/s, q in gal/min, d, d1 and d2 in inches and μ in cp)

(Pipe flow):

$$N_{Re} = 928 \times \frac{\rho\, vd}{\mu} \qquad v = \frac{q}{2.448 d^2}$$

(Annular flow):

$$N_{Re} = 757 \times \frac{\rho (V)(d_2 - d_1)}{\mu} \qquad v = \frac{q}{2.448\left(d_2{}^2 - d_1{}^2\right)}$$

As a general guideline, Reynolds numbers of less than 2,100 indicate laminar flow, while Reynolds numbers greater than 4,000 indicate turbulent flow. Between these values, flow is considered transitional.

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Determining a fluid's flow regime

- In field applications, we identify flow regimes by determining the critical Reynolds number or critical velocity (vc) at which flow changes from laminar to turbulent.
- For example, we may calculate vc and compare it to the actual fluid velocity (v).
- If vc < v, flow is laminar,
- while if vc >v, it is turbulent.
- Because the transition between laminar and turbulent flow may not be clear-cut, it often becomes necessary to calculate a range of critical velocities to determine the flow regime.

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Example: Flow regimes

A 10.5 lbm/gal drilling mud with a viscosity of 30 cp is circulating at 250 gallons per minute in an 8 3/4 inch diameter wellbore. Determine the flow regime inside 4.5 inch o.d., 16.60 lb/ft drill pipe (3.826 inch inside diameter), and in the drill pipe/hole annulus. For this example, assume that the mud behaves as a Newtonian fluid.

Solution:

Drill pipe:

$$N_{Re} = 928 \times \frac{\rho v d}{\mu}$$

$$v = \frac{250}{2.448\left(3.826^2\right)} = 6.98 \text{ ft/s}$$

$$N_{Re} = 928 \times \frac{(10.5)(6.98)(3.826)}{30} = 8{,}674$$

NRe > 4,000 Turbulent flow

Annulus:

$$N_{Re} = 757 \times \frac{\rho v (d_2 - d_1)}{\mu}$$

$$v = \frac{250}{2.448\left(8.75^2 - 4.5^2\right)} = 1.81 \text{ ft/s}$$

$$N_{Re} = 757 \times \frac{(10.5)(1.81)(8.75 - 4.5)}{30} = 2{,}038$$

NRe < 2,100 Laminar flow

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Bingham Plastic Fluids

For Bingham-Plastic fluids defining an apparent viscosity to account for the yield point and plastic viscosity:

(Pipe flow)

$$\mu_a = PV + \frac{6.66(YP)(d)}{v}$$

$$N_{Re} = \frac{\rho v d}{\mu_a}$$

(Annular flow)

$$\mu_a = PV + \frac{5(YP)(d_2 - d_1)}{v}$$

$$N_{Re} = 0.816 \times \frac{\rho v (d_2 - d_1)}{\mu_a}$$

where μa = apparent viscosity, cp

PV = plastic viscosity, cp

YP = yield point, lbf /100 ft2

d = inside pipe diameter, inches

d2 = hole or casing diameter, inches

d1 = outside pipe diameter, inches

v = average velocity, ft/s

the criterion for turbulence is the same as for Newtonian fluids, with laminar flow occurring below a Reynolds number of 2100.

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Power Law Fluids

For power law fluids, we may use correlations developed by Dodge and Metzner (1959):

Pipe flow:

$$N_{\mathrm{Re}} = \frac{89{,}100(\rho)\left(v^{2-n}\right)}{K} \times \left(\frac{0.0416d}{3+\left(\frac{1}{n}\right)}\right)^n$$

Annular flow:

$$N_{\mathrm{Re}} = \frac{109{,}000(\rho)\left(v^{2-n}\right)}{K} \times \left[\frac{0.0208(d_2-d_1)}{2+\left(\frac{1}{n}\right)}\right]^n$$

Where n = flow behavior index (dimensionless)
K = consistency index (dimensionless)
ρ = fluid density, lbm/gal (U.S.)
v = fluid velocity, ft/s
d2 and d1 are expressed in inches

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Power Law Fluids

- The turbulence criterion for power law fluids is based on a critical Reynolds number (NRec), which depends on the value of the flow behavior index. A simple equation for estimating the critical Reynolds number at the upper limit of laminar flow is

$$N_{Rec} = 3470 - 1370n$$

- For the region between transitional and turbulent flow, the critical Reynolds number is

$$N_{Rec} = 3470 - 1370n$$

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System Pressure Loss

✓ For mud to flow through the circulating system, it must overcome frictional forces between the fluid layers, solid particles and pipe or borehole walls. The mud pump or standpipe pressure corresponds to the sum of these forces:

$$P_{pump} = \sum \Delta P_{system} = \Delta P_{surf} + \Delta P_{ds} + \Delta P_{bit} + \Delta P_{ann}$$

where P pump = mud pump pressure

ΔP surf = pressure loss through surface equipment

ΔP ds = pressure loss through drill string

ΔP bit = pressure loss through bit

ΔPann = pressure loss in annulus

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System Pressure Loss

The general procedure for calculating system pressure losses is as follows:

1. Determine the fluid velocity (or Reynolds number) at the point of interest.
2. Calculate the critical velocity (or Reynolds number) to determine whether the fluid is in laminar or turbulent flow.
3. Choose the appropriate pressure loss equation. (The choice depends on which rheological model and flow regime apply to the point of interest).

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Drill string pressure loss equations for a Bingham Plastic fluid (After Bourgoyne et. al ,1986; and Adams ,1985)

Fluid velocity (v)

$$v = \frac{q}{2.448 d^2}$$

Critical velocity (vc)

$$v_c = \frac{1.08\,PV + 1.08\sqrt{(PV)^2 + 12.34\, d^2 (YP)(MW)}}{MW \times d}$$

laminar flow (ΔPds)
(Use for v < vc)

$$\Delta P_{ds} = \frac{PV \times L \times v}{1500 d^2} + \frac{YP \times L}{225 d}$$

turbulent flow
(Use for v > vc)

$$\Delta P_{ds} = \frac{MW^{0.75} \times v^{1.75} \times PV^{0.25} \times L}{1800 d^{1.25}}$$

d = inside diameter of pipe, inches
v = velocity, ft/s
L = pipe length, ft
vc = critical velocity, ft/s
MW = mud weight, lbm/gal
YP = yield point, lbf/100ft2

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Annular pressure loss equations for a Bingham Plastic fluid [After Bourgoyne et al (1986) and Adams (1985)]

Fluid velocity (v)

$$v = \frac{q}{2.448\left(d_2{}^2 - d_1{}^2\right)}$$

Critical velocity (vc)

$$v_c = \frac{1.08 PV + 1.08\sqrt{(PV)^2 + 9.26 (d_2 - d_1)^2 (YP)(MW)}}{MW \times (d_2 - d_1)}$$

Pressure Loss for laminar flow (ΔP ds)
(Use for v < vc)

$$\Delta P_{ann} = \frac{PV \times L \times v}{1000\,(d_2 - d_1)^2} + \frac{YP \times L}{200\,(d_2 - d_1)}$$

Pressure Loss for turbulent flow
(Use for v > vc)

$$\Delta P_{ann} = \frac{MW^{0.75} \times v^{1.75} \times PV^{0.25} \times L}{1396 (d_2 - d_1)^{1.25}}$$

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Drill string pressure loss equations for a Power Law fluid [After Bourgoyne et al (1986) and Adams (1985)]

Fluid velocity (v)

$$v = \frac{q}{2.448 d^2}$$

Critical velocity (vc)

$$v_c = \frac{1}{60} \times \left[\frac{58{,}200K}{MW}\right]^{\frac{1}{2-n}} \times \left[\left(\frac{1.6}{d}\right)\left(\frac{3n+1}{4n}\right)\right]^{\frac{n}{2-n}}$$

Pressure Loss for laminar flow (ΔP ds)
(Use for v < vc)

$$\Delta P_{ds} = \left[\left(\frac{96v}{d}\right)\left(\frac{3n+1}{4n}\right)\right]^n \times \frac{KL}{300d}$$

Pressure Loss for turbulent flow
(Use for v > vc)

$$\Delta P_{ds} = \frac{\left(3.6033 \times 10^{-4}\right) \times MW^{0.8} \times v^{1.8} \times PV^{0.2} \times L}{d^{1.2}}$$

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Annular pressure loss equations for a Power Law fluid [After Bourgoyne 0et al (1986) and Adams (1985)]

Fluid velocity (v)

$$v = \frac{q}{2.448\left(d_2^2 - d_1^2\right)}$$

Critical velocity (vc)

$$v_c = \frac{1}{60} \times \left[\frac{38{,}780K}{MW}\right]^{\frac{1}{2-n}} \times \left[\left(\frac{2.4}{d_2 - d_1}\right)\left(\frac{2n+1}{3n}\right)\right]^{\frac{n}{2-n}}$$

Pressure Loss for laminar flow (ΔP ds)
(Use for v < vc)

$$\Delta P_{ann} = \left[\frac{144v}{(d_2 - d_1)}\left(\frac{2n+1}{3n}\right)\right]^n \times \frac{KL}{300(d_2 - d_1)}$$

Pressure Loss for turbulent flow
(Use for v > vc)

$$\Delta P_{ann} = \frac{\left(7.7 \times 10^{-5}\right) \times MW^{0.8} \times q^{1.8} \times PV^{0.2} \times L}{(d_2 - d_1)^3 (d_2 + d_1)^{1.8}}$$

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Pressure loss through surface equipment

We can find the pressure loss through surface equipment (ΔP surf) by treating it as an equivalent length of drill pipe. To determine this equivalent length, we simply match our surface equipment specifications to one of the four groups shown next page. For example, if a rig has Group 4 surface equipment and uses 5-inch, 19.5 lb/ft drill pipe, we would, for calculation purposes, add 579 feet to the actual drill pipe length.

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Surface equipment specifications

Component	Typical Combinations							
	Case 1		Case 2		Case 3		Case 4	
	i.d.,in [cm]	L,ft [m]	i.d.,in [cm]	L,ft [m]	i.d.,in [cm]	L,ft [m]	i.d.,in [cm]	L,ft [m]
Standpipe	3 [7.62]	40 [12.192]	3.5 [8.89]	40 [12.192]	4 [10.16]	45 [13.716]	4 [10.16]	45 [13.716]
Drilling hose	2 [5.08]	45 [13.716]	2.5 [6.35]	55 [16.764]	3 [7.62]	55 [16.764]	3 [7.62]	55 [16.764]
Swivel, washpipe, gooseneck	2 [5.08]	4 [1.219]	2.5 [6.35]	5 [1.524]	2.5 [6.35]	5 [1.524]	3 [7.62]	6 1.829]
Kelly	2.25 [5.715]	40 [12.192]	3.25 [8.255]	40 [12.192]	3.25 [8.255]	40 [12.192]	4 [10.16]	40 40
Drill pipe:	Length of surface connections, expressed as equivalent ft [m] of drill pipe							
3.5 inch, 13.3 lb/ft	437 [133.2]	161 [49.1]						
4.5inch, 16.6 lb/ft	761 [232.0]	479 [146.0]	340 [103.6]					
5 inch, 19.5 lb/ft	816 [248.7]	579 [176.5]						

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Drill bit pressure losses

Drill bit pressure losses do not result primarily from friction forces, rather, they are due to the acceleration of the drilling fluid through the bit nozzles. We may express the bit pressure drop in psi as

$$\Delta P_{bit} = \frac{\left(q^2\right)(MW)}{\left(12{,}031 \times C_d{}^2\right)\left(A_T{}^2\right)}$$

where q = circulation rate, gal/min (U.S.)

MW = mud weight, lbm/gal

Cd = nozzle discharge coefficient (dimensionless)

AT = total nozzle area, in2

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Example

Determine the bit pressure drop for the following well:
Total Depth=9,950 ft
Casing: 9 5/8 inch, 43.50 lb/ft (8.755 in. i.d) cemented at 6,500 ft.
Open hole: 8 1/2 inch from 6,500 ft to 9,950 ft (T.D.)
Drill string:

- Drill pipe: 9500 ft. of 4 1/2 inch, 16.60 lb/ft (3.826 in. i.d.)
- Bottom hole assembly: 450 ft. of 6 3/4 inch o.d. x 2 1/4 inch i.d. drill collars and tools

Mud properties:

- Mud weight (MW)=10.5 lbm/gal
- Plastic viscosity (PV)=35 cp
- Yield point (YP)=6 lbf/100 ft2
- Assume Bingham Plastic fluid

Circulating rate=300 gal/min
Pump pressure=2,200 psi
Surface Equipment:

- Standpipe: 45 ft x 4 in. i.d
- Hose: 55 ft x 3 in. i.d.
- Swivel, washpipe, gooseneck: 5 ft x 2.5 in. i.d
- Kelly: 40 ft x 3.25 in. i.d.

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Solution

Solution:

1. Note first that the surface components correspond to a Case 3 equipment combination. The pressure loss through these components is equivalent to 479 ft. of 4 1/2 in., 16.6 lb/ft drill pipe. We can therefore combine ΔPsurf with our calculation of ΔPds.
2. Determine the pressure losses inside the drill string (ΔPds). This involves separate calculations for the drill pipe and the bottomhole assembly:

   a) Drill pipe:

$$v = \frac{q}{2.448d^2} = \frac{300}{2.448 \times 3.826^2} = 8.37 \text{ ft/s}$$

$$v_c = \frac{1.08PV + 1.08\sqrt{PV^2 + 12.34 \times d^2 \times YP \times MW}}{MW \times d}$$

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Solution

$$v_c = \frac{1.08(35) + 1.08\sqrt{(35)^2 + 12.34 \times 3.826^2 \times 6 \times 10.5}}{10.5 \times 3.826}$$

=3.96 ft/s v > vc turbulent flow

$$\Delta P_{dp} = \frac{MW^{0.75} \times v^{1.75} \times PV^{0.25} \times L}{1800d^{1.25}}$$

$$\Delta P_{dp} = \frac{10.5^{0.75} \times 8.37^{1.75} \times 35^{0.25} \times (9500 + 479)}{1800(3.826)^{1.25}}$$

= 605 psi

(Note that we accounted for surface pressure losses by adding in the drill pipe equivalent length of 479 ft)

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Solution

b) Bottomhole assembly:

$$v = \frac{q}{2.448d^2} = \frac{300}{2.448 \times 2.25^2} = 24.2 \ \text{ft/s}$$

$$v_c = \frac{1.08PV + 1.08\sqrt{PV^2 + 12.34 \times d^2 \times YP \times MW}}{MW \times d}$$

$$v_c = \frac{1.08(35) + 1.08\sqrt{(35)^2 + 12.34 \times 2.25^2 \times 6 \times 10.5}}{10.5 \times 2.25}$$

4.88 ft/s v > vc turbulent flow

$$\Delta P_{dp} = \frac{MW^{0.75} \times v^{1.75} \times PV^{0.25} \times L}{1800d^{1.25}}$$

$$\Delta P_{dp} = \frac{10.5^{0.75} \times 24.2^{1.75} \times 35^{0.25} \times 450}{1800(2.25)^{1.25}}$$

= 340 psi

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Solution

ΔPds=ΔPdp+ΔPbha=605+340=945 psi

3. Determine the pressure losses in the annulus. (ΔPann). This involves separate calculations for the cased-hole section (surface to 6,500 ft), the drill pipe/hole annulus (6,500 - 9,500 ft) and the BHA/hole annulus (9,500 - 9,050 ft).

a) Cased-hole annulus (surface-6500 ft):

$$v = \frac{q}{2.448\left(d_2^2 - d_1^2\right)} = \frac{300}{2.448\left(8.755^2 - 4.5^2\right)} = 2.17 \ \text{ft/s}$$

$$v_c = \frac{1.08PV + 1.08\sqrt{PV^2 + 9.26(d_2 - d_1)^2 \times YP \times MW}}{MW(d_2 - d_1)}$$

$$= \frac{1.08(35) + 1.08\sqrt{(35)^2 + 9.26(8.755 - 4.5)^2 \times 6 \times 10.5}}{10.5(8.755 - 4.5)}$$

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Solution

$= 3.47$ ft/s $v < vc$ laminar flow

$$\Delta P_{ann(cased\ hole)} = \frac{PV \times L \times v}{1000(d_2 - d_1)^2} + \frac{YP \times L}{200(d_2 - d_1)}$$

$$= \frac{35 \times 6500 \times 2.17}{1000(8.755 - 4.5)^2} + \frac{6 \times 6500}{200(8.755 - 4.5)}$$

$= 73$ psi

b) Drill pipe/hole annulus (6,500 ft - 9,500 ft):

$$v = \frac{q}{2.448\left(d_2{}^2 - d_1{}^2\right)} = \frac{300}{2.448\left(8.5^2 - 4.5^2\right)} = 2.36 \text{ ft/s}$$

Assume laminar flow (critical velocity will be close to that calculated for the cased-hole annulus)

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Solution

$$\Delta P_{ann(dp/hole)} = \frac{35 \times 3000 \times 2.36}{1000(8.5 - 4.5)^2} + \frac{6 \times 3000}{200(8.5 - 4.5)}$$

$= 38$ psi

c) BHA/open hole annulus:

$$v = \frac{300}{2.448\left(8.5^2 - 6.75^2\right)} = 4.59 \text{ ft/s}$$

$$v_c = \frac{1.08(35) + 1.08\sqrt{(35)^2 + 9.26(8.5 - 6.75)^2 \times 6 \times 10.5}}{10.5(8.5 - 6.75)}$$

$= 5.28$ ft/s $v < vc$ laminar flow

$$\Delta P_{ann(BHA/hole)} = \frac{35 \times (9950 - 9500) \times 4.59}{1000(8.5 - 6.75)^2} + \frac{6 \times (9950 - 9500)}{200(8.5 - 6.75)} = 31 \text{ psi}$$

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Solution

Total annular pressure losses: $\Delta Pann=73 + 38 + 31 = 142$ psi

4. Determine pressure loss at bit:

$\Delta Pbit=Ppump-(\Delta Psurf+\Delta Pds)-\Delta Pann=2200 - 945 - 142= 1,113$ psi

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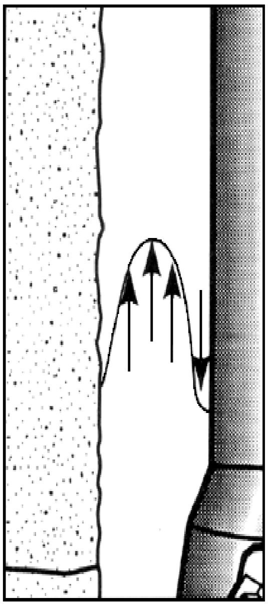
Surge and Swab Pressure

✓When we run pipe in a well, it forces drilling mud up the annulus and out of the flow line. At the same time, the mud immediately adjacent to the pipe is dragged down hole, as shown in Figure (*Annular flow profile resulting from downward movement*).

✓The resulting piston effect generates a surge pressure that is added to the hydrostatic pressure. Excessive surge pressures can increase the wellbore pressure to such a degree as to induce lost circulation.



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Surge and Swab Pressure

Conversely, when we pull pipe out of a well, mud flows down the annulus to fill the resulting void. This causes a suction effect, generating a swab pressure that can lower the differential pressure and possibly bring formation fluid into the wellbore.

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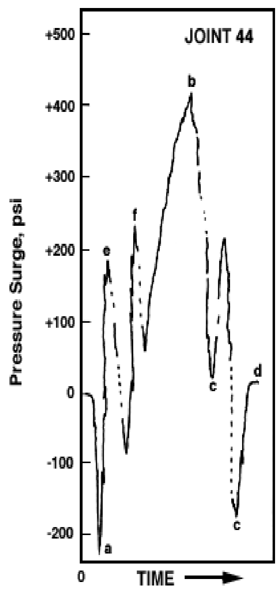
Surge and Swab Pressure

Typical pressure surge pattern for a joint of casing lowered into a wellbore) shows the pressure fluctuations that resulted from lowering casing into a mud-filled wellbore, and illustrates the significance of surge and swab effects.



(Burkhardt, 1961. Courtesy of Society of Petroleum Engineers)

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Calculating surge and swab pressures

➢Calculating surge and swab pressures can be a complex undertaking, depending on the pipe configuration and hole geometry. Burkhardt (1961) developed a relationship between well geometry and the effect of the mud being dragged by the pipe, which is referred to as the clinging constant, K (Next figure , *Mud clinging constant K as a function of annular geometry*).

➢To apply the clinging constant, we need to know the mud velocity in the annulus. For a closed drill string, this is equal to

$$v_{mud} = -v_{pipe}\left(\frac{d_1^{\,2}}{d_2^{\,2} - d_1^{\,2}}\right)$$

where v pipe = pipe velocity
d2 = hole diameter
d1 = pipe outside diameter

Calculating surge and swab pressures

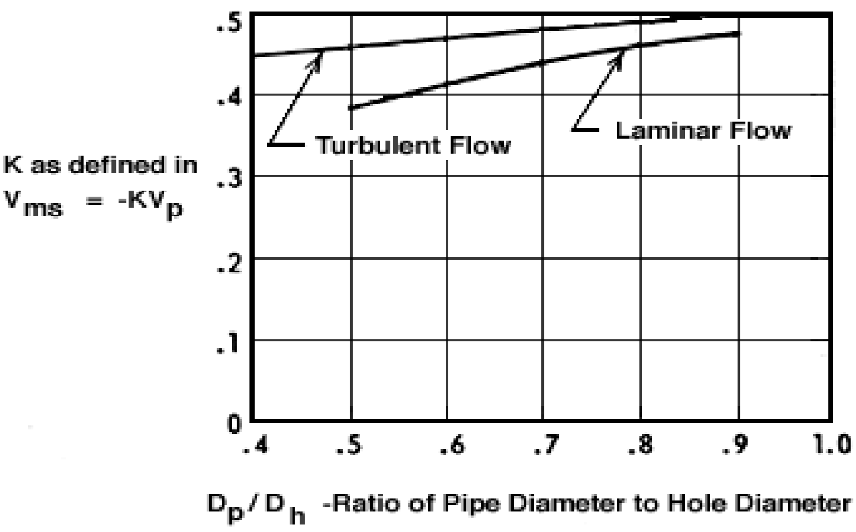
For open-ended pipe,

$$v_{mud} = -v_{pipe}\left[\frac{4d_1^{\,2}(d_2 - d_1)^2 - 3d_1^{\,4}}{4(d_2 - d_1)^2\left(d_2^{\,2} - d_1^{\,2}\right) + 6d_1^{\,4}}\right]$$

The effective annular velocity is equal to

$$v_e = v_{mud} - Kv_{pipe}$$

Calculating surge and swab pressures



(Burkhardt, 1961. Courtesy of Society of Petroleum Engineers)

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Example : Surge effects

Calculate the surge pressure generated by running a string of 10 3/4 inch casing under the following conditions, and determine whether the total wellbore pressure exceeds the fracture gradient. Assume that the casing is effectively “closed” with a float shoe.

Casing point = 6400 ft
Fracture gradient = 0.82 psi/ft
Pipe velocity = -110 ft/min = -1.83 ft/s ("-" denotes downward velocity)
Hole diameter = 14 3/4 inches
Mud: 15.0 lbm/gal; PV=37 cp, YP=6 lbf/100 ft2

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Solution:

$$v_{mud} = -v_{pipe}\left(\frac{d_1{}^2}{d_2{}^2 - d_1{}^2}\right)$$

$$= 1.83 \times \left(\frac{10.75^2}{14.75^2 - 10.75^2}\right)$$

= 2.07 ft/s

d1/d2= 10.75/14.75=0.73; from Figure , K=0.44 (assume laminar flow)

$$v_e = 2.07 - (0.44 \times 1.83) = 1.265 \text{ ft/s}$$

Use annular pressure loss equation for laminar flow:

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Solution:

$$\Delta P_{ann} = \frac{PV \times L \times v}{1000(d_2 - d_1)^2} + \frac{YP \times L}{200(d_2 - d_1)}$$

$$P_{surge} = \frac{37 \times 6400 \times 1.265}{1000(14.75 - 10.75)^2} + \frac{6 \times 6400}{200(14.75 - 10.75)}$$

P surge = 67 psi

$$EMW = \frac{67}{0.052 \times 6400} + 15.0 = 15.2 \text{ lb}_m/\text{gal}$$

$$EMW_{frac} = \frac{0.82}{0.052} = 15.77 \text{ lb}_m/\text{gal}$$

EMW < EMW fra

We can substitute the effective velocity into the friction pressure loss equations for a given flow regime to compute the surge (or swab) pressure.

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Hole Cleaning

❑From the time that rotary drilling came into its own with the dramatic Spindletop discovery of 1901, it was destined to ultimately replace the once dominant cable tool methods. Rotary drillers found out early on that they had a major advantage over cable tool operators: the ability to continuously remove drilled cuttings (as opposed to periodically removing them with a bailer).

❑Cuttings removal and transport are still primary functions of the drilling mud. Additionally, the mud must be able to hold these cuttings in suspension when circulation stops. The mud's effectiveness at removing cuttings significantly affects drilling efficiency.

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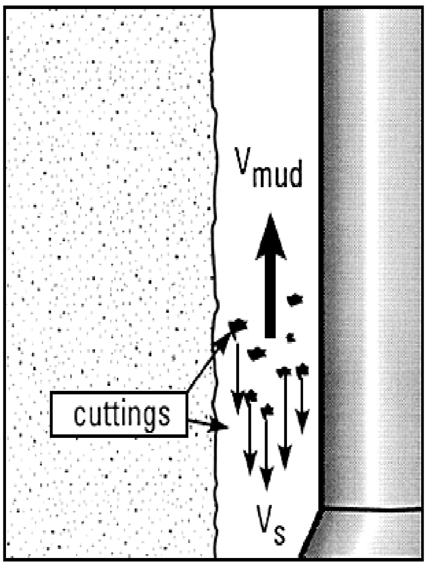
Hole Cleaning

- Drilled cuttings vary in size and density according to formation lithology, differential pressure, the cutting action of the bit and other factors. They are usually heavier than the drilling mud, and therefore tend to slip down through the annulus, back toward the bottom of the hole. A mud's ability to transport cuttings -- that is, its carrying capacity -- is related to the difference between the annular velocity and the slip velocity with which the cuttings fall (Figure , *Carrying capacity depends on a mud's annular velocity and the slip velocity with which cuttings fall back to bottom*).



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Hole Cleaning

Moore (1974), Chien (1971) and Walker and Mayes (1975) are among those who have developed correlations for estimating slip velocity (this section presents Moore's correlation by way of example). To use these methods, we need to determine the average densities and diameters of drilled solids by visually inspecting representative cuttings, or by doing a sieve or screen analysis.

We can use the following relationship to estimate the slip velocity of a particle suspended in a Newtonian fluid:

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where vs = slip velocity, ft/s

dp = particle diameter, inches

rp = particle density, lbm/gal

rf = fluid density, lbm/gal

Cdrag = drag coefficient

1.89 = numerical value of conversion constant, which has units of [ft2/(sec2-in)]1/2. In SI units, 1.89 becomes 3.615.

To determine the drag coefficient, we must first compute the particle Reynolds number (NRep):

$$N_{Re_p} = \frac{928 \times \rho_f \times v_s \times d_p}{\mu}$$

where μ = fluid viscosity, cp

In SI units (kg/m3, m/s,m, Pa-s), 928 reduces to 1.

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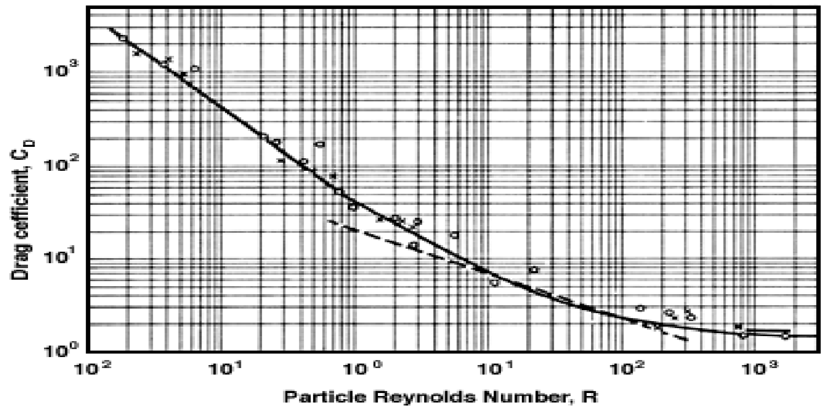
Hole Cleaning

We can then obtain Cdrag from Figure below (*Particle drag coefficient as a function of the particle Reynolds number*). As we can see, this is an iterative process.



(Moore, 1986)

Hole Cleaning

For (NRep) <1, Cdrag=40/(NRep) and

$$v_s = \frac{82.87 \times d_p^{\,2} \times \left(\rho_p - \rho_f\right)}{\mu_a}$$

For (NRep) >2,000 (turbulent flow), Cdrag has a constant value of about 1.5, and

$$v_s = 1.54 \sqrt{\frac{d_p\left(\rho_p - \rho_f\right)}{\rho_f}}$$

For intermediate particle Reynolds number values (i.e., 10< (NRep) <100) Cdrag $= 22 / \sqrt{N_{Rep}}$

$$v_s = \frac{2.90 \times d_p \times \left(\rho_p - \rho_f\right)^{0.667}}{\left(\rho_f\right)^{0.333}\left(\mu_a\right)^{0.333}}$$

Hole Cleaning

The term µa in these equations is the apparent viscosity, given in units of centipoise and defined as follows:

$$\mu_a = \left(\frac{K}{144}\right) \times \left(\frac{d_2 - d_1}{v}\right)^{1-n} \times \left(\frac{2+\frac{1}{n}}{0.0208}\right)^n$$

where K= consistency index = $\dfrac{\theta_{300}}{511^n}$

n = flow behavior index = $3.32 \times \log\left(\dfrac{\theta_{600}}{\theta_{300}}\right)$

v = fluid velocity, ft/s

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Example 1: Slip velocity (Moore's method)

Calculate the slip velocity of drilled cuttings having an average diameter of 0.25 inches and a density of 2.65 g/cc (22.1 lbm/gal), given the following mud and hole data:

- Hole size=12.25 inches
- Drill pipe=5 inches
- MW=10.2 lbm/gal
- Annular Velocity=60 ft/min (1.0 ft/s)
- n (from viscometer readings)=0.8
- K=150 cp equivalent
- Solution:
- 1. Determine apparent viscosity (µa):

$$\mu_a = \left(\frac{K}{144}\right) \times \left(\frac{d_2 - d_1}{v}\right)^{1-n} \times \left(\frac{2+\frac{1}{n}}{0.0208}\right)^n$$

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Example 1: Slip velocity (Moore's method)

$$\mu_a = \left(\frac{150}{144}\right) \times \left(\frac{1225-50}{10}\right)^{1-0.8} \times \left(\frac{2+\frac{1}{0.8}}{0.0208}\right)^{0.8}$$

= 88.1 cp

2. Assume an (NRep) range and then check the results obtained:

Let (NRe p) <1:

$$v_s = \frac{82.87 \times d_p{}^2 \times (\rho_p - \rho_f)}{\mu_a} \qquad v_s = \frac{82.87 \times 0.25^2 \times (22.1 - 10.2)}{88.1}$$

=0.7 ft/s

Verification: $N_{Re_p} = \dfrac{928 \times 10.2 \times 0.7 \times 0.25}{88.1}$

(NRep) >1.0 first assumption was invalid

Assume 1.0< (NRe p) <100:

Example 1: Slip velocity (Moore's method)

$$v_s = \frac{2.90 \times d_p \times (\rho_p - \rho_f)^{0.667}}{(\rho_f)^{0.333} (\mu_a)^{0.333}}$$

$$v_s = \frac{2.9 \times 0.25 \times (22.1 - 10.2)^{0.667}}{(10.2)^{0.333} (88.1)^{0.333}}$$

vs = 0.39 ft/s

Verification $N_{Re_p} = \dfrac{928 \times 10.2 \times 0.39 \times 0.25}{88.1}$

(NRep) = 10.5 Þ assumption was valid

3. Annular velocity = 1.0 ft/s;

Net upward velocity of cuttings = (1.0-0.39)

= 0.61 ft/s, or 37 ft/min.

Minimum Cost Drilling

- Most optimization methods are based on determining what set of operating parameters results in the minimum cost (C) to drill a given interval, where
- **C = (Bit costs) + (Trip costs) + (Rotating, or "on bottom" costs)**
- We usually express this relationship in terms of the cost to drill one foot (or meter) of interval:

$$\left[\frac{C}{\Delta D}\right] = \frac{C_{bit} + C_{rig}(t+T)}{\Delta D}$$

Where: C = overall drilling cost
ΔD = ft [m] of interval drilled
Cbit = bit cost
Crig = hourly rig cost
t = trip time, hours
T = rotating time, hours

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Rig Rates

$35-150 thousand/day

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Minimum Cost Drilling

Equation above is a basic tool in bit selection and in evaluating drilling performance under various sets of operating conditions. We can use it both for analyzing historical drilling data (i.e., from offset wells), and for monitoring the current bit run.

We can best evaluate cost per foot on the basis of *single bit runs*. This provides us with a means of comparing individual bits, and also allows us to make the following assumptions:

· Since the bit is already in the hole, Cbit is constant.

· Hourly rig cost is unlikely to vary significantly during a bit run; we can therefore consider Crig a constant.

· Trip time (t) does not change during the bit run

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Minimum Cost Drilling

We can thus define bit cost, rig cost and trip time as fixed cost parameters.

· Bit cost (Cbit), depending on a bit's size, type and condition (i.e., new or used), may range from several hundred to tens of thousands of dollars. We can group bit types into two basic categories:

-- Rolling cutter, which includes milled steel tooth and tungsten carbide insert bits

-- Fixed cutter, which includes steel cutter, natural diamond and polycrystalline diamond compact (PDC) bits

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Minimum Cost Drilling

Within these basic categories are an ever-growing variety of sub-classifications and a wide array of design features. Selection of a particular bit type is based on offset well records (when available) or earlier bit runs on the current well. Major considerations in bit selection include the following:

-- Formation hardness and abrasiveness
-- Mud type (oil-based, water-based, air or foam)
-- Differential pressure (amount of overbalance)
-- Directional or horizontal drilling requirements
-- Type of rotating system (rotary table or downhole mud motor)
-- Coring requirements
-- Hole size

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Minimum Cost Drilling

The effect of bit selection on overall cost per foot depends not only on the bit's cost, but also on its performance. An inexpensive bit (or, conversely an expensive, high-performance bit) may or may not result in minimum cost per foot.

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Example : Effect of bit cost

Compare the cost per foot of the bit runs shown in **Table 1.**, given a rig cost of $200/hour and a trip time of 12 hours.

Solution:

	Bit cost	Rotating time (T)	Footage (ΔD)
Bit 1	$1200	12.5 hrs	240 ft
Bit 2	$4500	24.9 hrs	504 ft
Bit 3	$12,000	45.1 hrs	902 ft

Table 1. *Effect of Bit Cost on Cost/ft (Example)*

Bit 1: $$\left[\frac{C}{\Delta D}\right]=\frac{1200+200(12+12.5)}{240}=\$25.42/\mathrm{ft}$$

Bit 2: $$\left[\frac{C}{\Delta D}\right]=\frac{4500+200(12+24.9)}{504}=\$23.57/\mathrm{ft}$$

Bit 3: $$\left[\frac{C}{\Delta D}\right]=\frac{12{,}000+200(12+45.1)}{902}=\$25.96/\mathrm{ft}$$

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Example : Effect of bit cost

Bit 2, which was neither the cheapest nor the most expensive, nevertheless had the most economical run. Note that even though the bit costs vary significantly, differences in performance result in similar costs per foot.

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Rig cost

·Rig cost (Crig)reflects all of the operating expenses directly related to drilling the well. These include the equivalent hourly rate for the drilling rig and crew, along with costs for

- rental equipment (e.g., blowout preventers, solids control equipment, drill string tools)
- services (e.g., directional drilling or mud consultants)
- mud logging
- drilling mud materials and services
- transportation of drilling equipment and materials
- allocated supervision and administration

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Rig cost

Examples of items that would not be included in hourly drilling costs are

-- site preparation and cleanup
-- casing, tubing and completion equipment
-- well head equipment
-- formation evaluation, including logging and testing
-- materials and services for running casing, cementing, perforating and running production equipment
-- stimulation or sand control
-- supervision and administration, unless specifically allocated to the job
-- most well problems

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Rig cost

▪Rig costs vary considerably according to supply and demand, location, drilling environment, well requirements, rig type, standard equipment and contract provisions.

▪Without entering into a discussion of the bidding and rig selection process, we should note that the cheapest hourly cost may not necessarily result in minimum cost per foot.

▪Those involved in rig selection must also consider the efficiency of the contractor's personnel and equipment.

▪ A highly competent crew and a well-maintained rig may justify extra expense.

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Trip time

The trip time (t) required to run and pull a bit depends on such factors as
-- well depth
-- hole size
-- required mud trip margin
-- bottomhole assembly configuration
-- presence of hole problems
-- hoisting capacity
-- use of automatic pipe-handling systems
-- rig and crew efficiency.

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Trip time

A common "rule of thumb" for estimating trip time, and one that is reasonably accurate over the life of a well, is to assume one hour of trip time to run or pull 1,000 feet of pipe.

As an alternative, **Table** below, can be used to estimate trip times for various hole sizes. When making cost per foot calculations, the trip time should include hours spent reaming back to bottom, as well as any "short trips" that may be required.

Table . *Average trip times in hours, compiled from field studies (After Adams, 1985)*

	Hole size, inches [cm]		
Depth, ft [m]	**< 8.75 [22.23]**	**8.75-9.875 [22.23-25.08]**	**> 9.875 [25.08]**
2,000 [610]	1.5	3.0	4.5
4,000 [1219]	2.5	4.2	5.75
6,000 [1829]	3.5	5.4	7.0
8,000 [2438]	4.7	5	8.0
10,000 [3048]	5.8	7.25	9.0
12,000 [3658]	7.0	8.25	10.25
14,000 [4267]	8.25	9.25	11.5
16,000 [4877]	9.75	10.25	12.5
18,000 [5486]	11.00	11.25	13.75
20,000 [6096]	11.8	12.25	15.0

Rotating hours (T) and drilled depth (ΔD)

Rotating hours (T) and drilled depth (ΔD) depend on a wide range of factors, some of which may change during a bit run. We thus refer to these elements of Equation 2 as *variable* cost parameters.

The average penetration rate for a bit run is equal to ΔD/T ,while the instantaneous penetration rate at any given time is defined as dD/dT.

Intuitively, we might expect that the longest bit runs and/or highest penetration rates result in minimum costs per foot. This is true in many cases. But as the following example shows, intuition can sometimes be misleading.

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Example : Effect of footage and rotating hours

Determine the cost/ft of the bit runs shown in **Table below.**, given a rig cost of $275.00/hour and a trip time of 9.5 hours. Each bit costs $4300.

Table 3. *Sample Bit Run Data*

	Rotating time (T)	**Footage (ΔD)**	**Average penetration rate, R = ΔD/T**
Bit 1	18.7 hrs	309 ft	15 ft/hr
Bit 2	24.5 hrs	374 ft	15.3 ft/hr
Bit 3	30.0 hrs	399 ft	13.3 ft/hr

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Example : Effect of footage and rotating hours

Solution:

Bit 1: $$\left[\frac{C}{\Delta D}\right] = \frac{4300 + 275(9.5 + 18.7)}{309} = \$39.01\Big/_{ft}$$

Bit 2: $$\left[\frac{C}{\Delta D}\right] = \frac{4300 + 275(9.5 + 24.5)}{374} = \$36.50\Big/_{ft}$$

Bit 3: $$\left[\frac{C}{\Delta D}\right] = \frac{4300 + 275(9.5 + 30.0)}{399} = \$38.00\Big/_{ft}$$

Bit 2 had neither the longest run, the most footage nor the highest average penetration rate; it was nevertheless the most economical.

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Rig cost

Rig cost (Crig) reflects all of the operating expenses directly related to drilling the well. These include the equivalent hourly rate for the drilling rig and crew, along with costs for

-- rental equipment (e.g., blowout preventers, solids control equipment, drill string tools)

-- services (e.g., directional drilling or mud consultants)

-- mud logging

-- drilling mud materials and services

-- transportation of drilling equipment and materials

-- allocated supervision and administration

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Rig cost

Examples of items that would not be included in hourly drilling costs are
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A common "rule of thumb" for estimating trip time, and one that is reasonably accurate over the life of a well, is to assume one hour of trip time to run or pull 1,000 feet of pipe.

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As an alternative, **Table** below, can be used to estimate trip times for various hole sizes.

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18,000 [5486]	11.00	11.25	13.75
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Rotating hours

- Rotating hours (T) and drilled depth (DD) depend on a wide range of factors, some of which may change during a bit run.
- We thus refer to these elements of Equation cost as *variable* cost parameters.
- The average penetration rate for a bit run is equal to ΔD/T ,while the instantaneous penetration rate at any given time is defined as dD/dT.
- Intuitively, we might expect that the longest bit runs and/or highest penetration rates result in minimum costs per foot.
- This is true in many cases. But as the following example shows, intuition can sometimes be misleading.

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Example : Effect of footage and rotating hours

Determine the cost/ft of the bit runs shown in **Table below**, given a rig cost of $275.00/hour and a trip time of 9.5 hours. Each bit costs $4300.

Table 3. *Sample Bit Run Data (Example 2)1.3*

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Solution:

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Bit 3: $$\left[\frac{C}{\Delta D}\right] = \frac{4300 + 275(9.5 + 30.0)}{399} = \$38.00/\text{ft}$$

Bit 2 had neither the longest run, the most footage nor the highest average penetration rate; it was nevertheless the most economical.

Overall cost/ft

The overall cost/ft of a bit run is equal to the sum of its fixed and variable costs. In terms of cost per foot,

$$\left[\frac{C}{\Delta D}\right] = \left[\frac{C_{fixed}}{\Delta D}\right] + \left[\frac{C_{variable}}{\Delta D}\right]$$

where :
$$\left[\frac{C_{fixed}}{\Delta D}\right] = \frac{C_{bit} + (C_{rig} \times t)}{\Delta D} \quad *$$

and
$$\left[\frac{C_{variable}}{\Delta D}\right] = \frac{C_{rig} \times T}{\Delta D} \quad **$$

Overall cost/ft

Equation * indicates that where bit cost, rig cost and trip time are constant, drilled depth is the governing parameter in determining fixed costs, while Equation ** shows an inverse relationship between variable cost and penetration rate.

The relative contributions of fixed and variable costs to overall drilling cost can change significantly during a bit run. When the bit first starts to drill, most of the operating expense is attributable to bit cost and trip time. As the bit continues to drill, the fixed cost begins to decrease. At the same time, the variable costs increase until they eventually overtake the fixed costs. The net effect of these changing contributions is that overall cost per foot decreases from a high initial value to a minimum, and then begins to increase as the bit dulls.

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Example : Fixed and Variable Costs

Given the information in **Table below,** calculate the fixed and variable costs for the following bit run. Determine the time at which the overall cost per foot reached a minimum.

Rig cost: \$200/hr Bit cost: \$5200

Trip time: 8 hr Bit pulled at 45 hr

Average bit weight: 60,000 lbf Average rotary speed: 90 RPM

Mud Weight: 10.0 lbm/gal dD/dT = instantaneous penetration rate

Table: *Bit run data.*

ΔD (ft)	**T (hours)**	**dD/dT (ft/hr)**
40	1	40.0
200	5	40.0
392	10	38.4
550	15	31.6
694	20	28.8
806	25	22.4
893	30	17.4
937	35	8.8
971	40	6.8
998	45	5.4

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Solution

DD, ft	T, hr	$\frac{dD}{dT}$, ft/hr	$\frac{C_{fixed}}{\Delta D}$, \$/ft	$\frac{C_{variable}}{\Delta D}$ \$/ft	$\frac{C}{\Delta D}$ \$/ft
40	1	40.0	170.00	5.00	175.00
200	5	40.0 3	4.00	5.00	39.00
392	10	38.4	17.35	5.10	22.45
550	15	31.6	12.36	5.45	17.82
694	20	28.8	9.80	5.76	15.56
806	25	22.4	8.44	20	14.64
893	30	17.4	7.61	6.72	14.33
937	35	8.8	7.26	7.47	14.73
971	40	6.8	7.00	8.24	15.24
998	45	5.4	6.81	9.02	15.83

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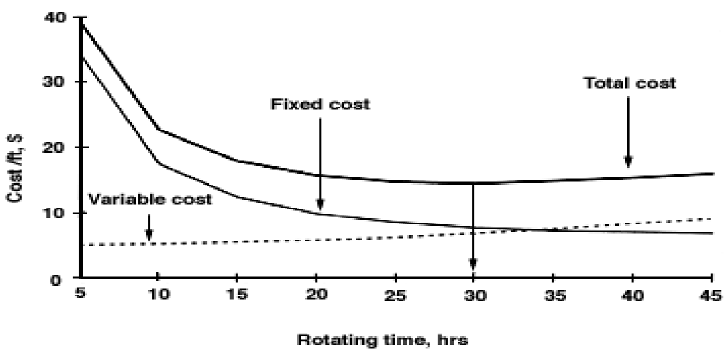
Solution

Minimum cost per foot of \$14.33 occurs at T = 30 hours.
It is interesting to note that the initial high cost per foot is due mainly to bit cost, and begins to drop off rapidly as the bit accumulates time on bottom. However, cost per foot does eventually reach a minimum--beyond this point, it is not economical to continue the bit run.



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Cost/ft

➢In the preceding example, we determined minimum cost per foot for a specific set of operating conditions (bit weight = 60,000 lbf, rotary speed = 90 RPM, mud weight = 10.0 lbm/gal).

➢We did not address the issue of how these conditions might have affected the bit run and our subsequent calculations. Would a different set of conditions have resulted in better drilling performance and lower cost per foot? If so, what are these conditions?

➢These are the sorts of questions that optimization efforts address.

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Cost/ft

There is an effective balance between drilling parameters that results in minimum cost drilling. The drilling engineer's job is to establish this balance by

- identifying the variables that affect these parameters
- determining what combination of these variables most favorably influences cost per foot

Since bit cost, rig cost and trip time are assumed constant for a single bit run, our primary concerns are rotating hours (i.e., bit life), drilled footage and instantaneous penetration rate (dD/dT).

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Factors Affecting Penetration Rate

There are many variables that affect how fast and for how long we can drill a given interval. They include:

- formation properties
- mud properties
- hydraulics
- bit type
- weight on bit
- rotary speed
- bit tooth wear

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Factors Affecting Penetration Rate

The relationships between each of these variables and drilling performance may involve many unknowns, making it difficult to develop a comprehensive drilling model. To get around this difficulty, researchers typically establish conditions where they can study the effects of one variable while holding the others constant. Correlations are, for the most part, empirical, and are based on laboratory and field data for specific areas or rock types.

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Formation properties

The most important formation properties with respect to drilling performance include:

- compressive strength and elastic limit
- porosity
- permeability

A highly porous, permeable formation with low compressive strength generally exhibits higher penetration rates than a high-strength, "tight" formation.

Formation depth plays a significant role in determining penetration rates. Compaction normally increases with increasing depth, resulting in lower porosity, higher compressive strength and, consequently, lower penetration rates. Mineralogical characteristics such as abrasiveness and hydration are also important in determining drilling performance.

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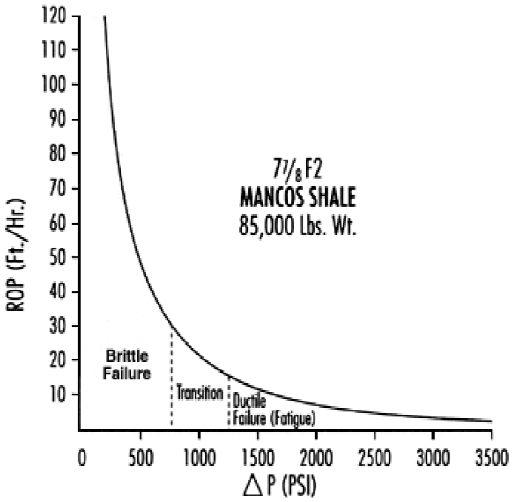
Mud properties

Mud properties also affect penetration rate. In a normal-pressure environment, differential pressure between the wellbore and the formation increases with increasing mud weight, inhibiting cuttings removal and causing penetration rates to decrease (Figure below , *Effect of differential pressure on penetration rate*).

Penetration rates also tend to decrease with increasing viscosity and solids content, while they usually increase with higher filtration rates.



(courtesy Smith International)

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bit type

The bit size used for a given interval depends mainly on completion requirements for pipe size, while the bit type is based primarily on formation characteristics.

Hydraulics

Formation properties are critical in determining drilling performance. At the same time, they are beyond our control. Mud properties and bit types, though they are controllable, do not change significantly during a normal bit run. We can, however, control hydraulics, bit weight and rotary speed. Drilling performance depends largely on how well we remove cuttings from the bottom of the hole. If hole cleaning is inadequate, the bit flounders--that is, its penetration rate decreases because it is regrinding unremoved cuttings or becoming buried in the formation. Fortunately, we can exercise a great deal of control over hole cleaning simply by varying a bit's jet nozzle diameters. Our objective is to deliver an optimum amount of hydraulic energy through these nozzles. In addition to removing cuttings, this energy works to cool the bit.

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Hydraulics

Hydraulic energy is related to pressure loss. The pressure loss across a bit (ΔPbit) is equal to the mud pump pressure (Ppump) minus the frictional pressure losses in the circulating system (ΔPf)

$$\Delta P_{bit} = P_{pump} - \Delta P_f$$

where ΔPf is the sum of the pressure losses in the surface equipment, drill pipe, bottomhole assembly and annulus.

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Hydraulics

We most commonly optimize bit hydraulics in terms of hydraulic horsepower (HHP), impact force (IF) or nozzle velocity (vn):

$$HHP = \frac{\Delta P_{bit} \times q}{1{,}714}$$

where q = circulation rate, gal/min (U.S.);
HHP is in units of horsepower

$$IF = 0.01823 \times C_d \times q\sqrt{\Delta P_{bit} \times MW}$$

where IF = impact force, lbf
MW = mud weight (lbm/gal)
Cd = nozzle discharge coefficient, normally equal to 0.95

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Hydraulics

$$v_n = 0.32086 \times \left(\frac{q}{A_T}\right)$$

where vn = nozzle velocity, ft/sec
q = flow rate through nozzles, gal/min
AT = total nozzle area, in2

The pressure drop across the bit nozzles, expressed in psi, is equal to

$$\Delta P_{bit} = \frac{\left(q^2\right)(MW)}{\left(12{,}031 C_d^{\,2}\right)\left(A_T^{\,2}\right)}$$

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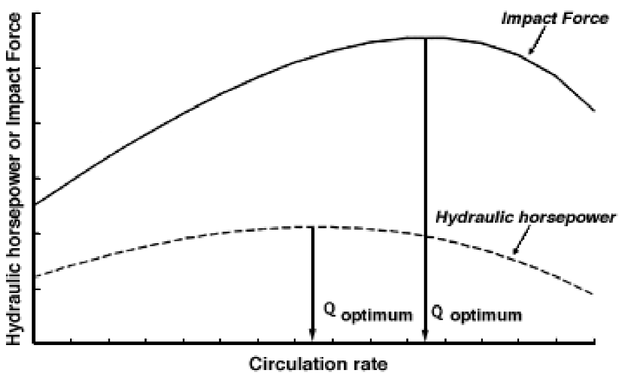
Hydraulics

Because of the higher friction pressure that accompanies increased circulation rates, hydraulic horsepower or impact force is limited by the pressure rating of the mud pumps. There are optimal circulation rates for which HHP and IF are maximums (Figure , *Bit hydraulic horsepower and impact force as functions of circulation rate*). At higher rates, friction losses become excessive.



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Hydraulics

We can show mathematically that maximum bit HHP occurs when

$$\Delta P_f = \frac{P_{pump}}{n+1}$$

and that maximum bit impact force occurs when

$$\Delta P_f = \frac{2P_{pump}}{n+2}$$

where n is a flow exponent determined from a logarithmic plot of pressure versus flow rate at two points:

$$n = \frac{\log(P_1/P_2)}{\log(q_1/q_2)}$$

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Example : Optimizing Hydraulic Horsepower and Impact Force (After Adams, 1985):

Determine the optimal jet sizes, based on hydraulic horsepower and on impact force criteria, for the following well.

Pump rate #1 = 420 gal/min at 3000 psi
Pump rate #2 = 275 gal/min at 1300 psi
Pump horsepower = 1250 HP
Mud weight = 13.0 lbm/gal
Nozzle sizes = 17/32 in. diameter (3 nozzles)
Minimum annular velocity = 70 ft/min (1.167 ft/s)
Minimum pump rate = 175 gal/min
Hole size = 8.5 in.
Drill pipe = 4.5 in.
Drill collars = 7 in.

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Solution

Maximum flow rate:

$$HHP = \frac{P \times q}{1{,}714}$$

$$1{,}250 = \frac{3{,}000 \times q}{1{,}714}$$

$$q = 714 \ \text{gal/min}$$

Minimum flow rate, based on minimum annular velocity:

$$v = \frac{q}{2.448\left(d_2^{\,2} - d_1^{\,2}\right)}$$

$$1.167 = \frac{q}{2.448\left(8.5^2 - 4.5^2\right)} \Rightarrow q = 148 \ \text{gal / min}$$

Solution

Frictional pressure losses

$$\Delta P_f = P_{pump} - \frac{(MW)\left(q^2\right)}{12{,}031\left(C_d^{\,2}\right)\left(A_T^{\,2}\right)}$$

Rate 1:

$$\Delta P_f = 3{,}000 - \frac{(13)\left(420^2\right)}{12{,}031\left(0.95^2\right)\left[3 \times \frac{\pi}{4} \times \left(\frac{17}{32}\right)^2\right]^2} = 2{,}523 \ \text{psi}$$

Rate 2:

$$\Delta P_f = 1{,}300 - \frac{(13)\left(275^2\right)}{12{,}031\left(0.95^2\right)\left[3 \times \frac{\pi}{4} \times \left(\frac{17}{32}\right)^2\right]^2} = 1{,}095 \ \text{psi}$$

Solution

Flow exponent (n):

$$n = \frac{\log(P_1/P_2)}{\log(q_1/q_2)}$$

$$n = \frac{\log(3{,}000/1{,}300)}{\log(420/275)} = 1.97$$

HHP

Optimal pressure losses, flow rate and nozzle sizes:

$$\Delta P_f = \frac{3{,}000}{1.97+1} = 1{,}010 \text{ psi}$$

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Solution

Optimum flow rate = 260 gal/min

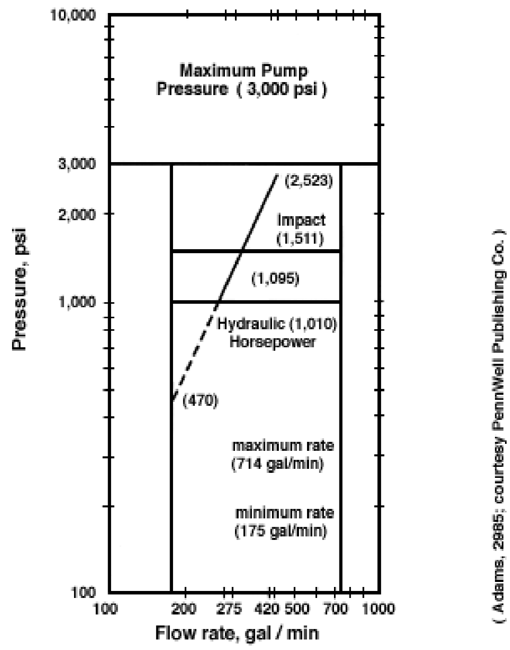
$$\Delta P_{bit} = 3{,}000 - 1{,}010 = 1{,}990 \text{ psi}$$

$$1{,}990 = \frac{(MW)(q^2)}{12{,}031 \times C_d^2 \times A_T^2}$$

$$A_T = \sqrt{\frac{13 \times 260^2}{12{,}031 \times 0.95^2 \times 1{,}990}} = 0.2017$$

$$\text{Nozzle Area} = \frac{0.2017}{3} = 0.06723 \text{ in}^2$$

$$0.06723 = \left(\frac{\pi}{4}\right) \times \left(\frac{d}{32}\right)^2 \Rightarrow d = 9.36$$



Use one 9/32nds and two 10/32nds nozzles.

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Solution

Impact force:

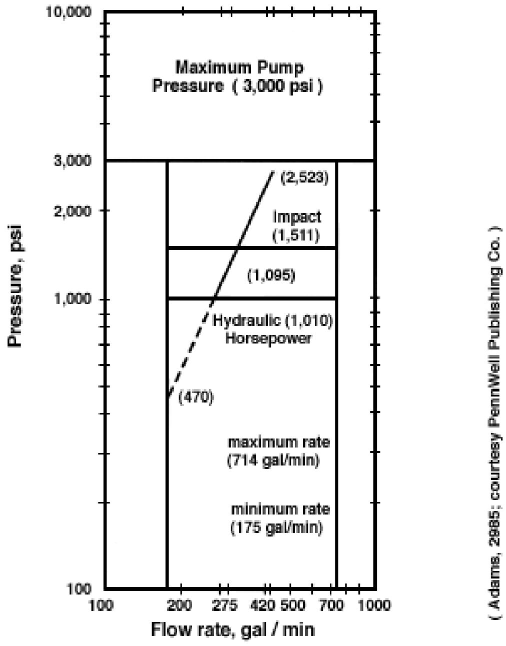
$$Optimum\,\Delta P_f = \frac{2 \times 3{,}000}{1.97 + 2} = 1{,}511\text{ psi}$$

Optimum flow rate = 315 gal/min

$$\Rightarrow \Delta P_{bit} = 3{,}000 - 1{,}511 = 1{,}489\text{ psi}$$

$$A_T = \sqrt{\frac{13 \times 315^2}{12{,}031 \times 0.95^2 \times 1{,}489}} = 0.2825\text{ in}^2$$

use three 11/32nds nozzles



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Hydraulics

On some wells, we may not be able to apply hydraulic horsepower or impact force criteria because of limited pump capacity, high friction pressures or annular velocity restrictions. In these cases, nozzle velocity becomes our optimization criterion. Maximum jet velocity occurs when ΔPbit is a maximum value for some established minimum flow rate (generally the lowest flow rate needed to overcome slip velocity).

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Example: Optimizing nozzle velocity

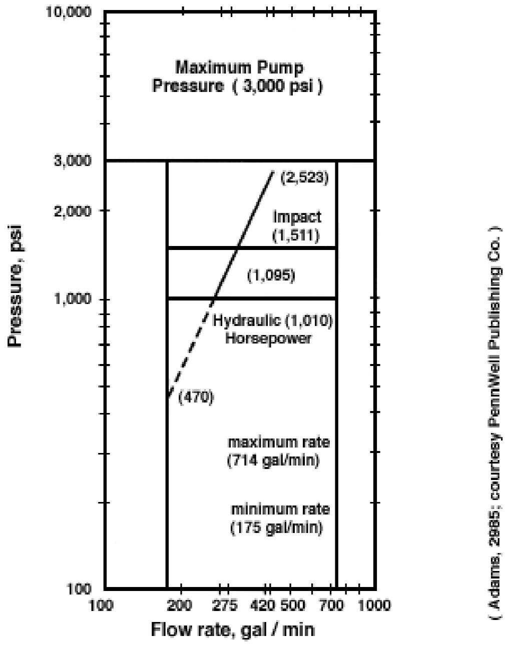
Using the well data from previous Example, determine the optimum nozzle sizes
based on maximum jet velocity--to lessen the risk of plugging the nozzles, do not use jet sizes less than 8/32nds.

Solution:

Minimum pump rate = 175 gal/min

From Figure , ΔPf = 470 psi at 175 gal/min

$$\Delta P_{bit} = 3{,}000 - 470 = 2{,}530\ psi$$



Solution

Jet sizes:

$$A_T = \sqrt{\frac{13 \times 175^2}{12{,}031 \times 0.95^2 \times 2{,}530}} = 0.120\ in^2$$

$$0.120 = 3 \times \frac{\pi}{4} \times \left(\frac{d}{32}\right)^2 \Rightarrow d = 7$$

Optimum nozzle size = three 7/32nds, which is below the 8/32nds limit.
Recalculate the sizes for two nozzles:

$$0.120 = 2 \times \frac{\pi}{4} \times \left(\frac{d}{32}\right)^2 \Rightarrow d = 8.8$$

Use two 9/32nds nozzles at 175 gal/min.

Weight on bit

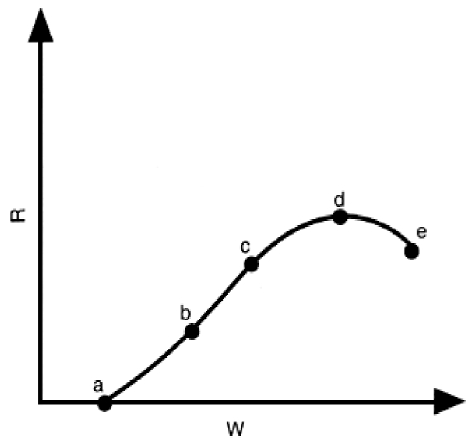
From Figure we may observe the following:

➢There is a minimum, or threshold bit weight (point a), below which the bit does not penetrate the formation.

➢Once the driller exceeds this threshold weight, penetration rate increases rapidly (from point a to point b).

➢Within the normal range of bit weights used in drilling operations (from point b to point c), dD/dT increases linearly with W.

➢Beyond this normal operating range, increasing bit weights result only in slight penetration rate increases (point c to point d).



(Bourgoyne et al., 1986. Courtesy of Society of Petroleum Engineers)

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Weight on bit

➢At extremely high W values (or if bottomhole hydraulics are poor), penetration rate may actually decrease because of inadequate cuttings removal, or because the cutting elements are being buried in the formation . We refer to this condition as bit floundering.

Over the normal operating range of bit weights, we can express the relationship between bit weight and instantaneous penetration rate as follows:

$$\frac{dD}{dT} \propto (W - W_0)^{a_5}$$

where W0 = threshold bit weight. For consolidated or hard rocks, W0 >0. For soft rocks, W0 may be equal to zero or, for formations that can be drilled by jetting or washing the hole, less than zero.

a5 = bit weight exponent, which is constant for a given set of operating conditions

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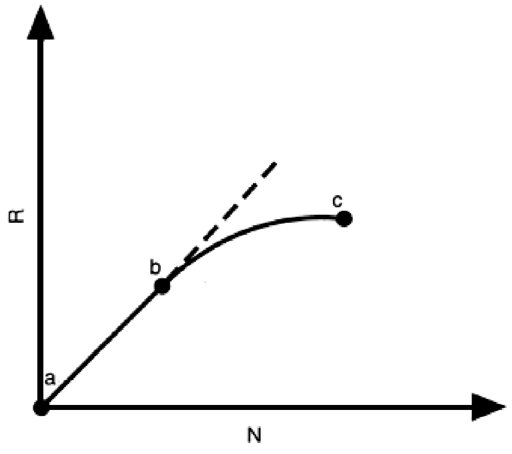
Rotary speed

As a rule, penetration rate increases non-linearly with increasing rotary speed (N), as shown in Figure. Note that as N increases past a certain point, the penetration rate does not increase as quickly. As is the case for extremely high bit weights, this is a consequence of inadequate cuttings removal at high rotary speeds. We may express the relationship between instantaneous penetration rate and rotary speed as follows (Young, 1969):



(Bourgoyne et al., 1986. Courtesy of Society of Petroleum Engineers)

$$\frac{dD}{dT} \propto N^{a6}$$

where a6 = rotary speed exponent

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Rotary speed

Field tests indicate that the rotary speed exponent's value depends on bit weight, and that low bit weights result in higher values of a6 than do high bit weights. Also, as indicated in Figure, a6 approaches a value of one at low N values, and decreases with increasing penetration rate.

As a bit run progresses, tooth wear causes a gradual decrease in penetration rate. Bit manufacturers can reduce the effects of this wear to some degree by selectively hardfacing the bit teeth, which results in a self-sharpening action. Hardfacing, however, does not compensate for the reduction in tooth length caused by abrasion and chipping. In many cases, of course, cutting elements may be broken or lost completely

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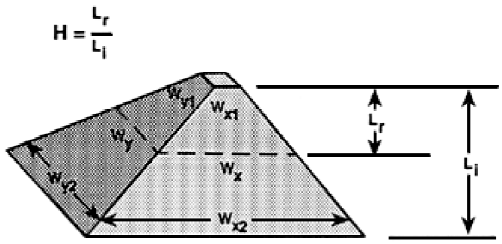
Bit tooth wear

The decrease in penetration rate with increasing tooth wear is non-linear. One reason for this behavior is that each tooth, as it wears down, presents a larger cross-sectional area to the formation (Figure 6 , *Idealized shape of a mille-tooth cutter as a function of fractional tooth wear*).



(Bourgoyne et al., 1986. Courtesy of Society of Petroleum Engineers)

A simple expression of this relationship (Bourgoyne and Young, 1974) is

$$\frac{dD}{dT} \propto e^{-(H)a_7}$$

where H = the fraction of tooth height that has been worn away, expressed as a decimal (e.g., for an IADC tooth wear code of T-5, H = 0.625)

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Penetration Rate Equations & Drilling Tests

Researchers have made various attempts to combine drilling variables into a single optimization model. Bingham's equation, from which we develop the concept of the dc exponent is one commonly used example

$$\frac{dD}{dT} = 60 \times a\left(\frac{W}{d_B}\right)^b \times N$$

where

$\frac{dD}{dT}$ = penetration rate, ft/hr

a = formation drillability constant (dimensionless)

W = weight-on-bit, 1000 lbf

dB = bit diameter, inches

b = bit weight exponent (dimensionless)

N = rotary speed, revolutions/minute (RPM)

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Penetration Rate (Bingham's equation)

This empirical relationship is commonly used in field calculations, and has been adapted as a tool for predicting pore pressures. It assumes a threshold bit weight of zero, a value of one for the rotary speed constant and perfect bottomhole cleaning. It accounts for formation and other effects by assigning constants (a and b) based on local drilling conditions.

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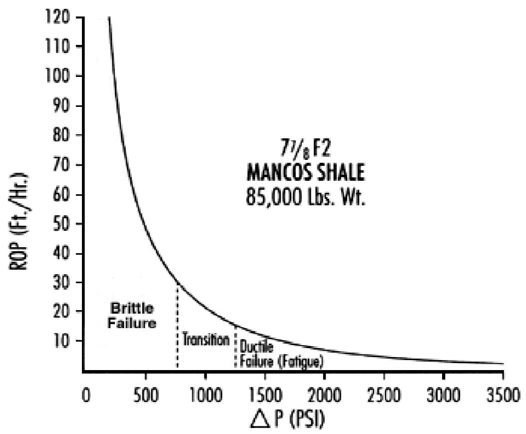
Penetration Rate

Other correlations have been developed to describe how mud properties, formation characteristics and other variables affect penetration rate. One example is the penetration rate vs. overbalance curve shown in (Figure 1 , *Effect of differential pressure on penetration rate*).



(courtesy Smith International)

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Penetration Rate Equation

Bourgoyne and Young (1974) developed the following drilling equation for rolling cutter bits.

$$\frac{dD}{dT} = \left(e^{a1}\right)\left(e^{a2x2}\right)\left(e^{a3x3}\right)\left(e^{a4x4}\right)\left(e^{a5x5}\right)\left(e^{a6x6}\right)\left(e^{a7x7}\right)\left(e^{a8x8}\right)$$

The terms a1 through a8 are constants reflecting local drilling conditions, while the terms x2 through x8 are functions derived from published correlations.

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Penetration Rate Equation

Bourgoyne and Young developed this equation for "normalized" drilling conditions in a given formation, namely

- normal compaction at a depth of 10,000 ft
- pore pressure gradient of 9.0 lbm/gal equivalent mud weight
- drilling with a new bit at a differential pressure of zero
- a bit weight of 4,000 lbf per inch of bit diameter , and a rotary speed of 100 RPM
- hydraulic impact force of 1,000 lbf at the bit nozzles

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Bourgoyne and Young’s Penetration Rate Equation

The term e^a1 is a drillability constant that describes the effect of formation strength and bit type on penetration rate, as well as the effects of drilling variables that have not been mathematically modeled. It has the units of ft/hr, and is numerically equal to the penetration rate that would be attained under the defined "normalized conditions." Under these conditions, dD/dT would equal e^a1.

The terms e ^a2x2 through e^a8x8 are *multipliers*--that is, if a condition's net effect is to decrease the "normalized" penetration rate, then the corresponding term e^azxz is less than one; if, on the other hand, it works to increase penetration rate over the normalized value, is greater than one.

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Bourgoyne and Young’s Penetration Rate Equation

- a2x2 and a3x3 describe the effects of formation compaction:

$$x_2 = 10{,}000 - TVD$$

where TVD = true vertical depth, ft
EMWpore = pore pressure fluid gradient, lbm/gal EMW

- a4x4 describes the effect of differential pressure:

$$x_4 = TVD \times \left(EMW_{pore} - ECD \right)$$

where ECD = equivalent circulating density, lbm/gal

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Bourgoyne and Young's Penetration Rate Equation

- a5x5 describes the effects of bit weight and bit diameter:

a5 = bit weight exponent

$$x_5 = \ln\left[\frac{(W/d_B) - (W_0/d_B)}{4.0 - (W_0/d_B)}\right]$$

where W = bit weight, 1000 lbf

W0 = threshold bit weight, 1000 lbf

dB = bit diameter, in.

- a6x6 describes the effect of rotary speed:

a6 = rotary speed exponent

$$x_6 = \ln(N/100)$$

where N = rotary speed, RPM

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Bourgoyne and Young's Penetration Rate Equation

- a7x7 describes the effect of bit tooth wear:

$$x_7 = -H$$

where H = fraction of tooth height that has been worn away, expressed as a decimal (e.g., for IADC grade of T-5, H = 0.625)

- a8x8 describes the effect of bit hydraulics, using impact force as the hole cleaning criterion (Bourgoyne et al, 1986):

$$x_8 = \ln\left(\frac{IF}{1000}\right)$$

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Example : Estimating formation drillability

Use Bourgoyne and Young's drilling model to estimate the apparent drillability (e^a1) for a shale formation under the following conditions:

TVD = 10,850 ft
Pore pressure = 5,200 psi = 9.2 lbm/gal equivalent
Equivalent circulating density = 10.0 lbm/gal
Bit size = 7 7/8 in.
New bit (i.e., H = 0)
Bit weight = 42,000 lbf (assume threshold bit weight = 0)
Rotary speed = 120 RPM
Penetration rate = 16.3 ft/hr (under "normalized" conditions, based on offset records)
Calculated hydraulic impact force = 1,200 lbf

Based on historic well data, the estimated values of a2 through a8 are

a2 = 0.0002 a3 = 0.0003 a4 = 0.00003 a5 = 1.0
a6 = 0.6 a7 = 0.7 a8 = 0.5

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Solution

$$\frac{dD}{dT} = \left(e^{a1}\right)\left(e^{a2x2}\right)\left(e^{a3x3}\right)\left(e^{a4x4}\right)\left(e^{a5x5}\right)\left(e^{a6x6}\right)\left(e^{a7x7}\right)\left(e^{a8x8}\right)$$

$$e^{a2x2} = e^{\left[0.0002(10{,}000 - TVD)\right]}$$

$$e^{a2x2} = e^{\left[0.0002\times(-850)\right]} = 0.8437$$

$$e^{a3x3} = e^{\left[0.0003\times TVD^{0.69}\times\left(EMW_{pore} - 9.0\right)\right]}$$

$$e^{a3x3} = e^{\left[0.0003\times 10{,}850^{0.69}\times(0.2)\right]} = 1.037$$

$$e^{a4x4} = e^{\left[0.00003\times TVD\times\left(EMW_{pore} - ECD\right)\right]}$$

$$e^{a4x4} = e^{\left[0.00003\times 10{,}850\times(9.2 - 10.0)\right]} = 0.7707$$

$$e^{a5x5} = e^{\left[1.0\times \ln\left(\frac{(W/d_B) - (W_0/d_B)}{4.0 - (W_0/d_B)}\right)\right]}$$

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Solution

$$\frac{dD}{dT} = e^{a1}(0.8437)(1.037)(0.7707)(1.333)(1.136)(1.0)(1.095)$$

$$16.3 = e^{a1} \times 1.119$$

$$e^{a1} = 14.6 \ \text{ft/hr}$$

In this example, we assume that the constants a1 through a8 are already known. In reality, of course, we would have to calculate them using offset well data and the multiple regression technique described by the authors. The applicability of the Equation to a given situation depends on having enough data to give meaningful values for these constants, and also on the range of values obtained for the functions x2 through x8. In many cases, a lack of information may force us to simplify the drilling model.

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Bourgoyne and Young's Penetration Rate Equation

If we assume that formation characteristics and mud properties are constant for a single bit run, that threshold bit weight is zero and that bit hydraulics are adequate, we may simplify the Equation as follows:

$$\frac{dD}{dT} = K \times e^{(a_5x_5 + a_6x_6 + a_7x_7)}$$

where K is a proportionality constant for a given bit diameter, comprised of the terms a1 through a4x4 and a8x8, along with the corresponding normalization constants (note similarity to Bingham's model)

Substituting the terms previously defined into above Equation , we can write

$$\frac{dD}{dT} = K \times (W)^{a5} \times N^{a6} \times e^{(-H)(a7)} \qquad *$$

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Bourgoyne and Young's Penetration Rate Equation

We can evaluate the quantities a5 and a6 in Equation * and estimate threshold bit weight, by performing drilling tests over short intervals and using information from previous bit runs. Short-interval testing has the following benefits:

- ✓ It minimizes the effects of lithology changes (which helps justify our assigning constant values to the terms a1 through a4x4).
- ✓ It minimizes the effects of tooth wear on penetration rate.

If we use a new bit over a sufficiently short interval, the tooth wear height H is effectively zero, and the term a7x7 reduces to one.

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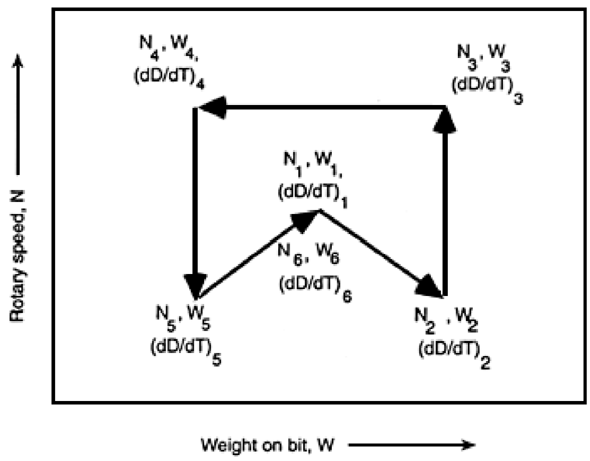
Five spot drilling test

Young (1969) describes a computer-controlled five-spot drill rate test, which monitors penetration rate for five programmed combinations of bit weight and rotary speed. As shown in Figure (*Five spot drilling test*), a penetration rate (R1) is determined for the rotary speed-bit weight combination (N1,W1).



(Young, 1969. Courtesy of Society to Petroleum Engineers)

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Five spot drilling test

The rig computer then commands weight and speed changes to obtain penetration rates for points 2, 3, 4 and 5. Point 6 serves as a control to determine if the test is acceptable. Since (N1,W1) is identical to (N6,W6), the penetration rates (R1) and (R6) should be equal within some specified tolerance (e.g., ±15%). The data points 1-6 are then used to calculate average values for the constants W0, a6 and K (the bit weight exponent is assigned a value of one for the operating ranges that Young describes).

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Example : Five-spot drilling test (after Adams)

Use the data in Table below to determine the threshold bit weight W0 and the rotary speed exponent a6. Initial and final check points should agree within 15%.

Test point	**W, lbf**	**N, RPM**	**dD/dT,ft/hr**
1	43,000	115	28
2	35,000	80	18
3	35,000	150	27
4	50,000	150	36
5	50,000	80	25
6	43,000	115	29

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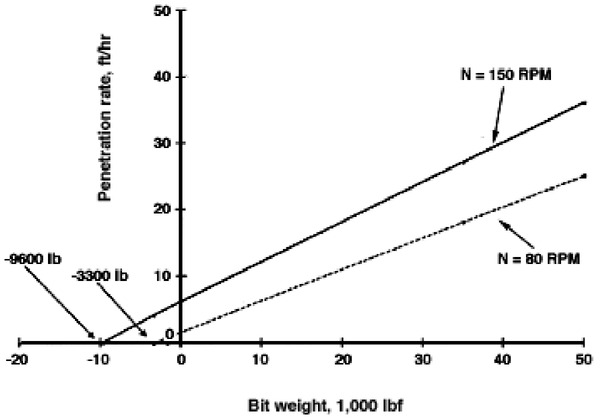
Solution

1. Plot dD/dT versus W, as shown in <u>Figure</u> (*Tooth wear parameters for Three-Cone Rock Bits*).
2. Check the agreement between points 1 and 6:
100 - (28/29)*100 = 3.4%, < 15% -- test is valid
3. Determine the threshold bit weights by extrapolating the constant-rotary-speed lines in <u>Figure</u> to dD/dT = 0. The average of the intercept values -9,600 lbf and -3,300 lbf is equal to -6,450 lbf.



(Example 6.7. After Adams)

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Solution

4. Determine the rotary speed exponent using the relationship

$$\left(\frac{dD}{dT}\right)_1 \Big/ \left(\frac{dD}{dT}\right)_2 = (N_1/N_2)^{a_6}$$

For a bit weight of 50,000 lbf,

$$\ln\left(\frac{36}{25}\right) = a_6 \times \ln\left(\frac{150}{80}\right) \qquad \Rightarrow a_6 = 0.58$$

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Drill-off test

The drill-off test, first proposed by Lubinski (1958), allows us to observe the relationship between penetration rate and bit weight over depth intervals even shorter than those we could attain using varying combinations of weight and rotary speed.

This test involves applying a predetermined maximum bit weight, then setting the brake and monitoring the decrease in bit weight as a function of time at constant rotary speed.

During a drill-off test, the drill string stretches as bit weight decreases and hook load increases. The amount of stretch is equal to

$$\Delta L = \left(\frac{0.95 \times L}{E \times A} \right) \times \Delta W$$

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Drill-off test

where : L = length of drill pipe

$$E = 30 \times 10^6 \text{psi} \left[206.84 \times 10^6 \text{kPa} \right] \text{ for steel}$$

A = cross-sectional area of drill pipe

ΔW = change in bit weight

Note that the stretch in the bottomhole assembly is small and is therefore not included in this equation. The constant 0.95 accounts for the fact that the stretch in the drill pipe upsets is also negligible.

In terms of penetration rate during the drill-off,

$$\frac{dD}{dT} = \left(\frac{0.95 \times L}{E \times A} \right) \times \left(\frac{\Delta W}{\Delta T} \right)$$

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Drill-off test

By plotting (dD/dT) against W on log-log paper, we can obtain a straight line having a slope equal to the bit weight exponent.

This is assuming a threshold bit weight of zero, as is the case for many soft formations. In hard formations, which have a significant threshold bit weight, we do not obtain a straight-line fit. In such cases, we determine W0 by trial and error, subtracting estimated values from the measured weight values until we see a linear log-log relationship.

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Example

The following information was recorded for a drill-off test (Table below). Determine the bit weight exponent and the rotary speed exponent

N = 100 RPM			**N = 130 RPM**		
W, lbf	T (Min:s)	ΔT (s)	W, lbf	T(Min:s)	ΔT (s)
70,000	0:00	0	70,000	0:00	0
66,000	0:35	35	66,000	0:32	32
62,000	1:11	36	62,000	1:04	32
58,000	1:51	40	58,000	1:38	34
54,000	2:35	44	54,000	2:13	35
50,000	3:25	50	50,000	2:53	40
46,000	4:22	57	46,000	3:39	46
42,000	5:27	65	42,000	4:31	52
38,000	6:43	76	38,000	5:32	61
34,000	8:12	89	34,000	6:44	72
30,000	9:59	107	30,000	8:10	86

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Example

Conditions prior to test:
Depth: 9750 ft
Drill pipe: 9300 ft of 5 inch, 19.50 lb/ft (i.d. = 4.276 in.)
Bit size and type: 12 1/4 inch, SVH (IADC code 215)
dD/dT = 15.0 ft/hr
W = 50,000 lbf
N = 100 RPM
Test data: ⇒
Characteristic time: 50,000 lbf
45,000 lbf in 105 s.
Initial test weight: 70,000 lbf
Test was run at N = 100 RPM and N = 130 RP

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Solution

$$\frac{dD}{dT} = \left(\frac{0.95 \times L}{E \times A}\right) \times \left(\frac{\Delta W}{\Delta T}\right)$$

$$A = \frac{\pi}{4}\left(5.000^2 - 4.276^2\right) = 5.275 \text{ in}^2$$

$$\frac{dD}{dT} = \left(\frac{0.95 \times 9{,}300}{30 \times 10^6 \times 5.275}\right) \times \left(\frac{4{,}000}{\Delta T}\right) \times \frac{3{,}600 s}{hr}$$

$$\frac{dD}{dT} = \frac{804}{\Delta T}$$

where dD/dT is in units of ft/hr and DT is given in seconds

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Solution

W, lbf	WAvg	ΔT (s)	Test 1: N = 100 RPM dD/dT,ft/hr	Test 2: N = 130 RPM ΔT (s)	dD/dT,ft
70,000					
	68,000	35	23.0	32	25.1
66,000					
	64,000	36	22.3	32	25.1
62,000					
	60,000	40	20.1	34	23.7
58,000					
	56,000	44	18.3	35	23.0
54,000					
	52,000	50	16.1	40	20.1
50,000					
	48,000	57	14.1	46	17.5
46,000					
	44,000	65	12.4	52	15.5
42,000					
	40,000	76	10.6	61	13.2
38,000					
	36,000	89	9.0	72	11.2
34,000					
	32,000	107	7.5	86	9.3
30,000					

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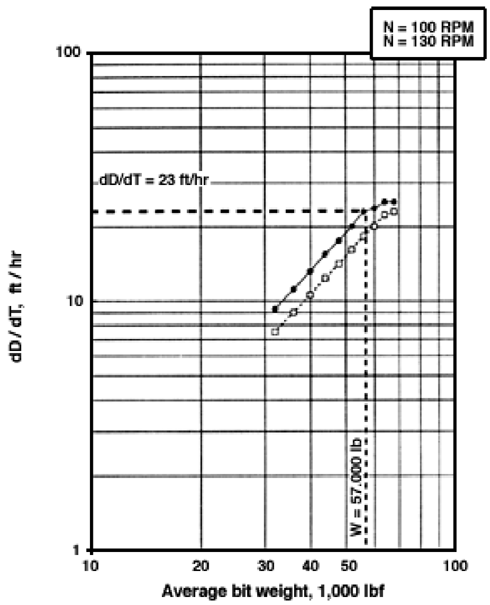
Solution

Figure (*Bit size parameters for Three Cone Rock Bits*) is a plot of penetration rate versus average bit weight for the tests run at 100 RPM and 130 RPM. In both cases, the logs of the points form straight lines, indicating that threshold bit weight is not a significant factor. The slope of each line, which is equal to the bit weight exponent, is about 1.6. We can determine the rotary speed exponent using the following relationship,



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Solution

$$\left(\frac{dD}{dT}\right)_1 \Big/ \left(\frac{dD}{dT}\right)_2 = (N_1/N_2)^{a6}$$

$$a6 = \frac{\log\left[\left(\frac{dD}{dT}\right)_2 \Big/ \left(\frac{dD}{dT}\right)_1\right]}{\log(N_2/N_1)}$$

In this case, using the dD/dT an N values for a bit weight of 52,000 lbf,

$$a_6 = \frac{\log[20.1/16.1]}{\log(130/100)} = 0.85$$

For the conditions described, we can thus express our optimization equation as

$$\frac{dD}{dT} = \left(\frac{0.95 \times L}{E \times A}\right) \times \left(\frac{\Delta W}{\Delta T}\right)$$

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Solution

Based on Figure , the optimum penetration rate for the test conditions (ignoring the non-linear portions of the plot, which indicate bit floundering) is about 23 ft/hr, and occurs at about 57,000 lbf and 130 RPM.

If we wished, we could run further tests for different values of N. Additional data would also allow us to estimate this interval's drillability (K), assuming that the bit type and tooth condition are identical, and that there are no changes in mud properties or hydraulic conditions.

To determine the constant a7, Bourgoyne and Young (1974) suggest evaluating observed declines in penetration rate with tooth wear (based on bit grading) for previous bits run under identical conditions.

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Example

The initial penetration rate for a bit drilling in the same shale interval that was tested in the previous example was 24 ft/hr. The previous bit, which was of the same size and type, and was graded T-7 after drilling in the same formation using identical and constant bit weight, rotary speed, hydraulics and mud properties. The penetration rate of the current bit was 13 ft/hr just before pulling. Determine the tooth wear constant a7.

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Solution

$$\frac{dD}{dT} = K \times W^{1.6} \times N^{0.85} \times e^{(-H)(a_7)}$$

Initial rate (new bit, H = 0):

$$24 \ \text{ft/hr} = K \times W^{1.6} \times N^{0.85}$$

Previous bit

$$13 \ \text{ft/hr} = K \times W^{1.6} \times N^{0.85} \times e^{(-0.875)(a_7)}$$

Treating W and N as constants

$$\frac{13}{24} = e^{(-0.875)(a_7)}$$

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Solution

$$a_7 = -\left(\frac{\ln(13/24)}{0.875}\right) = 0.7$$

For the conditions described, we may express our drilling rate equation as

$$\frac{dD}{dT} = K \times W^{1.6} \times N^{0.85} \times e^{(0.7)\times(-H)}$$

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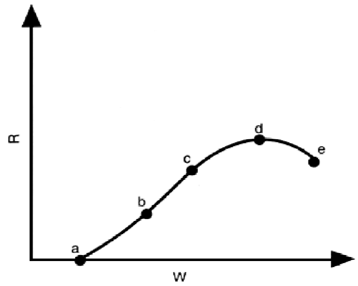
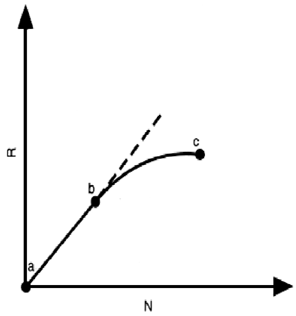
Constraints on Bit Weight & Rotary Speed

Optimal penetration rates do not necessarily occur under conditions of maximum bit weight and rotary speed. Indeed, such conditions can sometimes result in bit floundering due to inefficient cuttings removal. This indicates that there are practical limits on bit weight and rotary speed. These limits include:



(Bourgoyne et al., 1986. Courtesy of Society of Petroleum Engineers)

- *Hydraulics*, as indicated by the bit floundering regions in Figure abow (*Typical response of penetration rate to increasing bit weight*) and Figure front (*Typical response of penetration rate to increasing rotary speed*).



(Bourgoyne et al., 1986. Courtesy of Society of Petroleum Engineers)

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Constraints on Bit Weight & Rotary Speed

The penetration rate (i.e., the rate at which we generate cuttings) must not overwhelm our circulating system's ability to clean the hole and condition the mud. Also, it must not be so high as to make kick detection difficult. These conditions place limits on how fast we can drill (and thus on our bit weight and rotary speed).

- *Hole deviation* Excessive bit weights may cause doglegs or other crooked hole problems. We can overcome this limitation to a large degree, however, by properly designing the bottomhole assembly.

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Constraints on Bit Weight & Rotary Speed

- *Bit specifications* Bit manufacturers design their products to run within certain ranges of bit weight and rotary speed. For example, a bit might have a recommended weight range of 1,000-5,000 lbf per inch of bit diameter and a rotary speed range of 70-120 RPM. Operating outside of these established ranges can result in inefficient drilling or even damage to the bit. The manufacturer's representative can provide these specifications and recommend bit types for specific drilling conditions. World Oil also lists them in its Drill Bit Classifier (published annually).

- *Cost per drilled depth* Maximum penetration rates do not always result in minimum cost drilling. The footage and bit life parameters that result from various weights and rotary speeds must be substituted into the cost per foot equation to provide a true indication of optimum conditions.

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Constraints on Bit Weight & Rotary Speed

This last item--cost per drilled depth--is, of course, the most important limiting criterion on operating conditions. A primary concern regarding bit weight and rotary speed as they relate to minimum cost drilling is bit life. It does little good to maximize penetration rates with high bit weights and rotary speed if the result is premature bit wear, extra trip time or lost cones.

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Bit Life Estimation

The life of a rolling cutter bit depends on two parameters: tooth wear and bearing wear. Cutter life directly affects penetration rate, as shown by the drilling rate equation:

$$\frac{dD}{dT} = K \times (W)^{a5} \times N^{a6} \times e^{(-H)(a7)}$$

where $\frac{dD}{dT}$ = penetration rate

K = proportionality constant for a given bit diameter

W = weight on bit

N = rotary speed

e-(H)a7 = tooth wear exponent

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Bit Life Estimation

As the term e-(H)a7 indicates, tooth wear is a gradual process. By contrast, bearing failure results from fatigue and occurs much more abruptly, as evidenced by the characteristic "torquing up" of the bit. While bearing life does not directly affect penetration rate, it can bring a sudden end to a bit run.

Bit life estimates depend on determining whether tooth or bearing failure is most likely to occur first. As a rule of thumb, bearing failure is the deciding parameter in soft, non-abrasive formations, where bit cutters experience little wear. In hard, abrasive formations, on the other hand, the bit teeth tend to wear out before the bearings do.

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Tooth Wear

Drilling parameters that affect tooth wear include rotary speed, bit weight and tooth wear rate.

Rotary speed The rate of tooth wear for a given milled-tooth bit increases with increasing rotary speed, as indicated by the following equation (Young, 1969):

$$\frac{dh}{dT} \propto PN + QN^3$$

where dh/DT = rate of tooth wear
P, Q = empirical constants, based on bit type
N = rotary speed

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Tooth Wear

Bit weight The rate of tooth wear increases non-linearly with increasing bit weight. This increase is due to the severe chipping and eventual tooth destruction that occurs above some maximum weight. We may express the tooth wear-bit weight relationship as

$$\frac{dh}{dT} \propto \frac{1}{\left(-D_1 W + D_2\right)}$$

where D1, D2 = constants based on bit size
W = bit weight

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Tooth Wear

Tooth wear rate The rate at which tooth wear occurs is proportional to the cross-sectional area that the tooth presents to the formation. Because bit teeth are roughly pyramidal in shape, the cross-sectional area of the cutting surface increases as wear causes the tooth height to decrease. Thus, the rate of wear decreases as the tooth dulls. Young (1969) expresses this relationship as

$$\frac{dh}{dT} \propto \frac{1}{\left(1 + C_1 H\right)}$$

where C1 = constant, based on tooth shape, the type of hardfacing on the tooth and the degree of heat treating used in its manufacture.
H = fraction of tooth height that has been worn away

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Tooth wear rate

Combined effects of rotary speed, bit weight and tooth wear We can combine the pervious Equations as follows:

$$\frac{dh}{dT} = 0.001 \times A_f \times \frac{\left(PN + QN^3\right)}{\left(-D_1 W + D_2\right)} \times \frac{1}{\left(1 + C_1 H\right)}$$

where Af is an abrasiveness constant for the given formation. Table 1 and Table 2 list empirically derived values of P, Q, C1, D1 and D2 for various bit types and sizes.

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Table 1

Tooth Wear Parameters

IADC Group	P	Q	C1
1-1 to 1-2	2.5	1.008*10-4	7
1-3 to 1-4	2.0	0.870*10-4	6
2-1	1.5	0.653*10-4	5
2-2 to 2-3	1.2 0	.522*10-4	4
2-4	0.9	0.392*10-4	3
3-1	0.65	0.283*10-4	2
3-2 to 2-4	0.5	0.218*10-4	2
4	0.5	0.218*10-4	2

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Table 2

The values given for P and Q apply where rotary speed (N) is expressed in RPM. The values given for C1 apply where the fraction of tooth wear (H) is expressed as a decimal (e.g., IADC grade of T6

H = 0.750) Table 1 Tooth Wear Parameters for Three-Cone Rock Bits (After Young, 1969)D1 D2

Bit o.d., in. [mm]	D1 (see note below)	D2 (see note below)
6.250 [158.75]	0.088	5.50
6.750 [171.45]	0.083	5.61
7.785 [197.739]	0.074	5.94
8.625 [219.075]	0.071	6.11
9.625 [244.475]	0.066	6.38
9.875 [250.825]	0.065	6.44
10.75 [273.05]	0.062	6.68
12.25 [311.15]	0.058	7.15

NOTE: The values given for D1 and D2 apply where bit weight (W) is expressed in 1,000 lbf.
[1,000 lbf = 4448 N]

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Example : Determining bit failure mode

Estimate the abrasiveness constant and determine the most likely mode of bit failure, given the following data from the previous bit run. Assume constant bit types, formation properties, operating conditions and rotating hours for both the current and the previous run. If tooth failure is the determining failure criterion, estimate the time at which it occurs.

Rotary speed: 60 RPM
Weight on bit: 40,000 lbf
Bit : 9 7/8 in., IADC code 214
Rotating hours: 12
Tooth Grade: T6 (H = 0.75)

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Solution:

$$A_f = \frac{1{,}000\times\left(-D_1W+D_2\right)}{\left(PN+QN^3\right)\times T}\times\left[H_f+\left(\frac{C_1}{2}\times H_f{}^2\right)\right]$$

D1 = 0.0065

D2 = 6.44

P = 1.5

Q = 0.653*10-4

C1 = 5

$$A_f = \frac{1{,}000\times\left[\left(-0.065\times 40\right)+6.44\right]}{\left[\left(1.5\times 60\right)+\left(0.653\times 10^{-4}\right)60^3\right]\times 12}\times\left[0.75+\left(\frac{5}{2}\times 0.75^2\right)\right]$$

Af = 6.6

Solution:

For the conditions described, tooth wear is the determining failure criteria. Tooth failure occurs when the rotating hours are equal to

$$T = \frac{1{,}000\times\left(-D_1W+D_2\right)}{A_f\times\left(PN+QN^3\right)}\times\left(1+\frac{C_1}{2}\right)$$

$$T = \frac{1{,}000\times\left[\left(-0.065\times 40\right)+6.44\right]}{6.6\times\left[\left(1.5\times 60\right)+\left(0.653\times 10^{-4}\right)\times 60^3\right]}\times\left(1+\frac{5}{2}\right)$$

$T = 19.6$ hours

Abrasiveness Constant

The abrasiveness constant, Af, is an indicator of formation characteristics as they relate to tooth wear. An Af value between 0 and 4 indicates low abrasiveness, and suggests bearing wear as the bit's failure mechanism. An Af range between 5 and 10 indicates high abrasive tendencies, and suggests that tooth wear is the primary failure mechanism (values between 4 and 5 are not diagnostic of the failure mode). If we rearrange and integrate Equation 5, using the initial and final bit condition as limits, we can estimate Af as follows

$$A_f = \frac{1{,}000 \times \left(-D_1 W + D_2\right)}{\left(PN + QN^3\right) \times T} \times \left[H_f + \left(\frac{C_1}{2} \times H_f{}^2 \right) \right]$$

where Hf = final wear fraction of tooth height

Tooth failure corresponds to complete wear (i.e., Hf = 1). The time at which this occurs is equal to

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Time to tooth failure

$$T = \frac{1{,}000 \times \left(-D_1 W + D_2\right)}{A_f \times \left(PN + QN^3\right)} \times \left(1 + \frac{C_1}{2}\right)$$

If we determine that tooth wear is not the critical bit life parameter (i.e., 0 < Af < 4), we then need to look at the bearings.

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Bearing Failure

Bit weight The rate of bearing wear increases rapidly and non-linearly with increasing bit weight. We can describe this relationship as follows (Young, 1969):

$$\frac{dB}{dT} \propto W^{\sigma}$$

where dB/dT = instantaneous rate of bearing wear
W = bit weight, 1,000 lbf
σ = bearing wear exponent (typically equal to 1.5)

Rotary speed Bearing life generally depends on the total number of times a bit turns, regardless of the rate at which it turns. This means that the rate of bearing wear increases linearly with increasing rotary speed.

$$\frac{dB}{dT} \propto N$$

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Bearing Failure

Combined effects Combining Equations 8 and 9, and assigning a proportionality constant,

$$\frac{dB}{dT} = \left(\frac{1}{b}\right) \times N W^{1.5}$$

where b = bearing wear constant
We may determine the bearing wear constant from historical drilling data. Its value depends on mud properties, bit size and bit type.
Integrating this equation over the life of the bearings and then solving for b, we obtain

$$b = \frac{N W^{1.5} \times T}{B}$$

where B = final bearing grade, expressed as a decimal (e.g., if the IADC bearing grade is B-6, then B = 0.75)

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Example: Estimating bearing life

Given the following data from a previous bit run, and assuming no changes in operating conditions, determine when the current bit will experience complete bearing failure.

Af = 2.0 Grade = T4-B6-I

N = 110 RPM W = 55,000 lbf

T = 25.0 hours

Solution:

From previous run:

$$b = \frac{NW^{1.5} \times T}{B}$$

$$b = \frac{110 \times 55^{1.5} \times 25.0}{0.75} = 1{,}495{,}600$$

For the current run:

$$T = \frac{1{,}495{,}600 \times 1.0}{110 \times 55^{1.5}} = 33.3 \text{ hours}$$

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Bearing Life

If we have data from a previous bit run, where bit type, formation properties and other operating conditions are identical to the current bit run, we can calculate the bearing wear constant and estimate the bearing life for the current bit.

$$T = \frac{b \times B}{NW^{1.5}}$$

This procedure removes some of the guesswork involved in estimating bit life, and reduces our chances of either pulling a "green" bit (one with the bearings still in good condition) or losing cones in the hole.

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Example : Bearing life calculation for sealed bearing bit

Using the data from Example 2, estimate the bearing life of a 1,3,1 bit run with 55,000 lbf bit weight at 110 RPM.

Solution:

b = 1,495,600 (based on previous bit run)

Modify b to reflect increased bearing capacity:

$$1{,}495{,}600 \times 1.2 = 1{,}794{,}700$$

For current run:

$$T = \frac{1{,}794{,}700 \times 1.0}{110 \times 55^{1.5}} = 40 \text{ hours}$$

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Bearing Life

Effect of bit type Bearing life also depends on whether the bearing has a non-sealed or a sealed lubricating system. Non-sealed systems have no mechanical means of preventing mud entry into the bearing assembly. The bearings are packed with a high-viscosity grease for lubrication. While the grease may inhibit mud entry, it does not protect the bearings as effectively as a sealed-bearing bit, which is so-called because of the seal that is placed between the back of the cone and the interior of the bit leg. Field data have indicated that this seal assembly, by preventing mud entry, can increase bearing life by an estimated 30% over that of non-sealed bearing bits.

Bearing capacity varies among bit types, based on their design for hard or soft formations. Table 3. , below, shows relative bearing capacities for several bit types, where a value of 1.00 is the relative bearing capacity of a bit for soft, low-compressive strength rock.

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Relative Bearing Capacities for Several Bit Types

IADC Code	Bearing Capacity
1,1,1	1.00
1,2,1	1.15
1,3,1	1.20
2,1,1	1.35
2,2,1	1.45
3,1,1	1.45

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Practical Guidelines

Although the relationships among drilling parameters are complex, our efforts to describe them come back to a basic objective: to determine what combination of operating conditions results in minimum cost drilling. Once we know bit rotating times and footage for various combinations of weight and rotary speed, it is a relatively straightforward matter to use the cost per foot relationship to determine which of these combinations is most favorable.

Optimization procedures should be practical and simple enough to implement at the rig on a daily basis, and should include the following basic steps:

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Practical Guidelines

1.*Data gathering* We should begin by collecting as much information as possible about drilling conditions. This involves

- reviewing the drilling contract and analyzing daily drilling expenses to determine an equivalent hourly rig cost
- recording bit performance information, including footage, rotating hours and trip times
- accurately grading pulled bits
- conducting short-interval drilling test(s) during the current bit run to determine the formation's bit weight exponent, rotary speed exponent and threshold bit weight, and correlating this information with offset well data, if available

Practical Guidelines

2. *Bit performance evaluation* Based on information from the previous bit run, we can determine whether tooth wear or bearing wear is the defining bit failure criterion, and estimate maximum bit life and footage. We can summarize these steps as follows:

a. Calculate the abrasiveness factor.

$$A_f = \frac{1{,}000 \times \left(-D_1 W + D_2\right)}{\left(PN + QN^3\right) \times T} \times \left[H_f + \left(\frac{C_1}{2} \times H_f^{\,2}\right)\right]$$

b. If Af >5.0, use tooth failure criteria:

$$T = \frac{1{,}000 \times \left(-D_1 W + D_2\right)}{A_f \times \left(PN + QN^3\right)} \times \left(1 + \frac{C_1}{2}\right)$$

Practical Guidelines

c. If Af <4.0, calculate the bearing failure constant and use bearing failure criteria:

$$b = \frac{NW^{1.5} \times T}{B}$$

d. If 4.0< Af <5.0, assume bearing failure unless additional evidence indicates otherwise

3. *Bit selection* The previous bit run is our primary guideline in bit selection. This is assuming, of course, that the next interval that we drill exhibits the same bit wear characteristics as the previous interval.

- If the abrasiveness factor is less than four (as determined from Step 2), a longer-tooth, softer-formation bit should probably be used for the next run.
- If the abrasiveness factor is greater than four, a tungsten-carbide insert bit may be preferable to a milled tooth bit
- Sealed bearing bits are usually a cost-effective option for bit selection. Although more expensive than non-sealed roller bearings, they offer greater bearing capacity and longer bit runs.

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Practical Guidelines

4. *Predicting performance* If the bit type has changed from the previous run, we need to recalculate the bearing and tooth wear constants, and make a new estimate of bit life based on the current interval having the same drillability as the previous interval.

5. *Establishing optimum weight and rotary speed* We can insert the estimated values for bit life and footage at various weights and rotary speeds into the cost equation, and select the optimum conditions based on minimum cost drilling.

Note: As technological advances and increased competition among bit manufacturers gives rise to an ever-growing number of rolling-cutter and fixed-cutter bit types, bit selection becomes increasingly important in the overall task of optimization.

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Example

Determine the optimum bit weights and rotary speeds based on the following information from previous runs of the same bit in identical formations:

Rig cost=$220/hour

Bit cost=$3800.00

Average trip time=6 hours

Run 1: W=70,000 lbf , N=130 RPM; made 255 feet in 16.5 hours

Run 2: W=65,000 lbf , N=90 RPM; made 293 feet in 19.3 hours

Run 3: W=65,000 lbf , N=75 RPM; made 320 feet in 24.4 hours

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Solution

$$\left[\frac{C}{\Delta D}\right] = \frac{C_{bit} + C_{rig}(t+T)}{\Delta D}$$

$$\left[\frac{C}{\Delta D}\right] = \frac{3{,}800 + 220(6+T)}{\Delta D} = \frac{5120 + (220 \times T)}{\Delta D}$$

Run 1: $\left[\frac{C}{\Delta D}\right] = \frac{5120 + (220 \times 16.5)}{255} = \$34.31/\text{ft}$

Run 2: $\left[\frac{C}{\Delta D}\right] = \frac{5120 + (220 \times 19.3)}{293} = \$31.97/\text{ft}$

Run 3: $\left[\frac{C}{\Delta D}\right] = \frac{5120 + (220 \times 24.4)}{320} = \$32.78/\text{ft}$

Based on this data, the optimal bit weight and rotary speed is 65,000 lbs and 90 RPM.

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Example

Determine the expected failure mode for a milled tooth bit (teeth or bearings), and estimate how many rotating hours it will accumulate before it experiences complete wear, given the following information from a previous bit run and assuming identical operating conditions.

Rotary speed=90 RPM
Weight on bit=40,000 lbf
Bit size and type: 7.875 inch, IADC code 131
T=12 hours
Final grade=T6-B5-I

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Solution

$$A_f = \frac{1{,}000 \times \left(-D_1 W + D_2\right)}{\left(PN + QN^3\right) \times T} \times \left[H_f + \left(\frac{C_1}{2} \times H_f{}^2\right)\right]$$

D1= 0.074; D2 = 5.94; P = 2.0; Q = 0.870*10-4; C1 = 6; Hf = 0.75

$$A_f = \frac{1{,}000 \times \left(-0.074 \times 40 + 5.94\right)}{\left(2 \times 90 + 0.87 \times 90^3\right) \times 12} \times \left[0.75 + \left(\frac{6}{2} \times 0.75^2\right)\right]$$

$A_f = 2.5$; $A_f < 4$; Bearing wear is determining failure criterion

Determine bearing wear constant:

$$b = \frac{NW^{1.5} \times T}{B}$$

$$b = \frac{90 \times 40^{1.5} \times 12}{0.625} = 437{,}153$$

Estimated time to failure (i.e. B = 1.0):

$$T = \frac{b \times B}{NW^{1.5}}$$

$$T = \frac{437{,}184 \times 1.0}{90 \times 40^{1.5}} = 19.2 \text{ hours}$$

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DRILLING ENGINEERING
(Directional Drilling)

S. R. SHADIZADEH, Ph.D., PE.

Introduction

The planning, equipment and procedures involved in drilling non-directional wells also apply to directional ones. Over and above these basic considerations, however, are a number of requirements that are unique to directional drilling. These requirements may relate to any or all of the following areas:

- planning and calculating an optimal well trajectory
- employing specialized equipment (e.g., downhole motors, survey instruments, steering tools, measurement-while drilling
- (MWD) and logging-while-drilling (LWD) systems, non-magnetic drill collars and articulated drill pipe)
- specially designing bottomhole assemblies to help control the well course and transmit weight to the bit
- minimizing drill pipe and casing wear in highly deviated holes (e.g., extra drill pipe protectors, increased casing centralization)
- increasing hydraulics capacity to ensure effective annular hole cleaning, and using special drilling fluid lubricants to reduce torque and drag

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 subsurface target.

Applications Of Directional Drilling

Applications

Multiple wells from offshore structures

The most common application of directional drilling techniques is in offshore drilling. 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.

Applications Of Directional Drilling

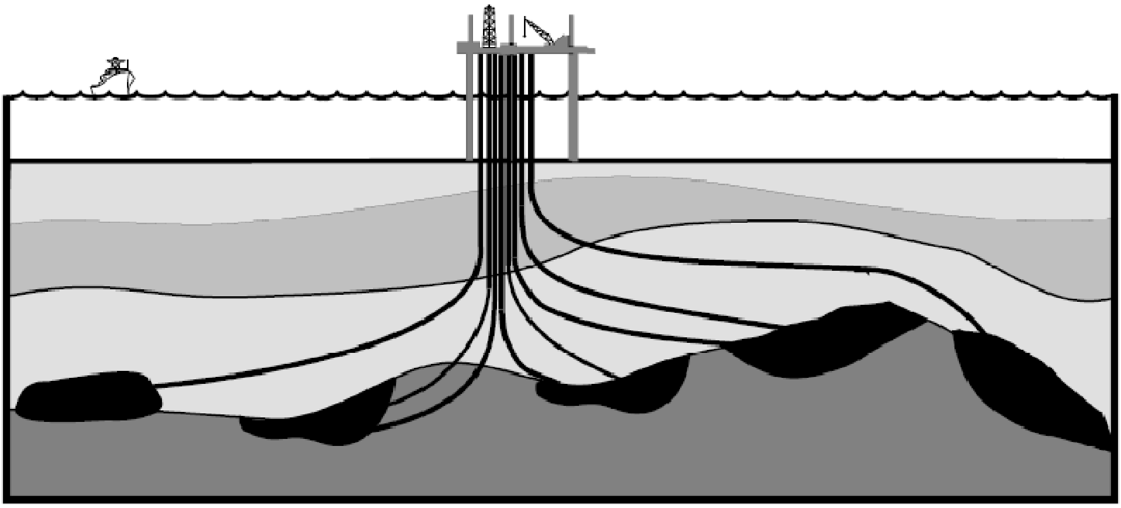

Figure 5-1: Multiple wells from offshore structures.

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Applications Of Directional Drilling

Relief Wells

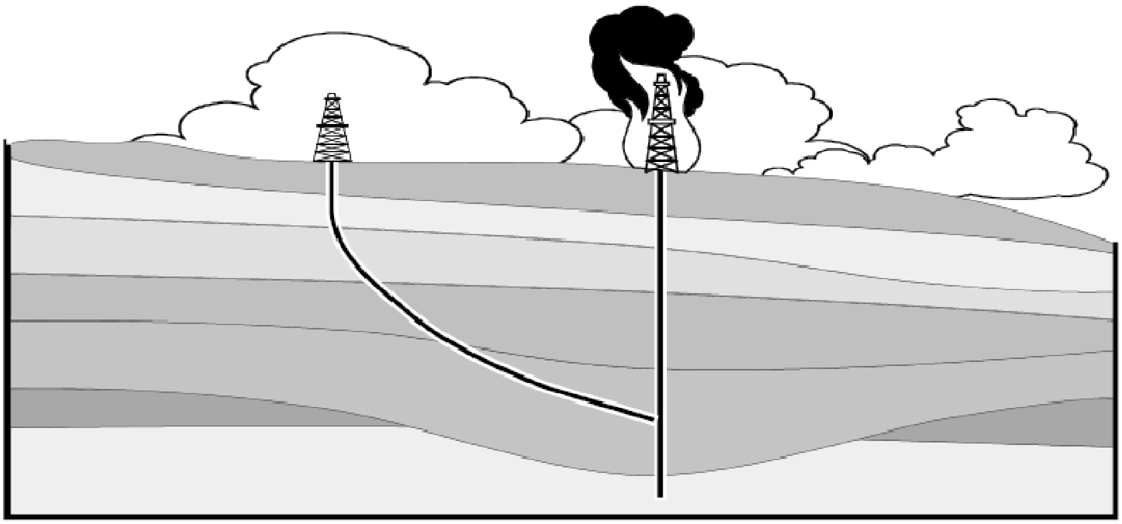

Figure 5-2: Relief wells.

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Applications Of Directional Drilling

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.

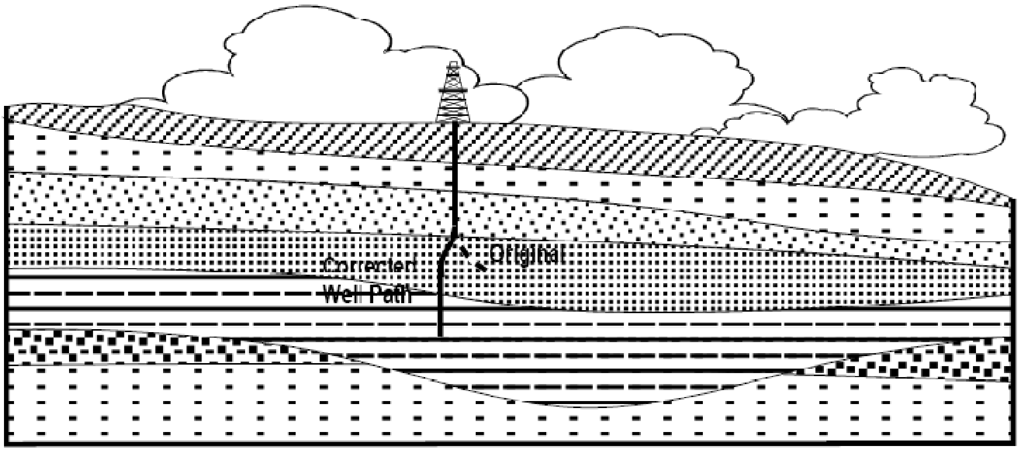

Figure 5-3: Controlling vertical wells.

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Applications Of Directional Drilling

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.

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Applications Of Directional Drilling

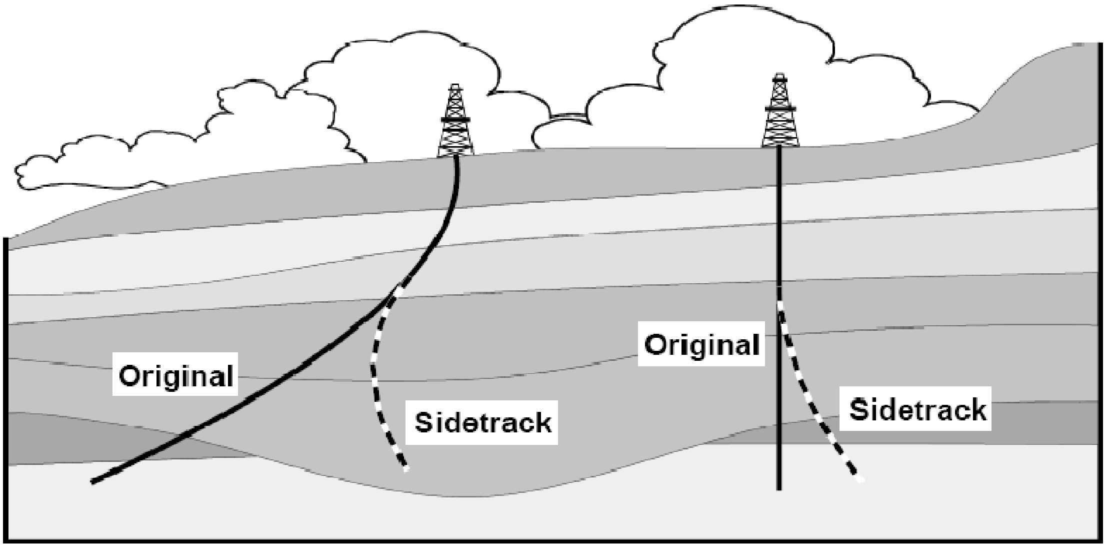

Figure 5-4: Sidetracking.

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Applications Of Directional Drilling

Inaccessible locations

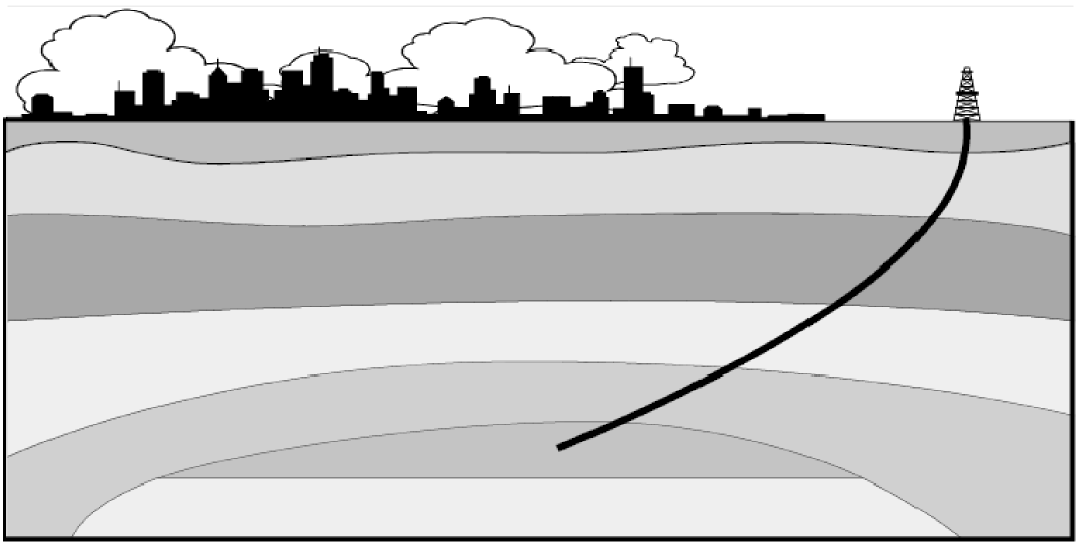

Figure 5-5: Inaccessible locations.

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Applications Of Directional Drilling

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.

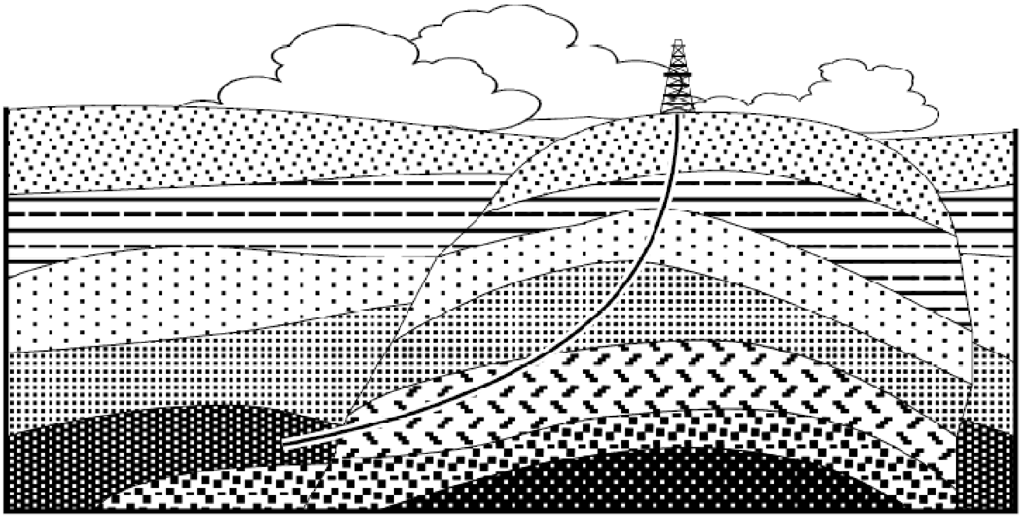

Figure 5-6: Fault drilling.

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Applications Of Directional 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.

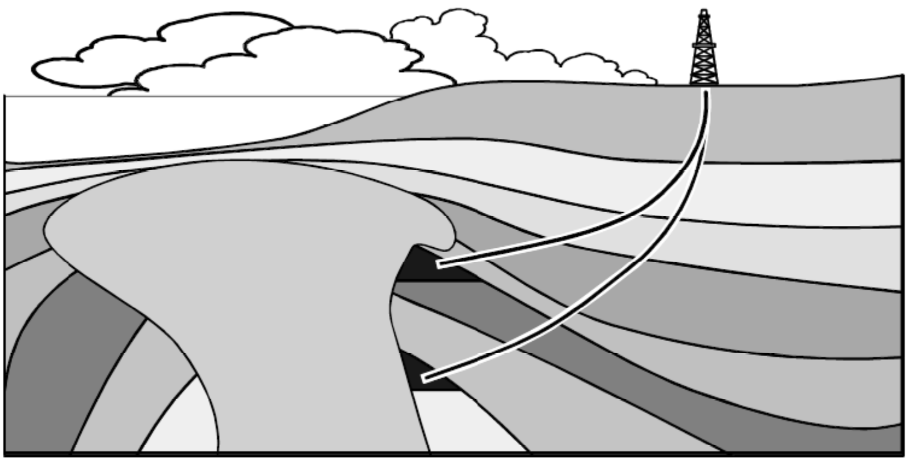

Figure 5-7: Salt dome drilling.

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Applications Of Directional 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.

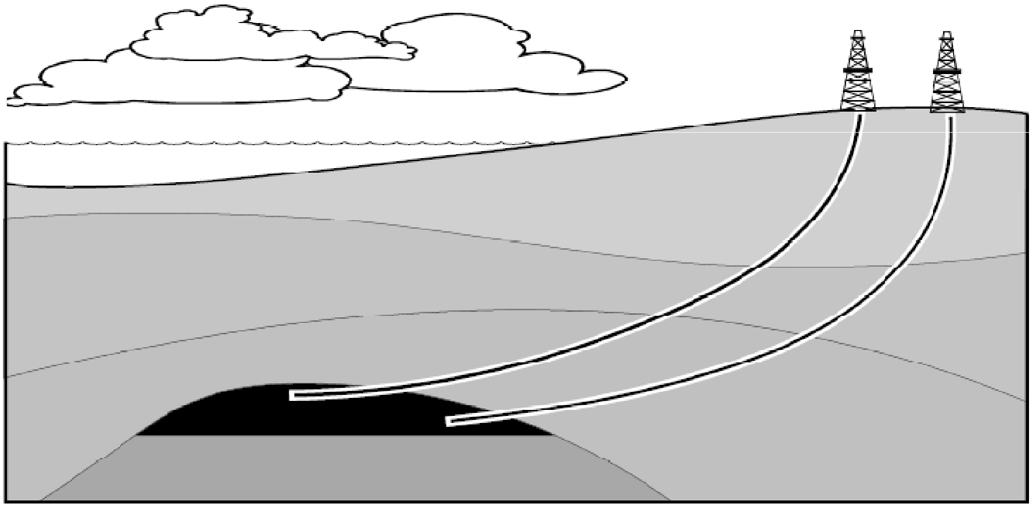

Figure 5-8: Shoreline drilling.

Applications Of Directional 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.

Azimuth Reference Systems

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.

Azimuth Reference Systems

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.

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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.

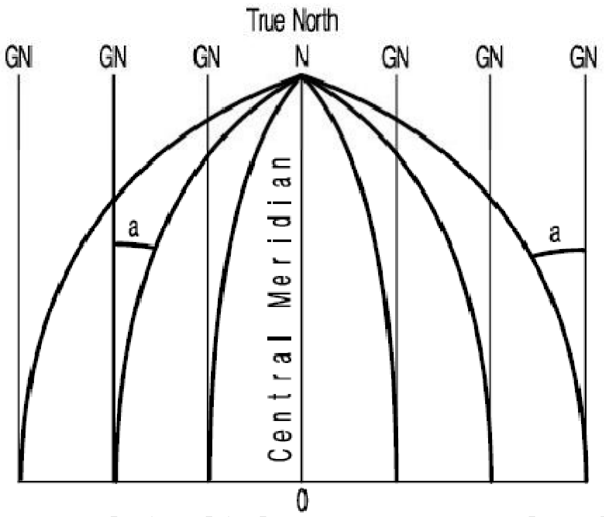

Figure 5-9: Relationship between True North and Grid North

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.

AZIMUTH

The azimuth of a wellbore at any point is defined as the direction of the wellbore on a horizontal plane measured clockwise form a north reference. Azimuths are usually expressed in angles from 0-360 , measured from zero north, e.g. 135 , **Figure 5.10**.

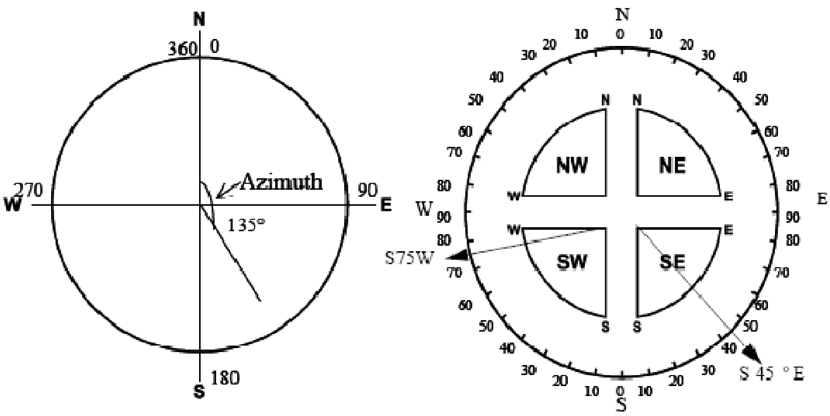

Figure 5.10 Definition of azimuth

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Azimuths can also be expressed in a quadrant system from 0-90 measured from north in the northern quadrants and from south in the southern quadrants. The azimuth reading of 135 equates to S45 E in quadrant readings, see **Figure 5.10**.

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WELL PROFILE: DEFINITIONS

INCLINATION ANGLE

The inclination angle of a well at any point is the angle the wellbore forms between its axis and the vertical, see **Figure 5.11**.

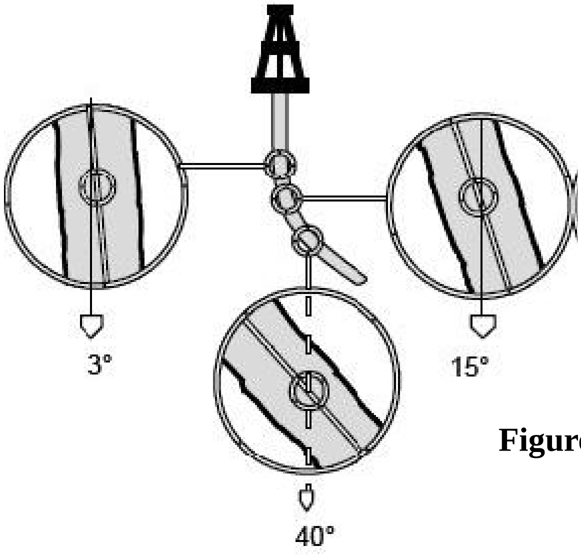


Figure 5.11 Inclination angle.

MEASURED DEPTH

Measured depth (MD) is the distance measured along the well path from one reference point to the survey point, **Figure 12**. Measured depth is also known as Along Hole Depth and is measured with the pipe tally or by a wireline.

True vertical depth (TVD)

True vertical depth (TVD) is the vertical distance measured from a reference point to the survey point. TVD is usually referenced to the rotary table, but may also be referenced to mean sea level, **Figure 12**.

KICK-OFF POINT

The kick off point is defined as the point below the surface location where the well is deflected from the vertical, **Figure12**. The position of the kick off depends on several parameters including: geological considerations, geometry of well and proximity of other wells.

BUILD UP AND DROP OFF RATES

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

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

The optimum build up and drop off rates in conventional directional wells are in the range of 1.5^0 to 3^0 per 100 ft, although much higher build up rates are used for horizontal and multilateral wells.

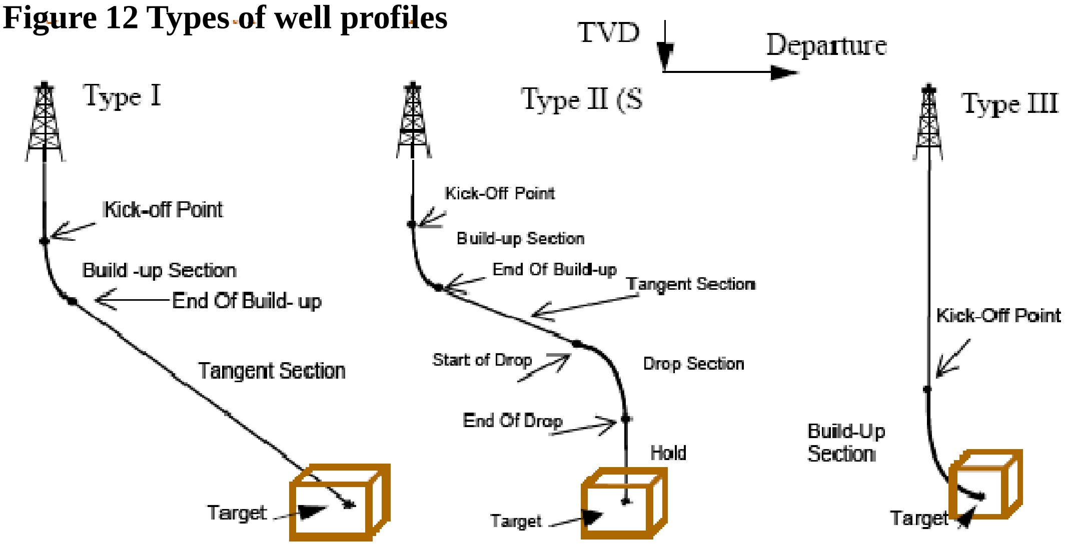
Well Trajectory Planning

Careful planning, always an important factor in minimizing well costs, is especially critical in directional drilling. The starting point in planning a directional well is to establish the target coordinates with respect to the surface location, and get an idea of the well course, or trajectory.

If the position of the surface location is known and given the location of the target, its TVD and rectangular coordinates, it is possible to calculate the best well profile that fits the coordinates of the surface and the bottom hole target that fit this data. The well profile is plotted in the vertical plane as shown in **Figure 12.**This figure also describes the various sections of a directional well.

Types of well profiles

Figure 12 Types of well profiles



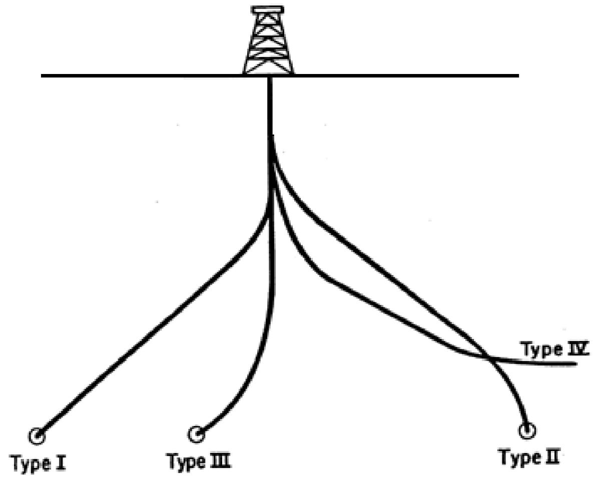


Figure 13

Type 1: Build and Hold

This pattern employs a shallow initial deflection and a straight-angle approach to the target.

It is most often used to reach single targets at moderate depths, and sometimes for drilling deeper wells with large horizontal departures.

Type 2: Build, Hold and Drop

After a relatively shallow deflection, this pattern holds angle until the well has reached most of its required horizontal displacement. At that point, angle is reduced or brought back to vertical to reach the target.

The Type 2 pattern is most applicable to wells exposing multiple pay zones, or wells subject to target or lease boundary restrictions.

Type 3: Continuous Build

Unlike the Type 1 and 2 patterns, this trajectory has a relatively deep initial deflection, after which angle is maintained to the target.

The continuous build pattern is well-suited to salt-dome drilling, fault drilling, sidetrack sand redrills.

Type 4: Build, Hold and Build

This is the general pattern describing horizontal wells.

The decision to drill horizontally is primarily based on reservoir engineering and reservoir management considerations.

Once we establish a basic well profile, the next step is to plan the trajectory in detail, again starting with the target location (Figure 14 , *Directional drilling parameters*).

We express the target location in terms of its *true vertical depth* (TVD) and *horizontal departure*, or throw.

The *bottomhole target* diameter or radius dictates how much control we have to exercise over the well trajectory. Generally, the greater the degree of control, the higher our drilling costs. We should therefore establish the largest target that will ensure our meeting well objectives.

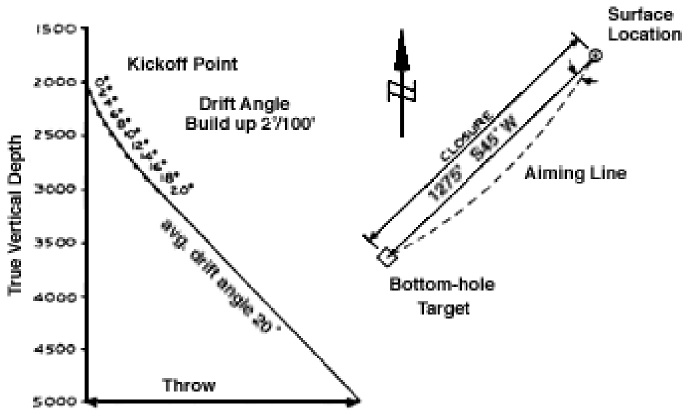


Figure 14 , *Directional drilling parameters.*

(Moore, 1986. Courtesy of Penn-Well Publishing Co.)

All wells (except for the special case of slant drilling) start off as more or less vertical. They become directional only when we reach the kick-off depth (KOD): the point at which we begin the incremental building of drift angle, or inclination from vertical.

We generally express inclination in terms of degrees per 100 feet of drilled section .

The *turn-off depth* (TOD) is a point at which we change the hole direction, or azimuth, as measured with respect to true North. For example, if a target is located at a direction of 20° from north in relation to the surface location, the azimuth at the turn-off depth is N20°E.

The *build-rate angle* and *drop-rate angle* refer, respectively, to the incremental increase or decrease in inclination from vertical, while the turn-rate angle is the change in azimuth per 100 feet of hole section. Because of drill string rotation, bits tend to "walk" to the right in the horizontal plane. To account for this natural drift, it is common to initiate the turn of the well path with a specified *lead angle* (LA) to the left of the target. The lead angle's magnitudes generally determined from offset well records.

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Calculation of the Well pattern

This section summarizes the equations used to calculate directional plans in the vertical plane for the Build and Hold, Continuous Build and Build, Hold and Drop well patterns. The reader may find derivations for these equations in Maurer (1966).

Calculation of the Build and Hold pattern

requires the following data:
(KOD) = kick-off depth, ft
(HYD)t = target horizontal departure in the y plane, ft
(TVD)t = target true vertical depth, ft
BR = build rate angle (°/ft)

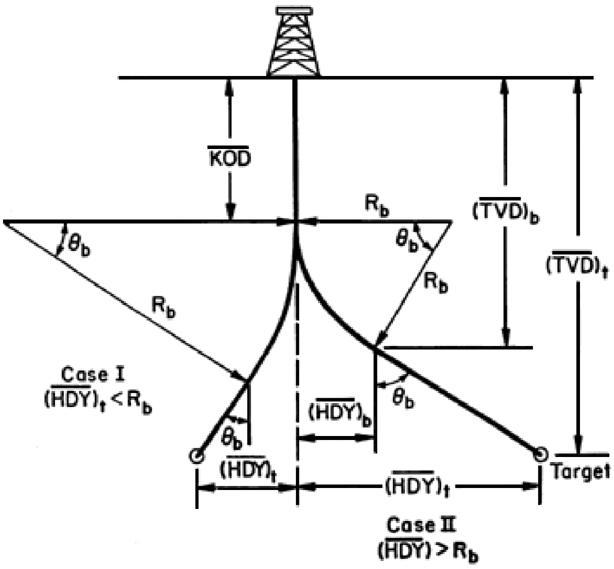

Figure 15

Calculation of the Build and Hold pattern

Case 1: (HYD)t < Rb

$$R_b = \frac{1}{BR}\left(\frac{180}{\pi}\right) \qquad \textbf{(1)}$$

$$\theta_b = \tan^{-1}\frac{a}{b} - \cos^{-1}\left[\frac{R_b}{a}\sin\left(\tan^{-1}\frac{a}{b}\right)\right] \qquad \textbf{(2)}$$

where a = (TVD)t-KOD)

b = Rb - (HDY)t

Ɵb = maximum angle of hole inclination at end of build.

The total measured depth to target (TMD) equals

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Calculation of the Build and Hold pattern

$$TMD = KOD + \frac{\theta_b}{BR} + \frac{(TVD)_t - KOD - R_b \sin\theta_b}{\cos\theta_b} \qquad \textbf{(3)}$$

and we can calculate kick-off depth as

$$KOD = TVD - R_b \sin\theta - \frac{(HDY)_t - R_b(1-\cos\theta)}{\tan\theta_b} \qquad \textbf{(4)}$$

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Calculation of the Build and Hold pattern

Case 2: (HYD)t > Rb

$$\theta_b = 180 - \tan^{-1}\left(-\frac{a}{b}\right) - \cos^{-1}\left[\frac{R_b}{a}\sin\left(\tan^{-1}\left(-\frac{a}{b}\right)\right)\right] \qquad \textbf{(5)}$$

(TMD) and KOD are as defined in Equations 3 and 4.

Calculation of the Continuous Build Pattern

The data required for the Continuous Build calculation (Figure 16)are the same as those required for the Build-and-Hold equations. The calculated horizontal departure in the y plane and the true vertical depth at a point i along the build section are as follows:

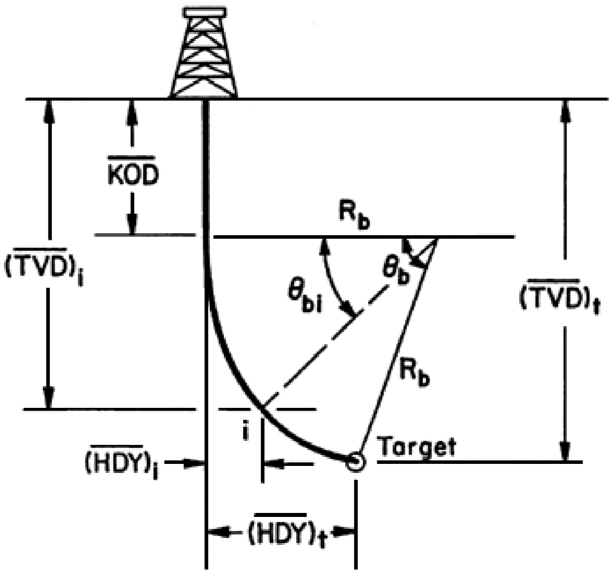

Figure 16

Calculation of the Continuous Build Pattern

$$(TVD)_i = (KOD) + R_b \sin\theta_{bi} \quad \textbf{(6)}$$

$$(HDY)_i = R_b (1-\cos\theta_{bi}) \quad \textbf{(7)}$$

The total True Vertical Depth (TVD)t and the Total Horizontal Departure (HDY)t can be found by substituting the total build angle, Ɵb, in Equations 5 and 6, respectively.

The total Measured Depth is given by

$$TMD = KOD + \frac{\theta_b}{BR} \quad \textbf{(8)}$$

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Calculation of the Build, Hold and Drop Pattern

Data requirements for the build, hold and drop pattern (Figure 17) are similar to those for the Build and Hold and Continuous Build patterns. The following equations are used to calculate the maximum angles of inclination:

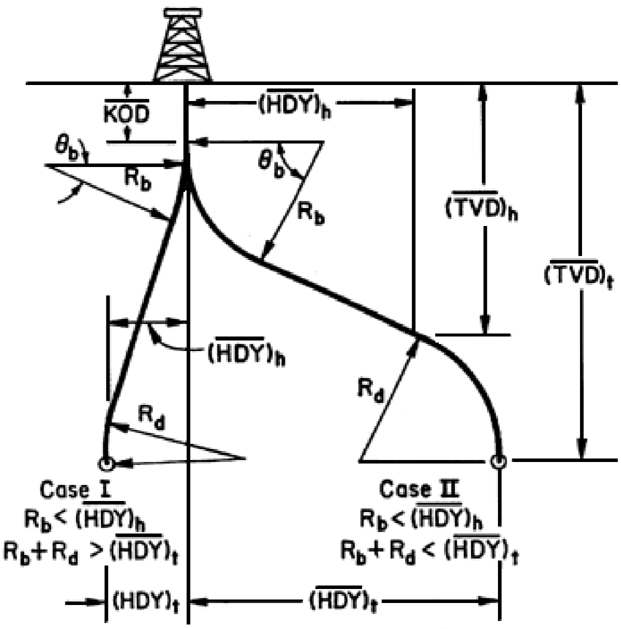

Figure 17

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Calculation of the Build, Hold and Drop Pattern

Case 1: Rb < (HDY)h

Rb+Rd > (HDY)t

$$\theta_b = \tan^{-1}\left(\frac{a}{b+R_d}\right) - \cos^{-1}\left[\frac{R_b+R_d}{a}\sin\left(\tan^{-1}\frac{a}{b+R_d}\right)\right] \qquad \textbf{(9)}$$

Case 2: Rb< (HDY)h

Rb+Rd <(HDY)t

$$\theta_b = 180 - \tan^{-1}\left(\frac{a}{b+R_d}\right) - \cos^{-1}\left[\frac{R_b+R_d}{a}\sin\left(\tan^{-1}\frac{a}{b+R_d}\right)\right] \qquad \textbf{(10)}$$

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Calculation of the Build, Hold and Drop Pattern

The Total Measured Depth is

$$TMD = KOD + \frac{\theta_b}{BR} + \frac{(TVD)_h - KOD - R_b\sin\theta_b}{\cos\theta_b} + \frac{\theta_d}{BR} \qquad \textbf{(11)}$$

The calculations that define the well path in the horizontal plane can be described by the following equations:

$$(NS)_i = \Delta d_i \sin\left(\frac{\theta_i+\theta_{i-1}}{2}\right)\cos\left(\frac{\theta_i+\alpha_{i-1}}{2}\right) \qquad \textbf{(12)}$$

$$(EW)_i = \Delta d_i \sin\left(\frac{\theta_i+\theta_{i-1}}{2}\right)\sin\left(\frac{\theta_i+\alpha_{i-1}}{2}\right) \qquad \textbf{(13)}$$

The incremental True Vertical Depth is

$$(TVD)_i = \Delta d_i \cos\left(\frac{\theta_i+\alpha_{i-1}}{2}\right) \qquad \textbf{(14)}$$

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Calculation of the Build, Hold and Drop Pattern

where (NS)i = incremental distance measured along north-south direction
(EW)i = incremental distance measured along east-west direction
Δdi = an assumed incremental distance of hole section (generally 100 ft)
Θi-1; αi-1= inclination and azimuth at previous station (i-1)

We may find the total distances by summing the total increments:

$$(TNS) = \sum_{i=1}^{n} (NS)_i \quad \textbf{(15)}$$

$$(TEW) = \sum_{i=1}^{n} (EW)_i \quad \textbf{(16)}$$

$$TVD = KOD + \sum_{i=1}^{n} (TVD)_i \quad \textbf{(17)}$$

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Attaining the Well Trajectory

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Downhole Mud Motors

Downhole motors (commonly known as *mud motors* because they are hydraulically driven by the circulating drilling fluid as it moves down the drill string) have played an integral role in the advancement of directional drilling technology, and in "straighthole" drilling as well.

The flexibility and control that they provide is far beyond that attainable with other wellbore deflection techniques, and their use has become prevalent in an ever-widening range of applications, including slim hole and coiled tubing operations.

Downhole Mud Motors

The distinguishing feature of downhole motors is that they are designed to turn the bit without rotating the drill string. Thus, it's possible to orient the bit in a desired direction, and maintain it in this direction throughout the bit run. Moreover, drilling in this "oriented" mode reduces the rig's power requirements and reduces wear on both surface equipment and tubulars.

Downhole motors come in two basic types:

1- positive displacement motors (PDM)
2- turbine motors.

Positive Displacement Motor

The *positive displacement* motor is easily the most versatile tool for building or maintaining hole angle, or for minimizing crooked hole tendencies. It can be run with a bent sub or eccentric stabilizer to initiate deflection. Or, in "crooked hole "formations, it can be run without these accessories to serve as a deviation control tool.

For maximum directional control with a minimum of trip time, we may use a motor with a bent housing. Figure 18 (*Steerable positive displacement motor*) illustrates a motor in which the bent housing is adjustable.

Positive Displacement Motor

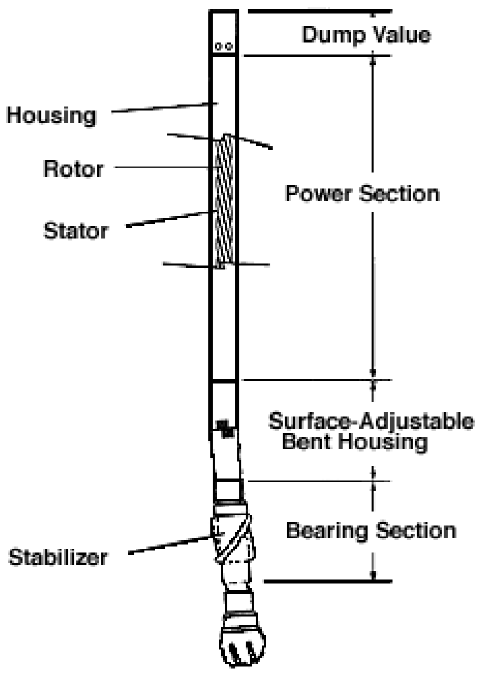

Figure 18

(Anadrill, 1992. Courtesy Anadrill / Schlumberger)

Positive Displacement Motor

The heart of the positive displacement motor is the rotor-stator assembly (Figure 19), consisting of a helicoidal rotor that moves within a molded, elastomer-lined stator. When circulating fluid is forced through this assembly, it imparts torque to the rotor, causing it to turn eccentrically. A universal connection transfers this rotation through a bearing and drive-shaft assembly to a rotating bit sub, which turns the bit.

Positive Displacement Motor

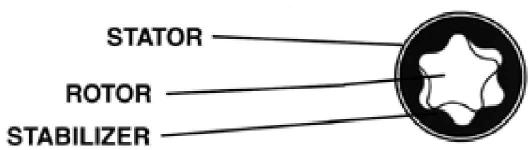

Figure 19

(Andrill, 1992. Courtesy Andrill / Schlumberger)

Positive Displacement Motor

Positive displacement motors provide excellent steerability for deflecting or straightening the well course. In addition, they allow us to increase the bit RPM without increasing the drill string rotation, and to drill with less weight-on-bit. This can result in higher penetration rates compared to drilling with a rotating kelly, and reduced drill pipe and casing wear--an important consideration, especially when drilling high-angle holes. Positive displacement motors are available in a wide variety of sizes, rotating speeds, rotor/stator configurations and output characteristics, for a broad range of downhole conditions .

Turbine Motor

A turbine motor (Figure 20) consists of multiple rotor/stator assemblies, which drive main thrust-bearing sections. Turbine motors operate at relatively high rotary speeds, and so are run exclusively with fixed cutter (PDC or natural diamond) bits. Some operators see this as an advantage in certain situations, in that these characteristics may help eliminate "bit walk" to the right, allow for higher bit weight (and thus improved drilling rates) and a smoother hole for logging and casing operations than a PDM would provide (von Flatern, 1991).

Turbine Motor

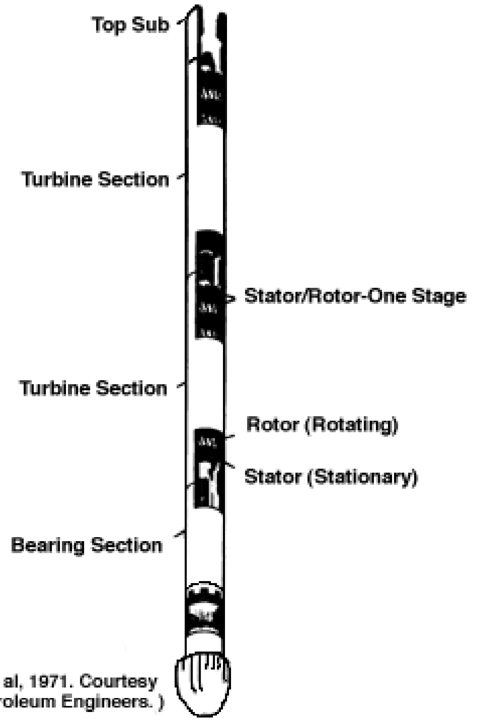

Figure 20

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Turbine Motor

Turbine motors have narrower operating ranges than positive displacement motors. The relatively small diameter of the turbines and resulting higher rotational speeds translate into greater fluid flow requirements. They also tend to be longer than PDMs, which limits their ability to make high-angle directional changes. ***Because of these limitations, which are inherent in the turbine motor design, positive displacement motors are used much more commonly***.

The operator and directional service company representative should consider the following basic information when selecting a downhole motor (von Flatern, 1991):

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Turbine Motor

- depths (kickoff point, target, etc.)
- hole size
- formation hardness
- faulting
- build rate
- bottomhole temperature
- conditions at the kickoff point (e.g., inside casing, sidetrack plug, etc.)
- hydraulics program
- mud program
- rig pump capabilities

Deflection Tools

Although the mud motor is overwhelmingly the tool of choice for controlled directional drilling, there are other tools that may be of some use in certain areas. These include

- directional wedges
- jet bits with oriented nozzles
- specialized bottomhole assemblies

Directional wedges

Directional wedges: Figure 24 shows a schematic of the wedge technique for deviating a wellbore. The wedge is attached to the bottomhole assembly by means of a shear pin. The assembly is lowered to bottom and oriented in the proper direction. The driller applies weight to set the wedge and shear the pin, drills ten to fifteen feet of undergauge hole, and then trips the tools so that a full-gauge hole opener can be run. After drilling the section, a survey is made to assure proper direction, and the process is repeated until the build section of the well is completed.

The directional wedge technique is time-consuming, has limited applications, and requires a high degree of technical expertise to properly implement. For these reasons, it is seldom used.

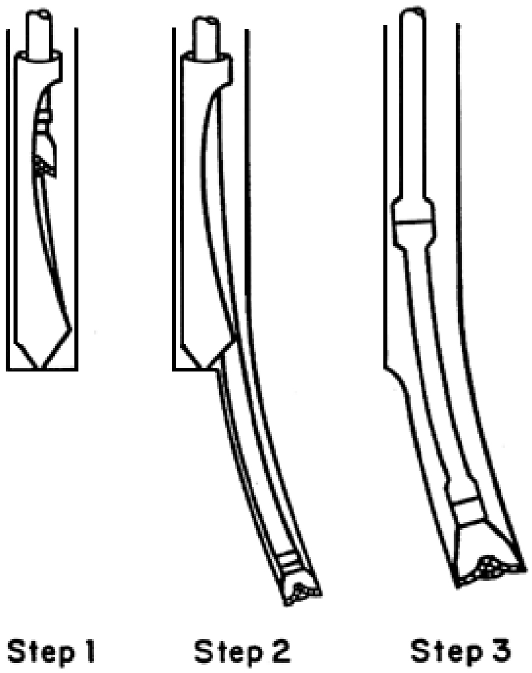

Figure 24

Whipstock

- The whipstock is a metal wedge placed in the wellbore that causes the bit to deviate
- In the early years of the petroleum industry, they were used to sidetrack wells if a portion of the drill string became stuck
    - Whipstocks were not very efficient

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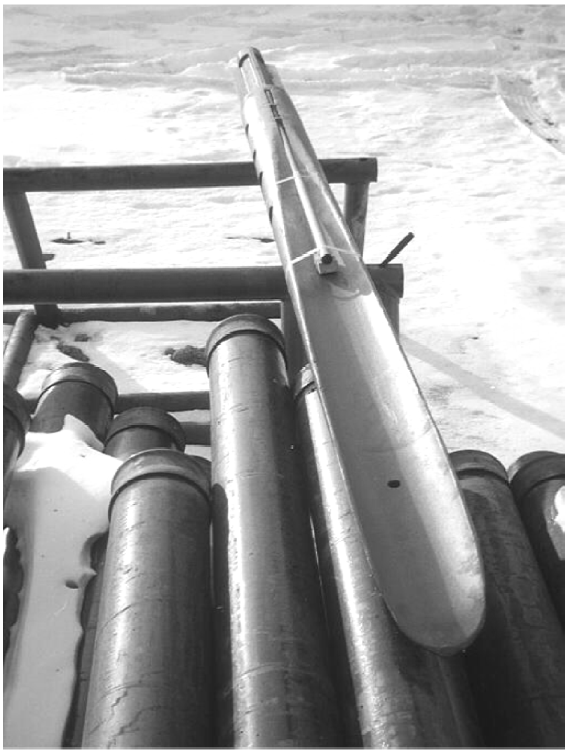

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–Retrievable whipstock

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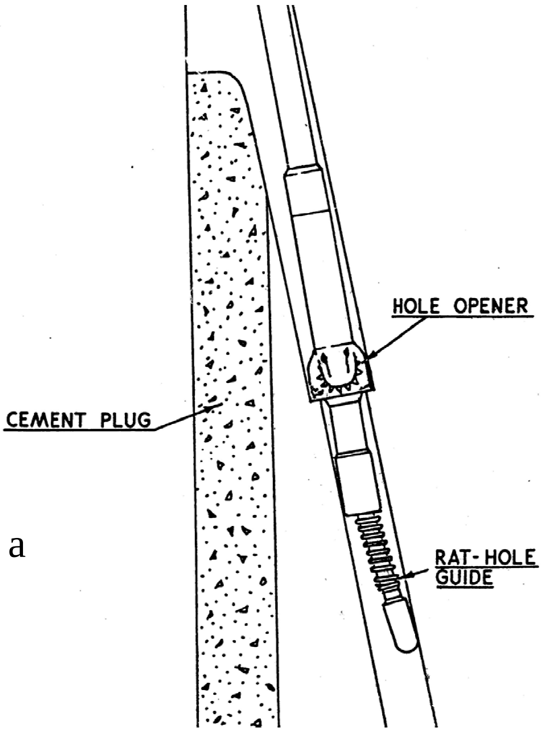
– Because the bit had to be run in with the whipstock, it was a smal diameter than the hole
– A second trip was made to open t hole to full gage

-In harder rock, a reaming trip may have been required

-Using the whipstock required a minimum of three trips, which was not cost effective



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Today, whipstocks are used frequently to sidetrack out of casing

The majority of casing sidetracks are now performed with a whipstock

Jet bits with oriented nozzles

Jetting bits with orienting nozzles can be effective at initiating deflection in very soft formations. Figure 25 illustrates the technique. The bit is lowered to bottom , the jet is oriented in the desired direction, and mud flow is initiated with no drill string rotation. After hydraulically gouging a small pilot hole (about 3 feet), the driller initiates conventional rotary drilling to open the section to full gauge. The process is then repeated. Hole surveys are made after drilling 10 to 15 feet of build section.

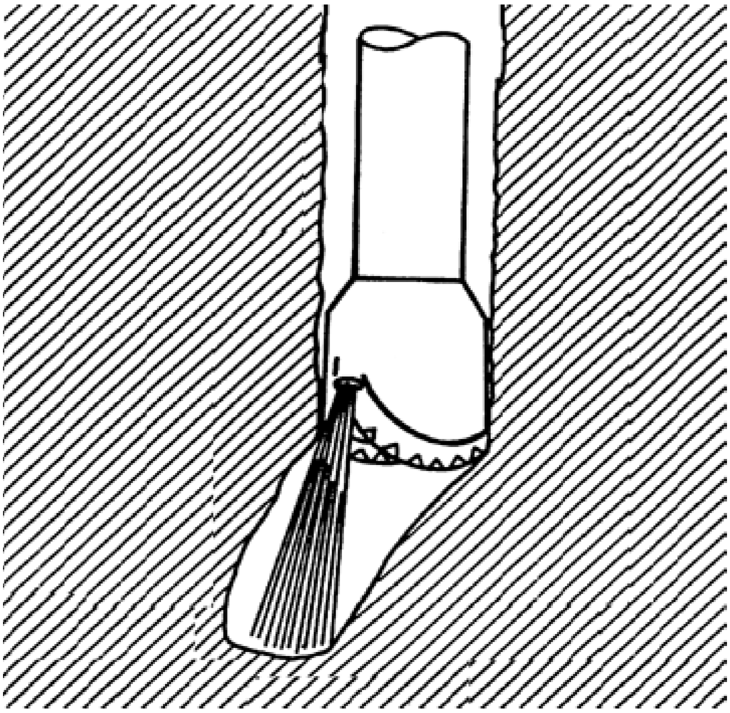

Figure 25

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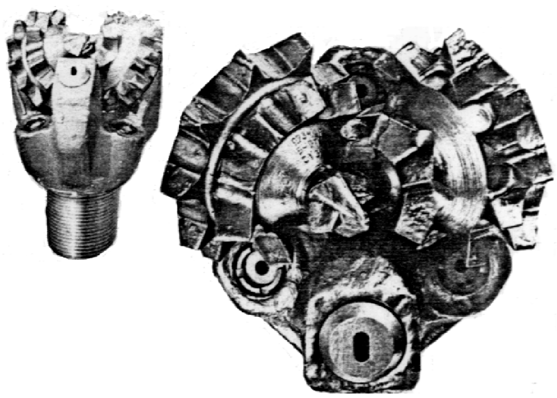
- Jetting was used as an alternative to whipstocks

- Jetting was only effective in softer rocks since formations have to be eroded to change the trajectory of the wellbore

– A bit with a larger diameter nozzle facing the side of the hole was used to erode the formation to one side of the bit

– The larger nozzle was oriented in the desired direction



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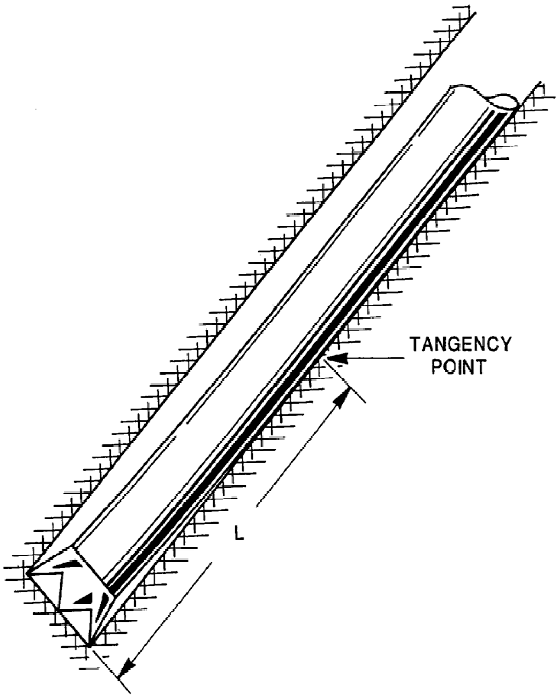
Specialized bottomhole assemblies

In developed fields, where drilling tendencies and formation characteristics are well known, it is often possible to build or drophole angle with a reasonable degree of control by using drill collars, stabilizers, reamers and other BHA components, without having to resort to mud motors or other deflection tools.

Rotary BHA

- The rotary BHA consists of a bit, drill collars, stabilizers, reamers, subs and other special tools run below the drill pipe
- Motors were used to put the wellbore on course and rotary BHA's were used to drill the majority of the well
- Even though rotary assemblies are used only occasionally, we will still look at them
- Steerable motor assemblies in the rotating mode are still rotary BHA's subject to the same influences as the rotary BHA

- A slick assembly is simply a bit and drill collars
- The deviation tendency is caused by the bending of the drill collars
- The point at which the collars touch the wall of the hole is the tangency point



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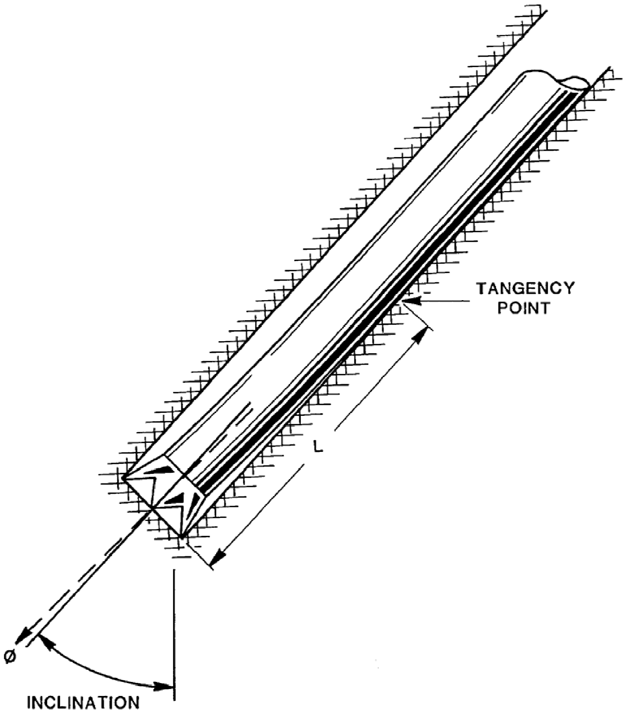
- The resultant force applied to the formation is not in the direction of the hole axis but in the direction of the drill collar axis



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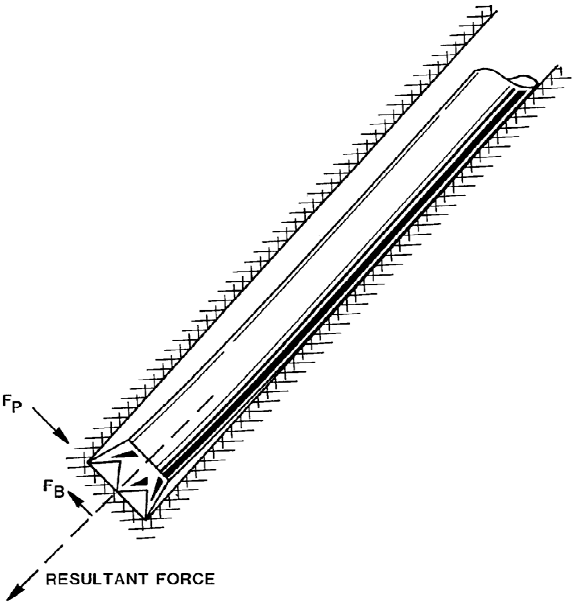
- The resultant force can be broken up into its components F_B and F_P
- F_B is the side force caused by the bending of the collars or building force
- F_P is the force due to gravity or pendulum force



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Ideally, if

$F_P > F_B$, *the hole inclination will drop*

$F_P < F_B$, *the hole inclination will increase*

$F_P = F_B$, *the hole inclination will remain constant*

The building force can be increased by increasing bit weight, which drives the tangency point down

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- The building force is also affected by the stiffness of the collars
- Stiffer collars will bend less
- As the diameter of the collar increases, the stiffness of the collar increases

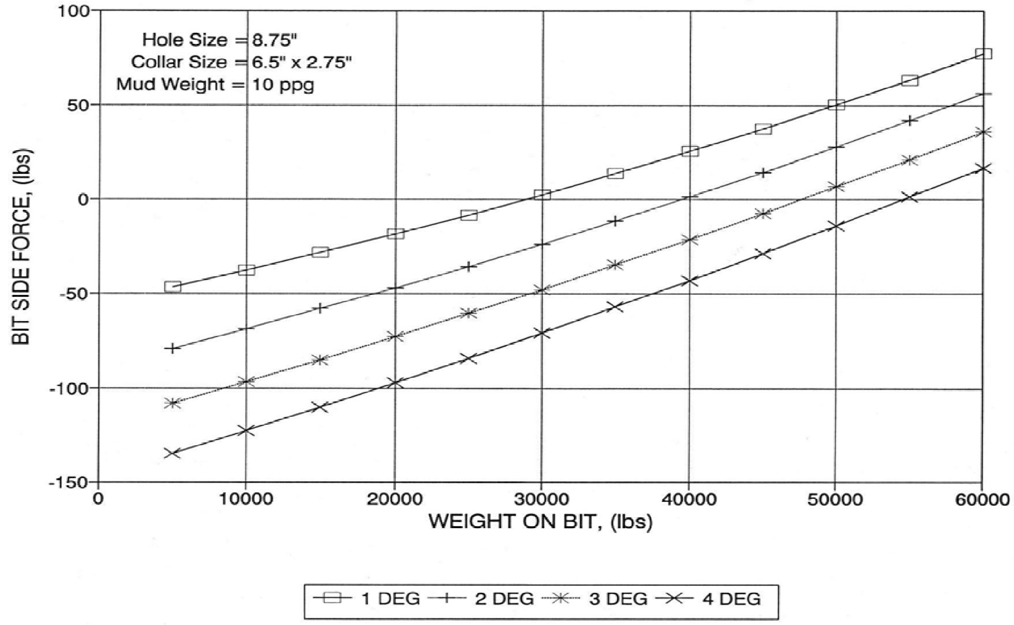
Collar Diameter	Relative Stiffness
12	16
10	8
8	3
6	1
4	0.2

The pendulum force can be increased by reducing bit weight and using larger diameter collars

Some inclination is required to have a pendulum force

For a slick assembly, the building and pendulum force will balance at relatively low inclinations; therefore, they are not expected to build much inclination

SLICK ASSEMBLY



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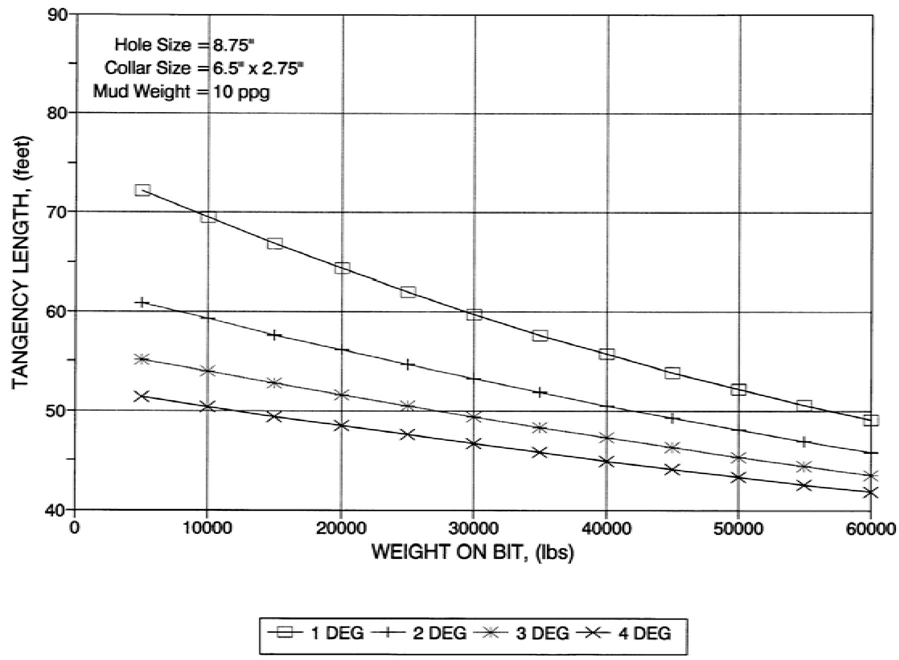
SLICK ASSEMBLY



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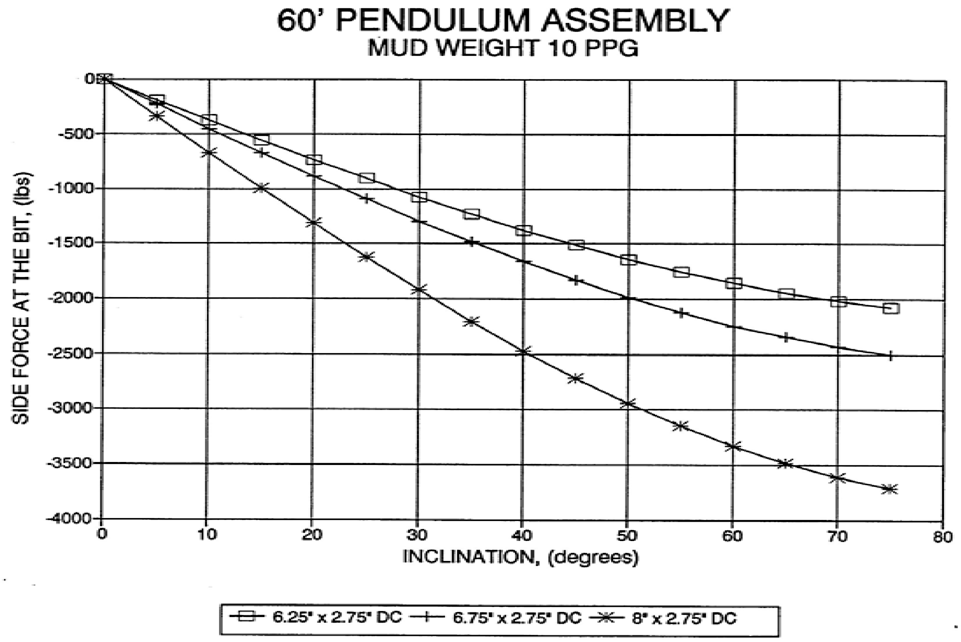

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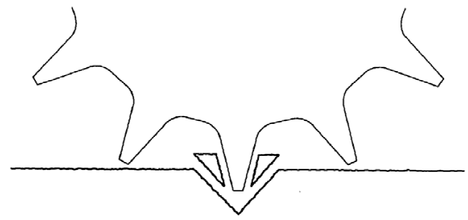
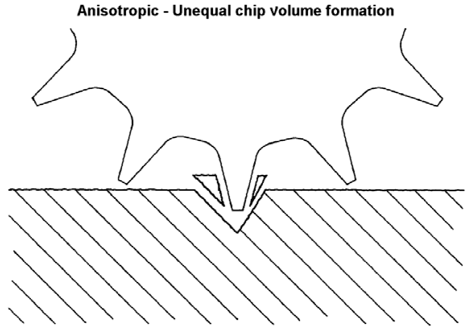
- ➢If the bed dip is relatively flat, we seldom have any deviation problems
- ➢When bed dip is encountered, we can experience deviation problems in harder rock
- ➢Deviation problems are associated with formation dip
- ➢The anisotropy of the formation causes deviation



Isotropic - Equal chip volume formation

Anisotropic - Unequal chip volume formation



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If the formation deviation tendency can be defined as a force F_F, the resultant force at the bit would be

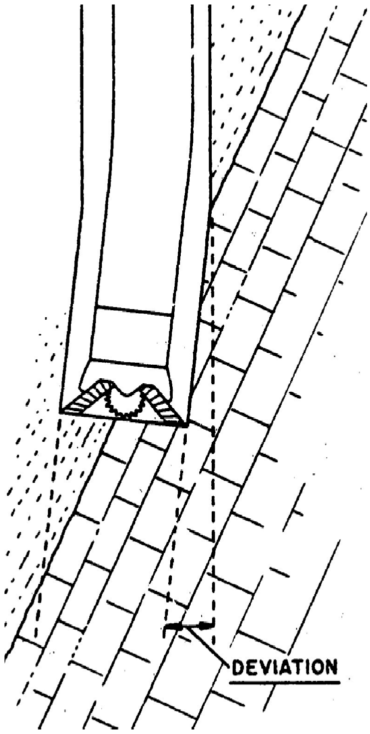
$$F_B + F_P + F_F$$

The wellbore will continue to build angle until the sum of the forces is equal to zero

Unfortunately it is difficult to define F_F and it changes with depth

Rule of thumb:

1- If the bed dip is less than 45 degrees, the bit will have a tendency to deviate perpendicular to the bed dip (up dip)



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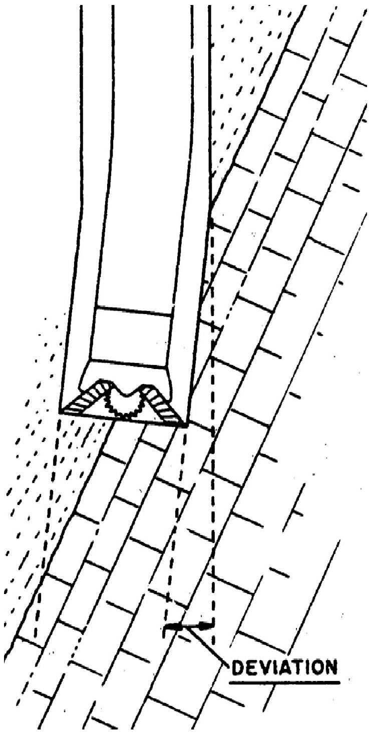
2- If bed dip is above 65 degrees, the bit will have a tendency to deviate along the bed dip

3- Between 45 and 65 degrees, the bit can do either



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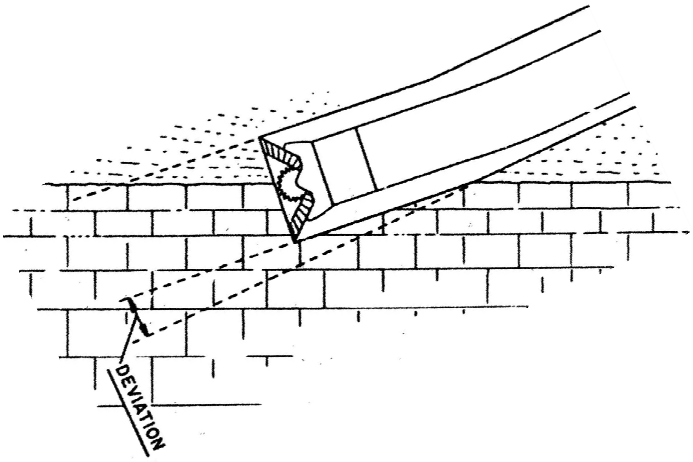
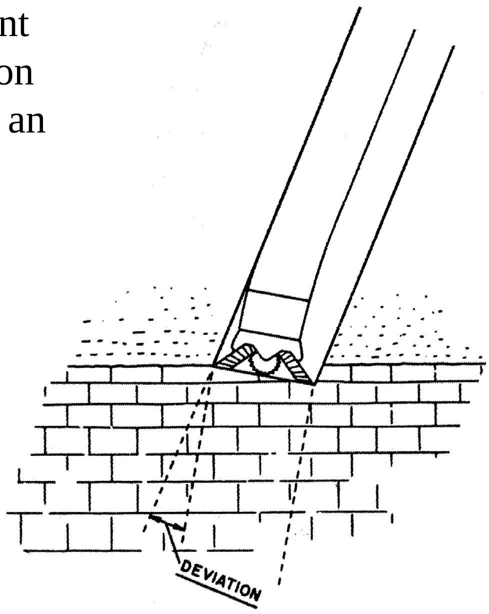
4- In directional drilling, it is the difference between the bit angle and the formation dip



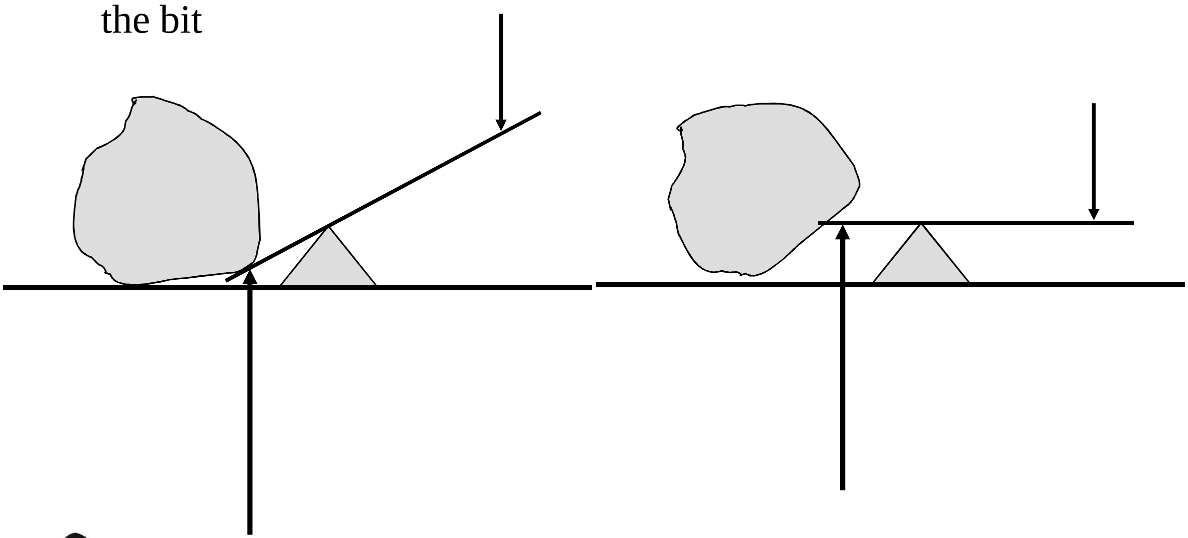
5-The formation may want the bit to drop inclination when the wellbore is at an inclination greater than bed dip



The two forces associated with a rotary assembly are the building force (F_B) and the dropping force (F_P)

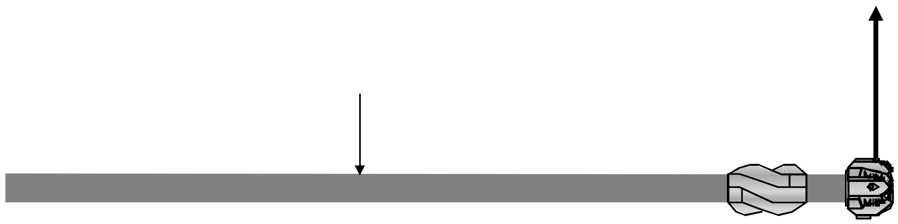
If we want to make a building assembly, the building force must be maximized

- Stabilizers are used as fulcrums in order to increase the side force at the bit



Building assembly

- A building assembly is constructed by placing a stabilizer near the bit
- Bending of the drill collars above the stabilizer causes the building force at the bit to increase substantially



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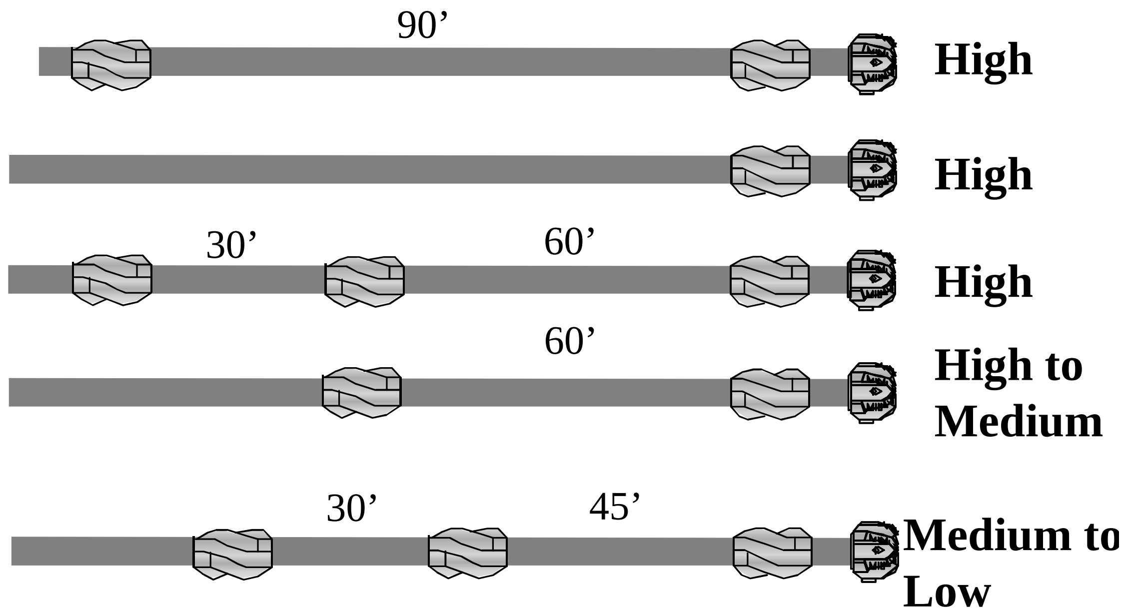

Building Assemblies

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At low inclinations, the drill collars are bent by increasing bit weight

At higher inclinations, gravity will bend the collars and the build tendency is less affected by bit weight

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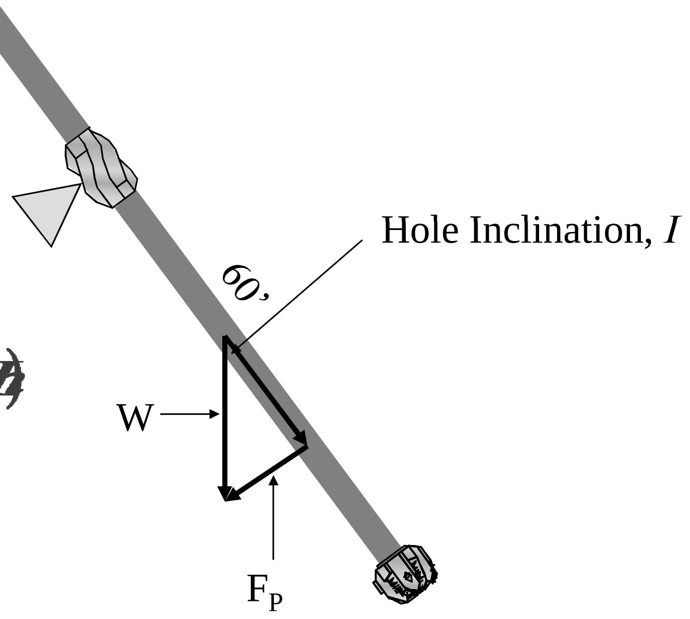
In order to make a dropping assembly, the pendulum force is maximized by placing a stabilizer at least 30 to 90 feet above the bit

$$F_p = 0.5 \times W \times Sin(I)$$



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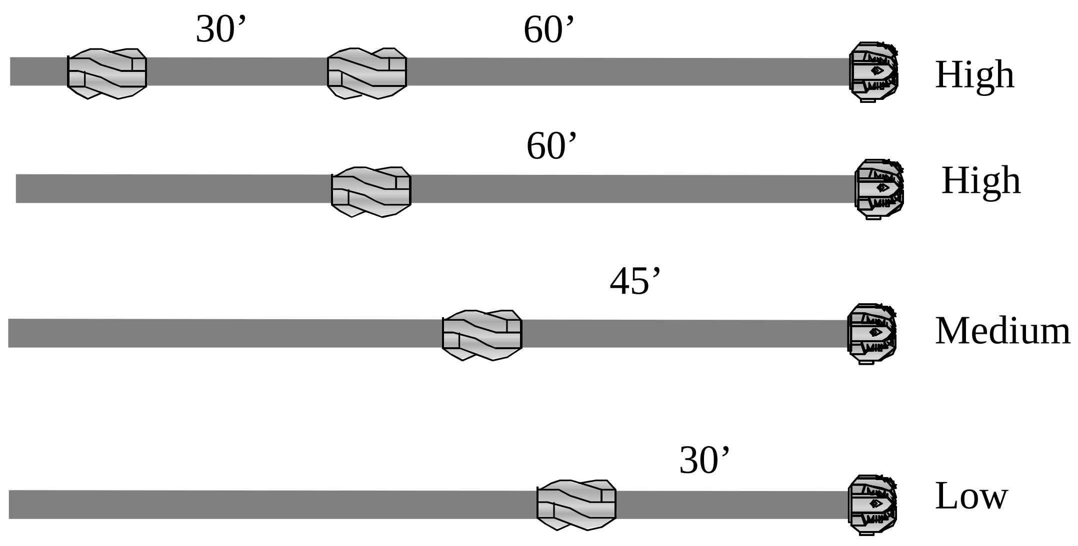

Dropping Assemblies

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➤If the stabilizer is too far above the bit, the collars will touch the wall and the pendulum force will be reduced

➤A holding assembly is constructed by placing stabilizers closer together so that the collars are more rigid

➤Bit side force is minimized

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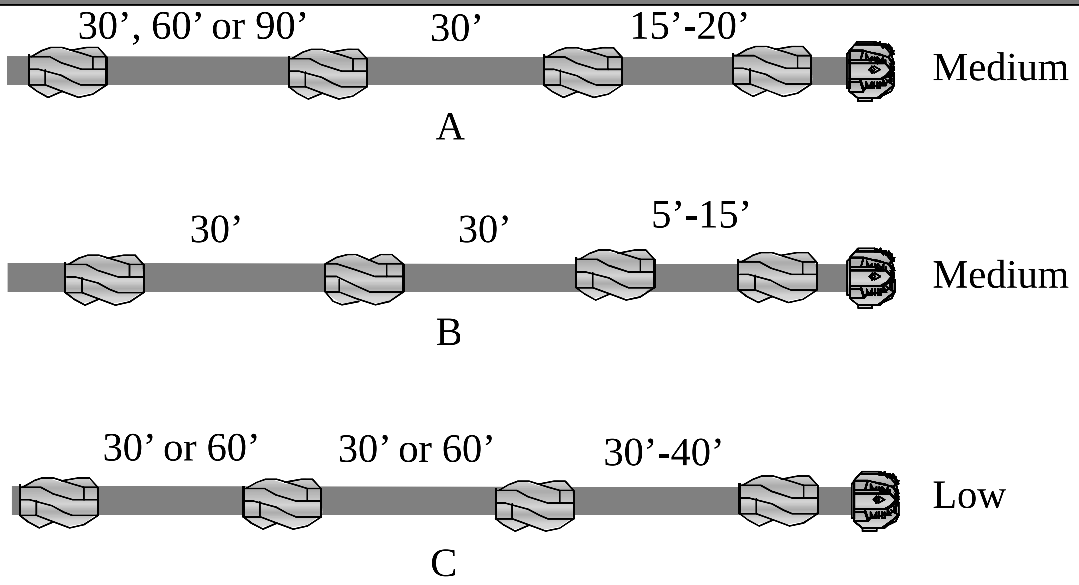

Holding Assemblies

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Figure 21 (*Angle-building bottomhole assemblies*),
Figure 22 (*Angle-dropping bottomhole assemblies*) and
Figure 23 (*Angle-holding bottomhole assemblies*) illustrate typical assemblies for building, dropping or maintaining hole angle.

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(*Angle-building bottomhole assemblies*)

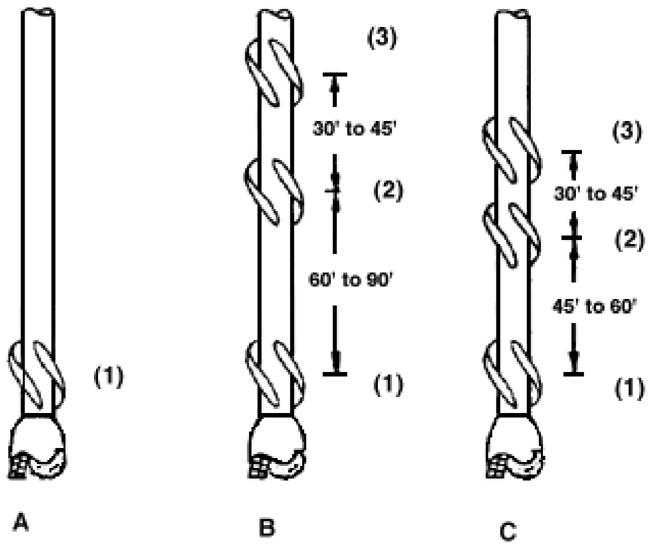

Figure 21

(Moore, 1986. Courtesy PennWell Publishing Company)

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(*Angle-dropping bottomhole assemblies*)

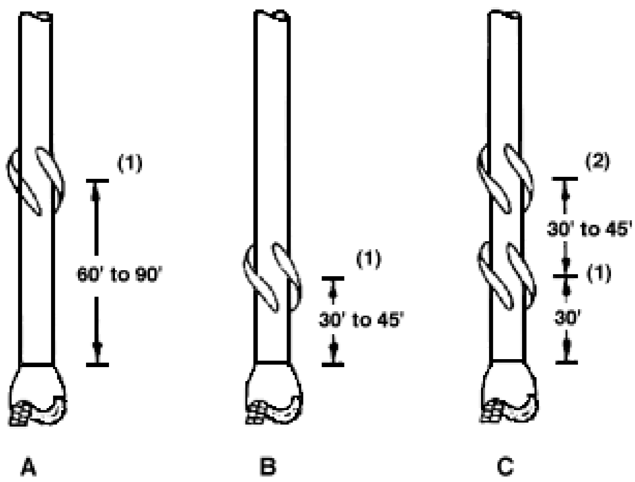

Figure 22

(Moore, 1986. Courtesy PennWell Publishing Company)

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(*Angle-holding bottomhole assemblies*)

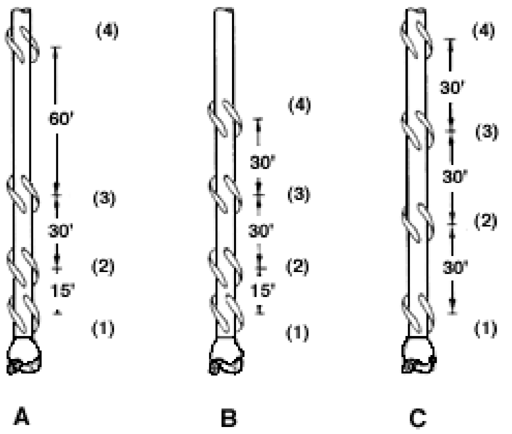

Figure 23

(Moore, 1986. Courtesy PennWell Publishing Company)

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Surveying the Well Trajectory

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Survey Tools

Mechanical Drift Indicator

The oldest and simplest type of directional survey tool is the mechanical drift indicator (Figure 26). This device works on a pendulum, or plum-bob principle. It gives no indication of azimuth, but measures only a well's inclination from vertical. It is used today for surface hole drilling, shallow vertical wells and other applications where dog-leg severity and horizontal departure are not likely to become significant problems.

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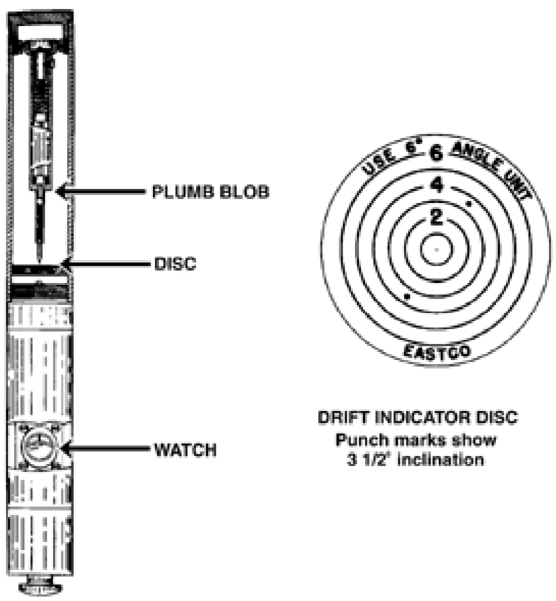

Figure 26

(From Gatlin, 1960; Eastman Oil Well Surveying Co.)

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Magnetic survey tools

Magnetic survey tools record the inclination, azimuth and tool-face orientation at various points, or stations, along the well course. Two basic types of tools are available: single-shot devices, which record one measurement (usually near the bottom of the well), and multi-shot devices, which can record a number of survey measurements in one running. Tools can be dropped or pumped to bottom, lowered on slick line or wireline, or run as part of a measurement-while drilling (MWD) package. When tools are dropped to bottom--typically before tripping pipe--they can be recovered when the pipe is pulled, or else by means of an overshot.

The basic components of a conventional magnetic survey tool are as shown in Figure 27:

- a magnetic compass and angle-indicating unit
- a camera unit for recording measurements on a photographic
- a timer or motion sensor, which activates the device at a desired time or depth interval

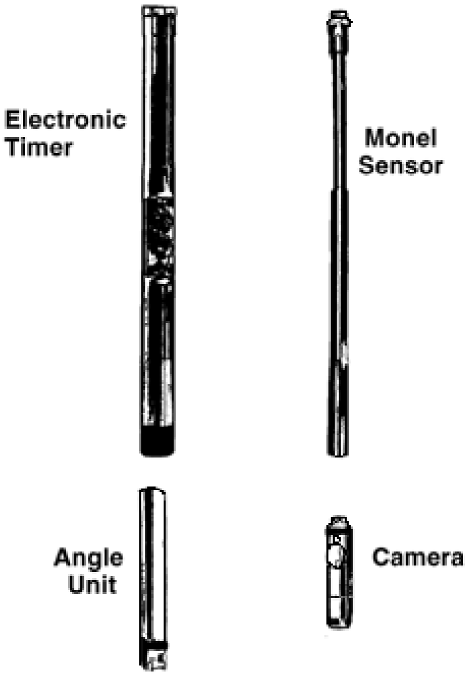

Figure 27

(Baker-Hughes Inteq, 1993. Courtesy Baker-Hughes Inteq.)

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In place of camera-based devices, more modern magnetic survey tools offer solid-state electronic recording capabilities. These devices are armed by means of a surface computer, and then run like standard multi-shot tools. Survey data are recorded electronically using highly sensitive magnetometers and accelerometers, stored, and then retrieved and processed by the computer. Their main advantages are time savings, improved accuracy, continuous readings with surface readouts, and elimination of errors caused by manually reading film records.

To prevent magnetic interference from the drill string, magnetic instruments must be run inside non-magnetic drill collars. They may be run with a collar, or "monel" sensor (Figure 27) to minimize mis-runs caused by the tool hanging up in the drill string.

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Figure 28 illustrates a typical running assembly for a single-shot magnetic tool. Note the orientation sub at the bottom of the assembly, which is used to orient deflection tools for directional drilling. Figure 29 shows a typical asembly for a multi-shot magnetic tool.

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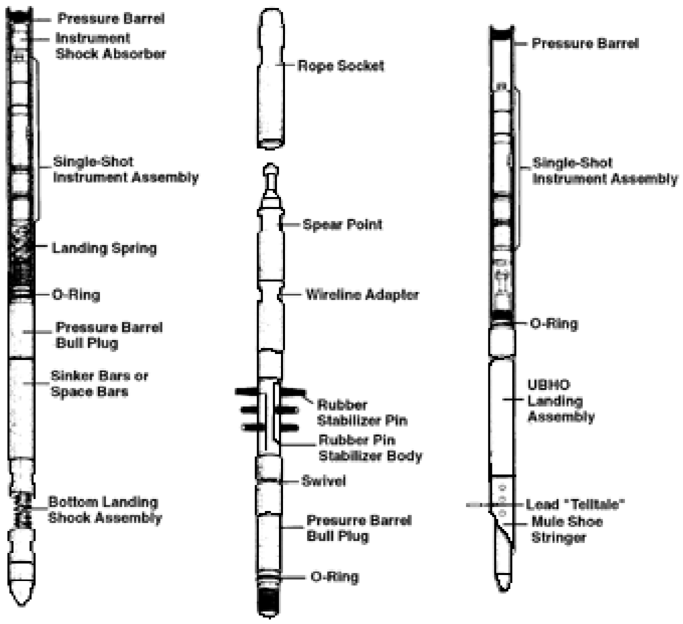

Figure 28

(Baker-Hughes Inteq, 1993. Courtesy Baker-Hughes Inteq.)

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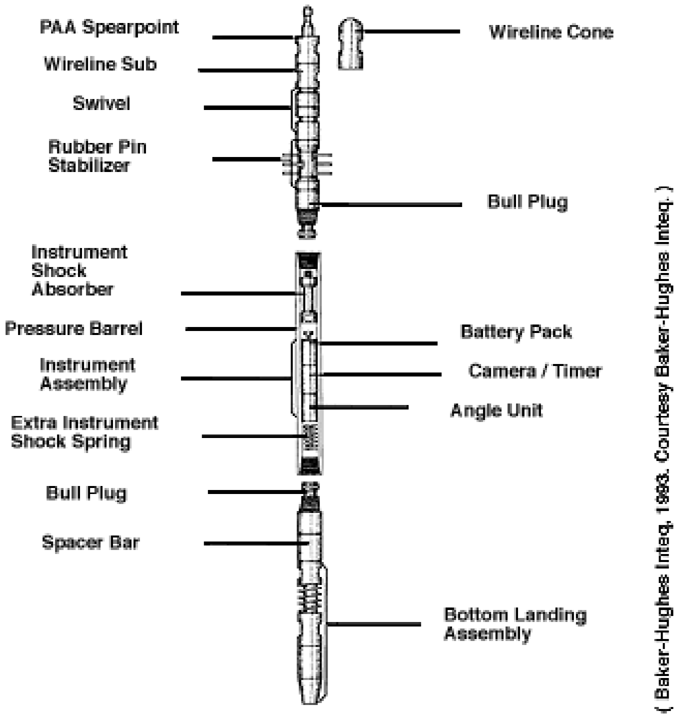

Figure 29

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Magnetic tools measure azimuth based on the earth's magnetic field. Consequently, they measure magnetic, rather than true north, and we have to correct for this difference, or declination, when we report these measurements (Figure 30 , *The earth's magnetic field* and Figure 31, *Declination, magnetic to true north*).

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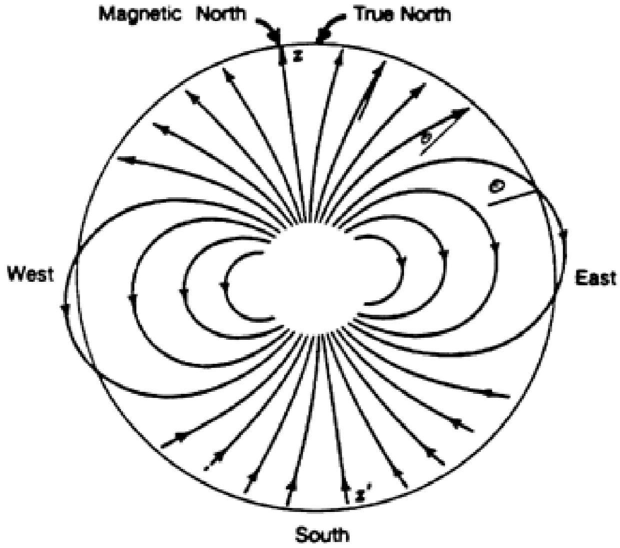

Figure 30

(Bourgoyne et al, 1991. Courtesy of Petroleum Engineers.)

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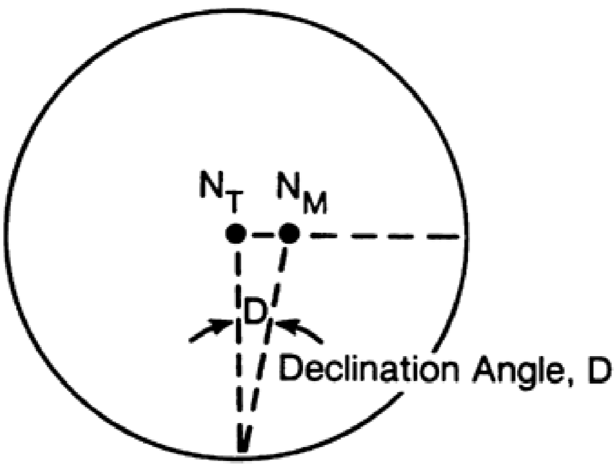

(Bourgoyne et al, 1991. Courtesy of Petroleum Engineers.)

Figure 31

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Gyroscopic survey tools

Gyroscopic survey tools, like magnetic devices, are used to measure inclination, azimuth and tool orientation. The primary difference is the use of a gyroscopic, rather than a magnetic compass. Gyroscopic tools are used for surveying wells where casing has been set, or where there is magnetic interference from nearby wellbores. Like magnetic instruments, gyroscopic tools can have single-shot or multi-shot capabilities, and there are devices available that have electronic, computer-aided data recording and processing, and continuous survey, surface readout features. They are not as rugged as magnetic tools, and so must be run on wireline. Figure 32 illustrates a gyroscopic compass unit.

Although gyroscopes are not subject to magnetic interference, they are sensitive to drift caused by the earth's rotation and are affected by the position of the wellbore on the earth's surface. With conventional instruments, it is therefore necessary to optically orient the gyroscope on surface, and then to make several check shots when running in the hole. Bourgoyne et al (1991) describe this orientation procedure.

Intertial Navigation Systems

The inertial guidance systems long employed in aircraft navigation are also proving applicable to directional well surveying. An inertial navigation system is a position measurement tool, which determines a moving body's position in three dimensions by mathematically integrating the measured components of its acceleration. Unlike conventional directional surveys, which calculate position based on measurements of inclination and azimuth angles, inertial systems provide a direct means of measurement.

Inertial navigation systems are fast, extremely accurate, and relatively independent of hole inclination and position on the earth.
They are particularly useful in high latitude, high-angle wells such as those drilled in the North Sea (-Baker-Hughes Inteq, 1993).

Wireline Steering Systems

A wireline steering system consists of a bottomhole assembly that accommodates a measurement probe run on wireline (Figure 32). The probe employs magnetometers to measure direction, and accelerometers to measure hole angle. It also measures the orientation of the tool-face, and other parameters such as time, depth and tool temperature.

The wireline is either run inside the drill-pipe or passed through a side-entry sub, and connected to a surface computer, which processes the information and provides a remote readout. The operator can then correct the tool-face angle as necessary to maintain the well on course.

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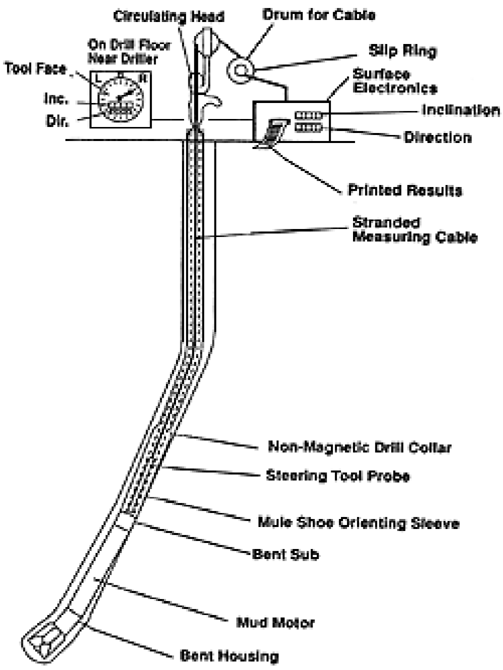

(Bourgoyne et al, 1991. Courtesy of Petroleum Engineers.)

Figure 32

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MWD and LWD Systems

One of the most important advances in modern petroleum technology has been the development of real-time Measurement-While-Drilling systems to transmit drilling and directional information, and Logging-While-Drilling systems to provide formation evaluation data.

MWD and LWD systems have made it possible to monitor and control operations even as drilling is taking place, by allowing operators to:

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· measure drill bit position and trajectory,
· monitor penetration rate, actual weight-on-bit, downhole torque and drag, vibration and other drilling parameters,
· compute pore pressures and get an early warning of potential overpressured zones,
· detect and correlate geologic markers and formation tops,
· and evaluate formations even as they're being drilled.

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Systems are modular in design, and can be run with various sensor combinations to fit the requirements of the well plan. Figure 33 is a schematic diagram of an MWD/LWD system, while Figure 34 shows typical system configurations in various bottomhole assemblies.

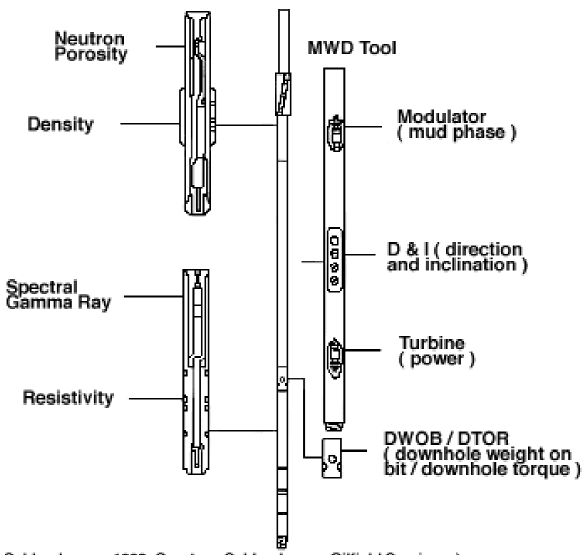

Figure 33

(Schlumberger, 1993. Courtesy Schlumberger Oilfield Services.)

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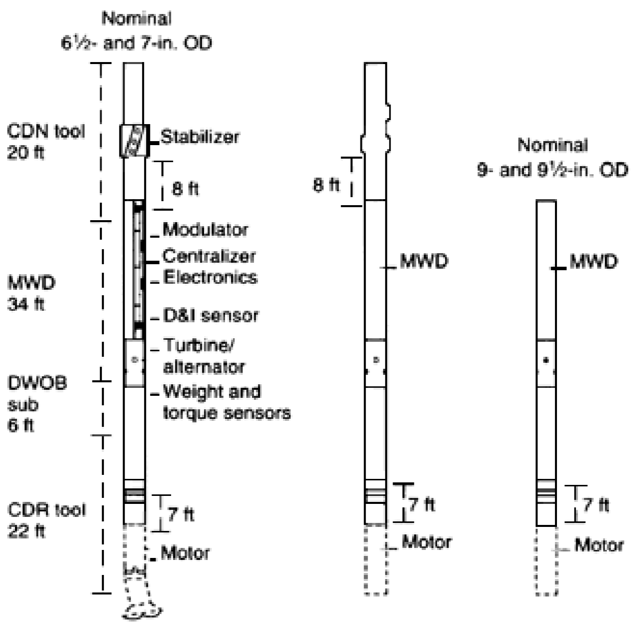

Figure 34

(Schlumberger, 1993. Courtesy of Schlumberger Oilfield Services.)

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MWD tools operate by creating pressure pulses in the mud column, in response to inputs from the various sensors. Depending on the type of tool, the pulses may be positive, negative or continuous (Figure 35 , *Mud pulse telemetry*). These pulses are converted into electronic signals, which are processed and displayed at the surface.

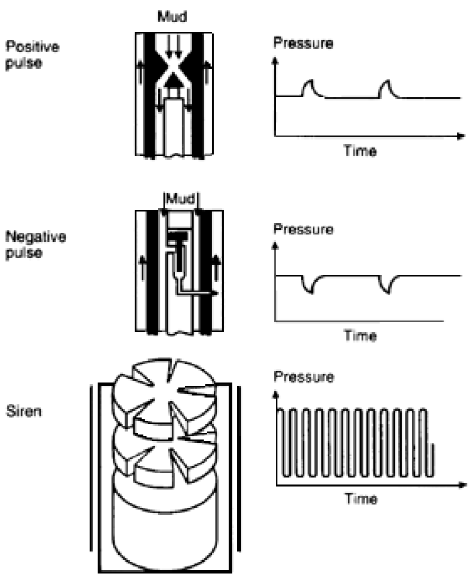

Figure 35

(Schlumberger, 1993. Courtesy of Schlumberger Oilfield Services.)

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The basic components of the MWD instrument package include

- a battery-powered pulser module, which in this case employs a continuous mud wave transmission,
- a sensor module containing tri-axial inclinometers to measure drift and tri-axial magnetometers to measure azimuth, along with temperature and pressure sensors,
- and an electronics module.

The MWD tool assembly shown in Figure 36 is run inside standard non-magnetic drill collars.

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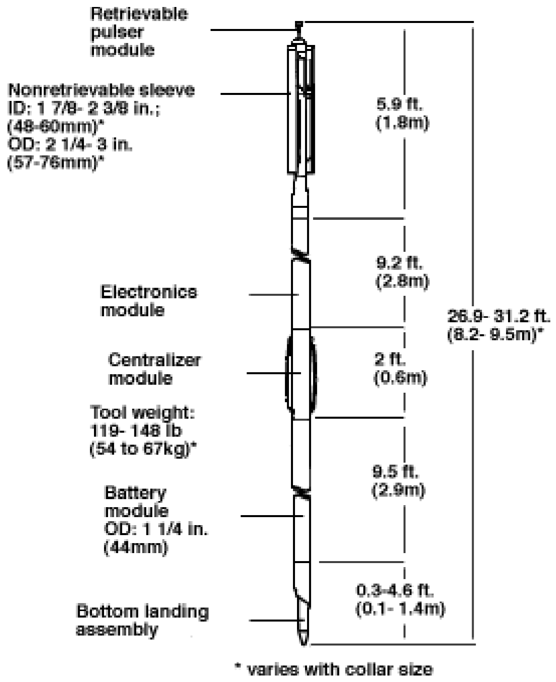

(Courtesy Anadrill/ Schlumberger)

Figure 36

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Logging-While-Drilling, or LWD tools, operate on basically the same principles as conventional wireline logging tools. The dual resistivity shown in Figure 37 (*Individual MWD and LWD tools*) contains a gamma ray tool, and two sets of transmitters and receivers to provide shallow and deep resistivity readings. The compensated density-neutron tool measures density and neutron porosity in a manner similar to that of analogous wireline tools.

When drilling with a mud motor, these particular tools are run above the motor assembly--in other words, about 30 or 40 feet above the bit. In some applications, such as drilling in very thin, dipping pay zones, even this small "information gap" between the bit and the tool could lead to problems. For this reason, systems have now come into use that allow "at-the-bit" measurements to be taken within a few feet of bottom.

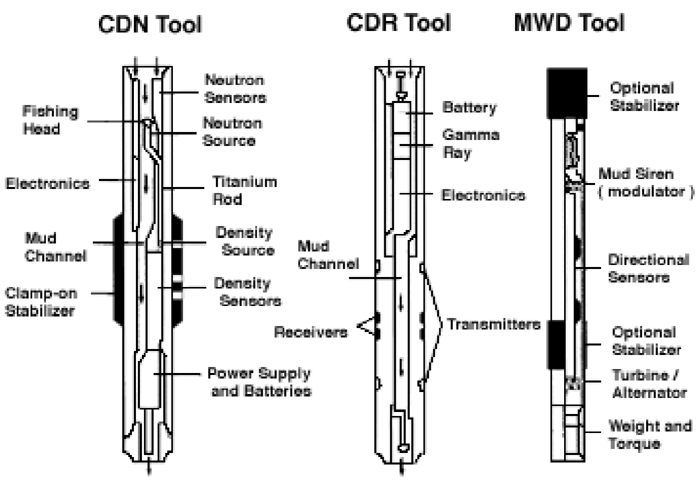

Figure 37

(Schlumberger, 1993. Courtesy of Schlumberger Oilfield Services.)

Although LWD tools work in generally the same manner as conventional logging tools, tool responses will most likely be different in highly deviated wells from what they would be in vertical wells. These responses require special methods of interpretation.

Well Trajectory Calculations

Permanent records of hole locations, and the accuracy of these records, can have significant impact on future drilling and completion operations, as well as on other technical, economic and legal issues relating to a field.
To describe the well trajectory, we must be able to determine the coordinates xi, yi and zi from the measured angles Ɵi and αi at every station i along the well path. There are several calculation methods available, including the following:

- Tangential method
- Balanced tangential method
- Minimum curvature method
- Radius of curvature method
- Angle-averaging method

The tangential method is the least accurate of all methods, and should not be used. The most accurate are the radius of curvature and minimum curvature methods. In this section, we summarize the equations representing the minimum curvature, radius of curvature and angle-averaging methods.

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Minimum curvature method

The minimum curvature method uses the angles measured at two consecutive stations, i-1 and i, to describe a smooth, circular curve that represents the wellbore path. It uses a dog-leg severity ratio factor, Rei, for each corresponding section of the curve.
The coordinates xi and yi represent, respectively, the departures in the west-east and north-south directions, while zi is the vertical departure. These coordinates are expressed as follows:

West-east departure:

$$x_i = \frac{\Delta d_i}{2}\left(\sin\theta_{i-1}\sin\alpha_{i-1} + \sin\theta_i \sin\alpha_i\right)R_{ei}$$

North-south departure:

$$y_i = \frac{\Delta d_i}{2}\left(\sin\theta_{i-1}\cos\alpha_{i-1} + \sin\theta_i \cos\alpha_i\right)R_{ei}$$

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Minimum curvature method

Vertical departure:

$$y_i = \frac{\Delta d_i}{2}\left(\sin\theta_{i-1}\cos\alpha_{i-1} + \sin\theta_i \cos\alpha_i\right)R_{ei}$$

where

$$R_{ei} = \frac{2}{e_i}\tan\frac{e_i}{2}$$

ei= angle change of drill string between i and i-1, given by

$$e_i = \cos^{-1}\left[\sin\theta_i \sin\theta_{i-1}\cos(\alpha_i - \alpha_{i-1}) + \cos\theta_i \cos\theta_{i-1}\right]$$

Minimum curvature method

We can determine the coordinates at the nth point along the well path by algebraically summing over the total number (n) of survey points:

$$x_n = \sum_{i=1}^{n} x_i$$

$$y_n = \sum_{i=1}^{n} y_i$$

$$z_n = \sum_{i=1}^{n} z_i + (\text{Kick - off depth})$$

Radius of curvature method

Like the minimum curvature method, radius of curvature assumes that the wellbore is a smooth curve represented by circular or spherical segments. From survey data at two consecutive stations, i-1 and i, we can determine the coordinates xi, yi and zi from the following equations:

$$x_i = \frac{180\Delta d_i}{\pi(\theta_i - \theta_{i-1})(\alpha_i - \alpha_{i-1})}(\cos\theta_{i-1} - \cos\theta_i)(\cos\alpha_{i-1} - \cos\alpha_i)$$

$$y_i = \frac{180\Delta d_i}{\pi(\theta_i - \theta_{i-1})(\alpha_i - \alpha_{i-1})}(\cos\theta_{i-1} - \cos\theta_i)(\sin\alpha_i - \sin\alpha_{i-1})$$

$$z_i = \frac{180\Delta d_i}{\pi(\theta_i - \theta_{i-1})}(\sin\theta_i - \sin\theta_{i-1})$$

where **Θi** ≠ **Θi-1** and αi ≠ αi-1

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Angle-averaging method

The angle averaging method takes the mean of two measured sets of inclination and azimuth values [(Θi, αi) and (Θi-1, αi-1)], and assumes that the wellbore follows a tangential path. The coordinates at station i are given by

$$x_i = \Delta d_i \sin\frac{\theta_i + \theta_{i-1}}{2}\cos\frac{\alpha_i + \alpha_{i-1}}{2}$$

$$y_i = \Delta d_i \sin\frac{\theta_i + \theta_{i-1}}{2}\sin\frac{\alpha_i + \alpha_{i-1}}{2}$$

We may use Equations below to calculate the total departures.

$$x_n = \sum_{i=1}^{n} x_i \qquad y_n = \sum_{i=1}^{n} y_i \qquad z_n = \sum_{i=1}^{n} z_i + (\text{Kick - off depth})$$

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Geosteering

Geosteering is the drilling of a horizontal, or other deviated well, where decisions on well path adjustment are made based on real time geologic and reservoir data.

Geosteering is required when the marker is ill defined, target tolerances are tight or geology so complicated that as to make conventional directional drilling impractical.

Geosteering methods
- Drilling rate
- Samples
- LWD (Logging While Drilling)
  - Gamma ray
  - Resistivity
  - Density – Neutron
  - Sonic

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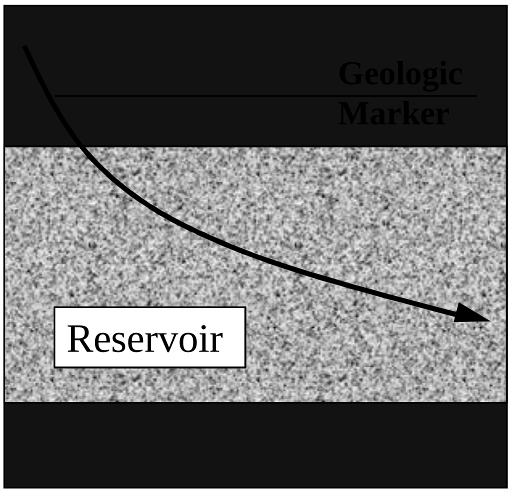
- Because of the inaccuracy of directional surveys and geology, it may not be possible to establish a horizontal wellbore within the pay zone in small targets (geometric steering).
- Geosteering is required in order to accomplish the task.
- Geologic markers can be used to establish the wellbore within the pay zone



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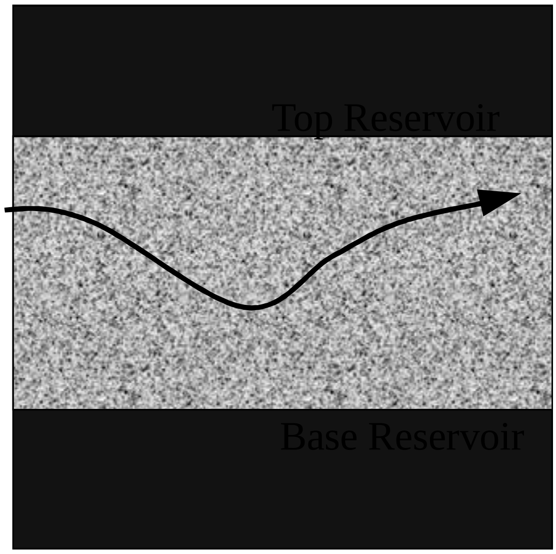
- Penetration rate may indicate geologic markers
- Samples can be used to determine the depth of geologic markers though it is not extremely accurate
- LWD data can be used to determine geologic markers

- Typical layout of LWD tools within the directional bottomhole assembly

- Once the well is within the reservoir, it must be kept in the reservoir
- LWD such as GR and resistivity



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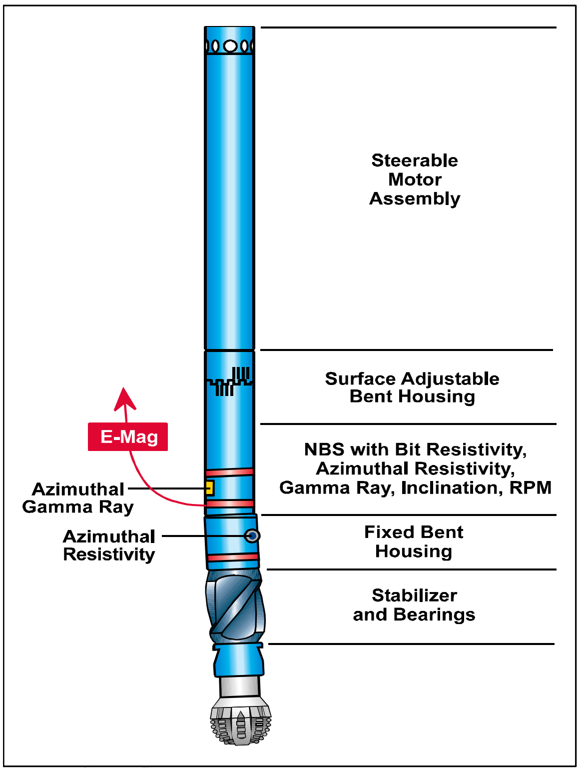

- Azimuthal resistivity and GR can be used to determine if the wellbore is close to the top or bottom of the formation

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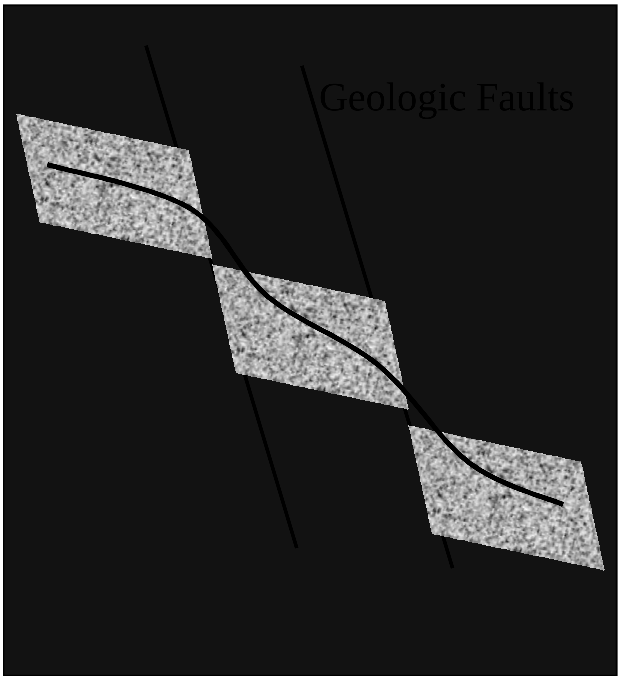
- Drilling fault blocks
- Must recognize when a fault is encountered and reestablish the wellbore within the payzone



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DRILLING ENGINEERING (Horizontal Wells)

S. R. SHADIZADEH, Ph.D., PE.

Introduction

Horizontal drilling is the process of directing part of a well course through a reservoir such that its inclination angle is approximately 90° from vertical. This horizontal section may be anywhere from a few feet to thousands of feet in length.

Horizontal wells can trace their roots back to at least the 1930s (Ranney, 1939). But it is only since the 1980s that advances in directional drilling and formation evaluation have brought them into the mainstream of oil and gas operations. Since then, in a number of fields, they have significantly outperformed conventional wells in terms of increased productivity, improved ultimate recovery and lower overall development costs.

Introduction

There have also been disappointments along the way, which have shown that the benefits of horizontal drilling are largely contingent on reservoir characteristics.

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Horizontal Drilling Applications

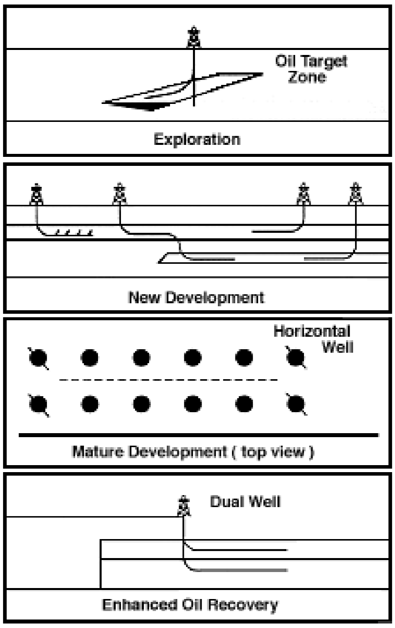
Horizontal wells work to best advantage in thin reservoirs having a relatively high ratio of vertical to horizontal permeability (vertically fractured formations are prime candidates) and a potential for drawdown-sensitive production problems like water and gas coning.

Horizontal Drilling Applications

Other common candidates for horizontal drilling are:

- reservoirs that would otherwise be economically inaccessible
- heavy oil reservoirs
- channel sand and reef core reservoirs
- coal bed methane reservoirs

Horizontal Drilling Applications



(Crouse, 1991. From World Oil's Handbook of Horizontal Drilling and Completion Technology. Copyright 1991, Gulf Publishing Co., Houston, TX. Used with permission. All rights reserved.)

Figure 1: illustrates some typical applications of horizontal well technology

Well Configurations

Horizontal drilling begins with a more-or-less vertical surface section (except in the case of slant drilling rigs, where this section is pre-inclined), followed by a bend section, which progresses from approximately 0° to 90° inclination with depth, and finally by a horizontal or lateral section.

The transfer of weight to the drill bit during the horizontal drilling phase involves different concepts, which translate into different well configurations. We may generally distinguish these configurations based on radius of curvature as follows:

Well Configurations

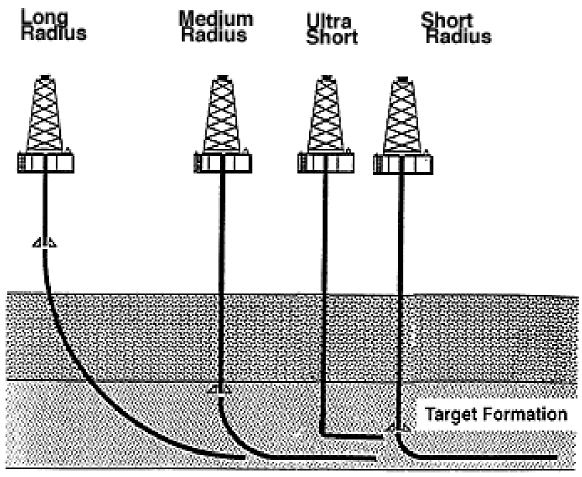


Figure 2 , *Horizontal drilling methods*

Well Configurations

- long turn radius (LTR)
- medium turn radius (MTR)
- short turn radius (STR)
- ultra-short turn radius (USTR)

Well Configurations

The considerations that enter into selecting one of these well configurations include:

- cost
- well spacing and lease restrictions
- conditions of re-entry wells
- reservoir rock characteristics
- production methods
- well objectives
- problem-causing lithologies above the pay zone
- amount of total horizontal departure
- completion methods
- availability of specialized downhole tools
- kick-off depth constraints
- horizontal displacement constraints

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	Long radius	Medium radius	Short radius
Build Rate	Up to 6° per 100ft	6 - 20° per 100 ft	1.5 - 3° per one ft
Build radius (ft)	1000 - 3000	300 - 700	20 - 40
Hole size (in)	No limits	4 3/4, 6 1/8, 8 1/2, 9 7/8	4 3/4, 6 1/2
Drilling method	Rotary or steerable motor systems for curve and horizontal sections	Specially designed motors for angle-build section; rotary or steerable motor systems for horizontal tools sections	Specially designed deflection tools or articulated motors for angle-build section; rotary and special drill pipe for horizontal sections
Tubulars used	Conventional tubulars	Heavy-wall drill pipe for build rates of up to service drill pipe for rates greater than 15°/100 ft	Special articulated tubulars; special drill pipe with short articulated motors
Drill bit	No limits	No limits	Rotary:no limits Motor: Diamond or PDC
Drilling fluids	No limits	No limits	No limits
Surveying	No limits	MWD capabilities imited for hole sizes smaller than 6 1/8 in	Special
Coring	Conventional coring, No limits	Conventional coring , No limits	3 ft core barrel, 1-inch diameter core

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	Long radius	Medium radius	Short radius
Selective completion Capabilities	Yes	Yes	No
Multiple pay zones	No	Yes	Yes
Artificial lift Capabilities	All Types	All Types	Rod pumps in vertical portion
Workover capabilities	Yes	Yes	Yes
Typical productivity index increase in non- fractured zones	3.5	2.5	2.5
Typical productivity index increase in fractured zones	>10	>10	Depends on fracture distribution
Production enhancement ratio (horizontal/ vertical well)	6	7	Varies widely; can be from 1 to 100
Cost ratio (horizontal/ vertical well)	>2	>2	1.5

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Comparative characteristics of horizontal wells

Long Turn Radius Drilling

A long turn radius well is a well having at least one section with a build rate of between 1° and 6° per 100 ft, and a build radius of 1000 ft or more. Long radius applications include:

- drilling multiple, extended-reach wells from offshore platforms or other single surface locations
- reaching otherwise inaccessible locations
- drilling exploratory wells over long intervals
- drilling wells that require zone isolation and selective completion/stimulation

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Long Turn Radius Drilling

The advantages of long radius drilling over other horizontal drilling methods include minimal dog-leg severity, attainment of horizontal departure while drilling the build section, and the ability to employ either conventional rotary bottomhole assemblies or steerable drilling systems.

In addition, long radius methods impose no restrictions on hole diameter, bit type, coring or MWD capabilities, and they permit various options with respect to completion, stimulation and artificial lift.

Long Turn Radius Drilling

Long-radius drilling also has some limitations, including high torque-and-drag tendencies, and greater difficulty in hole cleaning.
A limiting factor in designing a long radius well is the ability to rotate the pipe at the surface as the bit approaches total depth.
There may also be constraints imposed by shallow pay zones, lease boundaries or other restrictions.

The use of conventional rotary assemblies to drill long radius wells is quite common. There are a number of software packages available for optimizing and predicting BHA operating parameters. The BHA designs that are generated can prove very successful, assuming that accurate information on formation anomalies is available. If this information is not available, then frequent trips may be required to correct the well course, resulting in high drilling costs. In such cases, it may be more economical to use a steerable drilling system.

Long Turn Radius Drilling

A steerable, or navigation drilling system, is a bottomhole assembly that can be controlled from the surface while it is in the hole. Thus, it is possible to direct such a system along a pre-selected well trajectory without having to trip it out of the well. Drilling cost saving, along with reduced dog-leg severity problems, result from the steerable system's ability to:

- build, drop, turn or hold angle
- continually monitor well trajectory
- control drilling parameters from the surface

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Long Turn Radius Drilling

The tools that make up a steerable system generally consist of a bit, a bent housing positive displacement motor (PDM), bent subs, measurement-while-drilling tools, drill collars and stabilizers.

The system can operate in an oriented mode, where drill bit rotation is induced only by the PDM, or a rotary mode, where the main source of bit rotation is still the PDM, but the drill string is rotated as well to negate deviation tendencies.

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Medium Turn Radius Drilling

A medium turn radius well has at least one section with a build rate angle of between 6° and 20° per 100 ft in the rotary mode, and as much as 30° per 100 ft in an oriented mode, in reaching horizontal.

The radius of curvature ranges from about three hundred up to a thousand feet.

Medium-radius wells are appropriate for areas that could benefit from horizontal drilling, but where long-radius methods are either unnecessary or impractical, as would be the case when lease boundary restrictions limit the well course. They are particularly applicable for re-entry wells, reef reservoirs, fractured reservoirs and reservoirs with potential for gas or water coning.

Medium Turn Radius Drilling

The primary advantage of medium radius over long radius drilling is that the well profile is shorter. A medium-radius well can reach the lateral section with greater precision at a shallower depth, with less departure from vertical, and in less time than it takes to drill the curved section of a long radius well.

Torque and drag tendencies are also less than in long-radius wells. The vertical portion of the well can be drilled deeper and casing set deeper before beginning the directional drilling phase, and upon completion, production equipment can be set in the vertical section, closer to the pay interval.

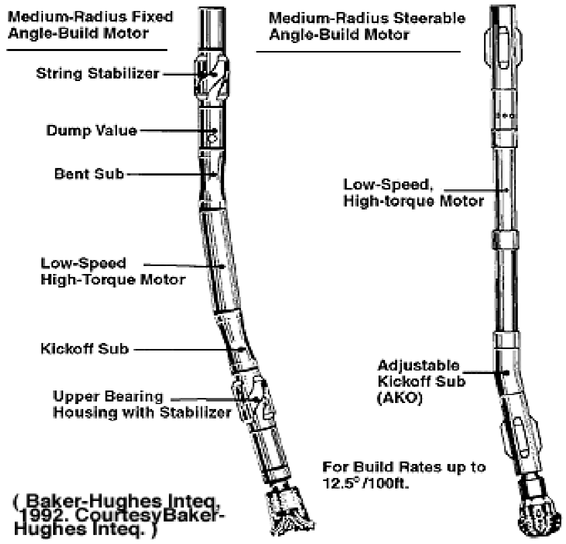
Medium Turn Radius Drilling

Relative disadvantages of medium radius drilling are an inability to build angle using rotary methods (however, steerable systems are commercially available that allow an operator to switch from a rotary to an oriented mode without having to trip the drilling assembly), and that fact that the tighter radius places more stress on the drill string.

There are no restrictions on bit type or coring capabilities, although MWD applications are limited for hole diameters smaller than about six-and-one eighth inches

Medium Turn Radius Drilling

Heavy-wall drill pipe can be used for build rates of up to 15 degrees per 100 feet. Higher build rates require compressive service drill pipe. Figure 1 (*Medium radius fixed-angle and steerable angle-build motors*) illustrates typical fixed-angle build and steerable angle build assemblies, which allow for continuous, smooth curvature build-up. The angle hold assembly may be of the conventional rotary type, or it may contain a downhole motor.



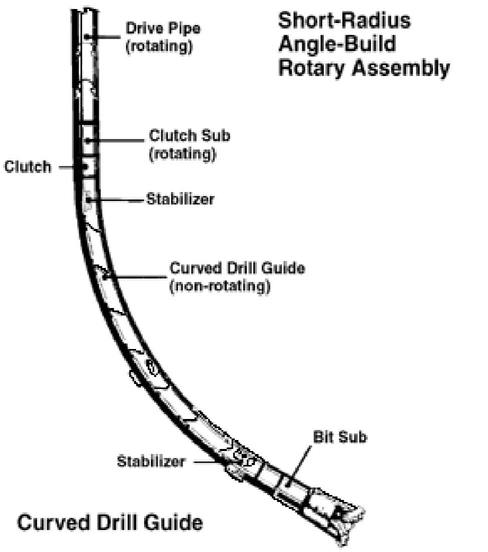
(Baker-Hughes Inteq, 1992. CourtesyBaker-Hughes Inteq.)

Medium Turn Radius Drilling

In some cases, an operator may drill a vertical or inclined rat hole for locating, logging and testing the pay zone before drilling the curved portion of the horizontal well. This works to good advantage in identifying the target horizon, especially if the structure is not thoroughly understood or the target zone is very narrow. Where coning is a problem, or in interbedded sands, this is a good way to identify the various gas, water and formation interfaces. Once the target has been defined in this manner, the usual procedure is to plug back the rat hole with a good quality cement plug and prepare to drill the angle build portion of the well.

Short Turn Radius Drilling

The build rate angle on a short radius well may range from 1 to 3 degrees per foot. The radius of curvature may be 50 feet or less, with a hole size of between 4 3/4 inches and 6 1/2 inches. Figure below (*Short radius angle-building assembly*) illustrates a short radius angle-build assembly that employs curved, articulated tubulars.



Curved Drill Guide

(Baker-Hughes Inteq, 1992. CourtesyBaker-Hughes Inteq.)

Short Turn Radius Drilling

Short-radius applications include infill drilling in depleted reservoirs, drilling shaly intervals or other trouble-prone formations and drilling multiple drainholes from one vertical wellbore. They are also proving useful for enhanced oil recovery, particularly steam flooding.

Short-radius wells are relatively inexpensive. They provide easy, precise entries to the horizontal sections, and can reach lateral displacement at a minimum measured depth. This makes them particularly appropriate, and sometimes necessary, for shallow reservoirs.

Short Turn Radius Drilling

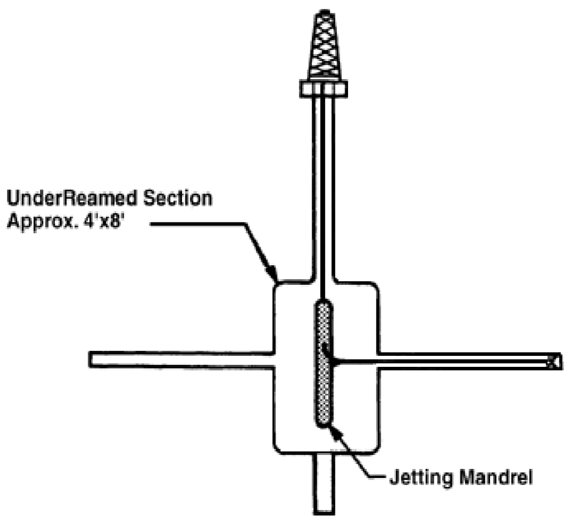
Disadvantages of short radius wells include special drilling equipment requirements such as articulated tubulars, limits on hole size and reach, limited azimuth control, and an inability to run logging tools or casing. Coring abilities are limited to 3-foot sections of 1-inch diameter core, and diamond or PDC bits must be used when drilling with a short, articulated motor.

Ultra-Short Turn Radius Drilling

A special class of short-radius wells is the ultra-short radius well, which effectively has no bend section. Ultra-short drilling methods employ jetting techniques and coiled tubing to eliminate angle build sections, and are used in soft, unconsolidated formations to drill multiple drainholes from existing vertical wells.

Dickinson et al (1989) describe a system developed by Bechtel Investments, which uses high-pressure water jets (10,000 psi) and high-pressure coiled tubing to drill 2-inch diameter holes around a 1-ft radius turn (see next Figure).

Ultra-Short Turn Radius Drilling



(after Dickenson et. al, 1989. Courtesy Society of Petroleum Engineers)

Figure 1 , *Ultra-short turn radius drilling system.*

Ultra-Short Turn Radius Drilling

This system is capable of drilling 100 to 200 ft horizontally in unconsolidated or weak rock. It includes a specially designed, flexible surveying tool and a special electrochemical perforator. Once the lateral sections are drilled, the flexible pipe can be cut off at the wellbore, perforated and gravel-packed.

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Trajectory Planning

The starting point in planning a horizontal well trajectory is to specify the entry depth into the reservoir and the minimum drainhole length inside the reservoir.

Reaching the target involves three phases:

- vertically drilling to the kick-off point
- directionally drilling to the objective zone
- laterally drilling within the objective zone

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Trajectory Planning

By the time a well reaches kick-off depth, plans have already been made to either:

- continuously build angle until reaching the entry depth, and then hold angle through the target zone (Figure 1 , *Continuous build tangent section*)

- build-and-hold in two phases until the lateral section reaches the minimum drainhole length (Figure 2 , *Two-build tangent section*).

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Continuous build tangent section

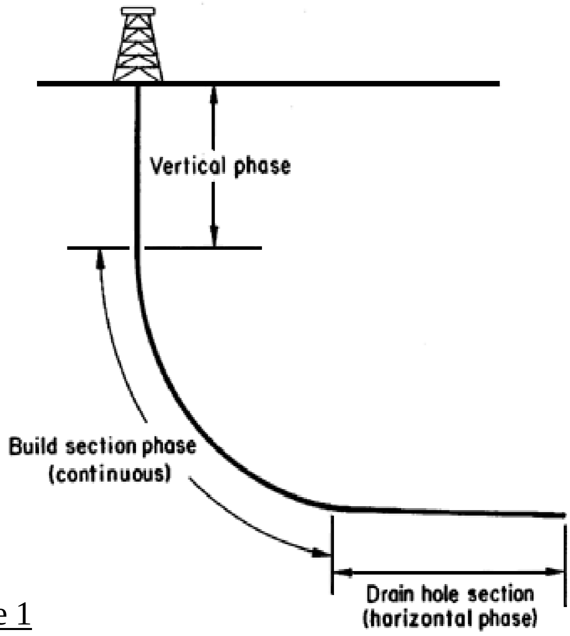

Figure 1

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Two- build tangent section

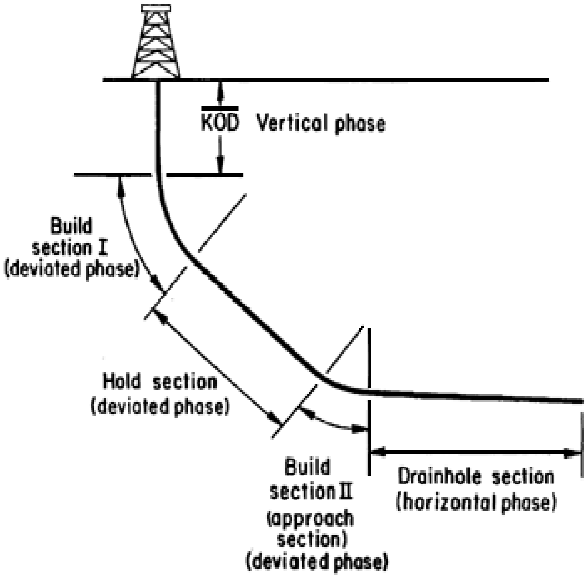

Figure 2

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Trajectory Planning

The trajectory we choose for a given well is based on minimizing problems related to hole cleaning, torque and drag, and wellbore instability. We also have to consider "future" issues such as the expense and effort involved in completing and producing the well.

The two most common problems that occur while drilling build sections are inability to build hole angle and inability to correct azimuth. For the most part, these problems result from troublesome formations and improper bottomhole assembly design.

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Build Curve Design

There are four basic build curve designs used in bringing a well from vertical to horizontal:

- single build (Figure 1)
- simple tangent (Figure 2)
- complex tangent (Figure 3)
- ideal (Figure 4)

Single build curve

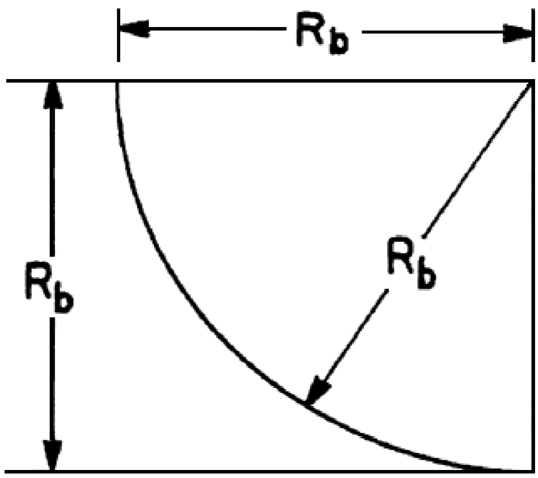

Figure 1

Simple tangent build curve

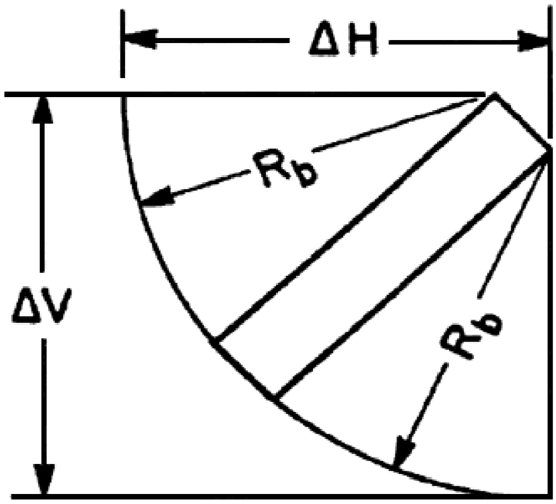

Figure 2

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Complex tangent build curve

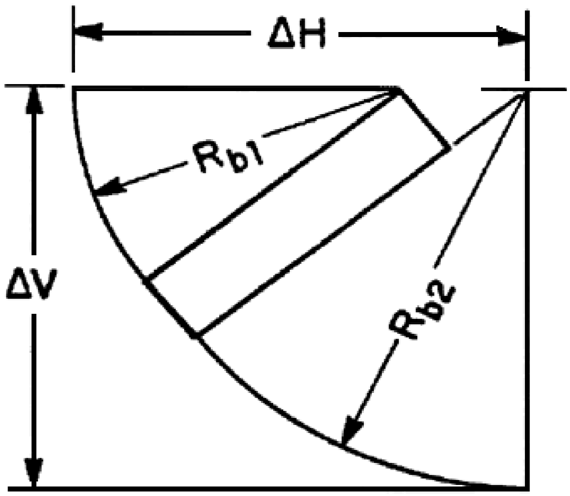

Figure 3

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Ideal build curve

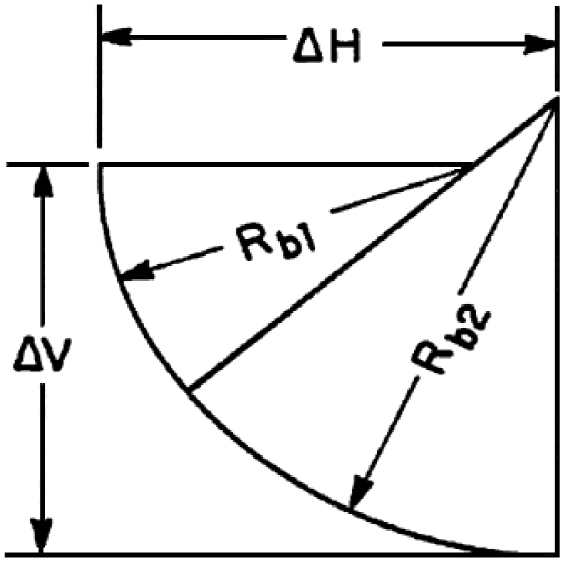

Figure 4

Build Curve Design

The equations for designing these curve types are easy to derive, and are summarized below (Schuh, 1989):
From Figure 5 (*Circular arc*),

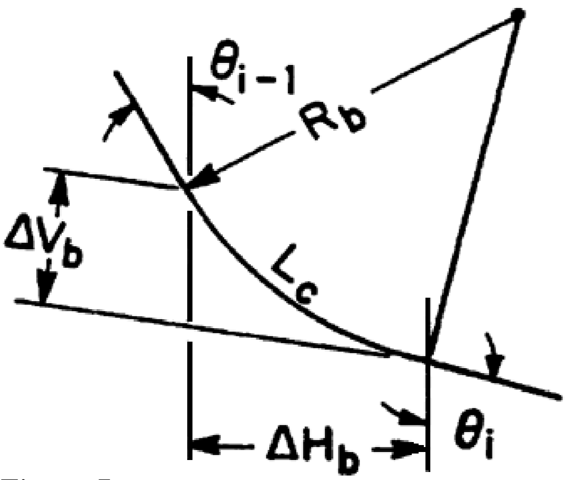

Figure 5

Build Curve Design

$$L_c = \frac{\theta_i - \theta_{i-1}}{BR}$$

$$\Delta H_b = R_b\left(\cos\theta_{i-1} - \cos\theta_i\right)$$

$$\Delta V_b = R_b\left(\sin\theta_{i-1} - \sin\theta_i\right)$$

where Lc = length of curved section
Rb = build curve radius
BR = build rate angle
DHb = horizontal displacement of build curve section
DVb = vertical displacement of build curve section
qi, qi-1 = inclination angles at stations i and i-1, respectively, on build curve

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Build Curve Design

The straight section required to hit a sloping target (Figure 6) is

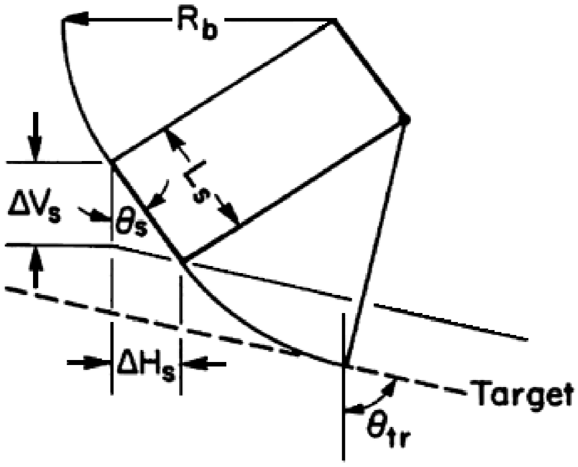

Figure 6

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Build Curve Design

$$L_s = \frac{\Delta H_s}{\sin\theta_t}$$

$$\Delta H_s = \frac{\Delta V_s}{\cot\theta_s - \cot\theta_{tr}}$$

where Ls = length of curved section
DHs = horizontal displacement of straight section
DVs = height to target slope
qs, qtr = straight section and target angles, respectively.

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Build Curve Design

The build rate angle required to hit a sloping target (Figure 7) is

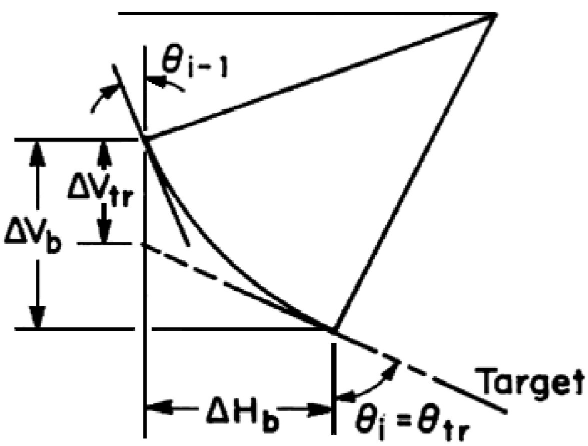

Figure 7

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Build Curve Design

$$BR = \frac{57.3}{\Delta V_{tr}}\left(\sin\theta_i - \sin\theta_{i-1} + \frac{\cos\theta_i \cos\theta_{i-1}}{\tan\theta_{tr}}\right)$$

$$\Delta H = \frac{57.3}{BR}\left(\cos\theta_{i-1} - \cos\theta_i\right)$$

$$\Delta V_{tr} = \frac{57.3}{BR}\left(\sin\theta_i - \sin\theta_{i-1} + \frac{\cos\theta_i \cos\theta_{i-1}}{\tan\theta_{tr}}\right)$$

$$\Delta V = \frac{57.3}{BR}\left(\sin\theta_i - \sin\theta_{i-1}\right)$$

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Build Curve Design

The tool face angle required for the second build is

$$\phi_{tf} = \cos^{-1}\frac{BR_1}{BR_2}$$

The dog-leg severity is

$$DL = \left(\theta_i - \theta_{i-1}\right)\left(\frac{BR_1}{BR_2}\right)$$

The azimuth change is

$$\alpha = \left(57.3\tan\phi_{tf}\right)\ln\left[\frac{\tan(\theta_i/2)}{\tan(\theta_{i-1}/2)}\right]$$

where: Φtf = tool face angle, degrees
DL = dog-leg severity, degrees
BR1 = first build rate angle
BR2 = second build rate angle

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Build Curve Design

The required final curvature build rate, BRr, to hit a target is given by

$$BR_r = \frac{57.3(\sin\theta_{tr} - \sin\theta_i)}{TVD_{tr} - TVD_i}$$

where θtr = target inclination angle
θi = present inclination angle
TVDtr = target true vertical depth
TVDi = target present true vertical depth

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Formation Evaluation Aspects

The purpose of the formation evaluation program is to enhance drilling efficiency, and to provide data for reserves and production rate estimates. Formation evaluation methods used at the wellsite include coring, drill stem testing, mud logging and well logging. Well logging techniques may involve any of the following:

logging using drill pipe
logging using coiled tubing
pump-down logging
MWD and LWD tools

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Formation Evaluation Aspects

With these techniques, it is feasible to log most horizontal wells, even where wireline methods are impractical. Coiled tubing logging systems and pump-down stinger systems offer a particular advantage, in that they can be operated under pressure. For more frequent use, MWD and LWD tools are recommended.

The cost of obtaining a given set of logging measurements depends on the rig time required. In making cost comparisons, the engineer should note that in certain cases, pump-down stinger and coiled tubing systems can be used without a rig.

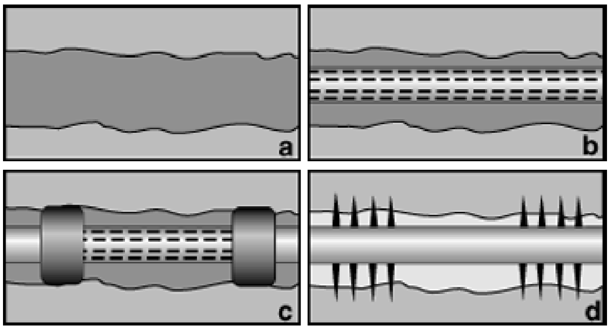
Completion & Stimulation Aspects

The most common types of horizontal well completions are:

- open hole, or open hole with slotted, perforated or pre-packed liner
- liner with external casing packer
- cased, cemented and perforated

Completion & Stimulation Aspects

Figure below illustrates these completion types ((a) *open hole,* (b) *open hole with slotted liner,* (c) *liner with external casing packer,* (d) *cemented and perforated*).



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Completion & Stimulation Aspects

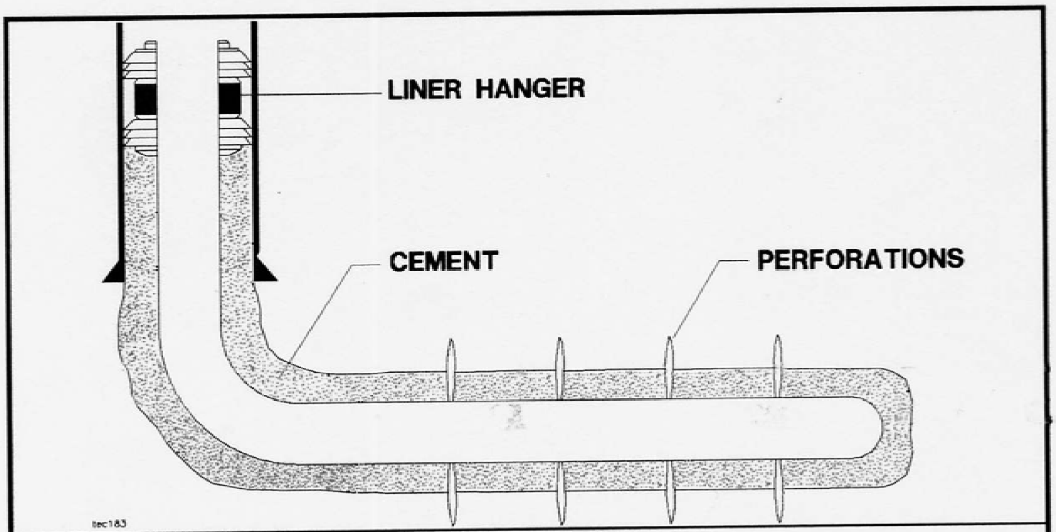

FIGURE 6
Cased, Cemented, Perforated

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Completion & Stimulation Aspects

Selection of a particular type depends on such reservoir conditions as:

- permeability and permeability anisotropy
- fractures
- section isolation along the horizontal well section
- hole stability
- sand problems
- coning problems
- production control

Completion & Stimulation Aspects

Open hole completions, where only the vertical section of the well is cased, were the most common completion types in the early years of horizontal drilling, and they are still widely used. They are relatively inexpensive and easy to execute, and they work well in consolidated formations were sand production and hole collapse problems are not matters of concern. In homogeneous formations that are not well-consolidated, operators often run slotted or pre-perforated liners in open hole. Where sand production is a problem, they may substitute pre-packed liners.

Completion & Stimulation Aspects

The main disadvantage of open hole and slotted liner completions is their inability to isolate zones. Considering that most formations are heterogeneous to at least some degree, this is a significant drawback, particularly if the completion interval is a long one.

In a number of instances, slotted liners equipped with external casing packers (ECPs) have proven successful at isolating formation intervals and providing for selective completion and stimulation. ECPs can be placed at strategic points in the liner string, and then inflated with mud or cement to seal off the liner/hole annulus. Their main drawbacks are that hole eccentricities can make it difficult to form an effective seal, and that they result in a relatively inflexible well design with respect to future workovers or recompletions.

Completion & Stimulation Aspects

A cased, cemented and perforated completion is the most expensive horizontal well design, and the most difficult to properly execute. At the same time, it is the most effective configuration for attaining zone isolation, and the most flexible in terms of future workover, recompletion or stimulation jobs.

Stimulation of Horizontal Wells

In general, the fluids and additives used in matrix stimulations for horizontal wells are the same as those employed in vertical wells. The formation damage profiles for horizontal wells, however, differ significantly from those of vertical wells. This requires modifications in treatment volumes and placement techniques.

With respect to hydraulic fracturing in horizontal wells, the materials used are likewise similar to those used for vertical wells. The orientation of well trajectories, and of the fractures themselves, represent the critical difference, and require careful planning of fracture stimulations even before drilling begins.

Artificial Lift in Horizontal Wells

Hole inclination is a limiting factor in applying artificial lift techniques, although most methods can be applied with some modifications. Specifically, we may note the following:

- Gas lift and hydraulic pumping by jetting, while they cannot be applied at very low bottomhole pressures, are relatively unaffected by high inclination angles.
- High inclination angles limit the use of wireline-installed equipment.
- In sucker rod pumping, protective devices are essential for preventing excessive rod and tubing wear.

Artificial Lift in Horizontal Wells

- Electric submersible pumps, with slight modifications, can be used for high-angle wells.
- Hydraulic pumping by turbo-pump should be satisfactory in high-angle holes.
- Reciprocating hydraulic pumps are limited to cases where deviation angles are compatible with the operation of the pump check valves.

Drilling Hydraulics

Whether a well is directional or non-directional, the drilling mud and circulating system are keys to its successful drilling and completion. Smith (1990) presents a detailed discussion of drilling fluids and circulating system components, while Adams (1993) discusses drilling hydraulics from the standpoint of drilling problems and optimization.

One of a drilling fluid's primary functions is to remove drilled cuttings and transport them to the surface--in other words, to clean the hole. The term carrying capacity refers to a fluid's ability to transport cuttings up the wellbore annulus to the surface.

Drilling Hydraulics

If the mud's hole cleaning abilities are inadequate, cuttings accumulate below the bit and in the annulus. This can lead to costly drilling problems.

➢Cuttings accumulation below the bit results in inefficient drilling, premature bit wear, and reduced penetration rates.

➢A high concentration of drilled solids in the annulus increases the effective mud weight, which reduces penetration rates. If the mud weight becomes too high, then lost circulation or even formation fracturing may occur, which in turn increases the possibility of well control problems (Adams, 1993).

➢High cuttings concentrations in the annulus and around the bit tend to increase torque and drag. In severe cases, pipe may become stuck.

To prevent such problems from occurring, it is important to have a solid understanding of how the drilling fluid works to remove and transport cuttings.

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Drilling Hydraulics

For a drilling mud to lift cuttings to the surface, its average annular velocity ($\bar{v}_a$) must be greater than the average slip velocity ($\bar{v}_s$) with which the cuttings fall downward. The difference between and $\bar{v}_s$ is the average cuttings transport, or *rise* velocity

$$\bar{v}_t = \bar{v}_a - \bar{v}_s$$

$$\frac{\bar{v}_t}{\bar{v}_a} = 1 - \frac{\bar{v}_s}{\bar{v}_a} = R_t$$

where Rtis the cuttings transport ratio. Recommended Rt values for vertical wells range from 0.5 to 0.55.

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Cuttings slip velocity

In a vertical well, slip velocity has only one axial component:

$$\overline{v}_s = \overline{v}_{sa}$$

On the other hand, when the annulus is inclined at an angle θ from vertical, slip velocity has two components:

$$\overline{v}_{sa} = \overline{v}_s \cos\theta$$

$$\overline{v}_{sr} = \overline{v}_s \sin\theta$$

where $\overline{v}_{sa}$ and $\overline{v}_{sr}$ are, respectively, the average slip velocity's axial and radial components (Figure 1 , *Particle settling velocity in an inclined annulus*).

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Cuttings slip velocity

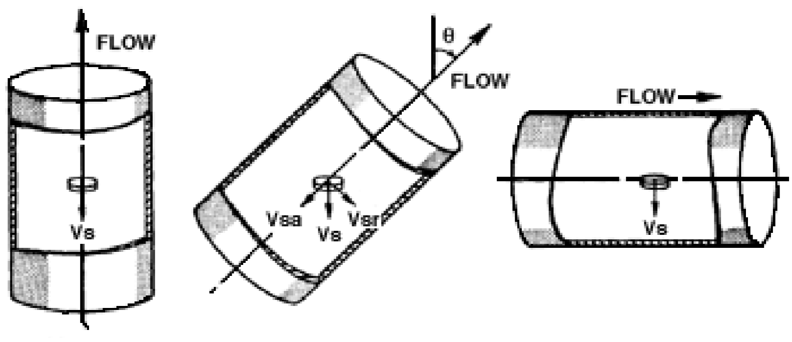

Figure 1

Vsa = Vs
Vsr = 0

Vsa = Vs cos θ
Vsr = Vs sin θ

Vsr = Vs
Vsa = 0

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(Okrajni and Azar, 1986)

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Cuttings slip velocity

When the inclination angle increases, the slip velocity's axial component decreases, becoming zero in a horizontal annulus. At the same time, the radial component reaches a maximum when the annulus is horizontal. Thus, factors that tend to improve cuttings transport by reducing particle slip velocity become less effective with increasing inclination angle.

Cuttings slip velocity

In vertical drilling, the annular fluid velocity has to be sufficient to prevent cuttings from settling, and to transport these cuttings to the surface in reasonable time. In an inclined annulus, where the axial component of particle slip velocity plays a less important role, one might conclude that a proportionately lower annular velocity should be adequate to prevent particle settling. Such a conclusion, however, would be inaccurate. In reality, the increasing radial component of slip velocity in an inclined annulus tends to push cuttings toward the lower wall of the annulus, causing a cuttings bed to form. The annular velocity, therefore, has to be sufficient to prevent or limit bed formation. In general, annular velocities in directional wells have to be much higher than for vertical wells.

Cuttings slip velocity

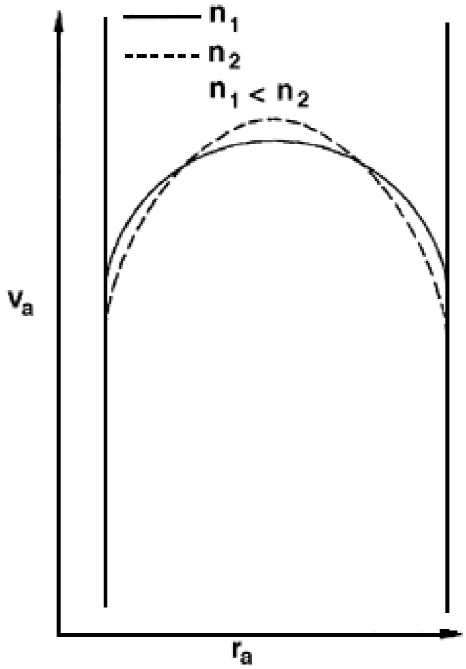
When considering cuttings transport phenomena, we must at the same time consider the fluid flow regime and vertical slippage. A fluid in turbulent flow always induces a turbulent regime of particle slippage, independent of the cuttings' shapes and dimensions. In this case, the only factor that determines the particle slip velocity is the momentum of the fluid; fluid viscosity has little or no influence. If the mud is in laminar flow, then depending on the cuttings shape and size, we may expect either a turbulent or laminar regime of slippage. The laminar slippage regime will always provide a lower value of particle slip velocity, indicating that laminar flow will usually provide better transport than turbulent flow. In an inclined annulus, however, the significance of the axial slip velocity component decreases, tending to nullify the advantages of laminar flow.

Cuttings slip velocity

Velocity distribution profile in laminar flow:

The power law index n in the power law fluid model has a bearing on the mud's velocity profile distribution in laminar flow, as shown in Figure 2 (*Effect of power law index (n) on velocity profile*). As n decreases, the velocity profile becomes more flat. In vertical wells, this is advantageous to cuttings transport efficiency. However, in inclined wells with highly eccentric annuli, the decrease in n causes the hydraulic requirements for effective hole cleaning to increase. This is due to the increase in diversion of fluid flow from the narrow gap of the annulus to the wider gas as viscosity increases.

Cuttings slip velocity



(Okrajni and Azar, 1986. Courtesy Society of Petroleum Engineers.)

Figure 2

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Cuttings slip velocity

As shown in Figure 3 (*Definition of annular eccentricity*), the position of the inside pipe may vary. The displacement of the inside pipe toward the lower wall of the annulus (i.e., positive eccentricity) reduces the mud velocity in this area (Figure 4 , *Effect of eccentricity on annular velocity profile*, and Figure 5 , *3-D Velocity profile for yield power law fluid vs. eccentricity*). Cuttings transport problems thus become more acute for inclined wellbores with positive eccentricity.

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Cuttings slip velocity

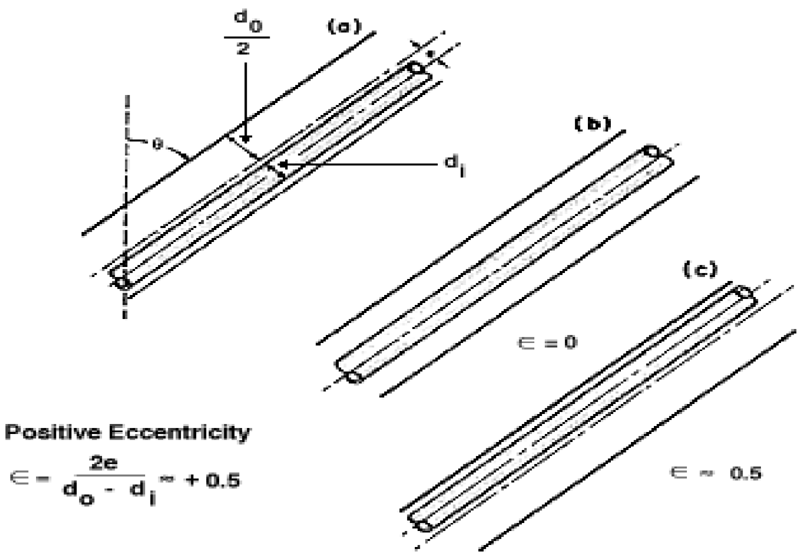

Figure 3

(Iyoho, 1980)

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Cuttings slip velocity

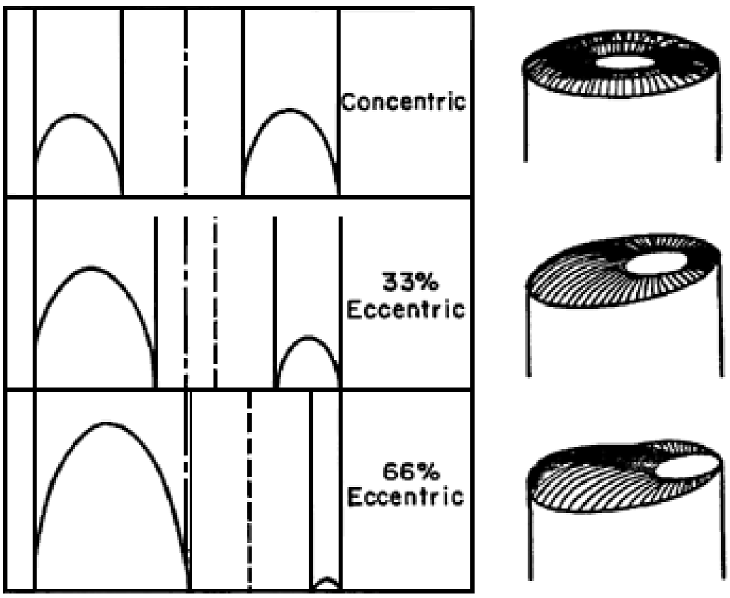

Figure 4

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(Tomren, 1979.)

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Cuttings slip velocity

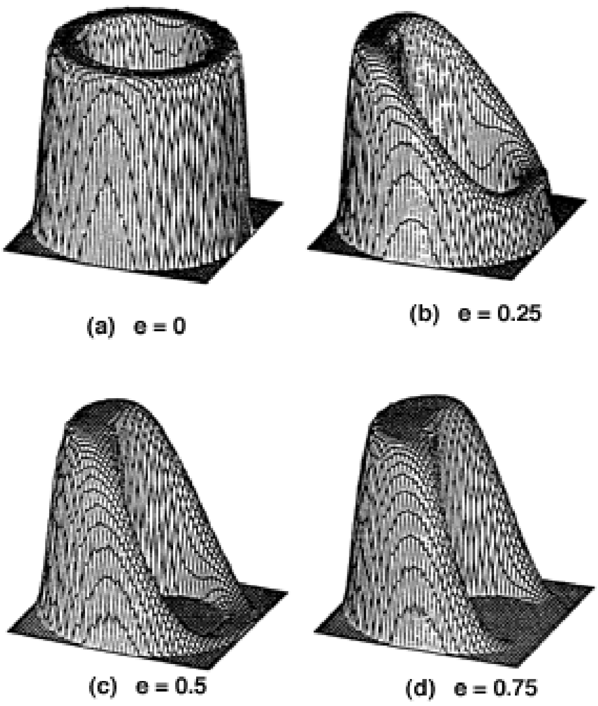

Figure 5

Cuttings Transport

As hole inclination angle deviates beyond about 10° from vertical, the inclined, generally eccentric annulus begins to pose cuttings transport problems that are not encountered in vertical wells. For example, as hole angle approaches the 20°-to-30° range and fluid velocity is at some low value, a cuttings bed begins to form on the low side of the wellbore (Figure 1 , *Critical flow condition schematic*).

Cuttings Transport

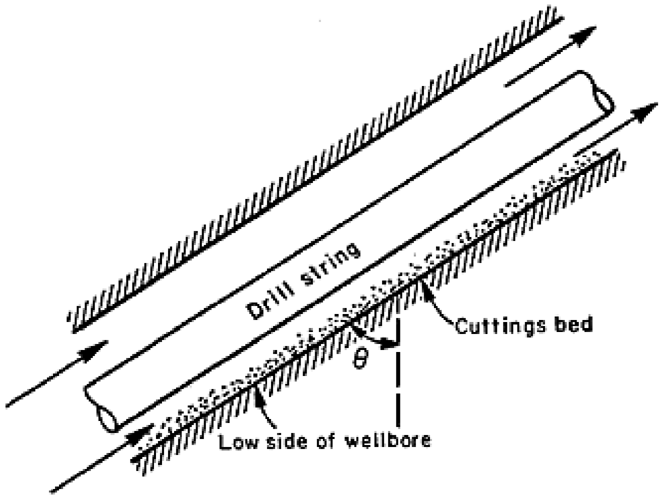

Figure 1

Cuttings Transport

To determine the hydraulics requirements for effective hole cleaning in inclined wells, we apply the concept of critical transport annular fluid velocity--this is the minimum annular fluid velocity for adequate hole cleaning. For wells with inclination angles of less than 35°, the critical transport fluid velocity corresponds to the annular velocity that results in no more than 5% by volume of annular cuttings concentration. On the other hand, for wells with inclination angles exceeding 40°, the critical transport fluid velocity corresponds to the minimum annular velocity that results in no stationary cuttings bed formation.

Cuttings Transport

The following factors are thought to affect cuttings transport in directional drilling:

➢ *Mud rheology*: Based on full scale laboratory data, it appears that mud rheology has little or no effect on cuttings transport when the annular fluid velocity is greater than 120 ft/min, regardless of the inclination angle. At high inclination angles (θ>40°), clear water drilling is slightly more effective in hole cleaning than a mud having yield point and plastic viscosity greater than 7 lb/100 ft2 and 7 cp (Figure 2 , *Effect of mud rheology and hole angle on critical fluid velocity in 5" hole,* and Figure 3 , *Effect of mud rheology and hole angle on critical fluid velocity in 8" hole*).

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Cuttings Transport

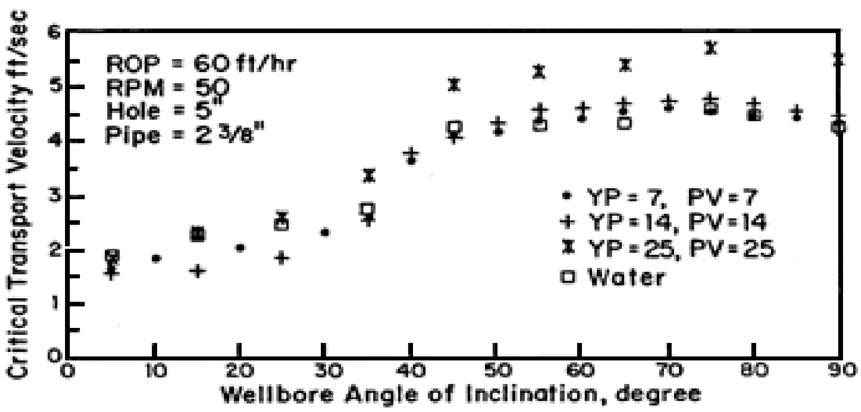

Figure 2

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Cuttings Transport

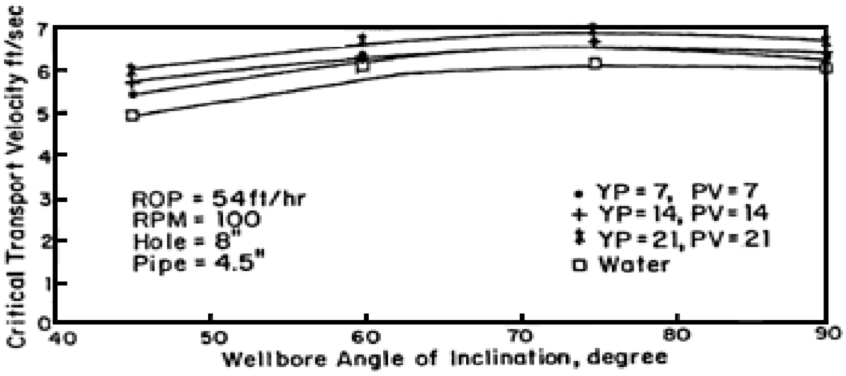

Figure 3

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Cuttings Transport

- *Eccentricity*: For viscous muds, the drill string's position in the wellbore becomes important with respect to hole cleaning. At high inclination angles, as eccentricity goes from positive (i.e., pipe on the low side of the wellbore) to negative (i.e., pipe on the high side of the wellbore), hydraulic requirements for adequate hole cleaning decrease. The opposite is true for clear water drilling. At low inclination angles, eccentricity has a minimal effect on hole cleaning.

- *Mud weight*: An increase in mud weight slightly enhances cuttings transport abilities, as long as there is not an accompanying viscosity increase. Mud weight effects become more significant as inclination angle increases.

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Cuttings Transport

- *Cuttings size*: At high inclination angles, it is harder to transport smaller cuttings. At low inclination angles, it is easier to transport medium-sized cuttings than it is to move the smallest or largest-sized particles.
- *Drilling rate*: The drilling rate has an important effect on the quantitative aspect of cuttings transport. Increased drilling rates tend to increase the hydraulics requirements for effective cuttings removal. There is a linear relationship between drilling rate and required critical transport fluid velocity.
- *Rotary speed*: The effects of rotary speed on cuttings transport range from small to significant, depending on hole size and pipe diameter, hole angle, cuttings size, mud rheology and other well parameters. If drilling ceases, pipe rotation will always enhance the removal of the cuttings left in the annular space.

Drill String Considerations

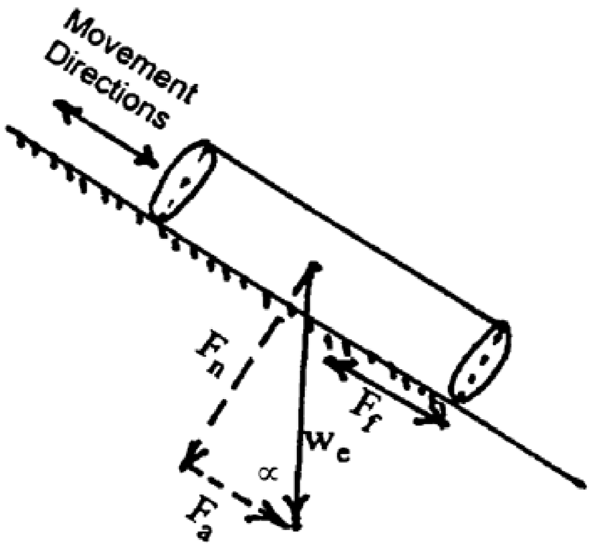
As inclination angle increases in a directional or horizontal well, the borehole walls support more of the drill string weight. This contact, along with the capstan effect (i.e., the normal force caused by the deformation of an axially loaded member about some obstacle), results in frictional forces that oppose the drill string's rotation and axial movement.

During pipe rotation, frictional loading manifests itself as surface torque above and beyond that applied at the bit. During axial movement, it shows up as a difference in hook load between the indicated drill string weight and the actual vertical component of drill string weight--either as updrag (when pulling out of the hole) or downdrag (when running in the hole).

Depending on the well profile, torque and drag loads can become significant limiting factors during drilling and casing operations. Factors that affect drill string torque and drag limits are:

- length of the well's directionally drilled portion
- drill string makeup and buckling tendencies
- coefficient of friction
- rig limitations
- drilling method

As shown in Figure 1 (*Schematic of a drill string section*), the components of drill string weight in a wellbore inclined at an angle a from vertical are



$$F_a = w_e \cos\alpha$$

$$F_n = w_e \sin\alpha$$

where Fa, Fn = weight components in axial and normal directions
we = effective unit weight of string (e.g., lb/ft)
gm gs = densities of drilling mud and steel
wa = weight of string in air
a = hole inclination angle

Critical helical buckling force:

Inclined wells (straight section):

$$F_{hel} = 2\sqrt{\frac{EIw_e \sin\alpha}{r}} + 2.705\sqrt[3]{EIw_e^2 \cos^2\alpha}$$

Horizontal wells:

$$F_{hel} = 2\sqrt{\frac{EIw_e}{r}}$$

Vertical wells:

$$F_{hel} = 2.705\sqrt[3]{EIw_e^2}$$

where E = Young's Modulus
I = Area moment of inertia
r = radial clearance between hole and pipe

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Updrag/Downdrag forces on drill string:

DRAG = µsFn

Torque on drill string:

TORQUE = µΓDopFn
where µs = coefficient of sliding friction
µΓ= rotational coefficient of friction
Fn = resultant normal force
Dop = pipe outer diameter

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In a vertical well, the most basic design rule is to keep the drill pipe in tension, using drill collars and heavy-wall drill pipe in the bottomhole assembly to transmit weight to the bit. For the most part, this is a simple matter of running enough drill collars in the BHA to ensure that the neutral point (i.e., the point at which the drill string goes from being in tension to being in compression) is always below the drill pipe

The design criteria for a horizontal well are much more complicated. Transmitting bit weight in the hole's lateral section requires drilling in compression rather than tension. This requires compressive service drill pipe (i.e., the largest diameter of conventional pipe that the rig can handle) in order to minimize buckling tendencies. At the same time, torque and drag must be kept to a minimum.

In the bend section (or sections, depending on the well profile), the pipe must be able to transmit the same axial and torsional loads as does the pipe in the lateral section. At the same time, it must be able to withstand the bending forces resulting from the section's curvature, and to resist buckling forces.

The vertical portion of the well may contain a weight stack section that provides the necessary bit weight, consisting of drill collars or heavy-wall drill pipe. This section is generally kept out of the hole's bend portion to minimize torque and drag. The remainder of the vertical portion may consist of conventional drill pipe run in tension. It is particularly necessary in horizontal wells to consider the length of the section drilled into each bit run. This is because over the course of a bit run, the pipe moves from one hole section to the next--for example, the compressive drill string segment moves through both the vertical and bend sections before it reaches the section for which it was designed. Thus, the drill string make-up dictates the maximum length of the bit run. This is in contrast to a vertical drill string design, in which we lengthen the drill string simply by adding pipe at the surface. The need to consider bit life adds an additional complication to drill string design.