

A photograph of an offshore oil drilling rig mounted on a barge. The rig's derrick is tall and made of metal lattice, with the letters 'SDC' visible on its side. It is positioned on a body of water, with large white containment booms in the foreground. In the background, there are other barges and a small white control building. The sky is blue with scattered white clouds.

PRINCIPLES OF DRILLING FLUID CONTROL

Twelfth Edition

Contents

1. FUNCTIONS AND COMPOSITION OF DRILLING FLUIDS	1
<i>Principal Functions of Drilling Mud</i>	1
Keeping the hole free of cuttings—Overcoming gas, oil, and water flows—Preventing the walls from caving—Cooling the bit and lubricating the drill string—Securing proper information from the well.	
<i>Relationship Between Functions, Composition and Properties of Drilling Fluid</i>	2
The composition of water base drilling: a simple three-part system—Make-up water—The nature of clays and shales—Yield of clay and shale—Making mud	
2. FIELD TESTS OF DRILLING FLUIDS	5
<i>Density or Mud Weight Tests</i>	5
The mud balance	
<i>Tests for Viscosity and Gel Properties</i>	9
Marsh funnel—Direct-indicating viscometer	
<i>Filtration and Wall Building Tests</i>	12
Low temperature test—High temperature test	
<i>Sand Content Determination</i>	13
<i>Determination of Solid and Liquid Content—Oil Content of Emulsion Muds</i>	14
Distillation of oil and water—Estimation of composition of solids	
<i>pH Determination</i>	15
The colorimetric method—The electrometric method	
<i>Filtrate Analysis</i>	16
Alkalinity determinations—Lime content estimation—Salt concentration (chloride) test—Preservative concentration—Tests for hardness and calcium concentration—Calcium sulfate—Estimation of calcium by oxalate—Versenate test for hardness—Versenate test for calcium—Estimation of sulfate by barium chloride—The Photo Tester—Methylene blue test for cation exchange capacity.	
<i>Resistivity</i>	22
Equipment—Procedure	
<i>Electrical Stability of Emulsions</i>	23
Equipment—Procedure	
<i>Treatment of Make-up Water</i>	23
<i>Pilot Testing</i>	24
3. DRILLING FLUID CIRCULATING SYSTEMS AND AUXILIARY EQUIPMENT	25
MAIN COMPONENTS OF A MUD SYSTEM	25
<i>Mud Pumps</i>	25
<i>Hose, Swivel, and Mud Return</i>	27
<i>Mud Return Line</i>	27
<i>Pits</i>	28

ACCESSORY EQUIPMENT	30
<i>Chemical Tank</i>	30
<i>Mixing Hopper</i>	30
<i>Mud Storage</i>	31
AUXILIARY EQUIPMENT	32
<i>Shale Shakers and Vibrating Screens</i>	32
<i>Mud Guns</i>	33
<i>Paddle Agitators</i>	33
<i>Cone-Type Desanders and Desilters</i>	34
<i>Centrifuges</i>	36
Decanting centrifuge—Concentric cylinder centrifuge	
<i>Mud-Gas Separator</i>	38
<i>Degasser</i>	39
<i>Mud Handling Pumps</i>	40
<i>Instrumentation</i>	40
Mud pit indicators and totalizers—Mud weight indicators—	
Mud flow meters—Pump stroke counters	
4. COMMON DRILLING AND DRILLING FLUID PROBLEMS	43
<i>Mud Records</i>	43
<i>Shale Problems</i>	43
Mechanical factors in shale problems—Shale types and contained	
clays—Effect of geology on shale problems—Effect of compaction	
on shale pore pressure—Causes of shale instability—Shale	
stabilization with oil mud—Shale stabilization with water base	
mud—Conclusion.	
LOST CIRCULATION	48
<i>Formations Subject to Lost Circulation</i>	48
Cavernous and open-fissured formations—Coarsely permeable	
formations—Natural or intrinsic fractured formations—Easily	
fractured formations.	
<i>Lost Circulation Materials</i>	50
<i>Procedures for Lost Circulation</i>	50
<i>Locating Lost Returns Zone</i>	51
Temperature survey—Spinner survey—Radioactive tracer	
survey—Hot wire survey—Pressure transducer survey	
HIGH BOTTOM HOLE TEMPERATURES	52
FORMATION PRESSURE CONTROL	53
<i>Porosity Data as an Index of High Pressure Shales</i>	54
<i>Hydrostatic Pressure and Effective Circulating Density</i>	55
<i>Recognizing the Kick</i>	56
Well kicks while circulating—Well kicks when pump is shut	
down—Well kicks when coming out of the hole—Well kicks	
when going into the hole.	
<i>Bottom Hole Pressure Reduction from Gas Expansion</i>	57
<i>Blowout Prevention Procedures</i>	58
Constant bottom hole pressure method—Drillers method	
<i>Corrosion</i>	63
Oxygen—Carbon dioxide—hydrogen sulfide	
5. WIDELY USED DRILLING FLUIDS	67
<i>Classification of Drilling Fluids</i>	67
Water base fluids—Oil base fluids—Gaseous fluids	

CONDITIONING WATER BASE DRILLING FLUIDS	67
<i>Additives</i>	67
<i>Treatment Terminology</i>	68
Mud-up—Weight-up—Thin—Water-back—Emulsify	
<i>Control of Mud Weight</i>	68
<i>Control of Viscosity and Gel Strength</i>	70
<i>Control of Filtration or Water Loss</i>	71
<i>pH Control</i>	71
<i>Treatment for Contamination</i>	72
Cement contamination—Anhydrite and gypsum contamination—	
Salt contamination.	
<i>Safety Precautions</i>	73
WATER BASE DRILLING FLUIDS	74
<i>Inhibited Muds</i>	74
<i>Spud Mud</i>	75
<i>Natural Muds</i>	75
<i>Phosphate Treated Muds</i>	76
<i>Wood and Bark Extract Treated Muds</i>	76
<i>Chrome Lignosulfonate Muds</i>	76
Viscosity—Gel strength—Filtration.	
<i>Calcium Treated Muds</i>	78
<i>Saltwater Muds</i>	79
<i>Seawater Muds</i>	79
<i>Saturated Saltwater Muds</i>	80
<i>Oil-Emulsion Muds</i>	81
Emulsifying agents for emulsion muds—Oils for emulsion	
muds—Preparation and maintenance of emulsion muds.	
<i>Surfactant Muds</i>	83
<i>Low Solids Fluids</i>	83
Clear water—Low solids oil-in-water emulsions—Polymer	
muds—Low solids non-dispersed aggregated muds—Low	
clay solids muds—Mud solids control by centrifugal methods.	
OIL BASE AND INVERT EMULSION DRILLING FLUIDS	87
<i>Osmotic Effects</i>	87
<i>Composition of Oil Muds</i>	88
<i>Carrying Capacity and Solids Suspension</i>	88
<i>Filtration Control</i>	89
<i>Weighting Material and Thinners</i>	89
<i>Testing and Maintenance of Oil Muds</i>	89
Funnel viscosity—Water content—Electrical stability—	
Aging tests—Contaminants.	
<i>Special Rig Equipment and Displacement Techniques</i>	90
<i>Logging in Oil Muds</i>	90
<i>Mud Logging</i>	91
<i>Oil Muds and Lost Circulation</i>	91
<i>Application of Oil Muds</i>	91
AIR AND GAS DRILLING FLUIDS	92
<i>Introduction</i>	92
<i>Air/Gas Drilling Techniques</i>	92
Dusting-Mist drilling—Aerated muds.	
6. PACKER FLUIDS	99

<i>Solids-Free Liquid</i>	99
Sodium chloride—Sodium chloride-soda ash—Calcium chloride— Calcium chloride-sodium chloride—Calcium chloride-zinc chloride.	
<i>Water Base Muds</i>	101
Drilling mud—Gel-CMC packer mud.	
<i>Oil Muds</i>	101
<i>Placement of Special Packer Fluids</i>	102
7. DRILLING FLUID PRACTICES IN THE GULF COAST OF TEXAS AND LOUISIANA	103
<i>Mud and Casing Programs</i>	103
<i>Muds for Normal-Pressure Drilling</i>	104
<i>Muds for Abnormally High Pressures</i>	104
<i>High Formation Temperatures</i>	105
<i>Shallow Blowout Hazard</i>	105
<i>Salt-Dome Drilling</i>	106
<i>Offshore and Bay Drilling Muds</i>	107
<i>Lost Circulation</i>	107
8. DRILLING FLUID PRACTICES IN THE ARK-LA-TEX AND MISSISSIPPI AREA	109
<i>General Considerations</i>	114
<i>Mud Types and Treatment</i>	114
Native and gel muds—Lignosulfonate muds—Calcium and salt muds—Oil muds—Workover fluids.	
<i>Drilling Hazards</i>	114
Lost circulation—Abnormal pressure—Shales and mud- making formations—High temperature—Hydrogen sulfide.	
9. DRILLING FLUID PRACTICES IN WEST TEXAS AND NEW MEXICO	117
<i>General Considerations</i>	117
Salt—Red beds—Solids control—Lost circulation—Under- balanced drilling—Hole stability—Oil mud—Corrosion— Air and gas drilling.	
EASTERN SHELF	121
MIDLAND BASIN	122
<i>Shallow Well Casing Program</i>	122
Surface casing—Production string.	
<i>Shallow Well Fluid Program by Casing Interval</i>	122
Surface to 150 feet to 300 feet—Surface casing to T. D.	
<i>Medium Depth Casing Program</i>	122
Surface casing—Production casing.	
<i>Medium Depth Fluid Program by Casing Interval</i>	122
Surface to 1,400 feet to 2,100 feet—Surface casing to T. D.	
<i>Deep Hole Casing Program</i>	123
Surface casing—Intermediate casing—Production casing.	
<i>Deep Well Fluid Program by Casing Interval</i>	123
Surface to 150 feet to 300 feet—Surface casing to 4,000 feet to 5,500 feet—Intermediate casing to T. D.	
<i>Spraberry Field Casing Program</i>	123
Surface casing—Production casing.	

<i>Spraberry Field Fluid Program by Casing Interval</i>	124
Surface to 300 feet to 350 feet—Surface casing to T. D.	
CENTRAL BASIN PLATFORM	124
<i>Casing Programs</i>	124
<i>Drilling Fluid Programs and Practices</i>	125
NORTHWESTERN SHELF	126
<i>Casing Depths and Formations</i>	126
<i>Drilling Fluids by Casing Intervals</i>	126
Surface to 150 feet to 400 feet—Surface to 1,800 feet to	
2,200 feet—Surface casing to 4,000 feet to 5,000 feet	
intermediate casing—Surface casing to 6,000 feet to 7,000	
feet production casing—Intermediate casing to 8,000 feet to	
15,000 feet production casing.	
DELAWARE BASIN	127
<i>Casing Program</i>	128
Surface casing—Intermediate casing—Second intermediate	
or protection liner—Production casing.	
<i>Drilling Fluid Program by Casing Interval</i>	128
Surface to 400 feet to 2,500 feet—Surface casing to	
9,000 feet to 13,000 feet—Intermediate casing to 12,000	
feet to 18,500 feet—Second intermediate or protection	
liner to total depth.	
VAL VERDE BASIN	129
<i>Casing Program</i>	129
<i>Mud Program</i>	130
MARFA BASIN	131
MARATHON-OUACHITA THRUST	131
10. DRILLING FLUID PRACTICES IN THE MID-CONTINENT,	
NORTH TEXAS, OKLAHOMA AND KANSAS	133
NORTH TEXAS DRILLING MUD PRACTICES	133
<i>Geological Considerations and General Nature of the Mud Problem</i>	133
<i>Eastern Section</i>	134
Cooke and Grayson Counties—Clay, Montague, Wise and Jack	
Counties—Archer, Wichita, Wilbarger, and Young Counties.	
WESTERN SECTION	135
OKLAHOMA DRILLING MUD PRACTICES	137
<i>Southern Oklahoma—Marietta Syncline and Southern Ardmore Basin</i>	137
<i>Eastern Oklahoma—Arkoma Basin</i>	138
<i>Western Oklahoma—Anadarko Basin</i>	138
General mud programs—Deep Simpson-Ordovician—Western	
and west central—Eastern shelf—Western shelf—Oklahoma	
Panhandle—Cimarron uplift—Texas and Beaver Counties—	
Texas Panhandle.	
KANSAS DRILLING MUD PRACTICES	143
<i>Central Kansas Uplift</i>	143
<i>South Flank of Central Uplift</i>	143
<i>North Extension of the Anadarko Basin</i>	143
<i>Forest City and Salina Basin</i>	144
<i>Cambridge Arch</i>	144
<i>East Flank of the Los Animas Arch</i>	144
<i>Shale Dispersion</i>	144

<i>Corrosion</i>	144
11. DRILLING FLUID PRACTICES IN THE ROCKY MOUNTAIN AREA, INCLUDING THE WILLISTON BASIN	145
BASINS WITHIN THE ROCKY MOUNTAINS	145
<i>Wyoming Area</i>	145
WILLISTON BASIN	148
<i>Central Basin and Nesson Anticline</i>	148
<i>Cedar Creek Anticline and Eastern Montana</i>	149
<i>Eastern Basin Area</i>	149
<i>South Dakota</i>	149
UINTA BASIN (UTAH)	149
12. DRILLING FLUID PRACTICES ON THE PACIFIC COAST	151
DRILLING FLUID PRACTICES IN THE LOS ANGELES BASIN	151
Surface zone—Intermediate zone.	
<i>Production Zone Completion Fluids</i>	154
<i>Special Purpose Muds</i>	155
<i>Mud Disposal</i>	155
DRILLING FLUID PRACTICES—COASTAL AREA	155
<i>Santa Maria Basin</i>	155
<i>Ventura Basin</i>	155
Ventura Avenue Field—San Miguelito Field—Oxnard area—	
Santa Paula area—Castaic area.	
CALIFORNIA OFFSHORE OPERATIONS	157
DRILLING FLUID PRACTICES—CENTRAL SECTION	157
Geologic formation in San Joaquin Valley—Mud practices	
in the San Joaquin Valley—San Joaquin Valley completion fluids—	
Sacramento Valley—Sacramento Valley mud practices—Sacramento	
Valley completion fluids.	
DRILLING FLUID PRACTICES IN WASHINGTON, OREGON, AND	
SOUTHWESTERN BRITISH COLUMBIA	159
<i>Washington Coastal Region</i>	159
<i>Central Washington-Cowlitz Basin</i>	160
<i>Eastern Washington</i>	161
<i>Oregon</i>	161
<i>Southwestern British Columbia, Canada</i>	161
13. DRILLING FLUID PRACTICES IN ALASKA	163
<i>Cook Inlet</i>	163
Mud properties in the Cook Inlet Basin—Casing practices.	
<i>North Slope</i>	163
<i>Gulf of Alaska</i>	166
<i>Bristol Bay</i>	166
14. DRILLING FLUID PRACTICES IN CANADA	167
<i>Geology</i>	167
<i>Pressure and Temperature Gradients</i>	170
<i>Types of Drilling Muds Used in Canada</i>	170
Surface hole—Below surface casing	
<i>Drilling Mud Problems</i>	172
Lost circulation—Bad make-up water—Shallow gas bearing	
formations—Mud rings—Sloughing shales—Anhydrite—Salt—	
Other mud problems.	

<i>Recent Mud Practices</i>	174
<i>Northwest Territories</i>	175
<i>East and West Coastal Regions</i>	176
15. DRILLING FLUID PRACTICES IN THE NORTH SEA	177
<i>Surface to 100 Feet (Outside Conductor Casing Point)</i>	177
<i>To 1,000 Feet—1,500 Feet (Conductor Casing Point)</i>	177
<i>Conductor Casing Point to Next Casing Point—4,000 Feet to</i> <i>5,000 Feet</i>	177
<i>From Casing Point to T. D.</i>	179
16. DRILLING FLUID PRACTICES IN ALGERIA	181
17. ENGINEERING DATA AND CALCULATIONS USED IN MUD WORK	185
<i>Volume of Mud in System</i>	185
Volume of mud pit—Capacity of hole.	
<i>Pump Output and the Mud Cycle</i>	185
<i>Annular Velocity</i>	187
<i>Quantities and Volumes of Materials</i>	188
Increase in weight—Increase in volume from additions of weight material—Weight increase using clay—Volume increase using clay—To determine quantity of water necessary to obtain a given weight reduction—Oil addition to give a desired percent oil—Solids determination—Calculation of percent solids by volume on muds containing no barites	
<i>Circulating and Static Well Pressures</i>	191
<i>Equations Involved in Blowout Prevention</i>	192

1 · Functions and Composition of Drilling Fluids

The fluid used in rotary drilling, once regarded only as a means of bringing rock cuttings to the surface, is now recognized as one of the major factors involved in the success or failure of the drilling operation. In addition to lifting the cuttings, the drilling fluid must perform other, equally important functions directed toward the efficient, economical, and safe completion of the drilling operation. For this reason, the composition of the drilling fluid and its resulting properties have become the subject of much study and analysis.

As attempts are made to drill deeper and consequently more hazardous wells, and to more fully exploit productive formations, the drilling fluid is expected to have physical and chemical properties that enable it to contend with a greater variety of well conditions. The satisfactory performance of these more complex functions has required that the composition of the fluid become more varied and its properties more subject to control, with the result that the cost of maintaining an effective drilling fluid has become a major drilling expense in many areas. This manual discusses the well conditions which occasion the need for control of drilling fluid properties, and the most economical means of gaining and maintaining this control.

The term "drilling fluid" includes air, gas, water, and mud. The term "mud" refers to a suspension of solids in water or oil, or of solids and droplets of one of these liquids dispersed in the other. This training manual discusses each of these drilling fluids, including the modification of muds for use as packer fluids, but deals primarily with those fluids used most often in the field, namely, suspensions of solids in a liquid, "muds," and suspension of solids and droplets of a liquid in a second liquid, "emulsion muds."

PRINCIPAL FUNCTIONS OF DRILLING MUD

Keeping the Hole Free of Cuttings. A basic function of the drilling fluid is to carry away the cuttings while drilling is in progress. Although the drilling mud should allow the cuttings to separate readily at the surface so that the fluid can be recirculated, it should also have the property of gelling to keep the cuttings in suspension when circulation is shut down. Fluids such as air and gas

do not have this property and can permit cuttings to settle during connections and trips unless they are circulated out of the hole. Air, gas, and foam are normally used for a single pass through the hole while muds are recirculated.

The ability of a drilling mud to carry cuttings up the hole and into a settling pit depends partly on the characteristics of the mud and partly on the circulating rate in the annulus between the drill pipe and the wall of the hole. When the mud pump capacity is too low to provide an annular velocity sufficient to lift the cuttings, raising the mud viscosity, particularly by increasing the yield point, may result in a cleaner hole.

Overcoming Gas, Oil, and Water Flows. The gas, oil, or water encountered in permeable formations penetrated by the bit is usually prevented from flowing into the hole by the pressure exerted by the column of drilling fluid. The amount of this hydrostatic pressure, or head, depends largely upon the density of the drilling fluid and the height of the fluid column. The pressure in the well bore also depends to some extent on the dynamic pressures brought about by the circulating mud and the movement of the drill pipe. Dynamic pressures, in turn, are related to the plastic viscosity, yield point, and gel strength of the mud.

Preventing the Walls from Caving. The pressure exerted by the column of mud against the wall of the bore hole helps to prevent caving of formations, as does the filter cake, a thin but tough film of mud plastered on the wall of the hole in permeable formations.

Cooling the Bit and Lubricating the Drill String. All fluids circulated through the drill string cool the bit, and most fluids provide adequate lubrication of the drill string. Oil emulsion muds, special emulsifiers, and extreme pressure lubricants are used to provide better lubrication of the drill string and bit when needed.

Securing Proper Information from the Well. The drilling fluid should permit securing information necessary to evaluate producing intervals; thus the fluid characteristics of the mud should be such that good cuttings, cores, and electric logs are obtained.

2 · Field Tests of Drilling Fluids

The drilling fluid properties usually measured by the drilling crew are mud weight, funnel viscosity, and filter loss. Crews may also measure the sand and salt content and the alkalinity of the mud. In deep and expensive wells, all of the physical properties of the mud and the soluble ions present in it are checked at regular intervals. The art in mud engineering is the thoughtful connection of the mud properties with the manner in which the mud performs its several functions under the conditions found in the well.

Following is a list of tests that are made for control of mud properties that relate to the drilling problem.

1. Density or mud weight
2. Viscosity and gel properties
 - a. Marsh funnel
 - b. Direct-indicating viscometer
3. Filtration and wall-building
 - a. Low temperature test
 - b. High temperature test
4. Sand content
5. Liquids and solids content
 - a. Distillation of oil and water
 - b. Estimation of composition of solids
6. Determination of pH
 - a. Colorimetric method
 - b. Electrometric method
7. Filtrate analysis
 - a. Alkalinity and lime content
 - b. Chloride
 - c. Formaldehyde
 - d. Calcium - qualitative method
 - e. Hardness
 - f. Calcium sulfate
 - g. Sulfate - qualitative method
8. Methylene blue test for cation exchange
9. Resistivity
10. Electrical stability of emulsions

Note: Methods here given conform to API 13B, Second Edition, April, 1969, "Standard Field Procedure for Testing Drilling Fluids."

DENSITY OR MUD WEIGHT TESTS

Density is weight per unit of volume. Once the density is determined it may be expressed in any convenient unit; for example, in pounds per gallon, pounds per cubic foot, specific gravity, or in pressure gradient as pounds per square inch (psi) per 1,000 feet of mud in the hole. The latter unit is most convenient because it may be readily used to calculate the hydrostatic head of the mud column for any depth of hole in the same units in which the pump pressure and the reservoir or formation fluid pressure are calculated. This unit is also required on the AAODC-API Standard Daily Drilling Report form. This facilitates control when excessive formation pressure or lost circulation is encountered. A comparison of density as expressed in these units is given in Table 2-1.

The Mud Balance. Figure 2-1 shows examples of two mud balances in common use. The mud balance consists of a supporting base, a cup, a lid, and a graduated arm carrying a sliding weight. A knife edge on the arm rests on the supporting base.

The procedure for measuring the density of the mud is as follows:

1. Set up the instrument base so that it is approximately level.
2. Fill the clean, dry cup with the mud to be weighed.
3. Place the lid on the cup and seat it firmly but slowly with a twisting motion. Be sure some mud runs out of the hole in the cap.
4. With the hole in the cap covered with a finger, wash or wipe all mud from the outside of the cup and arm.
5. Set the knife on the fulcrum and move the sliding weight along the graduated arm until the cup and arm are balanced.
6. Read the density of the mud at the left-hand edge of the sliding weight. Make appropriate corrections when a range extender is used.

3 · Drilling Fluid Circulating Systems and Auxiliary Equipment

Once the principal surface feature of the mud circulating system of a drilling rig was merely a hole dug in the ground adjacent to the well. On today's rigs such a large variety of mechanical mud control devices are to be found between the mud discharge line from the well and the standpipe that only a general description of them can be given in this space.

Figure 3-1 illustrates the main components of a fluid circulating system for rotary drilling: the pump, hose and swivel, drill string, mud return line, and pits. Accessory equipment also depicted includes the standpipe, chemical tank, mixing hopper, and mud storage. Auxiliaries for mud circulation include the shale shaker, agitators—mud guns and mechanical stirrers—desander, desilter, mud centrifuge, mud-gas separators, mud handling equipment, and pit instruments.

The mud pump is the primary component of any fluid circulating system. It may be operated by steam—such pumps were standard equipment forty years ago—but almost all mud pumps today are power pumps operated by diesel or gas engines. Power pumps for rotary drilling have ratings up to 1,750 input horsepower. They are capable of moving large volumes of fluid at pressures exceeding 3,000 psi, depending upon the size of the pistons and the power rating of the pump.

The pressure provided by the mud pump forces the drilling fluid up the standpipe, through the mud hose, swivel, and kelly, and down to the bit through the drill pipe. Completing a cycle of circulation, the mud returns through the annulus to the mud pits at the surface, carrying with it the cuttings from the bit.

The mud pits are an essential part of the drilling fluid circulating system. Their main function is to accumulate mud circulated through the hole and provide a constant supply to the suction of the pump. Secondly, the pits serve as a reservoir in which the mud stream

is allowed to slow down so that the cuttings can settle out, and into which mud materials and chemicals can be added.

Surface mud circulating equipment may include accessory components not needed for every rotary arrangement. A standpipe in the derrick may be used to suspend the mud hose so that it is clear of the work on the rig floor. When the hose is suspended in this manner the drill string may be moved vertically nearly twice the length of the hose. A return line from the wellhead to the pit is a neater arrangement than the ditch that is often used, and becomes essential when steel pits are employed, in order to raise the fluid stream to the height of the tanks. A small tank for mixing chemicals with water and feeding them into the mud stream may be an accessory item on some rigs and a necessary one on rigs where the mud must be chemically treated. Likewise, a mud hopper for mixing dry materials with the drilling fluid becomes a requirement when weighted mud is being used. Storage facilities for protecting the dry mud and chemicals from the weather, although accessory, may be required.

Most of the auxiliaries for mud handling become essential when heavy mud is being circulated. The saving of rig time, mud materials and chemicals made possible by these devices more than justifies their cost. A shale shaker will remove nearly all of the larger particles from the fluid stream, making it possible to use smaller pits than would otherwise be needed. Mud agitators enable mud weight material to be maintained in suspension. A degasser will remove entrained gas from the mud much more quickly than allowing the mud to stand still in a pit. Desanders, desilters and mud centrifuges are useful to separate sand or fine particles from liquid mud, to salvage weight material, and for mud conditioning.

MAIN COMPONENTS OF A MUD SYSTEM

MUD PUMPS

There are usually two mud pumps per rig, and they are the very heart of a fluid circulating system for rotary

drilling. Their function is to impart power to the fluid in forms of pressure and volume, thus to move the fluid

4 · Common Drilling and Drilling Fluid Problems

The selection of a drilling mud with properties that make it suitable for a particular well is sometimes a difficult process. Mud properties can be tested before and after the mud is circulated through the well, and adjustments can be made with additives, but there is no way to predict the exact conditions existing in the formations or the effect of mud properties upon them. Much unnecessary expense has resulted from inaccurate predictions of adverse formation conditions or from wrongly attributing these conditions to the mud properties.

As a result of experience in predicting actual mud requirements, several ordinarily routine practices for handling unforeseen adverse formation conditions have been determined to be faulty. Among the practices not recommended when such conditions are encountered are increasing the mud weight and viscosity with well depth, increasing mud viscosity before running casing, and continuing to use viscous, low water loss muds when hole problems persist. In other words, past practices should not be blindly followed. A thorough understanding of the nature of the problems likely to be encountered is essential so that more accurate predictions of conditions can be made and a more effective course of action pursued in the event unforeseen adverse conditions are encountered.

General problems to be considered include sloughing shales, lost circulation, high borehole temperatures, abnormal formation pressures, and blowout hazards. It should be realized that any one of these problems may create others.

MUD RECORDS

All mud companies furnish the operator a recap of the mud program used in drilling. In addition, API-AAODC standard drilling report forms have a daily mud log section for recording mud properties and treatments used. Complete records of mud properties and materials added should be kept on the mud and drilling report form shown in Figures 4-1 and 4-2. The remarks section of the form should be carefully filled out so that the explanations of the problems encountered in one well may permit better planning of mud and casing programs in future wells.

When a drilling program is being planned, there is no substitute for a study of the mud data available from previous drilling in the area. Such data make it possible to steadily improve the mud program and to lower the drilling and mud costs by profiting from experience. There are few places in the U.S. today where a true wildcat can be drilled. The formations to be encountered and the type of geologic structure are usually known with some exactness before a location is made. By working with geologists and analyzing scouting records, electric logs, and well records from nearby wells, it is possible to properly plan casing and mud programs for a prospect well. Before a contractor makes a bid in a territory where he has not been operating, he secures bit records and data on drilling conditions, surface water supply, power requirements, etc., for all recently drilled wells in the vicinity.

SHALE PROBLEMS

Maintaining hole stability while drilling shale sections can be troublesome. No simple solution exists, but good drilling practices combined with good mud practices are helpful. Shales causing trouble have been variously described as sloughing shale, heaving shale, running shale, bentonitic shale, mud making shale, plastic flow shale, gas bearing shale, and pressured shale.

Problems associated with hole instability in shale sections are (1) ineffective hole cleaning, (2) stuck pipe and its recovery, (3) bridges and fill-up, (4) increased mud volume and treating costs, (5) poor cement jobs and increased cement requirements, (6) difficult logging, (7) poor sidewall recovery, (8) well bore enlargement, and others.

Mechanical Factors in Shale Problems. Shale problems cannot always be solved by the drilling fluid alone since many shale problems can be caused by physical or mechanical action rather than chemical. Contributing to the shale problem are:

1. Erosion due to high annular velocities.
2. Drill string whip breaking down the wall of the hole.
3. Dislodging shale either through direct contact, pressure surges, or swabbing action when

5 · Widely Used Drilling Fluids

There are many drilling fluids today which are classed among the "widely used." These encompass as the main general classes the water base fluids, the oil base fluids, and air or gas. Each of these—particularly the water base fluids—can be further divided into numerous subtypes. Although the oil base fluids currently enjoy a healthy use, and air and gas fill a necessary but somewhat lesser position, water base muds are used preponderantly. Because of the extensive use of water base muds, considerably more attention must be paid to their conditioning and characteristics than is necessary with the other two types of fluids.

Table 5-1 lists one method of grouping the various drilling fluids into the several subclassifications.

Table 5-1

CLASSIFICATION OF DRILLING FLUIDS

WATER BASE FLUIDS

Fresh Water Muds—Little or no chemical treatment

1. Spud mud
2. Natural muds

Chemically Treated Muds—No calcium compounds added

1. Phosphate muds
2. Organic treated muds
 - a. Lignite
 - b. Quebracho and other extracts
 - c. Chrome lignosulfonates

Calcium Treated Muds

1. Lime
2. Calcium chloride
3. Gypsum

Salt Water Muds

1. Seawater muds
2. Saturated saltwater muds

Oil-Emulsion Muds (oil-in-water)

Special Modifications

1. Low solids oil-emulsion muds
2. Low clay solids weighted muds
3. Surfactant muds

OIL BASE FLUIDS

Oil Base Muds

Invert Emulsion Muds (water-in-oil)

GASEOUS DRILLING FLUIDS

Air or Natural Gas

Aerated Muds

CONDITIONING WATER BASE DRILLING FLUIDS

ADDITIVES

The control of drilling fluids always presents two problems:

1. Determination of what is needed in the way of properties, i.e., weight, viscosity, gel strength, filtration, etc., for the drilling mud to satisfactorily handle a drilling operation.
2. The selection of the type of mud and the materials and chemicals which will give the desired mud properties.

The properties of drilling muds can be adjusted to meet any reasonable set of conditions, and thereby to overcome most drilling problems, such as abnormal pressure, lost circulation, and sloughing shale. The selection of the proper mud additive for certain conditions is sometimes confusing, however, because of the large number of mud dealers and the wide variety of trade names. To simplify this problem it is convenient to think of mud additives according to their application or specific performance requirements:

1. Barite weight materials for preparing muds weighing in excess of 10 lb/gal.

6 · Packer Fluids

Packer fluids are those fluids left in the annular space between the tubing and casing. The primary function of a packer fluid is to provide hydrostatic head for pressure differential reduction across the packer, casing, and tubing. While meeting its primary requirement, the packer fluid should also (1) provide sufficient suspending ability to prevent settling of solids, and yet remain fluid for good placement and removal, (2) remain stable at down-hole conditions of temperature and pressure, and (3) provide protection from corrosion.

Industry practice has been to utilize the drilling fluid as the packer fluid—a natural choice, if the cost of the packer fluid is the principal consideration. In many instances, particularly in shallow wells where moderate temperatures and normal pressures are encountered, this has proved to be an acceptable practice. In other instances the practice has proved to be less than successful, and costly wash-over operations and severe corrosion attacks have been reported.

Recently the drilling trend has been toward very deep wells, where high strength steels are used in the casing and tubing strings to withstand the loads placed upon them. These steels are more subject to damage from corrosion than ordinary steels. Another problem in very deep wells is that the more severe pressures and temperatures found at the greater depth cause ordinary drilling mud to deteriorate over an extended period of time. Since the cost of producing and servicing this type of well continues to increase, the prospect of investment in protective packer fluids has become more attractive. Generally, the industry is reevaluating the packer fluid practice.

Packer fluids may be categorized as follows:

1. Solids-free liquids
 - a. Oil
 - b. Water
2. Water base muds
 - a. Drilling mud
 - b. Prepared packer mud
3. Oil muds
 - a. Invert
 - b. Oil base

SOLIDS-FREE LIQUIDS

Solids-free liquids are divided into two groups: oil and water. Oil at 6.7 lb/gal fulfills the foregoing requirements. A sweet crude or diesel may be used, and corrosion inhibitors may be added to protect against corrosion in wells where inefficient displacement of mud or water is anticipated. In high pressure wells, however, the low hydrostatic head of oil usually rules out its use.

Clear-water chemical solutions may be used in the density range 8.4 to 11.8 lb/gal, at the lower end of which is fresh water. Corrosion inhibitors such as sodium chromate or organic inhibitors have been used effectively in fresh water. Above 275°F temperature, many organic inhibitors suffer degradation and lose their effectiveness. Sodium chromate has been used with success, but special attention is necessary to hold the concentration to a specific range. Anodic inhibitors such as sodium chromate tend to cause corrosive attack to be localized, resulting in pitting and increased susceptibility to stress cracking. Use of dianodic inhibitor combinations such as zinc/phosphate/chromate lessens the tendency toward localized attack. Control of pH to 9.5–10 range results in a greatly reduced corrosion rate. When calcium chloride is used to build higher densities, pH control with caustic is limited due to buffering by precipitation of calcium hydroxide from caustic additions at advanced pH values.

Sodium Chloride. Sodium chloride, or common salt, brines have been extensively used for a number of years. Salt brines obtained from wells in which fresh water is pumped down tubing or casing and circulated through a salt cavity provide the most economical source of denser solutions. If such brines are unavailable, common salt may be mixed with fresh water. Density range is from 8.4 to 10 lb/gal, as shown in Table 6-1.

Control of pH to 9.5 or above has been helpful in the corrosion problem. Corrosion inhibitors such as sodium chromate, and organic inhibitors may be used in sodium chloride solutions with the same restrictions mentioned for fresh water.

7 · Drilling Fluid Practices in the Gulf Coast of Texas and Louisiana

Astride the coast line of the Gulf of Mexico, in the states of Texas and Louisiana, extending inland a distance of more than 100 miles and offshore roughly half that distance, lies an oil belt that is in many ways unique in the industry. After many years of development, the Gulf Coast continues to be the most active drilling area in the country. Activity may be said to be concentrated on the outer flanks of domes and on deeper zones; but with the offshore lease situation cleared up, drilling is now at a high level on the continental shelf, particularly in Louisiana.

The principal producing horizons of the Gulf Coast are formations of Tertiary age, most production being from Miocene, Oligocene (Anahuac and Frio-Vicksburg, principally), and Eocene sands (Yegua-Cockfield and Wilcox). Figure 7-1 is a map displaying the productive trends of the region. The outstanding structural characteristic of the Gulf Coast is the presence of many producing piercement and deeper-seated salt domes. Generally, the formations penetrated in the Gulf Coast consist of poorly cemented sands and mud-making shales, and faulting is prevalent on practically all structures. Salt and anhydrite are absent in this Tertiary section but present a special, localized problem in drilling some salt domes. High temperatures, from 200° to more than 400°F, and abnormally high formation fluid pressures, ranging up to 80 to 90 percent of the weight of the overburden, are encountered in deeper wells and require special drilling fluids. The available water is almost universally good, except in offshore drilling, where transportation of good water is a problem. Sea water is now being used successfully in some proven fields offshore and brackish water is being used in marsh drilling.

Mud costs for Gulf Coast drilling are frequently very high, possibly higher than in any other area in the world. These high costs are the result chiefly of two conditions: abnormally high formation fluid pressures, and shale sections that have a tendency to slough. The drilling platforms, auxiliary tenders, extra crews, and special transportation that are required for offshore drilling add tremendously to the average cost of drilling. Drilling progress, however, is fast. As much as 14,000 ft of hole has been drilled in seven days.

MUD AND CASING PROGRAMS

Not all Gulf Coast wells are expensive and difficult to drill. It is estimated that in excess of 75 percent of all wells drilled are routine wells that use muds less than 12 lb/gal in weight and have modest drilling and mud costs. Successful drilling operations are being carried on from spudding to completion with only nominal attention to the mud and minimum mud treatment.

It is, however, a characteristic of Gulf Coast operations that when wells are being drilled to the formations which require a mud weight greater than 14.5 lb/gal, a protective casing string must be set at some depth before the high mud weight is needed. The selection of this casing point is the chief problem in the planning of such a deep well. A major complication is the fact that, due to the faulting in many structures, many wells have some of the aspects expressed in the Gulf Coast phrase, "Every well is a wildcat."

Abnormally high formation fluid pressures in the Gulf Coast are not mere random occurrences. They are found throughout the trends outlined in Figure 7-1, and are encountered below what has been commonly called the pressure transition zone. This zone is that depth interval where the formation pore pressure begins to increase above the normal gradient of .465 psi/ft. The depth of the transition zone varies from 8000 to 11,000 feet depending on the geographic location.

In recent years, the drilling of the deep wells which encountered abnormally high formation pressures has been accomplished with much less difficulty than was experienced five to ten years ago. This has been made possible through more systematic planning of the intermediate casing setting depth. With adequate electric and acoustic log data from previously drilled wells, the pressure-depth relationship can be estimated with reasonable accuracy for the well being planned. This technique is discussed in more detail in Chapter 4. Use of the method permits selection of the proper casing setting depth in advance of drilling. The pressure prediction can be confirmed by well behavior and by performing the previously mentioned calculations on logs as they are run. If radical variations from predictions are found, the planned casing setting depth can be changed to fit actual conditions. In this manner, the

8 · Drilling Fluid Practices in the Ark-La-Tex and Mississippi Area

The area covered in this chapter includes parts of East Texas, Arkansas, Louisiana, Mississippi, and Southeast Alabama, which is an area of recent interest. Drilling activity, particularly in recent years, has been focused on the Jurassic Trend of the Gulf Coast Geosyncline and the shallow Wilcox Trend of Central Louisiana and Southwest Mississippi. These generalized features are shown by Figure 8-1. Subsurface conditions are affected

by a number of features, among which are the Mexia-Talco Fault Zone, the Sabine and Monroe Uplifts, the Jackson Dome, and the Pickens-Gilbertown Fault System.

The geologic section of Figure 8-2 illustrates the number of formations penetrated and shows a great number of them to be productive. In recent years the search for hydrocarbons has to a great degree been

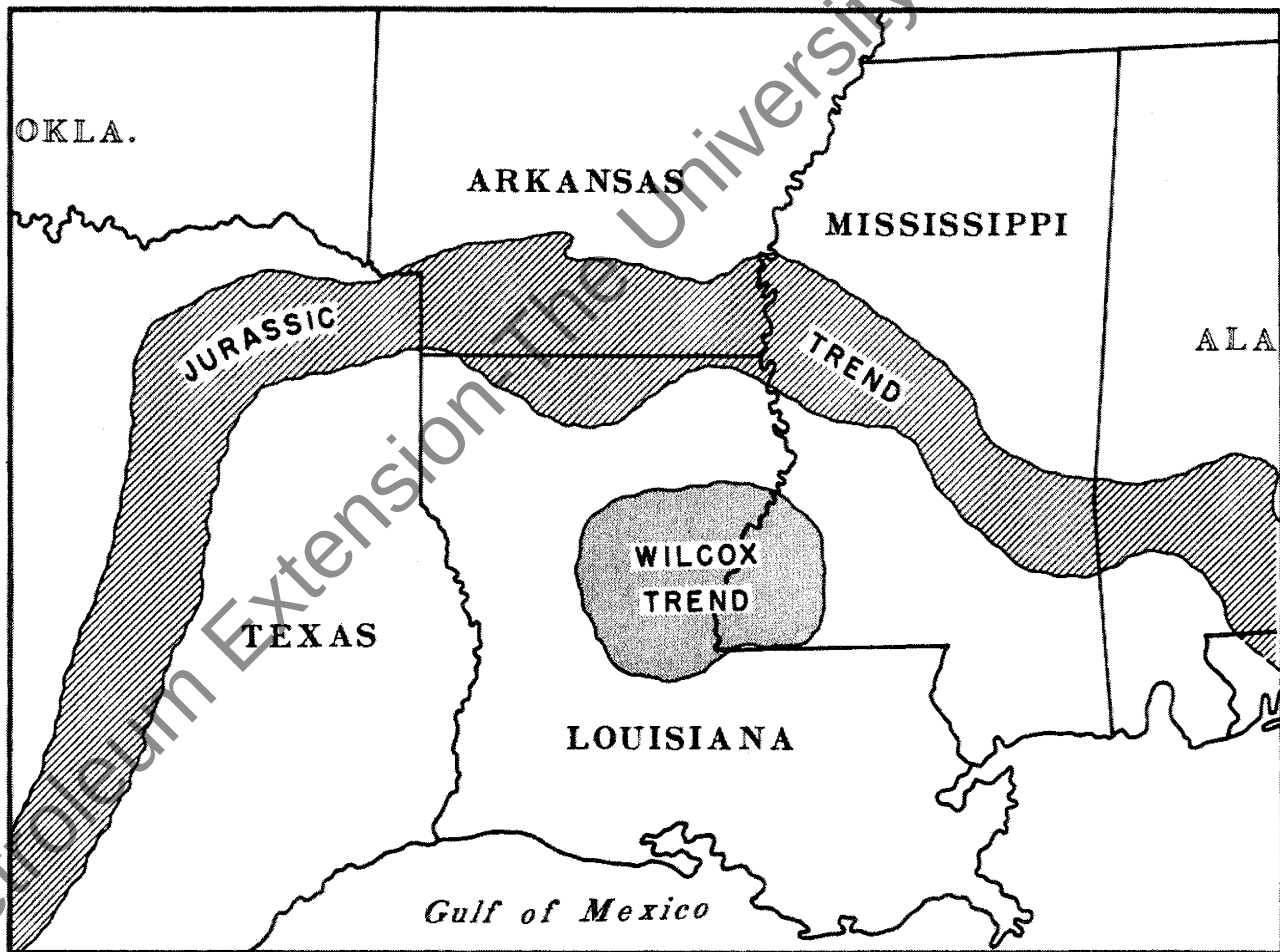


Figure 8-1
Important Areas of Drilling Activity in Ark-La-Tex and Mississippi

9 · Drilling Fluid Practices in West Texas and New Mexico

GENERAL CONSIDERATIONS

Because of the existence of Permian sediments throughout West Texas and Southeastern New Mexico, the area is frequently designated as the Permian Basin. Mud practices are described for each of the major basins or structural features as shown in Figure 9-1.

A general Paleozoic correlation chart for most of these features is given in Figure 9-2. General remarks applying to the whole area are made in discussing the following topics: salt, red beds, solids control, lost circulation, underbalanced drilling, hole stability, oil muds, corrosion, and air and gas drilling.

Salt. The Salado (Permian) salt consists primarily of sodium chloride in stringers and thick beds. This salt is encountered within the hachured area shown in Figure 9-1, at less than 5,000 ft. Casing and mud programs must always consider these beds and provide for the tendency of the salt to dissolve in freshwater drilling fluids. The hole enlargement that results from the dissolved formation salt will affect subsequent drilling and cement requirements, and the salt, if left uncased, will preclude the use of freshwater muds for deeper drilling.

Red Beds. Clay and shale stringers of Permian age are interbedded with the salt beds. These are not generally troublesome in themselves, but are affected by salt washed out of the sections above and below. It is not usually necessary to control filtration to stabilize the red beds; however, it is well known in this area that red beds exposed for too long a time to water muds become extremely unstable. The time limit is from ten days to two weeks.

Solids Control. The hardness of subsurface rocks in the Permian Basin makes it difficult to maintain a high penetration rate. To achieve a maximum penetration rate, every effort should be made to reduce the solids content of the drilling fluids. Many thick intervals are drilled with clear fluids, from fresh water to saturated brine. Where higher density has been required, drilling has been done with water to which calcium chloride, soda ash, and other electrolytes were added.

Flocculants are used widely to further clarify the drilling water. Mechanical means are frequently employed to reduce the solids content in clear water and in formulated muds. These include circulating through reserve pits, special design of rig pits, conventional and double deck shakers, desanders, desilters, and centrifuges.

The widespread use of clear liquids plus a desire to postpone the use of formulated fluid for as deep as possible has given rise to considerable use of asbestos fiber additives. These improve the cleaning and carrying power of clear fluids without significantly reducing the penetration rate.

Lost Circulation. Cavernous, fractured, or extremely porous formations are frequently drilled without returns until a suitable casing point is reached. Lost circulation from induced formation fractures has been reduced greatly by drilling through the weak formations with a drilling fluid of minimum circulating density and then setting casing. This minimum circulating density is an important feature of minimum solids programs and underbalanced drilling which is described below.

The use of clean fluid and low solids mud has increased the frequency of "seepage" type losses. In these cases, some portion of circulation is maintained while a gradual and continuous loss of fluid occurs. The use of shredded paper as a lost circulation material has proved very effective against seepage losses and is widely used.

When lost circulation occurs and conditions are such that full circulation is required before drilling ahead, the familiar lost circulation techniques are applied. These include spotting "pills" of high concentrations of a variety of lost circulation materials, the use of high solids squeezes, and the use of special oil-bentonite and oil-cement mixtures. In all these cases the withdrawal of several stands of drill pipe and an adequate waiting time are believed to be very important.

The proper use of air/gas drilling techniques in known lost circulation zones has also reduced the number of severe lost circulation problems.

10 · Drilling Fluid Practices in the Mid Continent, North Texas, Oklahoma and Kansas

NORTH TEXAS DRILLING MUD PRACTICES

The area generally referred to in this chapter as North Texas includes several counties centered around Wichita Falls. Westward the area extends to and includes Knox, Foard, Cottle, and King Counties, while at the eastern extreme is Cooke County. Also included are the central counties of Montague, Wise, Clay, Wichita, Archer, Young, Jack, Baylor, and Wilbarger.

GEOLOGICAL CONSIDERATIONS AND GENERAL NATURE OF MUD PROBLEM

Drilling in north-central Texas involves penetrating rocks which are mostly Pennsylvanian in age. The Cisco, Canyon, and Strawn formations are well known for their prolific oil production. Production is also in the Oil Creek and Ellenburger formations of Ordovician age.

Permian rocks similar to those in the well-developed Permian Basin of West Texas encroach upon the area from the west. These formations appear at the surface in the western counties and are from 2,000 to 3,000 feet thick. They gradually thin and disappear near the center of the area. The thick Pennsylvanian system that underlies the Permian rocks in the west appears at the surface in the eastern sector of the area, where it gradually dips eastward into the Fort Worth Basin. In Cooke County, on the extreme eastern edge, Cretaceous formations overlie the area.

Mud types in North Texas range from the freshwater muds of the eastern section for Pennsylvanian shale drilling to the highly contaminated muds of the west where Permian formations are encountered. Make-up waters highly contaminated with gypsum and salt from surface Permian formations constitute the most serious of the problems in the west. Shallow gas and salt water sands are common over most of the areas. Although a 10 lb/gal mud is sufficient to control the pressure, the situation is often aggravated by the presence of lost circulation zones in the lower portion of a hole. Flows and salt contamination resulting from reduced hydrostatic head due to the lowering of the fluid in the hole are

costly to the operator both in shut-down time and in mud conditioning. Experience has shown that some effort to keep the hole full during trips is a necessity in many parts of the area.

In general, extremely low water loss mud is not necessary in the area; however, some control is essential to help prevent caving of long exposed shale sections and protect potential pay sands. Usually, water loss is maintained at 10 cc unless a lower value is required for a troublesome shale or a particular production zone. Filtrates as high as 20 to 30 cc even during completion are not uncommon. Mud viscosities are generally in the range of 35 to 50 sec over the area; however, in certain localized sections extremely high viscosities are used and are thought to be necessary to clean the hole prior to testing, logging, or running pipe. Because of lost circulation difficulties in the lower part of the hole, it is desirable that mud weights be maintained below 10 lb/gal. In some areas densities as low as 9.4 to 9.6 lb/gal are required.

The area can be considered one of low mud cost. However, because of the nature of the shale sections, large water dilutions are necessary to overcome solids buildup and maintain the necessary low mud weights. Good mechanical design of the surface system has proved to be an aid to mud maintenance. Proper control of viscosity and gel strength also aids in the removal of cuttings in the settling pits. Careful consideration of pumps and mud facilities plays a large part in mud control in the North Texas area.

Much of the shallow footage in the North Texas area down to 2,000 to 3,500 feet can be drilled with clear water. The natural dispersion of cuttings causes a buildup of weight and viscosity to the point that the system is actually a native mud. Most operators and contractors try to keep the solids content of this native mud at a minimum in order to achieve a maximum penetration rate and decrease loss of circulation. The addition of crude or diesel oil to this native mud has become quite common. The added oil serves the purpose of improving hole condition and reducing mud weight

11 · Drilling Fluid Practices in the Rocky Mountain Area, Including the Williston Basin

The Rocky Mountain area includes the states of Colorado, Wyoming, Montana, Utah, and western Nebraska. The Williston Basin area of North and South Dakota and eastern Montana is also included in this chapter because it is adjacent and there is a similarity of drilling problems and types of mud used. However, the mud problems vary throughout this large area. For the most part, formation fluid pressures are normal or subnormal, and as a result, high-pressure drilling problems are limited to isolated areas. Loss of circulation, contamination of mud when penetrating thick sections of evaporites, and instability of certain thick shale sections and coal stringers are the major mud problems.

The productive formations throughout this extensive region include strata of almost every geologic age,

ranging from Cambrian to Oligocene. Structurally, the area consists of several basins, varying in areal extent and thickness of sedimentary section. Figure 11-1 is a sketch map showing the location of these basins. From the standpoint of mud treatment and drilling problems, the basins can be divided into three general groups, which are

1. Basins within the Rocky Mountains: Powder River, Big Horn, Wind River, Green River, Uinta (Colorado), Laramie, and Denver-Julesburg
2. Williston Basin
3. Uinta Basin (Utah)

BASINS WITHIN THE ROCKY MOUNTAINS

Within this grouping are included the Powder River, Big Horn, Wind River, Green River, Uinta (Colorado), Laramie, and Denver-Julesburg Basins. Structurally, all of these basins are broad synclines with marginal zones of relatively steep folding and faulting, and even local overthrusting, but with interior parts with low relief folding. The formations are characterized by fracturing, which is the result of the action of mountain-making forces on generally hard formations.

The Powder River Basin may serve as a type for the other basins. Approximately 16,000 ft of strata, ranging from Cambrian to Eocene, are present in the deepest parts of the Basin. About one-third of the sedimentary section encountered in the deeper parts is exposed along the rim of the Basin. Oil and gas fields are present on all borders of the Basin and they yield or have yielded oil from formations ranging in age from Mississippian to Oligocene. Some basins are older and further developed than the Powder River Basin, and others have a thicker sedimentary section. For instance, the Green River Basin has a sedimentary column of 30,000 ft along the marginal areas, and probably considerably more in the deeper regions in its southwestern portions. One of the world's deepest wells is located in this Basin and was

drilled to a total depth of 20,521 ft in Upper Cretaceous strata.

WYOMING AREA

Essentially, two basic drilling mud programs are applied throughout Wyoming. The first program is applicable to wells scheduled to test the various producing horizons above the Jurassic/Triassic red beds. These include the Sussex, Shannon, Frontier, Muddy, Dakota, Lakota, and Sundance formations. The second program is applicable to wells penetrating the deeper Tensleep (Pennsylvanian) and Madison (Mississippian) producing formations. Drilling to the lower producing horizons requires penetration of the Triassic-Permian, Chugwater, and Embar formations. These formations contain gypsum and anhydrite in varying amounts from stringers to massive sections, depending upon well locations. Bedded salt is present in the lower section of the red beds in the northeastern part of the Powder River Basin. Small amounts of salt are also found in a bedded overthrust of the red beds in the lower southwest section of the Green River Basin around the town of Evanston.

12 · Drilling Fluid Practices on the Pacific Coast

The three main oil-producing provinces in California are the Los Angeles Basin, the San Joaquin Valley, and the Coastal Area. There is a gas-producing area in California's Sacramento Valley, and there have been a limited number of wildcat wells drilled in the Pacific Northwest—in Washington, Oregon, and southwestern British Columbia. For convenience in discussion, the mud practices will be treated under these area headings. A separate section on California Offshore operations has also been included. Figure 12-1 shows the location of the principal geologic basins in the state and Fig. 12-2 gives the geologic correlation of the principal formations of the various basins.

The formations encountered in California consist of shales, sands, silts, and various mixtures of these. Shale hardness varies considerably, and in the extreme case of cherty shales, penetration rates may drop to 1 to 2 ft/hr. Absent are the limestones, dolomites, anhydrites, salt beds, and domes of the Mid-Continent and Gulf Coast. The only formation contaminants are gypsum stringers or high-pressure salt water. In general, the surface hole tends to be sandy, and grades to shaliness with depth. A factor contributing to the complexity of oil well completion in this state is the loss of permeability in some sands following exposure to poorly selected drilling fluids.

In California, the trend to optimum solids and some use of various inhibited muds has become apparent in the past few years. Lignosulfonates predominate as the chemical thinner. Emphasis is on rheology and the newest mud testing techniques; high-temperature testing and mechanical solids separation devices are being widely used to provide desirable and economical drilling fluids. Muds having a 40 sec/qt viscosity, 6.0 to 7.0 cc filtrates, and a density spread from 70 to 90 lbs/cu ft

(9.3 to 12.0 lb/gal) are generally used. However, lower or higher viscosities and weights are used when conditions warrant.

It should be noted that mud weight is reported in pounds per cubic foot and salinity is reported in grains per gallon, but other tests and procedures are similar to those in use elsewhere. One grain per gallon is 17.1 parts per million. Viscosity measurements are made with the Marsh funnel by rig personnel; however, the direct indicating viscometer is a necessary instrument with mud service engineers. It is general practice in California to use metal circulating tanks, usually with flooded suction. The vibrating screen is considered standard equipment; settling tanks and/or ditches are also frequently used; desanding and desilting equipment are familiar tools on many locations, especially permanent drilling installations.

Generally, wells are spudded in and drilled with clay-water muds, bentonite-water muds or mixtures of the two. The surface formations are usually loosely consolidated, and solids incorporated in the mud tend to quickly raise the mud weight to between 75 and 85 lb/cu ft (10.0 and 11.3 lb/gal), depending upon the nature of mud-making clays and shales picked up in drilling. These natural densities may be used in many instances, but in others it is necessary to lower them by using large quantities of water. Of course, weight material and bentonite may be required, depending upon the characteristics to be maintained. The upper hole is often drilled with low-viscosity, low-solids mud. Large quantities of sand are usually picked up in this part of the hole, and the dangers of settling and/or bridging are always present unless the sand is settled out in the surface system or removed by a cyclonic desander.

DRILLING FLUID PRACTICES IN THE LOS ANGELES BASIN

Drilling mud problems in the Los Angeles Basin are generally not severe. Clay-water or bentonite-water muds treated with small amounts of polyphosphates and organic additives are normally adequate for efficient

drilling, except for the complications noted later. Special muds or more carefully controlled clay-water muds are often used to minimize damage to the producing formation. Because much of the Los Angeles Basin is

13 · Drilling Fluid Practices in Alaska

At present there are two basins of considerable interest in Alaska, the Cook Inlet basin, which at present is the only producing basin, and the North Slope area, which has had several recent discoveries of considerable magnitude. Several other basins in Alaska have had limited drilling, but commercial quantities of hydrocarbons have not yet been found in them.

COOK INLET

Drilling on the east side of the Cook Inlet basin in the Swanson River area and on the southern Kenai lowlands has encountered an average of 10,000 feet of non-marine Tertiary clastics generally referred to as the Kenai Group, overlying indurated Mesozoic marine sediments that are generally considered economic basement.

The Tertiary section is sandy and conglomeratic in the upper 5,000 feet, and primarily silty and coaly in the lower 5,000 feet, with the Hemlock conglomeratic sand formation near the base of the section. The sediments range in age from Oligo-Miocene to Plio-Pleistocene.

On the west side of the basin, which includes all of the offshore fields, the thickness of the section is about the same, but the lower Kenai section is more coarsely clastic, containing thick sand and conglomeratic sand beds.

Objective horizons are generally gas in the upper part of the Kenai and oil in the lower part, primarily in the Hemlock formation. In the north end of the basin deep wells have encountered an older Tertiary non-marine sandstone and a siltstone section of probably Eocene age, the Chickaloon formation. Numerous deep wells have encountered abnormally high pressures in the Lower Kenai and the Chickaloon. Figure 13-1 shows the location of fields within the Cook Inlet basin.

Mud Properties in the Cook Inlet Basin. At present, low solids systems are generally being used, along with seawater and saltwater muds. These systems have replaced the lignosulfonate muds that were used extensively during the first few years of development in Cook Inlet. Very low permeabilities have caused concern among many operators over possible damage to the producing formation.

Another problem in drilling this area has been extensive lignite seams with steeply dipping beds that slough and cause much stuck pipe.

Hole temperatures are abnormally low, with the temperature gradient running about 0.88°F/100 ft. Above normal pressures have been encountered in several wells, but this is not usually a problem.

Lost circulation generally is not a problem, and usually occurs only in drilling the surface hole in unconsolidated sediments and glacial drift. Viscosity will normally run 40–50 seconds, except when drilling in glacial drift, in which very high viscosities are normal. Fluid loss ranges from 10 cc in upper hole to 4 cc to 6 cc by total depth.

High solids problems are common due to the drilling of large sections of siltstones and clays. Mechanical equipment to remove these undesirable solids is now commonly used in this area.

None of the common contaminants are present in the Cook Inlet area.

Due to the steep dips, frequent in this area, straight hole drilling and directional drilling problems are common.

Casing Practices. Generally speaking, the following casing program has been followed for this area:

20-in. conductor	100 ft to 300 ft
Surface pipe 13 3/8-in.	2,000 ft to 2,500 ft
Intermediate is usually 9 5/8-in.	7,000 ft to 9,000 ft
Production string normally is 7-in. liner hung to TD	

NORTH SLOPE

Past drilling in the Naval Petroleum Reserve in the Umiat area has encountered thick sections of siltstone and greywacke with relatively thin, poorly developed sand reservoirs in the basal Upper and Lower Cretaceous. In the Barrow area the Cretaceous section is thin, about 3,000 feet, and rests directly on metamorphic basement rocks of probable Devonian age.

More recent drilling in the Prudhoe Bay area has encountered Tertiary and Cretaceous-Jurassic clastic sediments to depths in the range of 8,000 feet, below

14 : Drilling Fluid Practices in Canada

Canadian drilling muds have undergone a tremendous change during the past decade. The trend has been away from the typical native mud to the low solids, non-dispersed variety. The non-dispersed muds have been aided by advances in mud chemistry and drilling solids removal equipment. These muds have resulted in improved penetration rates and hole stability in most areas. They are easily converted to other mud types when necessary to handle sloughing shale, salt, anhydrite, etc.

The principal area involved is the Western Canada Basin. In addition, there are small active areas on the West Coast, in Eastern Canada, on the East Coast, and the MacKenzie Delta. The latter two could become the most significant areas. The Basin divides naturally into the Foothills and Plains areas.

GEOLOGY

The Western Canada sedimentary basin embraces an enormous area, stretching from the Canadian Shield in the east to the Rocky Mountains in the west, and from the international boundary in the south into the Northwest Territories. The extent of the basin is indicated on the map, Figure 14-1, which also shows principal towns and rivers and points of present major activity in the petroleum industry within the area reviewed.

The great prism of sediments occupying the basin varies in thickness from a feather edge at the margin of the shield to in excess of 20,000 ft along the mountain belt which marks the site of the old Rocky Mountain geosyncline. Generally speaking, the sedimentary section dips and thickens to the west and southwest towards the mountain front. An exception to this pattern occurs in the subsidiary Williston Basin of southeastern Saskatchewan and southwestern Manitoba. Here the sedimentary dips tend to converge on the structural center of the basin located in western North Dakota.

Tertiary and Cretaceous sediments in the basin, ranging in thickness from a few hundred feet in the east to several thousand feet in the deeps of the Alberta syncline, consist of continental, freshwater and marine shales, sands, conglomerates, and coals. Beneath the

ubiquitous cover of Quaternary drift, the Upper Cretaceous beds form the present erosion surface over most of the area involved. Numerous sands, many productive of oil or gas, occur in the Cretaceous section. The correlation of the principal zones of interest is shown in the upper part of the basin-wide correlation chart, Figure 14-2.

Jurassic rocks in the basin are confined chiefly to southern Saskatchewan, southern and western Alberta, and eastern British Columbia. The lithologies present are mainly sands and shales with subordinate carbonates interbedded with anhydrite in the Williston Basin area. Oil and gas production is developed in these beds in the southern parts of Alberta and Saskatchewan. Triassic deposits are of importance along the foothills, mountain belt, and in the plains area of Peace River. Important gas deposits, with minor oil, occur in porous Triassic carbonates and sands throughout the Fort St. John-Fort Nelson area of northeastern British Columbia.

Carboniferous deposits (here including both Mississippian and Permo-Pennsylvanian formations) are widely distributed throughout the western and southern portions of the basin. They range in thickness from an erosional edge in the east to in excess of 3,500 ft along the mountain belt. The dominant lithologies are carbonate and shale, with relatively large gas and oil deposits occurring in widespread porous horizons. In addition to such important plains fields as Sundre-Westward Ho and East Calgary, these beds are undergoing active exploration, and are yielding large gas reserves, along the mountain belt (Waterton-Castle River, Savannah Creek, Quirk Creek, Wildcat Hills, Stolberg, etc.).

Upper Devonian sediments are present throughout a wide area of the basin, ranging in thickness from an erosional edge in the east to some 2,500 ft along the mountain front. The Upper Devonian is of paramount importance from a petroleum standpoint, since it includes the biohermal Leduc formation, the Beaverhill Lake group, and the biostromal Nisku formation. These reservoirs, composed largely of vugular, sometimes cavernous dolomite, contain a large percentage of the proven gas and oil reserves of the basin, in such fields as Leduc, Redwater, Golden Spike, Wizard Lake, Innisfail, Swan Hills, Kaybob, Kaybob South, Clark Lake, and Joffre.

16 · Drilling Fluid Practices in Algeria

Separated from the Mediterranean Sea by the Atlas Mountains, the main producing zones of Algeria lie in the Middle South of Algeria in the Sahara Desert. The basins in the Southwest, Tindouf, Regan, McMahon, Colomb Bechar, Ahnet, and Monydir, have been unproductive and sparsely drilled. The Atlas Mountains area also is not too well explored. The Erg Oriental and Fort Polignac basins in the Southeast on the Libyan border have been productive, while the main production comes from the Plateau de Hassi Messaoud and the Haut Fond de Telemzane areas in the Central Sahara. These basins

are shown in Figure 16-1. Mud control practices discussed here pertain to these last two areas.

Generally the terrain in these two latter areas is underlain by a not too thick bed of Tertiary followed by the Cretaceous, the Triassic, the Carboniferous, Devonian, Gothlandian (Silurian), Ordovician and Cambrian. The lower section of the Triassic is gas producing, but the major Algerian oil production comes from fractured sand formations in the Cambrian, accounting for the discovery field of Hassi Messaoud. Figure 16-2 shows the lithology and type section of this region.

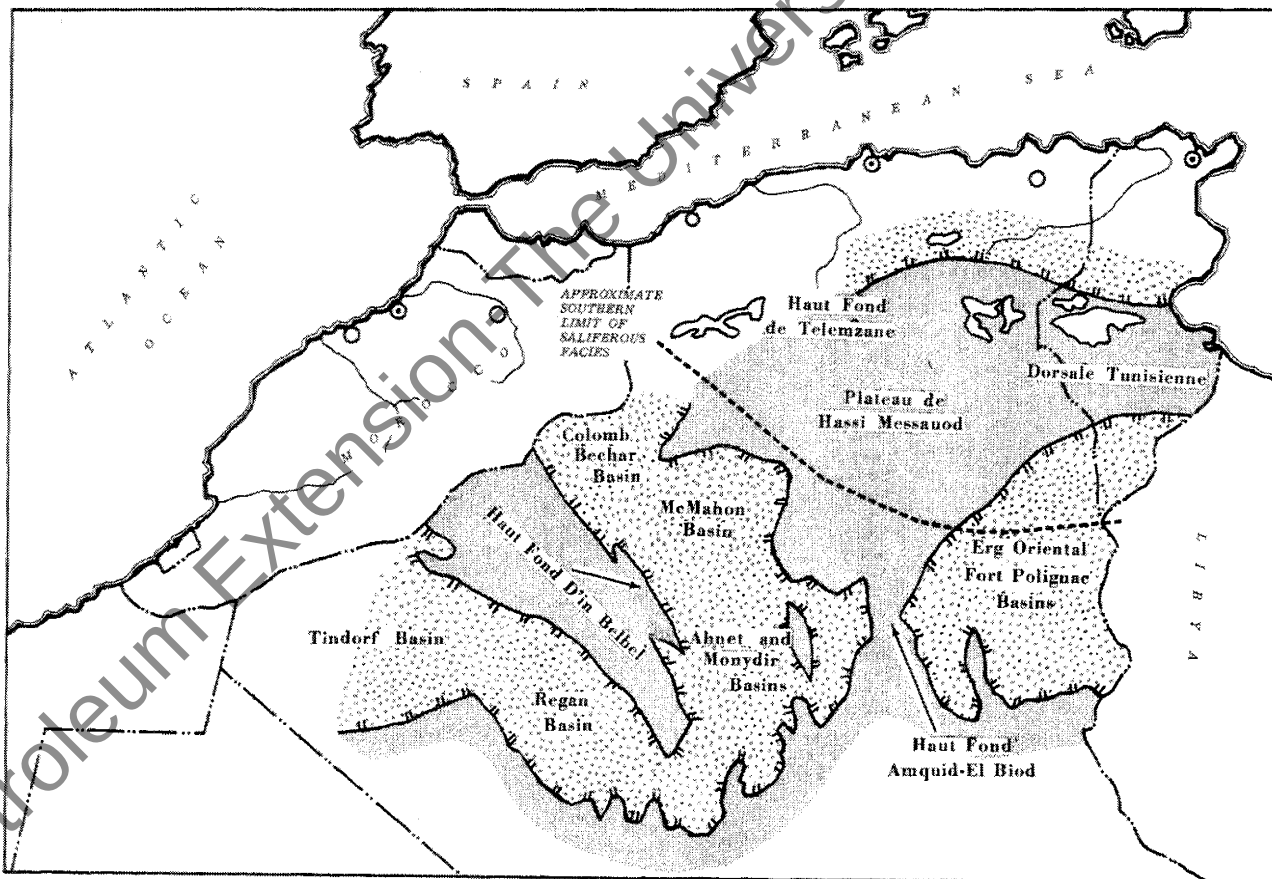


Figure 16-1
Algerian Sahara Basins

17 · Engineering Data and Calculations Used in Mud Work

The calculations required in mud conditioning are few and simple but quite important. The computations most used on the job are here presented in the form of easily used formulas and tables. Additional useful tables have been included throughout this manual.

VOLUME OF MUD IN SYSTEM

One of the first concerns of the personnel on a rotary drilling rig is the volume of mud in the system; that is, the mud in the pit and the mud in the hole. It is also useful to know how much reserve mud is available in storage tanks or pits.

Bbl of mud
in system = bbl of mud in pit + bbl of mud in hole

Volume of Mud in Pit.

Volume in barrels =

$$\frac{\text{Length (ft)} \times \text{width (ft)} \times \text{depth (ft)}}{5.6} \quad (\text{Eq. 17-1})$$

In the case of earthen pits, the slopes at the ends and sides of the pit must be taken into consideration.

Figure 17-1 illustrates the method of measuring an earthen pit. The effective length "L" includes a measurement of one sloped end. For all practical purposes, the end not measured is balanced by the remaining tapered sections. If the sides also slope, this same type of measurement should be used to determine width.

Working mud pits and tanks are hardly ever clean; the rule is that cuttings and sand have settled to cover the bottom irregularly. It is therefore necessary for the depth of the mud in a pit or tank to be taken from

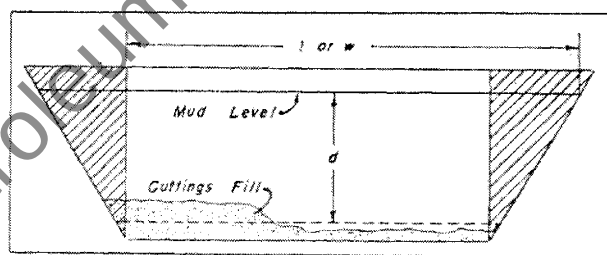


Figure 17-1

Method of Measuring an Earthen Pit

soundings made with a timber, shovel, or similar instrument. Several soundings must be made and an average depth determined.

Capacity of Hole. The most frequently used formula for determining the volume of mud in the hole is:

Volume in bbl per

$$1,000 \text{ ft of hole} = (\text{diameter in inches})^2 \quad (\text{Eq. 17-2})$$

thus, if a hole is made up of 10 3/4-in surface pipe and 9 7/8-in drilled hole, the squaring of the approximate diameter of 10-in (10 x 10) gives, as a close approximation of the actual volume, 100 bbl/1,000 ft of hole. If the diameter includes a fraction of an inch, the interpolation between the squares of the nearest whole numbers is readily made. The volume occupied by the steel in the drill pipe is generally disregarded and the foregoing simple multiplication is all that is used to give "bbl mud in hole."

It is well known that open hole is rarely of bit size; that salt, shales, and similar formations are generally overgauge, while sands and hard limes may be close to bit size in diameter. This fact is generally disregarded in mud calculations, and the approximate volume indicated by the bit size is used. Some engineers, however, add 50 percent of the volume of open hole to allow for overgauge places, but this practice is generally frowned upon.

Because of the uncertainty as to the exact volume of the open hole, volume calculations in mud work are rarely carried out exactly. This is not carelessness, and the experience of years teaches that these practical and reasonable approximations are proper. For those occasions, however, when close figures are desired, Tables 17-1 and 17-2 are included; also, these tables are necessary for the calculation of annular velocities.

PUMP OUTPUT AND THE MUD CYCLE

In mud conditioning, it is frequently important to know the time required for the mud to make a cycle from the pump suction to the bottom of the hole and back. When adding weight material or chemicals it is almost always desirable to add these materials at such a rate that the mud will make at least one complete cycle during the treatment. Two factors are involved in cycling

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