

Drilling Fluids Manual

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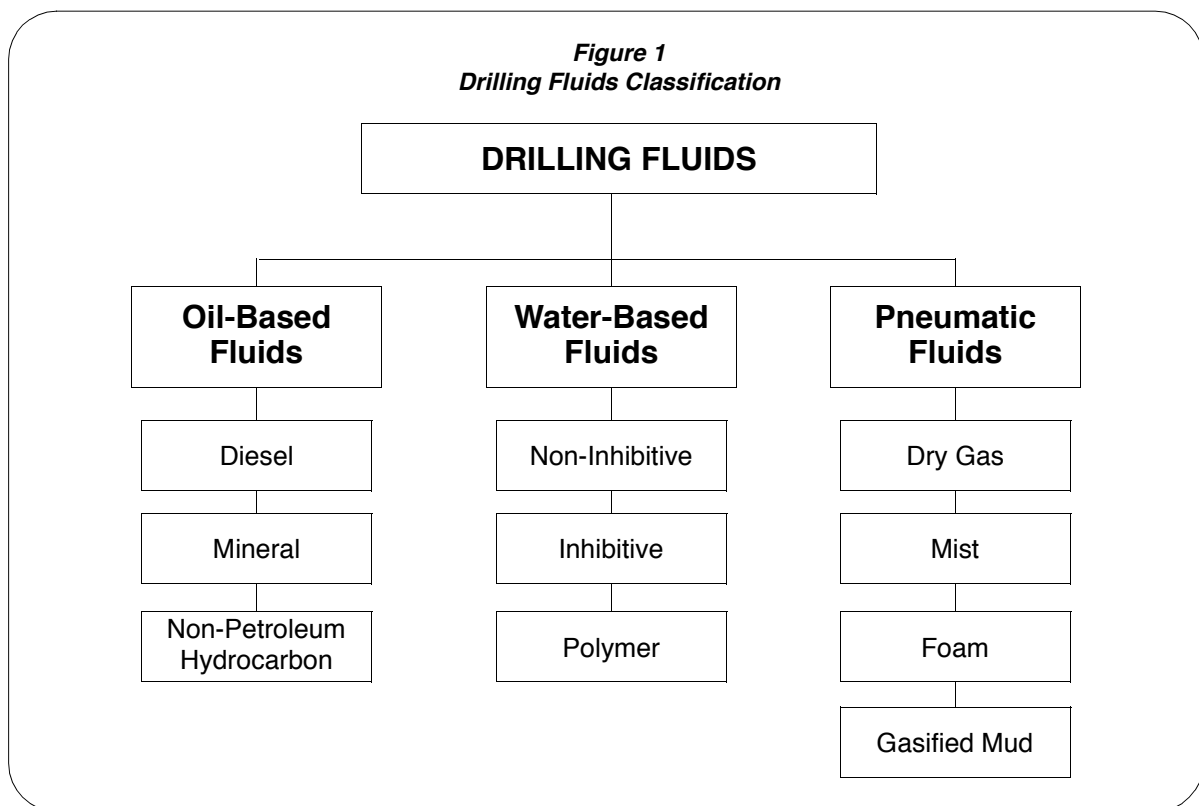
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Section 1 Introduction

Drilling Fluid Classifications

- a. Drilling fluids are separated into three major classifications (Figure 1):
- Pneumatic
 - Oil-Based
 - Water-Based



Pneumatic Fluids

Pneumatic (air/gas based) fluids are used for drilling depleted zones or areas where abnormally low formation pressures may be encountered. An advantage of pneumatic fluids over liquid mud systems can be seen in increased penetration rates. Cuttings are literally blown off the cutting surface ahead of the bit as a result of the considerable pressure differential. The high pressure differential also allows formation fluids from permeable zones to flow into the wellbore.

Air/gas based fluids are ineffective in areas where large volumes of formation fluids are encountered. A large influx of formation fluids requires converting the pneumatic fluid to a liquid-based system. As a result, the chances of losing circulation or damaging a productive zone are greatly increased. Another

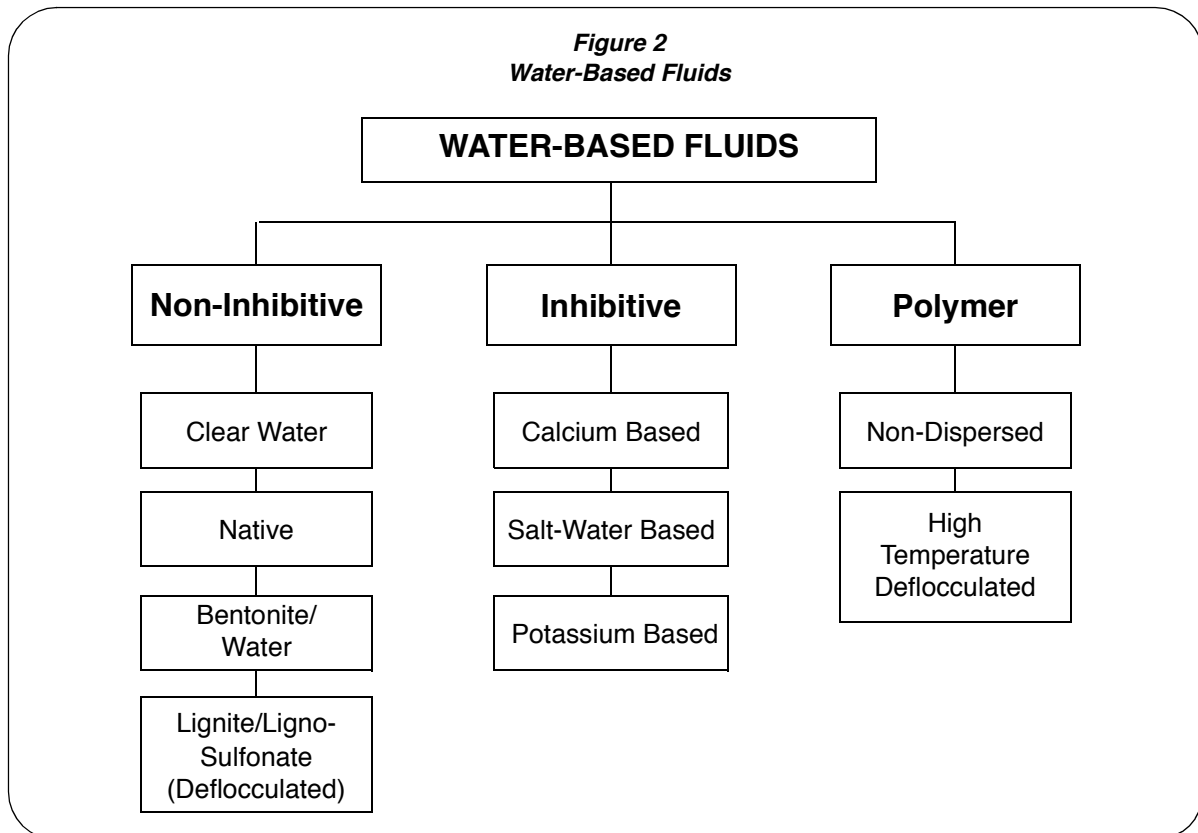
consideration when selecting pneumatic fluids is well depth. They are not recommended for wells below about 10,000 ft because the volume of air required to lift cuttings from the bottom of the hole can become greater than the surface equipment can deliver.

Oil-Based Fluids

A primary use of oil-based fluids is to drill troublesome shales and to improve hole stability. They are also applicable in drilling highly deviated holes because of their high degree of lubricity and ability to prevent hydration of clays. They may also be selected for special applications such as high temperature/high pressure wells, minimizing formation damage, and native-state coring. Another reason for choosing oil-based fluids is that they are resistant to contaminants such as anhydrite, salt, and CO₂ and H₂S acid gases.

Cost is a major concern when selecting oil-based muds. Initially, the cost per barrel of an oil-based mud is very high compared to a conventional water-based mud system. However, because oil muds can be reconditioned and reused, the costs on a multi-well program may be comparable to using water-based fluids. Also, buy-back policies for used oil-based muds can make them an attractive alternative in situations where the use of water-based muds prohibit the successful drilling and/or completion of a well.

Today, with increasing environmental concerns, the use of oil-based muds is either prohibited or severely restricted in many areas. In some areas, drilling with oil-based fluids requires mud and cuttings to be contained and hauled to an approved disposal site. The costs of containment, hauling, and disposal can greatly increase the cost of using oil-based fluids.



Water-Based Fluids

Water based fluids are the most extensively used drilling fluids. They are generally easy to build, inexpensive to maintain, and can be formulated to overcome most drilling problems. In order to better understand the broad spectrum of water-based fluids, they are divided into three major subclassifications:

- Inhibitive
- Non-inhibitive
- Polymer

Non-Inhibitive Fluids

Those which do not significantly suppress clay swelling, are generally comprised of native clays or commercial bentonites with some caustic soda or lime. They may also contain deflocculants and/or dispersants such as: lignites, lignosulfonates, or phosphates. Non-inhibitive fluids are generally used as spud muds. Native solids are allowed to disperse into the system until rheological properties can no longer be controlled by water dilution.

Inhibitive Fluids

Those which appreciably retard clay swelling and, achieve inhibition through the presence of cations; typically, Sodium (Na^+), Calcium (Ca^{++}) and Potassium (K^+). Generally, K^+ or Ca^{++} , or a combination of the two, provide the greatest inhibition to clay dispersion. These systems are generally used for drilling hydratable clays and sands containing hydratable clays. Because the source of the cation is generally a salt, disposal can become a major portion of the cost of using an inhibitive fluid.

Polymer Fluids

Those which rely on macromolecules, either with or without clay interactions to provide mud properties, and are very diversified in their application. These fluids can be inhibitive or non-inhibitive depending upon whether an inhibitive cation is used. Polymers can be used to viscosify fluids, control filtration properties, deflocculate solids, or encapsulate solids. The thermal stability of polymer systems can range upwards to 400°F. In spite of their diversity, polymer fluids have limitations. Solids are a major threat to successfully running a cost-effective polymer mud system.

Functions of Drilling Fluids

Results of extensive research at both Amoco Production Research, Tulsa, and in the field show that penetration rate and its response to weight on bit and rotary speed is highly dependent on the hydraulic horsepower reaching the formation at the bit. Since the drilling fluid flow rate sets the system pressure losses, and these pressure losses set the hydraulic horsepower across the bit, it can be concluded that the drilling fluid is as important in determining drilling costs as all other "man-controllable" variables combined. Considering these factors, "an optimum drilling fluid is a fluid properly formulated so that the flow rate necessary to clean the hole results in the proper hydraulic horsepower to clean the bit for the weight and rotary speed imposed to give the lowest cost, provided that this combination of variables results in a stable borehole which penetrates the desired target."

A properly designed drilling fluid will enable an operator to reach the desired geologic objective at the lowest overall cost. A fluid should enhance penetration rates, reduce hole problems and minimize formation damage.

Major Functions

Drilling fluids are designed and formulated to perform three major functions:

- Control Subsurface Pressure
- Transport Cuttings
- Support and Stabilize the Wellbore

Control Subsurface Pressure

A drilling fluid controls the subsurface pressure by its hydrostatic pressure. Hydrostatic pressure is the force exerted by a fluid column and depends on the mud density and true vertical depth (TVD).

Borehole instability is a natural function of the unequal mechanical stresses and physico-chemical interactions and pressures created when support in material and surfaces are exposed in the process of drilling a well. The drilling fluid must overcome both the tendency for the hole to collapse from mechanical failure and/or from chemical interaction of the formation with the drilling fluid. The Earth's pressure gradient is 0.465 psi/ft. This is equivalent to the height of a column of fluid with a density of 8.94 ppg, which is approximately the density of seawater.

In most drilling areas, a fresh water fluid which includes the solids incorporated into the water from drilling subsurface formations is sufficient to balance formation pressures. However, abnormally pressured formations may be encountered requiring higher density drilling fluids to control the formation pressures. Failure to control downhole pressures may result in an influx of formation fluids, resulting in a kick, or blowout.

$$P_h = (k)(MW)(d)$$

P_h = Hydrostatic Pressure

k = Conversion Constant

MW = Mud Density

d = Depth TVD

$k = .052$ when $d = \text{Feet}$,

MW = lb/gal, $P_h = \text{Psi}$

$k = .00695$ when $d = \text{Feet}$,

MW = lb/ft³, $P_h = \text{Psi}$

$k = .098$ when $d = \text{Meters}$,

MW = g/cm³, $P_h = \text{Atmosphere}$

The 0.052 conversion factor is derived in the following manner:

$$\left(\frac{\text{Water Density, lb}}{\text{ft}^3}\right)\left(\frac{1 \text{ ft}^2}{\text{Area, in.}^2}\right)\left(\frac{1 \text{ gal}}{\text{Water Density, lb}}\right) = \frac{\text{Conversion}}{\text{Factor}}$$
$$\left(\frac{62.30 \text{ lb}}{\text{ft}^3}\right)\left(\frac{1 \text{ ft}^2}{144 \text{ in.}^2}\right)\left(\frac{1 \text{ gal}}{8.33 \text{ lb}}\right) = \frac{0.0519 \text{ gal}}{\text{ft in.}^2}$$

Note: 62.30 lb is the weight of 1 ft³ of water at 60°F and 8.33 lb is the weight of 1 gal of water at 60°F.

Transport Cuttings

Fluid flowing from the bit nozzles exerts a jetting action to clear cuttings from the bottom of the hole and the bit, and carries these cuttings to the surface. Several factors influence cuttings transport.

If the cuttings generated at the bit face are not immediately removed and started toward the surface, they will be ground very fine, stick to the bit and in general retard effective penetration into uncut rock.

Velocity - Increasing annular velocity generally improves cuttings transport. Variables include pump output, borehole size and drill string size.

Density - Increasing mud density increases the carrying capacity through the buoyant effect on cuttings.

Viscosity - Increasing viscosity often improves cuttings removal.

Pipe Rotation - Rotation tends to throw cuttings into areas of high fluid velocity from low velocity areas next to the borehole wall and drill string.

Hole Angle - Increasing hole angle generally makes cuttings transport more difficult.

Drilling fluids must have the capacity to suspend weight materials and drilled solids during connections, bit trips, and logging runs, or they will settle to the low side or bottom of the hole. Failure to suspend weight materials can result in a reduction in the drilling fluid density, which in turn can lead to kicks and a potential blowout.

The drilling fluid must also be capable to transporting cuttings out of the hole at a reasonable velocity that minimizes their disintegration and incorporation as drilled solids into the drilling fluid system. At the surface, the drilling fluid must release the cuttings for efficient removal. Failure to adequately clean the hole or suspend drilled solids are contributing factors in such hole problems as fill on bottom after a trip, hole pack-off, lost returns, differentially stuck pipe, and inability to reach bottom with logging tools.

Support and Stabilize Wellbore

Fluid hydrostatic pressure acts as a confining force on the wellbore. This confining force acting across a filter cake will assist in physically stabilizing a formation.

Borehole stability is also maintained or enhanced by controlling the loss of filtrate to permeable formations and by careful control of the chemical composition of the drilling fluid.

Most permeable formations have pore space openings too small to allow the passage of whole mud into the formation; however, filtrate from the drilling fluid can enter the pore spaces. The rate at which the filtrate enters the formation is dependent on the pressure differential between the formation and the column of drilling fluid, and the quality of the filter cake deposited on the formation face.

Large volumes of drilling fluid filtrate, and filtrates that are incompatible with the formation or formation fluids, may destabilize the formation through hydration of shale and/or chemical interactions between components of the drilling fluid and the wellbore.

Drilling fluids which produce low quality or thick filter cakes may also cause tight hole conditions including stuck pipe, difficulty in running casing and poor cement jobs.

Filter Cake - A layer of concentrated solids from the drilling mud which forms on the walls of the borehole opposite permeable formations.

Filtrate - The liquid portion of the mud which passes through the filter cake into the formation.

Minor Functions

Minor functions of a drilling fluid include:

- Support Weight of Tubulars
- Cool and Lubricate the Bit and Drill String
- Transmit Hydraulic Horsepower to Bit
- Provide Medium for Wireline Logging
- Assist in the Gathering of Subsurface Geological Data and Formation Evaluation
- Cool and Lubricate the Bit

Support Weight of Tubulars

Drilling fluid buoyancy supports part of the weight of the drill string or casing. The buoyancy factor is used to relate the density of the mud displaced to the density of the material in the tubulars; therefore, any increase in mud density results in an increase in buoyancy. The equation below gives the buoyancy factor for steel.

$$\text{Buoyancy Factor} = \frac{65.4 - (\text{MW, lb/gal})}{65.4}$$

Multiply the buoyancy factor by the tubular's air weight to obtain the buoyed weight (hook load). For example, a drillstring with an air weight of 250,000 lb will show a hook load of 218,000 lb in an 8.33 lb/gal fluid and 192,700 lb in a 15.0 lb/gal fluid.

Cool and Lubricate the Bit and Drill String

Considerable heat and friction is generated at the bit and between the drill string and wellbore during drilling operations. Contact between the drill string and wellbore can also create considerable torque during rotation, and drag during trips. Circulating drilling fluid transports heat away from these frictional sites, reducing the chance of pre-mature bit failure and pipe damage. The drilling fluid also lubricates the bit tooth penetration through the bottom hole debris into the rock and serves as a lubricant between the wellbore and drill string thus reducing torque and drag.

Transmit Hydraulic Horsepower to Bit

Hydraulic horsepower generated at the bit is the result of flow volume and pressure drop through the bit nozzles. This energy is converted into mechanical energy which removes cuttings from the bottom of the hole and improves the rate of penetration.

Provide Medium for Wireline Logging

Air/gas-based, water-based, and oil-based fluids have differing physical characteristics which influence log suite selection. Log response may be enhanced through selection of specific fluids and conversely, use of a given fluid may eliminate a log from use. Drilling fluids must be evaluated to assure compatibility with the logging program.

Assist in the Gathering of Subsurface Geological Data and Formation Evaluation

The gathering and interpretation of surface geological data from drilled cuttings, cores and electrical logs is used to determine the commercial value of the zones penetrated. Invasion of these zones by the fluid or its filtrate, be it oil or water, may mask or interfere with the interpretation of the data retrieved and/or prevent full commercial recovery of hydrocarbon.

Since the objective in drilling is to make and keep a borehole which can be evaluated for the presence of commercially-producible fluids, functions four and five should be given priority in designing a drilling fluid and controlling its properties. The conditions imposed by these functions will determine the type of drilling fluid system to be used in each hole section and the products needed to maintain it. After the drilling fluid has been selected, the properties required to accomplish the first three functions can then be estimated by hydraulic optimization procedures.

While drilling, a considerable amount of heat is generated at the bit and along the drillstring due to friction. An additional source of heat is derived from the increasing thermal energy stored in formations with depth. The circulating fluid not only serves as a lubricant helping to reduce the friction between the drilling components in contact with the formation, but also helps conduct heat away from the friction points and formation.

Additional Benefits

In addition to the essential functions of a drilling fluid, there are other benefits to be gained from proper selection and control, such as to:

- Minimize Formation Damage
- Reduce Corrosion
- Minimize Lost Circulation
- Reduce Stuck Pipe
- Reduce Pressure Losses
- Improve Penetration Rates
- Reduce Environmental Impact
- Improve Safety

Minimize Formation Damage

A producing formation can be damaged by a poor drilling fluid. Damage mechanisms include formation fines migration, solids invasion, and wettability alterations. Identification of potential damage mechanisms and careful selection of a drilling fluid can minimize damage.

Reduce Corrosion

Corrosion control can reduce drill string failure through removal or neutralization of contaminating substances. Specific corrosion control products may be added to a drilling fluid; or the drilling fluid itself may be selected on the basis of its inherent corrosion protection (see *Figure 3*).

Minimize Lost Circulation

Extensive loss of whole mud to a cavernous, vugular, fissured, or coarsely permeable formation is expensive and may lead to a blowout, stuck pipe, or formation damage. Selection of a low density drilling fluid and/or addition of sized bridging agents can reduce lost circulation (see *Figure 4*).

Reduce Stuck Pipe

Pipe sticking can be caused by several factors:

- Poor Cuttings Removal
- Hole Sloughing
- Lost Circulation
- Differential Pressure Sticking
- Keyseating

Two common types of pipe sticking are illustrated in *Figures 5 and 6*.

Reduce Pressure Losses

Surface equipment pressure demands can be reduced by designing a fluid to minimize pressure losses. The reduction in pressure losses also permits greater hydraulic efficiency at the bit and a lower equivalent circulating density (ECD) (see *Figure 7*).

Improve Penetration Rates

Proper fluid selection and control can improve the rate of penetration (ROP). Benefits of improved penetration rates are reduced drilling time and fewer hole problems because of shorter open-hole exposure time. Generally, improved penetration rates result in reduced costs. Operations such as cementing, completion, and logging must be factored in to determine true cost effectiveness of improved penetration rates.

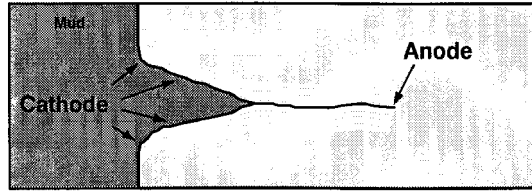
Reduce Environmental Impact

Fluid selection and engineering can reduce the potential environmental impact of a drilling fluid. In the event of a spill, reclamation and disposal costs, as well as pollution associated problems are greatly reduced by proper fluid selection and control.

Improve Safety

A drilling fluid should be engineered for safety. It should have sufficient density to control the flow of formation fluids and when circumstances merit, be able to tolerate toxic contaminants such as hydrogen sulfide (H₂S).

Figure 3
Electrochemical Corrosion Cell
(Development in a Fatigue Stress Crack)



**Electrochemical
Corrosion
Cell**

**Oxygen
Corrosion
Cell**

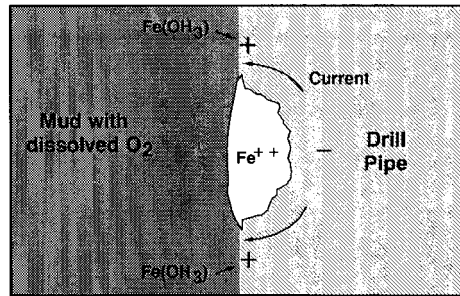


Figure 4
Types of Lost Circulation Zones
Found in Soft and Hard Rock Formations

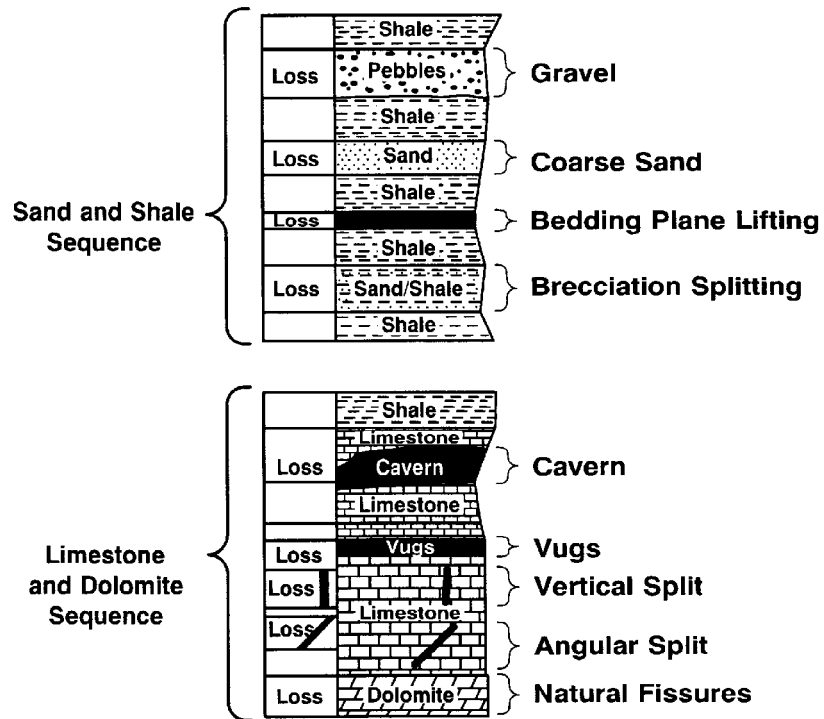


Figure 5
Differential Pressure Sticking

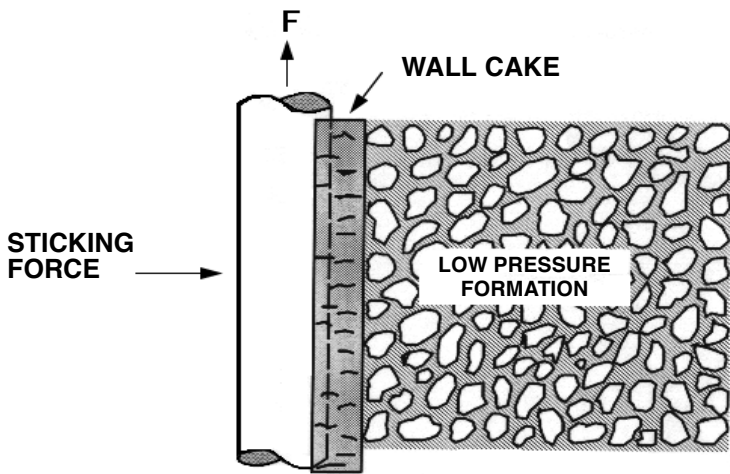
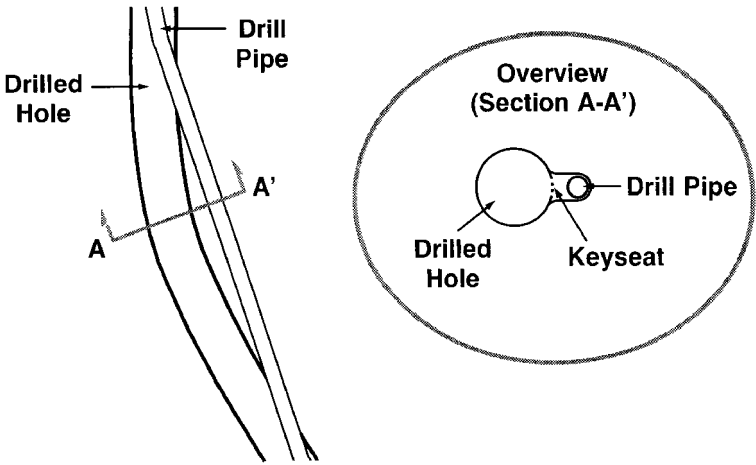


Figure 6
Keyseating



Dog-Leg Resulting in the Formation of a Keyseat

Drilling Fluids Selection Criteria

Drilling fluids are selected on the basis of one or more of the following criteria:

- Cost
- Application and Performance
- Production Concerns
- Logistics
- Exploration Concerns
- Environmental Impact and Safety

Cost

A traditional focus for drilling fluids selection is cost. However, there are other equally important factors such as total well cost and the fluid's effect on well productivity.

Application and Performance

Drilling fluid systems should be selected to provide the best overall performance for each specific well. Historical data should be reviewed and pilot testing performed to assure the greatest hole stability and lowest total well cost are achievable.

Production Concerns

Production personnel are primarily concerned with minimizing formation damage. Drilling fluid/formation interactions and other processes which alter in situ formation characteristics must be considered in the selection of additives and fluid systems. Production zones can be partially or totally lost depending upon fluids selected to drill and/or complete a well (*see Figure 8*).

Logistics

Logistics is a major consideration in well planning and mud program development when operating in remote areas. Product efficiency, shelf life, packing, transportation costs, warehousing, and inventory volumes should also be considered.

Exploration Concerns

The geologist's concern with drilling fluids and additives is centered on the effect of the drilling fluid on cuttings analysis and log interpretation. Extended gas chromatography and pyrolysis provide geological personnel with distinct fingerprints of hydrocarbons present and a means of isolating and identifying source rocks and oil migration paths. Unfortunately, trace amounts of drilling fluid may remain on the residue extracted from the cuttings and exert a masking effect that makes it difficult to accurately characterize (fingerprint) the formation hydrocarbons. Therefore, characterizing and cataloging drilling fluid additives and fluid systems can greatly enhance the geologist's interpretation of reservoir potential.

Environmental Impact and Safety

Minimizing the environmental impact of a drilling operation as well as safety considerations both directly affect the choice of drilling fluid additives and drilling fluid systems. Products that have been used in the past may no longer be acceptable. As more environmental laws are enacted and new safety rules applied, the choices of additives and fluid systems must also be reevaluated. To meet the challenge of a changing environment, product knowledge and product testing become essential tools for selecting suitable additives and drilling fluid systems.

Figure 7
Pressure Losses in a Circulating Mud System

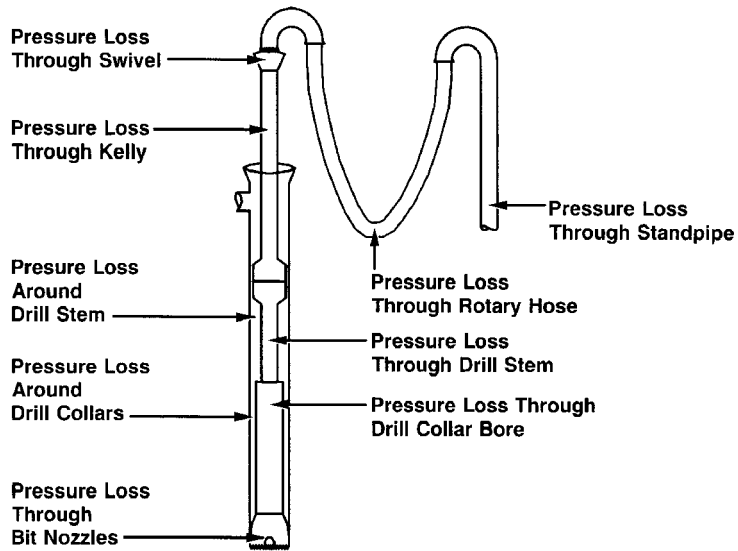


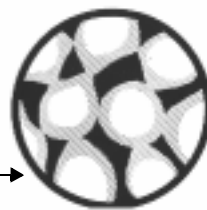
Figure 8
Types of Formation Damage

Formation clays around sand grains in equilibrium with water (maximum permeability).

Formation clays swollen and dislodged by low salinity filtrate. Blocking of pore throats causes loss of permeability.



← Undamaged



Fines Migration →

Oil flow restricted by water block (oil wet sandstone).

Oil flow restricted by waterblock (wet water sandstone).



← Wettability Alteration



Section 2 Engineering

Basic Engineering Calculations

This section discusses basic engineering calculations pertaining to: Specific Gravity; Volume, Capacity and Displacement; Annular Velocity; Circulation Time; Downhole Pressures; Weight-Up and Dilution; and Concentration Units. These are essential calculations that the drilling personnel will need in routine work in the office or at the rig. An understanding of these principles will be beneficial throughout use of this manual.

Specific Gravity

The density of any material is derived by multiplying the specific gravity of that material by the density of pure water. For example, the specific gravity of barite is 4.2 and its density is equal to $(4.2)(8.33 \text{ lb/gal}) = 35 \text{ lb/gal}$. Conversely, to convert from density to specific gravity, divide the density of a material or mud by the density of pure water. As an example, a 17.5 lb/gal mud has a specific gravity of 2.1.

$$\left(\frac{17.5 \text{ lb/gal}}{8.33 \text{ lb/gal}}\right) = 2.1 \text{ SG}$$

To determine the weight of 1 bbl of barite, determine the density of 1 bbl of pure water and multiply the result by the specific gravity of barite.

$$(8.33 \text{ lb/gal water}) (42 \text{ gal/bbl}) = 349.86 \text{ lb/bbl}$$

(weight of 1 bbl of pure water)

$$(349.86 \text{ lb/bbl}) (4.2 \text{ SG Barite}) = 1469.41 \text{ lb/bbl}$$

(weight of 1 bbl of 4.2 SG Barite)

Volume, Capacity and Displacement

Capacity and Volume have the same units, but are not always equal. As an example, a mud pit may have a capacity of 300 bbl, but only contain a volume of 175 bbl of water. Displacement is the volume of fluid displaced when tubulars are put into a wellbore full of fluid.

Nomenclature

Volume	Vol	Open Hole	OH
Barrel(s)	bbl	Gallon	gal
Length	L	Pump Output	Q
Width	W	Strokes per Minute	SPM
Depth	d	Stroke	STK
pi (3.14159265)	π	Stroke Length	L _{STK}
Height	h	Pump Efficiency	E
Radius	R	Pump Liner Inside Diameter	ID _{LINER}
Diameter	D	Pump Rod Diameter	OD _{ROD}
(inside)	ID		
(outside)	OD		

Volume

1. **Mud System Volume** - The total mud system volume may be calculated with the drill string either in or out of the hole.

$$\text{Total Mud Volume} = \text{Pit Volume} + \text{Hole Volume}$$

2. **Pump Output Volume** - Pump output tables must be adjusted for estimated or measured pump efficiencies. Triplex pumps usually have an efficiency between 90-98%. Double action duplex pumps usually have an efficiency between 85-95%.

The following two equations calculate pump output at 100% volumetric efficiency. The constant, K, may be changed to obtain units of bbl/STK, gal/STK, or Liter/STK.

- a. $Q_{\text{Duplex}} = [2(\text{ID}_{\text{LINER}})^2 - (\text{OD}_{\text{ROD}})^2](\text{L}_{\text{STK}})$

- b. $Q_{\text{Triplex}} = \frac{(\text{ID}_{\text{LINER}})^2(\text{L}_{\text{STK}})}{K}$

Pump Constant, K

Pump Type	BBL/STK	GAL/STK	Liter/STK
Duplex Pump	6174.00	147.00	38.82
Triplex Pump	4117.67	98.04	25.90

See Appendix, for Pump displacement tables.

3. **Mud Pit Volume** - The same capacity equations shown in *Dilution of Water-Based Muds* hold true for volume. Depth will be the actual depth of mud in the mud pits.

Capacity (Mud Pits)

1. Rectangular Mud Pits

$$\text{Mud Pit}_{\text{cap, bbl}} = \frac{(L)(W)(h)}{5.6146 \text{ ft}^3/\text{bbl}}$$

L = Length, ft

W = Width, ft

h = Height, ft

2. Sloping Sided Mud Pits

$$\text{Mud Pit}_{\text{cap, bbl}} = \frac{(L)(W_{\text{avg}})(d)}{5.6146 \text{ ft}^3/\text{bbl}}$$

W_{avg} = Average width

3. Horizontal Cylindrical Mud Pit

$$\text{Mud Pit}_{\text{cap, bbl}} = \left[\left(\frac{R^2 \arccos\left(\frac{R-h}{R}\right)}{57.296} \right) - ((R-h)\sqrt{2Rh-h^2}) \right] \left(\frac{L}{5.6146} \right)$$

Note: Calculator must be set for degrees for above equation. If you wish to use radians on the calculator, simply remove (57.296) from the above equation.

4. Upright Cylindrical Mud Pits

$$\text{Mud Pit}_{\text{cap, bbl}} = \frac{(\pi)(R)^2(h)}{5.6146 \text{ ft}^3/\text{bbl}}$$

Capacity and Displacement (Drill String and Hole)

Nomenclature

Outside diameter, in.	OD
Inside diameter, in.	ID
Hole diameter, in.	D_h
Annular outer pipe diameter, in.	D
Annular inner pipe diameter, in.	d
Closed-ended pipe	CE
Open-ended pipe	OE

- Capacity** - Capacity, as related to drill pipe, drill collars and other tubulars is the volume of fluid the pipe can contain. The internal pipe diameter, ID, (inches) is used in the equation shown below.

$$\text{Capacity, bbl/ft} = \frac{(\text{ID})^2}{1029.4}$$

Capacity of a wellbore, either cased or open hole, is the volume of fluid the hole can contain. The hole diameter, D_h , or casing ID are used in the equation above.

2. Displacement

- a. **Open-End Pipe** - Displacement, as related to drill pipe, drill collars and tubulars is the volume of fluid that the pipe will displace if placed into fluid open ended to allow it to fill inside. The displacement volume equals the volume of metal in the pipe. The pipe's outside diameter, OD, and inside diameter, ID, are used in the equation below.

$$\text{Displacement/OE, bbl/ft} = \left[\frac{(\text{OD})^2 - (\text{ID})^2}{1029.4} \right]$$

3. **Closed-End Pipe** - Displacement, as related to drill pipe, drill collars and tubulars is the volume of fluid that the pipe will displace if placed into fluid with the lower end closed to allow no fluid inside. The pipe's outside diameter, OD, is used in the equation below.

$$\text{Displacement/CE, bbl/ft} = \frac{[(\text{OD})^2]}{1029.4}$$

Annulus Capacity and Multiple-Pipe Annulus Capacity

1. **Annulus Capacity** - Annulus capacity, (Ann_{cap}) is the volume contained between two cylinders - one inside the other, such as casing with drill pipe inside. The casing ID, drill pipe OD are used in the calculation.

$$\text{Annulus capacity, bbl/ft} = \frac{[(\text{ID})^2 - (\text{OD})^2]}{1029.4}$$

Annulus capacity of pipe or casing in an open hole of diameter, D_h , is calculated using D_h (instead of ID) and OD of the pipe or casing using the equation above.

2. **Multiple-Pipe Annulus Capacity** - An annulus may contain more than one pipe inside a casing or open hole. To calculate the fluid volume in a multiple annulus use the equation below, which assumes all pipes are the same OD (n = number of pipes in annulus.) When interior pipes are of different sizes, the individual ODs must be squared and summed and the sum subtracted from the ID² value in the numerator of equation below.

$$\text{Multiple annulus capacity, bbl/ft} = \frac{[(\text{ID})^2 - n(\text{OD})^2]}{1029.4}$$

For an open hole with multiple pipes, annulus capacity is calculated based on hole diameter, D_h in equation above, substituting D_h for ID.

Conversion to Other Units

Below are equations that allow annulus capacity and displacement volume calculations to be made in other useful units. In these equations, "D" represents the larger diameter and "d" represents the smaller diameter.

$$\begin{aligned} \text{gal/ft} &= (D^2 - d^2)(0.0408) \\ \text{ft/gal} &= \frac{24.51}{(D^2 - d^2)} \\ \text{bbl/ft} &= (D^2 - d^2)(0.0009714) \\ \text{ft/bbl} &= \frac{1029.4}{(D^2 - d^2)} \\ \text{ft}^3/\text{ft} &= (D^2 - d^2)(0.005454) \\ \text{ft}/\text{ft}^3 &= \frac{183.35}{(D^2 - d^2)} \end{aligned}$$

Note: For multiple-pipe annulus volumes substitute the value $n(d^2)$ for d^2 in equations above when pipes are all same diameter. If not all same diameter, the OD of each pipe must be squared, summed and the sum subtracted from the value of ID^2 in the numerator of the appropriate equation above.

Tabulated Capacity and Displacement Data

Tabulated values for capacity and displacements of various sizes, weights and tool-joint tubular goods is found in the *Appendix* of this Manual.

Annular Velocity

Annular velocity depends on pump output, hole size and pipe OD.

Nomenclature

Annulus Capacity	Ann_{cap}
Annular Velocity	AV
Pump Output	Q

$$AV, \text{ ft/min} = \frac{Q, \text{ bbl/min}}{Ann_{cap}, \text{ bbl/ft}}$$

Mud Circulation Time

Various circulating times are used to calculate treatment schedules, well control operations, drill cuttings lag, etc. The following equations give the more common circulating times.

Nomenclature

Annulus Capacity	Ann_{cap}
Drill String Capacity	DS_{cap}
Pump Output	Q

$$\text{Surface to Bit, min} = \frac{DS_{\text{cap}}, \text{ bbl}}{Q, \text{ bbl/min}}$$

$$\text{Bit to Surface, min} = \frac{\text{Ann}_{\text{cap}}, \text{ bbl}}{Q, \text{ bbl/min}}$$

$$\text{Total Hole Circulation, min} = \frac{DS_{\text{cap}} + \text{Total Ann}_{\text{cap}}}{Q, \text{ bbl/min}}$$

$$\text{Total Circulation System, min} = \frac{\text{Hole Volume, bbl} + \text{Pit Volume, bbl}}{Q, \text{ bbl/min}}$$

Pressures

The following are the commonly used pressure calculations in drilling operations.

Nomenclature

Pounds per Square Inch	psi
True Vertical Depth, ft	TVD
Hydrostatic Pressure, psi	P_h
Equivalent Circulating Density, lb/gal	ECD
Mud Density, lb/gal	MW
Annular Pressure Loss, psi	P_{APL}

Hydrostatic Pressure

Hydrostatic pressure is the pressure exerted by a column of fluid and is a function of fluid density and true vertical depth (not measured depth).

$$\text{Hydrostatic Pressure, psi} = (\text{MW})(\text{TVD})(0.052)$$

Pressure Gradient

The pressure gradient is the pressure change with depth, commonly expressed in psi/ft.

$$\text{Pressure Gradient, psi/ft} = (\text{MW})(0.052)$$

Annular Pressure Loss

The annular pressure loss is the total pressure loss resulting from the frictional forces developed by circulation of the mud in the wellbore annulus over a given length (measured depth).

Equivalent Circulating Density (ECD)

The equivalent circulating density is a pressure translated into a mud density.

$$\text{ECD @ Total Depth, lb/gal} = \text{MW} + \frac{P_{\text{APL}}}{(\text{TVD})(0.052)}$$

Weight-Up and Dilution

Nomenclature

Initial Mud Density, lb/gal	MW _I
Final Mud Density, lb/gal	MW _F
Initial Volume	V _I
Final Volume	V _F
Specific Gravity Weight Material	SG _{WM}
Specific Gravity Oil	SG _O
Specific Gravity Water	SG _W

Weight-Up

1. **Volume Increase** - The general mud weight increase formula is used for any weight material where SG_{WM} is the specific gravity of the weight material and MW_I and MW_F are the initial and final mud densities in pounds per gallon.

$$\text{Volume Increase, bbl} = \frac{\text{total pounds weight material}}{(350)(SG_{WM})}$$

For barite, this becomes:

$$\text{Volume Increase, bbl} = \frac{\text{total pounds barite}}{1470}$$

2. **No Volume Increase** - To determine the initial volume of mud, V_I, to start with to attain a final volume V_F, the starting volume is defined by:

$$V_I = \frac{V_F[(8.33)(SG_{WM}) - MW_F]}{[(8.33)(SG_{WM})] - MW_I}$$

For barite, this becomes:

$$V_I = \frac{V_F(350 - MW_F)}{(350 - MW_I)}$$

To calculate the pounds per barrel of weight material required per final barrel of mud:

$$\text{Weight Material, lb/bbl} = \frac{[(350)(SG_{WM})](MW_F - MW_I)}{[(8.33)(SG_{WM})] - (MW_I)}$$

For barite, SG_{WM} = 4.20, the equation becomes:

$$\frac{1470(MW_F - MW_I)}{35.0 - MW_I}$$

Density Reduction

3. Water Addition

$$\text{Volume of dilution water, bbl}(V) = \frac{V_1(MW_I - MW_F)}{[MW_F - (SG_W \times 8.33)]}$$

V = volume of mud to be reduced

Note: For pure water, $SG_W = 1$. If the specific gravity of the dilution water is unknown, density may be measured and substituted for $(SG_W \times 8.33)$ in the equation.

4. Oil Addition

$$\text{Volume of dilution oil, bbl} = \frac{V_1(MW_I - MW_F)}{[MW_F - (SG_O \times 8.33)]}$$

Note: The specific gravity of diesel (SG_O) is approximately 0.84. If the specific gravity of the oil is unknown, density may be measured and substituted for $(SG_O \times 8.33)$ in the equation.

Concentrations - Weight Percent and Volume Percent

The concentrations of components in mixtures or solutions can be expressed as: Weight Percent or Volume Percent.

Percentages of components in a mud can be calculated if the mud density and the specific gravity of the components are known for a two-part system. An average specific gravity of solids must be assumed for calculating percent solids in a mud. The following are general equations for volume percent and weight percent.

Nomenclature

Volume Percent	V%
Weight Percent	W%
Specific Gravity Solids	SG_S
Specific Gravity Water	SG_W
Mud Density, lb/gal	MW

Volume Percent Solids

$$\text{Volume \% Solids} = \frac{12[(MW) - (8.33)(SG_W)]}{(SG_S - SG_W)}$$

Weight Percent Solids

$$\text{Weight \% Solids} = \frac{(8.33)(SG_S)(V\%)}{MW}$$

EXAMPLE - Find the volume % and weight % of the solids given the following information:

Given: Mud Density, lb/gal 10.4
 Specific Gravity Seawater 1.04
 Average Specific Gravity Solids 2.6

$$\text{Volume \%} = \frac{12[(10.4) - (8.33)(1.04)]}{(2.6 - 1.04)} = 13.36$$

$$\text{Weight \%} = \frac{(8.33)(2.6)(13.36)}{10.4} = 27.82$$

Parts Per Million and Milligrams Per Liter

Milligrams Per Liter is a weight per volume measurement. On the other hand, *Parts Per Million* refers to a weight per specified weight measurement or a volume-per-volume measurement. Basically ppm is a ratio. It is very important to understand the difference between the two units. The following equations will contrast the difference in the two measurements.

Nomenclature

Water	SG _W
Parts per Million	ppm
Milligrams per Liter	mg/L

$$\text{ppm} = \frac{\text{mg/L}}{\text{SG}_W}$$

$$\text{or } \text{mg/L} = \text{ppm} \times \text{SG}_W$$

$$\text{SG}_W = 1 + [(1.94 \times 10^{-6}) (\text{Cl}^-)^{0.95}]$$

$$\text{Where Cl}^-, \text{ (chlorides)} = \text{mg/L}$$

EXAMPLE - How many parts per million of sodium chloride are in 1 cm³ of filtrate that contains 140,000 mg/L chlorides?

$$\text{SG}_W = 1 + [(1.94 \times 10^{-6}) (140,000)^{0.95}] = 1.1502$$

$$\text{Chlorides, ppm} = 140,000 = 121,718$$

$$= 1.1502$$

$$\text{NaCl, ppm} = (121,718) (1.65) = 200,835$$

Material Balance

Material balance concepts are useful to the mud engineer for solving many field problems that can be represented as simple mathematical relationships. Applications for the material balance method are:

- Weight-Up
- Dilution
- Mixing Two Fluids
- System Building
- Solids Analysis

Many of the formulas commonly used in the oil field were derived from material balance equations. Maintaining consistent units is the key to setting up and solving material balance equations. The general material balance equation is written as follows:

$$V_1 D_1 + V_2 D_2 + V_3 D_3 + \text{etc.} = V_F D_F$$

The following examples show how the material balance method is used for solving different types of problems.

Nomenclature

Mud Density, lb/gal	MW
Initial	MW _I
Final	MW _F
Density of Weight Material, lb/gal	D _{WM}
Density of Water, lb/gal	D _W
Specific Gravity of Weight Material	SG _{WM}
Average Specific Gravity Solids	SG _{AVG}
Sack	SX
Volume	V
Oil	V _O
Water	V _W
Solids	V _S
Weight Material	V _{WM}
Low Gravity Solids	V _{LGS}
Drill Solids	V _{DS}
High Gravity Solids	V _{HGS}
Mud System, bbl	V _{MS}
Initial Volume, bbl	V _I
Final Volume, bbl	V _F

Weight-Up of Water-Based Muds

No Volume Increase

Given:

	(V _I MW _I) <u>Old Fluid</u>	(V _{WM} D _{WM}) <u>Weight Mat'l</u>	(V _F MW _F) <u>New Fluid</u>
System Volume, bbl	500	X	500
System Density, lb/gal	9.5	35.0	10.0

The material balance approach means that to increase the density of 500 bbl of a 9.5 lb/gal fluid to 10.0 lb/gal, without increasing the total volume of fluid, the problem can be represented as follows:

$$\text{Old Fluid} + \text{Weight Material} = \text{New Fluid}$$

Or

$$V_I MW_I + V_{WM} D_{WM} = V_F MW_F$$

Each of these materials will be represented in terms of the product density and volume. Since it is not known how much barite (weight material) is needed, the volume of barite is represented by (x). The volume of 9.5 lb/gal fluid is represented by (500 - x). The new fluid is 10.0 lb/gal, and the final volume is 500 bbls. The starting fluid volume is the 500 bbl initial fluid volume minus the volume of barite which will be added.

$$\begin{array}{rclcl}
 \text{Old Fluid} & + & \text{Barite} & = & \text{New Fluid} \\
 (500 \text{ bbl} - x) (9.5 \text{ lb/gal}) & + & (x) (35.0 \text{ lb/gal}) & = & (500 \text{ bbl}) (10.0 \text{ lb/gal})
 \end{array}$$

Solving the equation for x:

$$\begin{aligned}
 (V_I)(MW_I) + (V_{WM})(D_{WM}) &= (V_F)(M_{WF}) \\
 (500 - x)(9.5) + (x)(35.0) &= (500)(10.0) \\
 4750 - 9.5x + 35.0x &= 5000 \\
 25.5x &= 250 \\
 x &= 9.8 \text{ bbl of barite}
 \end{aligned}$$

Then

$$500 - x = 500 - 9.8 = 490.2 \text{ bbl of mud}$$

Thus, 9.8 bbl of old mud must be jetted and 9.8 bbl of barite added. One barrel of barite equals 1470 pounds. Therefore, 9.8 bbl of barite equals 1470 (9.8) equals 14,406 lb. Add 14,406 lb of barite after jetting 9.8 bbl of mud. The amount of barite required can further be simplified as sacks of barite required to add to the mud system as follows:

$$\frac{14,406 \text{ lb barite}}{(100 \text{ lb/sx})} = 144.065 \text{ sx barite (144 sacks)}$$

Volume Increase

Given:

	$(V_I MW_I)$ <u>Old Fluid</u>	$(V_{WM} D_{WM})$ <u>Weight Mat'l</u>	$(V_F MW_F)$ <u>New Fluid</u>
System Volume, bbl	500	X	--
System Density, lb/gal	9.5	35.0	10.0

Again, using the material balance equation:

$$\text{Old Fluid} + \text{Weight Material} = \text{New Fluid}$$

Or

$$V_I MW_I + V_{WM} D_{WM} = V_F MW_F$$

Substitute the product density and volume for each term in the equation. Since it is not known how much barite will be needed, the volume of barite is represented by (x). The volume of the 10.0 lb/gal

fluid is equal to the **Old Fluid** volume plus the volume of barite added. Thus the **New Fluid** volume equals: $500 + x$.

$$\begin{array}{rccccccc} \text{Old Fluid} & & + & & \text{Barite} & & = & & \text{New Fluid} \\ (500 \text{ bbl}) (9.5 \text{ lb/gal}) & & + & & (x) (35.0 \text{ lb/gal}) & & = & & (500 \text{ bbl} + x) (10.0 \text{ lb/gal}) \end{array}$$

Solving the equation for x:

$$\begin{aligned} (V_I)(MW_I) + (V_{WM})(D_{WM}) &= (V_F)(M_{WF}) \\ (500)(9.5) + (35.0)(x) &= (500 + x)(10.0) \\ 4750 + 35x &= 5000 + 10x \\ 25.5x &= 250 \\ x &= 10 \text{ bbl of barite} \end{aligned}$$

Then

$$500 + x = 500 + 10 = 510 \text{ bbl of new fluid}$$

It is significant to note that by not jetting mud prior to weighting up, 10(1470) or 14,700 lb of barite are needed. This increases the system volume by 10 bbl. When you compare the *No Volume Increase* versus the *Volume Increase* weight up, the differences are:

- Weight-Up / No Volume Increase Requires 14,406 lb barite
- Weight-Up / Volume Increase Requires 14,700 lb barite

This is a difference of 294 lb of barite.

$$\frac{294 \text{ lb}}{100 \text{ lb/sx}} = 3 \text{ extra sacks of barite}$$

Three extra sacks of barite are required to weight up the **Old Fluid** allowing the total volume of fluid to increase by 10 bbl. The decision to weight up either without a volume increase or with a volume increase is based on economics, the type of available surface equipment, and environmental disposal considerations. Another factor to consider is the total amount of drill solids in the **Old Fluid** versus the total amount of drill solids in the **New Fluid**. In some cases, especially in heavily weighted fluids, solids can have a detrimental effect on fluid properties. It is generally better to discard fluid and then weight up the system.

Dilution of Water-Based Muds

Density Reduction/No Volume Increase

Once the material balance equations are mastered, density reduction becomes a simple problem. To reduce density, a lighter fluid must be added to the existing fluid. In these examples, fresh water will be used.

Given:

	(V_I, MW_I) <u>Old Fluid</u>	(V_{WM}, D_{WM}) <u>Weight Mat'l</u>	(V_F, MW_F) <u>New Fluid</u>
System Volume, bbl	500	X	500
System Density, lb/gal	9.5	8.33	9.0

Again, using the material balance equation:

$$\text{Old Fluid} + \text{Dilution Water} = \text{New Fluid}$$

Or

$$(V_I)(MW_I) + (V_W)(D_W) = (V_F)(MW_F)$$

Substitute the product density and volume for each term in the equation. Since it is not known how much water will be needed, the volume of water is represented by (x).

$$\begin{array}{rclcl} \text{Old Fluid} & + & \text{Fresh Water} & = & \text{New Fluid} \\ (500 \text{ bbl} - x)(9.5 \text{ lb/gal}) & + & (x)(8.33 \text{ lb/gal}) & = & (500 \text{ bbl})(9.0 \text{ lb/gal}) \end{array}$$

Solving the equation for x:

$$\begin{aligned} (V_I)(MW_I) + (V_W)(D_W) &= (V_F)(MW_F) \\ (500 - x)(9.5) + (x)(8.33) &= (500)(9.0) \\ 4750 - 9.5x + 8.33x &= 4500 \\ -1.17x &= -250 \\ x &= 214 \text{ bbl of Fresh Water} \end{aligned}$$

Thus, 214 bbl of the **Old Fluid** must be jetted and 214 bbl of **Fresh Water** must be added to have 500 bbl of 9.0 lb/gal fluid.

Density Reduction - Volume Increase

Given:

	(V_I, MW_I) <u>Old Fluid</u>	(V_{WM}, D_{WM}) <u>Weight Mat'l</u>	(V_F, MW_F) <u>New Fluid</u>
Volume, bbl	500	X	--
Density, lb/gal	9.5	8.33	9.0

Using the same material balance approach, write an equation to represent the problem and substitute representative values for the terms.

$$\text{Old Fluid} + \text{Dilution Water} = \text{New Fluid}$$

Or

$$(V_I)(MW_I) + (V_W)(D_W) = (V_F)(MW_F)$$

Substitute the product density and volume for each term in the equation. Since it is not known how much water will be needed, the volume of water is represented by (x). The volume of the 9 lb/gal fluid is equal to the Old Fluid volume plus the volume of water added. Thus, the New Fluid volume equals 500 + x.

$$\text{Old Fluid} + \text{Barite} = \text{New Fluid}$$

$$(500 \text{ bbl})(9.5 \text{ lb/gal}) + (x)(8.33 \text{ lb/gal}) = (500 \text{ bbl} + x)(9.0 \text{ lb/gal})$$

Solving the equation for x:

$$\begin{aligned} (V_I)(MW_I) + (V_W)(D_W) &= (V_F)(MW_F) \\ (500)(9.5) + (x)(8.33) &= (500 + x)(9.0) \\ 4750 + 8.33x &= 4500 + 9.0x \\ -0.67x &= -250 \\ x &= 373 \text{ bbl of water} \end{aligned}$$

The 500 bbl of **Old Fluid**, with a 9.5 lb/gal density will have a volume of 873 bbl when its density is reduced to 9.0 lb/gal with fresh water. This is a volume increase of 373 bbl. For comparison purposes, diluting a system without allowing a volume increase (see *Density Reduction/No Volume Increase*) versus diluting a system and allowing the volume to increase results in a net volume difference of 159 bbl. Once again, availability of water, surface equipment, economics, and environmental considerations (disposal costs) play a major role in deciding to decrease density with or without a volume increase.

$$373 \text{ bbl} - 214 \text{ bbl} = 159 \text{ bbl}$$

Mixing Two Fluids

Mixing two fluids to achieve specific results is another application for material balance concepts. Simple equations can be utilized for calculating desired parameters. The following examples should help to clarify and demonstrate the use of the material balance approach.

Example Calculations

EXAMPLE #1 - A circulating system of 1000 bbl has a density of 12.0 lb/gal. There are 300 bbl of 10.0 lb/gal mud in storage on the rig site. How many barrels of 10.0 lb/gal mud are needed to reduce the fluid density to 11.6 lb/gal?

Given:

	(V _I , MW _I) <u>Old Fluid</u>	(V _S , MW _S) <u>Weight Mat'l</u>	(V _F , MW _F) <u>New Fluid</u>
Volume, bbl	1000	X	--
Density, lb/gal	12.0	10.0	11.6

Where:

$$(V_I)(MW_I) + (V_S)(MW_S) = (V_F)(MW_F)$$

- MW_F = Final Mud Density
- MW_I = Initial Mud Density
- MW_S = Stored Mud Density
- V_S = Volume Stored Mud to Add
- V_F = Final Volume
- V_I = Initial Volume

This problem can be solved by representing everything in terms of material balance. In other words, the total desired weight is equal to that of the combined systems. The equation is set up as follows:

$$\text{Old Fluid} + \text{Stored Fluid} = \text{New Fluid}$$

Or

$$(V_I)(MW_I) + (V_S)(MW_S) = (V_F)(MW_F)$$

Solving the equation for x (where x is volume of 10.0 lb/gal mud to be added):

$$\begin{aligned} (V_I)(MW_I) + (V_S)(MW_S) &= (V_F)(MW_F) \\ (1000)(12.0) + (x)(10.0) &= (1000 + x)(11.6) \\ 12,000 + 10.0x &= 11,600 + 11.6x \\ -1.6x &= -400 \\ x &= 250 \text{ bbl of } 10.0 \text{ lb/gal mud} \end{aligned}$$

EXAMPLE #2 - How much volume of 16.0 lb/gal mud with 0 volume % drill solids ($V_A D_A$) must be added to the old 16.0 lb/gal lb fluid with 8 volume % drill solids to reduce the drill solids in the resulting new 16 lb/gal fluid to 5 volume %?

Given:

	$(V_I, \%SOL_I)$ <u>Old Fluid</u>	$(V_A, \%SOL_A)$ <u>Weight Mat'l</u>	$(V_F, \%SOL_F)$ <u>New Fluid</u>
Volume, bbl	1200	X	--
Density, lb/gal	16.0	16.0	16.0
Drill Solids, %	8	0	5

Where:

$$V_I (\%SOL_I) + V_A (\%SOL_A) = V_F (\%SOL_F)$$

V_A = Volume of mud to add

$\%SOL_A$ = Percent solids in fluid being added

$$\text{Old Fluid} + \text{Mud to Add} = \text{New Fluid}$$

Or

$$V_I (\%SOL_I) + V_A (\%SOL_A) = V_F (\%SOL_F)$$

Solving the equation for x (where x is volume of 16 lb/gal mud to be added):

$$\begin{aligned}(V_I)(\%SOL_I) + (V_A)(\%SOL_A) &= (V_F)(\%SOL_F) \\ (1200)(0.08) + (x)(0) &= (1200 + x)(0.05) \\ 96 + 0x &= 60 + 0.05x \\ 0.05x &= 36 \\ x &= 720 \text{ bbl new 16.0 lb/gal mud}\end{aligned}$$

Checking the result:

$$8\% = 0.08 \text{ fraction drill solids}$$

Therefore, 8% of 1200 bbl = (.08) (1200) = 96 bbl of drill solids
The total resulting barrels of mud is 1200 + 720 = 1920 bbl

Therefore:

$$\frac{96 \text{ bbl}}{1920 \text{ bbl}} = 0.05 \text{ or } 5 \text{ volume } \%$$

EXAMPLE #3 - Using the same criteria as Example #2, but keeping the final volume at 1200 bbl, how much 16.0 lb/gal mud must be added and how much 16.0 lb/gal **Old Fluid** with 8% drill solids must be discarded?

Given:

	$(V_I, \%SOL_I)$ <u>Old Fluid</u>	$(V_A, \%SOL_A)$ <u>Weight Mat'l</u>	$(V_F, \%SOL_F)$ <u>New Fluid</u>
Volume, bbl	1200	X	1200
Density, lb/gal	16.0	16.0	16.0
Volume, Drill Solids, %	8	0	5

$$\text{Old Fluid} + \text{Mud to Add} = \text{New Fluid}$$

Or

$$V_I (\%SOL_I) + V_A (\%SOL_A) = V_F (\%SOL_F)$$

Solving the equation for x (where x is bbl of 16 lb/gal mud to be added):

$$\begin{aligned}(V_I)(\%SOL_I) + (V_A)(\%SOL_A) &= (V_F)(\%SOL_F) \\ (1200 - V_A)(0.08) + (V_A)(0) &= (1200)(0.05\%) \\ 96 + 0.08x + 0 &= 60 \\ -0.08x &= -36 \\ x &= 450 \text{ bbl new 16.0 lb/gal mud.} \\ &\text{Before adding new mud,} \\ &\text{dump 450 bbl of 16.0 lb/gal} \\ &\text{mud with 8\% drill solids.}\end{aligned}$$

System Building

Building a drilling fluid system from scratch is nothing more than applying material balance concepts. As long as the specific gravity or density, and volumes of the materials are known, any fluid system can be built. All calculations should be carried to at least two decimal places. Field calculations are normally rounded to whole barrels and the results may be slightly different.

The general material balance equations are:

$$V_1D_1 + V_2D_2 + V_3D_3 + \text{etc.} = V_F D_F$$

$$V_1 + V_2 + V_3 + \text{etc.} = V_F$$

Where:

D_F = Final Fluid Density

The subscripts of V and D represent different volumes and densities of different components. The two material balance equations may then be solved simultaneously for any two unknowns. See example problems.

Example Calculations

EXAMPLE #1 - We want to build 400 bbl of 12.5 lb/gal fluid with 21 lb/bbl bentonite.

Given:

Additive	Specific Gravity	Density lb/gal	Density lb/bbl
Barite	4.2	35	1470
Water	1.0	8.33	349.86
Bentonite	2.6	21.66	909.72

The final volume will be 400 bbl which contains 21 lb/bbl bentonite. Thus, 8400 lb (21 lb/bbl x 400 bbl) of bentonite will be needed. Since a barrel of bentonite weighs 909.72 lb, the volume of 8400 lb of bentonite is 9.23 bbl (8400 lb/909.72 lb/bbl). Therefore, the volume of barite plus water must be 400 bbl - 9.23 of bentonite or 390.77 bbl. A material balance equation can now be used to represent the problem.

$$V_1D_1 + V_2D_2 + V_3D_3 = V_F D_F$$

Bentonite + Water + Barite = Final Fluid

$$(9.23 \text{ bbl})(21.66 \text{ lb/gal}) + (390.77 - x)(8.33 \text{ lb/gal}) + (x)(35 \text{ lb/gal}) = (400 \text{ bbl})(12.5 \text{ ppg})$$

Density and volume have been represented for each material. If the volumes for all three materials are combined, the total volume is 400 bbl.

Solving the equation for x (where x is the volume of barite to be added):

$$\begin{aligned}
 (9.23)(21.66) + (390.77 - x)(8.33) + (x)(35) &= (400)(12.5) \\
 199.92 + 3255.11 - 8.33x + 35x &= 5000 \\
 26.67x &= 1544.96 \\
 x &= 57.93 \text{ bbl of barite} \\
 390.77 - 57.93 &= 332.84 \text{ bbl of water}
 \end{aligned}$$

57.93 bbl barite is equivalent to 85,157 lb of barite

$$\frac{85,157 \text{ lb}}{100 \text{ lb/sx}} = 852 \text{ sx of barite}$$

Now, check the weight and volume for each material:

Material	Total Barrels	Total Pounds
Water	332.84	116,447
Bentonite	9.23	8,399
Barite	57.93	85,157
Total	400.00	210,003

$$\frac{210,003 \text{ lb}}{(400 \text{ bbl})(42 \text{ gal/bbl})} = 12.5 \text{ lb/gal}$$

Thus, the system contains 400 bbl of fluid with a density of 12.5 lb/gal.

EXAMPLE #2 - We want to build 650 bbl of 11.5 lb/gal fluid with 21 lb/bbl bentonite, 0.5 lb/bbl caustic soda, and 3 lb/bbl Lignite.

Given:

Material	Specific Gravity	Density lb/gal	Density lb/bbl
Barite	4.2	35.00	1470.00
Water	1.0	8.33	349.86
Bentonite	2.6	21.66	909.72
Caustic Soda	2.1	17.49	734.71
Lignite	1.5	12.495	524.79

Representing final material volumes, in pounds and barrels:

Material	lb/bbl	Total System Barrels	Total Pounds	Total Volume Barrels
Bentonite	21.0	650	13,650	15.00
Caustic Soda	0.5	650	325	0.44
Lignite	3.0	650	1950	3.71
Total				19.16

To determine the total volume of each material, calculate by the following procedure:

Volume of Bentonite

$$\frac{13,650 \text{ lb of bentonite}}{909.72 \text{ lb/bbl bentonite}} = 15.00 \text{ bbl}$$

Volume of Caustic Soda

$$\frac{325 \text{ lb of caustic soda}}{734.71 \text{ lb/bbl caustic soda}} = 0.44 \text{ bbl}$$

Volume of Lignite

$$\frac{1950 \text{ lb of Lignite}}{524.79 \text{ lb/bbl Lignite}} = 3.72 \text{ bbl}$$

The total known volume of all materials (EXCEPT barite and water) is 19.16 bbl.

$$15.00 \text{ bbl} + 0.44 \text{ bbl} + 3.72 \text{ bbl} = 19.16 \text{ bbl}$$

Therefore, the volume of barite and water can be calculated by subtracting 19.16 bbl of bentonite, caustic and lignite from the required volume of 650 bbl.

Now, let: $x = \text{Volume of barite}$

Therefore: $650 - 19.16 = 30.84 \text{ volume of water.}$

Representing the problem in terms of a material balance equation:

$$\begin{aligned} V_1 D_1 + V_2 D_2 + V_3 D_3 + V_4 D_4 + V_5 D_5 &= V_F D_F \\ \text{Bentonite} + \text{Caustic} + \text{Lignite} + \text{Water} + \text{Barite} &= \text{Final Fluid} \\ (15.00)(21.66) + (0.44)(17.49) + (3.72)(12.495) + (630.66 - x)(8.33) + (x)(35) &= (650)(11.5) \end{aligned}$$

Solving the equation for x:

$$\begin{aligned} 325.00 + 7.700 + 46.42 + 5253.40 - 8.33x + 35x &= 11.5(650) \\ 26.67x &= 1842.47 \\ x &= 69.08 \text{ bbl barite} \\ (69.08 \text{ bbl barite})(1470 \text{ lb/bbl}) &= 101,551 \text{ lb of barite} \end{aligned}$$

Therefore

$$\begin{aligned} 630.66 - 69.08 &= 561.58 \text{ bbl water} \\ (561.58 \text{ bbl water})(349.86 \text{ lb/bbl}) &= 196,474 \text{ lb water} \end{aligned}$$

Now, check the volumes for each material:

Material	Total Barrels	Total Pounds
Water	561.58	196,473
Bentonite	15.00	13,650
Caustic Soda	0.44	325
Lignite	3.72	1,950
Barite	69.08	101,551
Total	649.82	313,950

$$\frac{313,950 \text{ lb}}{(649.8)(42 \text{ gal/bbl})} = 11.5 \text{ lb/gal}$$

Thus, the system contains 650 bbl with a density of 11.5 lb/gal.

EXAMPLE #3 - Find the quantities of each material required to build 1200 bbl of 14.5 lb/gal mud. Each final barrel of mud should contain 2.5 lb/bbl CMC, 0.5 lb/bbl caustic, 23 lb/bbl bentonite, and 4 lb/bbl Lignite.

Given:

Material	Specific Gravity	Density lb/gal	Density lb/bbl
Barite	4.20	35.000	1470.00
Seawater	1.03	8.580	360.36
Bentonite	2.60	21.660	909.72
Caustic Soda	2.10	17.490	734.71
Lignite	1.50	12.495	524.79
CMC	1.55	12.910	542.22

Representing final material volumes, in pounds and barrels:

Material	lb/bbl	Total System Barrels	Total Pounds	Total Volume Barrels
Bentonite	23.0	1200	27,600	30.400
Caustic Soda	0.5	1200	600	0.817
Lignite	4.0	1200	4800	9.150
CMC	2.5	1200	3000	5.530
Total				45.84

To calculate the total volume of each material, calculate by the following procedure:

Volume of CMC

$$\frac{3,000 \text{ lb of CMC}}{542.22 \text{ lb/bbl CMC}} = 5.53 \text{ bbl}$$

Volume of Bentonite

$$\frac{27,600 \text{ lb of bentonite}}{909.72 \text{ lb/bbl bentonite}} = 30.34 \text{ bbl}$$

Volume of Caustic Soda

$$\frac{600 \text{ lb of caustic soda}}{734.71 \text{ lb/bbl caustic soda}} = 0.817 \text{ bbl}$$

Volume of Lignite

$$\frac{4800 \text{ lb of lignite}}{524.79 \text{ lb/bbl lignite}} = 9.15 \text{ bbl}$$

Therefore, the volume of barite and water can be calculated by subtracting the volumes of bentonite, caustic and lignite from the required volume of 1200 bbl.

$$1200 \text{ bbl} - 45.84 \text{ bbl} = 1154.16 \text{ bbl (volumes of barite and water)}$$

The total known volume of all materials (EXCEPT barite and water) is 45.84 bbl.

Now, let $x = \text{Volume of barite}$

Then, $(1154.16 - x) = \text{Volume of water}$

Representing the problem in terms of a material balance equation:

$$\begin{aligned} V_1 D_1 + V_2 D_2 + V_3 D_3 + V_4 D_4 + V_5 D_5 + V_6 D_6 &= V_F D_F \\ \text{CMC} + \text{Caustic} + \text{Bentonite} + \text{Lignite} + \text{Barite} + \text{Seawater} &= \text{Final Fluid} \\ (12.91)(5.53) + (0.82)(17.49) + (21.66)(30.4) + (12.495)(9.15) + (35)(x) + (8.58)(1154.16 - x) &= (14.5)(1200) \end{aligned}$$

Solving the equation for x:

$$\begin{aligned} 71.39 + 14.34 + 658.46 + 114.3 + 35x + 9902.69 - 8.58x &= 17,400 \\ 10,746.8 + 26.42x &= 17,400 \\ 26.42x &= 6653.13 \\ x &= 251.8 \text{ bbl barite} \\ (251.8 \text{ bbl barite})(1470 \text{ lb/bbl}) &= 390,0146 \text{ lb} \end{aligned}$$

Therefore

$$1154.16 \text{ bbl} - 251.8 \text{ bbl barite} = 902.40 \text{ bbl seawater}$$

$$(902.40 \text{ bbl seawater})(360.36 \text{ lb/bbl}) = 325,189.94 \text{ lb}$$

Now, check the volumes for each material:

Material	Total Barrels	Total Pounds
Bentonite	30.340	27,600
Caustic Soda	0.817	600
Lignite	9.150	4800
CMC	5.530	3000
Barite	251.800	370,146
Seawater	902.400	325,189
Total	1200.00	731,335

$$\frac{731,335 \text{ lb}}{(1200 \text{ bbl})(42 \text{ gal/bbl})} = 14.5 \text{ lb/gal}$$

Thus, the system contains 1200 bbl with a density of 14.5 lb/gal.

Solids Analysis

Material balance concepts can easily be applied to solids analysis problems.

Nomenclature

Volume	
Initial	V_I
Oil	V_O
Water	V_W
Solids	V_S
Low Gravity Solids	V_{LGS}
High Gravity Solids	V_{HGS}
Mud Density	SX
Initial	MW_I
Final	MW_F

Example Calculations

EXAMPLE #1 (Weighted Muds) - Find the volume percent of high gravity solids and the volume percent of low gravity solids in a 16.0 lb/gal mud with 32 volume % retort solids and 6 volume % oil.

Given:

Mud Density, lb/gal	16.0
Retort, volume %	
Solids	32
Oil	6
Water	62

Assume

Components	Specific Gravity	Density (lb/gal)
Oil	0.84	7.0
High Gravity Solids	4.2	35.0
Low Gravity Solids	2.6	21.66
Water	1.03	8.6

Let $x = V_{HGS}$

Then, $32 - x = V_{LGS}$

$$V_{HGS}D_{HGS} + V_{LGS}D_{LGS} + V_O D_O + V_W D_W = V_F MW_F$$

$$(x)(4.2)(8.33) + (32 - x)(2.6)(8.33) + (6)(7.0) + (62)(8.6) = (100)(16.0)$$

Solving the equation for x:

$$(34.986x) + (693.056 - 21.66x) + (42) + (533.2) = 1600$$

$$13.326x = 331.744$$

$$x = 24.89 V_{HGS}$$

$$32 - 24.89 = 7.106 V_{LGS}$$

Checking the results:

$$(24.89)(4.2)(8.33) + (7.106)(2.6)(8.33) + (6)(7.0) + (62)(8.6) = (100)(16)$$

$$(871) + (154) + (42) + (533) = 1600$$

$$1600 = 1600$$

EXAMPLE #2 (Unweighted Muds) - An equation for calculating either the volume percent low gravity solids or mud weight of an unweighted freshwater fluid is presented below:

$$x = 7.5 (MW - 8.33)$$

Where

$$x = \%LGS$$

- Using the above equation, determine the volume percent solids if the density of the mud is 10.0 lb/gal and all solids are low gravity solids having a specific gravity of 2.6.

$$x = 7.5(MW - 8.33)$$

$$x = 7.5(10.0 - 8.33)$$

$$x = (7.5)(1.67)$$

$$x = 12.5\% \text{ low gravity solids}$$

- If solids are reduced by one percent, what is the resulting mud density?
Since the original volume percent solids is 12.5%, the reduced volume percent solids would be 11.5%. From the equation:

$$\begin{aligned}
 11.5 &= 7.5(\text{MW} - 8.33) \\
 11.5 &= (7.5)(\text{MW}) - 62.475 \\
 (11.5) + (62.475) &= 7.5(\text{MW}) \\
 \frac{73.975}{7.5} &= \text{MW} \\
 \text{MW} &= 9.86 \text{ lb/gal}
 \end{aligned}$$

3. How many barrels of water must be added to a 1000 bbl system to reduce the mud density from 10.0 lb/gal to 9.86 lb/gal?

Using the weight reduction formula:

$$V_W = \frac{V_I(\text{MW}_I - \text{MW}_F)}{\text{MW}_F - 8.33} = \frac{1000(10.0 - 9.86)}{9.86 - 8.33} = \frac{140}{1.53} = 91.5 \text{ bbl water to add}$$

$V_W = 91.5$ bbl water to add to 1000 bbl to reduce the mud density.

Table 1
Drilling Fluid Components

Component	Specific Gravity	Component	Specific Gravity
Fresh Water	1.00	Gypsum	2.3
Sea Water	1.03	Caustic Soda, NaOH	2.1
Saturated Saltwater	1.20	Lignosulfonate	0.83
Diesel #2	0.84	Lignite	1.5
API Bentonite	2.6	Soda Ash, Na ₂ CO ₃	2.53
API Barite	4.20	Salt, NaCl	2.16
API Hematite	5.05		
Lime, Ca(OH) ₂	2.2		
Calcium Carbonate			
aragonite	2.71		
calcite	2.83		

Calculating Maintenance and Treatment Requirements for an Active Mud System

A mud system during drilling and circulation is undergoing continual change. Because of the change, the mud must be treated to maintain its desired properties. In order to make the most economical treatments, it is important to know the current component concentrations, and based on assumed or calculated losses, be able to calculate the amounts of materials required to maintain the system.

Utilizing material balance techniques, it is possible to estimate the quantities of materials needed to maintain a mud system. Assumptions and known information will be utilized in developing the values for the material balance problems. Known information includes hole size, penetration rate and nature of the solids drilled. Assumed data includes losses to the formation through seepage and filtrate, hole washout, and losses through solids control equipment. With this information, estimates of the daily chemical consumption rates can be calculated.

For the purpose of this exercise, assume the following:

- Hole size: 8.5 in.
- Washout: 10%
- Penetration rate: 35 ft/hr
- Total circulating volume: 1000 bbls
- Losses due to solids control equipment: 15 bbl/hr (1.5%/hr)
- Losses due to filtration and seepage: 10 bbl/hr (1%/hr)
- Losses due to adsorption on cuttings: 1 bbl/hr (0.01%/hr)

The last analysis of the drilling fluid yielded the following data:

- Mud weight: 12.0 ppg (1.44 SG)
- Solids: 18.0% by volume
- Water: 82.0% by volume

Determine the Average Specific Gravity of Solids (ASG):

$$(V_1 D_1 + V_2 D_2 = V_F D_F) , \text{ where}$$

- V_1 = Volume fraction of water (82%)
- D_1 = Density of water (8.33)
- V_2 = Volume Fraction of solids (18.0%)
- D_2 = Density of solids (unknown)
- V_F = Volume fraction of mud (100%)
- D_F = Density of mud (12.0 ppg)

Substituting:

$$(82)(8.33) + (18)(D_2) = (100)(12.0)$$

$$683.06 + 18 D_2 = 1200.0$$

$$18 D_2 = 516.94$$

$$D_2 = 28.72 \text{ ppg}$$

$$\text{ASG} = \frac{28.72}{8.33} = 3.45$$

Determine the concentrations of low gravity and high gravity solids in pounds per barrel. Assume a specific gravity of 2.65 and 4.20 for low gravity solids and barite respectively.

$$V_1 D_1 = V_2 D_2 + V_3 D_3$$

V_1 = Volume fraction of all solids (18%)
 D_1 = Average specific gravity of all solids (3.45)
 V_2 = Volume Fraction of high gravity solids (unknown)
 D_2 = Specific gravity of high gravity solids (4.20)
 V_3 = Volume fraction of low gravity solids = $V_1 - V_2$
 D_3 = Specific gravity of low gravity solids (2.65)

Substituting:

$$(0.18)(3.45) = V_2(4.20) + (0.18 - V_2)2.65$$

$$0.18(3.45 - 2.65) = (4.20 - 2.65)(0.18 - V_2)$$

$$V_2 = 0.18 \frac{(3.45 - 2.65)}{4.20 - 2.65}$$

$$V_2 = 0.0929, \text{ or } 9.29\%$$

Therefore:

$$V_3 = 18\% - V_2$$

$$V_3 = 18\% - 9.29\% = 8.71\%$$

Pound/bbl barite: 4.2 (8.33) (42) (0.0929) = 136.51

Pound/bbl low gravity solids: 2.65 (8.33) (42) (0.0871) = 80.75

The composition of the mud is as follows:

Mud weight: 12.0 ppg
Solids: 18.0% by volume
Low gravity solids: 80.75 ppb
Barite: 136.51 ppb
Average specific gravity of solids: 3.45

The next step is to calculate the daily maintenance requirements. The requirements will be related to the additions of water required to maintain the mud properties within optimum limits. Water additions will be regulated by hole size, rate of penetration, nature of solids drilled and removal of solids. As solids accumulate in the fluid, mud weight, plastic viscosity and yield point may increase, and the rate of increase will be governed by the degree of hydration, swelling and dispersion of the solids which is controlled by the chemical environment of the mud.

It is necessary to know the amount of solids generated, therefore, calculate the amount of solids drilled per hour using the data supplied earlier.

Average hole size: Bit size + Washout
Average hole size: 8.5 in. + (8.5) (0.1) = 9.35 in.

Volume of hole/ft: $(D)^2$ (0.000971)
Volume of hole/ft: $(9.35)^2$ (0.000971) = 0.0848 or 0.085 bbl/ft

$$\text{Volume of hole/hr: } (0.085) (35) = 2.975 \text{ bbl/hr}$$

Therefore:

The volume of drilled solids generated each hour is 2.975 bbl. Assuming a specific gravity of 2.65 for the solids, pounds per hour of drilled solids will be:

$$\text{Low gravity solids, bbl/hr: } (350) (2.65) (2.975) = 2,759 \text{ lb}$$

Note: The figure 350 used above denotes the weight of 1 bbl of fresh water (42 gal/bbl x 8.33 ppg = 349.86, or 350 ppb).

We now need to calculate the rate at which water must be added to maintain a constant mud weight. If the operating efficiency of the solids control equipment is known, those efficiency values will be used. If the operating efficiency is not known, assumptions must be made. This exercise assumes an operating efficiency of 50%.

The material balance equation used to calculate the amount of water required is as follows:

$$V_F D_F = V_1 D_1 = V_2 D_2 + V_3 D_3, \text{ where}$$

V_F = Volume of mud ($V_1 + V_2 + V_3$)

D_F = Final specific gravity (1.44)

V_1 = Volume of low gravity solids, $V_N = (0.50) (2.975) + (0.0871) = 1.5746$

D_1 = Specific gravity of low gravity solids (2.65)

V_2 = Volume of water to add (unknown)

D_2 = Specific gravity of water (1.00)

V_3 = Volume of barite (0.0929)

D_3 = Specific gravity of barite (4.20)

V_4 = Volume of water (0.82)

$D_4 = 1.00$ and,

$$V_2 = \frac{V_1(D_1 - D_F) + V_3(D_3 - D_F) + V_4(D_4 - D_F)}{(D_F - D_2)}$$

Substituting:

$$V_2 = \frac{1.57(2.65 - 1.44) + 0.0929(4.2 - 1.44) + 0.82(1.0 - 1.44)}{(1.44 - 1.00)}$$

$$V_2 = 4.08 \text{ bbl H}_2\text{O}$$

Therefore, 4.08 bbl of water/hour must be added to maintain a constant mud weight of 12.0 ppg. At the same time, low gravity solids are being incorporated into the mud at the rate of 1,380 lb/hr (remember the solids control equipment is operating at 50% efficiency - 2759 x 0.5 = 1380). This is equivalent to 1.49 bbl/hr (2.975 x 0.5 = 1.4875). At these rates, the density of the mud will decrease due to the addition of the water and the mud properties will deteriorate due to the accumulation of low gravity drilled solids. Additional water and barite must be added to maintain the desired properties and a 3.45 average specific gravity of solids.

Calculate barite requirements to maintain a 3.45 ASG of solids using:

$$V_F D_F = V_1 D_1 + V_2 + D_2 + V_3 D_3, \text{ where}$$

V_F = Final volume of solids ($V_1 + V_2 + V_3$)
 D_F = Final ASG of solids (3.45)
 V_1 = Volume of low gravity solids (1.57)
 D_1 = Specific gravity of low gravity solids (2.65)
 V_2 = Volume of high gravity solids (0.0929)
 D_2 = Specific gravity of high gravity solids (4.20)
 V_3 = Volume of high gravity solids to add (unknown)
 D_3 = Specific gravity of high gravity solids to add (4.20) and,

$$V_3 = \frac{V_1(D_1 - D_F) + V_2(D_2 - D_F)}{(D_F - D_2)}$$

Substituting:

$$\begin{aligned} V_3 &= \frac{1.57(2.65 - 3.45) + 0.0929(4.0 - 3.45)}{3.45 - 4.20} \\ V_3 &= \frac{1.57(-0.8 + 0.0929(0.75))}{-0.75} \\ V_3 &= \frac{-0.1256 + 0.0069675}{-0.75} \\ V_3 &= 1.58 \text{ bbl} \end{aligned}$$

Converting to pounds of barite per hour:

$$(1.58 \text{ bbl}) (1,470 \text{ lb/bbl}) = 2323 \text{ lb/hr}$$

Next the amount of additional water must be calculated. We know that 1380 lb of low gravity solids and 2323 lb of barite are being introduced into the system each hour.

Determine the amount of water required to maintain a 12.0 ppg mud weight using:

$$V_3 = \frac{V_1(D_1 - D_F) + V_2(D_2 - D_F)}{(D_F - D_2)}, \text{ where}$$

V_F = Final mud volume ($V_1 + V_2 + V_3$)
 D_F = Specific gravity of final mud (1.44)
 V_1 = Volume of solids added (3.07 bbl)
 D_1 = ASG of solids added (3.45)
 V_2 = Volume of water added (4.08 bbl)
 D_2 = Specific gravity of water added (1.00)
 V_3 = Volume of water to be added (unknown)
 D_3 = Specific gravity of water to be added (1.0)

Substituting:

$$\begin{aligned} V_3 &= \frac{3.07(3.45 - 1.44) + 4.08(1.00 - 1.44)}{(1.44 - 1.00)} \\ V_3 &= 9.94 \text{ bbl} \end{aligned}$$

Therefore, the required additions of barite and water must be made to the system to maintain a constant mud weight of 12.0 ppg and an ASG of 3.45 are:

	bbbl/hr	lb/hr
Water	14.02	4905
Barite	1.58	2323
Low Gravity Solids	1.49	1380
Total	17.09	8608

This can be validated using the formula:

$$V_D = \frac{V_1 D_1 + V_2 D_2 + V_3 D_3 + V_4 D_4}{V_F}, \text{ where}$$

- V₁ = Volume of initial mud (1000 bbl)
- D₁ = Specific gravity of initial mud (1.44)
- V₂ = Volume of water added (14.02 bbl)
- D₂ = Specific gravity of water (1.0)
- V₃ = Volume of barite added (1.58 bbl)
- D₃ = Specific gravity of barite (4.2)
- V₄ = Volume of low gravity solids added (1.49 bbl)
- D₄ = Specific gravity of low gravity solids (2.65)
- V_F = V₁ + V₂ + V₃ + V₄
- D_F = Specific gravity of final mud (unknown)

Substituting:

$$D_F = \frac{(1,000)(1.44) + (14.02)(1.0) + (1.58)(4.2) + (1.49)(2.65)}{1,000 + 14.02 + 1.58 + 1.49}$$

$$D_F = 1.44 \text{ specific gravity of final mud}$$

(This calculation ignores the volume and density affects of other materials such as bentonite and thinners required to maintain and control the muds properties.)

Next, determine the amount of new mud which must be mixed and added to the system to compensate for:

- Volume of new hole drilled
- Losses to filtration and seepage
- Losses through solids control equipment

Remembering our initial assumptions:

- New hole volume: 2.975 bbl/hr
- Losses to filtration and seepage: 10 bbl/hr
- Losses through solids control equipment and adsorption: 16 bbl/hr

The total volume lost per hour which must be replaced is 29 bbl less the 17 bbl of solids and water added to the system while drilling and maintaining a mud weight of 12.0 ppg and an ASG of 3.45.

Calculating the amount of barite and water required to build 12 bbls of 12.0 ppg mud per hour:

$$V_2 = \frac{V_F(D_F - D_1)}{(D_2 - D_1)}, \text{ where}$$

- V_F = Final volume (12 bbl)
- D_F = Specific gravity of final volume (1.44)
- V_1 = Volume of water ($V_F - V_2$)
- D_1 = Specific gravity of water (1.00)
- V_2 = Volume of barite (unknown)
- D_2 = Specific gravity of barite (4.20)

Volume of Barite:

$$V_2 = \frac{12(1.44 - 1.00)}{(4.20 - 1.00)}$$

$$V_2 = 1.65$$

Volume of barite required: 1.65 bbl/hr
Pounds of barite required: 2426 lb/hr

Volume of Water:

$$V_1 = 12 - 1.65$$

$$V_1 = 10.35$$

Volume of water required: 10.35 bbl/hr

The last step is the determination of the amounts of other materials required to maintain the desired properties for the system. This exercise assumes a fresh water mud having the following composition:

Chemical	lb/bbl
Lignosulfonate	8.0
Lignite	4.0
Bentonite	20.0
Caustic Soda	2.5

The hourly additions of barite and water were calculated to be:

Barite: 4749 lb/hr
Water: 24.4 bbl/hr

The consumption of the other materials will be based on the addition of 29 bbl of new mud volume per hour at the concentrations stated above.

Chemical	lb/hr	lb/8 hr tour	lb/12 hr tour	lb/day
Barite	4749	37,992	56,988	113,976
Lignosulfonate	232	1856	2,784	5568
Lignite	116	928	1392	2.784
Bentonite	580	4460	6,960	13,920
Caustic Soda	72.5	580	870	1740

Converting the above to sacks:

Chemical	sk/8 hr tour	sk/12 hr tour	sk/day
Barite	380	570	1,140
Lignosulfonate	38	56	112
Lignite	19	28	56
Bentonite	45	70	140
Caustic Soda	12	18	36

For the purpose of this exercise, the assumption was made that the solids contributed by bentonite and barite which are not lost from a system due to filtration or seepage were deposited as wall cake, and therefore removed from the system.

It must be emphasized that actual consumption rates will vary greatly depending on a number of different factors such as:

- Nature of formation being drilled
- Efficiency of solids control equipment
- Composition of the drilling fluid
- Physical and chemical properties of the drilling fluid
- Hole size and penetration rates

Barite Reclamation

A decanting centrifuge will normally process 12.0 ppg mud at the rate of 18 gpm and recover approximately 70% of the barite in the mud processed. Using this assumption, the amount of barite recoverable from the system can be estimated.

The amount of barite contained in this 12.0 ppg mud was calculated to be 136.51 ppb. The centrifuge will process 25.7 bbls of mud per hour.

$$(18 \text{ gpm}) (60 \text{ min/hr}) (0.0238 \text{ bbl/gal}) = 25.70 \text{ bbl/hr}$$

At 70% efficiency, the amount of barite recovered = (136.51 ppb) (25.70 bbl/hr) (0.70) = 2456 lb/hr.

Converting to barrels of barite/hr:

$$\frac{2.456}{1470} = 1.67 \text{ bbl/hr of barite recovered}$$

Determining the amount of water, low gravity solids and chemicals discarded:

$$25.70 - 1.67 = 24.0 \text{ bbl/hr discarded}$$

The amount of additional water required to maintain a constant mud weight of 12.0 ppg due to the barite being returned to the system via the centrifuge must also be calculated using:

$$V_2 = \frac{V_1(D_1 - D_F)}{(D_F - D_2)}, \text{ where}$$

V_F = Final volume of barite and water ($V_1 + V_2$)

D_F = Specific gravity of final volume (1.44)

V_1 = Volume of barite (1.67)

D_1 = Specific gravity of barite (4.2)

V_2 = Volume of water to add (unknown)

D_2 = Specific gravity of water (1.00)

$$V_2 = \frac{1.67(4.2 - 1.44)}{(1.44 - 1.00)}$$

$$V_2 = 10.48$$

Volume of water to add to maintain a mud density of 12.0 ppg is 10.48 bbl/hr

Total volume returned to system while centrifuge is running is equal to the volume of barite returned plus the water added to the system.

$$\text{Volume returned} = 10.48 + 1.67 = 12.15 \text{ bbl/hr}$$

The centrifuge is processing 25.70 bbl of mud per hour and 12.15 bbl is being returned to the system. New volume must be added to the system equal to the difference between the processed volume and the returned volume.

$$\text{New volume} = 25.70 - 12.15 = 13.55 \text{ bbl/hr}$$

Barite and water additions to build 13.55 bbl of new mud per hour.

$$V_2 = \frac{V_F(D_F - D_1)}{(D_2 - D_1)}, \text{ where}$$

V_F = Final volume of barite and water (13.55)

D_F = Density of final volume (1.44)

V_1 = Volume of water ($V_F - V_2$)

D_1 = Specific gravity of water (1.0)

V_2 = Volume of barite (unknown)

D_2 = Specific gravity of barite (4.2)

$$V_2 = \frac{13.55(1.44 - 1.0)}{(4.2 - 1.0)}$$

$$V_2 = 1.86$$

$$V_1 = 13.55 - 1.86$$

$$V_1 = 11.69$$

The additions of barite and water that must be added to the system each hour.

	Barrels	Pounds	Sacks
Barite	1.86	2,734	28
Water	11.69	-0-	-0-

Other materials must again be added to maintain the desired properties. The total volume, 25.70 bbl/hr, processed by the centrifuge and replaced by discharged barite and added water will need to be treated.

Chemical	sk/8 hr tour	sk/12 hr tour	sk/day
Barite	287	430	861
Lignosulfonate	33	50	99
Lignite	17	25	50
Bentonite	41	62	124
Caustic Soda	11	16	31

Daily Maintenance of Polymer Systems

Daily maintenance treatments for polymers consist of the polymer required to build new volume and replace polymer lost through filtrate invasion and solids removal.

In addition to normal maintenance, the polymer and a 10% loss of polymer while drilling, we can calculate the required daily maintenance.

$$P_L = PCVM \%p, \text{ where}$$

P_L = Pounds polymer lost while drilling per day, lb/day (unknown)

P_C = Concentration of polymer to maintain, ppb (0.5)

V_M = Volume of mud, bbl (1000)

$\%p$ = Percentage of polymer lost from system each day (0.10)

Substituting:

$$P_L = (0.5 \text{ ppb}) (1000 \text{ bbl}) (0.10)$$

$$P_L = 50 \text{ lb}$$

To replace polymer lost from system, we must add 50 lb of polymer each day.

In our previous calculations we found it necessary to create 54.88 bbl of new volume per hour.

$$P_A = V_N P_C, \text{ where:}$$

P_A = Polymer to be added to maintain required concentration in new volume, lb (unknown)

V_N = New volume added to system, bbls (54.8)

P_C = Required concentration of polymer, ppb (0.5)

Substituting:

$$P_A = (54.8 \text{ bbl}) (0.5 \text{ ppb})$$

$$P_A = 27.4 \text{ lb}$$

27.4 lb of polymer will need to be added each hour to maintain a concentration of 0.5 ppb in the new mud volume. The total polymer to be added each hour is that required to replace lost polymer (2.1 lb/hr) and that required to build new volume (27.4 lb/hr). 29.5 lb/hr of polymer is required each hour as a maintenance treatment. Converting the maintenance treatment to 50 lb sacks:

sk/8 hr tour	sk/12 hr tour	sk/day
5	7	15

The Drilling Mud Report

The following example problems introduce some of the basic engineering calculations related to the Drilling Mud Report. The drilling mud report is a good communications tool and when filled out completely and accurately, can be used to anticipate potential problems and assist in future well planning.

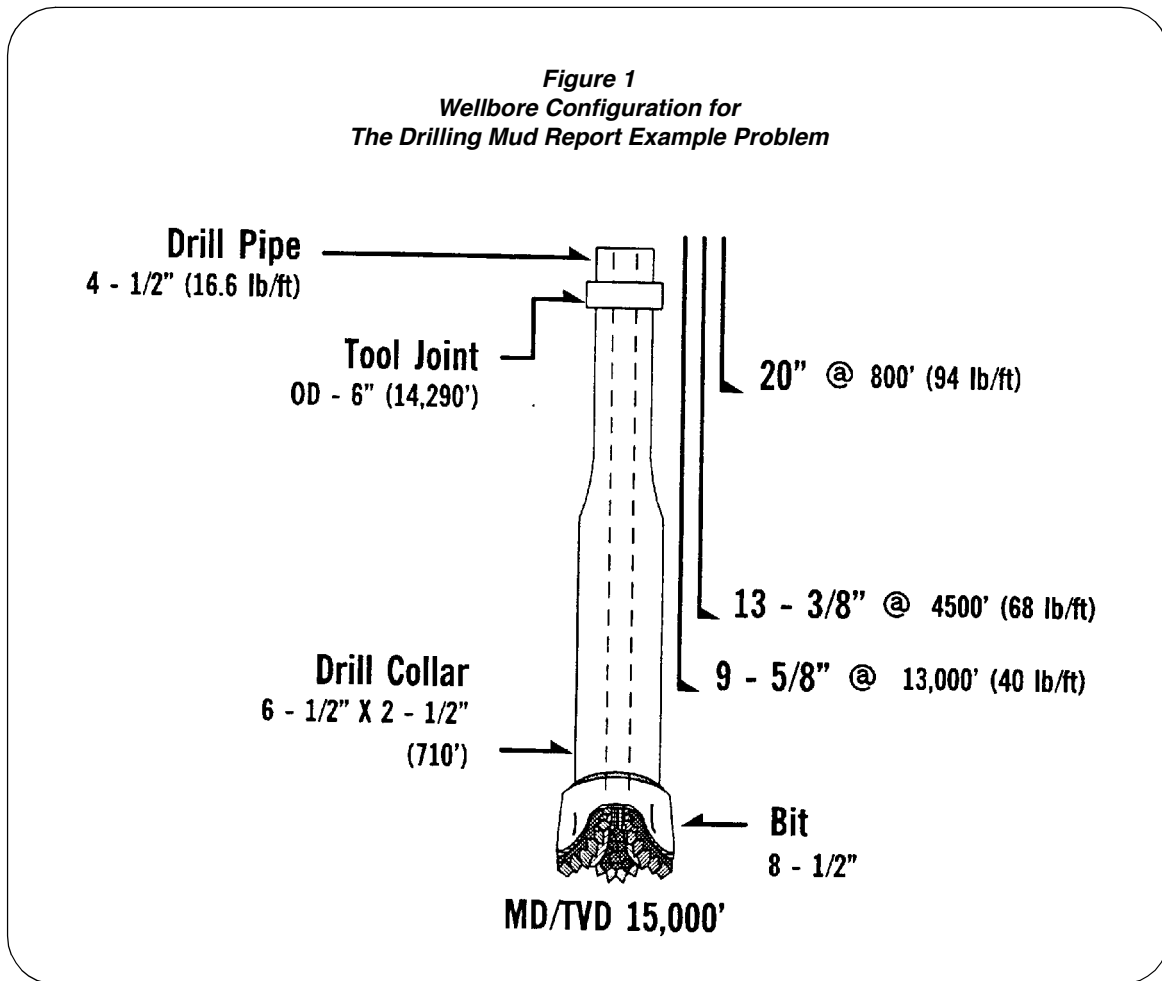



Figure 2
Given Data

 DRILLING MUD REPORT		REPORT NO.	DEPTH 15,000	
		DATE	MD 15,000	TVD 15,000
		SPUD DATE	PRESENT ACTIVITY Drilling	
REPORT FOR CHEVRON SUPERVISOR		CONTRACTOR		RIG NO.
DRILLING MUD SUPPLIER		REPORT FOR CONTRACTOR SUPERVISOR		SECTION, TOWNSHIP, RANGE
WELL NAME AND NO.		FIELD OR BLOCK NO.	COUNTY, PARISH OR OFFSHORE AREA	STATE/PROVINCE
DRILLING ASSEMBLY		CASING	MUD VOLUME (BBL)	CIRCULATION DATA
Bit Size 8 1/2	Type Smith	Jet Size 11-11-11	Surface 20 Set @ 800 Ft.	Hole Pits
Drill Pipe Size 4 1/2	Type XH	Length 14,290	Intermediate 13 3/8 Set @ 4500 Ft.	Total Circulating Volume
Drill Pipe Size —	Type —	Length —	Intermediate 9 5/8 Set @ 13,000 Ft.	In Storage Weight
Drill Collar Size 6 1/2 x 2 1/2	Length 710	Production of Liner — Set @ — Ft.	Mud Type KOH/Lime	Pump Size x in. 5 1/2 x 10
				Annular vel (Ft./Min.) DP DC
				Pump Make Model
				Assumed Eff 94%
				Circulation Pressure (PSI) 2,000
				Bbl/Stk Stk/Min 110
				Bottoms Up (Min.)
				Total Circ. Time (Min.)

Given Data

Given:

- Present Activity Drlg @ 15,000 ft MD/TVD
- Drilling Assembly**
 Bit Size 8-1/2 in. Smith F-2, Jets (11-11-11)
 Drill Pipe 4-1/2 in., 16.60 lb/ft S-135 NC46(XH) TJ-6 in. OD
 Length = 14,290 ft
 Capacity = 0.01422 bbl/ft (tables)
 Displacement = 0.00643 bbl/ft (tables)
 ID = 3.826 in.
 Drill Collar 6-1/2 in. x 2-1/2 in., Length - 710 ft

c. Casing

Hole, in.	CSG, in.	CSG WT, lb/ft	Depth, ft
26	20	94	800
17-1/2	13-3/8	64	4500
12-1/4	9-5/8*	40	13,000
8-1/2	-	-	15,000

*9-5/8 in. casing capacity = 0.758 bbl/ft, ID = 8.835"

d. Mud Volume

Pits 3 pits, each 30 ft x 12 ft x 9 ft
 Pit level = 7 ft (pipe in hole)
 In storage = 0
 Mud 16 lb/gal, KOH/Lime

e. Circulation Data

Pump.....(2) National 10-P-130, 5-1/2 in. x 10 in.
 110 SPM @ 94%E
pressure = 2000 psi circ.

f. Annular Pressure Loss.....250 psi

Mud Pit Capacity

What is the total mud pit capacity (Mud Pit_{cap}) for three rectangular pits, each one 30 ft x 12 ft x 9 ft?

- a. ____ bbl Total
- b. ____ bbl/ft per pit
- c. ____ bl/in per pit

The general equation for calculating the capacity of the surface mud system or pit capacity is as follows:

$$\text{Rectangular Mud Pits, (bbl)} = \frac{(L)(W)(D)}{5.6146}$$

a. $\frac{(30 \text{ ft})(12 \text{ ft})(9 \text{ ft})}{(5.6146 \text{ ft}^3/\text{bbl})} = 577 \text{ bbl/pit}$

$$\begin{aligned} \text{Mud Pit}_{\text{cap}} &= (577 \text{ bbl/pit})(3 \text{ pits}) \\ &= 1731 \text{ bbl Total} \end{aligned}$$

b. $\frac{577 \text{ bbl}}{9 \text{ ft}} = 64.1 \text{ bbl/ft per pit}$

c. $\frac{64 \text{ bbl/ft}}{12 \text{ in./ft}} = 5.3 \text{ bbl/inch per pit}$

Mud Volume in Pits

Each mud pit contains 7 ft of mud. With bit on bottom, what is the volume of mud in the pits?

- a. ____ bbl

$$\text{Mud Pit}_{\text{vol}} \text{ (DS in hole)} = \left[\frac{(30 \text{ ft})(12 \text{ ft})(7 \text{ ft})}{5.6146 \text{ ft}^3/\text{bbl}} \right] (3 \text{ pits}) = 1346 \text{ bbl}$$

Note: Total Pit Capacity is 1731 bbl and Total Mud Volume is 1346 bbl.

[See Figure 3]

Figure 3
Mud Volume in Pits

DRILLING ASSEMBLY				CASING		MUD VOLUME (BBL)		CIRCULATION DATA			
Bit Size	Type	Jet Size	Surface	Hole	Pits	Pump Size	x in.	Annular Vel. (Ft./Min.)	DP	DC	
8 1/2	F-2	11-11-11	20 Set @ 200 Ft.			5 1/2	x 10				
Drill Pipe Size	Type	Length	Intermediate	Total Circulating Volume		Pump Make	Model	Assumed Eff.	Circulation Pressure (PSI)		
4 1/2	XH	14,290	13 3/8 Set @ 4500 Ft.			NATIONAL	10-F-130	94%	2000		
Drill Pipe Size	Type	Length	Intermediate	In Storage	Weight	Bbl/Sik	Sik/Min	Bottoms Up (Min.)			
			9 7/8 Set @ 13,000 Ft.	0	16.0		110				
Drill Collar Size	Length	Production or Liner	Mud Type			Bbl/Min	Gal/Min	Total Circ. Time (Min.)			
6 1/2 x 2 1/2	710	— Set @ — Ft.	KOH/LIME								

Hole Volume

What is the volume of mud in the wellbore with no drill string in the hole if 9-5/8 in. casing is set at 13,000 ft and 8-1/2 in. hole to 15,000 ft?

a. _____ bbl

$$\begin{aligned} \text{Hole}_{\text{vol}} &= \left[\frac{(8.835)^2}{1029.4} \right] (13,000') + \left[\frac{(8.5)^2}{1029.4} \right] (2000') \\ &= 985.8 + 140.4 \\ &= 1126.2 \text{ bbl} \end{aligned}$$

Drill String Displacement

What is the displacement of the drill string (DS_{disp}) when the bit is on bottom at 15,000 ft?

a. _____ bbl

The general equation for calculating the displacement of the drill string as follows:

$$\begin{aligned} DS_{\text{disp}} &= (DP_{\text{disp}}) + (DC_{\text{disp}}) \\ DP_{\text{disp}} &= (0.00643 \text{ bbl/ft})(14,290 \text{ ft}) = 91.9 \text{ bbl} \\ DC_{\text{disp}} &= \frac{(6.5)^2 - (2.5)^2}{1029.4} (710 \text{ ft}) = 24.8 \text{ bbl} \end{aligned}$$

Therefore:

$$DS_{\text{disp}} = 91.9 \text{ bbl} + 24.8 \text{ bbl} = 116.7 \text{ bbl}$$

Drill String Capacity

What is the capacity of the drill string (DScap) when the bit is on bottom at 15,000 ft?

a. _____ bbl

The general equation for calculating the capacity of the drill string is as follows:

$$DS_{cap} = \text{Drill Pipe}(DP_{cap}) + \text{Drill Collar Capacity}(DC_{cap})$$

$$DP_{cap} = (0.01422 \text{ bbl/ft})(14,290 \text{ ft}) = 203.2 \text{ bbl}$$

$$DC_{cap} = \frac{(ID)^2(L)}{1029.4} = \frac{(2.5)^2(710 \text{ ft})}{1029.4} = 4.3 \text{ bbl}$$

Therefore

$$DS_{cap} = 203.2 \text{ bbl} + 4.3 \text{ bbl} = 207.5 \text{ bbl}$$

Mud Volume

In Pits/Pipe Out of Hole

What is the volume of mud in the pits when the drill string is out of the hole during a trip and the hole is full of mud?

a. _____ bbl

$$\begin{aligned} \text{Mud Pit}_{Vol} &= \text{Mud Pit}_{Vol} - DS_{disp} \\ (\text{DS out of Hole}) &= (\text{DS in Hole}) \\ &= 1346 - 116.7 \\ &= 1229.3 \text{ bbl} \end{aligned}$$

In Hole/Closed End Pipe

What is the volume of mud in the hole when the pipe is on bottom with a closed end (float)?

a. _____ bbl

$$\begin{aligned} \text{Hole}_{Vol_CE} &= \text{Hole}_{Vol_O} - DS_{disp} - DS_{cap} \\ &= 1126.2 - 116.7 - 207.5 \\ &= 802 \text{ bbl} \end{aligned}$$

In Pits/Closed End Pipe

What is the volume of mud in the pits when the pipe is on bottom with a closed end (float)?

a. _____ bbl

$$\begin{aligned} \text{Hole}_{Vol_CE} &= \text{Hole}_{Vol_O} - DS_{disp} - DS_{cap} \\ &= 1346 + 207.5 + 116.7 \\ &= 1670.2 \text{ bbl} \end{aligned}$$

In Hole/Open Ended Pipe

What is the volume of mud in the hole when pipe is on bottom with open end?

a. ____ bbl

$$\begin{aligned} \text{Hole}_{\text{Vol}_{\text{OE}}} &= \text{Hole}_{\text{Vol}_{\text{O}}} - \text{DS}_{\text{disp}} \\ &= 1126.2 - 116.7 \\ &= 1009.5 \text{ bbl} \end{aligned}$$

(See Figure 4)

Total Circulating Volume

What is the total circulating mud volume with pipe on bottom?

a. ____ bbl

$$\begin{aligned} \text{Total Circulating Volume} &= \text{Hole}_{\text{Vol}_{\text{OE}}} + \text{Mud Pit}_{\text{Vol}} \\ &= 1009.5 + 1346 \\ &= 2355.5 \text{ bbl} \end{aligned}$$

Figure 4
Hole Volume and Total Circulating Volume

DRILLING ASSEMBLY				CASING		MUD VOLUME (BBL)		CIRCULATION DATA			
Bit Size 8 1/2	Type F-2	Jet Size 11-11-11	Surface 20 Set @ 800 Ft.	Hole 1009	Pits 1346	Total Circulating Volume 2355		Pump Size 5 1/2 x 10	Annular Vel. (Ft./Min.) DP DC		
Drill Pipe Size 4 1/2	Type XH	Length 14,290	Intermediate 13 3/8 Set @ 4500 Ft.	In Storage 0	Weight 16	Bbl/Stk 110		Pump Make NATIONAL	Assumed Eff. 94%	Circulation Pressure (PSI)	
Drill Pipe Size 6 1/2	Type 2 1/2	Length 710	Intermediate 9 7/8 Set @ 13,000 Ft.	Mud Type KOH/Lime		Bbl /Min		Gal/Min		Total Circ. Time (Min.)	

Pump Output

Bbl/STK, Gal/STK

What is the pump output (Q) in barrels per stroke (bbl/STK) and gallons per stroke (gal/STK at 94% volumetric efficiency?)

- a. ____ bbl/STK
- b. ____ gal/STK

A National 10-P-130 which has a 10-in. stroke (with a 5-1/2 in. liner at 100% volumetric efficiency) will deliver 3.0996 gal/STK.

Table 2
Triplex Single Acting Mud Pump Capacities Per Cycle
Barrels per Stroke - 100% Volumetric Efficiency

Liner Size	Stroke Length								
	7	7-1/2	8	8-1/2	9	9-1/4	10	11	12
3	0.0153	0.0164	0.0175	0.0186	0.0197	0.0202	0.0219	0.024	0.0262
3-1/4	0.01795	0.0192	0.0205	0.0218	0.0231	0.0237	0.0257	0.0283	0.0307
3-1/2	0.0208	0.0223	0.0238	0.0252	0.0267	0.0276	0.0298	0.0326	0.0357
3-3/4	0.0238	0.0257	0.0273	0.0290	0.0307	0.0317	0.034	0.0376	0.0408
4	0.0271	0.029	0.0311	0.033	0.035	0.036	0.0388	0.0429	0.0467
4-1/4	0.0307	0.0328	0.035	0.0374	0.0395	0.0404	0.0438	0.0483	0.0526
4-1/2	0.0345	0.0369	0.0392	0.0419	0.0443	0.0455	0.0493	0.054	0.059
4-3/4	0.0383	0.0411	0.0438	0.0466	0.0493	0.0507	0.0547	0.0602	0.0657
5	0.0426	0.0455	0.0486	0.0517	0.0548	0.0562	0.0607	0.0669	0.0729
5-1/4	0.0469	0.0502	0.0535	0.0569	0.0602	0.062	0.0669	0.0736	0.0807
5-1/2	0.0514	0.044	0.0488	0.0624	0.0661	0.0678	0.0738	0.0807	0.088
5-3/4	0.0562	0.0602	0.0643	0.0683	0.0721	0.0743	0.0802	0.0883	0.0964
6	0.0611	0.0655	0.070	0.0743	0.0786	0.0809	0.0874	0.0961	0.105
6-1/4	0.0664	0.0712	0.0759	0.0807	0.0855	0.0878	0.0948	0.1043	0.1138
6-1/2	0.0719	0.0770	0.0821	0.0871	0.0924	0.0949	0.1026	0.1129	0.123
6-3/4	0.0774	0.083	0.0886	0.094	0.0995	0.1023	0.1107	0.1217	0.1328
7	0.0833	0.0893	0.0952	0.101	0.1071	0.11	0.119	0.131	0.143

Table 3
Duplex Double-Acting Mud Pump Capacities Per Cycle
Barrels per Revolution - 90% Volume Efficiency - Rods Deducted

Diameter Liner Inches	Area Sq. In.	Stroke 12" Rods 2"	Stroke 14" Rods 2"	Stroke 15" Rods 2-1/4"	Stroke 16" Rods 2-1/4"	Stroke 18" Rods 2-1/2"	Stroke 20" Rods 2-1/2"
4	12.566	0.0495	0.0577	—	—	—	—
4-1/4	14.186	0.0562	0.0655	—	—	—	—
4-1/2	15.904	0.0637	0.0743	0.0773	0.0868	0.0896	0.0996
4-3/4	17.720	0.0719	0.0838	0.0875	0.0934	0.1019	0.1133
5	19.635	0.0804	0.0938	0.0982	0.1047	0.1147	0.1275
5-1/4	21.647	0.0894	0.1042	0.1093	0.1166	0.1281	0.1424
5-1/2	23.748	0.0988	0.1151	0.1212	0.1292	0.1423	0.1581
5-3/4	25.967	0.1086	0.1268	0.1337	0.1423	0.1570	0.1745
6	28.274	0.1189	0.1388	0.1461	0.1560	0.1725	0.1916
6-1/4	30.680	0.1296	0.1513	0.1599	0.1703	0.1885	0.2095
6-1/2	33.183	0.1408	0.1640	0.1736	0.1852	0.2052	0.2280
6-3/4	35.785	0.1523	0.1777	0.1881	0.2006	0.2226	0.2474
7	38.484	0.1644	0.1917	0.2031	0.2166	0.2406	0.2674
7-1/4	41.282	0.1768	0.2062	0.2187	0.2332	0.2593	0.2882
7-1/2	44.179	—	—	0.2348	0.2504	0.2787	0.3096
7-3/4	47.186	—	—	0.2514	0.2682	0.2987	0.3319

Therefore, at 94% volumetric efficiency:

- a. $(30.0996 \text{ gal/STK}) (0.94) = 2.90037 \text{ gal/STK}$
- b. $(0.0738 \text{ bbl/STK}) (0.94) = 0.0694 \text{ bbl/STK}$

[Figure 5]

Figure 5
Pump Output

DRILLING ASSEMBLY				CASING		MUD VOLUME (BBL)		CIRCULATION DATA			
Bit Size 8 1/2	Type F-2	Jet Size 11-11-11	Surface 20 Set @ 800 Ft.	Hole 1009	Pits 1346	Pump Size 5 1/2 x 10	Annular Vel. (Ft./Min.) DP	Assumed Eff. % 94	Circulation Pressure (PSI) 2000	Bottoms Up (Min.)	Total Circ. Time (Min.)
Drill Pipe Size 4 1/2	Type XH	Length 14,290	Intermediate 13 3/8 Set @ 4,500 Ft.	Total Circulating Volume 2,355		Pump Make NATIONAL	Model 10-P-130	Stk/Min 110	Bottoms Up (Min.)	Total Circ. Time (Min.)	
Drill Pipe Size —	Type —	Length —	Intermediate 9 7/8 Set @ 13,000 Ft.	In Storage 0	Weight 16	Bbl/Stk 0.06906	Bbl/Min 7.5966	Gal/Min 319	Bottoms Up (Min.)	Total Circ. Time (Min.)	
Drill Collar Size 6 1/2 x 2 1/2	Type —	Length 710	Production or Liner Set @ — Ft.	Mud Type KOH/Lime		Bbl/Min 7.5966	Gal/Min 319	Bottoms Up (Min.)	Total Circ. Time (Min.)		

Bbl/Min, Gal/Min

What is the pump output for each pump at 110 SPM?

- ___ bbl/min
- ___ gal/min

The pump output (Q) for each pump at 110 SPM is equal to:

- $$Q, \text{ bbl/min} = (\text{SPM})(\text{bbl/STK})$$

$$= (110)(0.0694)$$

$$= 7.634 \text{ bbl/min}$$
[Figure 5]
- $$Q, \text{ gal/min} = (Q, \text{ bbl/min})(42 \text{ gal/bbl})$$

$$= (7.5966)(42)$$

$$= 320 \text{ gal/min}$$
[Figure 5]

Annular Velocity

What is the annular velocity at 110 SPM on one pump, opposite:

- Drill Collars/Open Hole ($AV_{OH/DC}$) ___ ft/min
- Drill Pipe/Open Hole ($AV_{OH/DP}$) ___ ft/min
- Drill Pipe/Casing ($AV_{CSG/DP}$) ___ ft/min

The annular velocity defines the average velocity at which the mud passes through a specific annular space and is normally expressed in units of ft/min.

$$\begin{aligned} \text{Annular Velocity (AV), ft/min} &= \frac{\text{Pump Output, bbl/min}}{\text{Annular Capacity, bbl/ft}} \\ &= \frac{Q}{\text{Annular Capacity}} \end{aligned}$$

The following annular velocities opposite specific intervals will be based on pump output at 110 SPM and 94% volumetric efficiency.

- a. Drill Collars/Open Hole, $AV_{OH/DC}$

$$AV_{OH/DC} = \frac{Q}{Ann_{OH/DC}}$$

$$Ann_{OH/DC} = \frac{(8.5)^2 - (6.5)^2}{1029.4} = 0.02914 \text{ bbl/ft}$$

$$AV_{OH/DC} = \frac{(7.634 \text{ bbl/min})}{(0.02914 \text{ bbl/ft})} = 262 \text{ ft/min}$$

[Figure 6]

- b. Drill Pipe Open Hole, $AV_{OH/DP}$

$$AV_{OH/DP} = \frac{Q}{Ann_{OH/DP}}$$

$$Ann_{OH/DP} = \frac{(8.5)^2 - (4.5)^2}{1029.4} = 0.05051 \text{ bbl/ft}$$

$$AV_{OH/DP} = \frac{(7.634 \text{ bbl/min})}{(0.05051 \text{ bbl/ft})} = 151 \text{ ft/min}$$

[Figure 6]

- c. Casing/Drill Pipe, $AV_{CSG/DP}$

$$AV_{CSG/DP} = \frac{Q}{Ann_{CSG/DP}}$$

$$Ann_{CSG/DP} = \frac{(8.835)^2 - (4.5)^2}{1029.4} = 0.05616 \text{ bbl/ft}$$

$$AV_{CSG/DP} = \frac{(7.634 \text{ bbl/min})}{(0.05616 \text{ bbl/ft})} = 136 \text{ ft/min}$$

[Figure 6]

Bottoms-Up Time

What is the bottoms-up time with one pump operating at 110 SPM?

- a. ____ min

Bottoms up time with one pump operating at 110 SPM is equal to the total annular capacity (drill string in the hole) divided by the pump output in barrels per minute. In Problem #7, the total annular capacity was calculated to be 802 bbl.

$$\begin{aligned} \text{Bottoms Up} &= \frac{Ann_{cap}, \text{ bbl}}{Q, \text{ bbl/min}} \\ &= \frac{802 \text{ bbl}}{7.634 \text{ bbl/min}} \\ &= 105 \text{ min} \end{aligned}$$

[Figure 6]

Total Circulation Time

What is the total circulation time with one pump operating at 110 SPM?

a. ____ min

The total circulation time with one pump is equal to total active circulating volume divided by pump output. In Problem #9, the total active circulating system volume was calculated to be 2355 bbl.

Total Mud System Circulation Time

$$= \frac{V_{MS}, \text{ bbl}}{Q, \text{ bbl/min}}$$

$$= \frac{2355 \text{ bbl}}{7.634 \text{ bbl/min}}$$

$$= 308 \text{ min}$$

[Figure 6]

Figure 6
Annular Velocity and Circulation Time

DRILLING MUD REPORT										REPORT NO.	DEPTH
										DATE	MD
REPORT FOR CHEVRON SUPERVISOR										CONTRACTOR	PRESENT ACTIVITY
DRILLING MUD SUPPLIER										REPORT FOR CONTRACTOR SUPERVISOR	RIG NO.
WELL NAME AND NO.										FIELD OR BLOCK NO.	COUNTY, PARISH OR OFFSHORE AREA
STATE/PROVINCE											
DRILLING ASSEMBLY			CASING			MUD VOLUME (BBL)		CIRCULATION DATA			
Bit Size	Type	Jet Size	Surface	Hole	Pits	Pump Size	x	in	Annular Vel. (Ft./Min.)		
8 1/2	F-2	11-11-11	20 Set @ 800 Ft.	1009	1346	5 1/2	x	10	DP 150 DC 261		
Drill Pipe Size	Type	Length	Intermediate	Total Circulating Volume		Pump Make	Model	Assumed Eff.	Circulation Pressure (PSI)		
4 1/2	x-A	14,290	1378 Set @ 4500 Ft.	2355		10-P-130	94%		2000		
Drill Pipe Size	Type	Length	Intermediate	In Storage	Weight	Bbl/Sik	Sik/Min	Bottoms Up (Min.)			
—	—	—	958 Set @ 13,000 Ft.	0	16	0.060906	110	106			
Drill Collar Size	Length	Production or Liner	Mud Type	Bbl/Min		319	Gal/Min	Total Circ. Time (Min.)			
—	710	— Set @ — Ft.	KOH/Lime	7.5766		319		310			

Note: Total Circulation time should be used when blending mud, increasing mud density or adding a chemical treatment so any addition is made uniformly to the entire mud system. For example, if 60 sacks of a product were to be added to the mud system, it would have to be added at a rate equal to 310 minutes divided by 60 sacks, or five minutes per sack.

Surface-to-Bit Travel Time

What is the surface-to-bit travel time with one pump operating at 110 SPM?

a. ____ min

The surface-to-bit travel time is equal to drill string capacity divided by the pump output. In Problem #3, the DS_{cap} was calculated to be 207 bbl.

$$\begin{aligned}\text{Surface to Bit} &= \frac{DS_{\text{cap}}, \text{ bbl}}{Q, \text{ bbl/min}} \\ &= \frac{207 \text{ bbl}}{7.634 \text{ bbl/min}} \\ &= 27 \text{ minutes}\end{aligned}$$

Hydrostatic Pressure

What is the hydrostatic pressure, P_h , at:

- 9-5/8 inch casing shoe, P_h ____ psi
- 15,000 ft TD/TVD, P_h ____ psi

Hydrostatic pressure is a function of mud density (MW) and true vertical depth (TVD); but measured depth must be used to calculate capacities.

$$P_h = (\text{MW}) (\text{TVD}) (0.052)$$

- P_h at 9-5/8 csg shoe = (16 lb/gal) (13,000 ft) (0.052) = 10,816 psi
- P_h at 15,000 ft = (16 lb/gal) (15,000 ft) (0.052) = 12,480 psi

Bottom Hole Circulating Pressure

What is the bottom hole circulating pressure at 15,000 ft if there is no imposed pressure and the annular pressure drop is 250 psi?

- ____ psi

The bottom hole circulating pressure, P_{BHC} is equal to the hydrostatic pressure, plus the sum of all the annular pressure losses, plus imposed pressure, if any.

$$\begin{aligned}P_{\text{BHC}} &= P_h + \text{APL} + P_i \\ P_h &= \text{Hydrostatic Pressure} \\ \text{APL} &= \text{Annular Pressure Loss} \\ P_i &= \text{Imposed Pressure} \\ P_{\text{BHC}} &= 12,480 + 250 + 0 = 12,730 \text{ psi}\end{aligned}$$

Equivalent Circulating Density

What is the equivalent circulating density (ECD) at 15,000 ft?

- ____ lb/gal

ECD is equivalent to total circulating pressure expressed in pounds per gallon rather than psi at the depth of interest.

$$\begin{aligned} \text{ECD} &= \frac{P_{\text{BHC}}}{(\text{TVD})(0.052)} \\ &= \frac{12,730 \text{ psi}}{(15,000 \text{ ft})(0.052)} \\ &= 16.32 \text{ lb/gal} \end{aligned}$$

Note: The actual mud weight is 16.0 lb/gal, but the formation at 15,000 ft has a force exerted on it of 16.32 lb/gal while circulating.

Section 3 Testing

Water-Based Drilling Fluids Testing Procedures

Mud Density

Mud Density is used to control subsurface pressures and stabilize the wellbore.

Mud density is commonly measured with a mud balance capable of ± 0.1 lb/gal accuracy. A mud balance calibrated with fresh water at $70^{\circ} \pm 5^{\circ}$ should give a reading of 8.3 lb/gal.

Step

4. Measure and record the temperature of the sample of mud to be tested.
5. Place the mud balance base on a flat, level surface.
6. Fill the clean, dry, mud balance cup with the sample of mud to be tested. Rotate cap until it is firmly seated. Ensure that some mud is expelled through the hole in the cap to remove any trapped air or gas.
7. Place thumb over hole in cap and hold the cap firmly on the cup. Wash or wipe the outside of the cup, and dry.
8. Place balance arm on the support base and balance it by moving the rider along the graduated scale until the level bubble is centered under the center line.
9. Read the density (weight) of the mud shown at the left-hand edge of the rider and report to nearest 0.1 lb/gal. Enter result on API Drilling Mud Report as Weight (lb/gal, lb/ft³) or Specific Gravity).

Marsh Funnel Viscosity

Marsh Funnel viscosity is used to indicate relative mud consistency or thickness.

Marsh Funnel viscosity is the time required (seconds) for a quart of mud to flow through a 2-in. long, 3/16-in. diameter tube at the bottom of the Marsh Funnel. This viscosity measurement is used to periodically report mud consistency. One quart of water should flow through a Marsh Funnel in 26 ± 0.5 seconds.

Step

1. Hold one finger over the orifice at the tip of the funnel. Pour the mud sample through the funnel screen until mud reaches the bottom of the screen (1500 cm³). Place viscosity cup beneath funnel tip. Remove finger and start stop watch.
2. Stop the watch when the mud level reaches the 1-qt mark on the viscosity cup.
3. Record the number of seconds required to outflow 1-qt of mud. Enter on Drilling Mud Report as Funnel Viscosity (sec/qt) API.
4. Measure and record temperature of mud sample to $\pm 1^{\circ}\text{F}$.

Rheology

Rheological properties measured with a rotational viscometer are commonly used to indicate solids buildups flocculation or deflocculation of solids, lifting and suspension capabilities, and to calculate hydraulics of a drilling fluid.

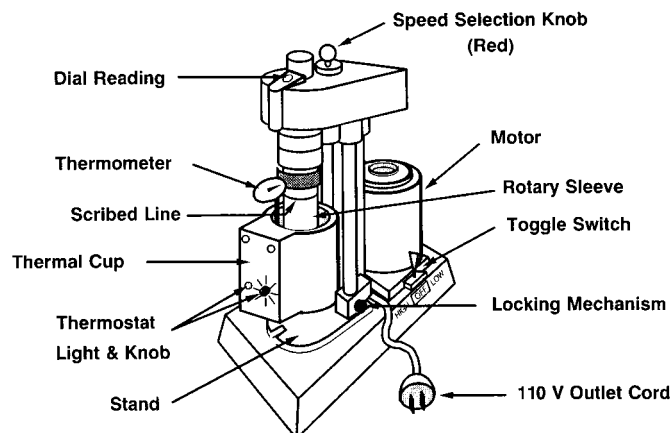
A rotational viscometer is used to measure shear rate/shear stress of a drilling fluid - from which the Bingham Plastic parameters, PV and YP, are calculated directly. Other rheological models can be applied using the same data. The instrument is also used to measure thixotropic properties, gel strengths. The following procedure applies to a Fann Model 35, 6-speed VG Meter.

Plastic Viscosity (PV) and Yield Point (YP)

Step

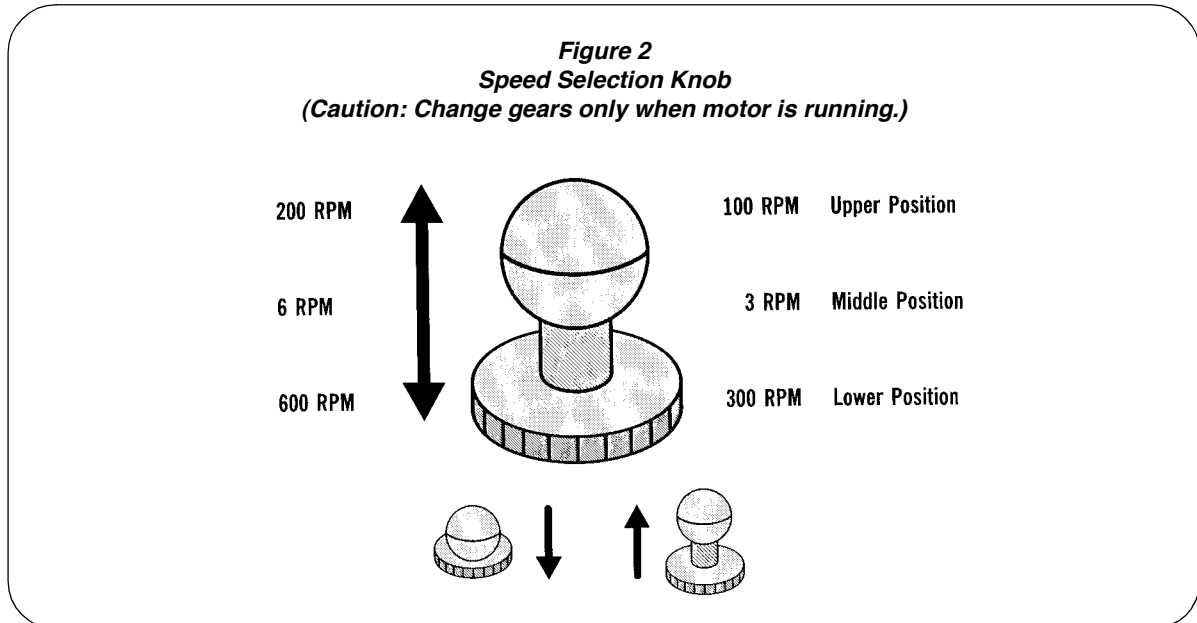
1. Obtain a sample of the mud to be tested. Record place of sampling. Measurements should be made with minimum delay.
2. Fill thermal cup approximately 2/3 full with mud sample. Place thermal cup on viscometer stand. Raise cup and stand until rotary sleeve is immersed to scribe lie on sleeve. Lock into place by turning locking mechanism (*Figure 1*).

Figure 1
Fann Model 35 6-Speed Viscometer



3. Place thermometer in thermal cup containing sample. Heat or cool sample to desired test temperature of $115^{\circ} \pm 2^{\circ}\text{F}$.
4. Flip VG meter toggle switch, located on right rear side of VG meter, to high position by pulling forward.

- Position red knob on top of VG meter to the 600-rpm speed. When the red knob is in the bottom position and the toggle switch is in the forward (high) position -this is the 600-rpm speed (Figure 2).



- With the sleeve rotating at 600-rpm, wait for dial reading in the top window of VG meter to stabilize (minimum 10 seconds). Record 600-rpm dial reading.
- With red knob in bottom position, flip the VG meter toggle switch to low position by pushing the toggle switch away from you. Wait for dial reading to stabilize (minimum 10 seconds). Records 300-rpm dial reading. [See Step 8 to calculate the Plastic Viscosity and Yield Point].
- The Plastic Viscosity and Yield Point are calculated from the 600-rpm and 300-rpm dial readings as follows:

$$PV, cP = \left(\frac{600\text{-rpm}}{\text{dial reading}} \right) - \left(\frac{300\text{-rpm}}{\text{dial reading}} \right)$$

$$YP, lb/100 \text{ ft}^2 = \left(\frac{300\text{-rpm}}{\text{dial reading}} \right) - \left(\frac{\text{Plastic}}{\text{Viscosity}} \right)$$

Gel Strength (10-sec/10-min)

Step

- With red knob in bottom position, flip toggle switch to 600-rpm position (forward position). Stir mud sample for 10 seconds.
- Position red knob to the 3-rpm speed. When the red knob is in the middle position and the toggle switch is in low (rear) position - this is the 3-rpm speed. Flip toggle switch to off position. Allow mud to stand undisturbed for 10 seconds.

3. After 10 seconds, flip toggle switch to low (rear) position and note the maximum dial reading. This maximum dial deflection is the 10-second (initial) gel strength in lb/100 ft². Record on the mud check sheet.
4. Pull toggle switch to high and position red knob to 600-rpm speed. Stir mud for 10 seconds.
5. After 10 seconds, and while mud is still stirring, position red knob to the 3-rpm speed. Flip toggle switch to off position and allow mud to stand undisturbed for 10 minutes.
6. After 10 minutes, flip toggle switch to low (rear) position and note the maximum dial reading. This maximum dial deflection is the 10-minute gel strength in lb/100 ft². Record on the mud check sheet.

Static Filtration Tests

Control of filtration properties of a drilling fluid can be useful in reducing tight hole conditions and fluid loss to formations.

Static filtration tests are used to indicate filter cake quality and filtrate volume loss for a drilling mud under specific testing conditions. Filtration characteristics are affected by the types and quantities of solids and their physical and chemical interactions. Temperature and pressure further affect these solids and their interactions.

To operate any equipment, manufacturer's instructions should be carefully read. The following are general instructions for a possible configuration of Low-Pressure/Low-Temperature Filtration and High-Pressure/High-Temperature Filtration equipment. To operate any other units, manufacturer's instructions should be carefully read before attempting to perform testing.

Low-Temperature/Low-Pressure Filtration

1. Open main air valve by turning handle (located on lab bench) counter clockwise. Adjust regulator to read 100 psi.
2. Be sure cell components, especially the screen, are clean and dry. Check gaskets and discard any that are worn or distorted.
3. Assemble filtration cell (as illustrated in *Figure 3*). Lock cell bottom into position by turning cell body until peg locks into *J slot*.
4. Pour mud sample to within 1/2 in. of top of cell. Place cell onto filter press rack.
5. Position cell lid onto top of cell body. To seal, turn filter press handle clockwise until hand-tight.
6. Place a clean, dry graduated cylinder under the drain tube of the filtration cell assembly.
7. Close bleeder valve. Maintain in the closed position while test is running (*Figure 4*).
8. Set interval timer for 30 minutes. Open valve located on filter press manifold by turning black knob counterclockwise. Pull timer arm down and begin timing immediately.
9. At the end of 30 minutes, remove graduated cylinder. Measure and record filtrate volume collected. Volume is measured in cm³ per 30 minutes. Close valve by turning black knob clockwise. Open bleeder valve and release trapped line pressure.

Figure 3
Low-Temperature/Low-Pressure Filtration Apparatus

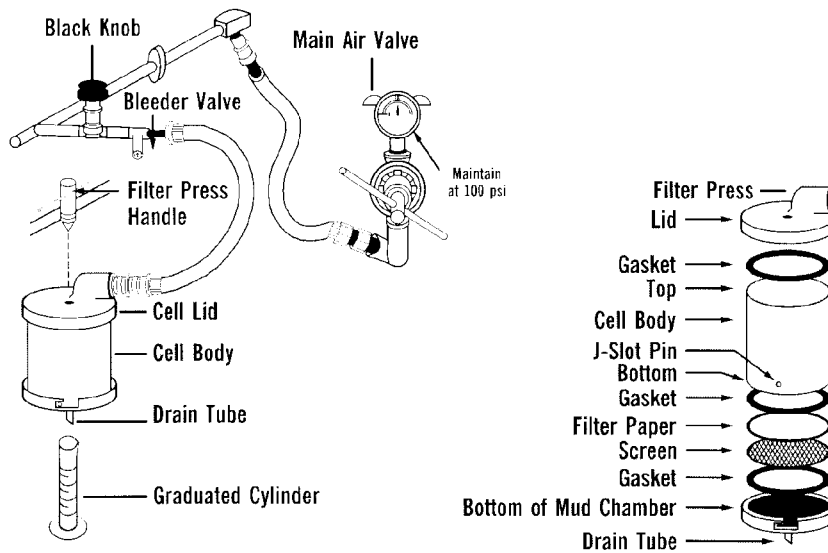
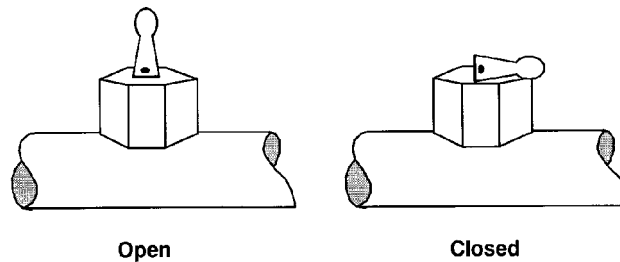


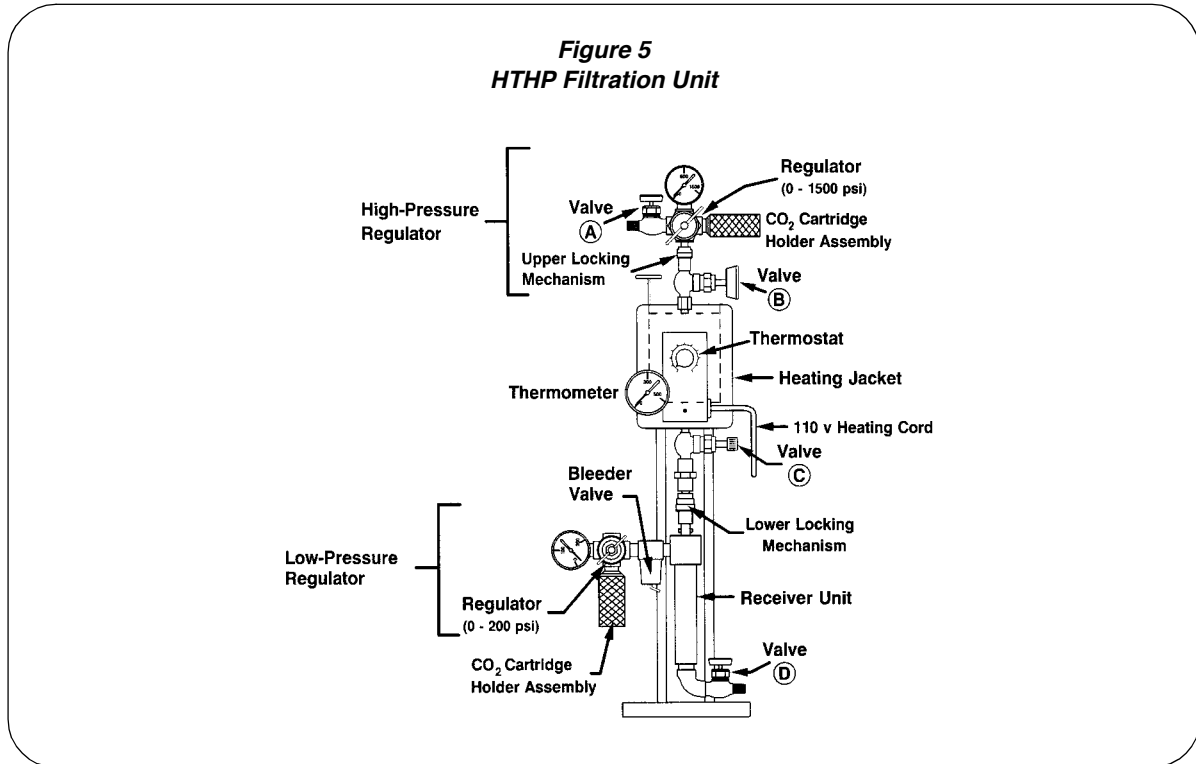
Figure 4
Bleeder Valve



10. Turn filter press handle counterclockwise to remove filtration cell assembly from frame. Pour mud back into viscosity cup, then carefully disassemble mud chamber.
11. Remove filter paper from screen, being careful not to disturb mud cake. Gently wash excess mud from cake with a stream of water.
12. Measure and report thickness of filter cake to nearest 1/32 of an inch. Describe cake; i.e., soft, tough, rubbery, firm, etc.

High-Temperature/High-Pressure Filtration (HTHP)

To operate this or any other unit, manufacturer's instructions should be carefully read before attempting to perform testing. Extreme caution should be used in running this test. Equipment should be cleaned and maintained in good working condition (*Figure 5*).



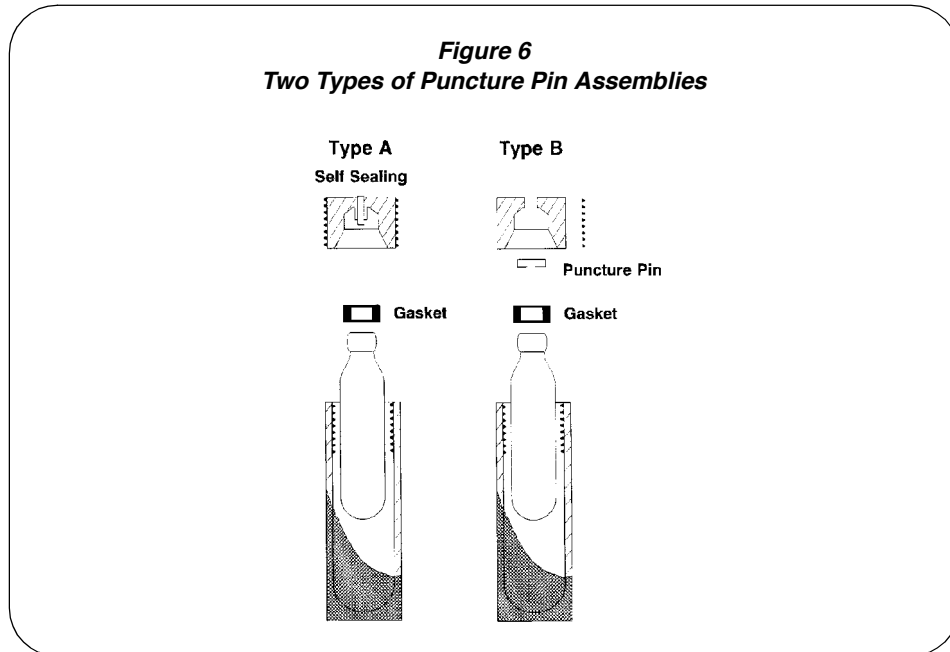
Step

1. Plug heating jacket cord into correct voltage for the unit.
2. Place metal thermometer in hole on outside from of heating jacket. Adjust thermostat and preheat jacket to 10°F above desired test temperature.
3. While jacket is heating, check o-rings (3) on the following components and replace if worn or distorted:
 - High-Pressure Regulator
 - Lid/Valve
 - Cell Body

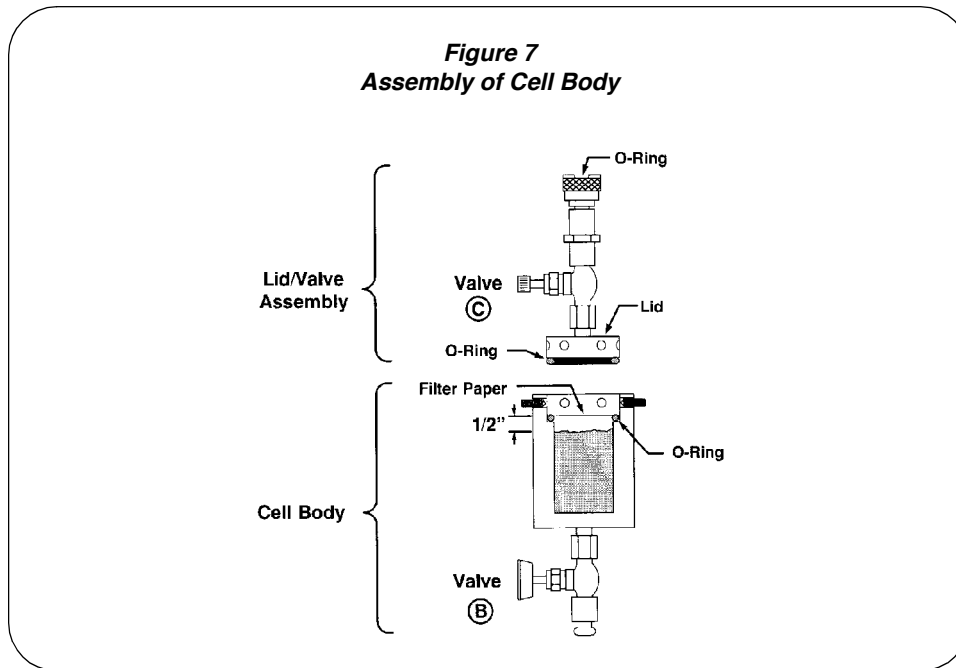
(See *Figures 6, 7 and 8* for details.)

4. Stir mud sample 10 minutes with a high-speed mixer.
5. Close valve A by turning black knob clockwise.

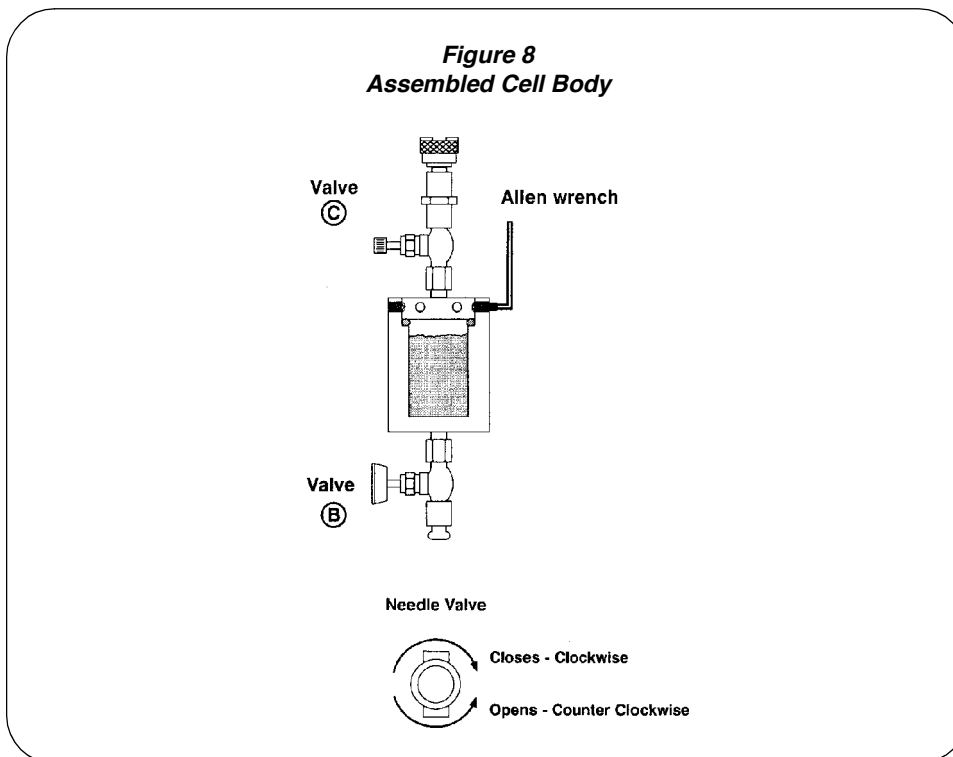
- Turn handle counterclockwise on high pressure regulator, then load CO₂ cartridge into chamber (Figure 6).



- Close valve B and pour stirred mud sample into cell, leaving 1/2 in. from the top lip to allow for expansion. Position o-ring in groove inside cell body. Place filter paper on top of o-ring (Figure 7).



- Open valve C and seat lid/valve assembly. Lubricate threads of allen screws with silicone grease and tighten (*Figure 8*).



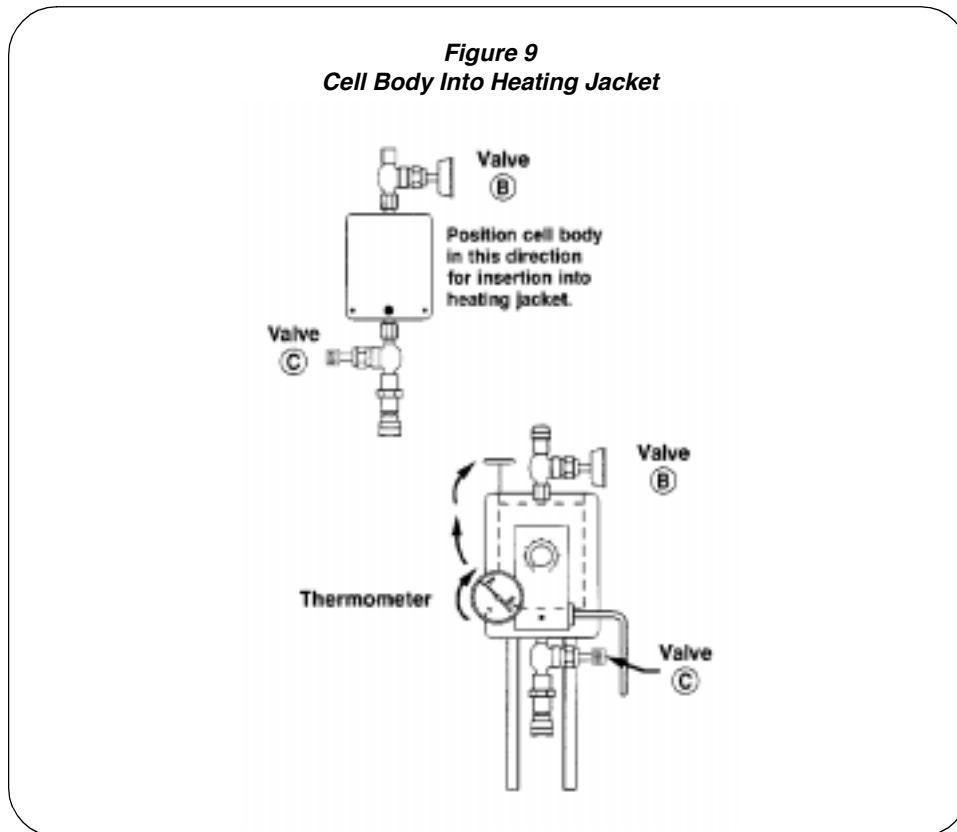
- Close low-pressure shut-off valve.
- Invert cell. (The lid/valve assembly is now at the bottom.) Carefully, install cell assembly into heating jacket.

Caution: The Heating Jacket is hot!

Transfer thermometer from the jacket to the thermometer well located on top of HTHP cell body (*Figure 9*).

- Slip high-pressure regulator (0-1500 psi) onto top of valve B and lock into place with steel ring.
- Slip low-pressure regulator (0-200 psi) on bottom of valve C. Lock into place with steel ring. Be sure bleeder valve on low-pressure regulator is in the horizontal (closed) position.
- With valves B and C closed, apply 100 psi to both the high-pressure regulator and the low-pressure regulator by turning regulator handles clockwise.
- Open valve B. This is done to maintain 100 psi back pressure in the cell body while heating to the desired temperature. Heating time should not exceed 1 hour (*Figure 10*).

Figure 9
Cell Body Into Heating Jacket



15. When desired temperature is reached, increase pressure on high-pressure regulator to 600 psi by turning regulator handle clockwise.

Note: If pressure on low-pressure regulator rises above 100 psi during the test, cautiously reduce pressure by drawing off a portion of filtrate using valve D located on bottom of filtrate collection chamber.

16. Open valve C. Start timer immediately at this point! Collect filtrate for 30 minutes, maintaining test temperature within $\pm 5^{\circ}\text{F}$ (Figure 11).
17. At the end of 30 minutes close valve. Carefully open valve D and collect filtrate. Leave valve open until low-pressure gauge reads 0 psi.
18. Note the total volume of filtrate, test temperature and pressure, and cell heat-up time. Because most HTHP filter presses have a filter area of 3.5 in.^2 , the filtrate volume collected must be doubled to correct to API standard 7.1 in.^2 . Calculate and record the API HTHP filtrate as follows:

$$\text{API HTHP Filtrate} = 2(\text{cm}^3 \text{ filtrate collected})$$

Figure 10
Valve Positions During Heat-Up

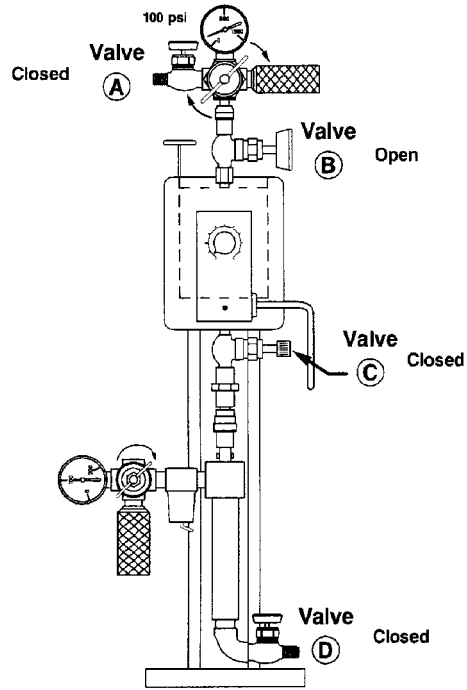
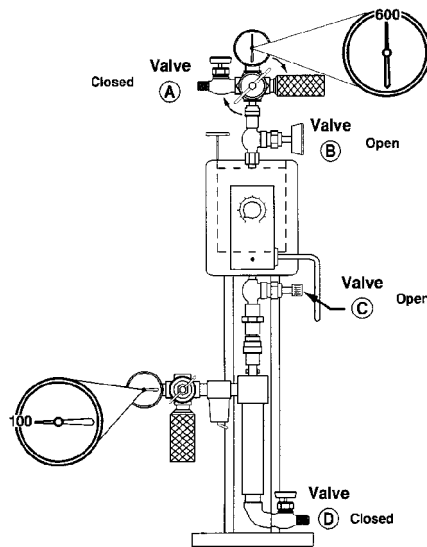


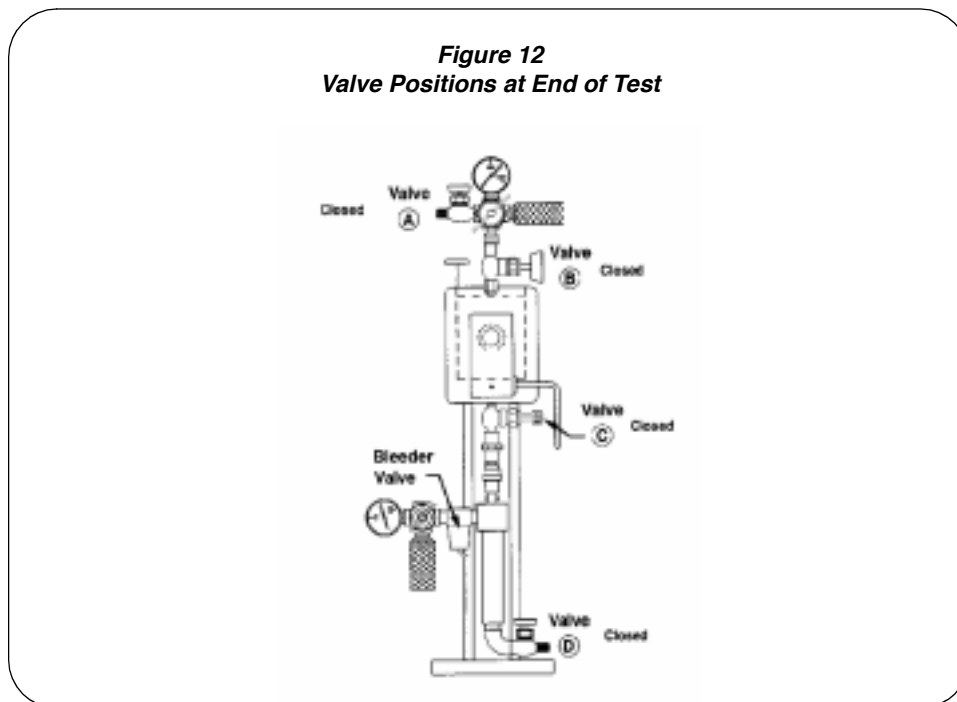
Figure 11
Valve Positions During Filtration



19. Unplug unit and allow cell and contents to cool to room temperature before proceeding to disassembly procedure.

Note: **CAUTION** - Throughout the disassembly procedure, always assume there could be trapped high pressure in the HTHP unit.

20. After HTHP cell assembly and contents are cooled to room temperature, proceed with disassembly and cleaning procedure. Valves B and C should already be in the closed positions (*Figure 12*).



21. To bleed pressure from the high-pressure (top) regulator, be sure valve B is closed. Turn regulator handle clockwise and carefully open valve A. Bleed pressure until CO₂ cartridge is expended and high-pressure gauge reads 0 psi (*Figure 13*).
22. To bleed pressure from the low-pressure (bottom) regulator, be sure that valve C is closed. Turn regulator handle clockwise and carefully open valve D. Bleed pressure until CO₂ cartridge is expended and low-pressure gauge reads 0 psi (*Figure 14*). The pressure on the high-pressure gauge and the low-pressure gauge should now read 0 psi. If not, carefully bleed pressure until both gauges read 0 psi, then remove regulators.
23. Remove cell from heating jacket and place in sink. Carefully open valve C and bleed pressure trapped in the cell. Now, open valve B. All pressure should now be released (*Figure 14*).

Figure 13
Valve Positions to Bleed Pressure

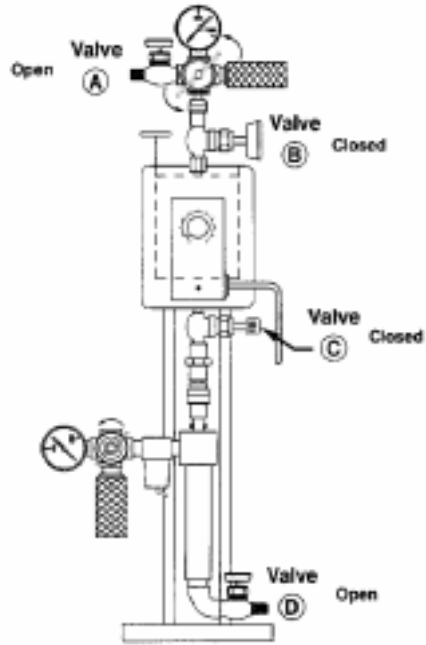
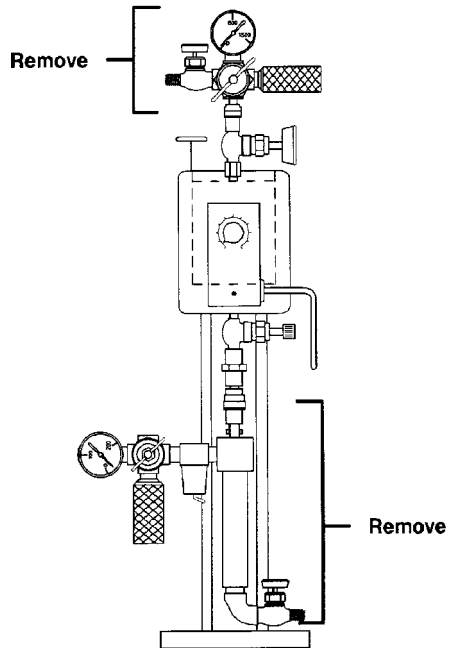
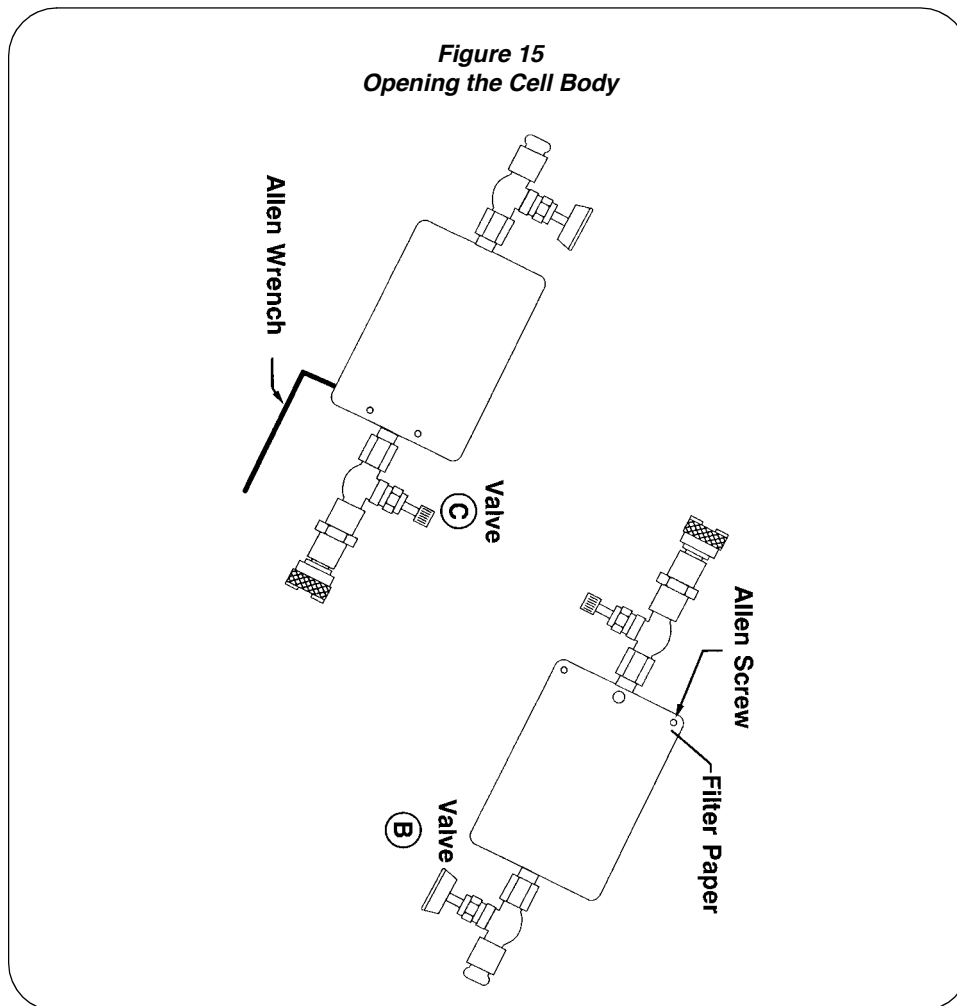


Figure 14
Removing Top and Bottom Pressure Regulators after Bleed Down



24. Remove Allen screws, being careful to point the top assembly away from your body in case any pressure may be trapped (Figure 15).

Note: If Allen Screws are tight, DO NOT attempt to remove them because the cell may contain trapped pressure! This requires special procedures to unplug valves C and B.



25. Open cell and carefully remove filter paper and cake from screen, being careful not to disturb the filter cake. Wash excess mud from cake with a small, gentle stream of water.
26. Measure and report thickness of filter cake to nearest 1/32 of an inch. Describe condition of the cake.
27. Discard the mud. Clean the cell. Cleaning includes removal of valves B and C to prevent mud from drying in the cell assembly, which could cause valves to plug in future tests.

Retort -Water, Oil and Solids

Accurate measurement of water, oil and solids content provides fundamental information for control of mud properties and is essential for evaluating solids control equipment.

The volume percent of liquid phase (water and oil) are measured by heating a known volume of whole mud in a retort unit. The liquid is evaporated from the mud, vapor is condensed and measured as oil and fresh water in a graduated glass tube. Suspended solids are calculated by difference of liquid collected subtracted from whole mud volume (retort cup volume).

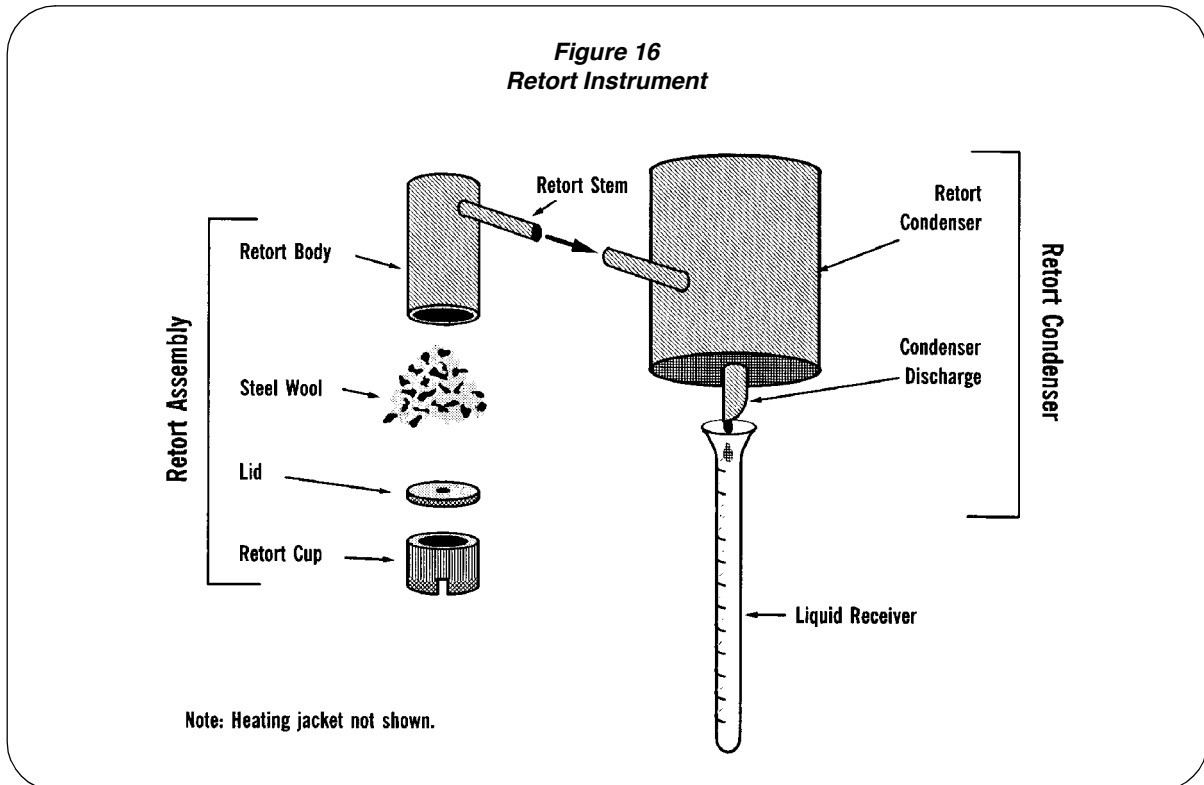
Retort Test Procedure

Step

1. Clean and dry the retort assembly and condenser. Condenser passage should be cleaned using a pipe cleaner.
2. Mix the mud sample thoroughly to ensure homogeneity, being careful not to entrain any air, and that no solids remain on the bottom of container. Air or gas entrapment will cause erroneously high retort solids due to reduced mud sample volume.
3. Use a clean syringe to obtain a sample of the mud to be tested.
4. Fill retort cup slowly to avoid air entrapment. Lightly tap side of cup to expel air. Place lid on the cup. Rotate lid to obtain a proper fit. Be sure a small excess of mud flows out of the hole in the lid. Wipe off any excess mud without wicking any of the sample from inside the cup. Wipe the cup clean with towel.
5. Pack retort body with steel wool.
6. Apply Never-Seez to threads of retort cup. With lid in place, hand tighten retort cup onto retort body (*Figure 16*).
7. Apply Never-Seez to threads on retort stem and attach the condenser.
8. Place the retort assembly inside the heating jacket and close the lid.
9. Place the clean, dry, liquid receiver below the condenser discharge tube. The length of the receiver may require that it be angled out from the retort and supported off the edge of the work table.
10. Plug cord into 110-volt outlet. Allow the retort to run for a minimum of 45 minutes.

Note: If mud boils over into the receiver, the test must be rerun. Pack the retort with a larger amount of steel wool and repeat the test.

11. Allow the receiver to cool. Read and record: (1) total liquid volume, (2) oil volume, and (3) water volume in the receiver.
12. Unplug retort and allow to cool. Disassemble and clean the retort assembly and condenser.



13. Calculate volume percent water (V_W), volume percent oil (V_O), and volume percent retort solids (V_S), as follows:

$$V_O = \frac{100(\text{volume of oil, cm}^3)}{V_{RC}}$$

$$V_W = \frac{100(\text{volume of water, cm}^3)}{V_{RC}}$$

$$V_S = \frac{100 - (V_W + V_O)}{V_{RC}}$$

$$V_{RC} = \text{Volume of the retort cup}$$

(See Retort Cup Verification Procedure)

Retort Cup Verification Procedure

Step

1. Allow retort cup, lid and distilled water to reach ambient temperature. Record the temperature.
2. Place the clean, empty retort cup and lid on a balance (precision of 0.01 g) and tare to zero.
3. Fill retort cup with distilled water. Place lid on the cup. Rotate lid to obtain proper fit. Be sure a small excess of water flows out of hole in lid. Wipe excess water from lid; avoid wicking out water.

4. Place filled retort cup and lid on the previously tared balance. Read and record weight of water, to 0.01 g.
5. Calculate the retort cup volume, V_{RC} , using density of water at measured temperature from Table 1 as follows:

$$V_{RC} = \frac{\text{Weight of water, g}}{\text{Density of water, g/cm}^3}$$

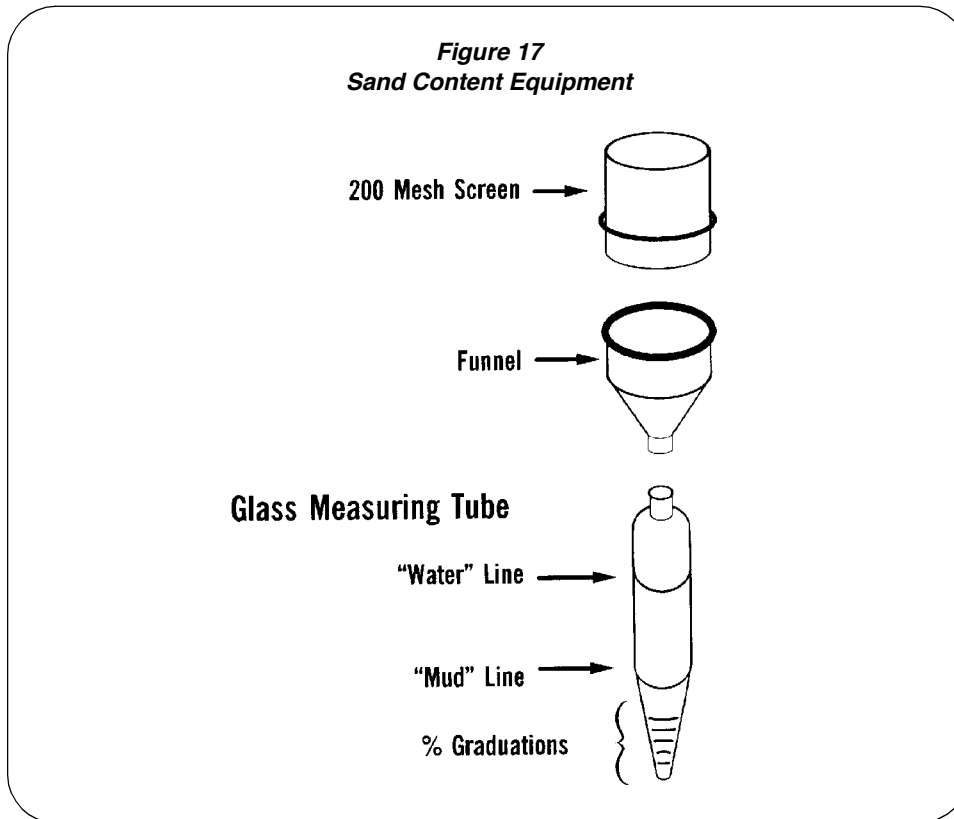
Table 1
Density of Water

°F	°C	Density, g/cm ³
59	15	0.9991
59.9	15.5	0.9991
60.8	16	0.9990
61.7	16.5	0.9990
62.6	17	0.9989
63.5	17.5	0.9987
64.4	18	0.9986
65.3	18.5	0.9985
66.2	19	0.9984
67.1	19.5	0.9983
68	20	0.9982
68.9	20.5	0.9981
69.8	21	0.9980
70.7	21.5	0.9979
71.6	22	0.9977
72.5	22.5	0.9976
73.4	23	0.9975
74.3	23.5	0.9974
75.2	24	0.9973
76.1	24.5	0.9971
77	25	0.9970
77.9	25.5	0.9969
78.8	26	0.9968
79.7	26.5	0.9966
80.6	27	0.9965
81.5	27.5	0.9964
82.4	28	0.9962
83.3	28.5	0.9961
84.2	29	0.9959
85.1	29.5	0.9958
86	30	0.9956
86.9	30.5	0.9955
87.8	31	0.9953
88.7	31.5	0.9952
89.6	32	0.9950
90.5	32.5	0.9949
91.4	33	0.9947
92.3	33.5	0.9945
93.2	34	0.9944
94.1	34.5	0.9942
95	35	0.9940

Sand Content

This simple test is used to determine the volume percent sand-sized particles in a mud. The information is used to make adjustments in solids control equipment. Sand causes excessive wear on mixing equipment, drill string, and on pump parts.

The sand content in a mud system is estimated by wet screen analysis using a 200-mesh (74-micron) screen. It should be recognized that it is a size-classification of particles and other products, such as lost circulation materials (LCM), lignite, coarsely-ground barite, etc. will also show up as sand-sized particles. The presence of these solids, especially LCM, should be noted and quantified if sufficient volume is present (*Figure 17*).



Step

1. Fill glass measure tube to *"mud"* line with mud. Add water to next scribed mark. Place thumb over mouth of tube and shake vigorously.
2. Pour mixture onto the clean screen. Add more water to tube and shake. Pour onto screen. Discard liquid that passes through the screen.
3. Repeat Step 2 until wash water is clean. Then wash sand retained on screen in order to free any adhering mud.
4. Place funnel on top of screen assembly. Slowly invert assembly and insert tip of funnel into glass tube. Wash sand back into tube with a fine spray of water or a wash bottle.

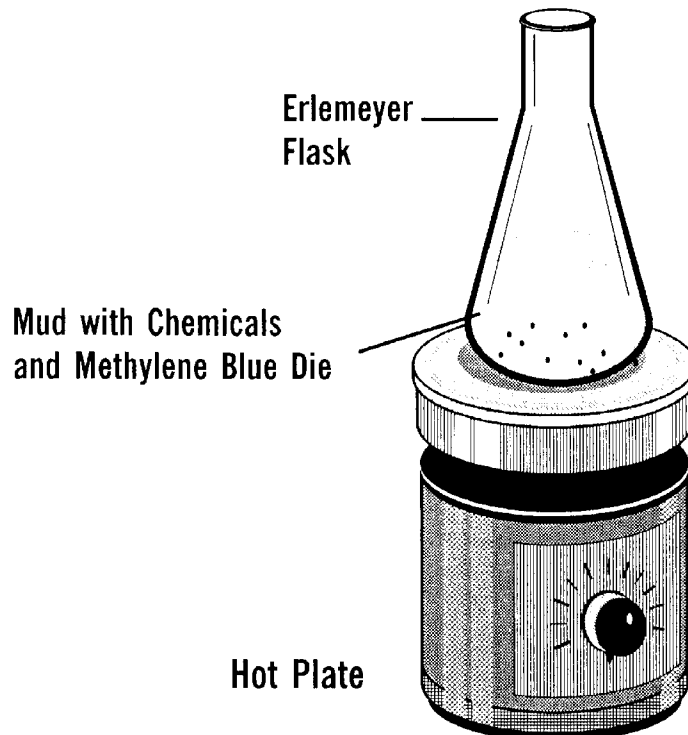
5. Allow sand to settle. Read and record volume percent sand from graduations on the glass measuring tube.

Methylene Blue Capacity

The methylene blue capacity test indicates the concentration of reactive clays present in a drilling fluid. Reactive clays are commercial bentonite and formation solids such as shales.

Methylene blue dye is added to a sample of whole mud until all reactive sites have adsorbed the dye. A faint blue/turquoise halo will form around the drop of solids when there is an excess of dye. Drilling muds frequently contain other materials that adsorb methylene blue. Treatment with hydrogen peroxide is intended to remove the effects of organic materials such as CMC, polyacrylates, lignosulfonates, and lignites. Commercial clays such as bentonite and formation solids such as shales adsorb methylene blue and contribute to the methylene blue capacity of the mud. A variation of the cation exchange capacity test can be used to determine the reactivity of shales and clays to allow better determination of the true bentonite concentration in the fluid (*Figure 18*).

Figure 18
Methylene Blue Test Set-Up



Step

1. If the mud to be tested contains air, stir slowly for 2-3 minutes to release entrapped air.

2. Use a 2.5 or 3.0-cm³ syringe to measure exactly 2.0 cm³ of drilling fluid.
3. To the Erlenmeyer flask, add 10 cm³ water and 2 cm³ of mud.
4. Next, add 15 cm³ of 3% hydrogen peroxide to the flask. Then, add 0.5 cm³ of 5N sulfuric acid.
5. Gently boil the suspension for 10 minutes on the hot plate.
6. After boiling, remove flask from hot plate and bring the total suspension volume in the Erlenmeyer flask to 50 cm³ with distilled water. Allow to cool before proceeding to the next step.
7. With a 1-cm³ pipette, add methylene blue to the flask in 0.5-cm³ increments. If the approximate amount of methylene blue is known from prior testing, larger increments can be added at the beginning of this titration.) After each addition of methylene blue solution, swirl the contents of flask for 30 seconds. While the solids are still suspended, remove a drop of liquid on the end of a glass rod. Place the drop onto a Whatman #1 filter paper. Observe the liquid that wicks out from around the solids on the paper. The solids will be blue. The liquid will become blue (and form a halo) when the initial endpoint of the methylene blue titration is reached. (This initial endpoint means that the active solids are almost saturated with the blue dye, but perhaps not all.)
8. To find the final endpoint, after detecting the initial endpoint, swirl the flask for 2 minutes and place another drop on a clean area of the filter paper. If the blue ring (or halo) is again evident, the final endpoint has been reached. If the blue ring is not evident, continue as before adding 0.5-cm³ increments of methylene blue solution - until the blue ring is present after 2 minutes of swirling the flask.
9. The methylene blue test results are reported as methylene blue capacity (MBC) or as lb/bbl bentonite equivalent as in equations (a) and (b) below:
 - a. $MBC = \text{cm}^3 \text{ methylene blue solution} / \text{cm}^3 \text{ mud sample}$
 - b. $\text{lb/bbl bentonite equivalent} = 5 (MBC)$

pH

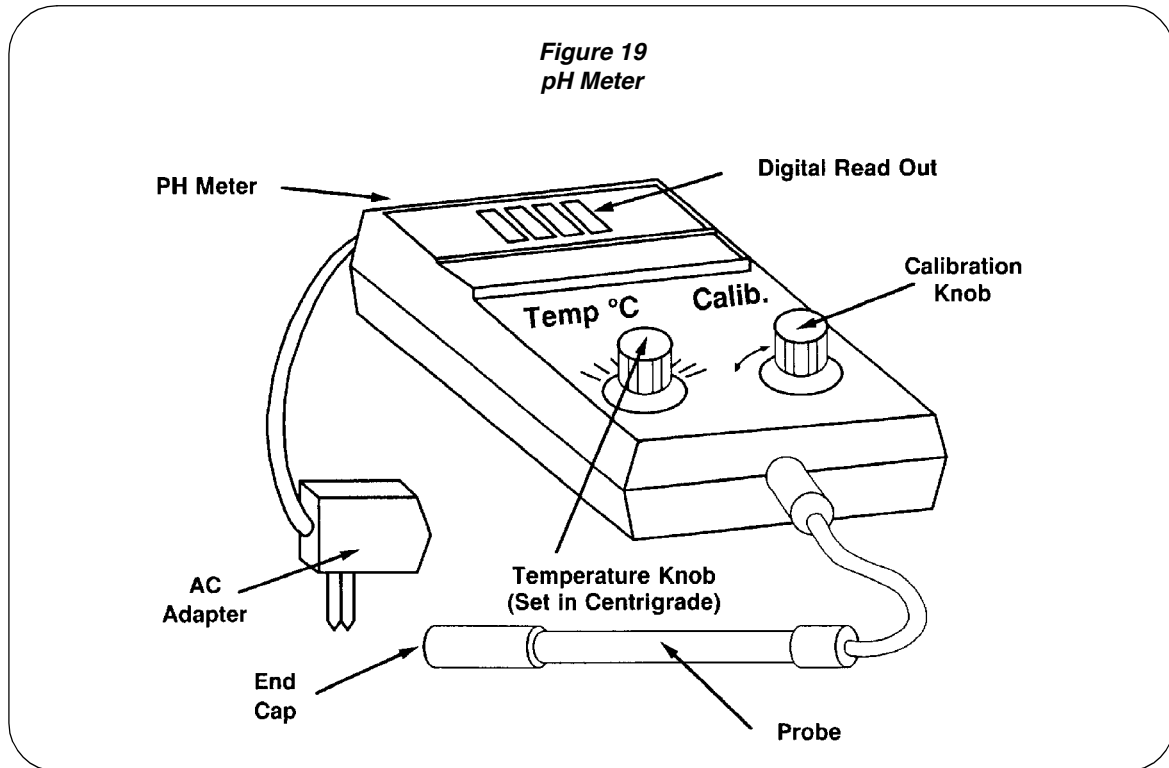
Drilling fluid pH measurements and pH adjustments are fundamental to drilling fluid control because clay interactions, solubility of additives, and contaminant removal are all pH-dependent.

The recommended method for pH measurement is with a pH meter. A portable pH meter (*Figure 19*) consists of a pH probe and an electronic voltage meter. The probe contains:

- glass electrode
- standard reference electrode
- temperature sensor (optional)

Step

1. Measurement consists of: (1) calibration of meter, (2) pH measurement of sample, and (3) cleaning and storing the probe.
2. Remove end-cap and rinse probe with distilled water. Blot dry.



3. Allow sample to come to temperature of the buffers and the probe, preferably 70-80°F (20-28°C).
4. Measure temperature of pH7 buffer solution. Place probe into pH7 buffer solution and turn on meter. Wait for reading to stabilize.
5. Set temperature knob to the temperature of the pH7 buffer solution. Adjust meter calibration knob to display the temperature-corrected pH. Buffer bottle will list the correct pH value for various temperatures. Rinse electrode with distilled water and blot dry.
6. Repeat Steps 4 and 5 using either pH4 or pH10 buffer. Choose the buffer closest to sample pH (usually pH10 for muds). If meter does not display correct buffer pH value, adjust calibration knob to obtain correct pH reading. Rinse electrode with distilled water and blot dry. Place probe back into pH7 buffer solution and recheck pH. If displayed pH value is the same as previously read in Step 5, use the slope adjustment screw located at rear of meter to set the correct pH reading. Then, repeat Step 6 until meter reads correct buffer values.
7. After meter is calibrated with the two buffers, rinse the probe and blot dry. Place probe in sample and gently stir. Allow reading to stabilize.
8. Record sample temperature in °F or °C. Record the sample's pH to nearest 0.1.
9. Unplug the meter. Clean probe with distilled water. Saturate the cotton in end cap with pH4 buffer. Place cap on probe.

Alkalinity and Lime Content

Alkalinity measurements are used to determine the buffering capacity of a drilling fluid (capacity to neutralize acidic components or contaminants). From the alkalinity measurements (P_M, P_F, M_F), concentration of hydroxyl (OH^-), carbonate (CO_3^{2-}) and bicarbonate (HCO_3^-) ions can be estimated. Knowledge of mud and filtrate alkalinities is important to ensure proper mud chemistry control of a drilling fluid. Hydroxyl alkalinity is necessary for solubilizing some products such as the lignite-based additives. On the other hand, carbonate and bicarbonate alkalinities adversely affect performance of clay-based muds.

Chemical Tests	Mud Alkalinity	Filtrate Alkalinity	
	P_M	P_F (Column 1)	M_F (Column 2)
Sample	1 cm ³ mud	1 cm ³ filtrate	con't from Column 1
Deionized Water	25-50 cm ³	None	None
Buffer	None	None	None
Color Indicator	4-5 drops Phenolphthalein	2-3 drops Phenolphthalein	2-3 drops Methyl Orange
Titrant	0.02N (N/50) H ₂ SO ₄ (Sulfuric Acid)	0.02N (N/50) H ₂ SO ₄ (Sulfuric Acid)	0.02N (N/50) H ₂ SO ₄ (Sulfuric Acid)
Color Change	Pink to Original Mud Color	Pink to Original Mud Color	Yellow to Pink
Record	$\frac{\text{cm}^3 \text{ of } 0.02N \text{ H}_2\text{SO}_4}{\text{cm}^3 \text{ of mud}}$	$\frac{\text{cm}^3 \text{ of } 0.02N \text{ H}_2\text{SO}_4}{\text{cm}^3 \text{ of filtrate}}$	$\frac{\text{cm}^3 \text{ of } 0.02N \text{ H}_2\text{SO}_4}{\text{cm}^3 \text{ of filtrate}}$ + cm ³ of H ₂ SO ₄ for P_F
Note		Proceed to Column 2	

Mud Alkalinity (P_M)

Whole mud (liquid + solids) alkalinity is used to estimate the quantity of undissolved lime, which is used in controlling lime muds and in treating out cement.

Step

1. Measure 1.0 cm³ of mud into a titration vessel using a 2.5 or 3.0-cm³ syringe.
2. Add 50 cm³ of distilled water to the mud sample and stir with stirring rod.
3. Add 5 drops of phenolphthalein indicator solution. A pink color will appear if alkalinity is present.

4. While stirring, rapidly titrate with 0.02 normal (N/50) sulfuric acid until the pink color disappears.

Note: If endpoint color change is masked, a pH meter can be used to determine when the endpoint of pH 8.3 is reached.

5. Report the phenolphthalein alkalinity of the mud, P_M , as the number of cm^3 of 0.02 normal (N/50) acid required per cm^3 of mud.

Filtrate Alkalinity (P_F)

Filtrate (liquid only) P_F alkalinity can indicate presence of hydroxyl and carbonate ions in most mud systems.

Step

1. Measure 1 cm^3 of LPLT (Sec. *Low-Temperature/Low-Pressure Filtration*) filtrate into titration vessel using a 2.5- or 3.0- cm^3 syringe.
2. Add 3 drops of phenolphthalein indicator solution.
3. If indicator turns pink, titrate (drop by drop) with 0.02 normal (N/50) sulfuric acid until the pink color just disappears.
4. Report the phenolphthalein alkalinity of the filtrate, P_F , as the number of cm^3 of 0.02 normal acid required per cm^3 of filtrate.

Note: If the indicator color change is masked because of a dark-colored filtrate, the endpoint can be determined using a pH meter. The endpoint is recorded as the cm^3 of sulfuric acid required to reduce the filtrate sample pH to 8.3.

Filtrate Alkalinity (M_F)

Filtrate (liquid only) M_F alkalinity can indicate presence of carbonate ions and can be roughly related with GGT carbonates.

Step

1. To the same sample which has just been titrated to the P_F endpoint, add 3 drops of methyl orange indicator solution.
2. Titrate with 0.02 normal (N/50) sulfuric acid (drop by drop) while stirring until the indicator changes from yellow to pink.
3. Report the methyl orange alkalinity (M_F) as the total cm^3 of 0.02 normal acid per cm^3 of filtrate required to reach the methyl orange endpoint. The M_F is recorded as the total volume of acid

require per cm³ of filtrate. (The total volume includes the cm³ of acid in the P_F titration plus the cm³ of acid in the M_F titration.)

Note: The endpoint can be determined using a pH meter. The endpoint is recorded as the total volume of acid required to reduce the filtrate sample pH to 4.3

Estimated concentrations of hydroxyl, carbonate and bicarbonate ions can be determined using Table 3 below.

Table 3
Ionic Relationships with Alkalinity Titrations
Estimated Concentrations, mg/L

	OH ⁻ (Hydroxyls)	CO ₃ ⁼ (Carbonates)	HCO ₃ ⁻ (Bicarbonates)
P _F = 0	0	0	1220 (M _F)
2P _F < M _F	0	1200 (P _F)	1220 (M _F - 2P _F)
2P _F = M _F	0	1200 (P _F)	0
2P _F > M _F	340 (2P _F - M _F)	1200 (M _F - P _F)	0
P _F = M _F	340	(M _F)	0

Note: These equations are valid for very simple filtrates, but become less valid as the filtrates become more complex with soluble lignite, ligno-sulfonates, acetates, etc.

Lime Content

Step

1. Determine the P_F and P_M alkalinities of the mud.
2. Determine the volume fraction of water in the mud, F_W, from the retort as follows:

$$F_W = \frac{\text{Volume percent water}}{100}$$

3. Calculate and report the lb/bbl lime content in the mud using the following equation:

$$\text{Lime, lb/bbl} = 0.26[P_M - (F_W)(P_F)]$$

Chloride

The chloride ion content is a useful indicator of drilling through salt stringers, taking saltwater flows and for checking the quality of make-up water.

Chloride ion (Cl^-) analysis is a titration of the filtrate sample using silver (Ag^+) ion to reach an orange-red endpoint of silver chromate from the potassium chromate indicator. Being able to see this endpoint is critical. Therefore, technique will depend on the color of the filtrate.

Table 4
Chloride Titration Chart

Chemical Tests	Chlorides (Cl ⁻) - Light-Colored Filtrates	
	Column 1	Column 2
Sample	1 cm ³ filtrate	con't from Col. 1
Deionized Water	None	25-50 cm ³
Buffer	None	None
Color Indicator	2-3 drops Phenolphthalein	8-10 drops Potassium Chromate
Titrate With: (Titrant)	0.02 (N/50) H ₂ SO ₄ (sulfuric acid)	0.028N AgNO ₃ or 0.282N AgNO ₃ *(silver nitrate)
Color Change	Pink to original Filtrate color	Yellow to Orange-Red
Record	None	$\frac{(\text{cm}^3 \text{ 0.0282N AgNO}_3)(1000)}{\text{cm}^3 \text{ Filtrate -OR-}}$ $\frac{(\text{cm}^3 \text{ 0.282N AgNO}_3)(10,000)}{\text{cm}^3 \text{ Filtrate}}$
Note:	Proceed to Col. 2	*Chlorides: 10,000 mg/L If < use: 0.0282N AgNO ₃ If > use: 0.282N AgNO ₃

Lightly-Colored Filtrates [Table 4]

Step

1. Measure 1 cm³ filtrate into the titration vessel.
2. Add 2-3 drops phenolphthalein indicator solution.
3. If indicator turns pink, stir sample with glass stirring rod. While stirring, add 0.02N (N/50) sulfuric acid (drop by drop) until the color disappears.
4. Add 50 cm³ deionized water and 10 drops of potassium chromate solution.
5. Stir continuously while adding silver nitrate solution (Use 0.0282N for chlorides <10,000 mg/L and 0.282N for chlorides >10,000 mg/L.) from pipette until the color changes from yellow to orange-red and persists for 30 seconds.
6. Record the number of cm³ of silver nitrate solution required to reach the endpoint.

7. Calculate and report the chloride ion concentration of filtrate, mg/L, as follows:

For Cl⁻ <10,000 mg/L:

$$\text{Chloride, mg/L} = \frac{(\text{cm}^3 \text{ of } 0.0282\text{N AgNO}_3)(1000)}{\text{cm}^3 \text{ of filtrate}}$$

For Cl⁻ >10,000 mg/L:

$$\text{Chloride, mg/L} = \frac{(\text{cm}^3 \text{ of } 0.282\text{N AgNO}_3)(10,000)}{\text{cm}^3 \text{ of filtrate}}$$

**Table 5
Chloride Titration Chart**

Chemical Tests	Chlorides (Cl ⁻) - Dark-Colored Filtrates	
	Column 1	Column 2
Sample	1 cm ³ filtrate	con't from Col. 1
Deionized Water	None	25-50 cm ³
Buffer	None	1 g CaCO ₃ (calcium carbonate)
Color Indicator	2-3 drops Phenolphthalein	5-10 drops Potassium Chromate
Titrate With: (Titrant)	0.02 (N/50) H ₂ SO ₄ (sulfuric acid)	0.028N AgNO ₃ or 0.282N AgNO ₃ *(silver nitrate)
Color Change	Pink to original Filtrate color	Yellow to Orange-Red
Record	None	$\frac{(\text{cm}^3 \text{ 0.0282N AgNO}_3)(1000)}{\text{cm}^3 \text{ Filtrate -OR-}}$ $\frac{(\text{cm}^3 \text{ 0.282N AgNO}_3)(10,000)}{\text{cm}^3 \text{ Filtrate}}$
Note:	Proceed to Col. 2	*Chlorides: 10,000 mg/L If < use: 0.0282N AgNO ₃ If > use: 0.282N AgNO ₃

Dark-Colored Filtrates [Table 5]

Step

1. Measure 1 cm³ filtrate into the titration vessel.
2. Add 2-3 drops phenolphthalein indicator solution. If solution is too dark to observe color, add 2 cm³ of 0.02N (N/50) sulfuric acid and stir.
3. To this solution add 1 g calcium carbonate and stir. While stirring add 50 cm³ deionized water and 10 drops of potassium chromate solution
4. Continue to stir. Add silver nitrate solution (Use 0.0282N for chlorides <10,000 mg/L, and 0.282N for chlorides >10,000 mg/L.) from pipette until the color changes from yellow to orange-red and persists for 30 seconds.
5. Record the number of cm³ of silver nitrate solution required to reach the endpoint.
6. Report the chloride ion concentration of filtrate in mg/L as follows:

For Cl⁻ <10,000 mg/L:

$$\text{Chloride, mg/L} = \frac{(\text{cm}^3 \text{ of } 0.0282\text{N AgNO}_3)(1000)}{\text{cm}^3 \text{ of filtrate}}$$

For Cl⁻ >10,000 mg/L:

$$\text{Chloride, mg/L} = \frac{(\text{cm}^3 \text{ of } 0.282\text{N AgNO}_3)(10,000)}{\text{cm}^3 \text{ of filtrate}}$$

Total Hardness [Table 6]

The hardness of water or mud filtrate is due primarily to the presence of calcium (Ca⁺⁺) and magnesium (Mg⁺⁺) ions. The harder the water, the more difficult for many chemicals to function, particularly bentonite clay. Also, hardness decreases efficiency of most polymers.

Hardness analysis is a titration of divalent cations in a filtrate using EDTA reagent with an indicator that changes from wine-red to blue at the endpoint. The endpoint will be gray-blue in dark-colored filtrates.

Step

1. Add 50 cm³ deionized water to titration vessel; then, add 2 cm³ (20 drops) of Versenate Hardness Buffer Solution.
2. Add 10 drops of Versenate Hardness Indicator solution. If calcium and/or magnesium is present in the deionized water, a wine-red color will develop. If not, the solution will remain blue.
3. While stirring, titrate with EDTA (standard versenate) until solution color changes from wine-red to blue. DO NOT GO PAST ENDPOINT!

Note: Steps 1-3 have removed the hardness from the deionized water if any was present.

4. Add 1 cm³ of filtrate to the deionized water. If calcium and/or magnesium is present, a wine-red color will develop. While stirring, titrate (drop by drop) with EDTA until color indicator changes from wine-red to blue.
5. Note the cm³ of EDTA and calculate hardness, mg/L, as follows:

$$\text{Total hardness, mg/L} = \frac{(\text{cm}^3 \text{ of EDTA})(400)}{\text{cm}^3 \text{ of filtrate}}$$

Table 6
Total Hardness Titration Chart

Chemical Tests	Total Hardness	
	Column 1	Column 2
Sample	None	1 cm ³ filtrate
Deionized Water	50 cm ³	None
Buffer	2 cm ³ Versenate Hardness Buffer	None
Color Indicator	10 drops Versenate Hardness Indicator	None
Titrate With: (Titrant)	EDTA (Standard Versenate)	EDTA (Standard Versenate)
Color Change	Wine Red to Blue Do not go past endpoint!	Wine Red to Blue
Record	None	$\frac{(\text{cm}^3 \text{ of EDTA})(400)}{\text{cm}^3 \text{ Filtrate}}$
Note:	Proceed to Col. 2	

Calcium and Magnesium [Table 7]

As mentioned under Total Hardness, divalent cations can adversely affect mud properties. Calcium and Magnesium can affect muds in different ways, therefore, they may need to be analyzed separately.

Calcium analysis is a titration of a filtrate using EDTA reagent, plus a high pH buffer so that the magnesium ions are precipitated and only calcium ion is being analyzed.

Table 7 Calcium/Magnesium Hardness Titration Chart			
Chemical Tests	Calcium		Magnesium (Mg⁺⁺)
	Column 1	Column 2	
Sample	None	1 cm ³ filtrate	None
Deionized Water	50 cm ³	None	None
Buffer	1 cm ³ Versenate Calcium Hardness Buffer	None	None
Color Indicator	Pinch of Calver II Indicator Powder	None	None
Titrate With: (Titrant)	EDTA (Standard Versenate)	EDTA (Standard Versenate)	None
Color Change	Wine Red to Blue Do not go past end- point!	Wine Red to Blue	None
Record	None	$\frac{(\text{cm}^3 \text{ of EDTA})(400)}{\text{cm}^3 \text{ Filtrate}}$	Total Hardness - Calcium x 243
Note:	Proceed to Col. 2		This calculation is based on recorded results from Total Hardness and Cal- cium tests.

Step

1. Add 50 cm³ deionized water to titration vessel, then add 1 cm³ Calcium Hardness Buffer solution.
2. Add a pinch of Calver II indicator powder. If calcium is present, a wine-red color will develop.
3. While stirring, titrate with EDTA (drop by drop) until sample color changes from wine-red to blue. **DO NOT GO PAST ENDPOINT!**
4. Add 1 cm³ of filtrate to the deionized water. If calcium is present, a wine-red color will develop. While stirring, titrate with EDTA (drop by drop) until the color indicator changes from wine-red to blue.
5. Note the cm³ of EDTA and calculate calcium, mg/L, as follows:

$$\text{Calcium, mg/L} = \frac{(\text{cm}^3 \text{ of EDTA})(400)}{\text{cm}^3 \text{ of filtrate}}$$

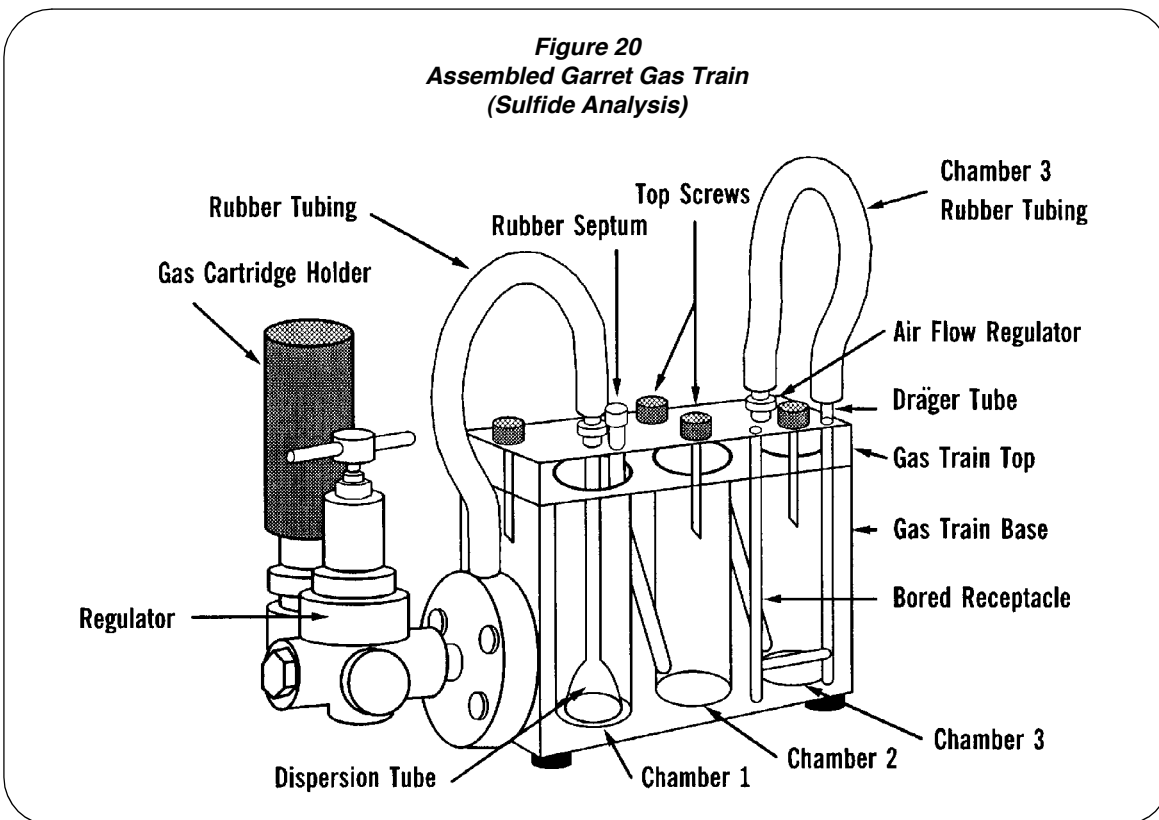
- The magnesium ion concentration is determined by difference of the total hardness less the calcium, times a factor of (0.6).

$$\text{Magnesium, mg/L} = [(\text{Total Hardness, mg/L}) - (\text{Calcium, mg/L})] (0.6)$$

Sulfide

If hydrogen sulfide gas (H_2S) or soluble sulfides exist in a mud they are very corrosive to the drill string and may lead to catastrophic pipe failure. H_2S , even in low concentrations, presents both health and environmental hazards. Therefore, the monitoring of soluble sulfides in a mud system is critical, especially when drilling in areas known to contain H_2S . Soluble sulfides can be quantitatively determined in a mud filtrate sample using a Garrett Gas Train (GGT).

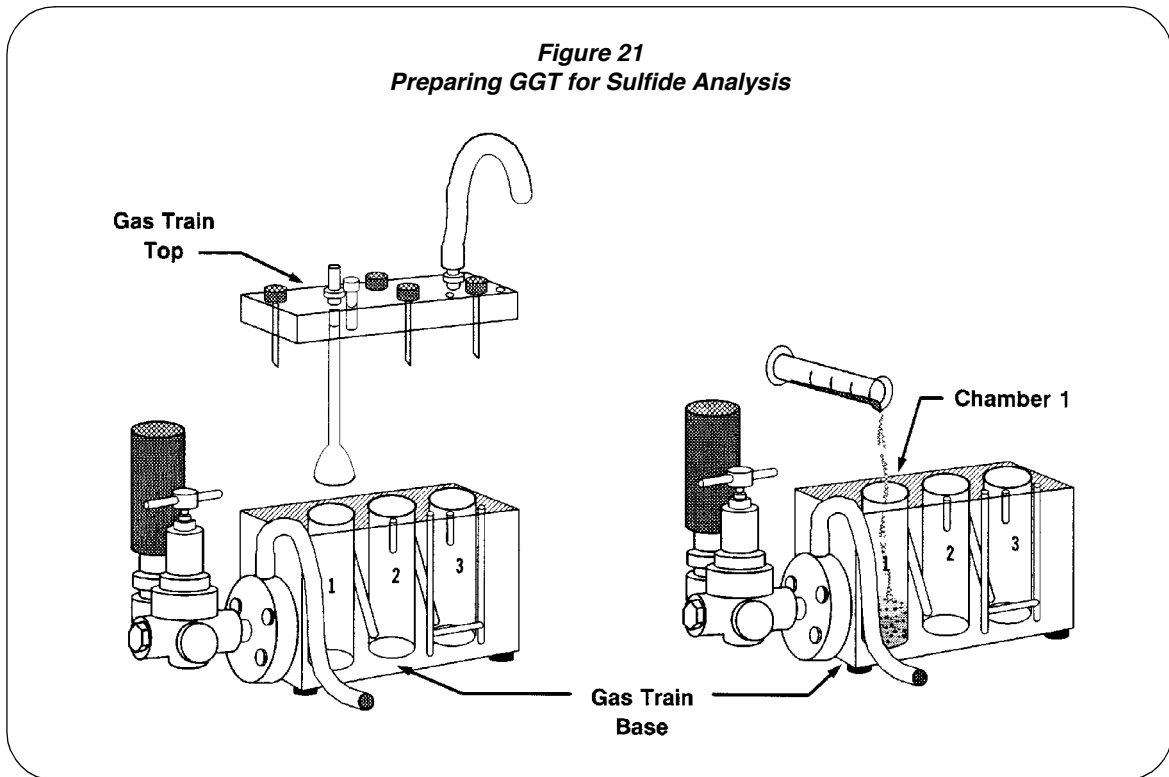
H_2S , when it enters an alkaline mud, immediately ionizes and is neutralized forming sulfide, S^{2-} , and bisulfide, HS^- ions. When the mud's filtrate is put into a GGT and acidified, the original H_2S gas is reformed, liberated and measured by a stain on the Dräger tube in the GGT.



Step

- Be sure the Garrett Gas Train is clean, dry and on a level surface with the top removed.
- To Chamber 1, add 20 cm³ of deionized water and 5 drops of defoamer (Figure 21).

Figure 21
Preparing GGT for Sulfide Analysis



- To select the correct Dräger tube and sample volume required for the expected sulfide range, use Table 8 below.

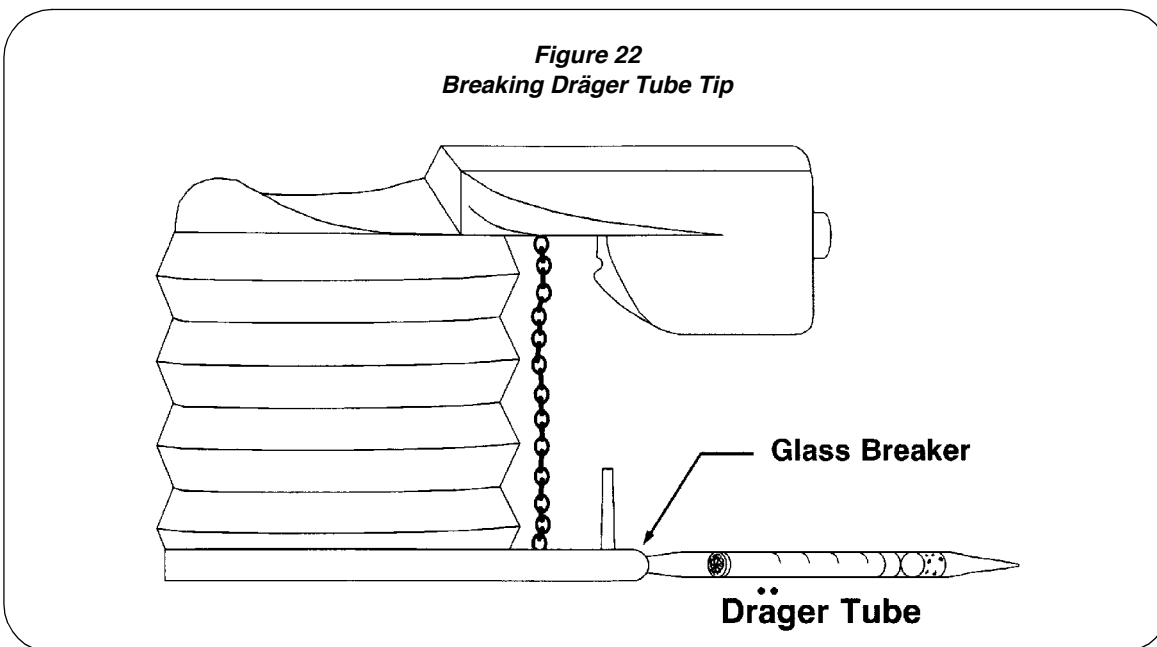
Table 8
Dräger Tube Identification
Sample Volumes and Tube Factors to be
Used for Various Sulfide Ranges

Sulfide Range (mg/L)	Sample Volume (cm ³)	Dräger Tube I.D. (See Tube Body)	Tube Factor
1.2 - 24	10.0	H ₂ S 100/a	12
1.5 - 48	5.0		
4.8 - 96	2.5		
60 - 1020	10.0		
120 - 2040	5.0	H ₂ S 0.2% A	600*
240 - 4080	2.5		

Note: *Tube Factor 600 is based on a *Batch Factor* (stenciled on box) of 0.40. For another *Batch Factor* (as stenciled on box), a corrected Tube Factor should be calculated:

$$\text{Correct Tube Factor} = (600) \left(\frac{\text{Batch Factor}}{0.40} \right)$$

4. Select the correct Dräger tube and sample volume, then carefully break the glass tip off each end of the Dräger tube (*Figure 22*).



5. Place the Dräger tube with arrow pointing downward into the bored receptacle. Install flowmeter tube with the word "Top" in the upward position in Chamber 3. Make sure o-rings seal properly (*Figure 23*).
6. Install the top on the gas train and hand-tighten all screws evenly to seal the o-rings.
7. With the regulator backed off (turn regulator handle counterclockwise), connect the carrier gas to the dispersion tube of Chamber 1 using rubber tubing. Install and puncture a new CO₂ cartridge. Connect the flexible tubing from Chamber 3 outlet to the Dräger tube (*Figure 24*).
8. Adjust the dispersion tube in Chamber 1 to be approximately 1/4 in. above the bottom using the white adjustment sleeve.
9. To purge air from the GGT, gently flow carrier gas for 30 seconds by turning handle on regulator clockwise. Check for leaks. Shut off carrier gas (CO₂) by turning regulator handle counterclockwise.
10. Collect a sufficient volume of solids-free filtrate obtained from low-pressure/low-temperature filtration test. If a low concentration of soluble sulfides is anticipated, a larger volume of filtrate will be needed (as shown in Table 8).

Figure 23
Dräger Tube Installed in GGT Base

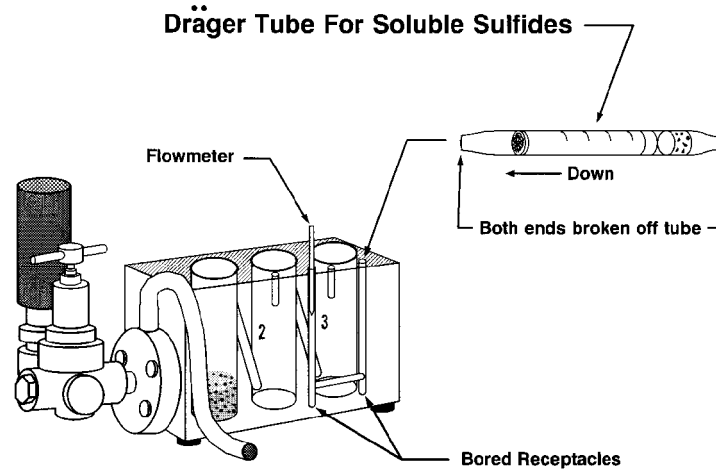
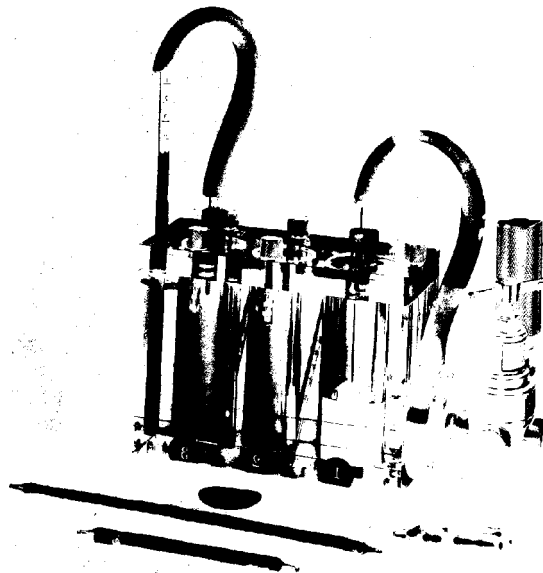


Figure 24
Reassembled GGT with Sulfide Test in Progress



11. Using a hypodermic syringe and needle, inject a measured volume of the solids-free filtrate sample into Chamber 1 through the rubber septum. Next, with another syringe, slowly inject 10 cm³ 5N sulfuric acid.
12. Immediately restart the carrier gas flow by turning handle clockwise. The flow rate should be maintained between 200-400 cm³/minute (keep ball between two lines on flowmeter). Continue flowing for a total of 15 minutes. One CO₂ cartridge should provide 15-20 minutes of flow at this rate.

13. Observe changes in appearance of the Dräger tube. Note and record the maximum darkened length (in units marked on the tube) before the stain front starts to smear.

Note: If sulfites are present in the high-range Dräger tube, an orange color (caused by SO₂) may appear ahead of the black front. This orange region should be ignored. Record only the darkened length.

Note: For best Dräger tube accuracy, the "Darkened Length" should fill more than half the tube's length.

14. Using the measured *sample volume*, the Dräger tube's maximum *Darkened Length* and the *Tube Factor* (Table 3), calculate mg/L sulfide as follows:

$$\text{Sulfide, Mg/L} = \frac{(\text{Darkened Length}^*)(\text{Tube Factor})}{\text{Sample Volume, cm}^3}$$

**In units marked on the tube*

15. To clean the gas train, remove the flexible tubing and remove the top. Take Dräger tube and flow-meter out of the receptacles and plug the holes with stoppers to keep them dry. Wash the GGT with a soft brush, warm water and mild detergent. A pipe cleaner may be used to clean the passages between the chambers. Wash, rinse and blow out the dispersion tube with a dry air. Rinse the GGT apparatus with deionized water and allow to dry.

A lead-acetate paper disk fitted under the o-ring of Chamber 3 can be substituted for the Dräger tube in the gas train. The lead-acetate paper will qualitatively show the presence or absence of sulfides in the sample. A dark discoloration of the paper is a positive indication of sulfides. After a positive indication of sulfides, the test should be repeated using a Dräger tube for a quantitative analysis.

Carbonate/Bicarbonate

Carbonate/bicarbonate contamination is often difficult to detect. It can cause poor filter cake quality and excessive mud rheology which can lead to problems such as loss of circulation and the sticking of pipe and logging tools. The Garrett Gas Train is a reliable means of measuring carbonate/bicarbonate contamination.

CO₂, when it enters an alkaline mud, immediately ionizes and is neutralized forming carbonate (CO₃⁼) and bicarbonate (HCO₃⁻) ions. When the mud's filtrate is put into a GGT and acidified, the original CO₂ gas is reformed, liberated and measured by the stain on the CO₂ Dräger tube (after first being collected in a 1-liter gas bag).

Step

1. Be sure the Garrett Gas Train is clean, dry and on a level surface, with the top removed.

Note: If CO₂ has been used as a carrier gas in the previous test, purge GGT with N₂O carrier gas for at least 1 minute.

2. Add 20 cm³ of deionized water to Chamber 1, then add 5 drops of octanol* defoamer. (*Avoid inhalation or skin contact.)
3. Install the top on the gas train and hand-tighten all screws evenly to seal the o-rings.
4. Turn regulator handle counterclockwise to avoid pressurization. Connect flexible tubing to the dispersion tube of Chamber 1. Install and puncture N₂O cartridge.
5. Adjust the dispersion tube in Chamber 1 to approximately 1/4 in. off bottom using white adjustment sleeve.
6. See Table 9 for sample volume required for the expected carbonate range and for the Dräger tube identification.

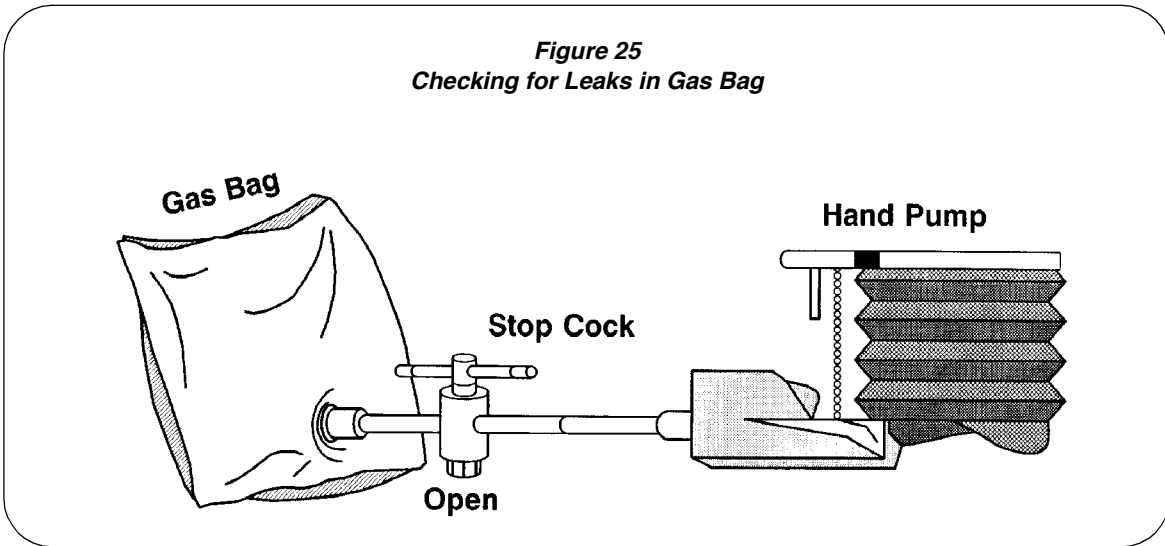
**Table 9
Dräger Tube Identification
Sample Volumes and Tube Factors
to be Used for Various Carbonate Ranges**

Carbonate Range (mg/L)	Sample Volume (cm ³)	Dräger Tube I.D. (See Tube Body)	Tube Factor
25 - 700	10.0		
50 - 1500	5.0	CO. 0.12%/a	25,000
250 - 7500			

7. Gently flow carrier gas for 1 minute by turning handle on regulator clockwise to purge air from the system. Check for leaks. Shut off carrier gas.
8. Connect the gas bag and stopcock to hand pump. Use a discarded Dräger tube as a connection and start with an empty gas bag (*Figure 25*).
9. Fully depress and release hand pump. When the bag is completely empty and free of leaks, the pump will remain depressed for several minutes. If leakage is detected, first check the pump and all connections. (See note below.) If the bag is found to leak, discard it.

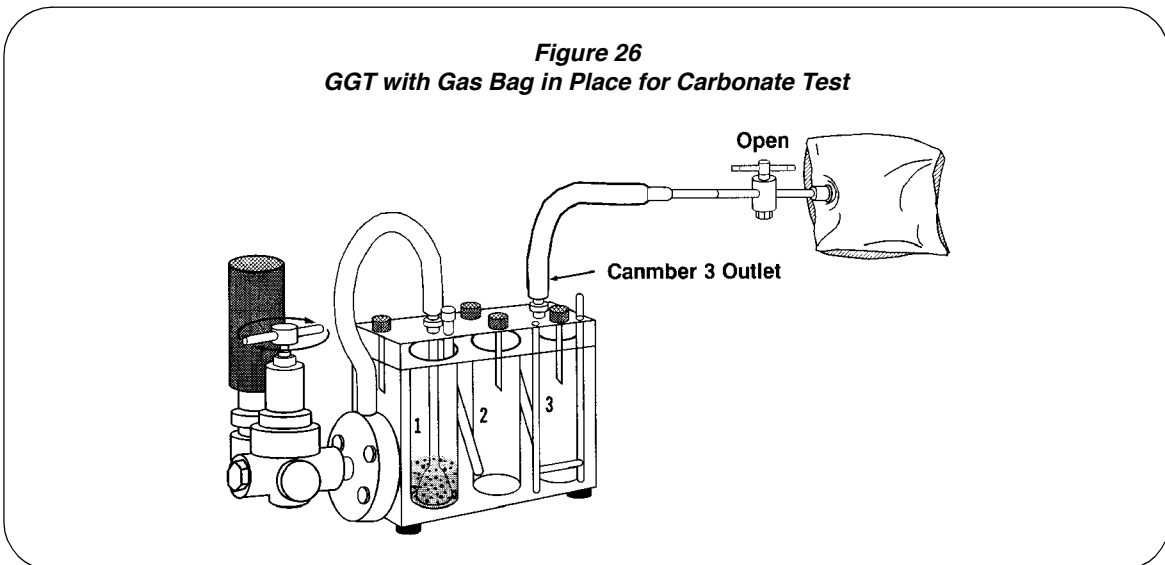
Note: To check the pump, insert a sealed Dräger tube into pump opening and depress bellows. It will remain depressed if pump does not leak.

Figure 25
Checking for Leaks in Gas Bag



10. With the bag fully collapsed, install rubber tubing from the stopcock and bag onto the outlet of Chamber 3. Close stopcock.
11. Inject a measured volume of solids-free filtrate into Chamber 1 through the rubber septum, using a hypodermic syringe and needle. Then slowly inject 10 cm³ of 5N sulfuric acid. Gently shake the gas train to mix acid with sample.
12. Open the stopcock on the gas bag and restart gas flow by turning regulator handle clockwise. Allow gas bag to gradually fill until the bag is firm to the touch (do not burst it). Try to fill bag over approximately a 10-minute interval. Shut off flow (turn handle counterclockwise) and close the stopcock.
13. Carefully break the tip off each end of the Dräger tube.

Figure 26
GGT with Gas Bag in Place for Carbonate Test



14. Remove the rubber tubing from Chamber 3 outlet and reinstall it onto the upstream end of the Dräger tube. Attach hand pump to downstream end of the Dräger tube.
15. Open the stopcock on the bag. With steady hand pressure, fully depress the hand pump. Allow pump to suction gas out of the bag and through the Dräger tube. When chain on pump is fully extended, once again depress the hand pump. Continue this procedure until the bag is empty. Ten strokes (one liter) should empty the bag. More than ten strokes indicates leakage has occurred and the test must be repeated.
16. A purple stain on the Dräger tube indicates the presence of CO₂. Record stain length in units marked on the Dräger tube including the faint blue tinge ahead of the purple stain. Using the measured *Sample Volume*, the Dräger tube *Stain Length* and *Tube Factor* (25,000) Table 4, calculate total soluble carbonates in the filtrate as follows:

$$\text{Carbonate, mg/L} = \frac{25,000(\text{Stain Length})}{\text{Sample Volume, cm}^3}$$

Note: For best Dräger tube accuracy, the *Stain Length* should fill more than half the tube length. Therefore, *Sample Volume* must be carefully selected.

17. To clean the GGT apparatus, remove the flexible tubing and top. Wash the GGT with a soft brush, warm water and mild detergent. A pipe cleaner may be used to clean the passages between the chambers. Wash, rinse and blow out the dispersion tube with a dry gas. Rinse the GGT apparatus with deionized water and allow to dry. Periodically replace the gas bag to avoid leaks and contamination.

Potassium

Potassium ions in drilling fluids are used to stabilize water sensitive shales. Maintaining proper potassium concentration is the key to successful use of potassium-based muds.

This test method is used to determine the concentration of potassium ions in mud filtrates at levels above 3.5 lb/bbl potassium chloride. K⁺ ion is precipitated as the perchlorate salt. The potassium ion concentration is determined by measuring the volume of precipitate in a graduated (Kolmer) tube and reading the concentration of potassium ions from a previously prepared standardization curve.

Equipment

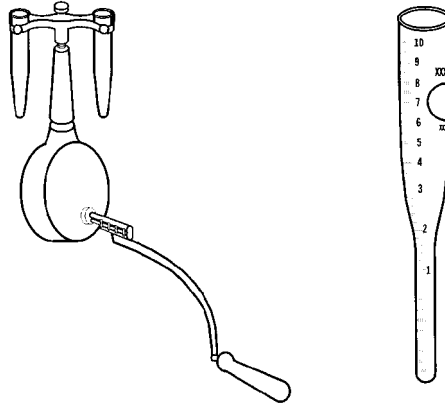
Centrifuge RPM Calibration

For this test a horizontal swing rotor head centrifuge capable of producing 1800 rpm is required. To obtain a fairly constant 1800 rpm with the manual centrifuge (*Figure 27*), determine the number of revolutions of the rotor per turn of the crank by the following procedure:

Step

1. Move the crank very slowly and count the number of revolutions of the rotor head during one turn of the crank.

Figure 27
Horizontal-Swing Rotor Head Centrifuge and Kolmer Tube



2. As an example, to obtain 1800 rpm of the head, the crank must be turned 120 times in 1 minute. At this rate, the handle must be turned 10 times in 5 seconds. By experimentation, this crank rate can be easily achieved.

Standard Potassium Calibration Curve Procedure

A standard calibration curve is required for each centrifuge and can be prepared using the following method. A minimum of three points (3.5, 10.5, and 17.5 lb/bbl KCl is required to obtain an accurate graph (Figure 28).

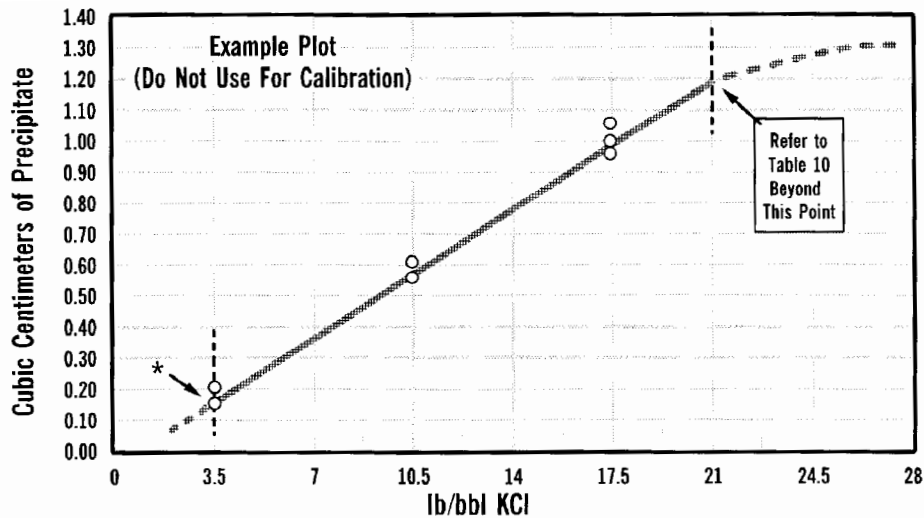
Table 10
Filtrate Volumes
for Various KCl Concentrations

Concentration Range		Filtrate Volume (cm ³)
KCl (lb/bbl)	K ⁺ (mg/L)	
3.5-18	5,250-27,000	7.0
18-35	27,000-52,500	3.5
35-70	52,500-105,000	2.0
over 70	over 105,000	1.0

Step

1. Take three Kolmer tubes and add to them: 0.5, 1.5, and 2.5 cm³ of standard potassium chloride solution. Dilute each Kolmer tube to the 7.0-cm³ mark with deionized water and agitate.
2. Add 3.0 cm³ of sodium perchlorate solution to the tube. (Do Not Agitate!)

Figure 28
Potassium Standard Example
Calibration Curve



3. Counterbalance the centrifuge tube with another tube of the same weight. Centrifuge at a constant speed of 1800 rpm for 1 minute.
4. Read the precipitate volume immediately.
5. Plot the volume of precipitate volume immediately.

Test Procedure - Potassium Ion

Step

1. Measure 7.0 cm³ of filtrate into the centrifuge tube.
2. Add 3.0 cm³ of the sodium perchlorate solution. DO NOT AGITATE! If potassium ions are present, precipitation occurs immediately.
3. Centrifuge at a constant speed of 1800 rpm for 1 minute. Immediately read and note the precipitate volume.

Note: To see if all the potassium ions have been precipitated, add 2 to 3 drops of sodium perchlorate solution to the centrifuge tube. If a white precipitate forms, repeat the test using the next smallest filtrate volume selected from Table 10.

4. Report the potassium concentration as lb/bbl of KCl. The potassium ion concentration in mg/L can be approximated by multiplying the lb/bbl value by 1500.

Oil-Based Drilling Fluids Testing Procedures

Mud Density

Mud Density is used to control subsurface pressures and stabilize the wellbore.

Mud density is commonly measured with a mud balance capable of ± 0.1 lb/gal accuracy. A mud balance calibrated with fresh water at $70^{\circ} \pm 5^{\circ}$ should give a reading of 8.3 lb/gal.

Step

1. Measure and record the temperature of the sample of mud to be tested.
2. Place the mud balance base on a flat, level surface.
3. Fill the clean, dry, mud balance cup with the sample of mud to be tested. Rotate cap until it is firmly seated. Ensure that some mud is expelled through the hole in the cap to remove any trapped air or gas.
4. Place thumb over hole in cap and hold the cap firmly on the cup. Wash or wipe the outside of the cup, and dry.
5. Place balance arm on the support base and balance it by moving the rider along the graduated scale until the level bubble is centered under the center line.
6. Read the density (weight) of the mud shown at the left-hand edge of the rider and report to nearest 0.1 lb/gal. Enter result on API Drilling Mud Report as Weight (lb/gal, lb/ft³) or Specific Gravity.

Marsh Funnel Viscosity

Marsh Funnel viscosity is used to indicate relative mud consistency or thickness.

Marsh Funnel viscosity is the time required (seconds) for a quart of mud to flow through a 2-in. long, 3/16-in. diameter tube at the bottom of the Marsh Funnel. This viscosity measurement is used to periodically report mud consistency. One quart of water should flow through a Marsh Funnel in 26 ± 0.5 seconds.

Step

1. Hold one finger over the orifice at the tip of the funnel. Pour the mud sample through the funnel screen until mud reaches the bottom of the screen (1500 cm³). Place viscosity cup beneath funnel tip. Remove finger and start stop watch.
2. Stop the watch when the mud level reaches the 1 qt mark on the viscosity cup.
3. Record the number of seconds required to outflow 1 qt of mud. Enter on Drilling Mud Report as Funnel Viscosity (sec/qt) API.
4. Measure and record temperature of mud sample to $\pm 1^{\circ}\text{F}$.

Rheology

Rheological properties measured with a rotational viscometer are commonly used to indicate solids buildup, flocculation or deflocculation of solids, lifting and suspension capabilities, and to calculate hydraulics of a drilling fluid.

A rotational viscometer is used to measure shear rate/shear stress of a drilling fluid - from which the Bingham Plastic parameters, PV and YP, are calculated directly. Other rheological models can be applied using the same data. The instrument is also used to measure thixotropic properties, gel strengths. The following procedure applies to a Fann Model 35, 6-speed VG Meter.

Plastic Viscosity (PV) and Yield Point (YP)

Step

1. Obtain a sample of the mud to be tested. Record place of sampling. Measurements should be made with minimum delay.
2. Fill thermal cup approximately 2/3 full with mud sample. Place thermal cup on viscometer stand. Raise cup and stand until rotary sleeve is immersed to scribe lie on sleeve. Lock into place by turning locking mechanism (*refer to Figure 1*).
3. Place thermometer in thermal cup containing sample. Heat or cool sample to desired test temperature of $115^{\circ} \pm 2^{\circ}\text{F}$.
4. Flip VG meter toggle switch, located on right rear side of VG meter, to high position by pulling forward.
5. Position red knob on top of VG meter to the 600-rpm speed. When the red knob is in the bottom position and the toggle switch is in the forward (high) position -this is the 600-rpm speed (*refer to Figure 2*).
6. With the sleeve rotating at 600-rpm, wait for dial reading in the top front window of VG meter to stabilize (minimum 10 seconds). Record 600-rpm dial reading.
7. With red knob in bottom position, flip the VG meter toggle switch to low position by pushing the toggle switch away from you. Wait for dial reading to stabilize (minimum 10 seconds). Record 300-rpm dial reading. [See Step 8 to calculate the Plastic Viscosity and Yield Point].
8. The Plastic Viscosity and Yield Point are calculated from the 600-rpm and 300-rpm dial readings as follows:

$$\text{PV, cP} = \left(\begin{array}{c} 600\text{-rpm} \\ \text{dial reading} \end{array} \right) - \left(\begin{array}{c} 300\text{-rpm} \\ \text{dial reading} \end{array} \right)$$
$$\text{YP, lb/100 ft}^2 = \left(\begin{array}{c} 300\text{-rpm} \\ \text{dial reading} \end{array} \right) - \left(\begin{array}{c} \text{Plastic} \\ \text{Viscosity} \end{array} \right)$$

Gel Strength (10-sec/10-min)

Step

1. With red knob in bottom position, flip toggle switch to 600-rpm position (forward position). Stir mud sample for 10 seconds.

2. Position red knob to the 3-rpm speed. When the red knob is in the middle position and the toggle switch is in low (rear) position - this is the 3-rpm speed. Flip toggle switch to off position. Allow mud to stand undisturbed for 10 seconds.
3. After 10 seconds, flip toggle switch to low (rear) position and note the maximum dial reading. This maximum dial deflection is the 10-second (initial) gel strength in lb/100 ft². Record on the mud check sheet.
4. Pull toggle switch to high and position red knob to 600-rpm speed. Stir mud for 10 seconds.
5. After 10 seconds, and while mud is still stirring, position red knob to the 3-rpm speed. Flip toggle switch to off position and allow mud to stand undisturbed for 10 minutes.
6. After 10 minutes, flip toggle switch to low (rear) position and note the maximum dial reading. This maximum dial deflection is the 10-minute gel strength in lb/100 ft². Record on the mud check sheet.

Static Filtration Tests

Control of filtration properties of a drilling fluid can be useful in reducing tight hole conditions and fluid loss to formations.

Static filtration tests are used to indicate filter cake quality and filtrate volume loss for a drilling mud under specific testing conditions. Filtration characteristics are affected by the types and quantities of solids and their physical and chemical interactions. Temperature and pressure further affect these solids and their interactions.

The following instructions for Low-Pressure/Low-Temperature Filtration and High-Pressure/High-Temperature Filtration will be applicable only to equipment used at DTC's training lab. To operate any other units, manufacturer's instructions should be carefully read before attempting to perform testing.

Low-Temperature/Low-Pressure Filtration

Step

1. Open main air valve by turning handle (located on lab bench) counter clockwise. Adjust regulator to read 100 psi.
2. Be sure cell components, especially the screen, are clean and dry. Check gaskets and discard any that are worn or distorted.
3. Assemble filtration cell (as illustrated in *Figure 3*). Lock cell bottom into position by turning cell body until peg locks into *J slot*.
4. Pour mud sample to within 1/2 in. of top of cell. Place cell onto filter press rack.
5. Position cell lid onto top of cell body. To seal, turn filter press handle clockwise until hand-tight.
6. Place a clean, dry graduated cylinder under the drain tube of the filtration cell assembly.
7. Close bleeder valve. Maintain in the closed position while test is running (*refer to Figure 4*).
8. Set interval timer for 30 minutes. Open valve located on filter press manifold by turning black knob counterclockwise. Pull timer arm down and begin timing immediately.

9. At the end of 30 minutes, remove graduated cylinder. Measure and record filtrate volume collected. Volume is measured in $\text{cm}^3/30$ minutes. Close valve by turning black knob clockwise. Open bleeder valve and release trapped line pressure.
10. Turn filter press handle counterclockwise to remove filtration cell assembly from frame. Pour mud back into viscosity cup, then carefully disassemble mud chamber.
11. Remove filter paper from screen, being careful not to disturb mud cake. Gently wash excess mud from cake with a stream of water.
12. Measure and report thickness of filter cake to nearest $1/32$ of an inch. Describe cake (i.e., soft, tough, rubbery, firm, etc.).

High-Temperature/High-Pressure Filtration (HTHP)

To operate this or any other unit, manufacturer's instructions should be carefully read before attempting to perform testing. Extreme caution should be used in running this test. Equipment should be cleaned and maintained in good working condition (*refer to Figure 5*).

Step

1. Plug heating jacket cord into correct voltage for the unit.
 2. Place metal thermometer in hole on outside from of heating jacket. Adjust thermostat and preheat jacket to 10°F above desired test temperature.
 3. While jacket is heating, check o-rings (3) on the following components and replace if worn or distorted:
 - High-Pressure Regulator
 - Lid/Valve
 - Cell Body
- (*Refer to Figures 6, 7, and 8 for details.*)
4. Stir mud sample 10 minutes with a high-speed mixer.
 5. Close Valve A by turning black knob clockwise.
 6. Turn handle counterclockwise on high pressure regulator, then load CO_2 cartridge into chamber (*refer to Figure 6*).
 7. Close valve B and pour stirred mud sample into cell, leaving $1/2$ in. from the top lip to allow for expansion. Position o-ring in groove inside cell body. Place filter paper on top of o-ring (*refer to Figure 7*).
 8. Open valve C and seat lid/valve assembly. Lubricate threads of allen screws with silicone grease and tighten (*refer to Figure 8*).
 9. Close valve C low-pressure shut-off valve.

10. Invert cell. (The lid/valve assembly is now at the bottom.) Carefully, install cell assembly into heating jacket.

Caution: The Heating Jacket is hot!

Transfer thermometer from the jacket to the thermometer well located on top of HTHP cell body (refer to Figure 9).

11. Slip high-pressure regulator (0-1500 psi) onto top of valve B and lock into place with steel ring.
12. Slip low-pressure regulator (0-200 psi) on bottom of valve C. Lock into place with steel ring. Be sure bleeder valve on low-pressure regulator is in the horizontal (closed) position.
13. With valves B and C closed, apply 100 psi to both the high-pressure regulator and the low-pressure regulator by turning regulator handles clockwise.
14. Open valve B. This is done to maintain 100 psi back pressure in the cell body while heating to the desired temperature. Heating time should not exceed 1 hour (refer to Figure 10).
15. When desired temperature is reached, increase pressure on high-pressure regulator to 600 psi by turning regulator handle clockwise.

Note: If pressure on low-pressure regulator rises above 100 psi during the test, cautiously reduce pressure by drawing off a portion of filtrate using valve D located on bottom of filtrate collection chamber.

16. Open valve C. Start timer immediately at this point! Collect filtrate for 30 minutes, maintaining test temperature within $\pm 5^{\circ}\text{F}$ (refer to Figure 11).
17. At the end of 30 minutes close valve C. Carefully open valve D and collect filtrate. Leave valve open until low-pressure gauge reads 0 psi.
18. Note the total volume of filtrate, test temperature and pressure, and cell heat-up time. Because most HTHP filter presses have a filter area of 3.5 in.^2 , the filtrate volume collected must be doubled to correct to API standard 7.1 in.^2 . Calculate and record the API HTHP filtrate as follows: API HTHP Filtrate = (2) (cm^3 filtrate collected).
19. Unplug unit and allow cell and contents to cool to room temperature before proceeding to disassembly procedure.

Note: **CAUTION** — Throughout the disassembly procedure, Always assume there could be trapped high pressure in the HTHP unit.

20. After HTHP cell assembly and contents are cooled to room temperature, proceed with disassembly and cleaning procedure. Valves B and C should already be in the closed positions (refer to Figure 12).

21. To bleed pressure from the high-pressure (top) regulator, be sure Valve B is closed. Turn regulator handle clockwise and carefully open Valve A. Bleed pressure until CO₂ cartridge is expended and high-pressure gauge reads 0 psi (*refer to Figure 13*).
22. To bleed pressure from the low-pressure (bottom) regulator, be sure that valve C is closed. Turn regulator handle clockwise and carefully open valve D. Bleed pressure until CO₂ cartridge is expended and low-pressure gauge reads 0 psi (*refer to Figure 14*). The pressure on the high-pressure gauge and the low-pressure gauge should now read 0 psi. If not, carefully bleed pressure until both gauges read 0 psi, then remove regulators.
23. Remove cell from heating jacket and place in sink. Carefully open valve C and bleed pressure trapped in the cell. Now, open valve B. All pressure should now be released (*refer to Figure 14*).
24. Remove Allen Screws, being careful to point the top assembly away from your body in case any pressure may be trapped (*refer to Figure 15*).

Note: If Allen Screws are tight, DO NOT attempt to remove them because the cell may contain trapped pressure! This requires special procedures to unplug valves C and B.

25. Open cell and carefully remove filter paper and cake from screen, being careful not to disturb the filter cake. Wash excess mud from cake with a small, gentle stream of base oil.
26. Measure and report thickness of filter cake to nearest 1/32 of an inch. Describe condition of the cake.
27. Discard the mud. Clean the cell. Cleaning includes removal of Valves B and C to prevent mud from drying in the cell assembly, which could cause valves to plug in future tests.

Retort - Water, Oil and Solids

Accurate measurement of water, oil and solids content provides fundamental information for control of mud properties and is essential for evaluating solids control equipment.

The volume percent of liquid phase (water and oil) are measured by heating a known volume of whole mud in a retort unit. The liquid is evaporated from the mud, vapor is condensed and measured as oil and fresh water in a graduated glass tube. Suspended solids are calculated by difference of liquid collected subtracted from whole mud volume (retort cup volume).

Retort Test Procedure

Step

1. Clean and dry the retort assembly and condenser. Condenser passage should be cleaned using a pipe cleaner.
2. Mix the mud sample thoroughly to ensure homogeneity, being careful not to entrain any air, and that no solids remain on the bottom of container. Air or gas entrapment will cause erroneously high retort solids due to reduced mud sample volume.
3. Use a clean syringe to obtain a sample of the mud to be tested.

4. Fill retort cup slowly to avoid air entrapment. Lightly tap side of cup to expel air. Place lid on the cup. Rotate lid to obtain a proper fit. Be sure a small excess of mud flows out of the hole in the lid. Wipe off any excess mud without wicking any of the sample from inside the cup. Wipe the cup clean with towel.
5. Pack retort body with steel wool.
6. Apply Never-Seez to threads of retort cup. With lid in place, hand tighten retort cup onto retort body (*refer to Figure 16*).
7. Apply Never-Seez to threads on retort stem and attach the condenser.
8. Place the retort assembly inside the heating jacket and close the lid.
9. Place the clean, dry, liquid receiver below the condenser discharge tube. The length of the receiver may require that it be angled out from the retort and supported off the edge of the work table.
10. Plug cord into 110-volt outlet. Allow the retort to run for a minimum of 45 minutes.

Note: If mud boils over into the receiver, the test must be rerun. Pack the retort with a larger amount of steel wool and repeat the test.

11. Allow the receiver to cool. Read and record: (1) total liquid volume, (2) oil volume, and (3) water volume in the receiver.
12. Unplug retort and allow to cool. Disassemble and clean the retort assembly and condenser.
13. Calculate volume percent water (V_W), volume percent oil (V_O), and volume percent retort solids (V_S), as follows:

$$V_O = \frac{100(\text{volume of oil, cm}^3)}{V_{RC}}$$

$$V_W = \frac{100(\text{volume of water, cm}^3)}{V_{RC}}$$

$$V_S = 100 - (V_W + V_O)$$

$$V_{RC} = \text{Volume of the retort cup}$$

(*See Retort Cup Verification Procedure*)

Retort Cup Verification Procedure

Step

1. Allow retort cup, lid and distilled water to reach ambient temperature. Record the temperature.
2. Place the clean, empty retort cup and lid on a balance (precision of 0.01 g) and tare to zero.
3. Fill retort cup with distilled water. Place lid on the cup. Rotate lid to obtain proper fit. Be sure a small excess of water flows out of hole in lid. Wipe excess water from lid; avoid wicking out water.

- Place filled retort cup and lid on the previously tared balance. Read and record weight of water to 0.01 g.
- Calculate the retort cup Volume, V_{RC} , using density of water at measured temperature from Table 1 as follows:

$$V_{RC} = \frac{\text{Weight of water, g}}{\text{Density of water, g/cm}^3}$$

Whole Mud Alkalinity (V_{SA}) and Lime Content (Lime_{OM})

The alkalinity of an oil mud is used to calculate the pounds per barrel of excess lime. Excess alkaline materials, such as lime, help stabilize the emulsion and also neutralize acid gases such as hydrogen sulfide and carbon dioxide.

To measure oil mud alkalinity, the emulsion is broken with a solvent and diluted with water and then titrated with 0.1N H_2SO_4 to the phenolphthalein endpoint.

Step

- Add 100 cm^3 of 50-50 xylene/isopropanol solvent to a 1000- cm^3 Erlenmeyer flask.
- Fill a 5- cm^3 syringe past the 3- cm^3 mark with mud to be tested.
- Displace 2 cm^3 mud into the flask; swirl until the mixture is homogenous.
- Add 200 cm^3 of de-ionized water to the mixture; then add 15 drops of phenolphthalein indicator solution.
- While stirring rapidly with a magnetic stirrer, slowly titrate with 0.1N sulfuric acid until pink color disappears; continue stirring. If no pink color reappears within 1 minute, stop stirring.

Note: It may be necessary to stop the stirring to allow the phases to separate in order to see the endpoint.

- Let sample stand 5 minutes; IF NO PINK COLOR REAPPEARS, the endpoint has been reached. IF A PINK COLOR RETURNS, titrate a second time with sulfuric acid. If pink color returns again, titrate a third time. If, after the third titration a pink color returns, call this the endpoint anyway. Record the cm^3 of 0.1N sulfuric acid required to reach endpoint. Save the mixture for Whole Mud Chloride test.
- Calculate Whole Mud Alkalinity (V_{SA}); then, calculate Lime Content (Lime_{OM}) as follows:

$$V_{SA} = \frac{\text{cm}^3 \text{ 0.1N Sulfuric Acid}}{\text{cm}^3 \text{ of mud}}$$
$$\text{Lime}_{OM}, \text{ lb/bbl} = (V_{SA})(1.295)$$

Whole Mud Chloride (Cl_{OM})

The chlorides in an oil mud (Cl_{OM}) are used with other data to calculate the salinity of the aqueous phase and from there, to calculate solids content.

Step

1. Using the same sample from the whole mud alkalinity test, ensure that the mixture is acidic (below pH 7.0) by adding 1-2 drops of 0.1N sulfuric acid.
2. Add 10-15 drops of potassium chromate indicator solution. While stirring rapidly with a magnetic stirrer, slowly titrate with 0.282N silver nitrate until a salmon pink color remains stable for at least 1 minute. Record cm^3 of 0.282N silver nitrate per cm^3 of sample ($2\ cm^3$) required to reach end-point. (This is V_{SN} on the Mud Report.)

Note: Additional potassium chromate indicator solution may be required during titration process and it may be necessary to stop the stirring of the mixture and allow separation of the two phases to occur to see the color of the aqueous phase.

3. Calculate Whole Mud Chlorides (Cl_{OM}) as follows:

$$V_{SN} = \frac{\text{cm}^3 \text{ of } 0.282\text{N Silver Nitrate}}{\text{cm}^3 \text{ of mud}}$$
$$Cl_{OM}, \text{ mg/L} = (V_{SN})(10,000)$$

Whole Mud Calcium (Ca_{OM})

Calcium in an oil mud (Ca_{OM}) is used with other data to calculate the calcium chloride and sodium chloride content aqueous phase salinity in a mixed brine or super-saturated brine phase of oil mud.

To measure oil mud calcium, the emulsion is broken with a solvent and diluted with water and then titrated with 0.1M EDTA after adding high pH buffer and color indicator.

Step

1. Add $100\ cm^3$ of 50-50 xylene/isopropanol solvent to $1000\text{-}cm^3$ Erlenmeyer flask.
2. Fill a $5\text{-}cm^3$ syringe past the $3\text{-}cm^3$ mark with mud to be tested.
3. Displace $2\ cm^3$ mud into the flask. Swirl until the mixture is homogeneous.
4. Add $200\ cm^3$ of deionized water to the mixture and then add $3.0\ cm^3$ 1.0 N sodium hydroxide buffer solution.
5. To the same mixture add 0.1-0.25 g Calver II indicator powder.
6. Stir rapidly with a magnetic stirrer for 2 minutes.

- Let sample stand 5 minutes. If a reddish color appears in the aqueous (lower phase), this indicates that calcium is present.
- Place flask on magnetic stirrer. While rapidly stirring, slowly titrate with 0.1M EDTA until a distinct color change from the reddish color to a blue-green endpoint is reached. Record cm³ of EDTA per cm³ of sample (2 cm³) to reach endpoint. This is Ca_{OM} on the mud report.
- Calculate Whole Mud Calcium (Ca_{OM}) as follows:

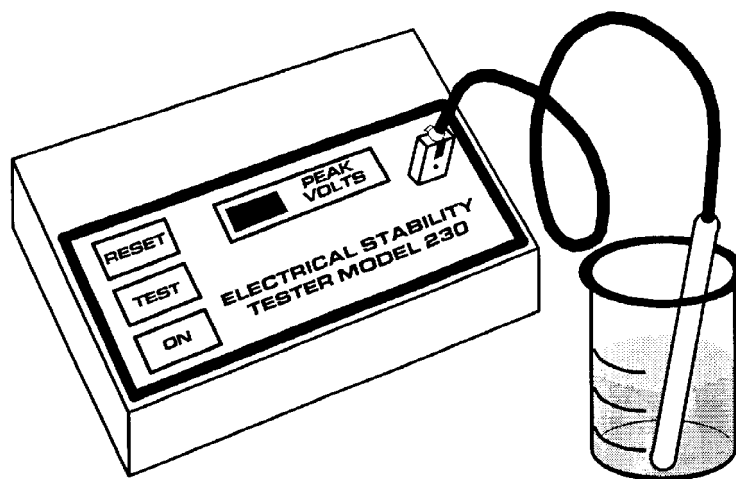
$$V_{EDTA} = \frac{\text{cm}^3 \text{ of } 0.1\text{M EDTA}}{\text{cm}^3 \text{ of Mud}}$$
$$\text{Ca}_{OM}, \text{ mg/L} = (V_{EDTA})(4000)$$

Electrical Stability (ES)

The relative stability of a water-in-oil emulsion mud is indicated by the breakdown voltage at which the emulsion becomes conductive.

The ES test utilizes a probe with a pair of electrodes which are placed in the oil mud. A voltage is applied until the mud conducts a current. The ES value is indicated by a light on the instrument. This test procedure is for the Fann Model 23C. The 23C will be replaced by the automated, sine-wave Fann 23D model (see Figure 29).

Figure 29
Electrical Stability Meter



Step

- Place sample which has been screened through a Marsh funnel into a thermal cup. Hand stir with ES probe for 30 seconds.

2. Heat sample to 120 ±5°F and record the temperature on the Drilling Mud Report.
3. Set ES meter dial to zero. Immerse probe into mud sample. Ensure that the probe does not touch the sides or bottom of the thermal cup.
4. Depress the red power button and hold it down during entire test. DO NOT MOVE probe during measurement.
5. Starting from a zero reading, gradually increase the voltage by turning the knob clockwise at a rate of 100-200 volts per second until red indicator light illuminates. Note dial reading. Return dial to zero. Wipe probe and thoroughly clean between the electrode plates with a paper towel. Repeat test to determine accuracy ±5% variation is satisfactory.

Note: DO NOT USE detergent solutions or aromatic solvents such as xylene to clean the probe or cable.

6. Electrical stability (ES) in volts is calculated as follows:

$$\text{ES, volts} = (2) (\text{Dial Reading})$$

Sulfide

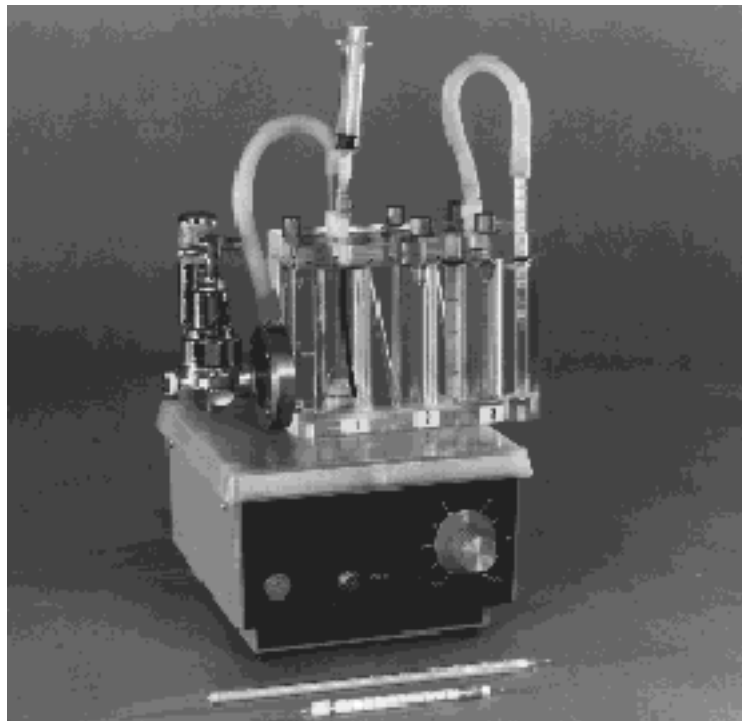
When hydrogen sulfide gas (H₂S) enters an oil mud it ionizes and slowly reacts with excess lime to form calcium sulfide salts. These *active* sulfides are able to revert to H₂S gas, if the oil mud is contaminated by acidic water flow or by a high CO₂ influx. Free H₂S gas, even in low concentration, or active sulfide salts in high concentration present both a health and safety hazard on the rig. Therefore, monitoring active sulfides in an oil mud is critical, especially when drilling in known high H₂S areas. Active sulfides can be quantitatively determined in a whole mud sample, not a filtrate, using a modified GGT test.

The oil mud sample to analyzed for sulfides is the whole mud, and not the filtrate. The sulfides of interest - that can be dangerous - are the sulfides that result from H₂S reactions with lime plus any unreacted H₂S. Therefore, it is necessary to analyze both liquid and solid phases of an oil mud. In the GGT a weak acid, citric acid (2M) with pH1.8, is used to avoid generating spurious sulfides from certain metal sulfide minerals. Sulfuric acid should not be used for this test as it is a strong acid and will liberate H₂S from accessory minerals in barite.

Step

1. Be sure the Garrett Gas Train is clean and dry. Position gas train on magnetic stirrer so that it is level. (Remove rubber feet off GGT base.) Remove the top of the gas train and insert a teflon-coated magnetic stir bar to Chamber 1.
2. Arrange the magnetic stirrer and gas train body so that the stir bar will rotate freely and vigorously agitate the contents of Chamber 1.

Figure 30
Garret Gas Train



3. With the gas regulator backed off, install and puncture a CO₂ cartridge. (Bottled nitrogen (N₂) or helium (He) is preferred.)

Note: **CAUTION** — DO NOT use air or nitrous oxide (N₂O) as a carrier gas.

4. Arrange the plastic injection tube through the rubber septum located on the top of Chamber 1 to allow the mud sample to be slowly injected to the bottom of Chamber 1 with a hypodermic syringe.
5. Add 20 cm³ of 2M citric acid solution containing the demulsifier. (See note below to prepare citric acid solution.)

Note: Citric Acid Solution (2 molar) containing Dowell Fluid Services Oil-Mud Demulsifier is prepared by dissolving 420 g reagent-grade citric acid, (C₆H₈O₇ · H₂O) into 1000 cm³ de-ionized water. To this citric acid solution, add 200 cm³ of isopropanol and 25 cm³ of Dowell

6. Add 10 drops of octanol* to the contents of Chamber 1. (*Avoid inhalation or skin contact.)

7. Select the correct Dräger tube and sample volume required for the expected sulfide range (See Table 9).

Table 11
Dräger Tube Identification
Sample Volumes and Tube Factors
to be Used for Various Sulfide Ranges

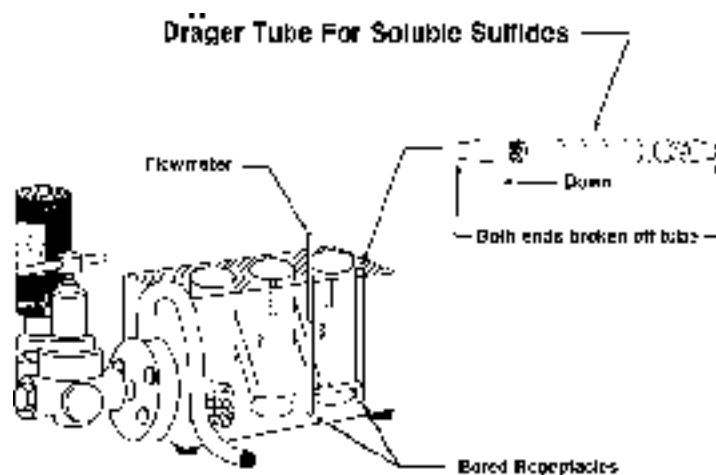
Sulfide Range (mg/L)	Sample Volume (cm ³)	Dräger Tube I.D. (See Tube Body)	Tube Factor
1.2 - 24	10.0	H ₂ S 100/a	12
1.5 - 48	5.0		
4.8 - 96	2.5		
60 - 1020	10.0	H ₂ S 0.2% A	600*
120 - 2040	5.0		
240 - 4080	2.5		

* Tube Factor 600 is based on a Batch Factor (stenciled on box) of 0.40. For another Batch Factor (as stenciled on box), a corrected Tube Factor should be calculated:

$$\text{Correct Tube Factor} = 600 \left(\frac{\text{Batch Factor}}{0.40} \right)$$

8. Break the tip off each end of the Dräger tube. Place the Dräger tube with the arrow pointing downward into the bored receptacle. Install flowmeter tube with the word, *Top*, in the upward position in Chamber 3. Make sure o-rings seal properly (*Figure 31*).
9. Install the top on the gas train, and hand tighten all screws evenly to seal the o-rings.
10. With the regulator backed off (turn regulator handle counter-clockwise), connect the carrier gas to the dispersion tube of Chamber 1 using latex rubber or flexible inert plastic tubing. Do not clamp tubing. Connect the flexible tubing from Chamber 3 outlet to the Dräger tube.
11. Adjust the dispersion tube in Chamber 1 to clear the stir-bar. Allow clearance of approximately 1/4 in. off the bottom by loosening the white adjustment sleeve.
12. To purge air from the GGT, gently flow carrier gas for 30 seconds by turning handle on regulator clockwise. Check for leaks. Shut off carrier gas by turning regulator handle counterclockwise.
13. With contents of Chamber 1 rapidly stirring, slowly inject a measured volume of oil mud through the injection tube using a hypodermic syringe. Keep the injection tube sealed with the syringe during the test. A rubber band can be used to hold the syringe plunger in place. Stir at least 5 minutes or until the sample is well dispersed with no obvious oil drops.

Figure 31
Flowmeter and Dräger Tube Installed in GGT Base



14. Immediately restart the carrier gas flow by turning the regulator handle clockwise. Adjust the rate between 200 to 400 ml/min (keep the flowmeter ball between the red lines on the flowmeter). Continue flowing for a total of 15 minutes.

Note: One CO₂ cartridge should provide about 15 to 20 minutes of flow at this rate.

15. Observe changes in the appearance of the Dräger tube. Note and record the maximum darkened length (in units marked on the tube) before the stain front starts to smear. Continue the gas flow for a total of at least 15 minutes. With prolonged flow, the stain front may appear as a diffuse, feathery coloration. In the high-range tube, an orange color may appear ahead of the black front if sulfites, SO₂⁻, are present in the sample. This orange region should be ignored. Record only the darkened length.
16. Using the measured *Sample Volume*, the Dräger tube's maximum *Darkened Length*, and the *Tube Factor* from Table 9, calculate the active sulfides as H₂S in the sample as follows:

$$\text{H}_2\text{S, mg/L} = \frac{(\text{Darkened Length}^*)(\text{Tube Factor})}{(\text{Sample Volume, cm}^3)}$$

* In units marked on the tube.

17. To clean the gas train, remove the flexible tubing and remove the top. Take the Dräger tube and flowmeter out of the receptacles and plug the holes with stoppers to keep them dry. Clean the chambers with warm water and a mild detergent, using a soft brush. Use a pipe cleaner to clean the passages between chambers. Wash the dispersion tube and the injection tube with mineral oil, and then blow out the tube with air or CO₂ gas. Rinse the unit with deionized water, and allow it to drain dry. If the dispersion tube frit plugs with solids, such as CaCO₃ which forms from using CO₂ carrier gas, soak the dispersion tube frit in strong acid; rinse thoroughly, and blow it dry with gas.

Aqueous Phase Activity (AWOM)

An oil-based mud which is used to drill water-sensitive shale sections must contain a large amount of salt dissolved in its water phase in order to prevent shale hydration and swelling, otherwise instability of these shales may result. Effective salinity of an oil mud's water phase can be measured as *activity* by measuring the water's vapor pressure or relative humidity in air. The Activity Test is a simple test that can be used at the rig and is very helpful in oil mud engineering in cases when the salts in an oil mud are too complex (mixed salts) to be accurately measured by API titration methods.

Introduction

The activity test uses an electrohygrometer (relative humidity meter) to measure the amount of water vapor that exists in air above an oil mud when sealed in a jar at room temperature. Water's vapor pressure, at a given temperature, depends on the concentration of dissolved salts in the solution. Activity is also related to the osmotic pressure that a solution can develop across a semi-permeable membrane - which exists when shales are coated with an oil mud. By keeping salt at a given concentration in the water phase of an oil mud, the osmotic pressure can be matched with that of the formation so that water is not adsorbed into the shale. Salt in very high concentration can even draw water out of a shale, hardening a wellbore and making the shale stronger to allow it to be drilled faster with less mud weight in some cases. Measuring and controlling salinity of oil mud is a key part of oil mud technology as applied at the rig site along with other tests and analyses.

Equipment

The following equipment is needed to measure oil mud activity:

1. Electrohygrometer with a moisture detector capable of measuring relative humidity (RH) from 20% to 100% (see *Figure 32*).
2. Standard saturated salt solutions, which are used for calibrating the electrohygrometer RH readings into water activity, A_{WS} . Salt solutions are prepared using deionized water and pure salts as shown in Table 12. These solutions must be saturated, showing undissolved crystals at room temperature. Approximately 40 cm³ of each of the four saturated salt solutions along with salt crystals are poured into four of the Fleakers (described below).
3. Fleakers (150-cm³ capacity) - A wide-mouthed calibrated container with special rubber cap made by Dow Corning Glass Co. One of the caps must be bored and the hygrometer probe stuck through it so that the probe sensor is about 1.5 in. from the bottom when the cap is on tightly (*Figure 1*). Six Fleakers are used: one (#1) for drying agent; four (#2-#5) for salt solutions agent; and, one (#6) for oil mud sample—and for storing probe when not in use.
4. Drying Agent (desiccant) - Drierite[®] or anhydrous calcium sulfate, CaSO₄, placed into a Fleaker to approximately 40-cm³ mark.
5. Insulating Cover - such as a Styrofoam jacket, to fit around the Fleaker (to maintain an even temperature).
6. Graph Paper - linear 10 x 10 per in. scale.
7. Thermometer - range 32-220°F.

Figure 32
Digital Electrohygrometer and Probe in Fleaker

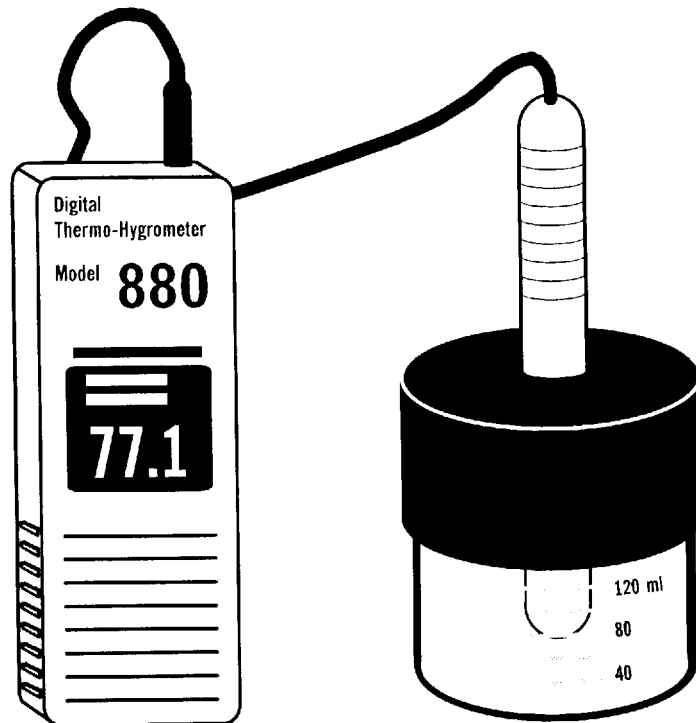


Table 12
Standard Saturated Salt Solutions

Salt Name, Formula	Amount in Water g/100 cm ³	Activity <i>A_{WS}</i>	Fleaker #
Calcium chloride, CaCl ₂	100	0.30	2
Calcium nitrate, CaNO ₃	200	0.51	3
Sodium chloride, NaCl	200	0.75	4
Potassium nitrate, KNO ₃	200	0.94	5

Procedure

The procedure (as given in API RP 13B-2, Appendix C) is also outlined here.

The electrohygrometer must be frequently calibrated at the start and every few days using the standard salt solutions. A calibration graph must be prepared each time. The oil mud activity is found by

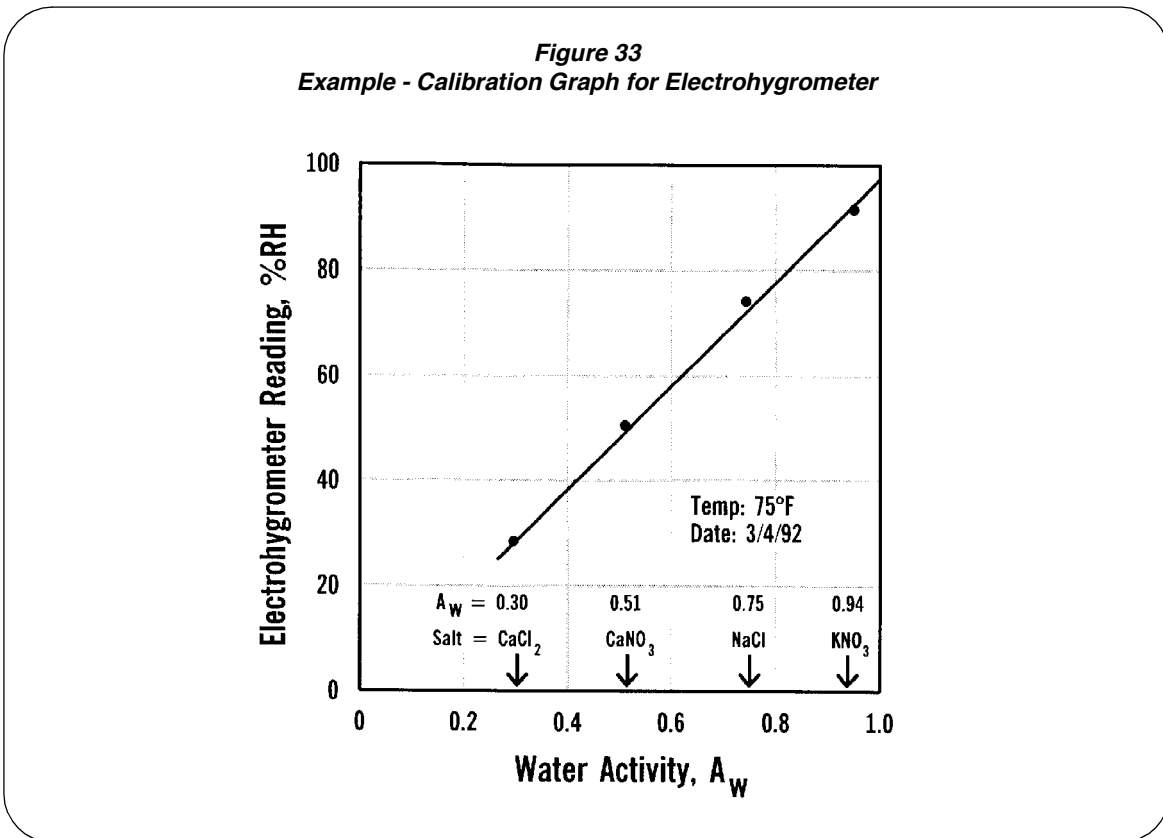
measuring its relative humidity and reading A_{WOM} from the calibration graph. (Salt solutions can be used many times, as long as they are not contaminated or allowed to absorb water from the air.)

Note: **CAUTION:** DO NOT TOUCH the sensor element on the probe. DO NOT allow salt water or oil mud to contact the sensor. IF THE SENSOR IS CONTAMINATED, IT MUST BE REPLACED.

Preparation of Calibration Graph for the Electrohygrometer:

Step

1. Prepare the graph paper with 0 to 100% RH on the vertical axis and 0 to 1.0 A_{WS} on the horizontal axis. (See sample graph, Figure 33.)



2. Dry the probe to $\leq 24\%$ RH by placing it in the air space above the drying agent in Fleaker #1.
3. Place the RH probe in air above the saturated $CaCl_2$ salt solution in Fleaker #2. Place the Fleaker in the insulation jacket. Wait at least 15 minutes for RH to reach equilibrium. Plot the RH reading on meter at 0.30 on graph paper.
4. Repeat Step 2, drying the probe.

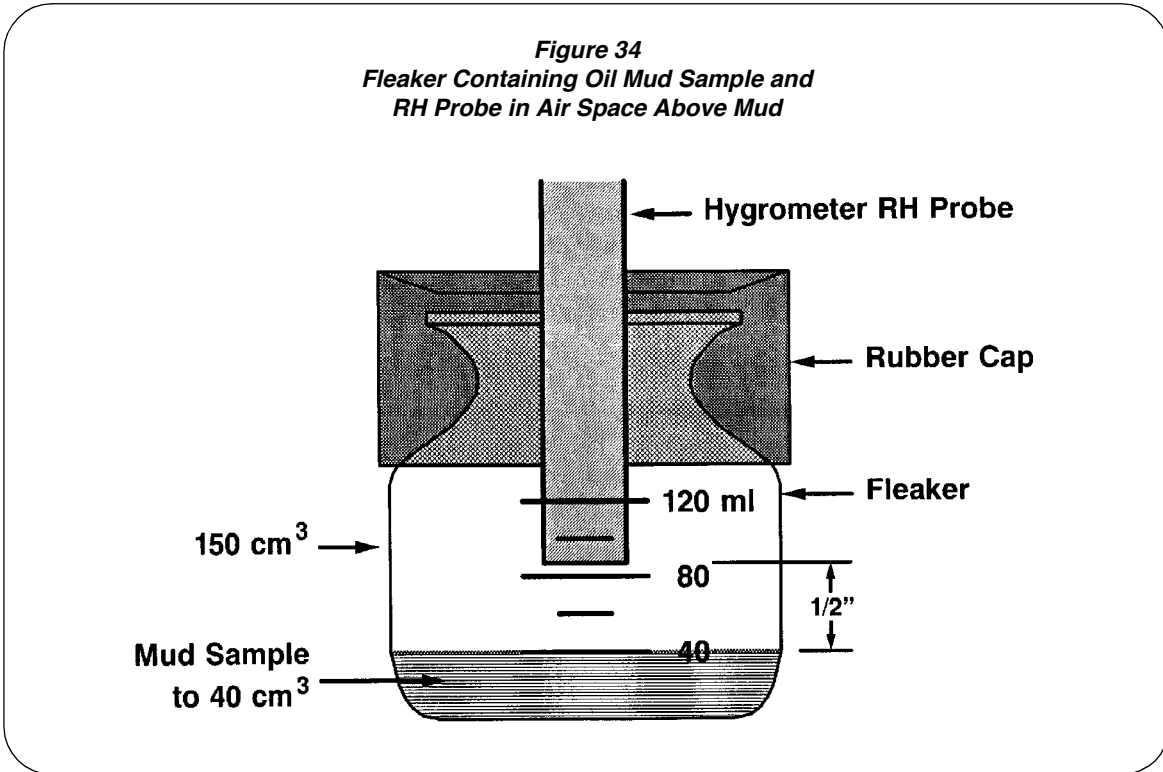
5. Place the RH probe in air above the saturated CaNO_3 solution in Fleaker #3. After at least 15 minutes, read RH on the meter. Plot this RH reading at $0.51 A_{\text{WS}}$ on graph paper.
6. Repeat Step 2.
7. Place the RH probe in air above the saturated NaCl solution in Fleaker #4. After at least 15 minutes, read RH on meter. Plot this RH reading at $0.75 A_{\text{WS}}$ on graph paper.
8. Repeat Step 2.
9. Place the RH probe in air above the saturated KNO_3 solution in Fleaker #5. After at least 15 minutes, read RH on meter. Plot this RH reading at $0.94 A_{\text{WS}}$ on graph paper.
10. Draw the best-fit straight line through the points on the graph. (The line may not fit the $0.94 A_{\text{WS}}$ as well as it should, but will likely pass through the other three points.)
11. Seal the standard salt solutions tightly and store at room temperature where they won't be tipped over.

Testing Oil Mud Sample - It is CRITICAL that the oil mud sample and the testing equipment (probe) be at the same temperature before starting this procedure. This avoids water condensation on the sensor.

Step

1. To allow the oil mud sample and equipment to reach the same temperature, place the oil mud sample, empty Fleaker #6 and stopper which holds the hygrometer probe, side-by-side on the test bench. Measure the mud temperature and air temperature to be sure they are within 5°F of each other before proceeding to Step 2.
2. Pour approximately 40 cm^3 of oil mud into a clean and dry Fleaker #6. Tilt the Fleaker and rotate it to make a film of oil mud on sides of the Fleaker. (This provides a larger surface area for water vapor to escape.)
3. Immediately place cap-with-probe onto the Fleaker containing the oil mud sample. Be sure the insulated jacket is on the Fleaker (*Figure 34*).
4. Wait at least 30 minutes for water vapor in oil mud to reach equilibrium with air in the Fleaker. Read the RH on the meter.
5. Using calibration graph, find the A_w that corresponds to the RH meter reading. Record that as A_{WOM} of oil mud.

Note: *Oil-Based Muds* in this Manual has more information on the relationship between activity and oil mud salinity.



Water-Wet Solids

Water wetting of solids in an oil-based mud begins with the failure of mud to flow through fine shale shaker screens. Continued problems may result from obstruction inside the drill string by water-wet solids buildup, causing high pump pressure and the eventual need to ream out the pipe. At latter stages, water wetting is associated with breaking of the oil mud's emulsion - causing settling of solids and disastrous failure (*flipping*) of the mud system.

There are several operational indicators and trends from the mud engineer's daily mud checks and a few special tests that can be used to identify water wetting of oil-mud solids before the problem becomes serious and irreversible.

Causes of Water-Wet Solids

Common causes of water wetting of solids can be anticipated or seen if the drilling supervisor and mud engineer are aware of potential problems and are communicating. Some common causes are:

1. Influx of water or contamination by water-based mud into the oil mud.
2. Insufficient oil-wetting chemical put into the oil mud over a period of time.
3. Excessive downhole temperature and high drill solids consuming the oil-wetting chemicals.

4. Drilling highly water soluble salt formations, such as carnalite and bischofite - magnesium chloride salts.
5. Adding freshly prepared, poorly treated oil mud into the pits and sending it down hole.
6. Excessive additions of solid CaCl_2 to the oil mud, exceeding aqueous phase saturation, thus allowing free CaCl_2 crystals to exist in the mud.

Visual Indicators of Water-Wet Solids

Early visual indicators of water-wet solids are fairly subtle, but the intermediate and latter indicators are clear cut (such as gross settling and *flipping* of the mud). Visual indicators are:

1. Dull, grainy appearance of the mud, rather than the normally mirror-like surface.
2. Sticky, agglomerated solids blinding the shaker screens.
3. Pump pressure increasing steadily from solids building up inside the drill string, usually the drill collars.
4. Settling of agglomerated solids despite adequate gel strengths.

Mud Test Indicators of Water-Wet Solids

Other indications of water-wet solids come from monitoring the mud testing that is routinely performed on oil-based muds. These indicators are:

1. Rheology - Erratic flow properties resulting from solids agglomeration affecting Fann VG meter readings.
2. Electrical Stability - Steadily decreasing ES voltages with time resulting from water film on solids causing a weakened emulsion.
3. HTHP Filtration - High and increasing filtrate volumes with water in the filtrate.
4. Mud Chemistry - Changes in salinity and decrease in lime as a result of: (1) drilling salts such as carnalite and bischofite; (2) excess treatments with calcium chloride; or (3) a water influx.
5. Retort Analysis - Increasing water content as a result of a water flow or rain or water-mud contamination.

Special Tests and Indicators of Water-Wet Solids

These are special tests that the mud engineer can perform at the rig and observations he can make during testing which can indicate presence of water-wet solids.

1. Sand Content Test - High percentage of sand-sized particles (agglomerated solids) measured by the Sand Content Test which screens the mud through a 200-mesh screen. The test for oil mud is performed as is the water-based mud test for Sand Content, except that oil is used to wash the solids on the screen rather than water. To show that these solids are actually water-wet and are agglomerated small particles, wash the oil-mud solids with a mixture of 50:50 xylene:isopropanol. If they disperse into finer size and pass through the 200-mesh screen, then they were agglomerated.
2. Coating Test - Water-wet, oil-mud solids will adhere to a highly water-wet surface such as clean glass or clean metal. (That is why solids build up and plug the inside of drill collars.) The Coating Test is performed by filling a round jar about half full of the oil mud to be examined. The mud is

stirred at moderate speed with a mixer for 30 minutes. Solids are slung against the glass and if they are water wet some will stick to the jar. The oil mud is poured out and the jar is left to drain. The jar is examined for a film. If no film exists (at the level of the stirrer blade) then there is no indication of water wetting problems. If there is a film, it can be judged by its thickness - the thicker and more opaque the film or coating, the more water wet are the solids. Also, the film will be difficult to wash or wipe off when solids are strongly water wet.

3. Settling - When solids settle badly in the testing equipment (mud cup, rheometer cup and mud balance), yet the mud's gel strength seems adequate to suspend barite, that is an indication of solids being water wet and agglomerated.

Lime, Solids and Salinity Calculations

This section describes the calculations for oil mud salinity and solids which only the chloride ion data and which can be used only for oil muds that contain either CaCl_2 or NaCl (not both salts mixed together). In the event that a "mixed salt" type of oil-based mud is to be analyzed, then it is necessary to perform the analysis for the calcium ion and to perform the calculations found in API RP 13B-2, Section 7.

The equations used in this procedure can be solved by using a hand calculator, but it is best to use a PC program. Several of these programs have been written.

Note: Data used in this API method are not compatible with Drilpro computer programs.

Note: Another test that can be related to oil mud salinity is the *Aqueous Phase Activity*, A_{WOM} , of oil muds. The relative vapor pressure of water in air above an oil mud is measured by an electrohygrometer to find A_{WOM} . This procedure is found in API RP 13B-2, Appendix C and also is outlined in this manual in Section 3.

Total Lime Content (Lime_{OM})

Information needed:

$$V_{SA} = \text{cm}^3 \text{ 0.1N sulfuric acid/cm}^3 \text{ oil mud sample}$$

$$\text{Lime}_{OM} = 1.295 (V_{SA}) = \text{lb/bbl}$$

Whole Mud Salinities (Cl_{OM} , CaCl_{2OM} , NaCl_{OM})

Information needed:

$$V_{SN} = \text{cm}^3 \text{ 0.282N silver nitrate/cm}^3 \text{ oil mud sample}$$

$$\text{Cl}_{OM} = 10,000 (V_{SN}) = \text{mg/L}$$

If salt is assumed to be CaCl_2 , then:

$$\text{CaCl}_{2OM} = 1.57 (\text{Cl}_{OM}) = \text{mg/L}$$

If salt is assumed to be NaCl , then:

Nomenclature

Mud density, lb/gal	M_W
Volume acid for alkalinity, cm^3 0.1N $\text{H}_2\text{SO}_4/\text{cm}^3$ mud	V_{SA}
Volume silver nitrate for chloride, cm^3 $\text{AgNO}_3/\text{cm}^3$ mud	V_{SN}
Whole mud $\text{Ca}(\text{OH})_2$ content, lb/bbl	Lime_{OM}
Whole mud Cl^- ion content, mg/L	Cl_{OM}
Whole mud CaCl_2 content, mg/L	CaCl_{2OM}
Whole mud NaCl content, mg/L	NaCl_{OM}
Oil from retort, vol%	V_O
Water from retort, vol%	V_W
Solids Corrected for salinity, vol%	V_S
Density of brine, g/cm^3	ρ_B
Density, average of solids, g/cm^3	ρ_{AVG}
Density of drill solids, g/cm^3	ρ_{LGS}
Volume of drill solids, vol%	V_{LGS}
Concentration of drill solids, lb/bbl	M_{LGS}
Density of weight material, g/cm^3	ρ_{HGS}
Volume of weight material, vol%	V_{HGS}
Concentration of weight material, lb/bbl	M_{HGS}
Density of base oil, g/cm^3	ρ_O
Weight percent CaCl_2 in brine, wt%	W_C
Weight percent NaCl in brine, wt%	W_N
Parts per million, $\text{g}/10^6\text{g}$	ppm
Milligrams per liter, $\text{g}/10^6\text{cm}^3$	mg/L
Oil-water-ratio, vol%/vol%	O/W
Oil-brine-ratio, vol%/vol%	O/B

$$\text{NaCl}_{OM} = 1.65 (\text{Cl}_{OM}) = \text{mg/L}$$

Aqueous Phase Salinity (Weight Percent)

Information needed:

Retort water %, V_W

Weight percent, if salt is assumed to be CaCl_2 :

$$W_C = \frac{100(\text{CaCl}_{2\text{OM}})}{(\text{CaCl}_{2\text{OM}}) + 10,000(V_W)} = \text{wt\% CaCl}_2$$

Weight percent, if salt is assumed to NaCl:

$$W_N = \frac{100(\text{NaCl}_{\text{OM}})}{(\text{NaCl}_{\text{OM}}) + 10,000(V_W)} = \text{wt\% NaCl}$$

Aqueous Phase Salinity - Parts per Million

Information needed:

Weight percent CaCl₂, W_C

$$\text{CaCl}_2 = 10,000 (W_C) = \text{ppm}$$

Weight percent NaCl, W_N

$$\text{NaCl} = 10,000 (W_N) = \text{ppm}$$

Aqueous Phase Salinity (Milligram per Liter)

Information needed:

CaCl₂ brine density and NaCl brine density (calculated from polynomial for r_B [See *Oil/Brine Ratio (O/B)*].)

$$\text{CaCl}_2 = (\text{CaCl}_2, \text{ppm}) (\text{CaCl}_2 r_B) = \text{mg/L}$$

$$\text{NaCl} = (\text{NaCl}, \text{ppm}) (\text{NaCl } r_B) = \text{mg/L}$$

Oil/Water Ratio (O/W)

Information needed:

Raw Data from retort: V_O, V_W

$$\text{Oil \% in O/W} = \frac{100(V_O)}{(V_O + V_W)}$$

$$\text{Water \% in O/W} = \frac{100(V_W)}{(V_O + V_W)}$$

$$\text{O/W} = \text{Oil \% / Water \%}$$

Oil/Brine Ratio (O/B)

Information needed: Brine density for calculating V_B.

Brine density for NaCl brine only:

$$\rho_B = 0.99707 + 0.006504 (W_N) + 0.00004395 (W_N)^2 = \text{g/cm}^3$$

Brine density for CaCl₂ brine only:

$$\rho_B = 0.99707 + 0.007923 (W_C) + 0.00004964 (W_C)^2 = \text{g/cm}^3$$

Note: Density of CaCl₂ brines are found in Table 14 and NaCl brines are found in Table 15.

$$V_B = \frac{100(V_W)}{(\rho_B)(100 - W_X)} = \text{vol}\%$$

where

$$W_X = W_C \text{ or } W_N$$

$$\text{Oil \% in O/B} = \frac{100(V_O)}{(V_O + V_B)}$$

$$\text{Brine \% in O/B} = \frac{100(V_B)}{(V_O + V_B)}$$

$$\text{O/B} = \text{Oil \%}/\text{Brine \%}$$

Solids Content

Information needed:

Mud density, density of high and low gravity solids, water, oil and brine phases.

Corrected Solids Content, V_S, vol%:

$$V_S = 100 - (V_O + V_B)$$

Average Density Suspended Solids, r_{AVG}, g/cm³

$$\rho_{AVG} = \frac{[100(M_w)] - [(v_o)(\rho_o)] - [(V_S)(\rho_S)(8.34)]}{8.34(V_S)}$$

Volume % and Concentration Low-Gravity Solids:

$$V_{HGS} = \left(\frac{\rho_{AVG} - \rho_{LGS}}{\rho_{HGS} - \rho_{LGS}} \right) (V_S) = \text{vol}\%$$

$$M_{HGS} = 3.5(\rho_{HGS})(V_{LGS}) = \text{lb/bbl}$$

Examples of Calculations for Oil Mud Analysis

Given Data Used in Examples		
Information Needed	EXAMPLE A CaCl ₂ Mud	EXAMPLE B NaCl Mud
M _W , lb/gal	11.0	11.0
V _O , vol%	59.5	59.5
V _W , vol%	25.0	25.0
V _{SA} , cm ³ acid/cm ³ mud	2.6	2.0
V _{SN} , cm ³ AgNO ₃ /cm ³ mud	5.8	4.4
ρ _B , g/cm ³ brine density	(Calculated values)	
ρ _{HGS} , g/cm ³	4.20	4.20
ρ _{LGS} , g/cm ³	2.65	2.65
ρ _O , lb/gal	7.00	7.00
ρ _W , lb/gal	8.34	8.34

EXAMPLE A - Oil Mud with CaCl₂ Aqueous Phase:

Step

1. Total Lime Content (Lime_{OM})

Information needed:

$$V_{SA} = \frac{\text{cm}^3 \text{ 0.1N sulfuric acid}}{\text{cm}^3 \text{ mud}}$$

$$\text{Lime}_{OM} = 1.295(V_{SA})$$

$$\text{Lime}_{OM} = 1.295(2.6) = 3.4 \text{ lb/bbl Ca(OH)}_2$$

2. Whole Mud Salinities (Cl_{OM}, CaCl_{2OM})

Information needed:

$$V_{SN} = \frac{\text{cm}^3 \text{ 0.282N silver nitrate}}{\text{cm}^3 \text{ oil mud sample}}$$

Salt is assumed to be CaCl₂, **then**:

$$Cl_{OM} = (10,000)(V_{SN})$$

$$Cl_{OM} = 10,000(5.8) = 58,000 \text{ mg/L Chloride}$$

$$CaCl_{2OM} = 1.57(Cl_{OM})$$

$$CaCl_{2OM} = 1.57(58,000) = 91,060 \text{ mg/L } CaCl_2$$

3. Aqueous Phase Salinity - weight percent

Information needed: Retort water %, V_W

Weight %, salt is assumed to be $CaCl_2$:

$$W_C = \frac{100(91,000)}{(91,000) + 10,000(25.0)} = 26.7 \text{ wt\% } CaCl_2$$

4. Aqueous Phase Salinity - parts per Million

Information needed: Weight percent $CaCl_2$, W_C

$$CaCl_2 = 10,000 (26.7) = 267,000 \text{ ppm}$$

5. Aqueous Phase Salinity - milligram per liter

Information needed: $CaCl_2$ brine density

$$\begin{aligned}\rho_B &= 0.99707 + 0.007923(26.7) + 0.00004964(26.7)^2 \\ &= 1.24 \text{ g/cm}^3\end{aligned}$$

$$\begin{aligned}CaCl_2 &= (CaCl_2, \text{ ppm})(\rho_B) \\ &= 266,000(1.24) \text{ g/cm}^3 \\ &= 329,840 \text{ mg/L } CaCl_2\end{aligned}$$

6. Oil/Water Ratio - O/W

Information needed: Raw Data from retort, V_O , V_W

$$\text{Oil \% in O/W} = \frac{100(59.5)}{59.5 + 25.0} = 70.4$$

$$\text{Water \% in O/W} = \frac{100(25.0)}{59.5 + 25.0} = 29.6$$

$$O/W = \text{Oil \% Water \%} = 70/30$$

7. Oil/Brine Ratio - O/B

Information needed: Corrected Retort Water, V_B

$$V_B = \frac{100(25.0)}{1.24(100 - 26.7)} = 27.5 \text{ vol\%}$$

$$\text{Oil \% in O/B} = \frac{100(59.5)}{59.5 + 27.5} = 68.4$$

$$\text{Brine \% in O/B} = \frac{100(27.5)}{59.5 + 27.5} = 31.6$$

$$\text{O/B} = 68/32$$

8. Solids Content

Corrected Solids, V_S , vol%:

Information needed: Retort Oil, V_O , and brine, V_B

$$V_S = 100 - (59.5 + 27.5) = 13.0 \text{ vol\%}$$

Average Density of Suspended Solids:

Information needed: Mud, Oil and Water Densities and Retort Data

$$\begin{aligned} \rho_{AVG} &= \frac{[100(11.0)] - [(59.5)(7.0)] - [(27.4)(1.24)(8.34)]}{8.34(13.0)} \\ &= 3.69 \text{ g/cm}^3 \end{aligned}$$

Volume of High-Density (barite) Solids, vol%:

Information needed: Density of high- and low-gravity solids and V_S , vol%.

$$V_{HGS} = \frac{(3.69 - 2.65)(13.0)}{4.20 - 2.65} = 8.6 \text{ vol\%}$$

Concentration of High-Density Solids, lb/bbl:

$$M_{HGS} = 3.5 (4.20) (8.6) = 126.4 \text{ lb/bbl}$$

Volume of low-density solids, vol%:

$$V_{LGS} = 13.0 - 8.6 = 4.4 \text{ vol\%}$$

Concentration of low-density solids, lb/bbl:

$$M_{LGS} = 3.5 (2.65) (4.4) = 40.8 \text{ lb/bbl}$$

Example B – Oil Mud with NaCl Aqueous Phase

1. Total Lime Content - Lime_{OM}

$$\text{Information needed: } V_{SA} = \frac{\text{cm}^3 \text{ 0.1N sulfuric acid}}{\text{cm}^3 \text{ mud}}$$

$$\text{Lime}_{OM} = 1.295(V_{SA})$$

$$\text{Lime}_{OM} = 1.295(2.0) = 2.6 \text{ lb Ca(OH)}_2/\text{bbl mud}$$

2. Whole Mud Salinities - Cl_{OM}, NaCl_{OM}

Information needed: $V_{SN} = \frac{\text{cm}^3 \text{ 0.282N silver nitrate}}{\text{cm}^3 \text{ oil mud sample}}$

$$Cl_{OM} = 10,000(V_{SN})$$

$$Cl_{OM} = 10,000(4.4) = 2.6 \text{ lb Ca(OH)}_2/\text{bbl mud}$$

$$NaCl_{OM} = 1.65(44,000) = 72,600 \text{ mg/L NaCl}$$

3. Aqueous Phase Salinity - Weight Percent

Information needed: Retort Water %, V_W

Weight %, salt is assumed to NaCl:

$$W_N = \frac{100(72,600)}{(72,600) + 10,000(25.0)} = 22.5 \text{ wt\% NaCl}$$

4. Aqueous Phase Salinity - Parts per Million

Information needed: Weight percent NaCl, W_N

$$\text{NaCl} = 10,000 (22.5) = 225,000 \text{ ppm}$$

5. Aqueous Phase Salinity - Milligram per Liter

Information needed: NaCl brine density, ρ_B

$$\begin{aligned} \rho_B(\text{NaCl}) &= 0.99707 + 0.006504(22.5) + 0.00004395(22.5)^2 \\ &= 1.17 \text{ g/cm}^3 \end{aligned}$$

$$\text{NaCl, mg/L} = (\text{NaCl, ppm})(\rho_B)$$

$$= 225,000(1.17) = 263,200 \text{ mg/L NaCl}$$

6. Oil/Water Ratio - O/W

Information needed: Raw Data from Retort, V_O , V_W

$$\text{Oil \% in O/W} = 100(59.5)/(59.5 + 25.0) = 70.4$$

$$\text{Water \% in O/W} = 100(25.0)/(59.5 + 25.0) = 29.6$$

$$\text{O/W} = \text{Oil \%}/\text{Water \%} = 70/30$$

7. Oil/Brine Ratio - O/B

Information needed: Corrected Retort Water, V_B

$$V_B = \frac{100(25.0)}{1.17(100 - 22.5)} = 27.6 \text{ vol\%}$$

$$\text{Oil \% in O/B} = 100(59.5)/(59.5 + 27.6) = 68.3$$

$$\text{Brine \% in O/B} = 100(27.6)/(59.5 + 27.6) = 31.7$$

$$\text{O/B} = \text{Oil \%}/\text{Brine \%} = 68/32$$

8. Solids Content - Corrected Solids, vol%, V_S :

Information needed: Retort Oil and Brine, vol%.

$$V_S = 100 - (59.5 + 27.6) = 12.9 \text{ vol\%}$$

Average Density of Suspended Solids:

Information needed: Mud weight, oil and water densities and retort data.

$$\begin{aligned} \rho_{AVG} &= \frac{[100(11.0)] - [(59.5)(7.0)] - [(27.6)(1.17)(8.34)]}{8.34(12.9)} \\ &= 3.85 \text{ g/cm}^3 \end{aligned}$$

Volume of High-Density Solids (barite), vol%:

Information needed: Density of high- and low-gravity solids and V_S .

$$V_{HGS} = \frac{\rho_{AVG} - \rho_{LGS}}{\rho_{HGS} - \rho_{LGS}} = \text{vol\%}$$

Concentration of high-density solids, lb/bbl:

$$M_{HGS} = 3.5 (4.20) (10.0) = 147.0 \text{ lb/bbl}$$

Volume of low-density solids, vol%:

$$V_{LGS} = 12.9 - 10.0 = 2.9 \text{ vol\%}$$

Concentration of low-density solids, lb/bbl:

$$M_{LGS} = 3.5 (2.65) (2.9) = 26.9 \text{ lb/bbl}$$

Table 13
Commonly Used Densities
(at 20° C)

Mud Component	Density, g/cm³	Density, lb/gal	Density, kg/m³
Fresh Water	0.998	8.33	998
Diesel Oil #2	0.84	7.000	840
Typical Low Viscosity Oil	0.80	6.700	800
Low Density Solids	2.65	22.100	2650
High Density Solids			
Barite	4.20	35.000	4200
Hematite	5.05	42.100	5050

Table 14
Calcium Chloride Brine Table
(Properties at 20° C)

% WT_C	CaCl₂ mg/L	Chloride mg/L	Final Volume	Water Activity	Density g/cm³	Density lb/gal
0	0	0	1.000	1.000	0.998	8.330
2	20,300	12,990	1.004	0.096	1.0166	8.484
4	41,340	26,410	1.008	0.989	1.0334	8.624
6	63,030	40,280	1.013	0.979	1.0505	8.766
8	85,420	54,590	1.018	0.967	1.0678	8.911
10	108,540	69,360	1.024	0.951	1.0854	9.058
12	132,400	84,600	1.030	0.933	1.1033	9.207
14	157,050	100,360	1.037	0.912	1.1218	9.361
16	182,510	116,630	1.044	0.888	1.1407	9.519
18	208,780	133,410	1.051	0.862	1.1599	9.679
20	235,920	150,750	1.060	0.832	1.1796	9.844
22	263,930	168,650	1.069	0.800	1.1997	10.011
24	292,820	187,100	1.078	0.765	1.2201	10.182
26	322,660	206,170	1.089	0.727	1.2410	10.356
28	353,420	225,820	1.100	0.686	1.2622	10.533
30	385,140	246,885	1.113	0.643	1.2838	10.713
32	417,890	267,020	1.126	0.597	1.3059	10.898
34	451,620	288,570	1.141	0.548	1.3283	11.047
36	486,430	310,780	1.156	0.496	1.3512	11.276
38	522,310	333,740	1.173	0.441	1.3745	11.470
40	559,280	357,370	1.192	0.384	1.3982	11.668

Note: The calcium ion concentration can be determined by subtracting the Chloride ion value from the Calcium Chloride value.

$$(Ca^{++}, \text{mg/L} = CaCl_2, \text{mg/L} - Cl, \text{mg/L})$$

*B. R. Staples and R. L. Nuttall, J. Phys. Chem. Ref. Data. 1977, Vol. 6, No. 2, p. 385-407.

Table 15
Sodium Chloride Brine Table
(Properties at 20° C)

% WT _N	NaCl mg/L	Chloride mg/L	Final Volume	Water Activity	Density g/cm ³	Density lb/gal
0	0	0	1.000	1.000	0.9980	8.330
2	20,250	12,310	1.006	0.989	1.0143	8.464
4	41,140	24,960	1.013	0.976	1.0286	8.584
6	62,590	37,980	1.020	0.964	1.0431	8.705
8	84,620	51,350	1.028	0.950	1.0578	8.827
10	107,260	60,680	1.036	0.935	1.0726	8.951
12	130,510	79,200	1.045	0.919	1.0876	9.076
14	154,390	93,680	1.054	0.901	1.1028	9.203
16	178,910	108,570	1.065	0.882	1.1182	9.331
18	204,100	123,840	1.076	0.861	1.1339	9.462
20	229,960	139,540	1.087	0.839	1.1498	9.595
22	265,520	155,660	1.099	0.815	1.1660	9.730
24	283,800	172,210	1.113	0.788	1.1825	9.868
26	311,820	189,210	1.127	0.759	1.1993	10.008

Note: The sodium ion concentration can be determined by subtracting the Chloride ion value from the Sodium Chloride value.

$$(\text{Na}^+, \text{mg/L} = \text{NaCl, mg/L} - \text{Cl, mg/L})$$

*E. C. W. Clarke and D. N. Grew, J. Phys. Chem. Ref. Data. 1985, Vol. 14, No. 2, p. 489-610

Permeability Plugging Test (PPT)

Introduction

The Permeability Plugging Test (PPT) Apparatus is a modified HTHP fluid loss cell that is used for estimating static fluid loss under downhole conditions (wellbore temperature and differential pressure). The filtrate of the drilling fluid can be measured and additives selected which will minimize this filtration, leading to less chance of differential sticking.

For economic reasons, many wells are currently drilled using fewer casing strings resulting in long open hole intervals and high differential pressures. Thus, the potential for differential sticking is significantly increased, especially when drilling through depleted intervals. To successfully drill these wells, properly designed muds and accurate pore pressure predictions are essential. The fluid must be not only inhibitive, but also must deposit a very low permeability filter cake to seal underpressured formations. The Permeability Plugging Test, which uses disks of selected permeability, measures fluid loss

at downhole temperature and differential pressure to predict drilling fluid performance under these conditions. Using the PPT, the effects of high differential pressure are readily apparent by measuring: spurt loss, *total fluid loss*, and *cake thickness*. In the PPT these properties are substantially different than those seen with HTHP fluid loss cells with filter paper.

PPT Principles

In running the PPT test, it is important to remember that the type of mud and the pore size of the disk used for the test will influence the results. The disks are meant to simulate the porous formations encountered in drilling. Trends are important to monitor rather than absolute values. Results of products run in different types of mud should not be compared.

The important parameter to consider is the ratio of the size of the particles in the mud and the pore size in the rock. Generally speaking, when the ratio of the particle size to pore size is less than 1/6, whole mud will pass through the formation and bridging will not occur. A ratio of 1/2 or greater will form a filter cake and intermediate values will show invasion with bridging (spur) until the effective bridged ratio is greater than 1/2 and the filter cake forms. No leakoff control can be obtained until a filter cake is formed.

When the mud contains very fine particles relative to the pore size, i.e., the ratio is less than 1/6, SCM is added as a bridging agent to allow a filter cake to form. SCM will bridge the pores until the effective pore size is reduced and filter cake can form. The SCM may also effect the quality of the filter cake such that both loss of whole mud and normal fluid loss (filtrate) are reduced. A given SCM's performance will be related to the core pore size that it is tested against. The performance of a SCM will also be a function of the mud type.

The deposition of a filter cake and bridging of pores is covered in filtration theory. The equations covering filtration have been known for several years. The basic form presented here for filtration with invasion comes from Barkman and Davidson:¹

$$V = S\sqrt{t} + V_B - \frac{S^2}{2Q_B}$$

where

V = cumulative throughput volume

S = slope of cumulative volume vs. square root of time

t = total time of filtration

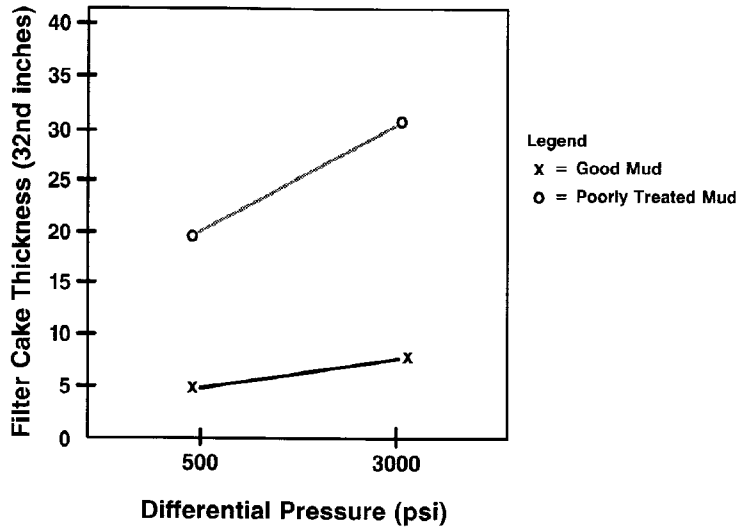
V_B = cumulative volume at bridging

Q_B = linear filtration rate at time of bridging

This is the case when both normal fluid loss and seepage occur. When total loss occurs, there is no external filter cake formed and V_B does not have a finite value. This equation is illustrated in Figure 35 for a suspension of silica flour on Berea sandstone.

As is seen from the figure, the slope is constant once the filter cake is formed. The values of t_B, the bridging time, and V_B, the bridging volume, may be solved for by iteration from the general filtration equation. In actuality, with PPT experiments at high pressure, the initial part of the curve is quite steep. Due to the extremely short bridging time, normally on the order of a few seconds, sufficient quality data is not available to accurately solve for t_B and V_B. The value reported, the spurt, is obtained by project-

Figure 35
Example of Filton Curve with Invasion (from Barkman and Davidson)



ing the linear portion of the curve to the y-axis. In the example above the spurt is approximately 290 mL.

The slope of the linear portion of the curve, S , gives valuable information concerning the quality of the filter cake. When $S=0$, an impermeable filter cake is formed. A large value of S indicates that a poor quality filter cake is formed. The permeability of the cake is related to the slope by the following equation:

$$S = \frac{\sqrt{2\rho_c k_c A_c^2 \Delta p_t}}{\mu w \rho_w}$$

where

ρ_c = bulk density of filter cake

k_c = filter cake permeability

A_c = area of filter cake

Δp_t = total pressure differential across filter cake and filter medium

μ = fluid viscosity

w = weight concentration of solids in water

ρ_w = density of fluid

As can readily be seen by examination of the equation, when only small changes are made to the fluid, the slope varies as the square root of the filter cake permeability.

Sized lost circulation materials (LCM) can also reduce cake thickness and filtration. Low permeability filter cakes are the result of optimizing the distribution of sized solids in a mud. Low permeability filter cakes not only reduce filtration, but also minimize differential pressure sticking. Commonly-used LCM's that reduce filtration are a variety of cullulosic material and sized solids calcium carbonate and gilsonite or similar material. Cellulosies are effective because of its ability to swell and physically bridge a wide range of pore openings.

Pilot tests which use the PPT cell, rather than conventional HTHP filtration equipment can be used to optimize additives and concentrations. Both PPT and conventional fluid loss tests should be performed to identify trends and to evaluate the effectiveness of product treatments. (Figures 35 and 36 illustrate how the PPT can be used to indicate improvements in the muds.) Running a PPT with every mud check can direct mud treatments and thus minimize differential sticking tendencies.

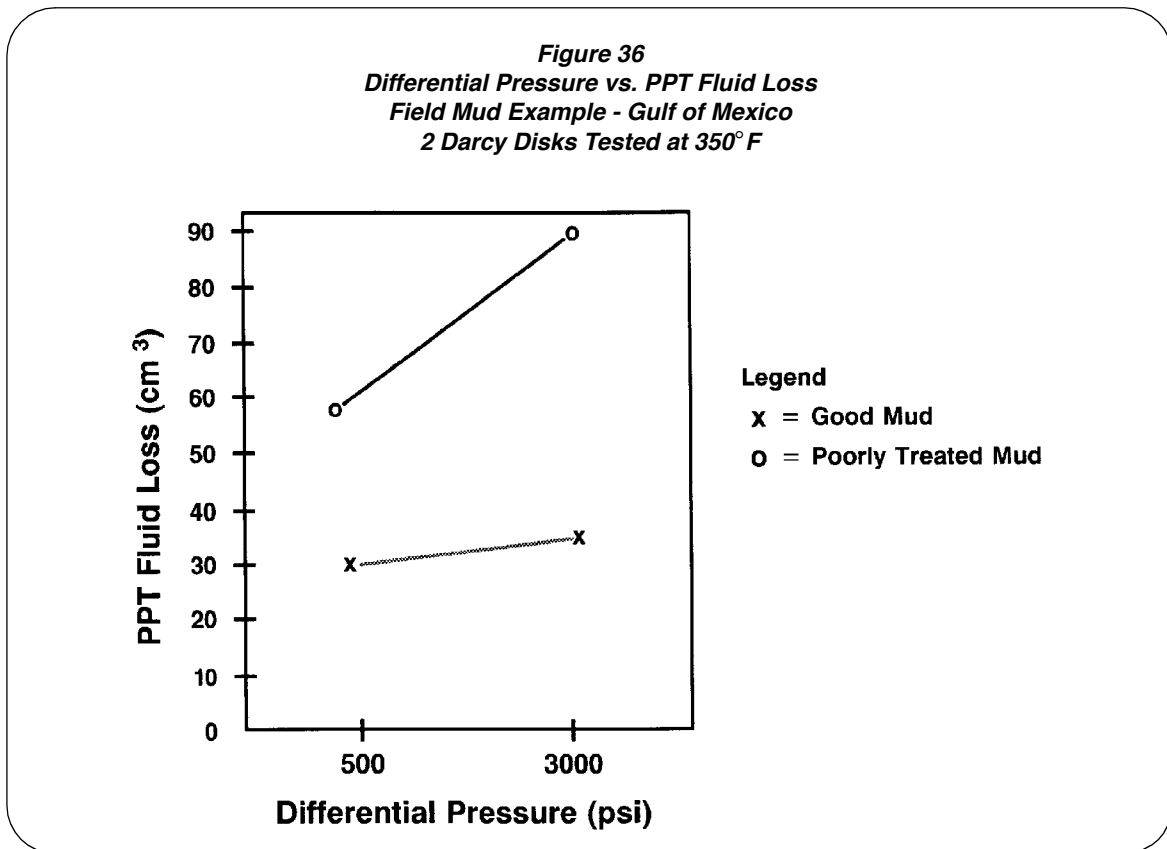


Table 16 contains PPT data which compare the effectiveness of various LCMs in a specific mud system.

This table includes total leakoff, spurt, the slope of the linear portion of the volume versus the square root of time curve and filter cake thickness for some runs. The last column consists of a value, the PPT Value, that is reported by some sources. The value is defined as:

$$\text{PPT Value} = \text{Spurt} + 2 \times [\text{Total Volume (30 minutes)} - \text{Spurt}]$$

The base mud is a water-based mud containing 20 ppb prehydrated bentonite, 30 ppb Rev-Dust, 0.5 ppb caustic, and 0.5 ppb PAC-L.

Table 16
PPT Study of LCM Sealing on Aluoxite Disk

Core	Sample	Total Leakoff, mL	Spurt, mL	Slope, mL/min	Cake, 32nd	PPT Value
AF-6	Base mud	23.56	1.91	3.95		45.2
AF-15	Base mud	25.71	1.71	4.38	-	49.71
AF-50	Base mud	55.45	33.55	4.00		77.34
FAO-50	Base mud	52.36	32.80	3.57	9	71.92
AF-50	Base mud - 35 ppb KCl	98.12	27.70	12.84	16	168.46
AF-50	Base mud - 10 ppb Baricarb 150 + 10 ppb Baricarb 6	35.51	14.12	3.00	9	56.90
FAO-50	Base mud	52.30	32.80	3.57	9	71.92
AF-50	Base mud + 10 ppb Ultra Seal XP	29.17	15.48	2.50	6	42.88
AF-50	Base mud + 10 ppb MIX 2	40.67	27.54	2.40	-	53.80
AF-80	Base mud	Total	Total	No Cake	No Cake	-
AF-80	Base mud + 10 ppb Ultra Seal XP	72.85	30.80	2.19	-	94.85
AF-80	Base mud + 10 ppb MIX 2	Total	Total	No Cake	No Cake	-
AF-80	Base mud + 10 ppb Single Seal	100.75	34.50	2.77	-	124.91
AF-80	Base mud + 10 ppb Gran Seal	102.72	87.52	2.73	-	17.95
AF-80	Base mud + 15 ppb Kwik Seal Fine + 10 ppb Kwik Seal Medium + 5 ppb Bore-Plate	69.47	51.47	3.29	-	87.47

If the core does not exhibit a high spurt, the material will not show its benefits as a seepage control material but rather as a filter cake additive. As can be seen very little spurt was seen for AF-6 and AF-15. Control here is provided by the filter cake which readily forms.

AF-50 did exhibit a significant spurt, but the solids in the base mud eventually bridged the pores and allow a filter cake form. Addition of 35 ppb (10%) potassium chloride (KCl) did not change the spurt appreciable but did increase the slope from 4.00 to 12.84. This is due to the flocculation of the bentonite in the mud which will deteriorate the filter cake. Addition of a sized calcium carbonate (BARA-CARB) significantly decreased the spurt and caused negligible effect on the quality of the filter cake. Two cellulosic materials are included for illustration. This series of tests does illustrate the changes seen in the filter cake quality and fluid loss with different type additives.

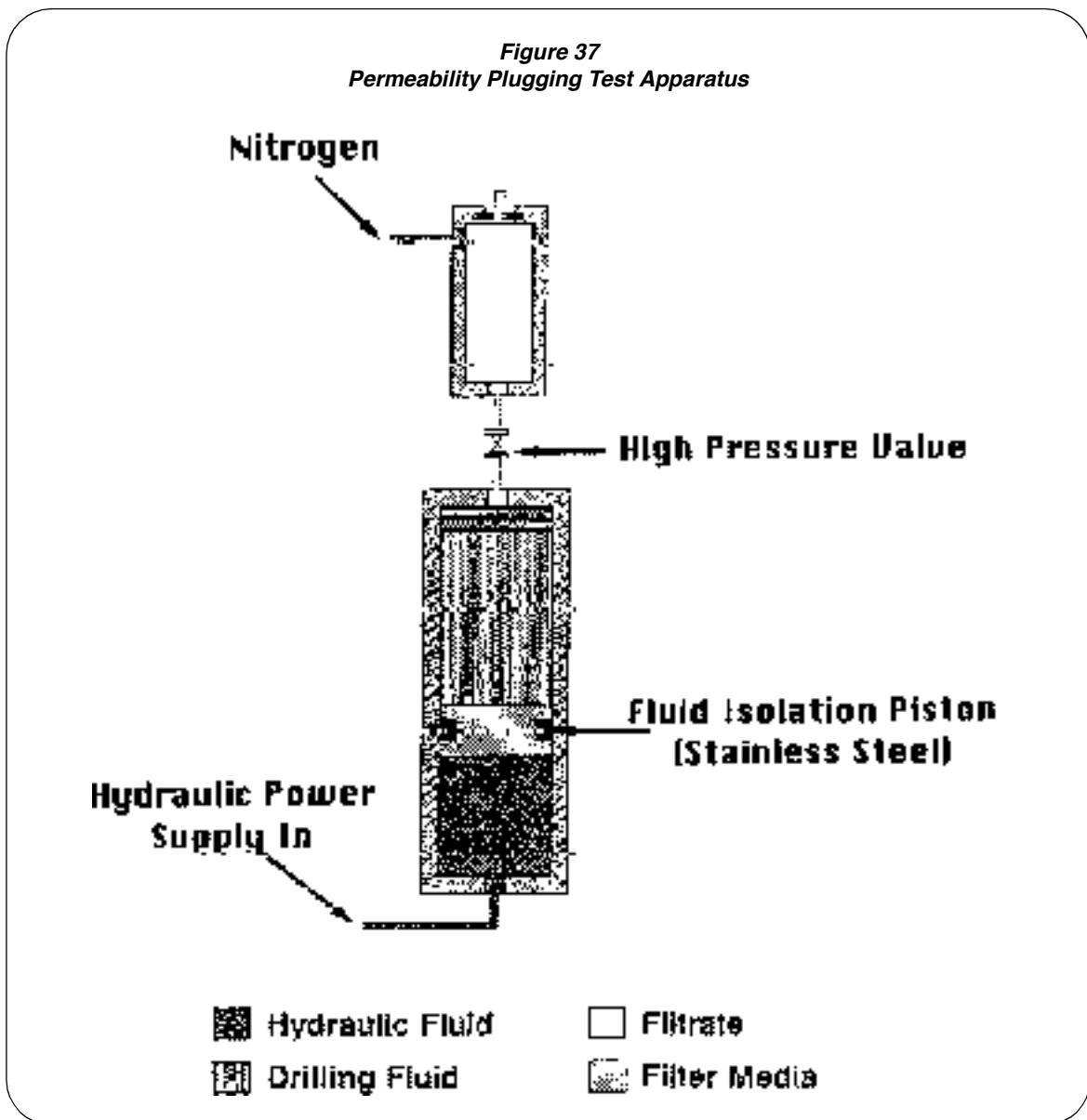
The pores in AF-80 were large enough that no filter cake was formed during the base mud test. The entire mud sample was passed through the core in a few seconds. This core was selected to run the bulk of the tests for evaluation of the seepage control materials.

The best performance of the materials tested in the base mud was the ULTRA SEAL XP. This, at 10 ppb, gave results similar to the base mud containing 15 ppb KWIK-SEAL MEDIUM, 15 ppb KWIK-SEAL FINE, and 5 ppb BORE-PLATE. GRAN SEAL and SINGLE SEAL gave similar, although inferior, performance as evidenced by their higher spurt and total leakoff values when compared to the ULTRA SEAL XP. MIX 2 failed to provide sufficient pore bridging to allow a filter cake to form.

Permeability Plugging Test Procedure

The PPT apparatus may be used in the lab to evaluate lab formulated muds or mud systems submitted by the field. The apparatus is also portable and can be used at the rig to evaluate the mud system and to test the bridging effectiveness at downhole temperature and pressure of various additives. Information from the PPT is especially useful on critical wells - drilling depleted sands or high angle holes. (A diagram of the PPT apparatus is shown in Figure 37.) The test procedure is as follows:

[Note: Several manufacturers supply the hardware for the device. These steps are not meant to be specific but rather apply to all cells. Manufacturer instructions should be consulted before any tests are performed.]



Step

1. Apply a thin coat of stopcock grease around the o-rings of the floating piston.
2. Screw the floating piston onto the T-bar wrench and install the piston into the bottom of the cell. Work the piston up and down to ensure that it moves freely. (The bottom of the cell will have a shorter recess than the top.) Position the piston so that it is near the bottom edge of the cell and unscrew it from the wrench.
3. Install the hydraulic end cap onto the bottom of the cell.
4. Turn the cell upright and fill with 350 cm³ of mud.
5. Acceptable: Soak Aloxite disks for at least 5 minutes in fresh water prior to testing a water-based mud. For oil muds, the Aloxite disks should be soaked in the representative base oil for at least 5 minutes prior to use.

Preferred: Place the aloxite disk in the appropriate solution. Place this in a vacuum cell and evacuate for 1 hour.

Note: Aloxite disks should NEVER be reused.

6. Install the top cap with valve onto the cell. Close the valve and install the cell into the heating jacket. Lower cell slowly until it bottoms out, then rotate clockwise until it locks in place.
7. Install a thermocouple in the small hole on the top of the cell.
8. Place the filtrate reservoir onto the top of the valve. Ensure that the small o-ring is in good condition. Lock reservoir in place by installing a safety key (modified cotter key).
9. Install the back pressure device onto the reservoir and lock in place with safety key.
10. Open the valve directly on top of the cell (green valve). Ensure that the other valves are closed on the reservoir and backpressure devices.
11. Apply the appropriate amount of back pressure to the cell for the desired test temperature using the CO₂ backpressure device. (*Refer to Table 17 for the recommended minimum backpressure.*) Once the backpressure is applied, close the valve on the cell (green valve) to trap the pressure.
12. Install the quick-connect from the hydraulic pump to the hydraulic end of the cell (bottom end). Leave the black valve on the pump open.
13. Heat the cell to the desired temperature. Open the valve on the cell (green valve).
14. Close the valve on the pump (black valve) and apply desired pressure to the cell with the pump.
15. Once the desired pressure is applied, open the valve on the reservoir and collect the mud and/or filtrate in a graduated cylinder. Continue to collect the liquid until the reservoir blows dry. This should be recorded as the spurt loss.
16. Close the valve on the reservoir and maintain the desired pressure on the cell with the hydraulic pump. (Most pumps leak slightly.) Hydraulic pressure will need to be applied to the cell to maintain pressure on the cell for 30 minutes. Monitor the flow by bleeding the cell every 5 minutes and recording the volume.

Table 17
Recommended Minimum Back Pressure

Test Temperature		Vapor Pressure		Minimum Back Pressure	
°F	°C	psi	kPa	psi	kPa
212	100	14.7	101	100	690
250	121	30	207	100	690
300	149	67	462	100	690
LIMIT of <i>Normal</i> Field Testing					
*350	177	135	932	160	1104
*400	204	247	1704	275	1898
*450	232	422	2912	450	3105

*DO NOT exceed equipment manufacturers' recommendations for maximum temperatures, pressures, and volumes.

17. After 30 minutes, record total amount of liquid recovered (exclude the spurt loss).
18. Release the pressure on the hydraulic pump and close the top valve.
19. Remove the hydraulic quick-connect from the cell to the pump.
20. Bleed off the back pressure. Remove back-pressure device and repeat the same for the reservoir. Remove the reservoir from the top of the cell and clean.
21. Turn heating jacket off. Allow cell to cool by removing it from the heating jacket or cooling it in cold water.
22. Open the top valve slowly to remove trapped pressure. Repeat this process several times to ensure that all the pressure is removed from the cell.
23. Remove the top cap of the cell and turn the cell upside down. Remove the hydraulic end cap (bottom cap) to expose the floating piston. Screw T-bar wrench into the piston and gently push down to force mud and disk out the opposite end of the cell.

Note: This may cause mud to splatter out if too much pressure is applied.

24. Recover the Aloxite disk and filter cake. Wash cake very lightly with fresh water.
25. Measure filter cake thickness.
26. Preferred: Plot volume versus square root of time (minutes) and calculate spurt and S.

Alternative: Total fluid loss is calculated as follows:

Note: Total Fluid Loss = (Spurt Loss, cm³) + [(2) (30 minute fluid recovery)]

The total fluid loss and filter cake thickness should be recorded daily on the mud sheet for trend analysis. Whole mud and filtrate recovery should be differentiated in the spurt loss and 30 minute recovery when possible.

27. Completely disassemble the cell and clean apparatus.

Pilot Testing

Introduction

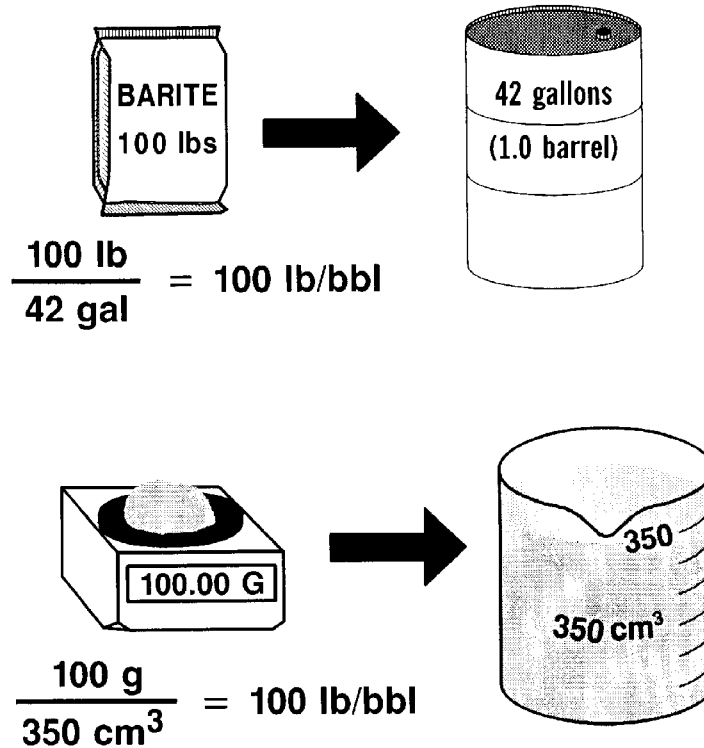
Pilot testing of drilling fluids is testing performed on proportionately small-scale samples. It is an essential part of drilling fluid testing and treating. Pilot testing minimizes the risk of sending a fluid downhole that may be incompatible with the formations to be drilled or that may be ineffective under downhole conditions. Generally, pilot testing is concentrated on the physical properties such as rheology and fluid loss; however, it is important that chemical properties also be evaluated. Most chemical reactions require heat, mixing, and time to drive the reaction. Therefore, it is necessary to have a means for heating and agitating pilot test samples. Problems such as carbonates and bicarbonates are not readily detectable and require a complete mud analysis and a pilot test series with heat aging to determine proper treatment. Without heat aging, it is easy to overtreat the contaminant and create an even more severe problem. A portable roller oven is a critical part of a pilot testing set-up at the rigsite. A pilot test sample should be representative of the fluid being used. Pilot testing is thus based on the fact that 1 g/350 cm³ of the sample is equivalent to 1 lb/bbl (42 gal) of the actual mud system. (See *Figure 38 which illustrates pilot testing equivalents.*)

Designing Pilot Tests

A pilot test or a series of pilot tests must be designed to answer the questions that you have in mind. Therefore, it is necessary to know exactly the reason for the test. Some typical reasons are:

1. Mud response to downhole conditions, such as:
 - temperature effects
 - drilling uncured cement
 - drilling anhydrite
 - encountering salt/saltwater flows
 - acid gas (CO₂, H₂S) intrusions
 - water on water-based mud contamination in oil-based mud
2. Product response as a result of:
 - purity, material variation (different lot #s)
 - concentration
 - compatibility with other components in the mud

Figure 38
Pilot Testing Equivalents



- comparison to other products
 - temperature/contamination
 - shelf life
3. Adjustments to mud properties such as:
- weight up/dilution
 - changing fluid loss properties
 - changing alkalinity/pH
 - treating carbonate/bicarbonate contamination
 - reducing hardness
 - adjusting MBT - clay content of the mud
 - changing oil/water ratio of oil muds
 - increasing electrical stability of oil muds
4. Study of effects of breakover, converting or displacement of muds, such as:
- displacing water-based mud with oil-based mud or vice versa

- converting from freshwater mud to saturated salt mud
- breakover to lime or gyp mud
- reducing components in mud to convert to *bland* coring fluid
- treatment required to convert mud to a packer fluid

To determine how to design a pilot test or test series, look at economics and potential for problems down the road. For example, if you expect to encounter a pressured saltwater flow (16 lb/gal) with a 15 lb/gal freshwater mud at 350°F, the parameters for testing could be: (1) maximum volume of saltwater anticipated in the mud, (2) weight up to 16 lb/gal with and without contaminant, (3) effects of temperature on mud (15 and 16 lb/gal) with and without contamination, and (4) dilution and thinner treatments.

Pilot test design requires calculating amounts of materials to put into the test samples. In pilot tests, grams are equivalent to pounds and 350 cm³ is equivalent to one 42-gal oilfield barrel. Material balance equations, as developed in “*Engineering*”, are used for pilot test design. For example, to weight the 15 lb/gal mud to 16 lb/gal without increasing the mud volume, one must calculate how much 15 lb/gal mud to dump and how much barite to add to increase density. For simpler pilot tests, such as adding only a few lb/bbl treatment, it is not necessary to account for material balance.

Note: For liquid additives, volumes (gallons, buckets, drums) must be converted into weights (pounds, grams) for pilot testing.

Rigsite pilot tests have distinct practical advantages over sending a mud into the laboratory or having a laboratory mud prepared for pilot testing. Rigsite testing allows actual material and mud to be used, which allows results to be readily available, quicker (which is usually very important), and allows rig supervisor and mud engineer to evaluate and review the pilot test results.

Laboratory pilot tests and planning are both important in preparing to drill a troublesome well. Both should be done long in advance of anticipated problems. In this case, lab pilot tests are advantageous in that they can be performed in advance, but then pilot tested again at the rigsite with the actual mud and chemicals.

Note: Protective eyewear (safety glasses or safety goggles) must be worn at all times when mixing chemicals.

Pilot Testing Equipment

A balance that can weight from 0.1 to 300 g and an oven (preferably roller oven) that can go to approximately 400°F are needed. Mud cells (three minimum) made of stainless steel to hold at least 300 cm³ of mud at 1000 psi, a mixer such as a Hamilton Beach mixer are also needed. Mud testing equipment that is accurately calibrated, along with fresh reagents for titrations are essential for pilot testing. Most mud companies can provide a *Pilot Test Kit*, they do not usually contain the oven and cells, but are available upon request.

Interpretation of Pilot Test Results

A single pilot test can give only limited information, but this is often sufficient for the need. Most often a series of pilot tests (three to five samples) are required to properly answer the questions. For every

Table 18
Specific Gravity of Common Drilling Fluid Components

Material	Specific Gravity	lb/gal	lb/bbl
Fresh Water	1.00	8.33	350
Seawater	1.03	8.58	361
Diesel Oil #2	0.84	7.0	294
Saturated Saltwater	1.20	10.0	420
API Bentonites	2.60	21.6	910
Calcium Carbonate, CaCO ₃	2.75	22.9	963
Caustic Soda*, NaOH	2.13	17.7	525
Lime, Ca(OH) ₂	2.20	18.3	746
Lignite	1.50	12.5	525
Gypsum CaSO ₄ .2H ₂ O	2.30	19.2	805
Lignosulfonate	0.83	6.9	290
Soda Ash, Na ₂ CO ₃	2.53	21.1	886
Salt, NaCl	2.16	18.0	756

$$\text{Volume Increase} = \frac{\text{lb}}{\text{lb/bbl}} = \text{bbl increase}$$

*Caustic Soda 50% Solution

$$1 \text{ cm}^3/350 \text{ cm}^3 = 1/2 \text{ lb/bbl}$$

$$2 \text{ cm}^3/350 \text{ cm}^3 = 1 \text{ lb/bbl}$$

pilot test (single or series) a *control* sample must be run along in parallel with the test sample. A control sample is the base mud which has not been treated, but which is taken through all the mixing, heating, rolling, etc. processes. The control is used to aid interpretation of results. Data are compared between the control and test sample to sort out the effects due to treatment versus mechanical effects (mixing, rolling or time of exposure). For example, a mud engineer has an oil mud with a low electrical stability (ES). He pilot tests a sample with 2 lb/bbl (2 g/350 cm³) additional emulsifier and shears it on the mixer for 10 minutes. The ES is much higher than before. He also has run a control sample on the mixer for 10 minutes, but without the additional emulsifier, and obtained almost the same higher ES. Was the emulsifier responsible for the improved ES? No, in this case the shearing was what gave the improvement.

Results of pilot testing should be thoroughly reviewed before drawing conclusions. Often, a pilot will lead to another one or two tests before the answer is satisfactorily clear.

Figure 39
Weighing Equipment

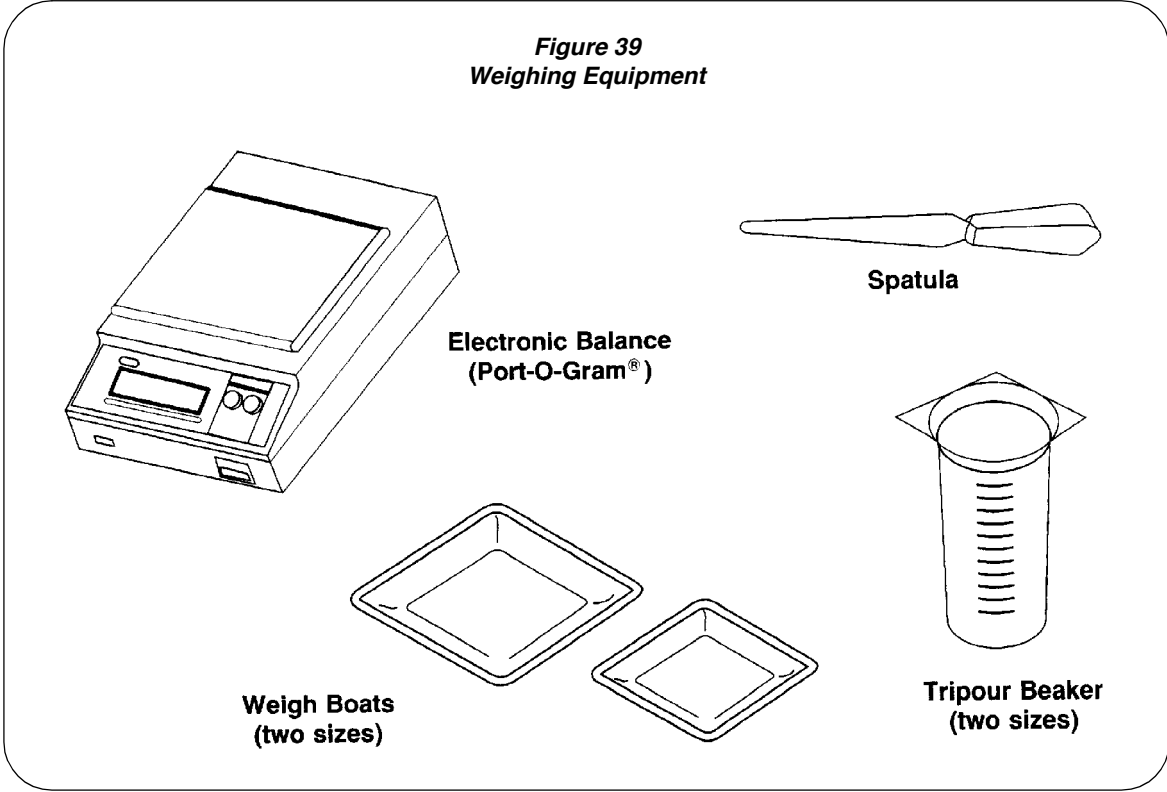
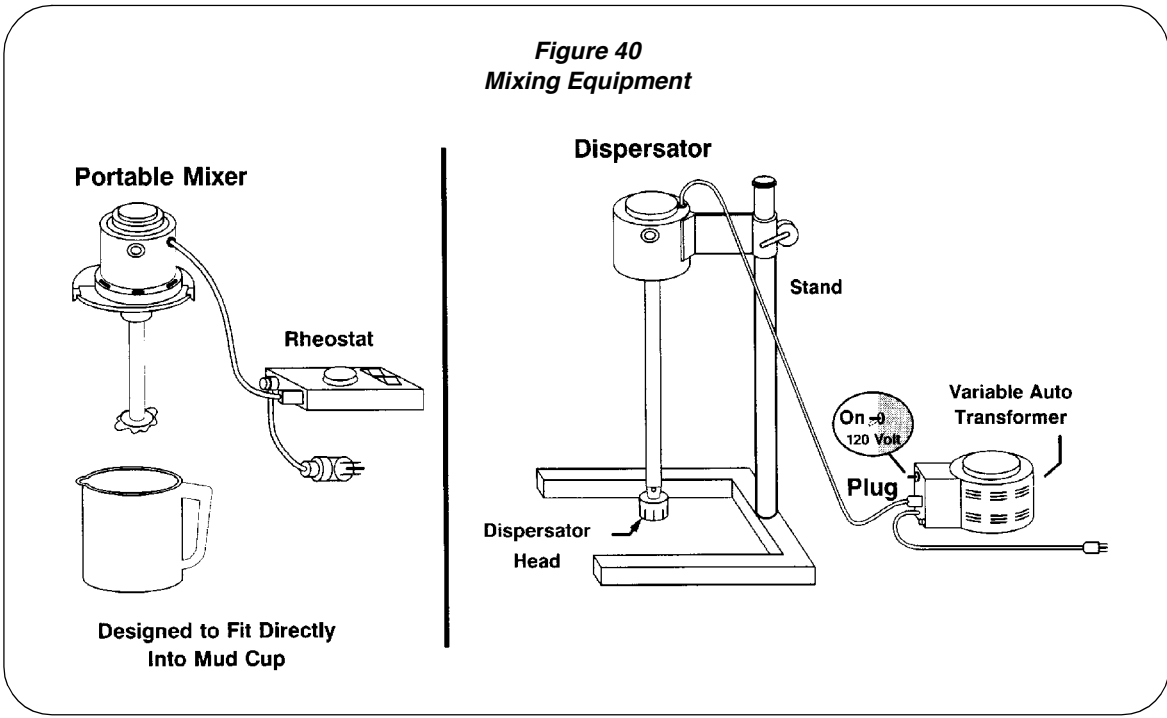


Figure 40
Mixing Equipment



Section 4 Chemistry and Filtration

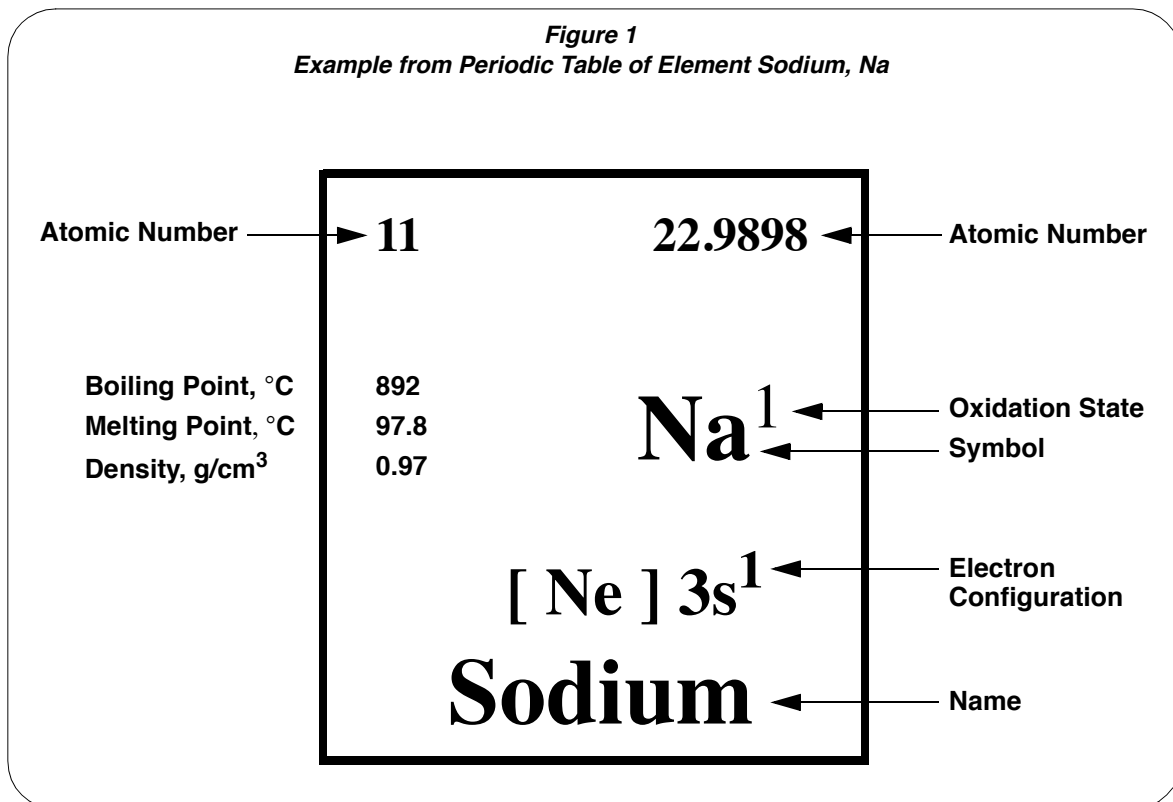
Basic Chemistry

Introduction

Matter is a generic term for any substance which has mass and occupies space. Although the terms mass and weight are often used interchangeably, mass is independent of weight. An object will have the same mass on the earth as on the moon, but will weigh one-fifth as much on the moon because the force of gravity is one-fifth that of earth. Weight is the effect of acceleration due to the force of gravity on a mass.

An element is a substance comprised of matter in which all atoms are identical. The atom is the smallest unit of matter which retains the basic characteristics of an element.

The Periodic Table of the Elements is a chart which groups elements of a similar nature together. Considerable information can be obtained from the Periodic Table, such as atomic weight, atomic number, boiling point and melting point. Symbols are used as a method of simplifying the representation of different elements in chemical equations.



**Table 1
Common Chemical Symbols**

Name	Symbol	Atomic Weight
Barium	Ba	137.35
Bromine	Br	79.91
Calcium	Ca	40.08
Carbon	C	12.01
Chlorine	Cl	35.45
Hydrogen	H	1.00
Magnesium	Mg	24.32
Nitrogen	N	14.00
Oxygen	O	16.00
Phosphorus	P	30.98
Potassium	K	39.09
Silicon	Si	28.06
Silver	Ag	107.88
Sodium	Na	22.99
Sulfur	S	32.06
Zinc	Zn	65.38

Table 2
Common Compounds

Name	Common Name	Formula	Molecular Weight
Barium Chloride		BaCl ₂	208.27
Barium Sulfate	Barite	BaSO ₄	233.42
Calcium Chloride		CaCl ₂	110.90
Calcium Carbonate	Calcite	CaCO ₃	100.09
Calcium Hydroxide	Slaked Lime	Ca(OH) ₂	74.10
Calcium Sulfate	Gyp	CaSO ₄	136.14
Hydrogen Oxide	Water	H ₂ O	18.01
Hydrogen Sulfide	Sour Gas	H ₂ S	34.08
Magnesium Chloride		MgCl ₂	95.23
Magnesium Carbonate		MgCO ₃	84.31
Magnesium Hydroxide		Mg(OH) ₂	58.34
Potassium Chloride		KCl	74.55
Potassium Hydroxide		KOH	56.10
Silver Chloride		AgCl ₂	143.34
Silver Nitrate		AgNO ₃	169.89
Sodium Bicarbonate	Bicarb	NaHCO ₃	84.00
Sodium Carbonate	Soda Ash	Na ₂ CO ₃	106.00
Sodium Chloride	Salt	NaCl	58.45
Sodium Hydroxide	Caustic Soda	NaOH	40.01
Sulfuric Acid	Oil of Vitriol	H ₂ SO ₄	98.08
Zinc Carbonate		ZnCO ₃	125.38
Zinc Oxide		ZnO	81.38

Table 3
Common Chemical Symbols

Cations	Anions
Ca ⁺⁺	CO ₃ ⁼
H ⁺	HCO ₃ ⁻
Mg ⁺⁺	OH ⁻
Na ⁺	SO ₄ ⁻
K ⁺	S ⁼
Zn ⁺⁺	SiO ₃ ⁼
AL ⁺⁺⁺	Cl ⁻

A list of the elements, symbols and atomic weights most often used in drilling fluid chemistry are found in *Table 1*.

A compound is a substance composed of two or more elements. Table salt, for example, is a compound which is made up of an equal number of sodium and chlorine atoms. A molecule is the smallest particle of a compound which retains the composition and properties of that compound. A molecule of salt contains one atom of sodium and one atom of chlorine and is represented by the chemical formula NaCl. (*Table 2 lists common compounds, chemical formulas, and molecular weights.*)

An atom or molecule which has an electrical charge associated with it is called an ion. In drilling fluid chemistry we are concerned with ions in an aqueous solution (compounds which ionize in water). Table salt, NaCl, in contact with water ionizes to form positive sodium ions (Na⁺) and negative chloride ions (Cl⁻). An overall positive ionic charge means the ion has lost an electron. A negative charge means the ion has gained an electron. Positively charged ions are called *cations*, negatively charged ions are *anions* (*Table 3*).

Elements combine into molecules or complex ions in specific integer ratios: 1 to 1, 2 to 1, 3 to 1, etc. Using salt as an example, 23 g of sodium combines with 35.5 g of chlorine to form sodium chloride, which is a 1 to 1 combination. While the mass of the elements differ, the numbers of atoms of each are equal. The number of atoms in a given amount of a compound is measured in moles. A mole is defined as being the same number of atoms as there are in exactly 12 g of carbon-12. This number, Avogadro's number, is 6.02252×10^{23} atoms or molecules per mole. From the mole comes the determination of atomic weight, which is the weight in grams of one mole. Molecular weight is the sum of the atomic weights of the elements comprising a compound.

Density is a measure of mass per unit volume where mass is a measure of the quantity of matter present. The common scientific unit is grams per cubic centimeter (g/cm³). Common oilfield units are pounds per gallon (lb/gal), pounds per cubic foot (lb/ft³), and kilograms per cubic meter (kg/m³).

Density and specific gravity are often confused. They are not interchangeable. The density of a material may vary with changes in temperature and pressure; but, specific gravity is based on a set temperature and pressure. Specific gravity is the density of a material at 25°C and 1 atmosphere of pressure divided by the density of water (0.997 g/cm³) at 25°C and 1 atmosphere of pressure. Since we are dividing density by density, specific gravity is unitless.

$$\text{SG of Water} = \frac{0.997 \text{ g/cm}^3}{0.997 \text{ g/cm}^3} = 1.00$$

$$\text{SG of Mercury} = \frac{13.5 \text{ g/cm}^3}{0.997 \text{ g/cm}^3} = 13.54$$

Aqueous Chemistry

Aqueous solubility is the ability of a compound to dissolve in water. Some factors which affect solubility are: temperature, pressure, salinity, pH, and ionic composition of water. Solute is the compound which is being dissolved, while solvent (in this case water) is the fluid in which the solute is dissolved.

(Table 4 shows the solubility of several common compounds used. Table 5 illustrates the effect of temperature on the solubility of several compounds.) Increasing temperature usually increases solubility; but, in some important instances (e.g., lime and gypsum), it decreases solubility.

Table 4
Solubilities of Common Compounds
(g/100 g water)

Compound	Solubility	Measured at °C
KOH	178	100
NaOH	347	100
NaCl	39.2	100
NaHCO ₃	16.4	60
Na ₂ CO ₃	45.5	100
CaSO ₄	0.162	100
Ca(OH) ₂	0.077	100
CaCO ₃	0.0018	75
CaCl ₂	159	100
MgCO ₃	NA	NA
Mg(OH) ₂	0.004	100
KCl	56.7	100
ZnO	0.00016	29

Table 5
Solubility as a Function of Temperature
(grams compound/100 grams water)

Compound	0	20	40	80	100
Ca(OH) ₂	0.185	0.165	0.141	0.094	0.077
KCl	27.6	34.0	40.0	51.1	56.7
NaCl	35.7	36.0	36.6	38.4	39.8
CaSO ₄	0.176	0.202	0.210	0.182	0.162
CaCl ₂	-	74.5	-	-	159
CaCO ₃	-	0.0012	-	-	0.002

The strength of a solution is measured in terms of concentration, which refers to an amount of solute per unit of solvent. Several units are used to measure the strength of a solution. The most common unit is milligrams per liter (mg/L) or thousandths of a gram of solute per liter of solution. Parts per million (ppm), equivalents per million (epm) and moles per liter (mol/L) are also still used.

pH is a frequently used measure for the concentration of acids and bases. pH is the negative log of the hydrogen ion concentration in moles per liter. At 25°C, acidic solutions have a hydrogen ion concentration greater than that of water. Thus, acidic solutions have pH values less than 7. At 25°C, basic solutions have a hydrogen ion concentration less than that of water. Thus, basic solutions have pH values greater than 7. In deionized water, the concentration of hydroxyl ions equals the concentration of hydrogen ions both 10^{-7} mol/L. By definition, the pH of pure water is $\log [1/10^{-7}]$ or 7. Since there is an equal number of hydrogen and hydroxyl ions, this is considered a neutral pH.

Chemical Analysis - Mud Check

The following discussions summarize the chemical analyses of mud. For detailed information, refer to Section 3 - Testing.

pH

An accurate method of measuring pH is with a pH meter. pH paper is another method, but is not always accurate and is not recommended. The majority of water-based muds are alkaline and run in the pH range 9-11. Some exceptions are lime muds with a pH around 12, and low pH polymer muds with a pH of 8-9. (*Table 6 and Figure 2 illustrate the pH of several oilfield and common household chemicals.*)

Table 6
pH of 10% Solution
(approximate)

Soda Ash	11
Sodium Hydroxide	14
Potassium Hydroxide	14
Calcium Hydroxide	12
Barium Carbonate	10
Gypsum	6
Calcium Lignosulfonate	7
Lignosulfonate	4.0
Chrome Lignite	3.4 - 4
Quebracho	4.0
Lignite	5
Sapp	4.8

Figure 2
pH Scale and Common Chemicals

(H ⁺)	(OH ⁻)	pH	Strength	Examples
10 ⁰	10 ⁻¹⁴	0	strong acid	1M HCl
10 ⁻¹	10 ⁻¹³	1		gastric juice
10 ⁻²	10 ⁻¹²	2		lemon juice
10 ⁻³	10 ⁻¹¹	3		Coca Cola, vinegar
10 ⁻⁴	10 ⁻¹⁰	4		orange juice
10 ⁻⁵	10 ⁻⁹	5		black coffee
10 ⁻⁶	10 ⁻⁸	6		urine
10 ⁻⁷	10 ⁻⁷	7	neutral	coffee with milk
10 ⁻⁸	10 ⁻⁶	8		milk
10 ⁻⁹	10 ⁻⁵	9		saliva
10 ⁻¹⁰	10 ⁻⁴	10		blood
10 ⁻¹¹	10 ⁻³	11		baking soda
10 ⁻¹²	10 ⁻²	12		milk of magnesia
10 ⁻¹³	10 ⁻¹	13		household ammonia
10 ⁻¹⁴	10 ⁰	14	strong base	caustic soda (0.1M)
				1 M NaOH

P_M

Alkalinity of the whole mud, or P_M, is a measure of both the soluble and insoluble materials in a mud. Soluble ions, such as hydroxyls, carbonates and bicarbonates, and insoluble compounds, such as lime and magnesium hydroxide, have an affect on the P_M. The P_M is expressed as the volume in cm³ of 0.02N sulfuric acid required to lower the pH of 1 cm³ of the mud to 8.3. This is the pH at which phenolphthalein, a color indicator, changes color from pink to clear. When titrating whole mud, the end-point color is the original color of the mud before phenolphthalein was added.

P_F

Alkalinity of the mud filtrate, or P_F, is a measure of only soluble materials and is reported as the volume (cm³) of 0.02N sulfuric acid required to lower the pH of 1 cm³ of filtrate to 8.3. Common soluble ions are hydroxyls, carbonates and bicarbonates. P_F will usually be lower than P_M due to removal of the insoluble alkaline materials in the filter cake.

M_F

The sum of the P_F plus the additional volume of 0.02N sulfuric acid required to reduce the pH of the filtrate to 4.3 is dubbed M_F. In this pH range, bicarbonate ions are commonly titrated. Humic acids from lignites, lignosulfonates, acetate ions, as well as some other organic additives, also have an effect on the amount of acid required to reach the M_F end point.

Total Hardness As Calcium

Total Hardness is a measure of the concentration of divalent cations, and is reported as mg/L Ca⁺⁺ ion. Hardness is primarily calcium and magnesium, although other cations may influence the results. It is possible to differentiate calcium from magnesium through a different test. The titrating solution is standard versenate (EDTA) solution.

Chlorides

Chlorides is a measure of chloride ions dissolved in the filtrate from all soluble sources. The filtrate is titrated with either 0.0282 N or 0.282 N AgNO₃ (silver nitrate) and reported in mg/L chlorides. Mg/L chlorides can be converted to mg/L NaCl by multiplying by 1.65, or to mg/L CaCl₂ by the factor 1.57. The derivation of the sodium chloride factor is shown below.

$$\text{Molecular wt of Cl} = 35.5$$

$$\text{Molecular wt of NaCl} = 58.5$$

$$\text{Molecular ratio of NaCl/Cl} = 58.5/35.5 = 1.65$$

The assumption in using any such factor is that all chlorides titrated result from that particular salt dissolved in water and, consequently, this titration is subject to error in interpretation. The color change observed is from yellow to red-orange. The proper endpoint in the titration is the first permanent orange color seen.

Carbonates

The Garrett Gas Train (GGT) is the most consistent test for the presence of soluble carbonates. A sample of filtrate is acidized causing all carbonates and bicarbonates to be converted to CO₂ gas, which is then measured with a Dräger tube and reported as mg/L total carbonates in the filtrate.

An alternative titration method for carbonates determination is the P1-P2 titration method. This titration is seldom used because it requires the use of barium chloride (BaCl₂), which is extremely toxic. Relationships between the various alkalinities (P_M, P_F, M_F) can also indicate a carbonate problem. A rule of thumb is: if the M_F is greater than 5, and greater than 4 times the P_F, then carbonates may be present. If these conditions exist, a Garrett Gas Train should be used to verify the presence of carbonates.

Methylene Blue Capacity (MBT)

The methylene blue test is a measure of the capacity of anionic clays to adsorb cationic methylene blue dye. The quantity of adsorbed dye is a direct indication of the quantity and activity of the clays in the fluid. The MBT value, in conjunction with the solids analysis, can indicate the amounts of drill solids and commercial clays in the fluid. The methylene blue capacity (MBT) is reported as cm^3 of methylene blue per cm^3 mud and can also be reported as equivalent lb/bbl bentonite as per the following equation:

$$\text{equivalent bentonite, lb/bbl} = \frac{(\text{cm}^3 \text{ methylene blue})(5)}{\text{cm}^3 \text{ mud}}$$

A similar test can be run on shale samples such as cuttings or sidewall cores to determine the activity of native clays. In this procedure, a solid sample is used instead of mud. The results are reported as milliequivalents per gram or equivalents per kilogram.

Mud Chemistry

Each individual type of mud system has its own chemical characteristics due to either the components that are in the system or the chemistry required to make the system function properly. Below are discussed the various types of muds and some of their unique chemical characteristics.

Saltwater Mud

Saltwater muds are arbitrarily designated to be muds with a chloride concentration in excess of 10,000 mg/L. They can range in salinity from brackish to saturated. A saturated NaCl salt mud is one which contains the maximum amount of dissolved salt, which at room temperature should be about 315,000 mg/L salt. A major benefit of salt based muds is their ability to inhibit hydration of clays.

Seawater Mud

Seawater muds are among the most common saltwater muds in use. They may be sub-grouped as chrome lignosulfonate, gyp, lime, or polymer muds. (*Table 7 shows the composition of seawater.*) The principal difficulty with seawater is its high concentrations of calcium and magnesium. Of the two, magnesium is the most detrimental to commercial clays, but is easily removed by the addition of caustic soda which precipitates magnesium hydroxide, $\text{Mg}(\text{OH})_2$.

Table 7
Composition of Seawater

Compound	Concentration (mg/L)
NaCl	24,540
MgCl ₂ · 6H ₂ O	11,103
Na ₂ SO ₄	4,090
CaCl ₂	1,160
KCl	690
NaHCO ₃	200
KBr	100
SrCl ₂ · 6H ₂ O	40
H ₃ BO ₃	30
NaF	3

Saturated Salt Mud

A saturated salt mud is one in which the maximum amount of salt (NaCl) is dissolved in the fluid. Approximately 125 lb/bbl is required if starting with freshwater. Saturated salt muds can be very inhibitive to certain types of shales. An added benefit is the reduced volume of solids needed to achieve a high density mud. They also permit drilling a more nearly gauge hole through salt zones since they do not tend to dissolve salt. Hole washout in salt zones can still be a problem, even when using saturated salt muds, because more salt can go into solution at the higher temperatures downhole (*Table 5*). Consequently, a fluid which is saturated at the surface may not be saturated downhole. In addition, because a saturated salt solution is a fairly harsh environment, many chemicals and polymers do not function well.

Salt is seen as *solids* when performing a retort test; therefore, it is necessary to correct the solids analysis figures for fluids having a salt content over about 10,000 mg/L.

Calcium-Based Mud

Calcium-based muds are muds in which an excess of calcium ion (Ca⁺⁺) is maintained in the fluid by additions of a calcium source, usually lime or gypsum. The calcium ion will undergo a base exchange with the clays in the drilling fluid and will help restrict hydration of active drill solids. Lime muds use lime, Ca(OH)₂, as a calcium source. They have a high pH and high alkalinities with about 200-400 ppm Ca⁺⁺ in the filtrate. Gyp-based muds, on the other hand, use gypsum (CaSO₄ · 2H₂O) as a calcium source and have lower alkalinities and pH and show about 1000 mg/L Ca⁺⁺ in the filtrate.

Calcium-based muds must be used with caution, however, as many additives that are commonly used in other muds are incompatible with Ca⁺⁺.

Potassium Mud

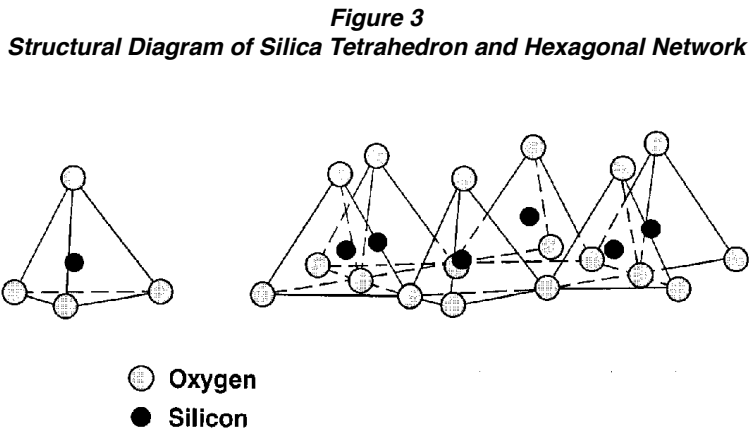
Potassium-based muds are used because the potassium ion (K^+) is very inhibitive to hydratable shales. The most common potassium source is potassium chloride (KCl), but potassium acetate ($KC_2H_3O_2$) is used occasionally. Potassium hydroxide (KOH) can be used for alkalinity control and will also provide some free potassium. Potassium chloride muds are usually run in the 3% to 15% KCl range. The concentration of potassium can be checked in the field by a precipitation procedure, a potassium ion electrode, or through the use of test strips. The precipitation and electrode procedures are the most accurate.

Clay Chemistry

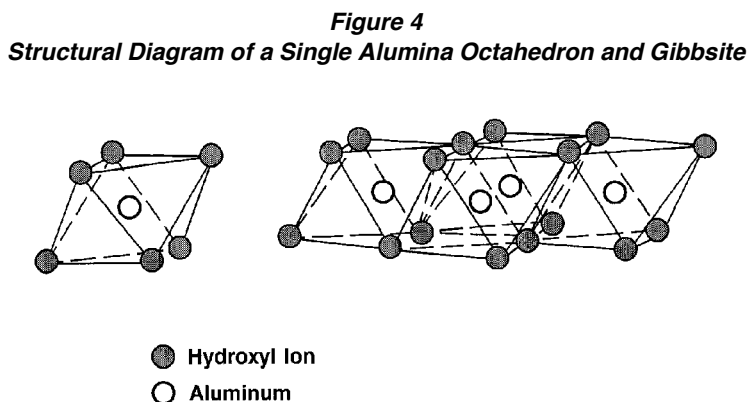
Structure of Clays

Clays are minerals which in the presence of water and agitation will adsorb water and break up into colloidal-sized particles. Each particle is only a few microns in thickness and consists of two or more discrete layers. The degree to which the clays dissociate is governed by the clay type, exchangeable cations associated with the clay, and the electrolytic make-up of the water.

Clays are hydrous aluminum silicates composed of alternating layers of alumina and silica. Silica is a tetrahedral structure with a silicon atom surrounded by four oxygen atoms at equal distance from each other. The silica tetrahedrons are joined in a hexagonal structure which is replicated to form a sheet (see Figure 3). The tips of all tetrahedrons point in the same directions and their bases are all the same plane.



Alumina has an octahedral structure consisting of an aluminum atom with six oxygen atoms arranged in an octahedron around it. These alumina octahedra are then joined in a structure which is replicated to form a sheet or layer. The structure is the same as the mineral gibbsite $[AL_2(OH)_6]$ (see Figure 4). These sheets of alumina and silica alternate to form the various clays. The clays we are most concerned with are either two-layer or three-layer clays.



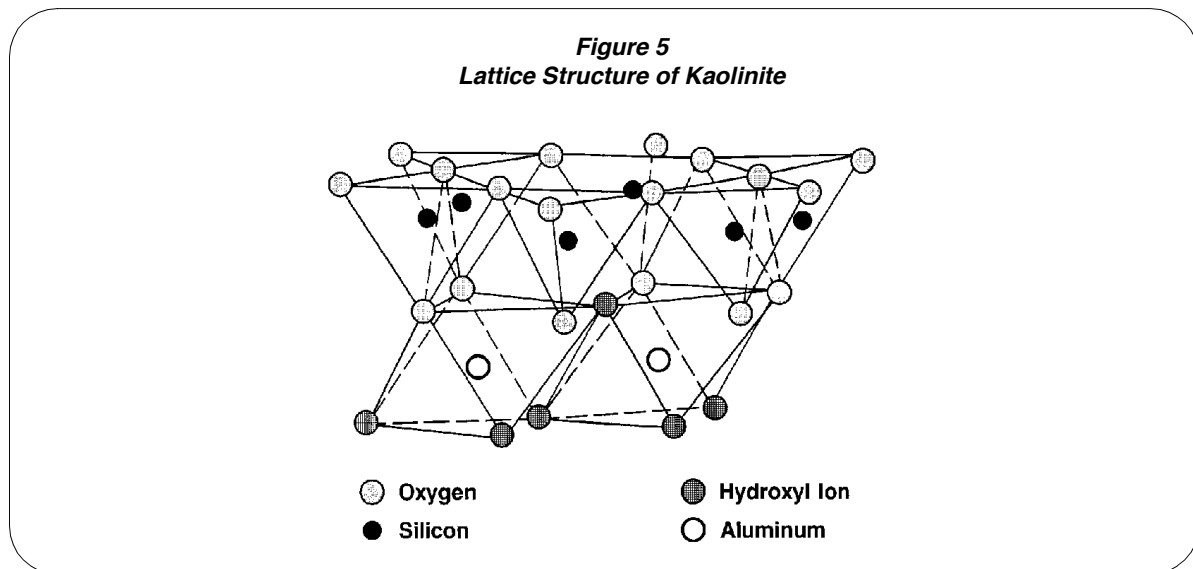
Most of the clays we encounter either as drill solids or as commercial clays have a platelike shape. The particles may be several microns wide, but only a few Angströms thick. Since a micron (micrometer) is 1×10^{-6} m and an Angström (Å) is 1×10^{-10} m, a clay particle will be roughly 10,000 times wider than it is thick. It is this form, in the case of bentonite, which makes it beneficial in reducing filtrate loss.

The principal clays are:

- Kaolinites
- Illites
- Chlorites
- Smectites
- Attapulgite and Sepiolite

Kaolinites

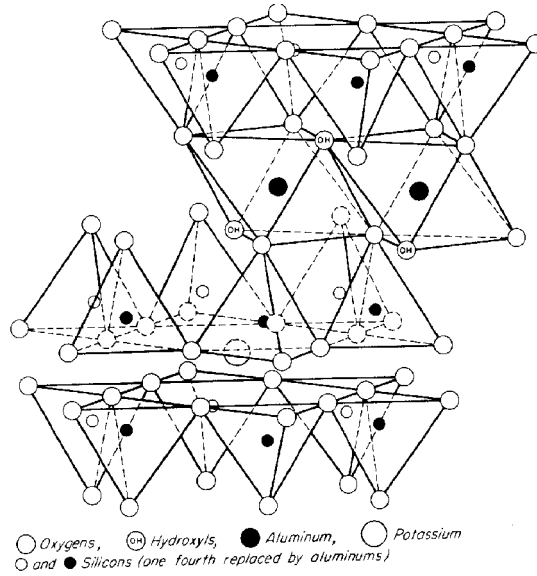
Kaolinites are a two-layer clay composed of a tetrahedral silica sheet and an octahedral alumina sheet (see Figure 5). The silica sheet is oriented so that the tips of the tetrahedra are in the same plane as the oxygen or hydroxyl groups on the alumina sheet. The kaolinite particles are held together by hydrogen bonding and the spacing between layers is about 2.76 Å. The hydrogen bonding is strong enough to exclude water from the clay surface; consequently, kaolinites are considered non-swelling clays. The cation exchange capacity of Kaolinites is typically 3-15 milliequivalents (meq)/100 g.



Illites

Illites are hydrous micas three layer clays which structurally resemble montmorillonites. Illites have no expanding lattice; therefore, no water can penetrate between the layers. They are composed of an alumina octahedral layer sandwiched by two silica tetrahedral layers (see Figure 6). Some of the silicon atoms in the illite structure are replaced by aluminum atoms. The resulting charge discrepancy is balanced by the association of potassium ions between layers. In some Illites the substitution of silicon by aluminum may be lower and the potassium may be replaced by divalent cations such as calcium or magnesium. In these cases the Illites may exhibit swelling tendencies similar to montmorillonites. The cation exchange capacity of Illites is 10-40 meq/100 g.

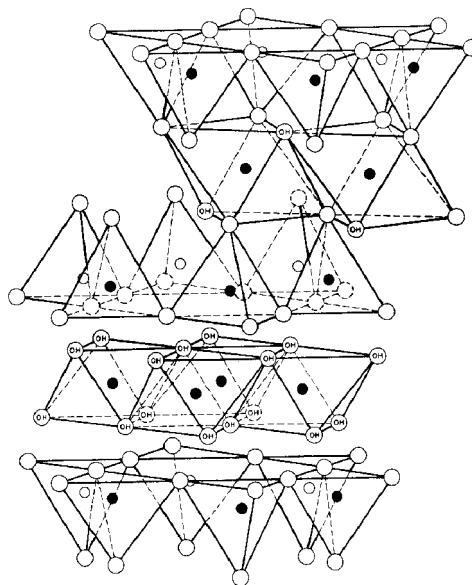
Figure 6
Structure of Illite



Chlorites

Chlorites are three-layer clays separated by a layer of brucite (see Figure 7). There is a strong bonding between layers and for this reason chlorite is a non-swelling clay. The cation exchange capacity for chlorites is 10-40 meq/100 g.

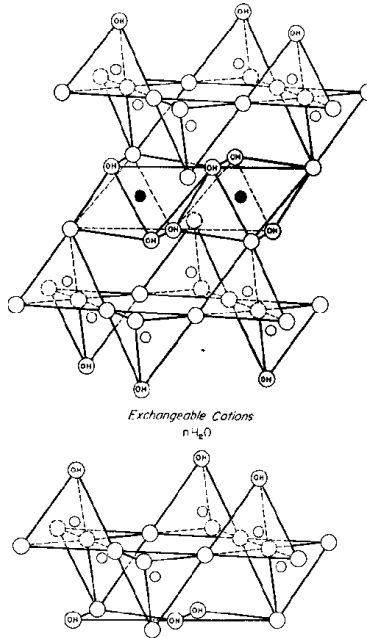
Figure 7
Structure of Chlorite



Smectites (Montmorillonites)

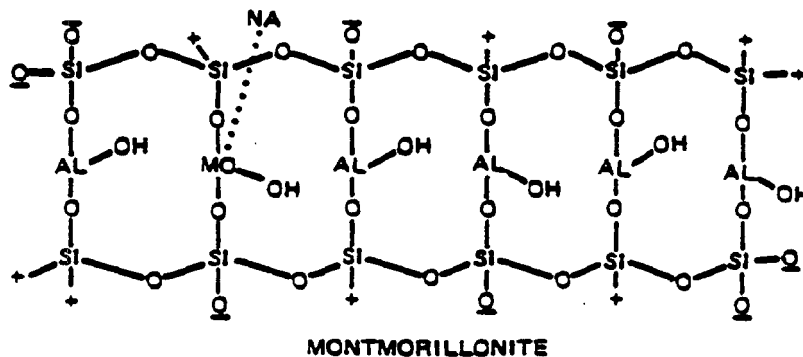
Smectites are a family of three-layer clays of which montmorillonites are members. They consist of an alumina octahedral layer sandwiched between two silica tetrahedral layers (see Figure 8).

Figure 8
Structure of Smectites



The aluminum atoms in the central layer may be replaced by magnesium or iron atoms causing a charge imbalance. This imbalance is countered by the association of positive cations at the particle surface. These cations may be monovalent, sodium for example (see Figure 9), or divalent such as calcium.

Figure 9
Structure of Sodium Montmorillonite



The character of the exchangeable cation influences the extent to which the montmorillonites will swell. The divalent cations, because of the extra charge, tend to associate with adjacent particles and consequently, restrict swelling of the clay. For this reason calcium montmorillonite is a poorer viscosifier than sodium montmorillonite. Due to their structure, the bonds between particles are weaker than other clays which adds to the ability of the montmorillonite to hydrate. This is the principal reason sodium montmorillonite is the most common commercial clay. The cation exchange capacity for smectites is 60-150 meq/100g.

Attapulgite and Sepiolite

Two other commercial clays, attapulgite and sepiolite, are used in special situations in which montmorillonite will not perform. These clays differ in structure from the more common clays in that they are elongated rod-shaped particles. Although there is water associated with these clays, they do not hydrate. These clays viscosify by shearing which causes fracturing along the axis of the rods and exposes charges which cause the rods to attract each other. Since these clays are shear dependent, they are as effective in saltwater as in freshwater. Sepiolite has the added advantage of being very temperature stable. Because they yield through shearing, little or no viscosity increase will be seen in the pits since the shearing of the hopper and mixers is usually insufficient to cause the clay to yield. It may take several trips through the bit before maximum benefit is obtained from the clay. For this reason, it is easy to overtreat with these clays in an effort to raise the viscosity of the mud. These clays provide little filtration control because of their shape. It is usually necessary to add filtration control agents when using these clays.

Clay Properties

Clay Particle Size

Clays are too small to be seen by optical methods and require electron-beam microscopes for study of size and shape. In general, individual layered clays are from 7 to 21 Å thick, but 1000 to 100,000 Å in their width and length. (A 44 micron-325 mesh silt particle is 440,000 Å). Having this small size and relatively large surface area, gives layered clays (such as bentonites) unique behavior when they are dispersed into water. Being highly charged as well, their behavior is more pronounced in terms of clay-clay particle interactions. Surface area that can be created by clay dispersion is very large, about 200 m²/g. The size and shape of clays allows them to be useful in building viscosity (when highly flocculated) or in building a tightly packed filter cake (when not dispersed or when deflocculated by a *thinner*).

Polymer chains are extremely long when compared to clay particle dimensions. When high molecular weight (several million) polymer chains become linked with multitudes of clay particles in a water system, there is a combined effect that creates highly viscous, but shear-thinning, rheology.

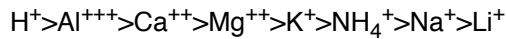
Cation Exchange

In the active clays, magnesium ions (Mg⁺⁺) may be substituted into the octahedral matrix for aluminum ions (Al⁺⁺⁺). This substitution leaves the clay particle with a net negative charge which must be balanced. This balancing of charge takes place in the form of cations which are adsorbed onto the surface of the clay platelets. These cations are loosely associated with the clay and may be displaced or exchanged by other cations. The quantity of cations available for exchange is referred to as the cation exchange capacity and is reported in milliequivalents per 100 g of shale (*Table 8*). The strength, or ability of cations to exchange, varies. (*Table 9 illustrates the relative strengths of various cations.*) A cation will tend to displace any of those to its right at equal molar concentration.

Table 8
Cation Exchange Capacity of Minerals in MEQ/100 g

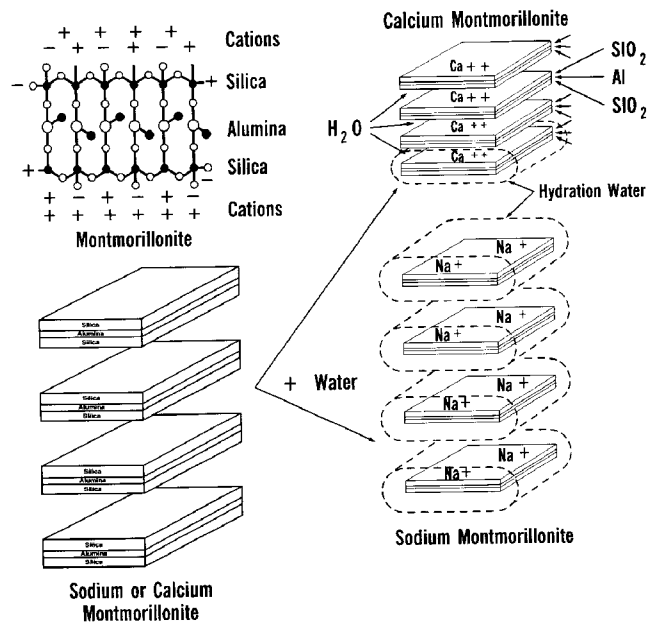
Kaolinite	3 - 15
Illite	10 - 40
Chlorite	10 - 40
Montmorillonite	60 - 150

Table 9
Cation Exchange Series



The presence and type of exchangeable cations will have an effect upon the hydration, or swelling ability of a clay. Strongly swelling clays, such as montmorillonite, will adsorb a water layer to the surface of the clay due to the presence of electrical charges on the surfaces and edges of the clays. This water layer will vary in thickness depending upon the type of cation associated. Sodium montmorillonite will form a thicker layer which will tend to move the clay platelets farther apart and make them more susceptible to dissociation. On the other hand, calcium montmorillonite, because it is less hydratable, will provide less viscosity than sodium montmorillonite in equal quantities (*Figure 10*).

Figure 10
Hydration of Sodium and Calcium Montmorillonites



Electrolyte makeup will have a similar effect on the water associated with a clay platelet. This water layer, also called the electric double layer, will be forced to shrink if the clay is immersed in a fluid with a high cation concentration. While this effect is greater with divalent cations such as calcium or magnesium, high concentrations of sodium will have the same effect. This shrinking of the electric double layer will allow the clay particles to approach each other more closely. They may reach the point when the physical attraction between the clay particles exceeds the repulsive force of the electric double layer at which time the clays will flocculate or clump together. It is difficult sometimes to understand why cations added to a bentonite water slurry will cause an increase in viscosity, while bentonite added to an electrolyte solution will provide little if any viscosity. In a freshwater bentonite slurry the clay platelets are dispersed and kept apart by the electric double layer surrounding each platelet. This electric double layer consists of a cloud of charged ions and water molecules loosely associated with the clay particle. Since all the particles have this similarly charged cloud surrounding them, they cannot approach close enough for their natural attraction to overcome the repulsion of the cloud. The addition of a cation, however, causes a decrease in the thickness of the electric double layer. This allows the particles to associate first edge to face, which will cause an increase in viscosity, and as cation concentration continues to increase, they will associate face to face which decreases viscosity. Clay added to an electrolyte solution on the other hand, is never allowed to form a substantial electric double layer and tends not to hydrate or viscosity. (These relationships are illustrated in Figures 11 through 13.)

Figure 11
Viscosity of Bentonite Slurry
vs. Salt Concentration

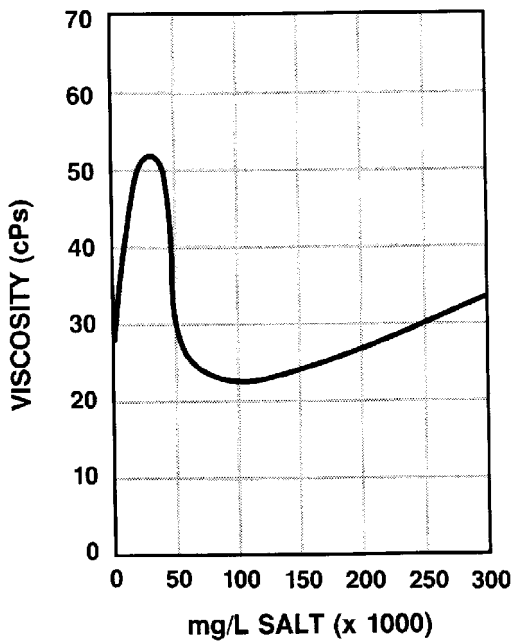


Figure 12
Viscosity of Bentonite Slurry vs. Calcium
Concentration

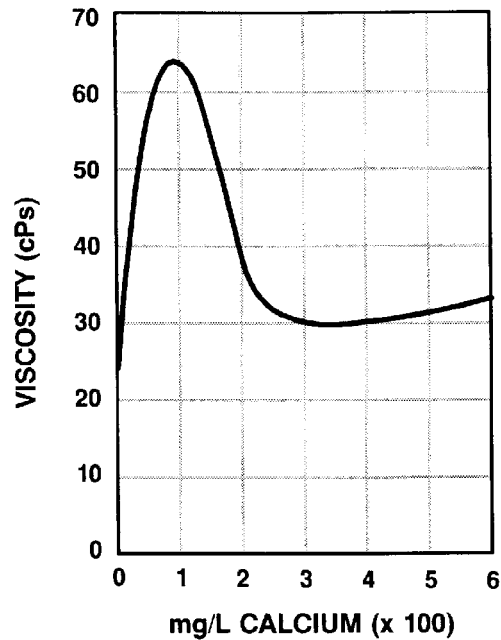
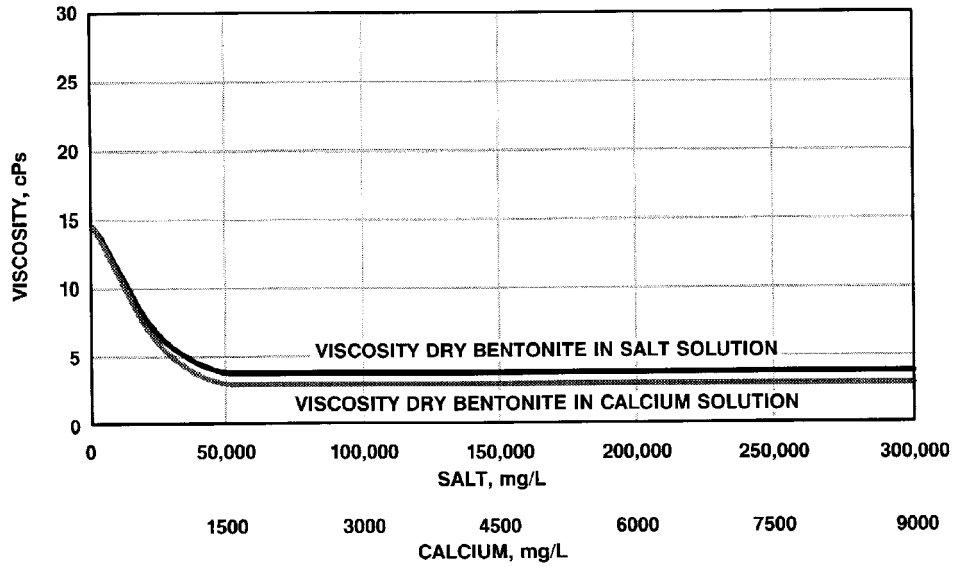


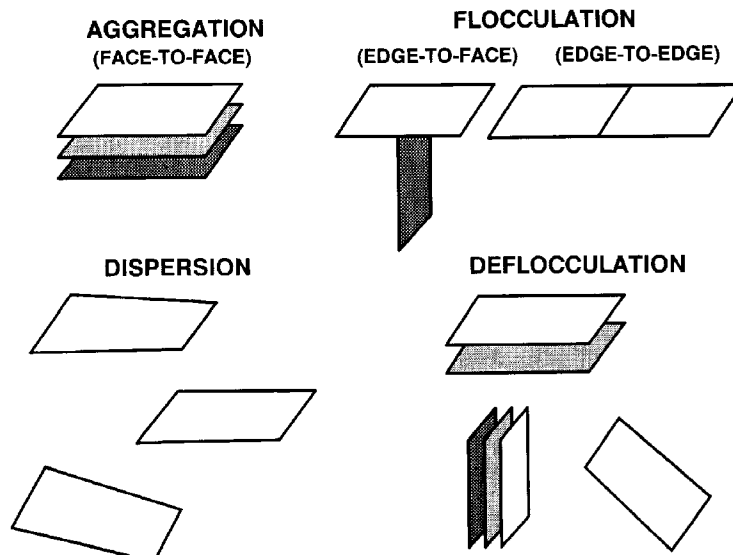
Figure 13
Dry Bentonite Added to Electrolyte Solution



Clay Interactions

We use several terms for describing the specific behavior of clay-water interactions. These are: aggregation, dispersion, flocculation and deflocculation (see Figure 14).

Figure 14
Types of Clay Associations



The clay in its dry state has platelets stacked in face-to-face association, like a deck of cards. This is **Aggregation**. When the dry clay is placed into fresh water with no agitation, the packets adsorb water, hydrate, and swell. Upon agitation, the swollen packets disintegrate into individual plates or smaller packets of plates. This is **Dispersion**. As long as agitation continues, dispersion will be retained and further dispersion can occur. When agitation is stopped, clay platelets will be mutually attracted in edge-to-edge or edge-to-face association. This forces a structure similar to a house of cards, termed **Flocculation**. If an anionic chemical thinner (deflocculant) is added, such as polyphosphate, lignosulfonate or lignite, etc., it neutralizes the positive edge charges on clay platelets and the flocculated state is now **Deflocculated**. When this deflocculated clay slurry encounters strong ionic contamination (NaCl, CaSO₄, Ca(OH)₂, etc.), the deflocculant chemical is often overpowered - leading again to **flocculation** and even to a sort of **aggregation** where water is lost from the clay surfaces.

Commercial Bentonite

Commercial bentonites used in drilling muds are naturally occurring clays and are mined in many areas of the world. They contain the clay mineral smectite and may contain accessory minerals such as quartz, mica, feldspar and calcite.

Drilling Fluid Bentonites

Smectites are three-layer swelling clays of which the most predominant form is calcium, but also sodium. Because smectites have the ability to swell (hydrate) in the presence of water, these bentonites are used to viscosify drilling fluids. Sodium bentonite, found exclusively in the northwestern part of the United States, is the most widely sought-after bentonite because its hydrational ability is considerably greater than that of calcium bentonite. Hence, the name "premium bentonite" is given to sodium bentonite. Because operational need for using bentonite varies around the globe, API established specifications to cover sodium and calcium bentonites.

Currently there are three API bentonites available (*see Table 10*). They are listed in order of degree of chemical treatment (**beneficiation**):

- API Nontreated Bentonite (no treatment)
- API Bentonite (some treatment level)
- API OCMA Grade Bentonite (high treatment level)

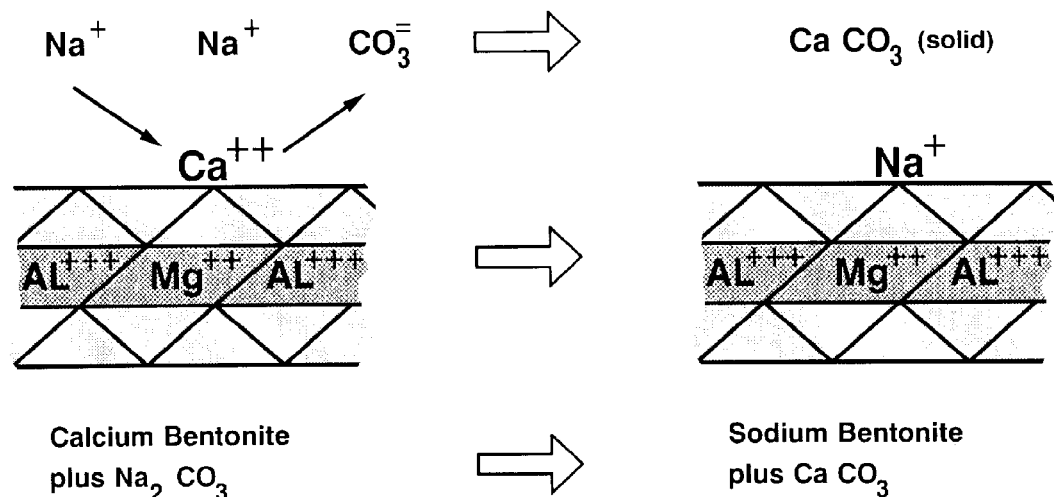
Table 10
Comparison - API Bentonite Specifications

Requirements	Nontreated Bentonite	Bentonite	OCMA Grade Bentonite
Water, cm ³	350	350	350
Clay, g/350 cm ³	25	22.5	22.5
Test for Spec:			
600 rpm, minimum	-	30	30
YP/PV ratio, maximum	1.5	3	6
Filtrate Volume/30 min., maximum	-	15.0	16.0
+200 mesh, wt%, maximum	-	4	2.5
Moisture, wt%, maximum	-	10	13
Added SHMP to Slurry*:			
PV, minimum	10		
Filtrate Volume/30 min., maximum	12.5		

* Nontreated Bentonite, in its testing, is *treated* with sodium hexametaphosphate thinner (SHMP) to assure that it has not previously been treated during manufacture.

Beneficiation is a process where chemicals are added to a low-quality clay to improve its performance. Soda ash is added for peptization (see Figure 15) and polymers are added to improve rheology and filtration control. All of this is done to make the clay pass API viscosity specifications.

Figure 15
Peptizing Calcium Clay to Sodium Clay



Bentonites that have been treated may exhibit poor performance in five respects:

- 1) intolerance to hardness ions,
- 2) incompatibility with other polymers in a mud,
- 3) low thermal stability,
- 4) limited shelf life, and
- 5) polymer structure breakdown as it passes through the bit.

For some drilling operations, API or OCMA bentonite may be economical and not create problems. However, based on the five items above, their performance in many of the mud systems we currently use can be unpredictable and increase bentonite consumption.

API Bentonites

API Nontreated Bentonite - API Nontreated Bentonite is a premium quality material without any chemical additives for beneficiation. Being premium clays, they bring a premium price; however, they can be cost effective in terms of predictable performance and lower usage.

API Bentonite - API Bentonite is generally predominantly sodium bentonite; however, some degree of beneficiation is allowed under specifications for this material. The YP/PV ratio specification (3 maximum) limits this amount of beneficiation. Hence, API bentonite, under many conditions, performs similarly to the nontreated bentonite.

API OCMA Grade Bentonite - API OCMA Grade Bentonite is predominantly a calcium bentonite and as such, cannot meet specifications of either of the other two API-grade bentonites. Even with less stringent performance requirements, OCMA Grade bentonites require high levels of chemical treatment (beneficiation) which is reflected by the high YP/PV ratio (6 maximum) allowable. However, API OCMA Grade Bentonite is used in many areas where the drilling fluid will not encounter excessive temperature nor contamination, and where suspension and hole cleaning are the primary requirements.

Polymer Chemistry

Introduction

A polymer is a large molecule composed of a relatively small molecules called monomers (8% units) bonded together. The molecular weight of polymers range from a few thousand to several million molecular weight units. Polymers can have thousands of repeating units. The lower molecular weight polymers serve as deflocculants; whereas, the high molecular weight molecules serve as viscosifiers and flocculants. The two major mechanisms for manufacturing polymers are condensation, which alters the makeup of the repeating units, and addition which utilizes the presence of a double bond in the reacting unit to form a long chain. The addition process will generally yield higher molecular weight polymers than will condensation. The condensation process produces a polymer in which the repeating units contain fewer atoms than the monomers from which they were formed. Frequently, water is formed as a by-product of the process. The process requires two or more compounds which react chemically and does not depend upon the presence of a double bond for propagation of the chain. This mechanism is susceptible to interruption by impurities or any outside influence which would reduce the efficiency of the process.

Many commercially available polymers are not readily soluble in water. This is an undesirable property for drilling fluid chemicals. Fortunately, many of the polymers available have been chemically treated in order to make them water-soluble. The solubility of these polyelectrolytes will be affected by the chemical makeup of the drilling fluid, pH, salts and presence of divalent cations, etc.

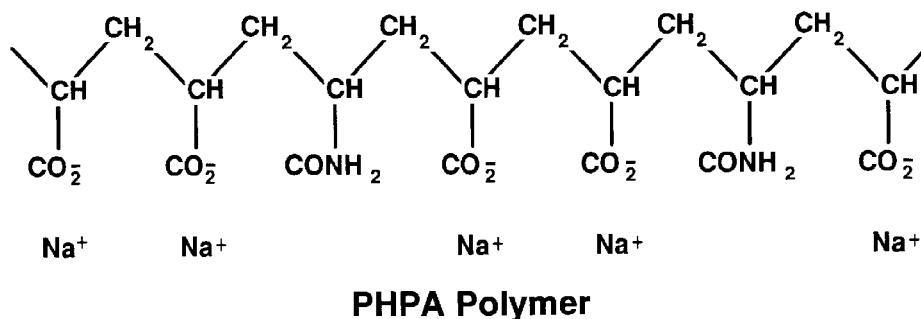
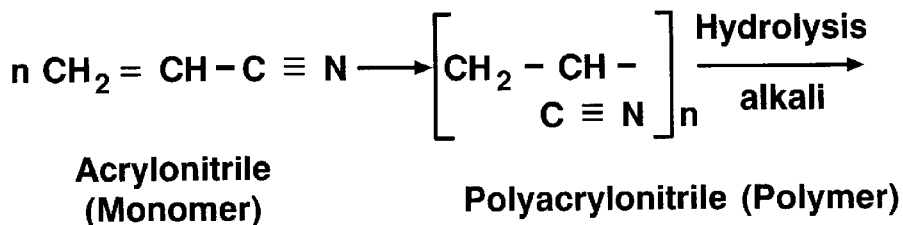
Polymer Types

Each type of polymer has its own characteristics in terms of how it functions in a particular type of drilling fluid. Therefore, selection of the correct type of polymer is critical to good performance. Below are listed five general types of polymers commonly used.

Polyacrylate, Polyacrylamide, and PHPA

Acrylonitrile is polymerized to form polyacrylonitrile which is then partially hydrolyzed to form acrylamide and acrylic acid groups along the polymer chain (*see Figure 16*). These polymers are referred to as PHPA, (partially hydrolyzed polyacrylamide), and are used as clay extenders, flocculants, and encapsulating colloids.

Figure 16
Manufacturing of PHPA from Monomer



Cellulose Derivatives

A number of different polymers exist which have cellulose as a base. They vary in: (1) degree of substitution (DS), (2) degree of polymerization (DP), (3) type of substitution, and (4) extent of purification (salt removal). Their properties and abilities can widely differ. The cellulose molecule is modified by reacting with an acid, then an oxidizing group, and then, an anionic radical is attached to the existing hydroxyl group.

1. **Carboxymethylcellulose (CMC)** - When cellulose is reacted with sodium monochloroacetate, a sodium methylacetate group is substituted on one of the three hydroxyl groups (*see Figure 17*). The degree of substitution (DS) refers to the number of hydroxyl groups upon which substitution takes place divided by the number of repeating units in the molecule (*see Figure 18*). The degree of substitution will range from zero to a maximum of three. Generally, CMCs will have a DS in the range of 0.4 to 0.8 with 0.45 being required for solubility. The degree of polymerization (DP) will range from 500 to 5000. The polymers with the greater DP will impart more viscosity to the fluid. High DS on the other hand, will permit more tolerance to salts and cation contamination. Thermal degradation accelerates above 250°F.
2. **Polyanionic Cellulose (PAC)** - Polyanionic cellulose is similar to CMC but generally has a DS of about 1.0. The PAC materials generally are more expensive than CMC due to higher processing costs, but show a greater tolerance to hardness and chlorides. PAC begins to thermally degrade at 250°F.
3. **Hydroxyethylcellulose (HEC)** - HEC is formed by causticizing cellulose and reacting it with ethylene oxide which replaces one or more of the hydroxyl groups present on the cellulose molecule (*see Figure 19*). Although HEC is nonionic, it is still water soluble due to the hydroxy ethyl groups. HEC imparts high viscosity to water or brines but exhibits no gel strengths. It is susceptible to degradation through shear or heat and has a maximum thermal stability of about 225°F.

Figure 17
Cellulose Structure

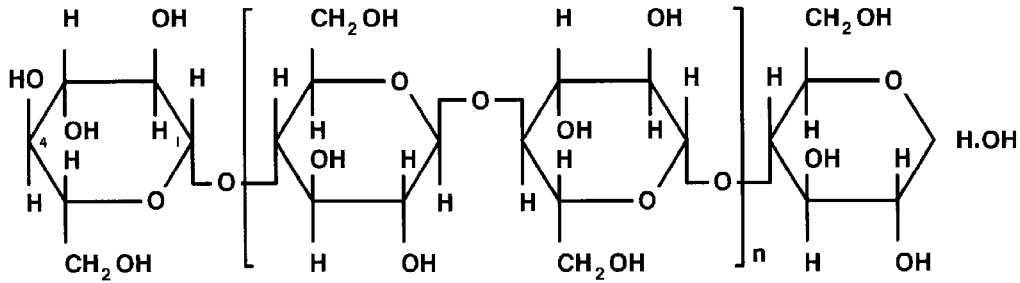


Figure 18
Carboxymethylcellulose Structure

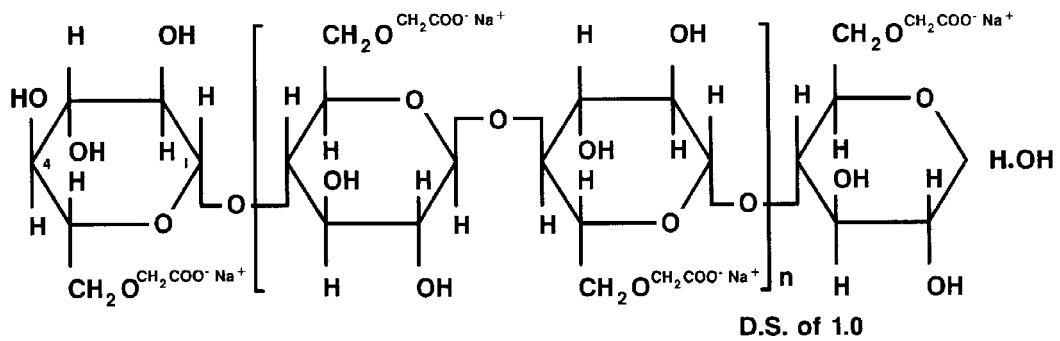
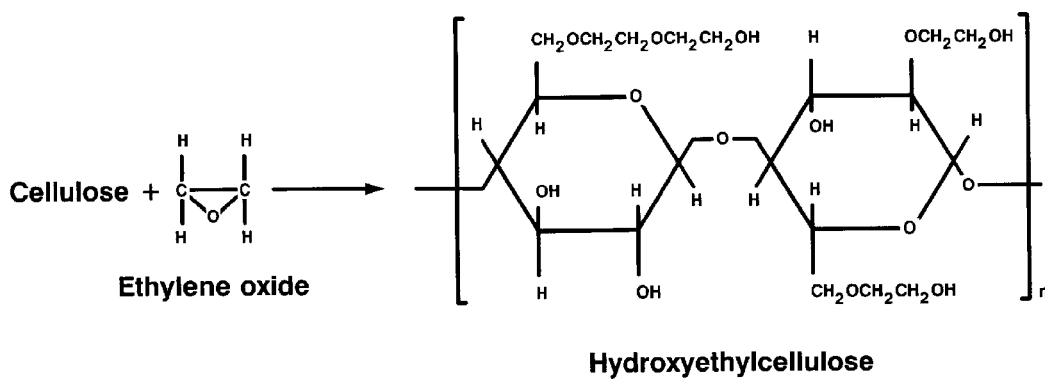


Figure 19
Hydroxyethylcellulose Structure



Starch

Starches used in the drilling industry are primarily derived from corn and other cereals, potatoes and tapioca. The starches are pre-gelatinized in order to permit them to readily hydrate. Starches are peptized chemically or by exposure to heat. The peptization ruptures the microscopic sacks which contain the amylose and amylopectin allowing them to come into contact with water and swell. Starches are used mainly for fluid loss control and are viable in a large range of fluid systems, such as seawater, saturated saltwater, KCl muds and lime muds. Starches are thermally stable to about 250°F. Starches are not resistant to bacteria and require a biocide to retard fermentation, except in saturated salt and high pH muds.

Guar

Guar is derived from the seed of the guar plant. Guar is a naturally occurring nonionic polymer used as a viscosifier in waters ranging from fresh to saturated salt (NaCl). High levels of hardness and alkalinity will slow or even eliminate the hydration process and can cause a significant decrease in viscosity. Guar has a maximum thermal stability of about 200°F and a biocide is necessary to retard fermentation. Guars have greater application to workover/completion operations.

Xanthan Gum

Xanthan Gum is a biopolymer and is a product of the action of a bacteria (*Xanthomonas Campestris*) on sugar. This material may be used in a variety of brines and salinity levels. Xanthan gum begins to degrade thermally at temperatures of about 225°F. Xanthum gum is the only polymer that provides thixotropy, i.e., formation of gel structures.

Polymer Uses

Some of the major uses of polymers in drilling fluids are:

- Viscosity
- Bentonite Extension
- Deflocculation
- Filtration Control
- Shale Stabilization

Viscosity

These are high molecular weight polymers, usually branched, and water soluble. Viscosity is due to interactions between: (1) polymer molecules and water, (2) polymers themselves, and (3) polymers and solids.

Bentonite Extension

The bentonite extenders work by cross-linking bentonite particles to increase the physical interaction between particles. There is a narrow band of concentrations which allow this cross-linking to occur, but above which a viscosity decrease may occur.

Flocculation

Flocculants are high molecular weight, long chain, anionic molecules which bridge between individual solids causing them to form an aggregate. The aggregates will settle or centrifuge readily for removal.

It is possible to have either total or selective flocculation. Selective flocculation removes some of the drill solids.

Deflocculation

Anionic polymers act as deflocculants by absorbing onto the edges of the clay particles and neutralizing existing charges. Polymer deflocculants are shorter molecules with a greater charge density. These characteristics facilitate adsorption onto the clay particle without causing cross-linking. These polymers are sensitive to divalent cations and are less effective when hardness exceeds about 400 mg/L.

Filtration Control

Starches, CMCs, PACs, and hydrolyzed polyacrylates are effective filtration control agents. Filtration control may be provided due to a physical plugging action by the polymer or by viscosifying the liquid phase of the drilling fluid. Anionic polymers control filtration by viscosifying the water phase to restrict fluid flow through the filter cake. Nonionic materials such as the starches, some anionic materials such as PAC and CMC, work by hydrating and swelling and physically plugging pores in the filter cake.

Shale Stabilization

Shale stabilization is provided through polymer attachment to the positively charged sites on the edge of clay particles in shales. This attachment minimizes water invasion into the clay particle and reduces hydration and dispersion. These polymers have been used with success in conjunction with salt and potassium-based muds for added inhibition.

Filtration

Filtration refers to the process of separating the liquid phase of a drilling fluid from the solid phase by passing the fluid through a permeable medium such as sandstone or filter paper. If the pores in the permeable medium are small enough, it will permit the passage of the liquid, but restrict the passage of the solids particles. These particles, which consist of formation solids as well as commercial clays and weighting materials, will build up and form a cake on the surface of the filtering medium. The liquid phase which passes through the medium is called the filtrate and contains soluble ions such as salts, calcium, and soluble chemicals.

Filtration Fundamentals

Filtration is controlled by depositing a tough, low permeability filter cake on the surface of the formation to prevent wellbore fluid from invading permeable zones. The tendency of the drilling fluid to penetrate permeable zones occurs because the pressure created by the drilling fluid is greater than the formation pressure. This pressure gradient forces fluid into the formation. The extent of this invasion depends on several characteristics of both the drilling fluid and the formation. The porosity and permeability of the formation, along with the solids content and particle size distribution in the drilling fluid, will determine the amount of invasion. Viscosity of the liquid phase, will also affect filtration rate.

Types of Filtration

Static Filtration

When drilling fluid is not circulating in the wellbore and there is no pipe movement, static filtration takes place. With static filtration, the filter cake continues to increase in thickness while the rate of filtration decreases. Filter presses measure static filtration, giving filtrate loss and cake thickness data under time and pressure (30 minutes, 100 psi). This is not an accurate representation of downhole filtration and more complex instruments are needed to duplicate downhole conditions.

Static filtration can be described by the following equation:

$$V_f = A \left[\frac{2K \left(\frac{C_C}{C_m} t \Delta P \right)}{\mu} \right]^{1/2}$$

- V_f = filtrate volume
- A = filtration area
- K = cake permeability
- C_C = volume fraction solids in cake
- C_m = volume fraction solid in mud
- p = filtration pressure
- t = filtration time
- μ = filtrate viscosity

Dynamic Filtration

When the mud is circulating, dynamic filtration takes place. With dynamic filtration, the flow of mud tends to erode the filter cake as it is deposited by the filtration process. The cake builds until the rate of deposition equals the rate of erosion. At this point the rate of filtration becomes constant. At first, the newly exposed formation will experience a high rate of invasion of filtrate and a rapid growth of filter cake. As time passes, the growth rate decreases and the filtration rate becomes constant.

An interesting study illustrates the cycle of static and dynamic filtration in the borehole. The filter cake and filtrate loss in each stage, dynamic and static, were measured. It was calculated that the amount of filtrate invading the formations under static conditions is small, even during prolonged periods of inactivity (i.e., tripping). When circulation begins, the upper layers of the static filter cake are eroded and the cake thickness decreases. Most of the static cake remains, however, and a new dynamic cake begins to deposit and attains a new equilibrium. It was shown that the cake thickness increase with each dynamic-static cycle is very small.

Problems Caused by Poor Filtration Control

Poor filtration control can cause a number of problems in drilling operations. Excessive filtrate loss and filter cake build-up can lead to:

- Tight spots in the hole causing excessive drag.
- Increased pressure surges when moving the pipe due to decreased hole diameter.
- Differential pressure sticking of the drill string due to the increased pipe contact area in thick, high permeability cake.
- Cementing problems due to poor removal of dehydrated, thick filter cake.
- Formation damage from filtrate invasion.

Most of these problems are caused by the filter cake that is left on the borehole wall, rather than by the amount of filtrate lost to the formation. Problems caused by excessive fluid loss are:

- Inability to make accurate formation evaluation.
- Formation damage.

Logging tools can give erroneous data for formation evaluation when large volumes of filtrate flush formation fluids away from the borehole. Coring tools cannot recover representative formation fluid samples when excess filtrate invasion occurs.

Formation damage by filtrate invasion can be caused by several different mechanisms. The filtrate can cause swelling or dispersion of clay particles in the pores of the formation, reducing the formation permeability. Surfactants in the filtrate can change the wettability of the formation or form an emulsion with the formation fluids which can block permeability. Efforts to control filtration will pay off in fewer drilling or completion problems. The goal is to deposit a filter cake which is as thin and impermeable as possible.

Factors Affecting Filtration

The general filtration equation given previously can be broken down into individual terms as discussed below.

Time

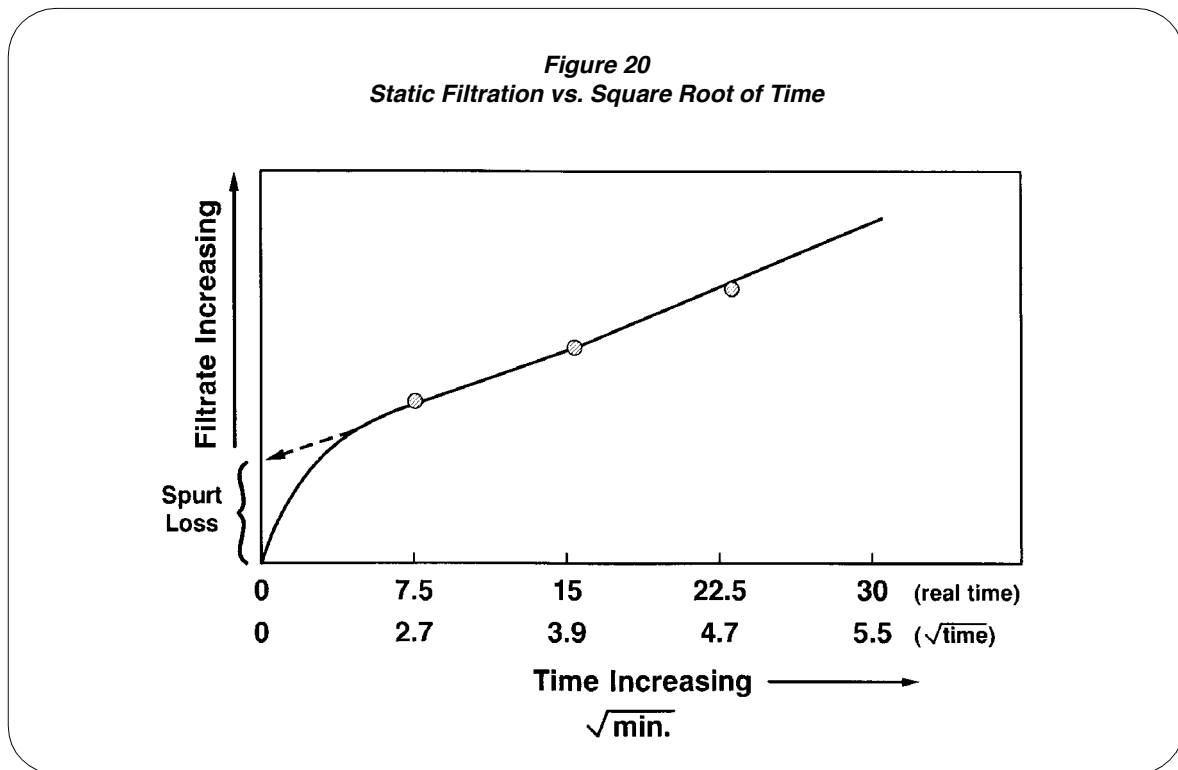
The static filtration rate is directly proportional to the square root of time, after the initial spurt loss:

$$V_2 = V_1 \sqrt{\frac{t_2}{t_1}}$$

Where

- V_1 = measured filtrate at time t_1 , cm^3
- V_2 = calculated filtrate at time t_2 , cm^3
- t_1 = time interval for filtrate 1, minutes
- t_2 = time interval for filtrate 2, minutes

This equation was developed for the purpose of estimating filtrate loss over long periods. The results of the equation will be less accurate for early filtration rates because this is the time in which spurt loss occurs. (Figure 20 shows that as time increases, spurt loss effects diminish and filtration rates stabilize.)



API specifications use 30 minutes as a time period for filtrate loss with both a low temperature-low pressure and high temperature-high pressure tests. Occasionally an API filtrate test will be run for 7-1/2 minutes and the volume of filtrate is then doubled to represent the 30 minute filtrate volume. This is not an API sanctioned practice and should be discouraged. Under no circumstances should the HTHP fluid loss test be run for less than the specified 30 minutes.

Pressure

If the filtration medium is uniform, the volume of filtrate varies as the square root of pressure. This does not apply for mud filter cake however, because the cake, which is subject to compression and contin-

ued deposition of material, undergoes continuous changes in porosity and permeability. If the cake were incompressible and static, the effects of pressure is approximated by the equation:

$$V_2 = V_1 \sqrt{\frac{P_2}{P_1}}$$

Where

V_1 = measured filtrate volume

P_1 = 100 psi

V_2 = estimated filtrate volume

P_2 = pressure in question in psi

This equation can be used to indicate the relative compressibility of an actual filter cake. Run an API fluid loss test at standard temperature and pressure and then run a second one at a higher pressure, for example at 200 psi. If the test results correspond closely to the results calculated by the above equation it indicates the formation of an incompressible filter cake. The lower the actual fluid loss at the higher pressure compared to the calculated fluid loss, the greater the compressibility of the cake. It is possible in extreme cases to have a fluid loss at higher pressure which is lower in volume than the fluid loss at the lower pressure. This situation indicates an extremely compressible filter cake.

Temperature

Increased temperature usually increases filtration rates by reducing the viscosity of the liquid phase, providing all other factors remain constant.

Figure 21 is a graph used to convert API fluid loss taken at any mud temperature to the theoretical API fluid loss value at 300°F if the pressure for both tests is the same. For example, if fluid loss at 140°F is 3.0 cm³, then multiplying by the constant 1.6 gives the theoretical value 4.8 cm³ at 300°F.

The effect on fluid loss due to temperature changes can be approximated by the following equation. Use Table 11 to obtain the viscosity of water at various temperatures.

$$V_2 = V_1 \sqrt{\frac{\text{Vis}_1}{\text{Vis}_2}}$$

Where

V_1 = measured filtrate volume at test temperature

V_2 = calculated filtrate volume at temperature 2

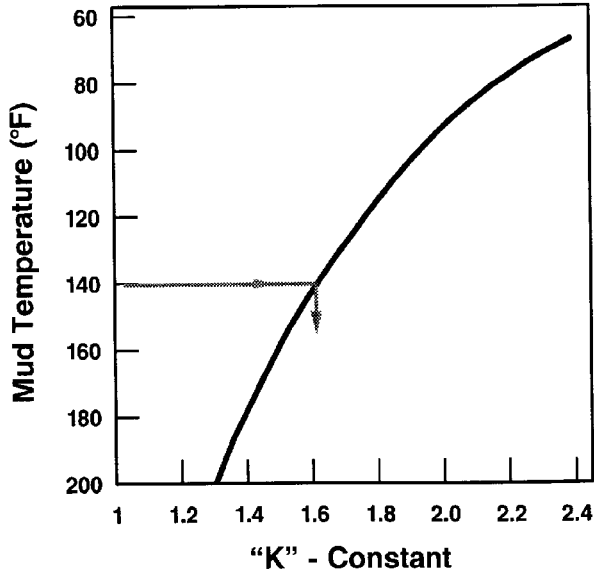
Vis_1 = water viscosity at test temperature

Vis_2 = water viscosity at temperature 2

This equation can be used to estimate a fluid loss value for a higher temperature. If the actual fluid loss at the higher temperature is much greater than the calculated value, it can indicate thermal degradation of mud chemicals.

High temperatures produce chemical changes in the mud. In particular, changes take place in the ionic atmosphere of clay particles and the effectiveness of many fluid-loss additives and dispersants decreases at high temperatures because of degradation.

Figure 21
Correlation Factors for Fluid Loss*



To convert API fluid loss to theoretical API fluid loss at 300°F, multiply fluid loss at mud temperature by "K"

Table 11
Viscosity of Water at Various Temperatures

Temperature		Viscosity of Water (cps)	Temperature		Viscosity of Water (cps)
°F	°C		°F	°C	
68	20	1.005	300	148.9	0.184
86	30	0.801	320	160	0.174
104	40	0.656	338	170	0.160
122	50	0.549	350	176.6	0.1535
140	60	0.469	356	180	0.150
158	70	0.406	374	190	0.142
176	80	0.356	392	200	0.134
194	90	0.316	410	210	0.127
212	100	0.284	428	220	0.121
230	110	0.256	446	230	0.116
248	120	0.232	450	232.2	0.1136
250	121	0.2316	500	260	0.100
266	130	0.212	550	287.7	0.0899
284	140	0.1916	572	300	0.086

Permeability

Permeability of the filter cake is largely a function of the size, shape and distribution of mud solids. Since the most effective way to control filtration rate is to control permeability of the filter cake, it follows that control of mud solids is of primary importance. Low filtration rates require low cake permeability, especially under temperature and pressure.

Small particles form a more tightly packed unit. Thus, the filter cake formed from small particles is less permeable than the filter cake formed from large particles. Generally, colloidal size particles (less than two microns) provide the maximum fluid loss control. However, optimum control is best obtained by having a range of different size particles. Smaller particles can wedge between large particles to form a cake with low permeability. Thin, flat hydrated particles are more effective than spherical or irregularly shaped particles. Under pressure, flat particles will pack more tightly, producing a compressible filter cake. Bentonite particles meet these criteria since they are hydratable, small, thin and plate-like in shape.

Distribution of the solids in the filter cake is related to the degree of dispersion of the solids in the mud. Proper solids size distribution and dispersion of colloidal particles allows a uniform, overlapping texture in the cake. In flocculated systems, the fluid passes easily between the non-uniform flocs or aggregates and results in high filtration rates.

Filtration Measurement

One objective in the measurement of filtration rate is to simulate downhole conditions. Because conditions change so rapidly and frequently it is impossible to duplicate actual conditions downhole, filtration tests have been designed to produce relative measurements which are standardized and accepted in the oil industry. The tests which are made under static conditions include: (1) the low temperature-low pressure test, or API fluid loss test, (2) the high temperature-high pressure test, and (3) the permeability plugging test, or PPT. The PPT allows for a larger range of temperature and pressure and allows the permeability of the filter media to be selected.

Many operating companies and drilling fluid service companies have designed instruments to measure filtration under dynamic conditions. These measurements simulate downhole conditions more closely because shear can be imposed and a core (rather than filter paper) can be used while applying high temperatures and high pressures. Many studies have been made using these tests and surprising data have been published concerning filtrate loss. While it is true that oil does tend to lower filtrate loss under static conditions, it was found that oil actually increased filtrate loss under dynamic conditions. Work is continuing in this area and eventually, it is expected that dynamic tests will be designed for use on the rig to provide information on how well mud treatments are working.

Comparison of Static Filtration Test Parameters

Test	Temperature, °F	ΔPressure, psi	Time, min.
HTHP	250-450	500	30
LTLF	Ambient (mud temp)	100	30
PPT	250-500	100-3000	30

Filtration Control Additives

In the oil industry, there is a wide spectrum of products used for filtration control. To lessen the confusion, only the broad classifications will be discussed, and the discussion will be limited to generic

names. Their application depends on the type of mud being used and on the chemical and physical environments encountered.

Bentonites

The primary fluid-loss control agents for water-based muds are clay-type solids. Since these solids are colloidal in nature, they provide viscosity as well as filtration control. The ability of bentonite to reduce filtration can be attributed to:

- small particle size
- flat plate-like shape
- ability to hydrate and compress under pressure

Insufficient bentonite in a mud causes increased filtrate loss, particularly at increased temperature and pressure. Sodium montmorillonite clays are used mostly in freshwater mud systems; however, they are occasionally used in saltwater muds.

Lignins and Tannins

These include: sulfonated tannins, quebracho, lignosulfonates, lignites and lignite derivatives. The mechanisms by which they work is by thinning the clays (adsorbing on the positive edges of the clay platelets, which leads to repulsion among the platelets), plus plugging action of the particles themselves. These additives improve the distribution of solids within the drilling fluid by deflocculating solids such as bentonite and through the colloidal nature of the chemical, skewing the particle size distribution to lower values.

Starches

Most starch products are used in salt and saturated saltwater environments. Most of the starches used in the domestic oil industry are made from corn or potatoes. The starch grains are separated from the vegetable and specially processed so that they will rapidly and efficiently swell and gelatinize to reduce filtration loss. The sponge-like pegs also fit into the tiny openings left in the filter cake and lower fluid loss by a plugging action. Biocide is recommended when bacterial degradation is a concern.

Sodium Carboxymethylcellulosics (CMC)

CMC is an organic colloid used for filtration control. This material is available in several grades, each varying in viscosity and filtration control qualities. The three grades are commonly called high-viscosity CMC, medium or regular-viscosity CMC, and low-viscosity CMC.

The choice of CMC depends upon the properties desired for the drilling fluid. When viscosity increase and filtration control are both desired, high or medium CMC should be used. When no viscosity increase is needed and a decrease in filtrate loss is required, low-viscosity CMC is adequate.

Polyanionic Cellulosics (PAC)

PAC materials are organic filtration control agents similar to CMC, but generally of higher purity and quality. This material can be used in both freshwater and saltwater environments. PACs are generally more calcium tolerant than are CMCs.

Sodium Polyacrylates (SPA)

SPAs are polymers that are available in various ranges of molecular weight and offer high temperature stability. SPAs of low molecular weight are deflocculants for clays and are used to improve fluid loss

control by that mechanism. SPAs of very high molecular weight are effective for fluid loss control by increasing the viscosity of the filtrate and by plugging in the cake. They are sensitive to calcium ions, especially at high molecular weight. Derivatives of SPA which are less sensitive to ionic content are available as proprietary thinners and fluid loss additives. An example is the AMPS type polymers.

Section 5 Contamination and Solids

Contamination of Water-Based Drilling Fluids

Introduction

In general, a contaminant is any material that causes undesirable changes in drilling fluid properties. Solids are by far the most prevalent contaminant. Excessive solids, whether commercial or from the formation, lead to high rheological properties and slow the drilling rate. Most other contaminants are chemical in nature and require chemical treatment to restore fluid properties. While there are specific treatments for each contaminant, it is not always possible to remove the contaminant from the system.

Some contaminants can be predicted and a treatment started in advance. The predictable contaminants are: cement, make-up water, and sometimes salt, gypsum, and acid gases such as, hydrogen sulfide and carbon dioxide. Pretreatment can be advantageous as long as it is not excessive and does not adversely affect mud properties.

Other contaminants may be unexpected and unpredictable such as those whose concentration increases gradually. Eventually, the contaminant shows its effect by altering the fluid properties. This change in fluid properties often occurs at times when deflocculants are expended at high downhole temperatures. It is essential to keep accurate records of drilling fluid properties to ensure that any gradual buildup of a contaminant is monitored and detected.

Some of the more common contaminants and associated treating agents are shown in *Tables 1 and 2*. It should be noted that water chemistry is more straightforward than the chemistry of drilling fluids. Organic materials not only interfere with the accuracy of titrations, but they also interfere with the treatment. For example, the addition of calcium ion to remove carbonates may result in the formation of calcium salts of organic acids (reaction between Ca^{++} and lignite) and calcium silicates. Both of these reactions are undesirable, but unavoidable. Treating contaminants, therefore, should be preceded by pilot testing and then, treating should be done with caution, particularly when high density fluids are involved.

Table 1
Common Contaminants and Treating Agents

Contaminant	Treating Agent	lb/bbl of Treating Agent to React with 100 mg/L Contaminant
Calcium	Soda Ash	0.093
	Sodium Bicarbonate	0.074
Magnesium Carbonate	Caustic Soda	0.116
	Gypsum (if high pH)	0.118
Bicarbonate	Lime	0.043
	Lime	0.043
Sulfide	Zinc Carbonate	0.140
	Zinc Oxide	0.106

Table 2
Drilling Fluids Contaminants
(A contaminant is anything that causes undesirable changes in mud properties.)

Contaminants	Source	Treatment
Solids	Drilled Solids Barite Bentonite	Dilution, dispersion, displacement or mechanical removal
Carbonates	CO ₂ intrusion; thermal or bacterial degradation of mud products; entrained air (from mud hoppers, shake screen or hydrocyclones)	Precipitate CO ₃ = ion with gypsum or lime
Anhydrite, Gypsum	Formations drilled; overtreatment of carbonate problem with gypsum	Convert to gypsum or lime mud; or precipitate Ca ⁺⁺ ion with bicarbonate of soda and/or soda ash
Salt, Saltwater	Formations drilled; formation water	Convert to salt saturated mud or treat system with water, caustic soda and thinners
Cement, Lime	Cementing operations or over treatment of carbonate problem with lime	Convert to lime mud or precipitate Ca ⁺⁺ ion with bicarbonate of soda and/or soda ash
Hydrogen Sulfide	Formations drilled; thermal degradation of products; bacterial degradation of products	Raise pH and/or precipitate sulfide with a zinc compound

Salt Contamination

Salt, NaCl, contamination may be a result of salty makeup water, drilling salt stringers, or saltwater flows. Saltwater-based drilling fluids are used when salt is drilled in large quantities or where salty makeup water is used. In saltwater muds, salt is not a problem; however, in freshwater muds salt becomes a contaminant.

Salt contamination is usually easy to detect. It will be accompanied by an increase in the chlorides content of the filtrate. Other possible indications are: an increase in rheology, specifically the yield point, an increase in fluid loss, and a possible decrease in pH and alkalinities. If the salt source is a saltwater flow, there may also be a decrease in mud density (*see Figure 1*).

Figure 1
Effects of Contaminants on Drilling Fluid Properties

Contaminant	Funnel Vis	PV	YP	Gels	pH	Fluid Loss	P _r /M _r	P _M	Cl ⁻	Ca ⁺⁺	Solids	MBT
Solids	↗	↑	↗	↗	—	↗	—	—	—	—	↗	↗
Cement	↑	↗	↑	↑	↑	↗	↑	↑	—	↗	—	—
Gypsum	↑	↗	↑	↑	↓	↑	↓	↓	—	↑	—	—
Salt	↑	↗	↑	↑	↓	↑	↓	↓	↑	↗	—	—
High Temperature	↗	—	↑	↑	↓	↑	↓	↗	—	—	—	—
Carbonates	↑	—	↑	↑	—	—	↑	—	—	—	—	—

— No Change ↗ May Change or Slight Change ↑ Will Increase ↓ Will Decrease

Salt contamination cannot be removed from a drilling fluid by chemical treatment. Salt concentration can only be decreased through dilution. The harmful effect of salt on a drilling mud is due to the increased ionic concentration which changes the charge distribution at the clay surfaces. The resulting flocculation causes an increase in rheological properties and fluid loss. Further exposure to high salt concentration will dehydrate the reactive solids in the mud and cause decreased viscosity and a continued increase in fluid loss.

The choice of reconditioning agents for salt contamination in freshwater muds depends on the severity of contamination. Lightly deflocculated drilling fluid systems can tolerate up to 10,000 mg/L chlorides as long as the colloidal reactive solids are at a reasonable level for the mud density being used. As the chloride content increases above 10,000 mg/L, rheological and fluid loss properties become difficult to control and an increase in deflocculant treatment is necessary. When salt is encountered, the high concentration of Na⁺ ions tends to replace some of the H⁺ ions at the clay surfaces and may slightly reduce the pH. The alkalinity of the system should therefore be slightly higher in salt contaminated drilling fluids to improve deflocculant performance. Calcium or magnesium are commonly associated with salt contamination and may magnify the effect of the salt on the drilling fluid.

Treatment - If the salt contamination is minimal (Cl⁻ <20,000 mg/L) or can be tolerated for a brief period such as to TD the well or set pipe within a few days, the mud should be treated with water to dilute the chlorides to an acceptable concentration level. This level will vary depending on the mud

weight, active solids concentration, temperature, etc. The fluid should simultaneously be treated with causticizing agents and deflocculants to restore flow properties. Finally, control fluid loss with PAC or other additives which are salt tolerant, and pre-hydrated bentonite.

If the existing salt contamination level cannot be tolerated or if continued contamination is expected, such as drilling massive salt sections, the fluid should be either converted to a saturated salt system or displaced with an oil-based system. The mud can be converted to a salt-saturated mud by addition of NaCl to saturate the system (± 125 lb/bbl) coupled with large quantities of deflocculant for viscosity control, caustic soda or lime for pH and P_F control, PAC materials and pre-hydrated bentonite for fluid loss control.

Calcium Contamination

The calcium ion is a major contaminant of water-based drilling fluids. Calcium can enter the mud as part of the makeup water or formation while drilling cement, anhydrite or gypsum. Calcium contamination drastically changes the nature of freshwater, clay-based systems. The calcium ion tends to replace sodium ions on the clay surface through a base exchange. The bound layer of water on the clay platelets is reduced, resulting in diminished hydration or swelling characteristics. The effects of calcium contamination on deflocculated muds are increased fluid loss, yield point and gel strengths.

In the case of cement contamination, diagnosis is usually simplified by the fact that we know ahead of time when we will be drilling cement. The physical and chemical indications of lime or cement contamination are: increased yield point and fluid loss, increased pH and alkalinities, and a possible increase in calcium. The calcium increase may be masked, however, by pH. Gypsum and anhydrite contamination are also characterized by an increase in yield point and fluid loss as these effects are the result of the divalent cation (Ca^{++}) in the drilling fluid. Alkalinities and pH decrease with anhydrite contamination because $CaSO_4$ and H_2O liberate H^+ ions. An increase in detectable Ca^{++} is also likely since there is not a high pH to limit its solubility.

Calcium contamination originating in makeup water or formation water is usually treated with soda ash. Approximately 100 mg/L of Ca^{++} should be left in the system to react with carbonate ions.

Cement Contamination

In most drilling operations, cement contamination occurs one or more times when casing strings are cemented and the plugs are drilled out. The extent of contamination and its effect on mud properties depends on several factors. These include: solids content, type and concentration of deflocculants, and the quantity of cement incorporated. One 94-lb sack of cement can yield 74 lb of lime. When cement is completely cured only about 10% is available; whereas, when it is soft (green) as much as 50% of the lime may be available to react. It is the calcium hydroxide (lime) in cement, reacting with solids, that causes most of the difficulty associated with cement contamination.

Freshwater bentonite systems are flocculated by cement, resulting in increased rheology and fluid loss. The severity of flocculation depends upon the quantity and quality of solids present and the solubility of the Ca^{++} ion. Therefore, when cement contamination reaches a level where it is no longer practical to treat out, it may be desirable to convert the system to a calcium-based mud. It may be possible to isolate the contaminated fluid and dump it.

Treatment - To maintain a low calcium drilling fluid, chemical treatment must be used to remove cement contamination. The aim of treatment is to control pH while removing calcium and excess lime from the system as an inert, insoluble calcium precipitate. The treatment of choice for cement or lime contamination is sodium bicarbonate ($NaHCO_3$). In its reaction with lime, a hydrogen ion is liberated which reacts with a free hydroxyl ion to form a water molecule. This reaction serves to further reduce

the pH and allow more lime to go into solution. The lime and sodium bicarbonate reaction is:
 $\text{Ca}^{++} + 2\text{OH}^- + \text{Na}^+ + \text{H}^+ + \text{CO}_3^{=} \rightarrow \text{CaCO}_3 + \text{Na}^+ + \text{OH}^- + \text{H}_2\text{O}$.

Excess lime can be estimated from the filtrate alkalinity (P_F), mud alkalinity (P_M) and volume fraction of water from retort analysis (F_W) by the following equation:

$$\text{Excess lime, lb/bbl} = 0.26[P_M - (F_W)(P_F)]$$

To chemically remove 100 mg/L of calcium originating from lime would require approximately 0.074 lb/bbl of bicarbonate of soda. If lignite is present in the system, it will also react with lime to form a calcium salt of humic acid. One lb/bbl of lime will react with 7-8 lb/bbl of lignite. Calcium salts of humic acids will create viscosity problems at higher concentrations.

Note: Lignite is not an acceptable treatment for cement contamination.

Chemical removal of calcium ions with bicarbonate ions does not normally correct the damage done to a dispersed system. It is usually necessary to treat with deflocculants to obtain desired rheological properties. Materials, such as prehydrated bentonite, CMC or PAC are used to restore filtration and filter cake characteristics.

Pretreating presents a problem, since it is difficult to predict the extent of contamination prior to drilling the cement. Overtreating with bicarbonate of soda could be as detrimental to drilling fluid properties as the cement contamination. Therefore, it is not advisable to pretreat with more than 0.5 lb/bbl of bicarbonate of soda. One approach to avoid overtreatment is to treat only soluble calcium and wait to treat lime when it goes into solution on subsequent circulations. Treatments should be discontinued when excess lime approaches 0.3 to 0.5 lb/bbl. Materials such as lignosulfonate and lignite are good supplementary pretreating agents because they buffer the pH and aid in deflocculating the system.

Note: SAPP (sodium acid pyrophosphate) is sometimes used to treat out cement; however, it will simultaneously thin the system. However, above about 180°F it can thermally degrade to orthophosphate which is a flocculant.

Consideration should also be given to low-gravity solids content prior to drilling cement, because high clay solids concentration is a primary cause of flocculation when cement contamination occurs. Reduction of solids concentration, if too high, is recommended as a defense against severe flocculation.

Because pH values are high when drilling cement, the quantity of calcium ion in solution rarely exceeds 300 to 400 mg/L. For this reason, much of the cement drilled remains as discrete particles and is available to dissolve and replace the calcium ion that has been treated out of solution. Unless cement particles (excess lime) are mechanically removed from the system by efficient solids removal equipment, it will take several days for the excess lime to solubilize, react and be chemically precipitated.

High temperature solidification can result from cement contamination in combination with high solids. Since tests at ambient temperature will not reflect this problem, tests which simulate downhole conditions should be run. The *Fann Consistometer* and *Fann Model 50 VG Meter* simulate downhole temperature, shear, and pressure conditions and give an indication of solidification tendencies. To determine remedial treatments, it is recommended that pilot testing procedures include hot rolling.

Anhydrite-Gypsum Contamination

Anhydrite and gypsum are calcium sulfate compounds (CaSO_4) which are sometimes encountered while drilling. Gyp is calcium sulfate with water of crystallization ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$), while anhydrite is the anhydrous (waterless) form of calcium sulfate (CaSO_4). These may occur as thin stringers or massive beds.

Calcium sulfate contamination is similar to cement contamination because both liberate calcium ions, which in turn cause flocculation. Unlike cement, calcium sulfate does not cause a pH increase since it supplies a sulfate ion in lieu of a hydroxyl ion. The sulfate ion contributes to flocculation of clay solids, although its effect is small compared to calcium ions.

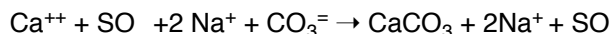
In lightly-treated muds, small amounts of CaSO_4 increase the rheological properties. The severity of flocculation depends to a great degree on clay content. When CaSO_4 causes the calcium concentration to increase above 200 mg/L, viscosity may fluctuate drastically and fluid loss may become difficult to control. As calcium ion concentrations further increase, a base exchange occurs in which sodium montmorillonite becomes calcium montmorillonite. Flow properties tend to decrease, and fluid loss becomes very difficult to control.

Treatment - There are several methods for handling CaSO_4 contamination. The drilling fluid can be maintained as a low-calcium fluid by chemically precipitating calcium from solution or it can be converted to a gyp system. For smaller amounts of CaSO_4 contamination, chemical removal of the calcium ion is best achieved by adding soda ash. Excess CaSO_4 can be estimated from the filtrate versenate (V_F), whole mud versenate (V_T), and volume fraction of water from retort analysis (F_W) by the following equation:

$$\text{Excess CaSO}_4, \text{ lb/bbl} = 2.38 [(V_T) - 0.48 (V_F)(F_W)]$$

Approximately 0.093 lb/bbl of soda ash is required to precipitate 100 mg/L of Ca^{++} ion. Caution should be exercised to avoid overtreatment. When Ca^{++} concentration is reduced to 100-150 mg/L, treatment should be suspended.

The reaction between gypsum or anhydrite with soda ash is:



Soluble sodium sulfate ($\text{Na}^+ + \text{SO}_4^{--}$ ions) is formed from this reaction and could cause flocculation problems after prolonged treatments. For this reason, it is generally necessary to convert to a calcium-based fluid when massive anhydrite is to be drilled with a freshwater system.

Magnesium Contamination

Magnesium is encountered when seawater is used as makeup water. It has also been encountered as magnesium water flows. Magnesium has similar effects as calcium on mud properties such as increased flow properties and fluid loss.

Treatment - Magnesium can be precipitated with caustic soda as insoluble magnesium hydroxide $\text{Mg}(\text{OH})_2$. One-half pound of caustic per barrel of mud will precipitate approximately 430 mg/L of magnesium. Most of the magnesium ion will be precipitated when pH is increased to 10.0. Additional filtrate control agents, deflocculants and causticizing materials will be required to restore drilling fluid properties after magnesium contamination. In the case of massive magnesium contamination, it is impractical

to treat it out; therefore, options are: (1) to attempt to maintain a low pH system with Mg⁺⁺ ion present, or (2) switch to a magnesium tolerant mud such as oil mud.

Carbonate/Bicarbonate Contamination

The most common source of soluble carbonate accumulation in muds is CO₂ intrusion from formations being drilled. As CO₂ enters an alkaline mud, it reacts with OH⁻ ions and soluble carbonates accumulate. Another common carbonate source is thermal degradation of organic additives such as lignite and lignosulfonate at temperatures in excess of 300°F. CO₂ is liberated at temperature by alkaline decarboxylation of organic acid groups such as found in humic acid. Lignite is a more potent source of carbonates than lignosulfonate because of its high humic acid content. Another minor source of carbonates is bacterial action on organic additives.

The mechanism by which bicarbonate (HCO₃⁻) and carbonate (CO₃⁼) ions affect the performance of a deflocculated, clay-based drilling mud is not well understood. The fact remains, however, that high concentrations of total carbonates (>1000 mg/L) will have a detrimental effect on freshwater-bentonite drilling fluids.

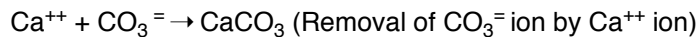
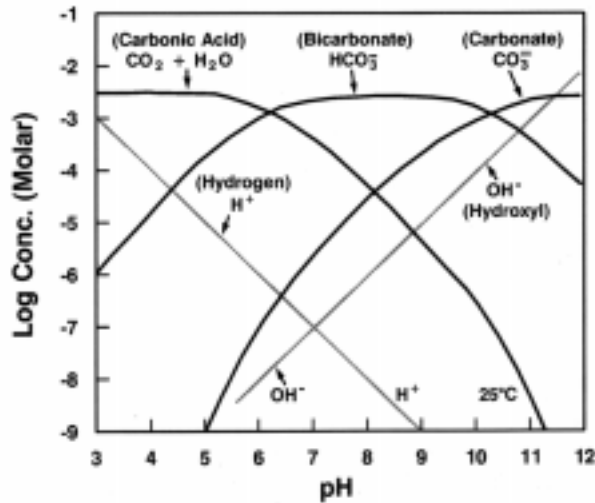
Only an estimate of carbonate concentration in filtrate samples is obtained by API alkalinity titrations. There are, however, some physical and chemical indications that carbonate contamination is taking place. Elevated yield point and 10-minute gel strength, particularly on bottoms up after a trip, may indicate a carbonate problem. In addition, if the M_F is greater than 5 cm³ and greater than 4 times the P_F, then carbonates may be present. If carbonates are suspected, a Garrett Gas Train carbonate analysis (GGT) should be run at the rigsite prior to initiating any treatment.

Soluble carbonates are formed when CO₂ enters the mud and reacts with hydroxyl ions (OH⁻) to form carbonic acid, which further reacts to form HCO₃⁻ and CO₃⁼ ions. A chemical equilibrium controlled by the pH of the fluid is established at any given temperature. These equilibria involve the components shown in the following equations:

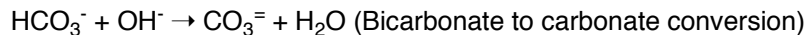


Carbonate equilibria with pH is shown in *Figure 2* for the system of carbonates in freshwater at 25°C. Total soluble carbonates are the sum of CO₂, HCO₃⁻ and CO₃⁼, and are measured by the GGT. The three species coexist in various proportions, depending on solution pH. For example, *Figure 2* shows that at low pH, gaseous CO₂ dissolved in water (carbonic acid) predominates, and HCO₃⁻ and CO₃⁼ are essentially zero. This is the basis for the GGT analysis. By acidification in the GGT all CO₃⁼ and HCO₃⁻ ions in the sample are converted to CO₂ gas, which is freed from solution and analyzed by a Dräger CO₂ detector tube. *Figure 2* also shows that for the approximate pH range of 6.3 to 10.3 the HCO₃⁻ ion predominates; above pH10.3 the CO₃⁼ ion predominates. The higher pH is desirable for chemical removal of soluble carbonates as insoluble CaCO₃.

Figure 2
Equilibrium Distribution of Soluble Carbonates in Water



At mud pH above 10.3 the reaction proceeds more rapidly because $\text{CO}_3^{=}$ ions predominate over HCO_3^{-} ions. If lime is selected as the treatment chemical for $\text{CO}_3^{=}$ ion removal, the pH of the fluid need not exceed 10.3 because OH^{-} ions from the lime are available to raise the pH and convert HCO_3^{-} to $\text{CO}_3^{=}$ for subsequent removal:



Treatment - Removing carbonates from a deflocculated, clay-based mud typically involves adding lime or gypsum to precipitate $\text{CO}_3^{=}$ as CaCO_3 . Adding lime to a solids-laden mud, especially in a hot well, can create severe rheological and filtration control problems. A GGT analysis will indicate if soluble carbonates are strongly present. Up to 500 mg/L of carbonates is not likely to cause a problem, but levels above 1000 mg/L (depending on mud density and solids present) may cause problems. If appreciable carbonates are measured, a pilot test series with a range of treatments should show whether lime or gypsum is the preferred treatment.

The soluble carbonate concentration may be reduced, but the fluid properties may not improve. Experience has shown that carbonate problems often are coupled with, or even mistaken for, excessive low gravity colloidal solids. These solids may be the more significant factor contributing to poor rheological control. Solids contamination and carbonate contamination exhibit similar characteristics, such as: poor response to deflocculant treatment, high yield point and gel strengths, high fluid loss, and poor filter cake quality. Pilot testing is always recommended to verify that the proposed treatment is sufficient,

but not excessive. Pilot testing with gypsum and lime can be deceiving, because the reaction is slow and may be interfered with by the presence of other ions in the fluid. In the laboratory it was found that about 30 to 40% of the expected reduction in carbonates occurs. The main point is that added lime does not necessarily all react to remove only carbonates in a complex mud. This is supported by field experiences which have shown that three to four times more lime may be required to improve fluid characteristics than predicted by GGT analysis.

Treatment level of lime to remove $\text{CO}_3^{=}$ ions in 0.118 lb/bbl for 100 mg/L $\text{CO}_3^{=}$ ion and for gypsum, the level is 0.043 lb/bbl for 100 mg/L. As mentioned above, however, three to four times this amount may be required to treat out most of the carbonates.

Solids Contamination

Among the various contaminants discussed in this section, excess solids are by far the most prevalent and detrimental to all types of drilling fluids. Solids problems are often magnified by the presence of other contaminants because excess solids and contaminant ions can strongly interact to create a more serious mud problem than either one separately.

Sources of solids in a mud are threefold: (1) cuttings or sloughings from the wellbore, (2) commercial solids added to the mud, and (3) chemically precipitated solids. Highly dispersive clays, originating from claystones and shales as well as commercial bentonite, are difficult to mechanically remove from the mud. Chemically precipitated solids are extremely small solids formed within the mud by chemically treating out contaminants, such as removing carbonate ions with lime or by treating out cement, gyp or anhydrite with soda ash or bicarb. These reactions create colloidal CaCO_3 , which can build up fine solids if chemical treatments continue for an extended period of time.

Operational problems are often directly related to excess solids causing thick filter cakes and solids crowding. Thick filter cakes lead to pipe sticking, to pressure surging and swabbing, and to lost circulation. Also, highly permeable filter cakes allow large volumes of filtrate to invade permeable zones causing formation damage. Solids crowding causes rheological problems, lowers the drilling rate, causes wear and tear on the pumps, and limits the bit hydraulics.

Detecting the point at which solids become excessive at the rig requires continual, accurate monitoring of the mud. Quantifying the volume percent solids in a mud and measuring the **D/B ratio** (Drill solids/Bentonite) requires complete and accurate mud test data: mud density, retort volumes, and chloride and MBT measurements. For solids calculations to be accurate, correct values for all densities of all mud components are also required. To find the D/B ratio, MBT measurements must be made on cuttings samples taken from the shale shaker and should be made on the bentonite sampled at the rigsite. With these accurate measurements and correct density values, solids calculations will be accurate. (See Section 5, *Solids Calculations* for details on how to analyze a solids problem.)

Graphical methods can also be used to provide a quick estimation of the concentration of solids in a mud to see if the low-gravity solids content is within an acceptable range. These charts are based on density values assumed for the high-gravity and low-gravity solids and the liquids in the mud. The chart in *Figure 3*, for example, is based on 4.20 gm/cm³ density barite and 2.60 gm/cm³ density low-gravity solids and fresh water. The top line shows the hypothetical solids content if all the solids were 2.60. The bottom line shows the minimum possible solids if low-gravity solids are zero and all solids are 4.20 barite. The **acceptable range** of solids on the chart, for a given mud density, allows for a minimum concentration of low - gravity solids (should be mostly bentonite) and the remainder being barite. As mud weight increases, notice that the acceptable concentration of low-gravity solids decreases.

Graphs can also be used to see if plastic viscosity and yield point are in the correct range for a given mud weight at a specified temperature. *Figure 4*, based on PV measurements at 115°F, shows two lines between which plastic viscosity is in an acceptable range for various mud densities. The upper line reflects excessive solids in the mud, while the lower line is a practical lower limit where most of the solids are barite.

Figure 3
Acceptable Range for Solids

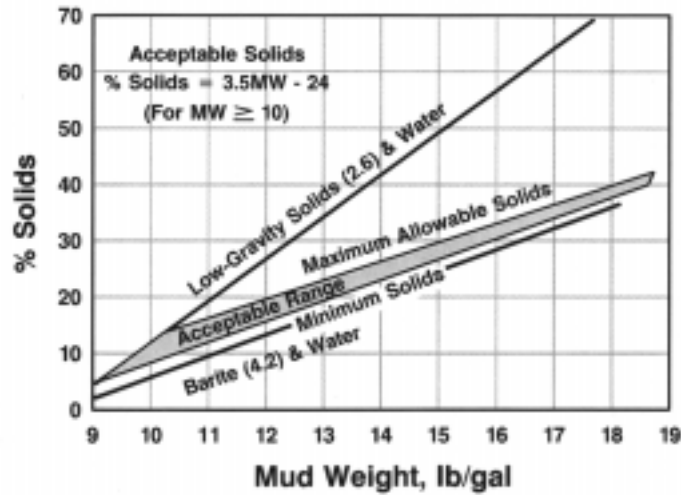
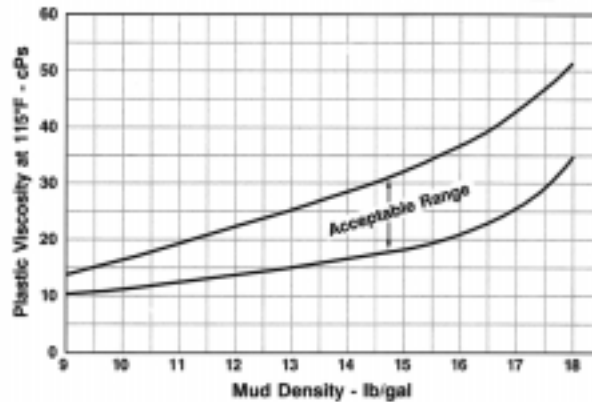


Figure 4
**Recommended Range of Plastic Viscosity
 in Various Weight Muds**



Symptoms of excess solids in muds are:

- High plastic viscosity
- High gel strengths
- Poor response to deflocculants
- High retort solids volumes
- High MBT values and high D/B ratio (Drill Solids/Bentonite)
- Thick filter cake and high fluid loss
- Slow rate of penetration
- Difficulty during trips with tight hole, swab and surge.

Treatment

Treatment for solids contamination should always be **prevention**. The objective of solids control is to physically remove drill solids from the mud, yet retain sufficient quantities of bentonite and high-gravity solids. Solids removal can be accomplished by three methods: (1) dilution, (2) mechanical separation, and (3) chemical-mechanical separation. Although not actually a method of solids removal, the addition of a chemical deflocculant can offset the adverse rheological and filtration effects of excessive solids for a period of time, and therefore is included here as a **treatment** method.

Dilution

The simplest method for lowering solids concentration (or any other contaminant in a mud) is by dilution of the contaminated mud. This can be done by the **dump and dilute method** which uses either clean mud or water for dilution. The two rules for dilution are: (1) keep total mud volume as small as practical and (2) dump as much mud as possible before each dilution. Disposal costs also must be taken into account when dilution is considered. Dilution is seldom the most economical approach when compared to mechanical solids removal.

Mechanical Separation

Screening and applied g-force settling are the two most commonly-used mechanical methods for solids removal. These and other mechanical separation methods are covered in Section 5, *Solids Control*.

Principles of Mechanical Solids Control

The basic principles of mechanical solids control are:

Processing in Sequence - Mud flow from the well and onward through solids control equipment must be in the proper sequence to remove the largest particles first.

Total Flow Processing - All of the mud must pass through all solids removal equipment (except the centrifuge) at least once per circulation.

No Bypassing - The solids removal devices (primarily the shale shaker) should not be bypassed.

Chemical-Mechanical Separation - Chemical-mechanical methods of separation combine the judicious use of chemicals in conjunction with screening devices and/or g-force devices to remove solids that are too small to remove otherwise. These methods are chemical flocculation and dewatering, as discussed below.

Flocculation - Chemicals are added to coagulate drill solids into larger groups in order to improve mechanical solids removal efficiency. High molecular weight polymers or aluminum or ferric salts are used to aggregate colloidal solids. This technique is mostly applicable to unweighted, and clear water drilling fluids.

Dewatering - Dewatering is a specialized chemical-mechanical means of controlling solids. Dewatering removes damp colloidal solids for disposal and recovers usable water from a mud through chemical flocculation of the solids followed by high-speed centrifugation. Dewatering is done for economical as well as environmental reasons and is often an integral part of a closed loop (zero discharge) system used in environmentally sensitive areas. (For more information see Section 4, *Clay Chemistry and Polymer Chemistry*; and Section 5, *Solids Control*.)

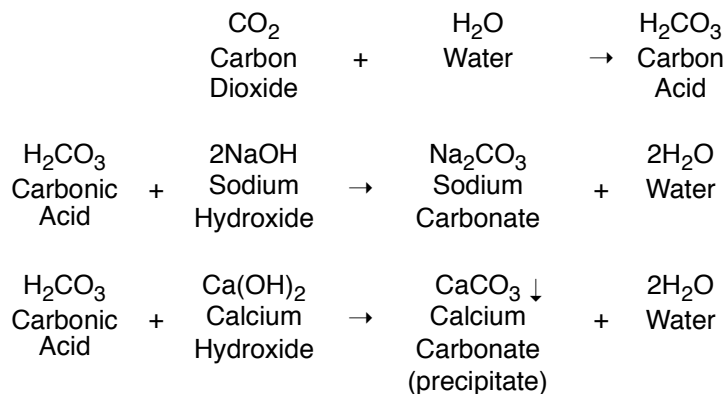
Chemical Deflocculation - Chemicals can also be used to mitigate the detrimental effects of solids contamination. Chemical deflocculants can lower gel strengths and yield point when they are excessive due to high solids. This can improve mud rheology and usually improves filtration control. However, there is a limit as to how far deflocculants can go in helping a solids problem. Deflocculation is not a solids removal technique, and can actually make solids removal more difficult by breaking up aggregates. (For more information see Section 4, *Basic Chemistry, Clay Chemistry and Polymer Chemistry*.)

Acid Gases

Carbon dioxide (CO₂) and hydrogen sulfide (H₂S) are often constituents of natural gas. Both form weak acid solutions in water which cause the clays to flocculate and may increase the viscosifying effect of polymers. Formations that contain H₂S as well as CO₂ can be drilled safely with water-based fluids provided the formation pressures are contained by a hydrostatic pressure greater than the pore pressure.

However, proper control of the mud properties is of lesser importance than the safety of personnel, and the avoidance of embrittlement and parting of the drill pipe when significant H₂S contamination occurs.

Treating out the acid gases and stopping their influx into the well are also important. Even high density fluids contaminated with CO₂ can be controlled satisfactorily provided the fluid contains low concentrations of bentonite and reactive drilled solids. Removal of CO₂ can be effected by treating with either caustic or lime.



Treatment with lime is preferred because the contaminant is removed from solution. Accumulation of Na_2CO_3 resulting from treatment with caustic soda can make control of a drilling fluids properties difficult. High density drilling fluids in which drill solids have accumulated through use over an extended period of time can experience extreme thickening from contamination with the acid gases. Such an occurrence may make the mud impractical for continued use as a drilling fluid.

Contamination Due to Bacteria

Bacteria are widely distributed in nature; a typical soil sample may contain 1,000,000,000/g, which in terms of weight may only represent about 10 mg of the total weight. Bacteria may be divided into two general groups: aerobic bacteria, which require oxygen, and anaerobic bacteria, which flourish in oxygen-free environments.

The presence of bacteria in a drilling fluid does not, in itself, present a problem. However, there are two general situations where bacteria may become problematic.

Aerobic bacteria can cause degradation of organic viscosifiers and filtrate loss reducers. This situation is more likely to occur following long periods of noncirculation.

Anaerobic bacteria may reduce sulfate ions to sulfide ions which combines with hydrogen to form hydrogen sulfide. H_2S can cause the fluid to become corrosive. Again, this is a situation more likely to occur following long periods of noncirculation.

A side effect of the presence of bacteria is the formation of enzymes. Although the use of bactericides can effectively kill all bacteria existing in a drilling fluid, it will not affect the growth of enzymes produced by the bacteria. These enzymes will continue to decompose all biodegradable materials in the drilling fluid. They can only be removed by the use of highly toxic complexing reagents.

The best method for prevention of bacterial problems is to treat the makeup with a biocide and maintain adequate levels of biocide in drilling fluids susceptible to biodegradation.

Note: See Amoco's Solids Control Handbook for more information.

Solids Calculations

Introduction

Fundamental material balance equations are used to calculate solids concentrations from data normally obtained from drilling fluid tests. These equations are based on measured, estimated or assumed volume percents and densities of the components. The generalized material balance equations are:

$$V_1\rho_1 + V_2\rho_2 + V_3\rho_3 + \dots = V_F\rho_F$$

Where

$$V_1 + V_2 + V_3 + \dots = V_F = 100 \text{ Vol\%}$$

V = Volume percents of components in a mud (as measured by retort analysis)

r = Densities of components in a mud

1, 2, 3 = Various components in a mud

Unweighted Water-Based Mud

To find the volume percent of solids (V_{LGS}) in an unweighted water-based mud which contains only low-gravity solids and water, the material balance equation is simple. Variables are: density of low-gravity solids (r_{LGS}), density of water (r_W), and mud density.

Weighted Water-Based Mud

To find the volume percent of solids (V_{LGS}) in a weighted water-based mud another component has to be taken into account in the material balance equation, the density of high-gravity solids, r_{HGS} . It is normally assumed that high-gravity solids are barite and therefore, the r_{HGS} is 4.20 g/cm^3 .

Oil-Based Mud

For oil-based muds which are composed of two liquid phases (oil and brine) and a solid phase having high- and low-densities, even more information is needed to calculate salinity and solids composition. (*These calculations are covered in Section 3, and will not be discussed here.*)

Note: 50 cc retorts are recommended for accuracy over smaller models.

Nomenclature

Parameters	Symbols	Notes
Methylene Blue Capacity, Mud (lb/bbl)	MBT _{MUD}	m
Methylene Blue Capacity, Drill Solids (lb/bbl)	MBT _{DS}	m
Methylene Blue Capacity, Bentonite (lb/bbl)	MBT _{BEN}	m
High Gravity Solids, lb/bbl	M _{HGS}	c
Low Gravity Solids, lb/bbl	M _{LGS}	c
Drill Solids, lb/bbl	M _{DS}	c
Bentonite Equivalent, lb/bbl	M _{BEN}	c
Volume % solids (from retort)	V _S	m
Volume % solids (calculated - unweighted muds)	V _{SOL}	c
Volume % water (from retort)	V _W	m
Volume % oil (from retort)	V _O	m
Volume % corrected solids	V _{CSOL}	c
Volume % corrected water	V _{CW}	c
Volume % drill solids	V _{DS}	c
Volume % low gravity solids	V _{LGS}	c
Volume % high gravity solids	V _{HGS}	c
Volume % barite	V _{BAR}	c
Volume % bentonite	V _{BEN}	c
Density, average	r _{AVG}	c
Density, solids	r _{SOL}	a
Density, water	r _W	a
Density, corrected water	r _{CW}	c
Density, oil	r _O	a
Density, high gravity solids	r _{HGS}	a
Density, low gravity solids	r _{LGS}	a
Density, barite	r _{BAR}	a
Density, bentonite	r _{BEN}	a
Density mud, lb/gal	MW	m
Chloride Ion, mg/L	Cl ⁻	m
Note: m = Measured Value c = Calculated Value a = Assumed Value		

Mud Test Data for Solids Calculations

In order for solids calculations to be reliable, all input data must be as accurate as possible. Small errors in input data can become magnified in the calculated concentrations. For example, the calculated concentration of low-gravity solids (M_{LGS}) will be larger than they should be if retort water is under-estimated or if the mud density used in the calculations is higher than actual.

A major consideration in the quality of input data for solids calculations is accurate mud test results. To obtain accurate mud test data, the testing equipment must be reliable, properly maintained and frequently calibrated.

The following tests, and data from these tests, are discussed below:

Mud Balance (MW)

The mud balance measures the mud density (MW, lb/gal) to an accuracy of ± 0.1 lb/gal. In the material balance equation, the mud density represents the sum of the composite liquid and solids densities, r_F , where $r_F = MW/8.33 = g/cm^3$.

Retort (V_W, V_O)

The retort breaks the whole mud into its composite fresh water, oil and total solids as volume percents. The accuracy is ± 1 volume %. In the material balance equation this provides direct (or indirect) data for the volume percent of components: water (or saline water) and solids (or corrected solids) and oil. Use a 50 cc model for improved accuracy.

Chlorides (C_L^-)

The chloride test allows the volume percent of the water phase to be corrected for the total dissolved chlorides, usually as NaCl. The corrected water, V_{CW} , is then used in the equation to correct the retort solids, V_{CSOL} . The chloride measurement is accurate to approximately 100-200 mg/L, which is accurate enough for use in solids calculations.

Density (ρ)

The densities of the liquid phase (water and oil) and the solid phase (weight material, drilled solids and commercial bentonite) must be assumed or measured. These values allow the corrected-solids volume percent, V_{CSOL} , to be further broken down into low-gravity solids, V_{LGS} , and high-gravity solids, V_{HGS} .

Methylene Blue Capacity (MBT)

The Methylene Blue Test in combination with assumed or measured drilled-solids MBT, is used to further divide the low-gravity solids into inert (drill solids) and active low-gravity solids (bentonite). Soil scientists measure clay activity as cation exchange capacity (CEC); but, in drilling fluid testing, the clay activity is measured as MBT. For practical purposes, MBT (methylene blue, cm^3/cm^3 whole mud) is the same number as CEC (meq/100 g solids). Splitting low-gravity solids into drill solids and bentonite is an imprecise classification because the calculated bentonite is based on activity (CEC) and may not actually be commercial API-grade bentonite.

Note: See Section 3 - Testing for additional information.

Densities Required to Perform Solids Calculations

Below are the specific gravity values commonly used in solids calculations.

<u>Symbol</u>	<u>Value</u>
ρ_W	= 1.00
ρ_{CW}	= calculated from chloride data
ρ_O	= 0.84
ρ_{HGS} = ρ_{BAR}	= 4.20
ρ_{HGS} = ρ_{HEM}	= 5.10
ρ_{LGS}	= 2.60
ρ_{BEN}	= 2.60

Note: See Nomenclature for symbol identification.

Salinity Corrections

Unless the mud contains fresh water, the **retort water volume** and the **density of the water** MUST BE CORRECTED for the amount of salt acting as a solid.

Correction of Retort Water

Based on the chloride ion analysis of the mud's filtrate, the water-phase salinity of the mud can be calculated, depending on the assumptions that are made. The most common assumption (and usually correct) is that the chlorides come from only NaCl. The equation, based on chloride ion concentration, mg/L, that is used to calculate corrected retort water volume is:

$$V_{CW} = V_W [1 + 5.88 \times 10^{-8} (Cl^-)^{1.2}] = \text{Vol } \%$$

Correction of the density of the Water

Based on chloride ion analysis of mud filtrate and assuming that the salt is only NaCl, the density of the mud's water phase can be calculated. The equation for calculating NaCl brine density (ρ_{CW}) is:

$$\rho_{CW} = 1 + [(1.94 \times 10^{-6})(Cl^-)^{0.95}] = \text{g/cm}^3$$

Table 3
Volume of Salt (NaCl) in the
Water Phase of the Mud
(Calculated From Chloride Analysis)

Chloride Ion mg/L	V _{CW} * cm ³ /cm ³	ρ _{CW} ** g/cm ³
5000	1.003	1.004
10,000	1.006	1.010
20,000	1.012	1.021
30,000	1.018	1.032
40,000	1.023	1.043
60,000	1.034	1.065
80,000	1.045	1.082
100,000	1.057	1.098
120,000	1.070	1.129
140,000	1.082	1.149
160,000	1.095	1.170
180,000	1.108	1.194
188,000	1.114	1.197

* V_{CW} is volume expansion due to dissolved sodium chloride.

** ρ_{CW} is density increase due to dissolved sodium chloride.

Table 3 can also be used to obtain corrected water volume and density.

Solids Calculations - Water-Based Muds

Based on the generalized material balance equations, the following equations are used for calculating solids in water-based muds.

Unweighted Freshwater Muds (No Retort Data Needed)

For water-based muds which are unweighted (containing only low-density solids), the material balance equation is:

$$V_{W\rho W} + V_{LGS\rho LGS} = V_{F\rho F}$$

A simplified form of the equation which assumes 2.6 density for all solids and 8.33 lb/gal for fresh water, is:

$$V_{LGS} = V_{SOL} = 7.5(MW - 8.33) = Vol \%$$

$$M_{LGS} = (3.5)(V_{LGS})(\rho_{LGS}) = \text{lb/bbl}$$

Note: The calculated values for V_{SOL} for fresh water muds should agree with the measured retort solids, V_S , within experimental error.

Weighted and Unweighted Mud (Retort Data Required)

Calculate the corrected solids volume percent, V_{CSOL} , from the corrected retort water volume percent, V_{CW} , and retort oil volume percent, V_O , using the equation below:

$$V_{CSOL} = 100 - V_{CW} - V_O = \text{Vol } \%$$

Calculate the average density of all solids, r_{AVG} , with the equation below, using V_{CSOL} and V_{CW} and V_O , plus the calculated r_{CW} and the assumed (or measured) r_O .

$$\begin{aligned} \rho_{AVG} &= \frac{\left[\frac{100(MW)}{8.33} \right] - [(V_{CW})(\rho_{CW})] - [(V_O)]}{V_{CSOL}} \\ &= \text{g/cm}^3 \end{aligned}$$

The volume percent of low-gravity and high-gravity solids can be found from the r_{AVG} , but we must assign values for the r_{LGS} and r_{HGS} . Usually we assume 2.6 for r_{LGS} (drill solids) and 4.20 for r_{HGS} (barite).

$$V_{LGS} = \frac{V_{CSOL}(\rho_{AVG} - \rho_{HGS})}{(\rho_{LGS} - \rho_{HGS})} = \text{Vol } \%$$

The volume percent of high-gravity solids is found from the equation below:

$$V_{HGS} = V_{CSOL} - V_{LGS} = \text{Vol } \%$$

The following equations are used to find the corresponding concentrations, in pounds per barrel from the volume percents.

$$M_{LGS} = (3.5)(V_{LGS})(\rho_{LGS}) = \text{lb/bbl}$$

$$M_{HGS} = (3.5)(V_{HGS})(\rho_{HGS}) = \text{lb/bbl}$$

Differentiating Drill Solids from Bentonite by CEC Ratio

At this point, the low-gravity and high-gravity solids have been calculated as volume percents and also as pounds per barrel. Often this is sufficient information for the type of solids control required. But, for high-density muds it may be desirable to mathematically split the low-gravity solids into **inert drill solids** and **active bentonite solids**. The reason to know the bentonite in and drill solids separately for high-density muds is to have sufficient bentonite in the mud for good filtration control, but not excessive amounts to cause undesirable flow properties.

Assumed 9:1 CEC Ratio

The MBT of the mud is used to split the low-gravity solids into drill solids and bentonite. An assumption is usually made that bentonite is 9 times more active (CEC) than kaolinite, which represents drill solids. The lb/bbl of bentonite equivalent is then calculated by the following equation, assuming an R value of 9-to-1 CEC ratio ($R = 1/9 = 0.11$).

$$M_{BEN} = (0.11)(MBT_{MUD}) - (V_{LGS}) = \text{lb/bbl bentonite equivalent}$$

Measured CEC Ratio

When the MBT value of the drill cuttings, MBT_{DS} , is determined by testing, (see note below) then the R value ($MBT_{DS}/100$) can be used in the equation below to calculate M_{BEN} . This equation assumes a CEC value for commercial bentonite as 100 meq/100 g. Bentonite CEC, however, may actually be less than 100, perhaps as low as 60 meq/100 g.

$$R = \frac{MBT_{DS}}{100}$$
$$M_{BEN} = \left[\frac{1}{1-R} \right] MBT_{MUD} - [(9.1)(R)(V_{LGS})]$$

To obtain more precise information for differentiating actual drill solids from the rig bentonite, a methylene blue test should be run on the cuttings and also on the rig bentonite. The measured MBT_{BEN} , along with the MBT_{DS} and MBT_{MUD} can then be used to calculate a more accurate **R** using the equation below. Then, this new **R value** can be used to calculate MBEN in the equation above.

$$R = \frac{MBT_{DS}}{MBT_{BEN}}$$
$$V_{BEN} = \frac{M_{BEN}}{(3.5)(\rho_{LGS})}$$
$$V_{DS} = V_{LGS} - V_{BEN}$$
$$M_{DS} = (3.5)(V_{DS})(\rho_{LGS})$$

Note: To find MBT_{DS} , and MBT_{BEN} , the testing procedures in API RP 131, Section 9 are used, in which a sample is dried, weighed and tested with methylene blue.

Drill Solids/Bentonite Ratio

From the split of bentonite (B) and drill solids (D) the following ratio is calculated:

$$D/B = \frac{M_{DS}}{M_{BEN}}$$

Note: As an operational guideline for freshwater or seawater muds, the D/B ratio should not exceed 3.

Example - Solids Calculations for Water-Based Muds

Using the equations in this section, calculate the solids concentrations and the ratio D/B from the data below.

Mud and Drill Solids Analysis Data		
Mud	Retort	Drill Solids
MBT _{MUD} = 28 lb/bbl	V _O = 7.5%	MBT _{DS} = 11 meq/100 g*
Cl ⁻ = 73,000 mg/L	V _S = 35.5%	MBT _{BEN} = 100 meq/100 g*
MW = 16 lb/gal	V _W = 57.0%	

*Can be measured

Solution

$$\begin{aligned}
 V_{CW} &= 57 [1 + 5.88 \times 10^{-8} (73,000)^{1.2}] &= 59.3 \text{ Vol \%} \\
 \rho_{CW} &= 1 + [(1.94 \times 10^{-6}) (Cl^-)^{0.95}] &= 1.08 \text{ g/cm}^3 \\
 V_{CSOL} &= 100 - 59.3 - 7.5 &= 33.2 \text{ Vol \%} \\
 \rho_{AVG} &= \frac{\left[\frac{(100)(16)}{8.33} \right] - 59.3(1.08) - 7.5(0.84)}{33.2} &= 3.66 \text{ g/cm}^{3ya} \\
 V_{LGS} &= \frac{33.2(3.66 - 4.2)}{(2.6 - 4.2)} &= 11.2 \text{ Vol \%} \\
 V_{HGS} &= 33.2 - 11.2 &= 22.0 \text{ Vol \%} \\
 M_{LGS} &= (3.5) (11.2) (2.6) &= 101.9 \text{ lb/bbl} \\
 M_{HGS} &= (3.5) (22.0) (4.2) &= 323.4 \text{ lb/bbl} \\
 R &= 11/100 &= 0.11 \text{ ratio} \\
 M_{BEN} &= 101.9 - \left[\frac{(101.9 - 28.0)}{(1.0 - 0.11)} \right] &= 18.9 \text{ lb/bbl} \\
 V_{BEN} &= \frac{18.9}{(3.5)(2.6)} &= 2.1 \text{ Vol \%} \\
 V_{DS} &= 11.2 - 2.1 &= 9.1 \text{ Vol \%} \\
 M_{DS} &= (3.5) (9.1) (2.6) &= 82.8 \text{ lb/bbl} \\
 D/B &= \frac{9.1}{2.1} &= 4.3
 \end{aligned}$$

Verification

After calculating the solids in the example above, the results can be verified by checking material balance to see that it adds to 100 volume % and that mud weight for the balance is as expected from the given data.

Material	Volume %	lb/bbl
Barite	22.0	323.3
Bentonite	2.1	18.9
Drilled Solids	9.1	82.8
Oil	7.5	22.0
Water	59.3	224.4
Total	100.0	671.0

$$\begin{aligned}\text{MudDensity} &= \frac{\text{lb/bbl}}{42 \text{ gal/bbl}} \\ &= \frac{671 \text{ lb/bbl}}{42 \text{ gal/bbl}} \\ &= 15.97 \sim 16.0 \text{ lb/gal (agrees with given data)}\end{aligned}$$

Solids Control

Introduction

This is a summary of solids control concepts dealing with the basics of solids removal techniques and the capabilities of various mechanical devices. (For more comprehensive detailed information on these devices, refer to Amoco's Solids Control Handbook.)

The purpose for implementing a solids control program is to improve the performance of the mud's basic functions, which are: (1) to build a low-permeability, thin, slick filter cake on the borehole wall, (2) to provide efficient drilling hydraulics, and (3) to transport cuttings.

In a hypothetical situation, if solids were incorporated while drilling (as they always are), but not removed, the mud would soon become unpumpable. Inadequate or inefficient solids removal leads to this same situation unless the mud is regularly diluted. Therefore, solids control, in reality, is a matter of degree of removal and of economics coupled with sound drilling practices.

The goal of solids control at the rig is to maintain the type, size and concentration of mud solids at an **acceptable level** at reasonable cost. Costs of improper or inadequate solids removal and the associated risks include (but are not limited to):

- Dilution costs for mud chemicals and barite
- Disposal costs for mud hauled away
- Slower drilling rate
- Reduced bit life
- Excessive abrasion of pumps, mud lines, swivel, guns etc.
- Inefficient hydraulics
- Pipe sticking from thick filter cakes
- Increased swab and surge pressures
- Greater risk of kicks
- Greater risk of production impairment

The magnitude of the costs and risks associated with NOT having proper solids removal capabilities far outweigh the cost of having good solids removal equipment on the rig and using it correctly.

Characteristics of Solids

The important factors of solids as they affect mud performance are type, size and shape. These characteristics depend on the source of the solids, whether from drilled shales, from hard rock, from materials added such as barite and bentonite, or from chemical precipitants. In a mud, solids can be quantified by their concentration (volume percent or pounds per barrel) and described according to their size and shape distribution and also their type.

Types of Solids

Drilled solids are usually classified as either **Active or Inert**. These terms refer to how the solids interact with water and ions in the water. Another classification is according to density - **High-Gravity or Low-Gravity**.

1. **Active Solids** - are clay-type solids having high surface activity and high surface area. Being electrochemically active, clay solids are strongly attracted to each other and to ions and polymers in the mud. More information on clays can be found in Section 4, *Clay Chemistry*.
2. **Inert Solids** - are those that do not have significantly charged surfaces and do not interact electrochemically. They crowd the system and in doing so, they force active solids closer together causing viscosity problems. Inert, high-gravity solids, such as barite, are needed in a mud; however, inert, low-gravity solids are generally unwanted.
3. **High-Gravity Solids** - are used as weighting materials (usually barite at 4.20 g/cm³) and are generally considered to be Inert solids.
4. **Low-Gravity Solids** - include various types of drill solids and commercial clays and can be inert or active. Bentonite is the most active, although some drill solids can also be active. Drill solids such as limestone and dolomite are inert. Their density ranges from 2.7-2.9 g/cm³. Salt crystals in saturated salt mud are inert and have a density of about 2.1 g/cm³. Shales can range from active to inert and have a density range of 2.4 to 2.8 g/cm³, depending upon their water content.

Size of Solids

Size of solids in a mud can be anything from the largest chunk that can be pumped up the annulus to clay platelets and chemical precipitates, both so small that an electron-beam microscope is needed to see them. The API has designated size ranges for particulate material in drilling muds. Sand is defined as particles larger than 74 microns (200 mesh). Particles in the 2 to 74 micron range are called silt. API barite and API hematite have size specifications set by API Spec. 13A (*see Table 4*).

**Table 4
Familiar Size Comparisons**

Particles	Microns
Fingers can feel "grit"	20
Talcum powder	5-50
Human hair (finest size)	30-200
Dust particles seen in air	approx 7
Colloids in muds	<2
API Silt	2-74
API Sand	>74
API Barite Specifications	
Max. 3% larger than	74
Max. 30% smaller than	6
Dispersed bentonite	<2

The following dimensions are used to define sizes of solids in muds:

1. **ÄNGSTROM** is the dimension used for molecular diameters and clay thickness. Smectite clay crystals are 14 Å thick. Kaolinites are 7 Å thick. There are 10,000 Å in one micron.

2. MICRON is a dimension used to describe very small particles. One micron is equivalent to 0.0000393 in. There are 25,400 microns in 1 in.
3. STANDARD SIEVE SIZES (*shown in Table 5*) give micron sizes for standard square-mesh sieves. *Table 6* shows standard market-grade screen cloths and corresponding opening sizes. Total screen cloth open area will vary with wire size.

**Table 5
Standard Sieve Sizes**

U. S. Test Sieve No.	Opening Size Microns
20	841
30	595
40	410
50	297
60	250
80	177
100	149
120	125
140	105
170	88
200	74
325	44

**Table 6
Standard Market-Grade Screen Cloths**

Screen Size	Opening Size Microns
8 x 8	2464
10 x 10	1905
20 x 20	864
40 x 40	381
80 x 80	178
100 x 100	140
120 x 120	117
200 x 200	74
325 x 325	44

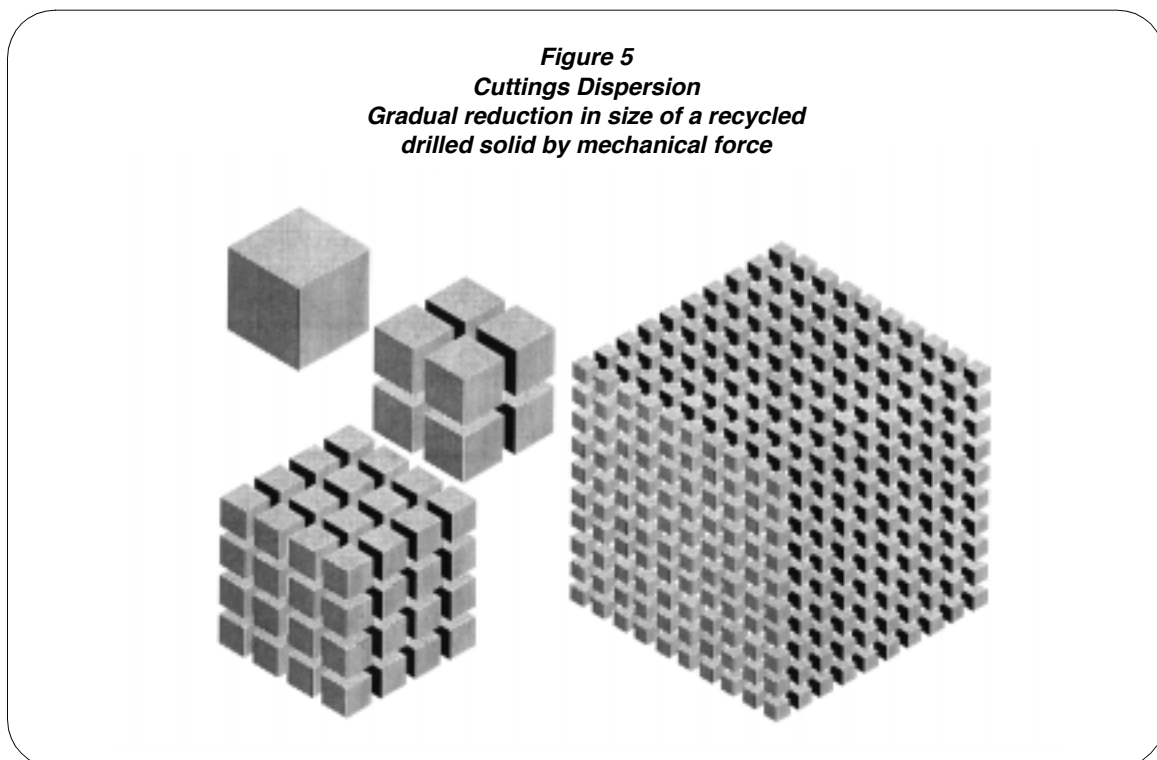
Shape of Solids

A distribution of particle shapes and sizes is needed to form a good filter cake. It is difficult to know what shapes and sizes are needed for each situation or what size distribution and particle shapes actually exist in a mud. Tests and analyses such as: the Permeability Plugging test, HTHP Static Filtration test, particle size measurements and microscope studies, can help define particle sizes and shapes. It is known that some of the particles should be deformable and flat, like bentonite, to build a low-permeability filter cake. [For more information, refer to Section 4, *Filtration*, and Section 3, *Permeability Plugging Test (PPT)*.]

Concentration and Size Distribution of Solids

Concentration of solids in a mud is usually measured as volume percent by an API retort test. Concentration as measured by the retort cannot indicate the total surface area of the solids, which is the main cause of mud problems. Another API test, the methylene blue test, gives an indication of total surface area of active solids. These tests, taken together, can help define when solids will cause a mud problem. For example, a high MBT value indicates a large surface area of solids in a mud even though the retort may be showing an acceptable low volume percent concentration of solids.

To illustrate the volume percent versus area concept, *Figure 5* shows a 20 x 20 x 20 micron cube of a solid. It occupies a certain volume percent when placed into a given volume of mud. Assuming that this cube is divided in half on each face and this happens again and again, then the original surface area of 2400 square microns becomes 24,000 square microns; but, the volume percent of this solid in the mud has not changed. This illustrates the large surface area that can be created when a 20-micron cube of shale is allowed to subdivide time after time by dispersion. Dispersive shale cuttings should be removed as soon as possible from a mud. We want commercial bentonite to disperse; however, it can become a solids contaminant just like the dispersive shale, if it is added in excess.



Methods for Solids Control

The approach to controlling solids vary and depend if the mud is weighted, containing barite or hematite.

The various methods of solids control include:

- Dilution
- Gravity Settling
- Mechanical Separation
- Chemical-Mechanical Separation

Dilution Method

Oil muds can be diluted with base oil (or clean oil mud) and water muds can be diluted with water (or clean water mud) to keep the concentration and surface area of solids within bounds. Two approaches for dilution are:

1. Dump and dilute continuously while drilling. This is the most expensive approach to solids control in most situations.
2. Dump periodically and dilute while drilling. This is more cost effective than the first approach. Certain practices can be applied to make it less costly.

The total costs of dilution are: the cost of the water hauled to the rig, the cost of converting that water into a mud of correct density, plus the cost of disposal of the mud that was dumped. To make dilution less expensive, these practices should be followed:

1. minimize the total volume of mud to be diluted,
2. dump (displace) the maximum possible dirty mud before adding water and materials, and
3. do as much dilution as possible in a single step - not a series of small dilutions.

Therefore, as mud becomes more expensive, dilution becomes a less attractive option and mechanical separation should be pursued.

The equations needed to calculate the volume of mud to dump, the volume of water to add for dilution, and the volume of barite required for density are found in Section 2, *Basic Engineering Calculations*.

Gravity Settling Method

In locations where large, shallow earthen pits can be built, a mud can be circulated through the pits and drill solids allowed to settle out. It is a rare situation today when this can be done; but, it is an alternative to be considered. On rigs with steel pits, the sand trap (under the shale shaker) is the only place where settling should occur.

Mechanical Separation Method

Devices that are available for processing muds to remove solids are more sophisticated and effective today than they were in prior years. However, they still operate on the principles of screening or by development of high centrifugal and gravitational forces to physically separate solids out of the mud. Screening is based on physical size separation of particles; particles either pass through a screen opening or not. However, particles smaller than the screen opening can ride on larger particles (piggy-backing) and thus, are removed. Centrifugal forces are generated by flow in hydrocyclones or

by spinning of centrifuge bowls. These devices are governed by complex physics and gravitational and centrifugal forces based on relationships between solid sizes, specific gravities, mud density and rheology.

Chemical-Mechanical Separation Method

There are situations where the solids that are too small to be removed by ordinary mechanical methods can be removed with the aid of chemical flocculation and aggregation. A centrifugate of a mud, or the overflow from the hydrocyclones, or the mud itself, can be processed by chemical-mechanical separation methods. High molecular weight polymers or alum or ferric salts are added to cause these colloidal solids to agglomerate and become large enough aggregates to be removed by mechanical methods. This is commonly done to dewater muds and is often a part of zero-discharge operations.

Principles of Mechanical Solids Separation

Three principles govern the operation of mechanical solids control devices on any mud system; they are:

- Processing in Sequence
- Total Flow Processing
- No Bypassing

Processing in Sequence

This refers to the principle that all of the mud must pass through each specific solids control device before passing to the next one. The reasoning behind this requirement is that solids are more efficiently removed in a sequence according to size - largest removed first. To accomplish this, device A must remove the larger particles before sending mud to device B or C downstream. Device B must take its input mud from the compartment where A discharges its processed mud and so forth.

Total Flow Processing

This refers to the requirement that at least 100% of the wellbore circulating volume must be processed through each device before it goes back down the hole to pick up more solids. In the case with hydrocyclones, the same mud volume must be processed 110 to 125% in order to clean it properly. An exception to the 100% rule is the centrifuge which cannot handle a large volume of mud.

No Bypassing

Bypassing refers to the practice of allowing some or all of the mud flow to bypass certain solids control equipment (usually the shale shaker). Bypassing permits retention of solids which will not be removed by any of the other solids control devices and should be avoided at all cost.

Sequence of Solids Control Devices

When planning a well, it is important to take into account the type and size of solids likely to be encountered and whether or not weighting materials will be needed. These factors will determine the solids control equipment needed on the rig. The number and kinds of mechanical devices and how each is controlled during use will depend mostly on whether the mud is weighted or unweighted. It may be necessary to modify the tank arrangement and the rig solids control equipment - rather than accept it **as is** and later try to make it do the job - usually with poor results. Tank arrangements should be planned according to the **regions** discussed below:

- Solids Removal Region
- Addition Region
- Mud Check Region

Solids Removal Region

The devices and associated tank arrangement in the removal region are: (1) Mud/Gas Separator, (2) Shale Shaker, (3) Sand Trap, (4) Degasser, (5) Hydrocyclones, (6) Mud Cleaner, and (7) Centrifuge(s).

1. Mud/Gas Separator - Ahead of the entire sequence of solids removal equipment on most rigs is the Gas Buster. This is a large volume mud/gas separator vessel that allows gross amounts of gas to escape from the mud prior to going on to the shale shaker. It has a gas line laid far from the rig where gas can be flared; however, it does not remove all gas. The degasser downstream of the shale shaker removes the hard-to-remove gas and will be discussed later.
2. Shale Shaker(s) - Shale shakers are vibrating screening devices and are fed by mud returning from the mud/gas separator or directly from the wellbore through the mud flowline. Total cuttings load goes onto the screens which can be a large mass per minute of solids during fast drilling. Mud should enter into the bottom of the cuttings box (possum belly) before going onto the screens. Mud flows upward and out of the box, providing a wide, slow flow over the screen surface. Cuttings should not be allowed to fill up the mud box, taking up the volume in the box which is intended to slow the mud flow before it passes onto the screen.

On some wells more than one type of shale shaker may be used. A low-speed, less efficient shaker may send its underflow onto the screen of a high-speed, fine screen shaker. The advantage of a cascading arrangement is that larger, coarser, more abrasive solids are removed or scalped by the rig shaker prior to sending fluid onto the finer-mesh shaker. Thus, solids loading is reduced and screening efficiency is improved. Also, in cases where more than one shaker is needed to handle the flow rate returning from the wellbore, shakers may be run in parallel to process the large volumes of fluid and cuttings. This is called a parallel shaker arrangement.

Shaker screens have capacity limits. Exceeding this limit means that mud will be lost over the screen(s). The capacity of shaker screens can be limited in three ways: (1) solids-load limit, (2) liquid-load limit, and (3) particle size plugging. The solids-load limit is reached in fast drilling of soft formations when the screen is handling so many solids that they cover the screen openings and thus, will not allow fluid to flow through. The liquid-load limit is simply excessive mud volume being pumped which is greater than the screen openings can handle. In either case, flow rate and/or screen size must be adjusted to allow the screens to handle the fluid. Particle size plugging is another factor which limits screen capacity. This is caused when screen openings are plugged by particles of the same size as the screen mesh openings. In this case, the screen size must be changed to prevent plugging (blinding) of the screen.

The shale shaker is positioned over the first tank above an unstirred compartment called the Sand Trap. Mud that passes through the shale shaker screens falls directly into the sand trap. Any mud that bypasses the shaker screen will also go into the sand trap. It is not recommended to bypass shaker screens.

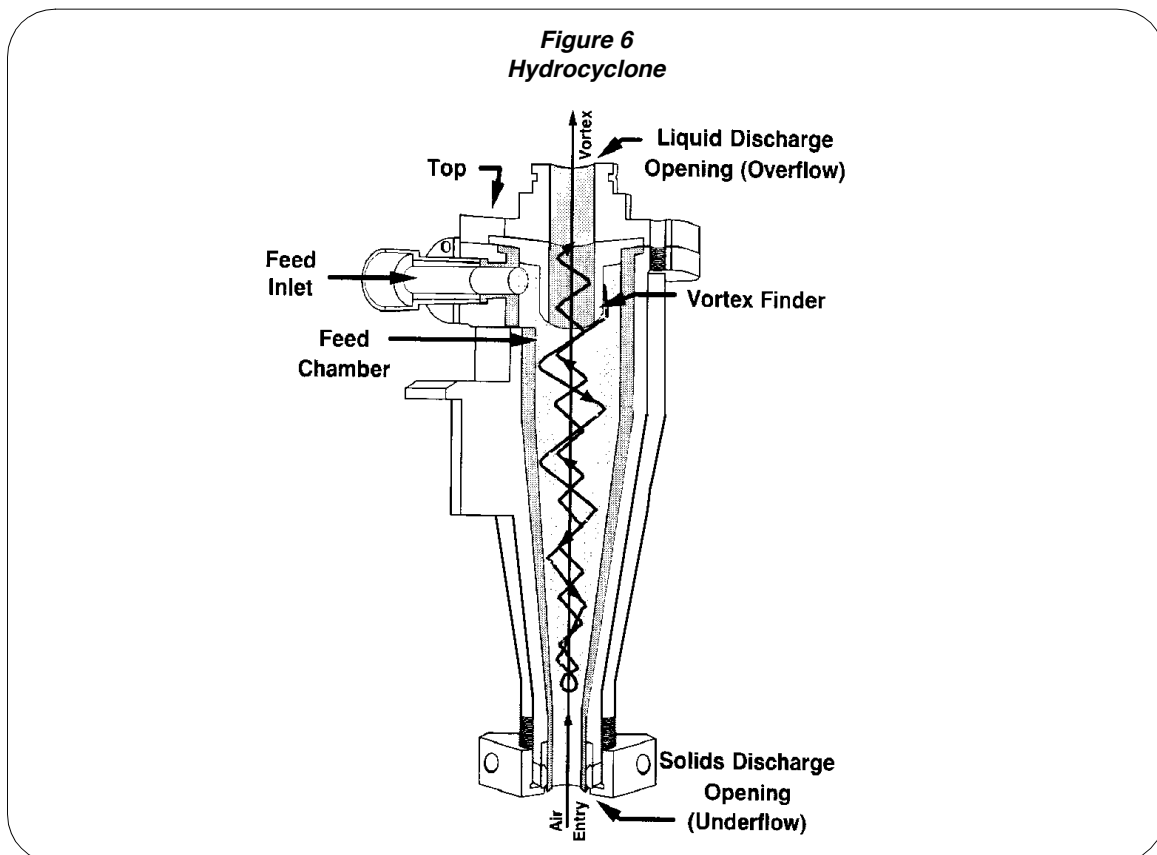
3. Sand Trap - The Sand Trap under the shaker has no agitation and allows particles an opportunity to settle and remain until the trap is periodically cleaned. Settling rate of particles depends on the rheological properties and density of the mud as well as the size and specific gravity of the particles in the mud. Sand traps are often built with sloping sides to allow particles to settle onto a solid surface and slide to the bottom. This shape also minimizes mud volume lost when cleaning out the

trap. A sand trap is a good **safety** device to prevent extraneous large cuttings (from any source) from moving downstream and plugging the hydrocyclones and degasser, etc.

4. Degasser - The degasser is an important part of auxiliary equipment in solids removal. It removes gas and air from the mud by one of several designs - usually by imposing a partial vacuum and flowing the mud as a thin film over a solid surface. If gas is allowed to exist in a mud, it can interfere with the centrifugal pumps which feed the solids removal devices. Also, if not removed at an early point in the solids removal sequence, gas could spread throughout the mud pit area creating a serious hazard.
5. Hydrocyclones - hydrocyclones are the next piece of equipment in the processing sequence and must process more than 100% of the flow. These are cone-shaped devices which by their design cause fluid to spin within the cone. Mud which is under pressure enters tangentially at the large diameter of the cone. The mud spirals from the large end toward the small end of the cone. Solids are forced outward to the wall and then down the wall and exit at the adjustable opening at the small end of the cone. Mud goes back up the vortex finder in the center, exits at the large end and returns to the active mud system (*see Figure 6*).

Two sizes of hydrocyclones are commonly used for muds: **desanders** - 6-in. and larger diameter and **desilters** - smaller than 6-in. diameter. The desilter handles less volume per cone and requires more cones to process a given volume; but, it discards smaller-sized solids compared to the desander.

In general, hydrocyclones are not used on oil muds or on any type mud containing appreciable amounts of weighting materials because they will discard a high proportion of expensive materials.



6. Mud Cleaner - The mud cleaner is a combination solids removal device which consists of a bank of hydrocyclones that discard onto a screening device (a small shale shaker). The mud cleaner is used for cleaning weighted muds and also for recovering the expensive liquid portion of any mud (such as KCl or oil mud). The desilter must be operated as usual with sufficient head to process the weighted mud through the cones. The discharge from the desilter cones spray into a tray and then flow out onto the fine-mesh vibrating screen, usually 150 to 200 mesh, where most of the barite and liquid pass through. Some barite is discarded, especially when the mud cleaner is not being carefully monitored. Today, economics will usually suggest spending money on fine-mesh primary shale shakers rather than on mud cleaners in most situations where weighted muds are to be processed.
7. Centrifuges - Centrifuges are of two basic types: low-speed or high-speed decanting, and fixed-speed, perforated-rotor machines. When the feed stream to a decanting machine is a weighted mud (with dilution water), its underflow is a damp mixture of barite and some drill solids. This mix is usually returned to the mud as **recovered barite**. The liquid overflow is usually discarded from the mud system - and contains colloidal solids and chemicals.

The perforated-rotor machine runs at fixed rpm and provides a liquid overflow stream and a liquid underflow stream. It can be adjusted to do a wider variety of separations than can the decanting machine; but, it does not discard damp solids. The perforated-rotor machine is limited to weighted water-based muds.

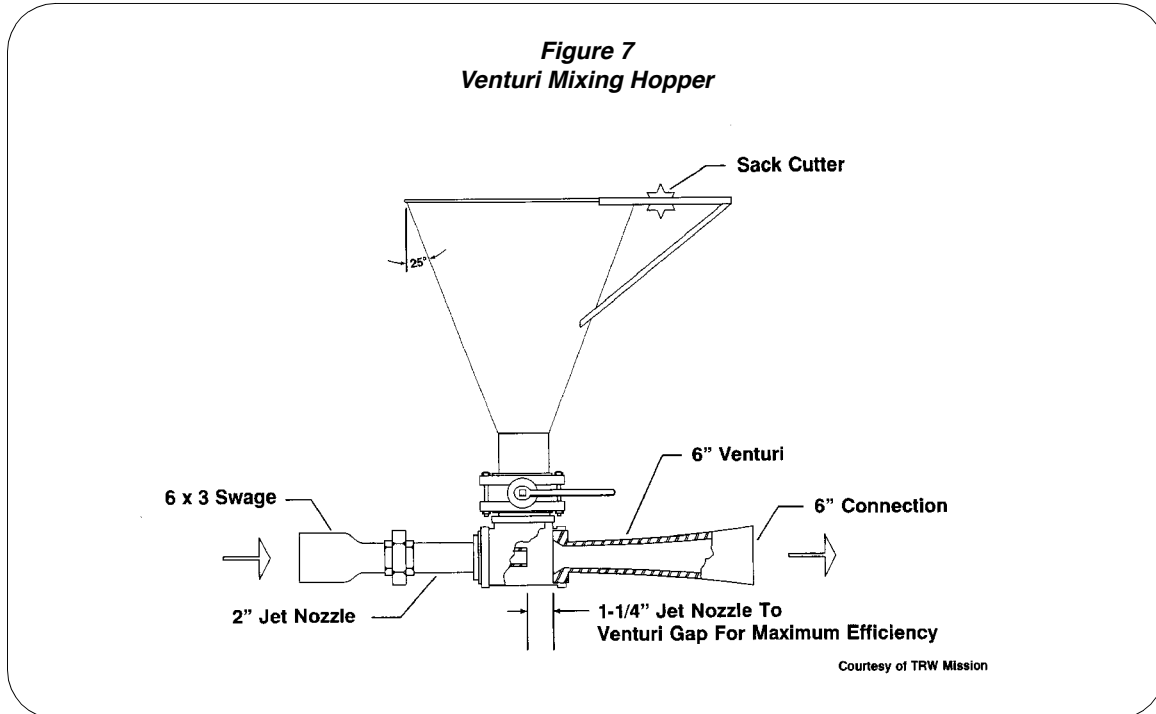
- a. For unweighted water-based muds - only the decanting type centrifuge is recommended. The damp underflow contains mostly drill solids and is discarded. The overflow contains the liquid phase and some silt materials and perhaps chemicals. In some cases, the centrifuge is fed from the underflow of hydrocyclones to increase the concentration of solids being processed to improve its efficiency.
- b. For weighted oil-based muds - where both liquid and solid phases are valuable, double centrifugation can be used. The primary low-speed centrifuge recovers barite. The liquid phase from the primary centrifuge is delivered to a second, high-speed centrifuge for silt removal. The liquid phase, with colloids, is returned to the active system. For unweighted oil-based muds, the decanting centrifuge can be used to remove unwanted drill solids and recover valuable liquid - oil and chemicals.

Today, as mud discards need to be less in volume and dryer for disposal purposes, one centrifuge may be used to feed its liquid overflow to another machine for further processing. This arrangement is generally used in **closed-loop** and **zero-discharge** operations.

Addition Region

The addition region of the mud system is downstream of the last solids removal device. It is the tank equipped with the mixing hopper, chemical barrel, mud guns, mixers-agitators, and perhaps special mixing/ shearing devices.

1. Mixing Hopper - Mixing hoppers are used to add dry materials to build and maintain a mud system. Where large quantities of dry materials are used, bulk hoppers normally gravity-feed dry materials into a rig mud hopper. Hopper mixing effectiveness depends upon design. Venturi-discharge hoppers have a venturi on the discharge side of the nozzle which provides the shearing action needed to mix dry materials (*see Figure 7*).
2. Chemical Barrel - Chemical barrels are used primarily to solubilize materials in water before adding them to the active mud system. Normally, this is a make-shift barrel with a valve installed to regulate flow. However, well designed and properly constructed, chemical barrels should be avail-



able on each rig for safety reasons. Causticizing materials are often mixed through a chemical barrel.

3. **Mud Guns** - Mud guns are useful to keep mud mixed and sheared; but, they can significantly lower the overall efficiency of solids control equipment if plumbed incorrectly. If guns must be used in the removal region, each mud gun's suction should be taken from the same tank that it discharges into. Otherwise, it is recommended that mud guns not be used in the removal region and agitators used instead.

Mud guns are of two types:

- a. high-pressure (3000 or 6000 psi) and operate from a rig pump, or
- b. low-pressure, operated from a centrifugal pump (*see Figure 8*).

Mud guns can be located either on the surface (surface mud guns) or beneath the surface (sub-surface mud guns). Surface mud guns are used to break up materials that float, such as lost circulation materials; but, they are prone to entrap air in the mud. Subsurface mud guns are useful to keep barite from settling.

4. **Mixers-Agitators** - Mixers-agitators should be properly sized, powered and positioned to prevent settling in corners of mud pits. They are generally recommended over mud guns for mixing. There are two basic impeller designs for these mixers-agitators. Radial flow impellers have vertical blades and are positioned close to the tank bottom. Axial flow impellers have canted blades, like propellers, and are positioned at 1/3 to 3/4 of the impeller diameter distance off bottom (*see Figure 9*).
5. **Mixing/Shearing Devices** - There are three types of mixing/shearing devices: (1) close-tolerance rotor/ stator, (2) high-pressure choke, and (3) counter-rotating shear (*see Figure 10*). Each of these devices produces a different degree of mixing and/or shearing.

Figure 8
Mud Guns

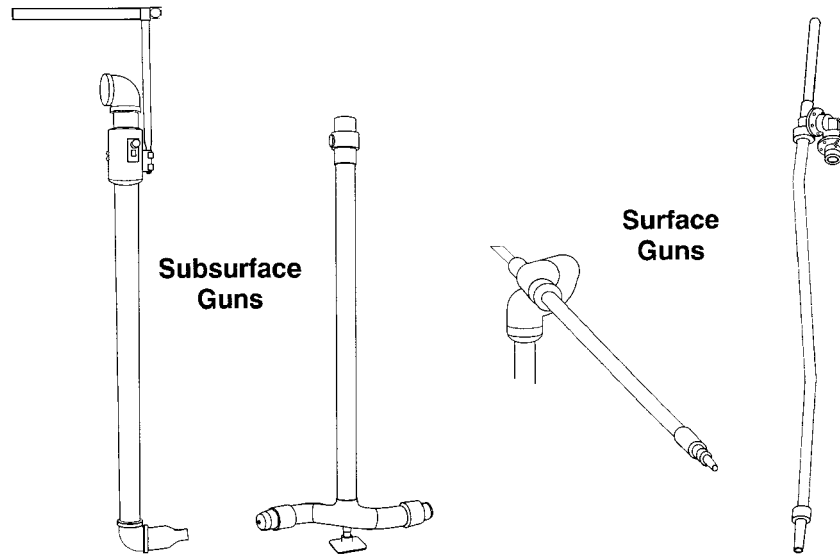
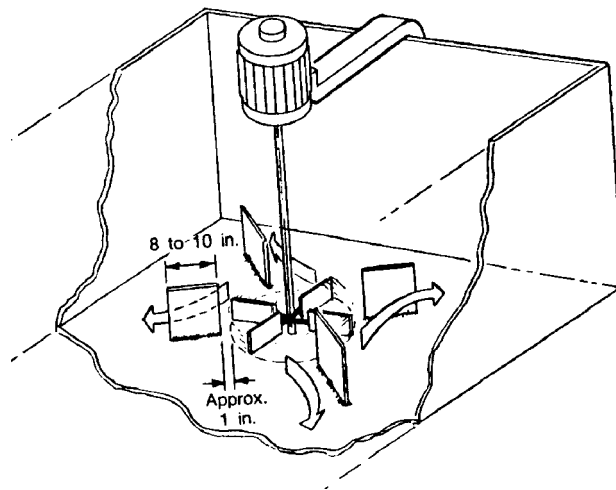
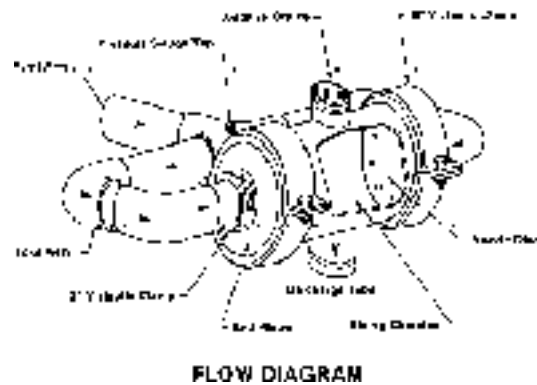


Figure 9
Mixer/Agitator



- a. Close-Tolerance Rotor/Stator Device - such as the **Seco-Colloid Mill**. This device produces high shear when fluid passes through a centrifugal pump that has been modified. Fluid is forced through a stationary perforated ring which is fitted over the impeller blades in the pump

Figure 10
Mixing/Shearing Devices



- housing. This design creates a high energy environment which is especially applicable to materials requiring high, prolonged shear to obtain suitable rheological properties.
- b. High-Pressure Choke Device - **Shear Master** from Petroleum Coordinators, produces mixing/shearing as fluid is pumped by a positive displacement pump through a restricted opening such as a choke or nozzle. As fluid accelerates through the restricted opening, both shear and water wetting of materials occurs.
 - c. Counter-Rotating Shear - **Jet Shear** from Flo-Trend, forces a split fluid stream to enter a mixing chamber by passing through jets in a disc on each end of the mixing chamber. The configuration of the jets on each disc produces a counter-rotational flow which hydraulically water wets materials. Water wetting is essential for proper dispersion when mixing polymers such as PAC, PHPA, etc. The counter-rotational shear device does not produce a high shear energy environment; therefore, it does not cause shear degradation of long chain, high molecular weight polymers.

Mixing/shearing devices greatly improve rigsite mixing. For hard-to-mix materials such as Aqualon HP-007, sepiolite and attapulgite clays, which require extremely strong and/or

long-term shearing to viscosify, high-shear devices such as the Polygator or Shear Master should be used. Oil-based muds require shear to form a stable emulsion. They are normally mixed at the supplier's mud-mixing plant; however, any of the three mixing/shearing devices could be used to mix oil-based muds on location and thereby reduce the potential for a transporting accident. Although mixing/shearing devices greatly improve rigsite mixing capabilities, these devices should never be used in the active mud system because of their ability to break up drill solids.

Mud Check (Suction) Region

In the Mud Check Region the mud has already been processed by solids control equipment, chemicals added and density adjustments made. This region is commonly known as the suction pit and is where the In mud sample is taken for testing. It is critical that mud leaving this pit have enough volume and retention time so that it is always uniform in density, chemistry, solids content, etc.

Basics of Solids Removal Devices

Mechanical solids removal devices selectively separate solids either through size differences, mass differences or both. Shale shakers use screens; hydrocyclones and centrifuges use centrifugal force. Understanding what are the key design factors and optimum operating limits for each of these devices will enable one to determine whether a particular device is needed, how to properly size the unit and how to properly use it. [For more information, refer to Amoco's Solids Control Manual.]

Basics of Shale Shakers

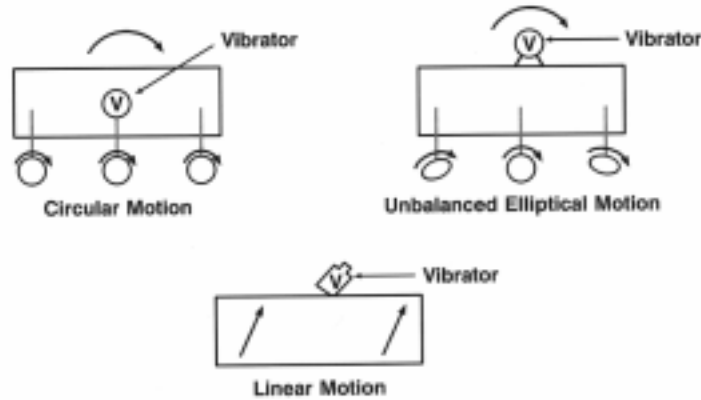
The characteristics of shale shakers are: (1) vibratory motion, (2) amplitude and frequency, (3) deck slope and number of decks of screens, and (4) screening area.

1. **Vibratory Motion** - There are three types of shale shaker screening motion: circular, unbalanced elliptical and linear (see *Figure 11*) Each is differentiated by the positioning of the vibrator(s) with respect to the center of gravity of the deck. Circular motion is produced when the vibrator is placed at the center of gravity of the deck; whereas, elliptical motion is produced when the vibrator is placed above the center of gravity. For elliptical motion, the screen deck must be sloped to convey solids; however, sloping reduces fluid capacity. Linear motion is produced when two vibrators are synchronized to rotate in opposite directions. This linear motion produces a uniform conveyance of cuttings. Screen decks can either be flat or sloped slightly uphill.
2. **Amplitude and Frequency** - The throughput capacity of shakers depends on three parameters: amplitude and stroke, vibratory motion and vibrator speed. Amplitude is defined as the maximum screen displacement perpendicular to the position of the screen. Stroke is defined as being twice the amplitude. Vibratory motion, defined previously, is either circular, unbalanced elliptical or linear. The vibratory speed is the speed at which the vibrator moves. For a shale shaker to perform effectively, it must separate as well as convey solids. Both are functions of acceleration (g factor where g = acceleration equal to the force of gravity). This g factor is defined by the equation below:

$$g \text{ factor} = \frac{(\text{stroke, inches})(\text{RPM})^2}{70,400}$$

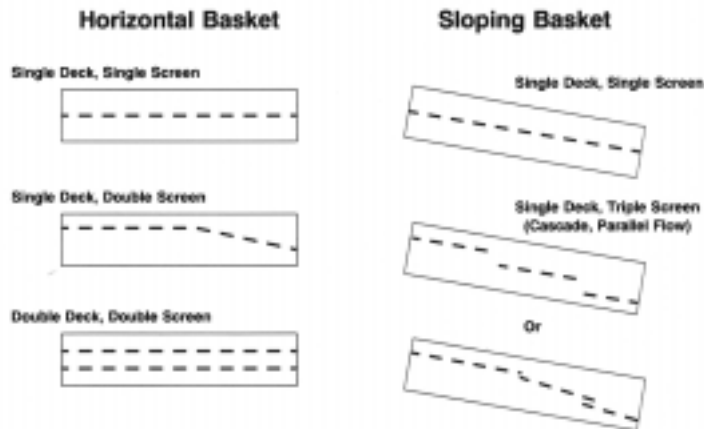
A higher g factor gives better solids separation; however, it will also reduce screen life. Proper screen tensioning is critical with high g shale shakers. Most circular-motion shakers have an acceleration of 4-6 g's. Most linear motion shakers have an acceleration of 3-4 g's.

Figure 11
Shale Shaker Motion



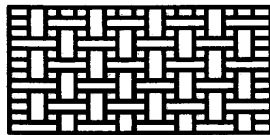
3. Slope and Number of Screen Decks - A screen deck (or basket) is vibrated to assist the throughput of mud and movement of separated solids (see Figure 12). Shale shakers that use an elliptical motion usually have divided decks with screens placed at different slopes in order to provide proper discharge of cuttings. Sloped-deck units can have one screen covering the entire deck length, or have a divided deck which has more than one screen used to cover the screening surface, or with individual screens mounted at different slopes. Multiple-deck units have more than one screen layer. In a 2 or 3-deck unit, mud must pass through one screen before flowing through the second, etc.

Figure 12
Deck Slope & Number of Decks

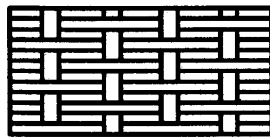


4. Screening Area - Shale shaker screening is the primary means of solids separation. If the shale shaker is not working correctly or if the screens are incorrectly sized or torn, efficiency is drastically reduced. Screening action depends on the vibrating action to make mud flow through it. Vibration under mud load creates stresses on the screen and if the screens are not properly installed and supported, they will quickly wear or tear.
 - a. Screens are available in square, rectangular and layered design. API has set standards on screen identifications. Screens are labelled with the following: separation potential (216, 250, 284), conductance and area. This notation is necessary because so many variables are possible in screen manufacture - wire size being the most significant.
 - b. Weave of wire cloth and mesh count are two interesting design variables. (Figure 13 shows four weaves: plain square weave, rectangular opening, plain dutch weave and twilled square weave.) The square and rectangular weaves are the types most often used.

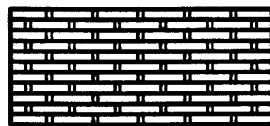
Figure 13
Screen Cloth Weaves



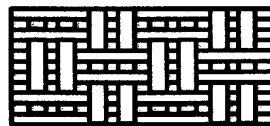
PLAIN SQUARE WEAVE



RECTANGULAR OPENING



PLAIN DUTCH WEAVE



TWILLED SQUARE WEAVE

1. **PLAIN SQUARE WEAVE**
Providing a straight through flow path with the same diameter warp and shute wires in and over and under pattern. This is the most common weave producing the same mesh count vertically and horizontally.



2. **RECTANGULAR OPENING**
Provides maximum open area and tends to prevent binding or clogging of material. Does not build up on the longer openings and smaller dimension controls the sizing of material.



3. **PLAIN DUTCH WEAVE**
Provides a tapered opening reducing flow rate. Warp wires are heavier in a plain weave and shute wires are driven close and crimped at each pass.



4. **TWILLED SQUARE WEAVE**
With the pattern of over two wires and under two wires, this weave produces a diagonal effect. To provide greater strength and corrosion resistance, a larger diameter wire can be woven.



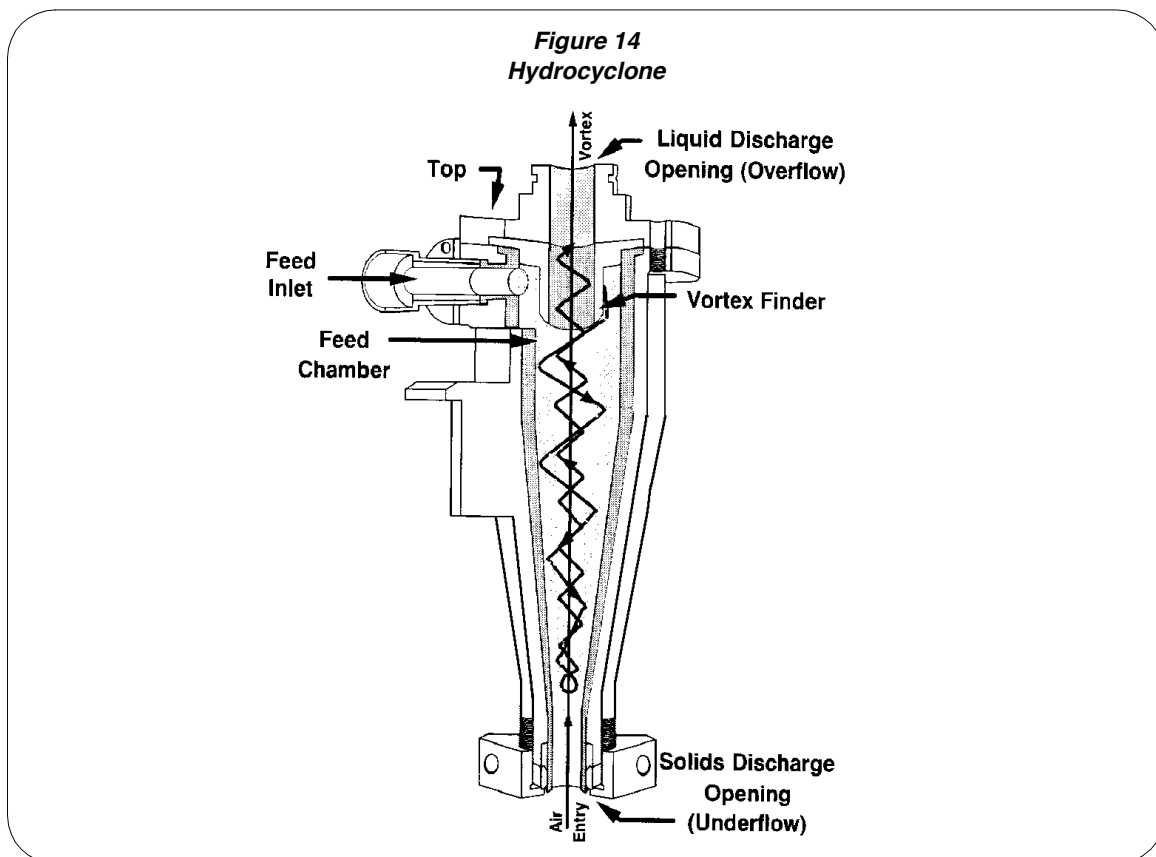
Since the thickness (diameter) of the wire used to weave a screen can be varied for the same mesh, actual aperture or opening dimension in either direction can be used to describe a screen. Where the opening is small, a micron scale eliminates the use of decimals or fractions. There are 25,400 microns to the inch. Thus, an opening of 0.0213 in., which is roughly the opening in a 30-mesh screen, has a dimension of 541 microns. Both open area and conductance are terms used to describe and compare screens. Although percent open area is related to the ability of a screen to handle flow rate, conductance is a much better measure of the amount of fluid that will pass through a screen. The flow rate of a shale shaker is directly related to the area the liquid can fall through.

Mesh Count is the term most often used to describe a square of rectangular screen cloth. Mesh is only an indicator of the size opening as it is the number of openings per linear inch counting from the center of a wire. A mesh count of 30 x 30 indicates a square mesh having 30 openings/in. in both axis directions; a 70 x 30 mesh indicates a rectangular opening having 70 openings/in. in one direction and 30 openings per inch in the other.

A square mesh screen will generally remove more solids and make a finer cut than a rectangular mesh having one dimension the same as the square mesh, and the other one larger. The main advantage of the rectangular mesh screen is that it does not blind as easily. Another advantage of a rectangular mesh is that it can be woven with heavier wires, which offer longer screen life. Also, it has a higher percentage of open area and higher conductance which increases the fluid volume capacity of the shale shaker.

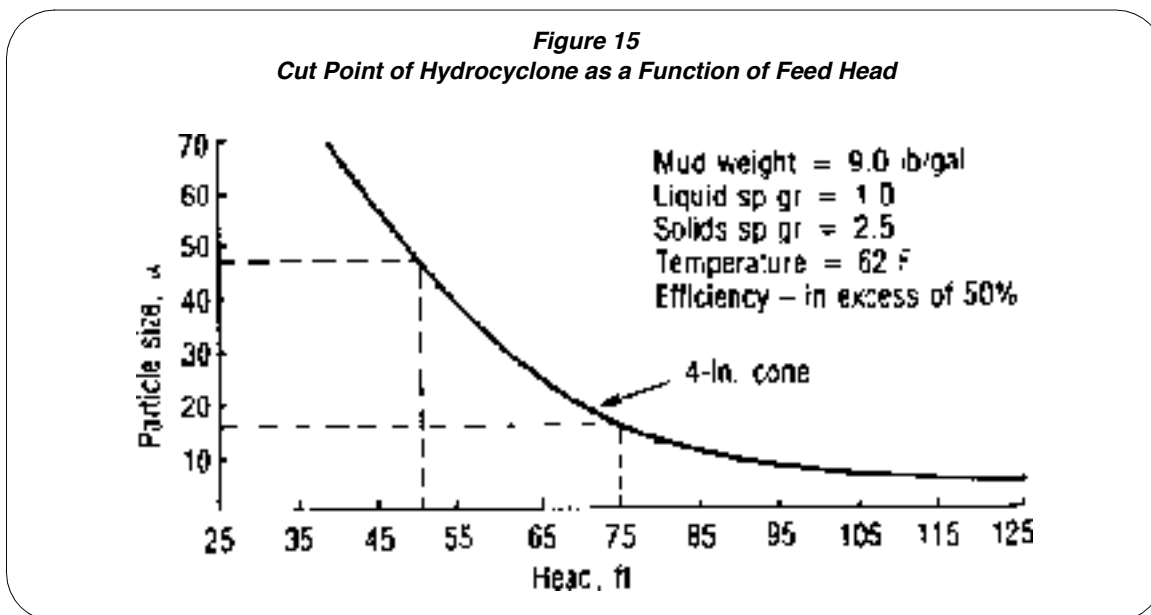
Basics of Hydrocyclones

(Figure 14 shows a cut-away drawing of a hydrocyclone.) It has no moving parts, only the mud moves. Mud enters the upper, large cylindrical section tangentially to cause spiralling fluid flow. As fluid spirals toward the smaller end, this creates centrifugal force to make particles move toward the outer wall and then downward toward the opening at the bottom of the cone. Mud returns to the system out the top center through the **vortex finder** opening.



The so-called **cut-point** of hydrocyclones is the size of particle (sand in water) that has 50:50 chance of either exiting at the bottom of the cone for discard or returning to the mud through the vortex finder. A published cut-point is not directly applicable to muds because of differences in fluid viscosities and particle size, shape, and composition. (Figure 15 shows cut point for a mud based on the amount of

feed head. Cut point is a function of cone size, mud viscosity, feed pressure, or centrifugal forces developed due to velocity.) Without sufficient feed pressure from the pump, the hydrocyclones will not work as well as they should.



To operate a hydrocyclone in **balanced** condition, the flow out the bottom discharge opening should be a slow spray of liquid and solids. An opening which is too large will discharge too much liquid; an opening which is too small will retain too many solids. When a mud is loaded with drill solids, the cone may eject the solids in a **rope**. This means the cut point is not as small as it would be if it were operating in spray discharge. Roping is not the normal operating mode, because solids are not being removed at top efficiency. If roping is a continual problem, a larger number of desilter cones or finer shaker screens should be used to lighten the load.

Hydrocyclones should not be operated for very long on a weighted mud because barite will be discarded due to its higher density. For example, a barite particle of 50 microns diameter will be processed the same as a drill solid particle of 74-microns diameter.

Basics of Centrifuges

Centrifuges are devices that rotate the mud in a bowl to generate high centrifugal forces causing solids to move toward the outside for removal. Two types of machines (*refer to Figure 16 and 17*) are used for drilling mud processing: decanting-type that delivers a liquid overflow and a moist underflow, and perforated-rotor type that delivers a liquid underflow and liquid underflow.

1. Decanting Centrifuges - Decanting centrifuges have a cylindrical-to-conical shaped bowl that rotates at approximately 1000-4000 rpm. A conveyor screw is geared with the bowl and turns at a slightly slower speed to scrape the centrifuged solids out of the **pool** onto the **beach** for discharge (*see Figure 16*). Design and control parameters for a decanting centrifuge are: bowl diameter; shape and speed; water and mud feed rates; and pool depth. Mud is usually fed into the machine by a positive displacement pump. If the feed mud is weighted, it is usually commingled with feed water to cut the mud viscosity within the machine. In a typical **barite recovery mode**, the underflow is put back into the mud and the overflow is discarded as a way of getting rid of very fine solids in a weighted mud. In another mode, the underflow is discarded and the overflow is returned to

the system. This process would return expensive fluid to the system while discarding solids. This overflow can also be further processed by another higher g-force machine in which the underflow is discarded to get rid of the fines before returning the overflow to the mud. This operation depends on density of the mud and the relative value of the liquid versus solid phase of the mud.

Figure 16
Hydrocyclone

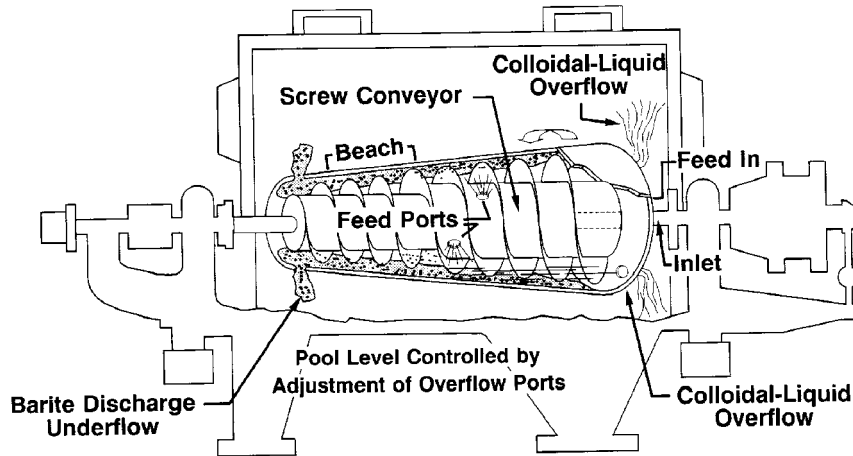
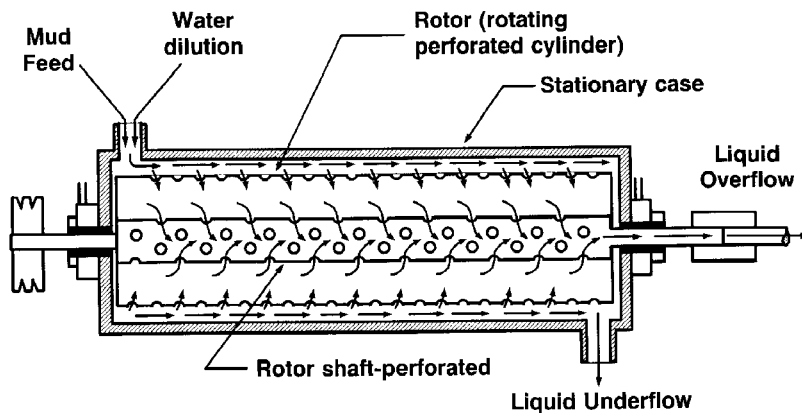
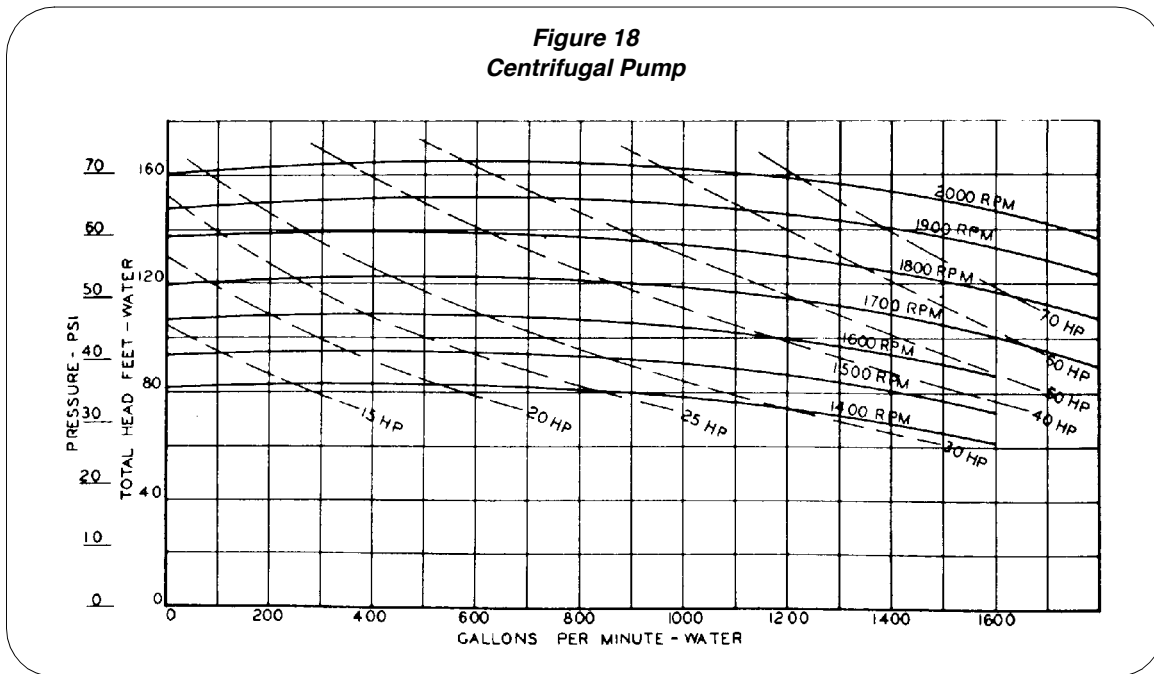


Figure 17
Perforated-Rotor Centrifuge



2. Perforated-Rotor Centrifuges - This type machine has an inner spinning cylinder, with holes in it, inside a case (see Figure 18). Design and control parameters for perforated-rotor machines are: rotor diameter, outer case diameter, and water and mud feed-rate ratios. Variables in design of these machines are: rotor diameter, outer case diameter, rotor speed, water and mud feed rate. Denser and larger particles are thrown to the outer diameter of the inner cylinder where they pass through the holes, while lighter and smaller particles go to the center and exit there. This machine

is not suited for processing unweighted muds because the discards are a liquid slurry. It is more suited for weighted muds to reclaim dense materials as a slurry while discarding fines as a slurry.



Basics of Centrifugal Pumps

Centrifugal pumps contain an impeller inside a housing. Mud is pumped at constant head by the spinning action of the impeller. Head is controlled by impeller diameter and speed. Flow rate is controlled by head loss in the suction and discharge piping. Impeller velocity is kept constant by its drive motor, regardless of fluid density. Choosing the correct pump and motor for a specific application requires consulting pump curves. A pump's size is normally defined by the size of the discharge and suction flanges. A 4 x 5 pump has a 4-in. discharge and 5-in. suction flange. To evaluate a pump, one must know the pump size, its rpm, and impeller diameter (*see Figure 18*).

The following rules apply to centrifugal pumps:

- Centrifugal pumps do not have a fixed flow rate.
- Discharge head is independent of mud density.
- Discharge head is changed by changing the impeller speed and impeller size.
- Discharge pressure is linearly proportional to mud density.
- Power consumed increases as mud density increases.
- Power consumed increases as flow rate increases.

Dewatering and Zero-Discharge Solids Control

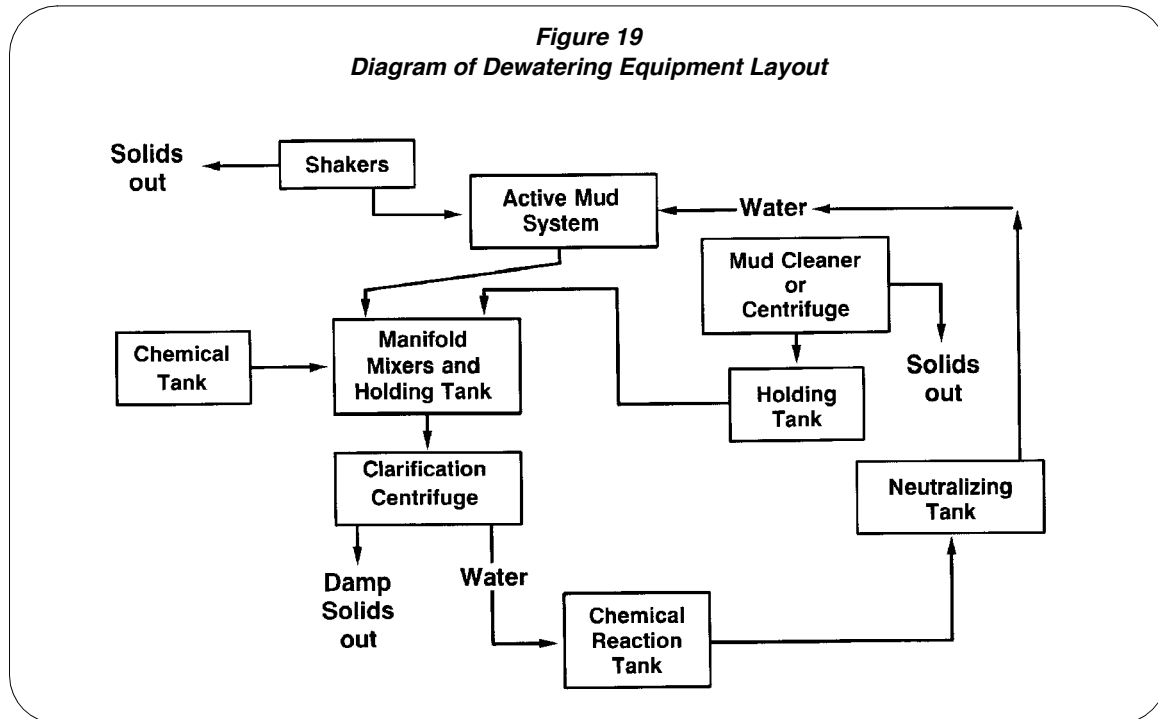
Rightsite dewatering of a mud removes fine solids and recovers usable water. The process usually involves adding acid to the mud to obtain a pH of 6 to 8, followed by a coagulant and a chemical flocculant (if needed) to cause the less than 2-micron solids to form aggregates large enough to be removed by centrifugation.

The water that is recovered can be almost clear or it can be murky or muddy as controlled by the amount of flocculant used and as dictated by the type of disposal or reuse requirements. For disposal into a local stream or into a water treatment system, clear water will likely be required, with low chlorides, neutral pH and no soluble metals or other contaminants. For disposal by injection into a well, the water may also need to be clear and polymer free to avoid plugging of the permeable zone. Water can be murky or muddy, if pumped into a fractured formation.

Solids separated by the unit's centrifuge will usually feel fairly dry but may still contain 20 to 40% liquid by volume. This will depend on the efficiency of the machine and how it is set to operate. Dampness may be acceptable for disposal into a local dump site or for on-site burial. Here again, salt and heavy metal content of the solids must be low.

Dewatering is usually undertaken to comply with local, state or federal environmental requirements. However, it can prove to be economically beneficial by keeping disposal volumes low, saving cost of water and minimizing future environmental liability.

Dewatering involves the following steps using the equipment shown in the diagram of *Figure 19*.



Step

1. Mud from the active system is drawn into a tank or taken directly into the injection manifold. This mud has previously been tested by the dewatering operator to determine volume of dilution water, amount of acid (to lower pH) and amount and kind of flocculant (polymer) or coagulant (alum or ferric salt) to be used. This testing involves a series of **bottle-shake tests** after which the dewatering operator compares the degree of clarification with what is desired.
2. Using the bottle-shake test results as a guide, the operator sets up the injection rate to give the desired concentration of water, acid and flocculant. The treated mud is then circulated in the holding tank to allow time for coagulation to occur before passing the fluid on to the next step, the centrifuge.

3. The treated fluid goes next into the clarification centrifuge, with dilution water if needed. Inside the machine, the solids are thrown outward and discarded. Water exits the machine as clear, murky or muddy water, which can be fine-tuned by the injection rate of coagulant and flocculant pumped into the manifold.
4. The water from the centrifuge is stored in a neutralizing tank. This is where the dewatering operator or mud engineer will test and adjust its **chemistry** before it is put back into the mud. The usual adjustment is to raise pH to offset the effects of the acid added upstream and treat out hardness, if needed. In some cases, this tank is partitioned for the pre-hydration of bentonite or polymers.

In summary, the dewatering process is an important aspect of a zero-discharge or closed-loop solids control system. This must work in conjunction with the normal solids removal devices on a rig. The chemicals for dewatering must be compatible with chemicals used in the mud - otherwise they must be removed from the water before reuse in the mud.

Section 6 Rheology and Hydraulics

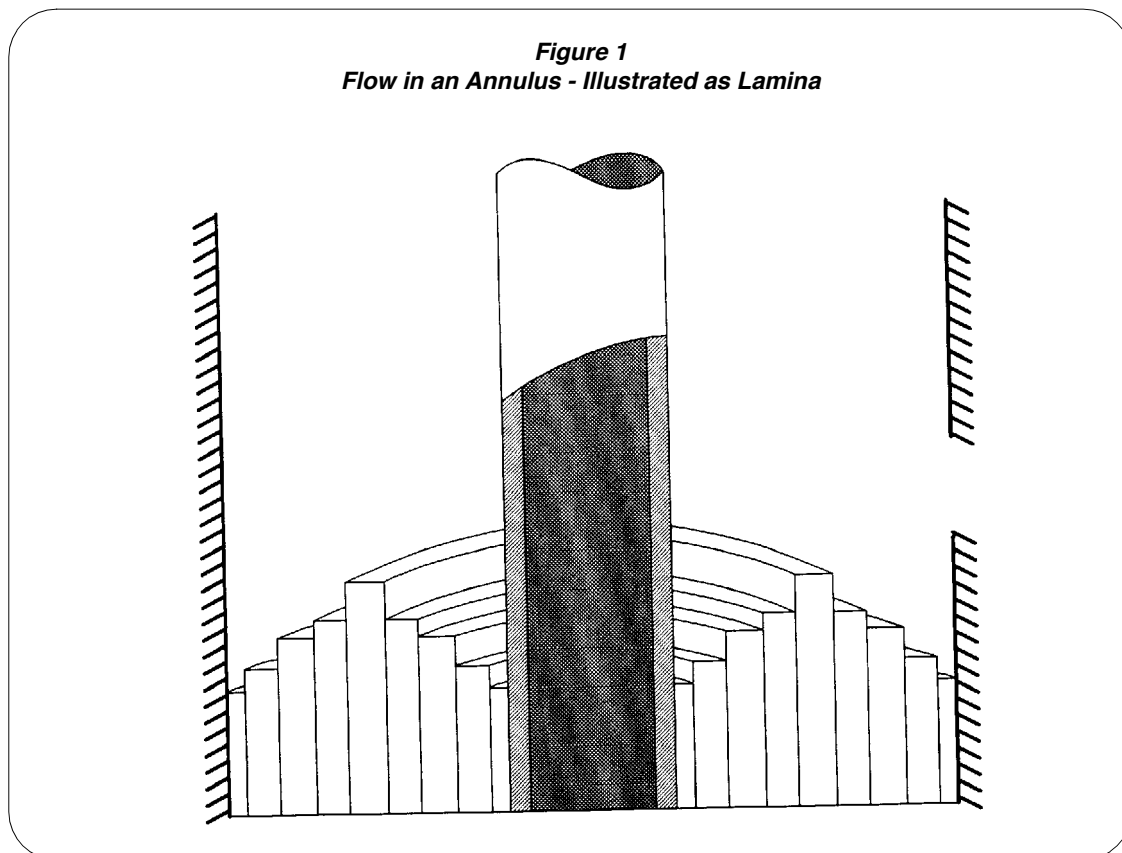
Rheology

Introduction

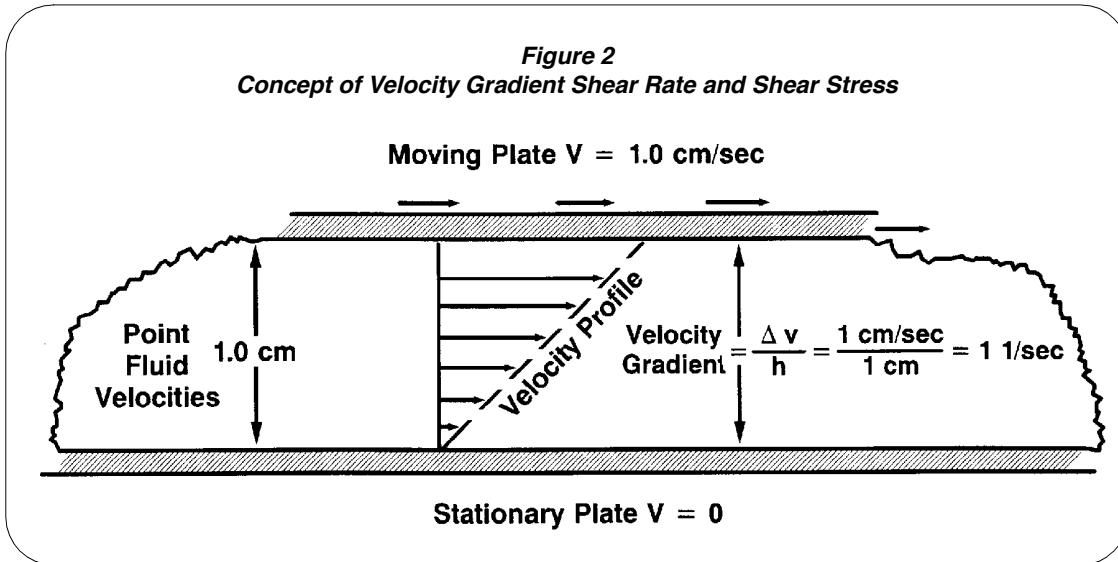
Rheology is the study of the deformation and flow of matter. The study of rheology is important because it allows the drilling fluid to be specifically analyzed in terms of fluid flow profile, viscosity, hole cleaning ability, pressure loss, equivalent circulating density - in general, wellbore hydraulics.

Velocity Profile

Figure 1 depicts a fluid flowing up an annulus. A force exists in the fluid which resists fluid flow. This force, shear stress, is analogous to the friction arising when one fluid layer moves past another. The fluid velocity increases progressively away from zero at the walls to a maximum near the center of the annulus. This occurs because it is easier for each fluid layer to move past another fluid layer than to move past the walls. The rate at which a fluid layer moves past another is called "shear rate".



The concept of shear stress and shear rate is further developed in Figure 2.



Shear Stress (τ)

Shear stress is the force required to sustain a particular type of fluid flow. In laminar flow, shear stress is the frictional drag existing between individual laminae.

$$\tau = \frac{\text{Force}}{\text{Area}}$$

This is expressed as lb/100 ft², or as Dynes/cm².

Note: 1 Dyne/cm² = 4.79 lb/100ft²

Shear Rate (γ)

This is the relative velocity of one lamina moving by adjacent lamina, divided by the distance between them.

$$\gamma = \frac{\text{Velocity}}{\text{Distance}} = \frac{\text{cm/sec}}{\text{cm}} = \frac{1}{\text{sec}} = \text{sec}^{-1}$$

This is expressed in sec⁻¹ (reciprocal seconds).

Note: 1Sec⁻¹ = 1.703 x RPM. (where RPM is on a Fann VG meter.)

Viscosity (μ)

Viscosity is the representation of a fluid's internal resistance to flow, defined as the ratio of shear stress to shear rate. Viscosity is expressed in poise.

$$\mu = \frac{\text{shear stress}}{\text{shear rate}} = \tau/\gamma$$

As previously defined:

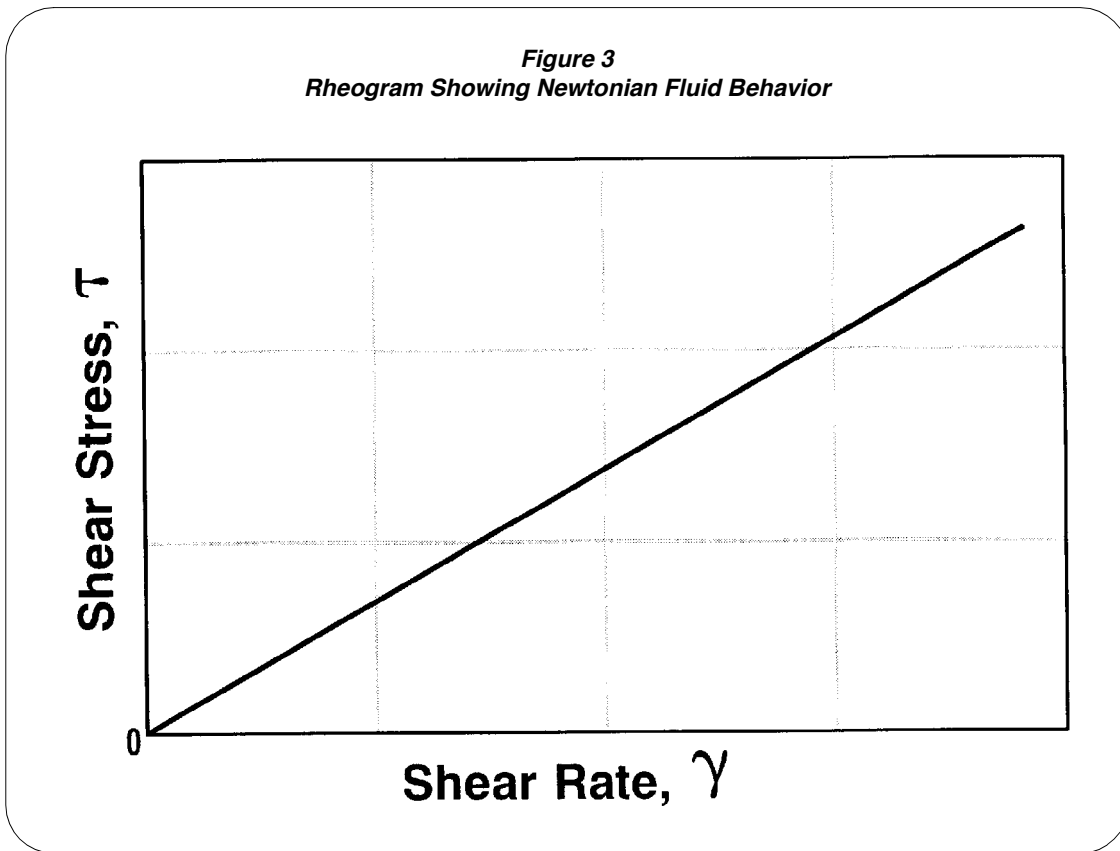
$$\mu = \frac{\text{Dyne} \cdot \text{sec}}{\text{cm}^2} \text{ (defined as poise)}$$

A poise is a very large number and therefore, viscosity is typically reported in centipoise (100 centipoise = 1 poise).

Newtonian Fluids

Newtonian fluids are those in which the viscosity remains constant for all shear rates providing temperature and pressure conditions remain constant. Examples of Newtonian fluids are water, glycerine and light oil. In these fluids, the shear stress is directly proportional to the shear rate, as shown in Figure 3. The rheogram curve of a Newtonian fluid is a straight line passing through the origin. The origin is the starting point on the graph of both the vertical and horizontal axes. The slope of the curve defines viscosity where g is the shear rate and t is the shear stress. Because m (viscosity) does not change with rate of shear, it is the only parameter needed to characterize the flow properties of a Newtonian fluid. Most drilling fluids are not this simple.

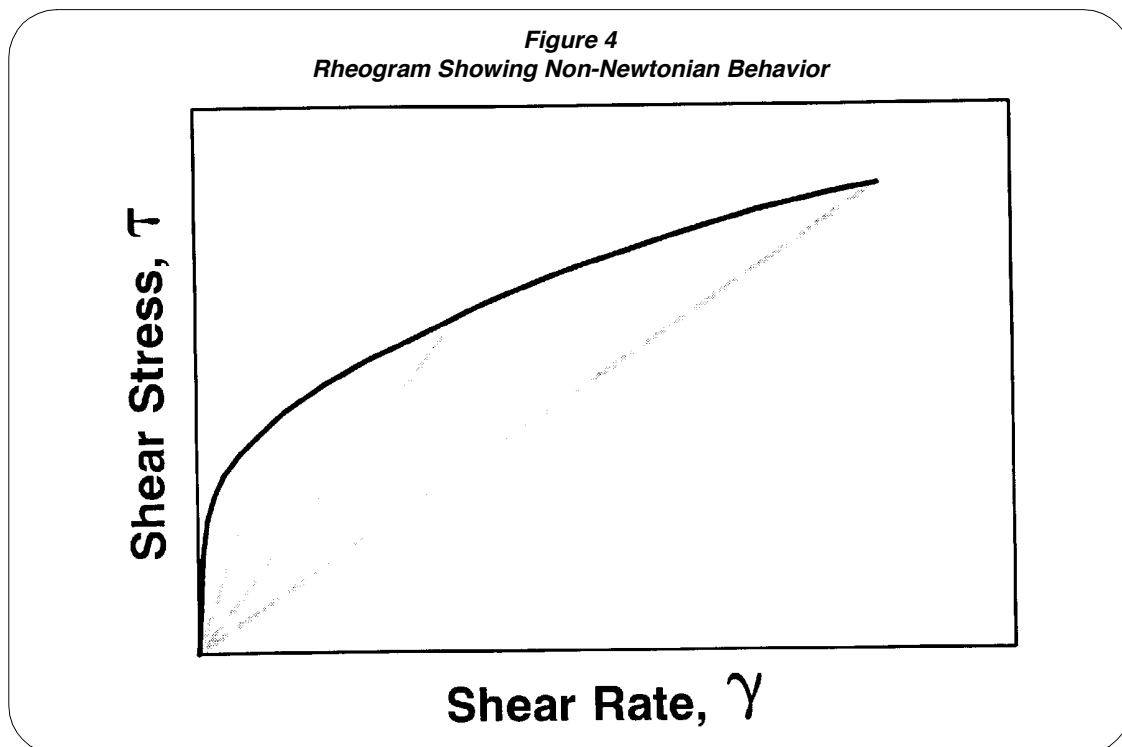
$$\mu = \tau/\gamma$$



Non-Newtonian Fluids

Non-Newtonian fluids (most drilling fluids fit this general classification) do not show a direct proportionality between shear stress and shear rate. The ratio of shear stress to shear rate (viscosity) varies with shear rate and the ratio is called “effective viscosity”, but this shear rate must be identified for each effective viscosity value.

An example of a non-Newtonian shear stress/shear rate (slope of the dashed lines) shear rate relationship is shown in Figure 4. Note that the ratio of shear stress to shear rate differs at each shear rate. The viscosity of non-Newtonian fluids is known as effective viscosity and the shear rate must be specified. Figure 5 shows that the effective viscosity decreases as the shear rate increases. This effect is called “shear thinning”.

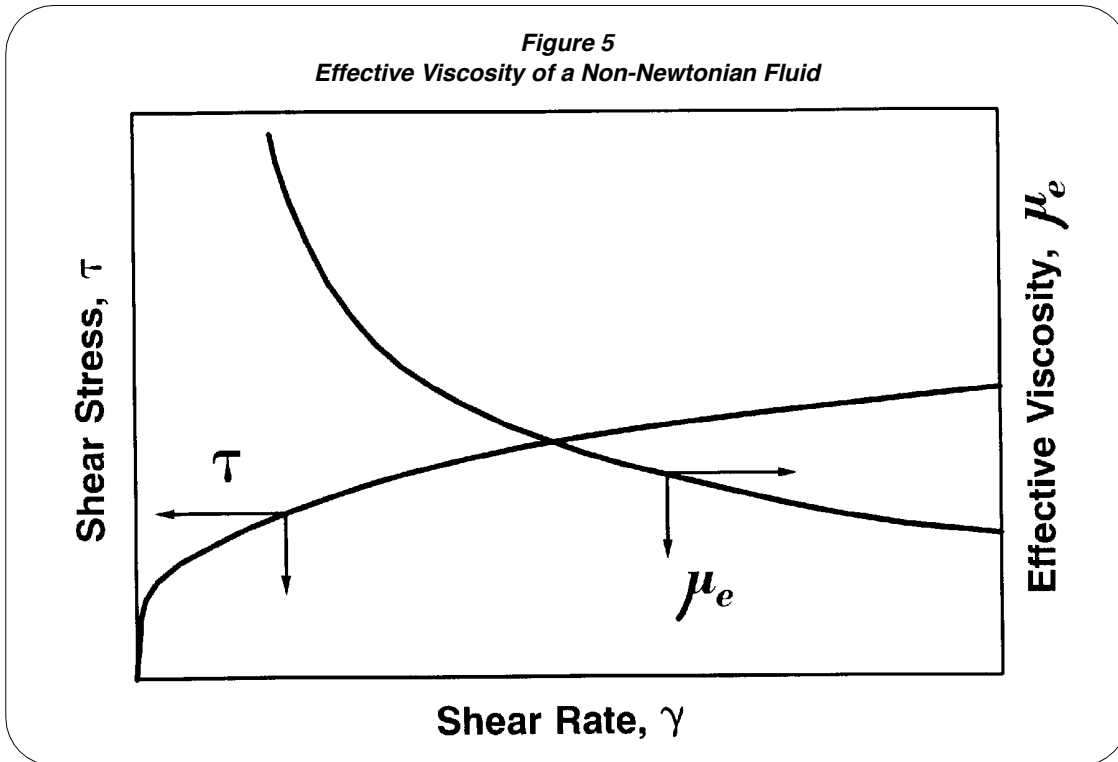


Non-Newtonian fluids are classified into four major categories:

- Those with properties independent of time,
- Those with properties dependent on time,

The first two categories are of principal concern to drilling fluids. There is a further subdividing of these categories as follows:

- Time Independent, Non-Newtonian Fluids
 - Bingham plastic fluids
 - Pseudoplastic fluids
 - Dilatant fluids
- Time Dependent, Non-Newtonian Fluids
 - Thixotropic fluids



Bingham Plastic Fluids

These fluids yield a straight-line relationship between shear stress and shear rate that does not pass through the origin. A finite shear stress is required to initiate flow. The value of this shear stress is called the “Yield Point” (Figure 6).

The Bingham Plastic Model is the most widely used mathematical rheological model in the oil field. All data are generated from the 600 and 300 readings on a VG Meter. The model assumes that the fluid evaluated acts in a linear manner on the shear rate - shear stress curve, but has a positive yield stress (Figures 7 and 8).

The equation for the Bingham Plastic model is:

$$\tau = PV(\gamma/300) + YP$$

Where

$$\text{Plastic Viscosity (PV)} = q600 - q300$$

$$\text{Yield Point (YP)} = q300 - PV$$

Common terms associated with the Bingham plastic model are: Plastic Viscosity (PV), Apparent Viscosity (μ_a), Yield Point (YP) and gel strengths. Most drilling fluids, as seen in Figure 7, do not conform exactly to the Bingham plastic model or to any universal model, but drilling fluid behavior can usually be approximated with acceptable accuracy. The Bingham Plastic model assumes that the curve (Figure 9) is approximated by a straight line. This is seldom true for drilling fluids, especially at low shear rates found in the annulus, (Table 1).

Figure 6
Rheogram Showing Bingham Plastic,
Pseudoplastic and Dilatant Fluids Behavior

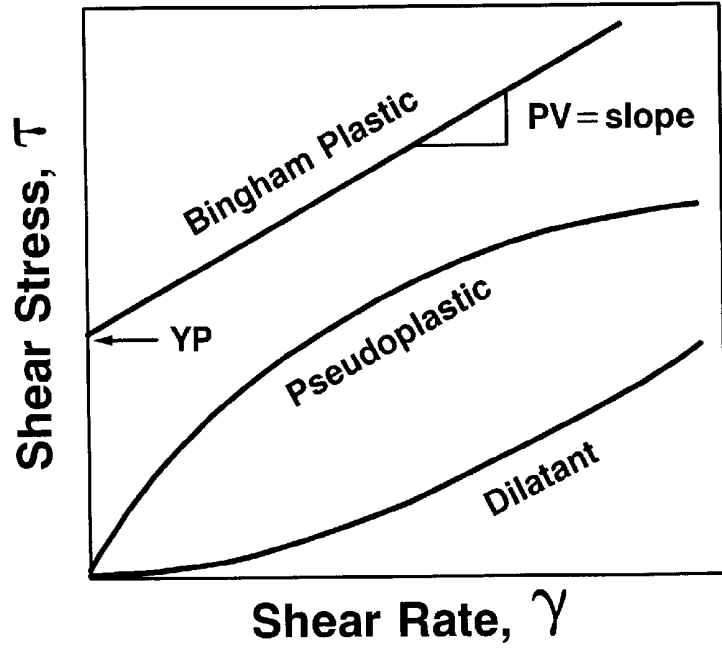


Figure 7
Shear Stress - Shear Rate Curves

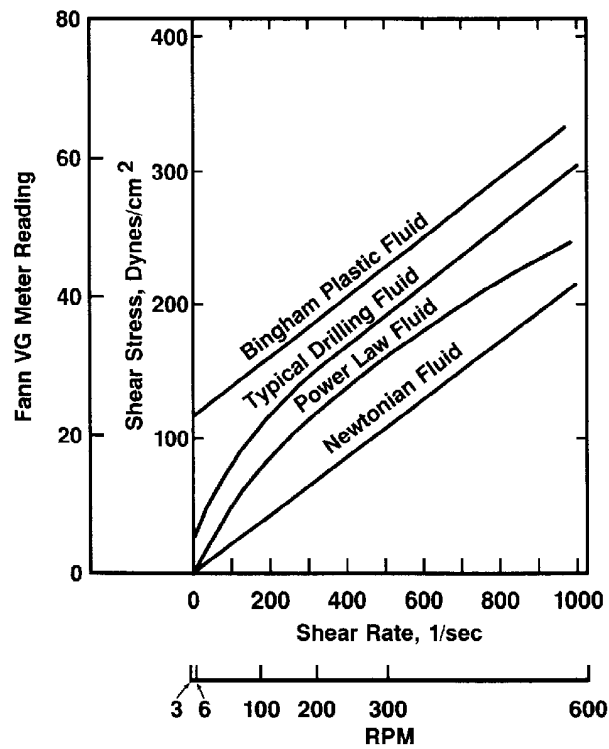


Figure 8
Viscosity - Shear Rate Curves

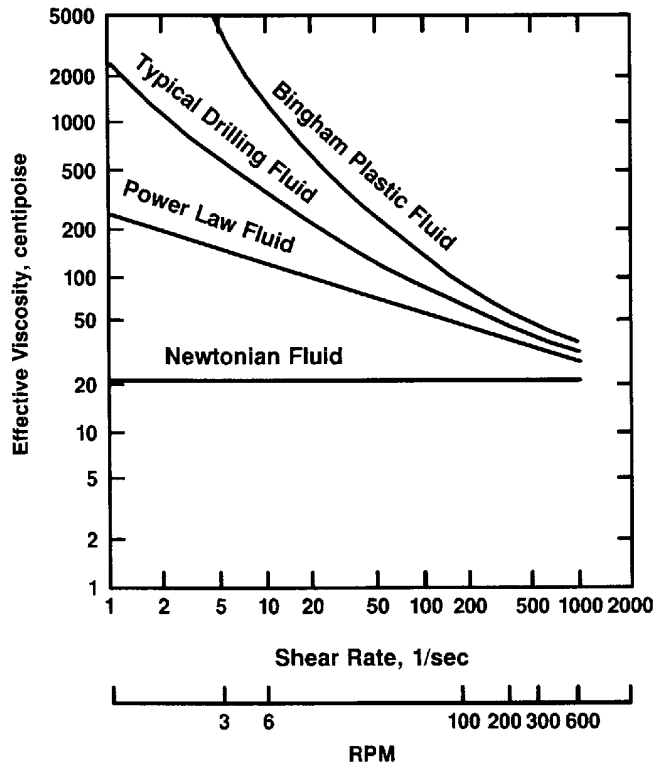


Figure 9
Bingham Plastic Model Parameters

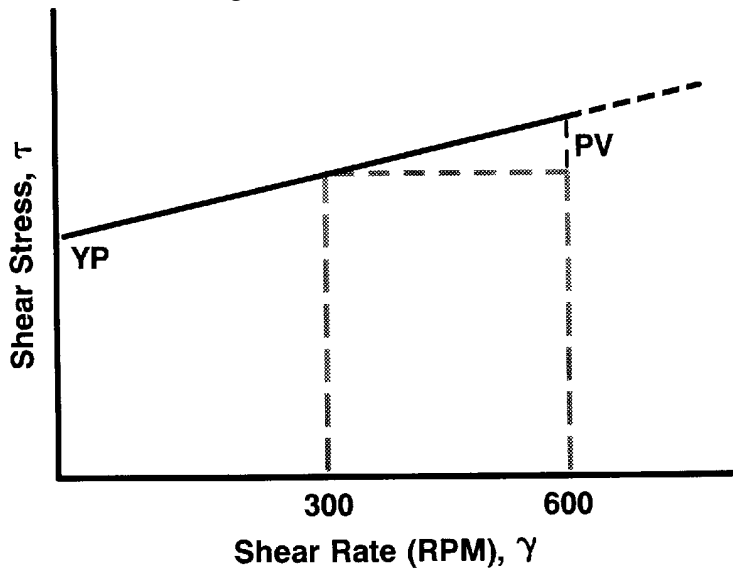


Table 1
Shear Rates in a Circulating System

Location	Shear Rate, sec⁻¹
Drill Pipe	100 - 500
Drill Collars	700 - 3000
Bit Nozzles	10,000 - 100,000
Annulus	10 - 500
Mud Pits	1 - 5

Plastic Viscosity (PV) - Drilling muds are usually composed of a continuous fluid phase in which solids are dispersed. Plastic viscosity is that part of the resistance to flow caused by mechanical friction. The friction is caused by:

- Solids concentration,
- Size and shape of solids,
- Viscosity of the fluid phase.

For practical field applications, plastic viscosity is regarded as a guide to solids control. Plastic viscosity increases if the volume percent of solids increases, or if the volume percent remains constant, and the size of the particle decreases. Decreasing particle size increases surface area, which increases frictional drag. Plastic viscosity can be decreased by decreasing solids concentration or by decreasing surface area. Plastic viscosity is decreased by reducing the solids concentration by dilution or by mechanical separation. As the viscosity of water decreases with temperature, the plastic viscosity decreases proportionally. Therefore, controlling PV of a mud in practical terms involves controlling size, concentration and shape of the solids and minimizing the viscosity of the liquid phase - such as avoiding viscosifying polymers and salts unless absolutely needed.

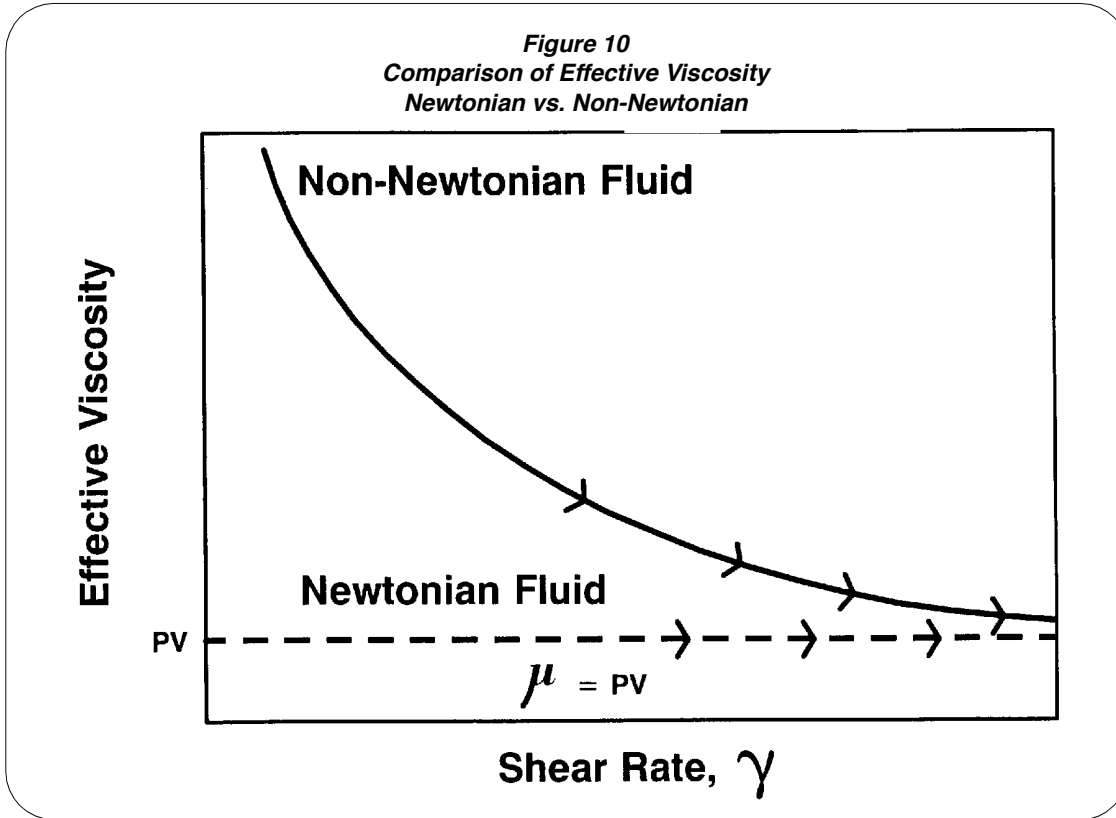
The value of plastic viscosity is obtained by subtracting the 300 RPM reading from the 600 rpm reading (Figure 9).

$$PV = \theta 600 - \theta 300$$

PV of a mud is the theoretical minimum viscosity a mud can have because it is the effective viscosity as shear rate approaches infinity. The highest shear rate occurs as the mud passes through the bit nozzles; therefore, PV will approximate the mud's viscosity at the nozzles. This is illustrated in Figure 10, where the effective viscosity of the mud approaches the value of plastic viscosity at high shear rates.

Yield Point (YP) - The yield point is the initial resistance to flow caused by electrochemical forces between the particles. This electrochemical force is due to charges on the surface of the particles dispersed in the fluid phase. Yield point is a measure of these forces under flow conditions and is dependent upon:

- The surface properties of the mud solids,
- The volume concentration of the solids and



- Ionic environment of the liquid surrounding the solids.

High viscosity resulting from high yield point is caused by:

- Introduction of soluble contaminant (ions) such as: salt, cement, anhydrite or gypsum, which interact with the negative charges on the clay particles,
- Breaking of the clay particles through mechanical grinding action creating new surface area of the particles. These new charged surfaces (positive and negative) pull particles together as a flocs.
- Introduction of inert solids (barite) into the system, increasing the yield point. This is the result of the particles being forced closer together. Because the distance between the particles is now decreased, the attraction between particles is greatly increased.
- Drilling hydratable shales or clays which introduces new, active solids into the system, increasing attractive forces by bringing the particles closer together and by increasing the total number of charges, and
- Insufficient deflocculant treatment.

Yield point can be controlled by proper chemical treatment. As the attractive forces are reduced by chemical treatment, the yield point will decrease. The yield point can be lowered by the following methods:

- Charges on the positive edges of particles can be neutralized by adsorption of large negative ions on the edge of the clay particles. These residual charges are satisfied by chemicals such as: tannins, lignins, complex phosphates, lignosulfonates, etc. The attractive forces

that previously existed are satisfied by the chemicals, and the negative charge of the clay particles predominates, so that the solids now repel each other.

- In the case of contamination from calcium or magnesium, the ions causing the attractive force are removed as insoluble precipitants, thus decreasing the attractive forces and YP of the mud.
- Water dilution can lower the yield point, but unless the solids concentration is very high, it is relatively ineffective.

Yield point (YP) is calculated from VG measurements as follows:

$$YP = \theta 300 - (\theta 600 - \theta 300)$$

or

$$YP = \theta 300 - PV$$

The limitation of the Bingham plastic model is that most drilling fluids, being pseudoplastic, exhibit an actual yield stress which is considerably less than calculated Bingham yield point. This error exists because the Bingham plastic parameters are calculated using a VG meter at 600 RPM (1022 sec⁻¹) and 300 RPM (511 sec⁻¹); whereas, typical annular shear rates are much less (Table 1).

Gel Strength - Gel strengths, 10-second and 10-minute, measured on the VG meter, indicate strength of attractive forces (gelation) in a drilling fluid under static conditions. Excessive gelation is caused by high solids concentration leading to flocculation.

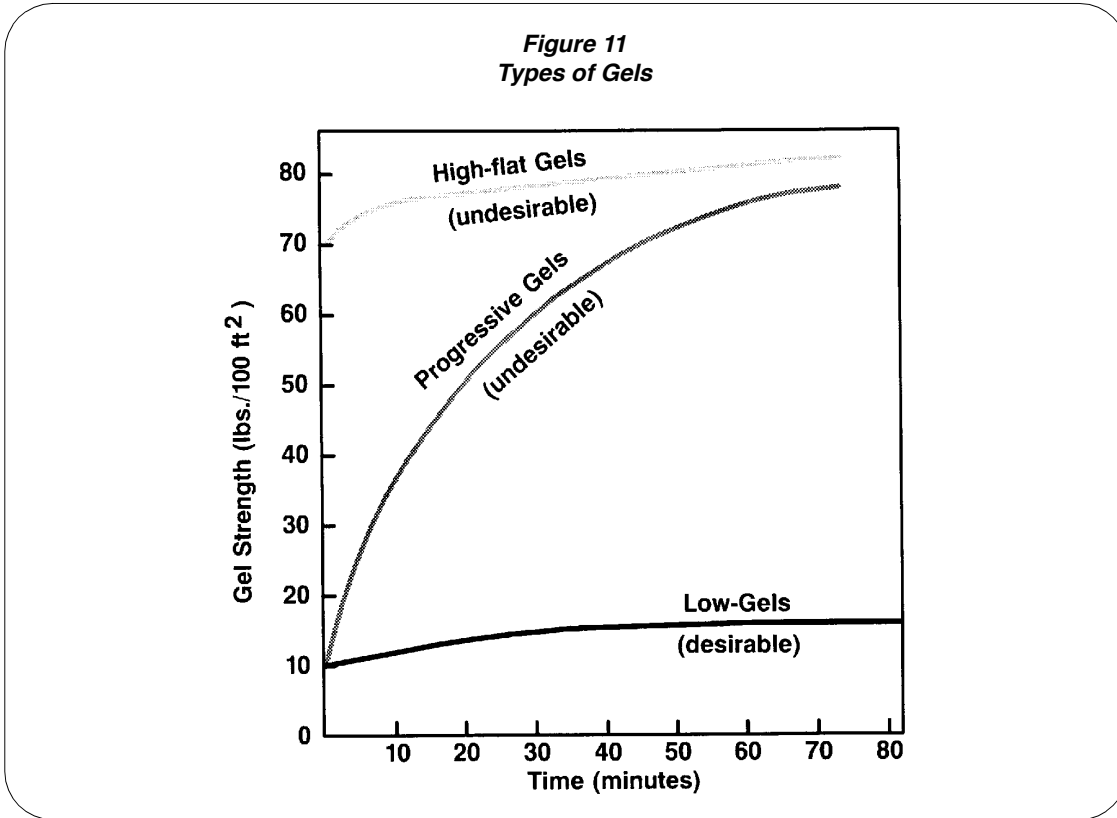
Signs of rheological trouble in a mud system often are reflected by a mud's gel strength development with time. When there is a wide range between the initial and 10-minute gel readings they are called "progressive gels". This is not a desirable situation. If initial and 10-minute gels are both high, with no appreciable difference in the two, these are "high-flat gels", also undesirable. The magnitude of gelation with time is a key factor in the performance of the drilling fluid. Gelation should not be allowed to become much higher than is necessary to perform the function of suspension of cuttings and weight material. For suspension "low-flat gels" are desired - as indicated in Figure 11.

Excessive gel strengths can cause:

- Swabbing, when pipe is pulled,
- Surging, when pipe is lowered,
- Difficulty in getting logging tools to bottom,
- Retaining of entrapped air or gas in the mud, and
- Retaining of sand and cuttings while drilling.

Gel strengths and yield point are both a measure of the attractive forces in a mud system. A decrease in one usually results in a decrease in the other; therefore, similar chemical treatments are used to modify them both. The 10-second gel reading more closely approximates the true yield stress in most drilling fluid systems. Water dilution can be effective in lowering gel strengths, especially when solids are high in the mud.

Apparent Viscosity (μ_a) - Apparent viscosity, measured by the VG meter, is the viscosity that a drilling fluid has at 600 RPM (1022 sec⁻¹). It is a reflection of the plastic viscosity and yield point combined. An increase in either or both will cause a rise in apparent viscosity (and probably in funnel viscosity). This is sometimes called single point viscosity. The equation for apparent viscosity is:



$$\mu_a = \frac{(300)(\theta 600)}{(\theta 600)} = \frac{\theta 600}{2}$$

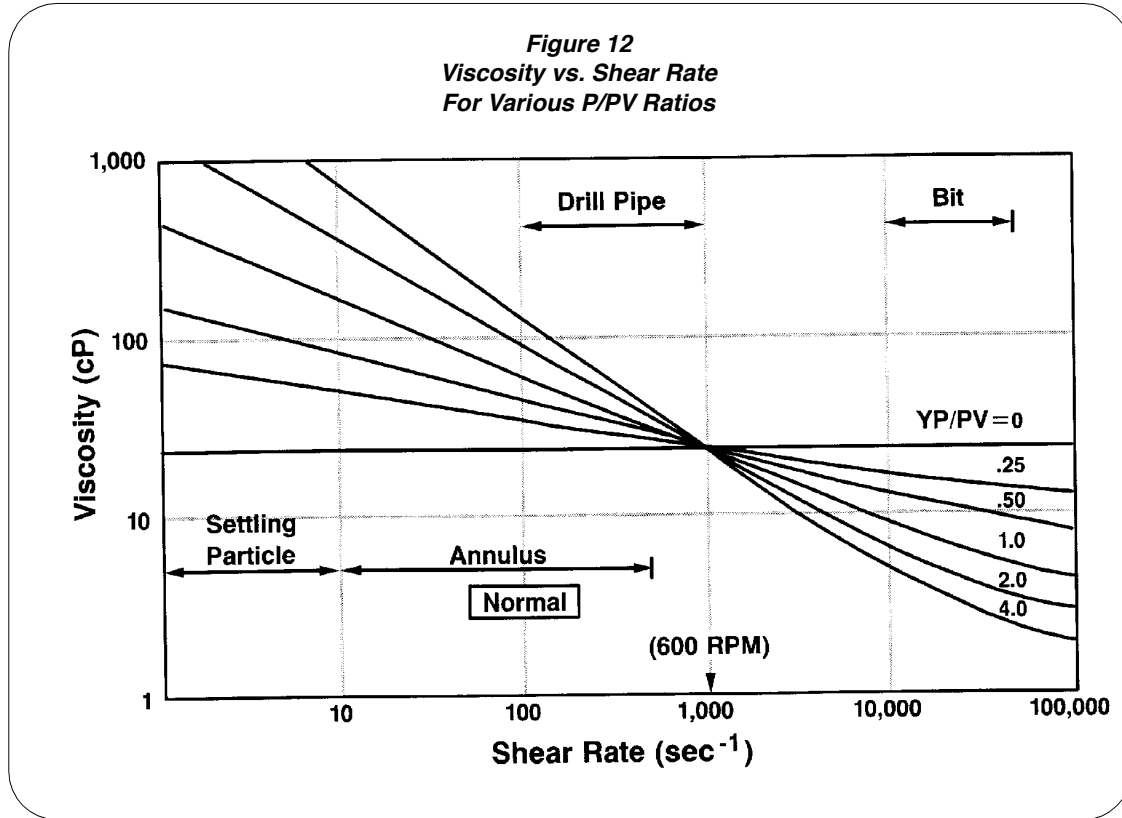
As shown in Figure 12, various muds may have the same μ_a at $1,022 \text{ sec}^{-1}$, but the effective viscosities at other shear rates may vary widely.

Effective Viscosity (μ_e) - The effective viscosity from a VG meter is the viscosity of the drilling fluid at that particular RPM. It is calculated by the equation below.

$$\mu_e = \frac{(300)(\theta \text{ at any RPM})}{\text{RPM}}$$

NOTE: One unit on the dial = 1.067 lb/100 ft²
 = 5.11 dynes/cm²
 and one RPM = 1.703 sec⁻¹

Funnel Viscosity - The funnel viscosity is measured with the Marsh funnel and is a timed rate of flow in seconds per quart. It is basically a quick reference check that is made routinely on a mud system; however, there is no shear rate/shear stress relationship in the funnel viscosity test. Thus, it cannot be related to any other viscosity nor can it give a clue as to why the viscosity may be high or low.



Pseudoplastic Fluids

These fluids are characterized by the shape of the flow curve illustrated in Figure 6. When the shear stress/shear rate plot of such fluids is made on logarithmic scale, a straight line is obtained. The effective viscosity of a pseudoplastic fluid decreases with increasing shear rates. For drilling fluids, pseudoplastic behavior is usually defined by using the Power Law equation. The Power Law equation uses two parameters, "K" and "n". K is a measure of a mud's consistency at very low shear rates. The larger the value of K, the more "viscous" is the fluid at low shear rates. n is a measure of the degree of non-Newtonian behavior. For n = 1, the fluid is Newtonian. For pseudoplastic fluids,

$$\tau = K(\dot{\gamma})^n; 0 < n < 1$$

where,

τ = shear stress

$\dot{\gamma}$ = shear rate

K = laminar flow consistency factor (constant for a particular fluid)

n = laminar flow behavior index

Dilatant Fluids

The behavior of dilatant fluids is characterized by the flow curve in Figure 6 and can be represented by the Power Law model where n is greater than 1.

$$\tau = K(\dot{\gamma})^n; (n > 1)$$

The effective viscosity of a dilatant fluid increases with increasing shear rate. This is not a desirable characteristic for drilling fluids and such fluids are rarely encountered.

Thixotropic Fluids

These fluids exhibit time-dependent behavior. They develop gel structure when at rest or when decreasing the applied shear rate. This gel structure may be manifested as a “true yield stress” or a gel strength or both. True yield stress is the residual stress on the fluid after reducing the shear rate to zero. True yield stress is not measured in the field but can be approximated by extrapolating low shear rate data to zero. A fluid may be described by one of constant shear rate models, e.g., Bingham Plastic or Pseudoplastic, and at the same time be thixotropic.

The strength of the gel structure depends on time. The structure begins to break down as shear is initiated and ultimately breaks with higher, prolonged shear.

Figure 13 is an example of a graph of a thixotropic fluid behavior. If the shear rate on a fluid is increased from point D it will follow the curve DEA. If, after reaching A, the shear rate is gradually reduced, the shear stress will follow curve AFD. The area within loop DEAFD is an indication of the degree of thixotropy. If the shear rate is held constant after point A is reached, the shear stress will decrease to its lowest point C. Beyond C there is no further structural breakdown for that constant shear rate. If the shear rate is reduced, the curve CHD is obtained.

Examples of thixotropic fluids are mayonnaise, drilling fluids, paints and inks.

Yield-Power Law (Herschel-Bulkley) Fluids - Virtually all drilling fluids display characteristics of both pseudoplastic and thixotropic fluids. One way to describe the behavior of such fluids is with the Yield-Power Law (YPL) Model:

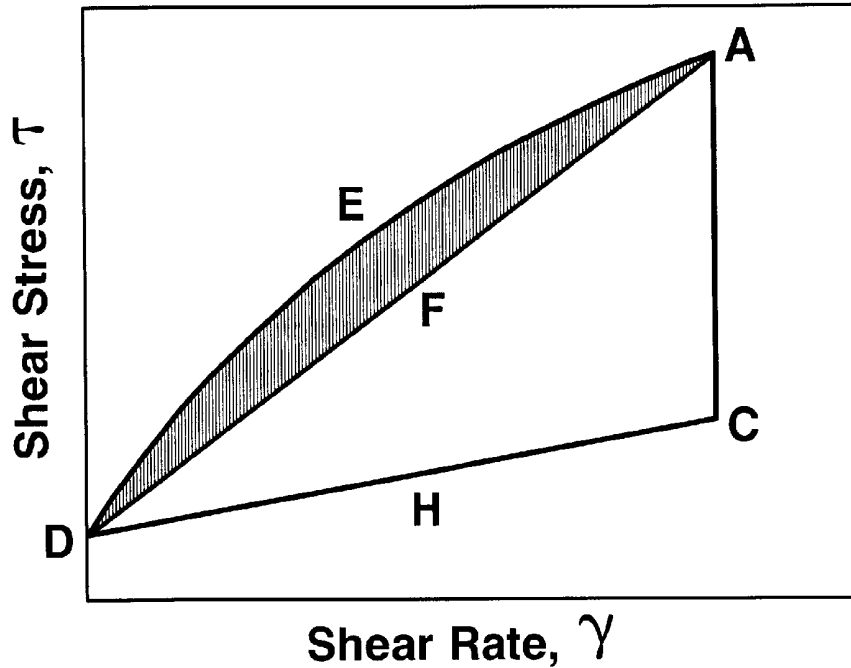
$$\tau = \tau_y + K(\dot{\gamma})^n$$

where τ_y is the YPL yield stress (a better approximation to the true yield stress than the yield point in the Bingham model), and K and n are the YPL consistency index and exponent, respectively. The YPL Model may be thought of as a combination of the Bingham Plastic and Power Law pseudoplastic models, but the Bingham plastic component may also be seen as a manifestation of thixotropic behavior. When τ_y is zero, the YPL model reduces to the Power-Law Model for pseudoplastic flow, and when n is one, it reduces to the Bingham model.

Flow Regimes

The mud flow in various parts of the circulating system will be either laminar, transition, or turbulent, depending on the magnitude of the Reynolds number. Reynolds number is a dimensionless number which indicates the type of fluid flow. The Reynolds number can be expressed:

Figure 13
Hysteresis Loops of Rheogram



$$N_R = \frac{DV(MW)}{\mu}$$

Where,

- D = Dimension of flow channel
- V = Average velocity in flow channel
- MW = Fluid density, lb/gal
- μ = Fluid viscosity

Typically, for power law fluids the flow regime can be predicted by the following Reynolds number relationships:

- Laminar Flow if the N_R is less than $3470-1370n$ where n is the Power Law constant.
- Transition Flow if the N_R is greater than $3470-1370n$ and less than $4270-1370n$.
- Turbulent Flow where N_R is greater than $4270-1370n$.

Laminar Flow

Laminar flow occurs when the individual flow layers (laminae) slide past each other with a minimum of mixing. Figure 1 demonstrates laminar flow in an annulus. Generally, laminar flow is the preferred annulus flow profile because it results in less pressure loss and reduces hole erosion. To achieve effi-

cient cuttings transport in laminar flow, the fluid rheology should be tailored to give a flat velocity profile, with a small “n” value for power-law fluid. This avoids excessive cuttings slip near the borehole wall and drill pipe.

Transition Flow

Transition flow occurs where laminar flow can no longer exist due to the increased momentum forces as the fluid goes into turbulence as velocity further increases. This is sometimes referred to as “unstable turbulence”. A Reynolds number range, given above, helps define the transition velocity.

Turbulent Flow

Turbulent flow occurs when the fluid is constantly swirling and eddying as it moves through the flow channel. Pressure losses within a circulating system increase as the degree of turbulence increases. Additionally, in turbulence, the viscous properties of a mud no longer have an effect on cuttings removal efficiency. Only the momentum forces of a mud; i.e., weight and predominantly velocity, affect hole cleaning in turbulent flow. In turbulent flow, the fluid velocity at the walls is zero; however, the velocity profile within the stream is essentially flat. This flat profile improves hole cleaning characteristics but, at the expense of increased pressure losses through fluid turbulence. A highly turbulent flow may also erode a soft formation (washout) which can reduce cuttings removal efficiency, increase cementing volumes, prevent zonal isolation, and affect wireline log quality. Generally, turbulent flow should be avoided if possible.

Yield-Power Law Rheology, Hydraulics, and Hole Cleaning

Amoco Research has determined that the yield-power law model is the preferred way to characterize drilling-fluid rheology because it is a more general model that includes both Bingham Plastic and Power Law behaviors.

$$\tau = \tau_y + K\gamma^n$$

τ_y may be estimated by extrapolating the 6-rpm and 3-rpm Fann readings to zero or, if these are not available, using the 10-sec gel strength. A log-log plot of $(\tau = \tau_y)$ vs. $\dot{\gamma}$ will give a slope equal to n. Extrapolation of $(\tau = \tau_y)$ to $\dot{\gamma} = 1 \text{ sec}^{-1}$ gives K.

Amoco presently formulates its hydraulics and hole cleaning design programs based on the YPL model. These design programs have been written as EXCEL spreadsheet programs and can be run under windows using EXCEL Version 4. A PC having a 80386 or higher processor with at least 4 Meg RAM is required. The hydraulics program is named HYDRAUL and the hole cleaning program is called the Solids Transport Efficiency Program, or STEP.

Documentation on HYDRAUL is given in the Appendix A as the “Hydraulics Technical Reference Manual” and includes sections on YPL rheology, fundamental equations for laminar and turbulent flow in arbitrary wellbore geometries, hydraulic calculations of downhole tools, system pressure losses, jet nozzle selection, and vertical cuttings transport.

Documentation for the design equations in STEP are also given in Appendix B. Included are the design equations for weighting material transport, and cuttings transport in both high and low angle wells. Guidelines for the identification, prevention, and remediation of hole cleaning problems are also included.

Section 7 Pneumatic Drilling Fluids

Introduction

Pneumatic drilling fluids are used to drill in areas where loss of circulation and low reservoir pressures restrict the use of conventional drilling fluids. Pneumatic fluids also find application to minimize formation damage caused by: (1) invasion of mud filtrate and solid particulates into reservoir pore spaces, (2) flushing of hydrocarbons, (3) hydration of clays within the reservoir, (4) emulsion blocking, or (5) formation of chemical precipitates within the reservoir. These damage problems are all caused by having a large overbalance of pressure resulting from a high hydrostatic pressure of the mud column and from chemical incompatibility between the invading filtrate and the reservoir fluid. Cause of damage is eliminated, or at least diminished, by reducing the hydrostatic pressure of the drilling fluid column and by selecting a fluid that will not hydrate clays and will not form precipitates in the pore space.

Major equipment components which are required for pneumatic drilling, but not required for conventional mud drilling, are: gas/air compressor and boosters, a rotating head, chemical injection pumps (for foaming agents and corrosion inhibitors), and foam generator units. In some cases other equipment may be needed. Of the required components, the gas/air compressor is by far the most important and costly. The entire drilling system design depends upon the capability and efficiency of the compressors.

The ratio of final pressure to initial pressure controls the number of compression stages that is required. The number of stages of compression bears directly on the total drilling cost. Type and number of compressors required to handle each specific pneumatic drilling operation must be well thought out in advance. Calculation of the compression ratio and ratio of discharge pressure to intake pressure is the first step in deciding on the number of compression stages. The compression ratio in a single stage should not exceed four because the temperature of the discharge air will be too high. Cylinder temperatures above 300-400°F will cause mechanical lubrication problems and metal fatigue. Large capacity, high-efficiency, radiator-type coolers are required in order to reduce the air temperature between each stage of compression. Elevation and maximum air temperature at the drillsite must be considered because compressor efficiency decreases with increasing temperature and elevation.

Pneumatic drilling fluids may require one or more of three basic chemicals, but simple air drilling may not need any of these:

- Surfactants, as detergents or foaming agents
- Corrosion Inhibitors
- Drying Agents

Surfactants as Detergents and Foaming Agents - Anionic or nonionic surface active agents (surfactants) are injected into the inlet air stream when formation water is encountered. These foaming agents also help clean the hole and keep the bit and drill string free of sticky solids. Surfactants prevent the cuttings from sticking together and from forming mud rings which can plug off the annulus.

Surfactants may also be added to the air stream or they may be added along with varying amounts of water to generate foam, as required by hole conditions. When water influx is minor, surfactants may be added in slugs down the drill pipe on connections. The surfactant (foaming agent) builds a homogeneous mixture that has ample consistency to bring out the water and cuttings, thereby cleaning the

hole. The amounts of injection water and foaming agent used will vary according to the hole size, formation characteristics, available air, and quality and quantity of water/oil influx.

Corrosion Inhibitors - Corrosion during pneumatic drilling can be “disastrous” unless the drill string is properly protected by corrosion inhibitors and scavengers. Oxygen, carbon dioxide and hydrogen sulfide in the presence of water are extremely corrosive in pneumatic drilling. The rate of corrosion can be minimized depending on the type of pneumatic fluid being used, by: (1) maintaining a high pH (10 or above) with NaOH or KOH if water is being injected or (2) injecting corrosion inhibitors into the gas or air. Sulfide scavengers such as zinc carbonate, zinc oxide or zinc chelate are used to react with hydrogen sulfide to form inert zinc sulfide. Water-soluble and/or coating-type corrosion inhibitors (such as filming amines or phosphonates) should also be added to the fluid in order to further protect the steel components which are exposed to the circulating fluid.

Drying Agents - A wellbore which contains only a minor amount of water may be dried simply by discontinuing drilling and circulating air for a short time. Another method, which may prove to be more economical, is to add slug treatments of drying agents such as CMC or silicate powders. These additives require the use of a dry chemical injector.

When deciding if a pneumatic drilling fluid is applicable, one must consider pore pressures, rock types, porosity and permeability, reservoir fluids, economics, and location. Types of pneumatic drilling fluids discussed in this section are:

- Dry Gas (air or natural gas)
- Mist
- Foam
- Gasified (Aerated) Mud

Dry Gas Drilling Fluids

Applications for dry-gas drilling are in hard formations where water or oil flows are not likely to be encountered and areas where drill water is scarce. Dry-gas drilling (also called “dusting”) uses compressed air or natural gas to cool and to lubricate the bit, to remove the cuttings from around the bit and to carry them to the surface. Dry gas is injected down the drill pipe while drilling and the cuttings are returned to the surface as fine particles. The returns are vented away from the rig in order to minimize the noise and dust. Cuttings are caught by a specially designed screen at the end of the blooey line.

In dry-gas drilling operations, the bottomhole pressure consists of the weight of the gas column, plus the annular pressure losses, plus the blooey-line pressure losses. The sum of these pressures will usually be far less than the formation pressure. Thus, the rate of penetration can be very rapid due to the low hydrostatic pressure. Chip-hold-down is also eliminated, making cuttings release from the bottom of the hole much more efficient. Overall, dry-gas drilling offers economic advantages in high ROP and lower operational costs per foot of hole, compared to mud drilling.

Dry-gas drilling operations require special and careful planning. Gas compressibility is a significant engineering consideration during both planning and drilling phases. Other equally important considerations are annular velocity requirements and logging suite selections. Fluid annular velocity, rather than fluid rheology, is the primary factor for cuttings transport when drilling with dry gas. The annular velocity necessary to lift cuttings determines the volume of gas that must be circulated. These annular velocities are such that turbulent flow always exists. To lift 3/8 in. to 1/2 in. cuttings, as a general rule, an annular velocity of about 3000 ft/minute is required. Although most air- or gas-drilled cuttings are quite small (dust particle size) when they reach the surface, they are larger when they leave the bot-

tom of the hole. The milling action of the drill string, impact with other cuttings, and regrinding of large particles at the bit are responsible for pulverizing them.

Logging is another factor to consider when drilling with dry gas. Wellbores containing no fluid other than air or gas can be surveyed only with devices that need no liquid to establish contact with the formation. The Induction Log is the only tool which can measure formation resistivities in such holes. The Gamma Ray Log can distinguish shales from non-shales. The Gamma-Gamma Density Log shows porosity even in gas-bearing zones where the Neutron Log indicates low apparent porosity. If both Gamma Ray and Gamma-Gamma Density Logs are run, the percent gas saturation may be computed in clean formations. In flowing gas wells, the Temperature Log detects the producing zones by showing the cooling effects of the gas as it expands into the hole. Also, in multiple-zone production, the Temperature Log indicates the relative volumes of gas coming from each zone. The Noise Log may be used to record zones of liquid or gas influx as well as zones of severe loss. A relative amplitude log is recorded and the noise may be monitored at the surface.

Water-bearing formations are the greatest limiting factor to air or gas drilling. Small amounts of water can be tolerated by adding drying agents such as CMC to the dry gas to absorb the water. However, if the cuttings become too moist they will stick together to form mud rings which can block the annulus. If this occurs, loss of circulation, stuck pipe, or even a downhole fire may result.

Air

Air drilling is commonly used in areas where loss of circulation with liquid type muds is a major problem. Air is also used to drill hard, extremely low permeability rock or formations. When drilling gas-bearing formations the risk of downhole fires can be high. The chance of a downhole fire, when gas is present, is increased if the annulus becomes restricted, thus increasing the pressure below the obstruction. Mud rings can cause this type of problem. The standpipe pressure must be continually monitored in order to detect and prevent an excess pressure build-up. Even an increase in pressure of about 15 psi can cause combustion to occur. Several downhole tools have been designed to help combat fire hazards. The Fire Float and Fire Stop are two of these tools. The Fire Float is installed above the bit as a near-bit protector. Under normal conditions it allows flow of air while drilling, but does not allow back flow of air. If the heat-sensitive ring is melted away by a downhole fire, a sleeve falls and stops air flow in either direction. A Fire Stop unit should be located at the top and midway in the drill collar assembly. It consists of a simple flap retained by a heat-sensitive zinc band. When the melt temperature of the zinc band is exceeded, the flap closes and air flow is halted. A quick rise in pressure at the surface is noted which alerts the crew to the likelihood of a fire.

Volume and pressure requirements must be considered when selecting equipment for an air drilling program. Surface pressure is determined by the total system pressure losses. Atmospheric pressure decreases with increasing elevation and temperature and increases with increasing relative humidity. Equipment requirements for a location which is situated at a high elevation in a hot and dry climate are considerably different than requirements for one which is in a cold, humid climate at sea level. Air requirements, based on an average annular velocity of 3000 ft/min, are listed in Table 1. In addition, as a rule of thumb for compressors there is a 3% loss in efficiency per 1000 ft of elevation.

Table 1
Hole Depth and Volume Required CFM

Hole Size	Stem Size	1000'	2000'	4000'	6000'	8000'	10,000'	12,000'
12-1/4	6-3/8	1840	1920	2090	2400	2520	2750	2870
	5-1/2	2100	2150	2350	2640	2780	3000	3100
	4-1/2	2260	2310	2520	2820	2930	3150	3230
11	6-3/8	1370	1430	1590	1850	1970	2180	2290
	5-1/2	1580	1650	1820	2070	2160	2380	2500
	4-1/2	1780	1810	1980	2250	2340	2530	2630
9-7/8	5-1/2	1180	1240	1400	1640	1730	1890	1970
	5	1300	1360	1490	1710	1800	1990	2100
	4-1/2	1350	1410	1540	1771	1850	2050	2150
9	5	990	1050	1180	1380	1480	1640	1740
	4-1/2	1080	1140	1260	1470	1550	1720	1820
	3-1/2	1130	1180	1300	1500	1580	1730	1790
8-3/4	5	930	970	1100	1320	1420	1570	1640
	4-1/2	1000	1050	1160	1360	1440	1620	1730
	3-1/2	1130	1180	1300	1500	1580	1730	1790
7-7/8	4-1/2	760	800	920	1080	1190	1330	1440
	3-1/2	910	950	1040	1220	1300	1440	1550
7-3/8	3-1/2	760	790	880	1050	1120	1250	1330
6-3/4	3-1/2	610	630	730	890	980	1080	1140
6-1/4	3-1/2	500	520	610	750	800	930	1000
	2-7/8	570	600	680	810	890	990	1070
4-3/4	2-7/8	300	340	400	480	560	630	690
	2-3/8	320	350	400	500	660	640	700

Natural Gas

Gas, rather than air, is used as the circulating medium when reservoirs contain appreciable quantities of gas. Air cannot be used because of the danger of downhole fires. The gas is compressed in the same manner as air, but the return gas must either be flared or collected to be put into a pipe line. Recycling of the gas is not recommended because of the abrasive particles in the used gas which would tend to damage the compressors. Fire and explosion hazards around the rigsite, due to gas leaks, are a constant danger when drilling with gas.

Mist Drilling Fluids

Misting may be used after drilling zones which produce more water than can adequately be absorbed by adding drying agents. In situations where the downhole influx of water is too much for dry-gas drilling, but too little for mist drilling, it is possible to inject water at the surface to allow mist drilling. The quantity of water for mist drilling will depend on the hole size, type of formation, rate of penetration, etc. A high-volume water flow presents a different set of problems. The intrusion of large volumes of water requires converting to a foam-type fluid and possibly other additives in order to successfully remove the water.

In mist drilling, air lifts the cuttings, but water wets the hole. Mist drilling requires at least 30% more air than with dry air or gas and higher injection pressures to adequately clean the hole. Increased air vol-

ume is necessary due to the weight of the heavier fluid-wet column, the higher frictional losses caused by the wet cuttings adhering to the drill string and the wall of the hole, and the higher slip velocities of the larger wet cuttings.

Air drilling techniques are used in areas where water-sensitive shales exist. In most cases these shales do not cause major problems if the air remains dry. However, these shales have a high affinity for water and may become completely unstable if mist is used. These problems have been controlled, in some cases, by adding 1 to 5 weight % potassium chloride and/or PHPA (liquid) to the injection water. Addition of the KCl reduces hydration and softening of shales and thus reduces hole enlargement. Small amounts (1 qt or less) of liquid PHPA can be added as a slug treatment down the drill pipe to act as a lubrication agent, reduce torque and drag and also to prevent hydration and softening of shales. Injection of KCl-water into the air stream creates severe corrosion problems. Oxygen corrosion can be reduced by raising the pH of the water to the 10-11 range and by adding a corrosion inhibitor.

Foam Drilling

Foams can be classified as "Foam", "Stiff Foam" and "Stable Foam" for discussion purposes. They are in many ways similar type drilling fluids.

Foam is differentiated from "mist" by the fact that foams may contain a blend of water, polymers, clays, surfactants and corrosion inhibitors. Transition from mist to foam may be necessary when difficulties are encountered while using dry gas or mist. Some of these problems are hole erosion, inadequate hole cleaning, loss of returns and water flows. Foam structure provides rheology for lifting cuttings. Foam quality is defined as the ratio of gas volume to total foam volume. This is the major factor which affects flow behavior. Apparent viscosity of the foam increases rapidly as the foam quality increases. Foam quality and foam stability will vary depending on the foaming agent used. The composition of the injection water and the type of fluids entering the wellbore also affect foam properties. Some foaming agents are not effective in salty or hard water. Foams are often damaged by presence of oil. Selection of the right foaming agent can determine the success or failure of a foam drilling operation.

Stiff Foam

Stiff Foam is another type of foam classification. It is rheologically more like a mud than ordinary form. It is a low-density drilling fluid used to drill poorly-consolidated formations in which hole-stabilizing materials can be included. The stronger foam supports larger cuttings compared to simple foam. When stiff foam is used, the annular velocity can be from 100 to 200 ft/minute for adequate hole cleaning. Consequently, compressor requirements are much less than for other types of pneumatic drilling.

Stiff foam is formulated by premixing polymers in water in a mud pit. Sometimes small concentrations of bentonite are added. The mixture is transferred to the foam tank and the foaming agent is folded into this mixture with as little agitation as possible. Then, it is injected into the air stream. Enough air must be injected into the mixture to give 100 to 200 ft/minute annular velocity near the surface. Air-to-mud ratios range from 100:1 to 300:1. The foam is very stiff, similar to the consistency of aerosol shaving cream, in order to inhibit air breakout in the annulus. It cannot be recirculated and must be discarded at the surface by running it through a blow line to a sump or reserve pit. Stiff foam was introduced by the U.S. Atomic Energy Commission for drilling large-diameter holes in loosely consolidated formations. The original composition consisted of 10 to 15 lb/bbl of bentonite, 0.2 to 0.5 lb/bbl of guar gum, 1 lb/bbl of soda ash, and 1% by volume foaming agent. Another relatively inexpensive, and somewhat more effective, formulation is: 12 lb/bbl of bentonite, 1 lb/bbl of soda ash, 1/2 lb/bbl Hi-Vis CMC, and 1/2 to 1% by volume foaming agent. This mixture, however, has the disadvantage of being relatively ineffective in the presence of salt water or oil.

Table 2 lists typical additives, their function and concentration for formulating a stiff foam drilling fluid.

Table 2 Stiff Foam			
Concentration			
Additive	lb/bbl	Vol. %	Function
Prehydrated Bentonite	10 - 15	---	Builds Foam Structure
Carboxymethylcellulose (CMC)	0.5	---	Foam Stabilizer Drying Agent
Guar Gum	0.2 - 0.5	---	Foam Stabilizer
Soda Ash	0.5 - 1.0	---	Calcium Treating Agent
Caustic Soda/Caustic Potash	0.55 - 0.5	---	Corrosion Protection
Foaming Agent	---	1%	Stabilizes Air in Liquid
Potassium Chloride	---	3 - 5%	Shale Stabilizer
Filming Amine	---	0.5%	Corrosion Protection

Stable Foam

The difference between Stiff Foam and Stable Foam is the method used to prepare the foam. Stable Foam, **developed by Chevron**, is a completion and workover fluid. Its distinguishing characteristic is that it is preformed on the surface in a foam generating unit. Then, it is injected into the drill pipe. The equipment required for making stable foam is: (1) an air compressor, (2) tanks for blending water, detergent and additives, (3) detergent solution pump, and (4) the foam generator and injection manifold.

Stable Foam consists of a detergent, fresh water and gas. Other additives such as viscosifiers, salts, or corrosion inhibitors may be included in the mixture. To be used effectively as a circulating medium, stable foam must be preformed. This means it is made before it encounters any solids and liquids from the wellbore. The foam is circulated only once. Foam systems have characteristics which make them stable and resistant to wellbore contaminants. Impurities introduced during foam generation can destabilize the foam.

Foams can be prepared with densities as low as two pounds/cubic foot by carefully controlling selection and mixing of components. (Bottomhole pressure measurements have indicated actual pressures of 15 psi at 1000 ft and 50 psi at 2900 ft while circulating stable foam.) Viscosity can be varied so that high lifting capacities result when annular velocities equal or exceed 300 feet/minute.

Stable foam should have a gas-to-liquid volume ratio in the range of 3 to 50 ft³/gal, depending on downhole requirements. The water-detergent solution which is mixed with gas to form stable foam can be prepared using a wide range of organic foaming agents (0.1-1 percent by volume). A schematic diagram of a stable foam unit is shown in Figure 1.

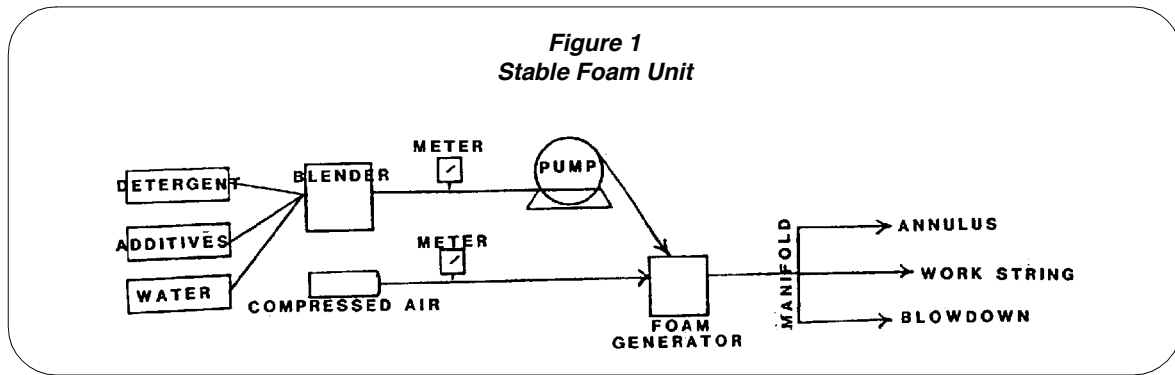


Table 3 lists typical components, their function and concentration for formulating a preformed stable foam drilling fluid.

**Table 3
Stable Foam**

Concentration			
Additive	lb/bbl	Vol. %	Function
Prehydrated Bentonite	10 - 15	---	Foam Stabilizer
Polyanionic Cellulose	0.5	---	Filtration Agent Drying Agent
Sodium Polyacrylate	1	---	Filtration Agent
Foaming Surfactant	---	1%	Foaming Agent
Potassium Chloride	---	3 - 5%	Borehole Stabilizer
XC Polymer	0.25 - 1	---	Foam Stabilizer
Filming Amine	---	0.5%	Corrosion Protection
Lime	0.25 - 0.5	---	Corrosion Protection

Gasified (Aerated) Mud Drilling Fluids

Air or gas can be used to reduce mud density and the resulting hydrostatic pressure of any mud. Gasified mud may be used for a drilling fluid when downhole drilling conditions prohibit the use of dry gas, mist or foams. It may also be used when drilling into low pressure reservoirs. Returns are often lost at a shallow or medium depth while an overpressured zone is being drilled at a greater depth. Gasification can be beneficial as a way to reduce the hydrostatic pressure of shallow zones while maintaining adequate hydrostatic pressure at the deeper zone. Two of the most common gases to reduce the hydrostatic pressure of the mud column are air and nitrogen. Both of these applications will be briefly discussed in this section.

Air Application

Due to its compressibility, air in an aerated mud is compressed to very small bubbles as it travels down the drill pipe and through the bit. As the air in the mud travels up the annulus toward the surface, the air bubbles slowly expand due to the decreasing hydrostatic pressures, which in turn increase the air-volume to mud-volume ratio in the upper portion of the annulus. The rate of air bubble expansion increases according to the general gas law as the aerated mud approaches the surface. This increase of air-volume to mud-volume ratio not only decreases the downhole hydrostatic pressure, but increases the annular velocity of the aerated mud as it approaches the surface. The nomograph in Figure 2 may be used to estimate air requirements for reducing density of a water mud by aeration.

A de-aerator, such as a mud-gas separator, must be used to control high velocity and possible surging of the returning mud before it goes to the shale shaker. This device will prevent surface mud losses due to surging and splashing as well as remove a large portion of the air from the mud. The separator should have an overflow line going to the shaker in case of excessive fluid flow. The balance of the air will be removed by the degasser prior to reaching the mud pumps.

Control of the mud properties is extremely important when drilling with aerated mud. The density, solids content, gel strengths, and plastic viscosity must all be controlled at low and constant values. The yield point will depend on the type of fluid being used, but should be in a proper range with respect to the plastic viscosity. Yield point control is required in order to allow the air to be removed when it reaches the surface. Injection pressures will remain low if hydrostatic pressure and system pressure losses are maintained at low values. As well depth increases, controlling hydrostatic and system pressure losses becomes more important in order to avoid surpassing the capabilities of the air equipment. Maintaining a pH above 10 will assist in corrosion control; however, higher pH could cause polymer precipitation or cuttings dispersion depending on the type of mud being used.

Some common fluids used in aerated drilling are low-solids, non-dispersed muds and salt muds. Low-solids, non-dispersed (LSND) muds are especially good as aerated drilling muds because they offer shear thinning properties which give low circulating pressures. Their major drawback is a tendency to disperse cuttings at high pH, so care must be exercised when selecting additives in order to prevent dispersion.

Potassium chloride muds are very successful in solving unstable shale problems in air-liquid circulating systems. Potassium hydroxide should be used for pH control. Fluid loss control may be obtained by using polyanionic cellulose. The major disadvantage of salt muds is higher corrosion rate compared to freshwater muds. Removal of entrained air or gas from a salt mud can be difficult.

Nitrogen Application

Nitrogen can be used to solve loss of circulation in areas which have an abnormally low pressure gradient. Nitrogen can be injected into the mud system at the standpipe in order to accurately control annular hydrostatic pressures and thus regain mud returns.

Nitrogen has advantages over other aerated systems because pressure, volume, and temperature of the gas from a tank of liquid N₂ can be better controlled and temperature is lower than air from a compressor. Temperature is a major factor to be considered while working with an aerated system. If nitrogen is put into the drill string at a cool temperature, it will expand as the temperature increases. The amount of expansion, and thus the effective lowering of mud density will be greater. The effective mud density at various depths is shown in Table 4. Tables available from nitrogen suppliers are designed for a geothermal gradient of 1.6°F/100 ft of depth.

Figure 2
Air Requirements for Reducing Density of Water Muds

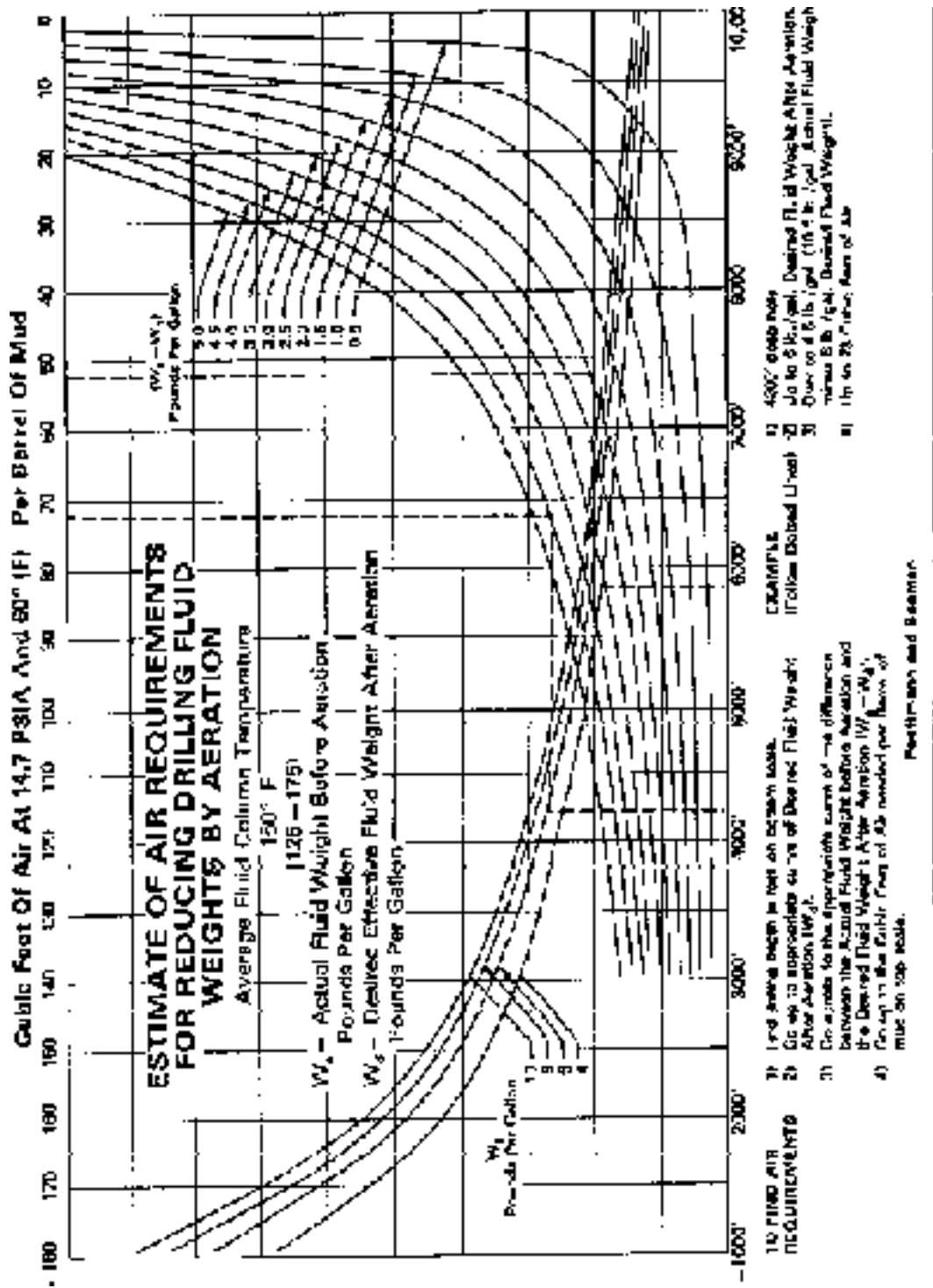


Table 4
Effective Mud Density at Various Depths Using Nitrogen

Mud Density lb/gal	Nitrogen scf/bbl	Depth, Feet								
		1000	2000	3000	4000	5000	6000	7000	8000	9000
9.0	10	7.72	8.16	8.36	8.48	8.56	8.61	8.65	8.68	8.71
9.0	20	6.62	7.19	7.63	7.88	8.05	8.17	8.26	8.33	8.39
9.0	50	3.04	4.58	5.53	6.13	6.55	6.85	7.08	7.26	7.41
10.0	10	8.69	9.15	9.35	9.47	9.55	9.60	9.64	8.68	9.70
10.0	20	7.16	8.15	8.60	8.86	9.03	9.16	9.25	9.32	7.42
10.0	50	3.67	5.41	6.43	7.07	7.50	7.81	8.04	8.23	8.38
11.0	10	9.66	10.13	10.34	10.46	10.54	10.60	10.64	10.67	10.70
11.0	20	8.08	9.11	9.85	9.94	10.02	10.14	10.24	10.31	10.37
11.0	50	4.29	6.25	7.33	7.99	8.44	8.76	9.00	9.19	9.35

Nitrogen is pumped at the required rate directly into the standpipe until a joint of pipe is drilled down. In order to prevent the mud in the drill pipe from blowing back during connections, a mud cap (a column of liquid mud) equal to approximately 1000 ft can be pumped prior to breaking the connection or a string float can be used. The connection can then be made before the nitrogen can come back up through the mud. A string float may also be used for this purpose.

Due to the compressibility of nitrogen, the pressure gradient of the mud inside the drillpipe while circulating is not greatly reduced. For example, a mud pressure gradient of 0.467 psi/ft, with a pump pressure of 2000 psi, will only be reduced to 0.440 psi/ft with the addition of 50 standard cubic feet (scf) of nitrogen per barrel. Only after passing through the bit jets and coming up the annulus will the nitrogen bubbles expand and lower the pressure gradient drastically. This can be seen in Table 4 where the density of a 9.0 lb/gal mud is reduced from 7.41 lb/gal at 9000 ft to 6.55 lb/gal at 5000 ft as the pressure is decreased in the annulus.

Advantages/Disadvantages of Air Drilling Fluids

There are a number of significant advantages for using air as a drilling fluid. Table 5 lists some of these advantages as well as some of the disadvantages.

Advantages	Disadvantages
Excellent ROP in dry competent formations.	Will not tolerate water.
Low-cost fluid.	Dust and noise problems on location.
Longer bit life.	Excessive erosion near top of hole where expansion results in high annular velocity.
Minimum damage to water-sensitive pay zones.	May cause downhole fire when hydrocarbons are encountered. (Air Drilling)
Little or no fluids disposal problems.	Hole cleaning success difficult to determine due to inability to adequately quantify cuttings removal.
Hydrocarbon identification immediate and continuous.	Requires experienced rig personnel.
Lost circulation eliminated.	Special (rental) equipment required. Limited information on reservoir characteristics because cuttings are pulverized.
	Disposal of waste gas can be a hazard. (Gas Drilling)

Table 6 compares Mist and Dry Gas drilling fluids. Mist offers nearly the same advantages as dry gas versus liquid muds with one exception: it can handle a sizable water volume compared to dry gas drilling. The Table also lists some of the disadvantages of using mist versus dry gas.

Advantages	Disadvantages
Same as dry gas except chemical additive cost increases	Requires more air volume.
Handles sizeable water influx.	Corrosive.
	More hole enlargement due to water-shale interaction.

Stiff foam exhibits additional advantages over dry gas or mist drilling fluids. Table 7 lists some of these advantages as well as some of the disadvantages.

Table 7 Foam Versus Mist or Dry Gas	
Advantages	Disadvantages
Wall building capability	Increased mud and chemical costs.
	Loses solids carrying capability when encountering oil, salt water or calcium ion contamination.

Table 8 Stable Foam Versus Stiff Foam	
Advantages	Disadvantages
Lost circulation and formation damage eliminated.	High surfactant costs.
Low compression requirements.	Additive ratios critical.
Good thermal stability.	Specialized equipment required for measuring and regulating liquid and air proportions and quantities.
Compatible with oil, salt water and calcium and most formation contaminants.	
Can safely absorb considerable volume of gas into aqueous foam rendering it nonflammable until sumped.	
Less hole washout in unconsolidated formations while drilling.	

Section 8 Water-Based Drilling Fluids

NON-INHIBITIVE FLUIDS

Introduction

Non-inhibitive fluids are simple and inexpensive. Their composition will vary depending on the requirements of the local lithology, type of makeup water, hole size, and anticipated contaminants. These muds have definite limitations which become evident when drilling dispersive formations, encountering contaminants and high temperatures, or increasing fluid density. Each of these situations may require converting to another type of fluid which is more adaptable to these conditions.

Non-Inhibitive muds are subdivided into the following types:

- Clear Water
- Native Muds
- Bentonite-Water Muds
- Lignite/Lignosulfonate (Deflocculated) Muds

Clear Water

Clear water is a nearly ideal drilling fluid; however, when drilled solids are incorporated they remain in suspension and thus, reduce the drilling efficiency. An effective means of removing solids from clear water is settling. The settling area should be large enough to allow sufficient time for small particles to settle. Treatment with polymers designed to flocculate drill solids or lime treatments may be used to accelerate settling.

Clear water varies in salinity from fresh to saturated brines. Water selection and salinity will depend upon available makeup water or salinity required to drill specific formations. Clear water fluids are Newtonian and thus, require high annular velocities for hole cleaning. Occasional viscous sweeps (small batches of high viscosity mud) are pumped around to clear the hole of cuttings as needed. Caustic soda or lime is usually added for corrosion control.

Native Muds

In some areas, drilled formations contain mud-making claystones or shales. When water is pumped down the hole during drilling, it returns with the native solids dispersed in it. Viscosity builds with continued drilling and circulation. The result is a viscous native mud. Dilution may be needed to keep the mud from becoming excessively viscous. On the other hand, small quantities of bentonite may be added to increase viscosity and improve filtration control. Caustic soda or lime is usually added for corrosion control.

Bentonite-Water Muds

Bentonite dispersed in fresh water produces a mud with good cuttings lifting capacity, good drilling rate, and usually adequate filtration control. These bentonite-water muds are commonly used as spud muds for drilling surface hole; however, they are sometimes used for drilling deeper.

Water quality is important in formulating a bentonite-water mud. Chlorides (Cl^-) and hardness (Ca^{++} and Mg^{++}) in the makeup water interfere with the hydration of the bentonite. Calcium ion concentration should not exceed 150 mg/L. If greater than 150 mg/L, it should be treated out with soda ash. Treatment with 0.1 lb of soda ash per barrel of water will remove approximately 100 mg/L of calcium ion. Magnesium hardness, on the other hand, is treated out with sodium hydroxide. At pH of 9.7 magnesium ions will have all been reacted with sodium hydroxide to precipitate $\text{Mg}(\text{OH})_2$. Chlorides, however, cannot be treated out of the makeup water. Less than 5000 mg/L chlorides will not seriously hamper hydration of commercial bentonite. When there is more than 20,000 mg/L chlorides, bentonite hydration is essentially prevented. Adding fresh water to reduce the chloride concentration becomes necessary to allow hydration.

In bentonite-water muds, viscosity can be increased by adding more bentonite or adding a bentonite-extender polymer, or lime or soda ash. The pH is usually maintained in the 8.0 to 9.5 range with caustic soda. Caustic soda flocculates hydrated bentonite; but, this effect can be minimized by slowly adding the caustic soda to the mud while it is being vigorously agitated.

Lignite-Lignosulfonate (Deflocculated) Muds

Lignite-Lignosulfonate Muds can be used to drill a variety of formations. They can be weighted up to 18 or 19 lb/gal, provided low-gravity solids (bentonite and drill solids) are in the proper range. As mud density is increased, the bentonite content should be decreased.

The pH range for controlling lignite-lignosulfonate muds is in the 9.5 to 10.5 range. In this range, the magnesium ion is precipitated. Calcium ion should be kept below 200 mg/L. Less than 10,000 mg/L chlorides should not hamper fluid performance, but if chlorides exceed 25,000 mg/L, the mud should be diluted with fresh water.

Lignite-lignosulfonate muds are thermally stable to approximately 325°F. This temperature limit is not well defined and is dependent upon the mud pH, on the type of lignosulfonate used, the length of time exposed to high temperature and the solids content of the mud. Generally, chrome lignosulfonates perform at temperatures higher than lignosulfonates which do not contain chromium. It is significant to note that when lignite-lignosulfonate fluids thermally degrade, carbon dioxide is produced and carbonate ions accumulate in the filtrate.

Principal Additives of Lignite/Lignosulfonate (Deflocculated) Muds

Lignite/Lignosulfonate Muds are relatively simple in their makeup, conversion, and maintenance. Table 1 lists additives, functions, and concentrations for a typical mud formulation.

Table 1
Principal Additives of Lignite/Lignosulfonate Muds

Additive	Concentration, lb/bbl	Function
Bentonite	10 - 25	Viscosity Filtration Control
Lignosulfonate	0.25 - 8	Deflocculant Filtration Control
Caustic Soda/Caustic Potash	for pH 9.5 - 10.5	Alkalinity Control
Soda Ash	0.25 - 1	Calcium Ion Removal
Lignite	1 - 4	Filtration Control
Barite	as needed for density	Weighting Agent
Low Viscosity PAC/CMC	0.25 - 1.0	Filtration Control
Gilsonite	2 - 8	Filtration Control

Bentonite - Bentonite is added for viscosity and filtration control. Fresh bentonite additions, preferably as a prehydrated slurry, should be made prior to other chemical additions. Overtreatment can compound rheological problems.

Lignosulfonate - Lignosulfonate is used to control rheology and provide filtration control through deflocculation of the bentonite. Deflocculation of clays is believed to be the result of adsorption of the negatively-charged lignosulfonate compound on the edges of the clay particles. This causes a disassociation of the clay particles (deflocculation) which causes a reduction in low shear-rate viscosities and yield point and gel strengths, and improves filtration control by forming a thin, compressible filter cake. At temperatures greater than about 325°F, lignosulfonates degrade to form CO₂ and carbonate ion. At higher temperatures, generally above 400°F, lignosulfonates may degrade to liberate hydrogen sulfide and sulfide ion. Chromelignosulfonate (CL5) may be replaced with chrome-free lignosulfonate in environmentally sensitive areas, but some reduction in performance can be expected.

Caustic Soda or Caustic Potash - Caustic soda (NaOH) or caustic potash (KOH) should be pre-mixed in a chemical barrel and then slowly added to the circulating system. These alkalinity agents improve the performance of both lignite and lignosulfonate, as well as reduce corrosion.

Soda Ash - Soda ash (Na₂CO₃) is used to treat out calcium ion hardness and to beneficiate calcium bentonite.

Lignite - Lignite is used as a filtration control agent and as a secondary deflocculant. To solubilize lignite it must have a highly alkaline environment. It functions as a fluid loss additive up to 400°F. Compared to lignosulfonate, lignite provides better filtration control at elevated temperatures. It is usually added with lignosulfonate. The ratio of lignite to lignosulfonate is generally 4:1; however, the ratio will decrease depending on quality of the lignite, mud weight, formations encountered, and wellbore temperature.

Barite - Barite is used to increase mud density. Barite stock should be checked periodically to ensure that it meets API specifications and is not a source of alkaline-soluble carbonate ions.

Typical Properties of Lignite/Lignosulfonate (Deflocculated) Muds

Typical properties of Lignite/Lignosulfonate Muds are listed in Table 2. These muds are characterized by their low yield point and gel strengths as well as low API filtrate.

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		API Filtrate (cm ³ /30 min)
9	8 - 12	6 - 10	2 - 4	4 - 10	8 - 12
12	15 - 20	10 - 14	2 - 4	4 - 10	4 - 8

System Conversion/Maintenance

Conversion - Lignite/Lignosulfonate (Deflocculated) Muds are quite flexible in their makeup, conversion, and maintenance. Care should always be taken so that conversion to a lignite/lignosulfonate mud is not initiated before hole and mud conditions dictate. When converting to a lignite/lignosulfonate mud, the volume of solids should be lowered by dilution with water or by mechanical removal prior to the conversion. Calcium ion hardness should not exceed 200 mg/L. If hardness is greater than 200 mg/L, treat with soda ash prior to making the conversion. Bentonite treatments, if needed, should be added prior to adding the lignosulfonate; otherwise, it will require more bentonite to achieve desired flow and filtration properties. The pH should be in the range of 9.5-10.5 and the P_F should be 0.2-0.8 cm³. Pilot test results will determine the correct caustic soda or caustic potash treatment. Lignite and/or lignosulfonate and caustic soda treatments should be added gradually and simultaneously over one or two circulations, maintaining a 9.5-10.5 pH.

Maintenance - For cost-effective maintenance of a Lignite/Lignosulfonate Mud, pilot testing is essential. Additional small lignosulfonate treatments should be made when flow properties become excessive. Above all, effective use of mechanical solids control equipment is essential. Minimizing unwanted solids will always minimize effects of various contaminants, lessen the treatment requirements, and lessen other mud and hole problems. The pH should be maintained in the range of 9.5-10.5 with a P_F of 0.2 -0.8 cm³. Additional filtration control can be obtained by using low-viscosity PAC, CMC or starch (with a biocide). Borehole instability can be mitigated by additional treatments with lignosulfonate, or by adding gilsonite, or by converting to an inhibitive fluid, such as a lime, gyp or oil-based mud.

Advantages/Disadvantages of Lignite/Lignosulfonate (Deflocculated) Muds

Lignite/Lignosulfonate Muds have many advantages. They are easily weighted, provide good filtration control and are economical to formulate and maintain. The major drawback to running this mud is that it tends to disperse cuttings unless lignosulfonate concentrations are high, in the 12-15 lbs per barrel range, in which case the yield point and gel strengths may be nil. Table 3 lists common advantages and disadvantages of lignite/lignosulfonate (deflocculated) muds.

Table 3
Advantages/Disadvantages of Lignite/Lignosulfonate Muds

Advantages	Disadvantages
Easily weighted to 18 lb/gal provided low gravity solids are kept low.	Disperses cuttings, making mechanical removal more difficult.
Good filtration control with low permeability filter cake.	More annular velocity required for adequate hole cleaning - low rheology.
Simple makeup and easy maintenance.	Hole enlargement in clay-bearing formations.
Good corrosion protection.	Effluent discharge considerations - BOD (Biological Oxygen Demand).
Economical to prepare and maintain up to 325°F.	Disposal concerns if it contains heavy metals or Cr ⁺⁺⁺ .
Effective in salinity range from fresh water to seawater.	Deteriorate at high temperatures (325°F or greater) forming carbonates and sulfide ions.
Easily converted to lime or gyp mud. (inhibitive muds).	

Troubleshooting and Contamination

Lignite/Lignosulfonate (Deflocculated) Muds. Lignite/Lignosulfonate (Deflocculated) Muds are fairly resistant to contamination. Table 4 shows typical contaminants, indicators of contamination, and treating strategies as well as recommended troubleshooting practices for product quality.

Table 4
Contaminant Treating of Lignite/Lignosulfonate Muds

Contaminant	Indicators	Treating Strategy
High Solids	Increasing PV, retort solids, gels. Thick mud on bottoms-up after trips.	Major dilution. Improve solids removal. Centrifuge mud.
Cement	Increasing P_M , P_F , pH, YP gels, and Marsh funnel viscosity. Possible increase in hardness.	Treat out cement (Ca^{++}) with bicarb and/or SAPP and lignosulfonate. Minor dilution. Increase P_F to limit Ca^{++} solubility. Breakover to lime mud, if necessary.
Carbonates	Increasing gels, YP, and M_F . Thick mud when weighting up or on bottoms-up after trips.	Run GGT for accurate analysis. Increase pH to 10.7 with NaOH or KOH. Treat with gyp and/or lime to remove carbonates (Avoid over-treatment.). Minor dilution.
Poor Product Quality	Change in product packaging. Increased treating amounts. Inability to control mud properties with standard treatments.	Documents product's history through supplier. Arrange for regular sampling and testing. Pilot test against good material.
Saltwater/Salt	Well flow. Increasing YP, gels Marsh funnel viscosity, hardness pH, P_M , P_F .	Increase density to kill flow, if possible. Dilute with freshwater. Add caustic and fluid loss, chlorides. Decreasing lignosulfonate to control rheology; when rheology stabilizes, add PAC for filtration control. If chlorides greater than 35,000 mg/L, convert to salt mud.
Temperature Gelation	Increasing pump pressure to break circulation. Thick mud on bottoms-up after trips.	Reduce low-gravity solids and MBT. Use a thermally stable deflocculant. Check for carbonates contamination.
Gypsum/ Anhydrite	Change in drilling rate. Increasing YP, Marsh funnel viscosity, hardness. Decreasing pH, P_M , P_F .	Treat out calcium ion with bicarb or soda ash. Use additional lignosulfonate and/or convert to gyp mud.
Salt Formation	Drilling break with thick mud on bottoms up. Increasing chlorides, YP, gels, Marsh funnel viscosity, fluid loss. Decreasing pH, P_M , P_F .	If significant salt to be drilled, convert to Saturated Salt Mud, OR treat as saltwater flow.

INHIBITIVE FLUIDS

Introduction

Inhibitive fluids are fluids which do not cause appreciable formation alteration. These fluids are primarily used for drilling shale and clay formations; however, they are also used in areas where contamination is a problem. Even in large quantities salt, anhydrite, and cement can be handled successfully with the proper inhibitive fluid. Inhibitive salt-based muds use sodium chloride (NaCl) to achieve inhibition. Calcium-based muds use lime ($\text{Ca}(\text{OH})_2$) or gyp ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$), and potassium-based muds use caustic potash (KOH), potassium chloride (KCl), potassium carbonate (K_2CO_3), and other potassium-based additives to achieve inhibition.

Inhibitive fluids are classified as follows:

- Calcium-based Muds
- Salt-based Muds
- Potassium-based Muds

Calcium-Based Muds

Calcium-based muds are primarily used to drill intervals of highly reactive shales. They exhibit greater inhibition than sodium-based muds by reducing hydration of clays. Calcium-based muds are highly resistant to contamination. They tolerate solids well, but a high concentration of low-gravity solids will cause unstable rheological properties. In a calcium-based mud, calcium ion and magnesium ion contamination do not have adverse effects on fluid performance. Chloride ions, however, do appreciably affect performance. Chloride ion concentrations above 100,000 mg/L are considered to be the upper limit in which these muds will operate effectively. When bottomhole temperatures exceed 300°F calcium-based muds, particularly lime muds, are not normally considered due to the possibility of high-temperature gelation. However, a gyp mud with an acceptable range of low-gravity solids can withstand bottomhole temperatures to 350°F. The principal calcium-based muds are:

- Lime Muds
- Lime/MOR-REX Muds
- Gyp Muds

Lime Muds

Lime muds may be used where an inhibitive mud is desired and where temperatures do not exceed 300-325°F. They are particularly useful because of their high solids tolerance. These muds vary widely in their range of filtrate alkalinities and lime content and are generally grouped into three broad categories as shown in Table 5.

Table 5
Lime Mud Classifications Based on Alkalinity Ranges

	Low Lime	Intermediate	High Lime
P_F	0.8 - 2	2 - 5	5 - 10
P_{VB}	4 - 9	9 - 15	15 - 25

The pH range for lime muds is from 10.5-12.5. Soluble calcium varies between 120-400 mg/L, and is controlled by the filtrate alkalinity of the mud. When the filtrate alkalinity (P_F) is increased, less calcium is able to go into solution. Caustic soda (NaOH) or caustic potash (KOH) additions raise the pH and limit lime solubility. If soluble calcium is not properly controlled, high viscosity and gel strengths may result. The upper limit for chlorides in a lime mud is 40,000-50,000 mg/L.

Principal Additives of Lime Muds

Lime or lime-treated muds generally contain native or commercial clays, caustic soda, organic defloculants, lime (as a source of calcium), and a fluid loss control agent. Principal additives of lime muds are listed in Table 6.

Table 6
Principal Additives of Lime Muds

Additive	Concentration, lb/bbl	Function
Bentonite	22 - 26	Viscosity, Filtration Control
Lignosulfonate	2 - 6	Deflocculant
Lime	2 - 10	Inhibition, Alkalinity Control
Caustic Soda/Caustic Potash	for pH 10.5 - 12.5	Alkalinity Control, Inhibition
Lignite	2 - 4	Filtration Control
Starch	3 - 4	Filtration Control
PAC	0.25 - 1.5	Filtration Control

Bentonite - Bentonite is added for viscosity and filtration control. Because sodium is replaced by calcium when the mud is "broken over" to a lime mud, the bentonite must be prehydrated in fresh water before adding it to the active system.

Lignosulfonate - Lignosulfonate is added as a deflocculant and for filtration control. In areas where chrome lignosulfonates are prohibited, calcium lignosulfonates such as Lignox and Setan can be used without compromising performance.

Lime - Lime is added to increase P_M . Excess lime is usually maintained in the range of 2-4 lb/bbl. Excess lime is a measure of the alkalinity reserves that are available to go into solution as drilling proceeds and calcium and hydroxyl ions are depleted.

Caustic Soda/Caustic Potash - Caustic soda or caustic potash are used to control filtrate alkalinity (P_F). Controlling filtrate alkalinity will in turn control the solubility of lime and stabilize rheological properties.

Lignite - Lignite is added for filtration control; however, lignite in the presence of soluble calcium forms a calcium salt of humic acid precipitate. At elevated temperatures, lignite degrades to form carbonates.

Starch - Starch can be added for filtration control up to mud temperature of 250°F. The high alkalinity of the mud filtrate will prevent fermentation. Thus, a biocide is not usually required.

Polyanionic Cellulose - PAC is used to control filtration provided that the calcium ion concentration does not exceed 400 mg/L. PAC can also provide supplemental viscosity and encapsulation of solids. For mud densities less than 12 lb/gal, regular viscosity can be used; however, as density increases low-viscosity PAC should be used to avoid excessive viscosities.

Other Additives - Gilsonite, asphalt, cellulosic fibers are added to seal permeable formations and stabilize the wellbore.

Typical Properties of Lime Muds

Typically, lime muds have low viscosity and gel strengths and are rheologically stable when subjected to contaminants such as gyp, anhydrite, cement or carbonates as compared to low pH freshwater muds. Table 7 lists typical properties for a 10 lb/gal low-lime mud and also for a 10 lb/gal high-lime mud.

Table 7 Typical Properties of a Low and High Lime Mud									
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10 min (lb/100 ft ²)		P_M	P_F	pH	Excess Lime (lb/bbl)	API Filtrate (cm ³ /30 min)
Low Lime									
10.0	15-18	6-10	0-2	0-4	5-10	1-2	10.5-12.5	1-2	6-12
High Lime									
10.0	15-18	6-10	0-2	0-4	12-18	5-10	12.0-12.5	5-15	6-12

System Conversion/Maintenance

To convert from a freshwater mud to a lime or lime-treated mud, it is preferred to make the conversion after returning to bottom with a new bit. Conversions often are made inside casing while drilling out cement, but may also be made in open hole. The mud pits should be jetted down and cleaned to remove as many settled out drilled solids as possible. Generally, a complete mud check is performed to determine the fluid condition. A pilot test may be run to determine the volume of water dilution required and the amount of chemicals needed for the conversion.

The mud should be converted prior to the need to increase mud density because 10% to 25% dilution is generally recommended prior to the breakover. The conversion usually is accomplished in two circulations; however, more may be required. If a weighted mud is to be converted and the density cannot be reduced without jeopardizing the safety of the well, the mud may be broken over in the pits and then

pumped down the hole in stages. Chemical deflocculants also will be required to control the viscosity during breakover.

Converting to a lime-treated mud may be accomplished by various methods; however, a typical break-over from a lightly-treated freshwater mud may be performed by first reducing the Marsh funnel viscosity to 30-35 sec/qt with water. Any water additions should be added before adding chemicals, but may be added during the breakover if allowances have been made for volume increase. Maintain adequate agitation in the suction pit and turn off all mud guns except those in the suction pit. This prevents the converted mud from flocculating the mud in the other pits and allows the mud to flow freely between the pits. Add the caustic first; then add deflocculant and lime together into the mud at a timed rate. Do this in two circulations, if possible. NaOH or KOH should be added through the chemical barrel while adding lime and deflocculants through the mud mixing hopper. Add all of the caustic in the first circulation. Then, add the deflocculant and lime over one or two circulations. The mud may thicken or "hump" before breakover. The degree of viscosity increase is dependent mainly upon the solids concentration. If the mud becomes too viscous, increase the addition of deflocculant or water, or both. Adjust the P_M , P_F , and excess lime after the breakover has been accomplished. A rule of thumb for determining the amount of caustic soda required to obtain a given filtrate alkalinity is shown in Table 8.

NaOH, lb/bbl	P_F , cm ³
1	1.0
2	3.0
3	5.0
4	7.0

Note: For a 1-cm³ increase in P_F above 7.0 cm³, it will require approximately one additional pound per barrel of caustic soda.

Approximately 20% additional lime should be added during conversion to obtain the desired amount of excess lime after the conversion is completed. For example, if 8.0 lb/bbl excess lime are required, approximately 10.0 lb/bbl lime should be added at the time of conversion. Also, if barite is added to the mud to increase density, it will take approximately two to three 50-lb sacks of lime per 100 sacks of barite to maintain the excess lime. Excess lime is determined by the equation below:

$$\text{Excess Lime, lb/bbl} = 0.26[P_M - (FW)(P_F)]$$

where:

P_M = Mud Alkalinity

P_F = Filtrate Alkalinity

FW = Volume Fraction Water (from retort analysis)

The amount of chemical required for the conversion will vary; however, treatments in the ranges shown in Table 9 are recommended.

Table 9
Treatment Ranges for Lime Mud Conversions

Additive	Concentration, lb/bbl
Caustic Soda/Caustic Potash	2 - 3
Lime	4 - 8
Deflocculant	2 - 5

Note: It takes approximately 1.6 times more KOH than NaOH to achieve the same alkalinity.

Maintenance - To maintain a lime or lime-treated mud, starch without preservative or PAC may be used to lower fluid loss. However, it is more economical to control fluid loss by adding lignite or ligno-sulfonate along with small additions of prehydrated bentonite. Additional prehydrated bentonite can be added if the viscosity is too low after the fluid loss agent has been added. On the other hand, if the mud becomes too viscous when adding the fluid loss agent, a deflocculant should be added. Add lime to control the alkalinity of the mud (P_M) and NaOH or KOH to control the P_F . A good balanced alkalinity ratio for a lime mud is 1:5:1. The excess lime and P_F should be approximately equal and the P_M should be 5 times greater than the P_F . A lime mud is highly solids tolerant; however, good solids control should always be maintained. The mud will have higher thermal stability if the low-gravity solids are maintained at a low level. Lignosulfonate concentration should be maintained at a level sufficient to maintain good rheological properties. This will ensure a slick, firm filter cake and good API and HTHP filtration control. Prior pilot testing is recommended to determine accurate quantities of materials for addition.

Advantages/Disadvantages of Lime Muds

Lime muds offer several advantages over low pH freshwater muds. They are able to maintain low viscosity and low gel strengths and in addition, they are very tolerant to solids contamination up to a point. Table 10 summarizes some of the advantages and disadvantages of Lime Muds.

Table 10 Advantages/Disadvantages of Lime Muds	
Advantages	Disadvantages
Low viscosity and gel strengths.	High ECD during conversion may cause hole damage.
High solids tolerance.	High-temperature gelation may occur when temperature exceeds 300°F
Easily weighted to 18.0 lb/gal.	
Inhibits hydration of shales and clay-bearing sands.	High pH may cause safety concerns.
Resistant to contamination such as: cement, anhydrite, and salt (50,000 mg/L Cl ⁻ .)	Borehole stabilization.

Troubleshooting and Contamination - Lime Muds

Chlorides and temperature are by far the most serious contaminants in lime muds. Table 11 lists common contaminants, indicators of contamination and treating strategies as well as some troubleshooting practices.

Table 11 Contaminant Treating of Lime Muds		
Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, 10-minute gel strength, MBT.	Major dilution. Improve solids removal. Centrifuge mud.
Salt/Saltwater	Increasing chlorides, Marsh funnel viscosity, yield point, gel strengths, fluid loss. Decreasing P_M , P_F , pH.	Increase density to kill flow. Dilute with freshwater. Add deflocculant, caustic to control rheology; when rheology stabilizes, add starch or PAC to decrease fluid loss. If more salt must be drilled, convert to saturated salt mud or displace with oil-based mud.
Carbonates/ CO ₂ Influx (Not likely to cause a problem in lime muds.)	Increasing M_F , 10-min gels. Decreasing P_M , pH. If CO ₂ influx is continuous, normal treatment with lime can result in a build up of fine solids (CaCO ₃).	Add lime to control P_M and KOH to control P_F . Ensure solids are maintained at low end of acceptable range.
Poor Product Quality	Change in product packaging. Increased treating amounts. Erratic mud properties.	Document product quality history through supplier. Arrange for regular sampling and testing. Work with supplier instead of changing suppliers.
Foaming	Foam on pits. Air entrapment. Decreasing pump pressure.	Add non-toxic, non-sheening defoamer. Locate cause of foam and eliminate.
Temperature Gelation	Increasing pressure to break circulation after trip. Thick mud on bottoms-up after trip. High flowline viscosities.	Reduce low-gravity solids. Add lignosulfonate if BHT < 300°F. Add high-temperature polymeric deflocculant if bottomhole temperature exceeds 300°F.

Lime/MOR-REX Muds

Lime/MOR-REX Muds are similar to the lime muds previously discussed; however, lignosulfonate is not required. Instead, a polysaccharide deflocculant (MOR-REX) is used to counteract rheological problems associated with lime muds. MOR-REX is a non-toxic, non-dispersive thinner which reduces the magnitude of the "breakover hump" through deflocculation.

Principal Additives of Lime/MOR-REX Mud

Table 12 lists typical additive concentrations and the function of these additives in a Lime/MOR-REX mud.

Additive	Concentration, lb/bbl	Function
Bentonite	10 - 30	Viscosity Filtration Control
Lime	2 - 10	Viscosity Filtration Control
MOR-REX	2 - 5	Deflocculant Temperature Limitation 250°F Alkalinity Control
Starch	2 - 6	Filtration Control
Caustic Soda/Caustic Potash	for pH 11.5 - 12.5	Alkalinity Control, Inhibition
PAC	0.25 - 1.25	Filtration Control Viscosity
Lignite	2 - 10	HTHP Filtrate Control
Gilsonite	2 - 8	Hole Stabilizer HTHP Filtrate Control

Bentonite - Bentonite is added for viscosity and filtration control. Because sodium is replaced by calcium when the mud is "broken over" to a lime/MOR-REX mud, the bentonite must be prehydrated in fresh water before adding it to the active system.

Lime - Lime is added to increase P_M . Excess lime is usually maintained in the range of 2-4 lb/bbl. Excess lime is a measure of the alkalinity reserves that are available to go into solution as drilling proceeds and calcium and hydroxyl ions are depleted.

MOR-REX - MOR-REX is a polysaccharide polymer that is added to a lime-based mud to control flocculation and increase lime solubility.

Starch - Starch is added to control filtration.

Caustic Soda/Caustic Potash - Caustic soda or caustic potash are used to control filtrate alkalinity (P_F). Caustic potash is also added for inhibition through the K^+ ion.

Polyanionic Cellulose - PAC is added to suspend barite, increase viscosity, and to control filtration.

Lignite - Lignite is added as an inexpensive supplementary filtration control additive. Although in the presence of lime it will form a precipitate, it still functions in lowering fluid loss.

Other Additives - Gilsonite, asphalt, cellulosic fibers are added to seal permeable formations and stabilize the wellbore.

Typical Properties of Lime/MOR-REX Mud

Properties of Lime/MOR-REX muds vary slightly from conventional lime muds. Lime/MOR-REX muds have higher soluble calcium and slightly higher yield point and gel strengths. Table 13 lists typical properties for Lime/MOR-REX muds.

Table 13 Typical Properties of Lime/MOR-REX Mud									
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10 min (lb/100 ft ²)		P _M	P _F	pH	Ca ⁺⁺ (mg/L)	API Filtrate (cm ³)
9	9-12	2-20	0-5	1-20	10-15	2-3	11.0-12.0	200-800	8-12
12	15-20	2-15	0-5	2-15	10-15	2-3	11.0-12.0	200-600	6-8

System Conversion/Maintenance

As with most mud breakovers, it is desirable to convert a mud while the mud density, solids, and gel strengths are low. To convert to an unweighted or low-density mud, the following procedures are followed. First, the solids content of the mud should be in an optimum range. If not, dilute with freshwater and run solids control equipment to reduce low-gravity solids to an acceptable limit. The Methylene Blue Capacity (MBT) of the mud should not normally exceed 20-25 lb/bbl bentonite equivalent. The primary conversion is accomplished by treating the system with 4 lb/bbl of lime, 3 lb/bbl of MOR-REX I-920 polymer, and 1 lb/bbl of caustic soda (NaOH) or caustic potash (KOH) together over one circulation, if possible. The chemicals should be added quickly and uniformly to minimize the effect of the viscosity hump. The mud pits should be well-agitated. A small but steady stream of water during the breakover helps water wet additives added. Mud alkalinity and calcium concentration are adjusted as necessary by treatment with caustic (KOH or NaOH), lime, and MOR-REX I-920 polymer.

The fluid loss is adjusted by adding 1-3 lb/bbl of starch (Control I-100 or Control I-165). Although lignite will react with calcium ion to form a precipitate, it can be used to lower the water loss and obtain a better filter cake. Following the breakover, any further adjustments in the mud system can be accomplished during tourly treatments. Occasionally during conversion viscosity and gel strengths may decrease to a value below that which will suspend barite. If this occurs, add additional lime or suspend treatment with MOR-REX I-920 polymer. The mud will then flocculate enough to impart gel strength and viscosity for temporary barite suspension. Prehydrated bentonite, starch, or PAC may then be added for additional viscosity to suspend bentonite. In open hole conversion, the pipe should be pulled up inside the casing. Then, proceed with breaking over the mud inside the casing and in the pits. After the breakover is completed, return to bottom and break over the rest of the fluid in the hole. If there is a large amount of open hole, staging back to the bottom and incrementally breaking over the mud is advisable.

Maintenance - To increase the calcium and P_M, MOR-REX and lime should be added together. To decrease the calcium, the P_F is raised with either caustic soda or caustic potash. Starch additions should never be added simultaneously with either lime or caustic. As a general rule of thumb, to increase the P_M by 3.0 cm³, add 1 lb/bbl lime along with one pound per barrel MOR-REX.

Advantages/Disadvantages of Lime/MOR-REX Mud

Lime/MOR-REX muds offer many of the same advantages and disadvantages as lime muds. Table 14 lists these advantages and disadvantages.

Table 14 Advantages/Disadvantages of Lime/MOR-REX Muds	
Advantages	Disadvantages
Low viscosity and gel strengths.	Expensive.
High solids tolerance.	Temperature limitation of approximately 300°F
Easily weighted to 18.0 lb/gal.	High pH may cause safety concerns.
Inhibits hydration of shales and clay-bearing sands.	High pH may cause safety concerns.
Resistant to contamination such as: cement, salt, and anhydrite.	
Borehole stabilization.	

Troubleshooting and Contamination - Lime/ MOR-REX Muds

Contamination and treating strategies for Lime/MOR-REX muds are essentially the same as for lime muds. Table 15 lists indicators and treating strategies for various contaminants.

Table 15
Contaminant Treating of Lime/MOR-REX Muds

Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, 10-minute gel strength, MBT.	Major dilution. Improve solids removal. Centrifuge mud.
Salt/Saltwater	Increasing chlorides, Marsh funnel viscosity, yield point, gel strengths, fluid loss. Decreasing P_M , P_F , pH.	Increase density to kill flow. Dilute with freshwater. Add deflocculant, caustic to control rheological properties. When rheology stabilizes, add starch, PAC to decrease fluid loss. If more salt must be drilled, convert to saturated salt mud or displace with oil-based mud.
Carbonates/ CO ₂ Influx (Not likely to cause a problem in Lime/MOR-REX mud.)	Increasing M_F , 10-min gels. Decreasing P_M , pH. If CO ₂ influx is continuous, normal treatments with lime can result in a build up of fine solids (CaCO ₃).	Add lime to control P_M and KOH to control P_F . Ensure solids are maintained at low end of acceptable range.
Poor Product Quality	Change in product packaging. Increased treating amounts. Erratic mud properties.	Document product quality history through supplier. Arrange for regular sampling and testing.
Foaming	Foam on pits. Air entrapment. Decreasing pump pressure.	Add non-toxic, non-sheening defoamer. Locate cause of foam and eliminate.
Temperature Gelation	Increasing pressure to break circulation after trip. Thick mud on bottoms-up after trip. High flowline viscosities.	Reduce low-gravity solids. Add lignosulfonate if BHT < 300°F. Add high-temperature polymeric deflocculant if bottomhole temperature exceeds 300°F.

Gyp Muds

Originally, gyp muds were used for drilling massive sections of anhydrite. Lack of an effective deflocculant confined their use to low-density muds that normally possessed high viscosity and high gel strengths, until the introduction of chrome lignosulfonate as a deflocculant.

Gyp mud systems are less susceptible to high-temperature solidification than lime muds due to their lower alkalinity values. If the P_F is kept low (0.1 to 0.4), a gyp mud may tolerate temperatures up to

350°F; however, they normally have higher fluid loss than lime-treated muds and usually require the use of additional deflocculant. Gyp muds also have higher soluble calcium.

The pH range for a gyp mud is from 9.5 - 12.5; however, it is usually maintained at 9.5 - 11.0 so that the hardness remains high which makes the mud more inhibitive. The calcium ion level is maintained from 200-1200 mg/L. A gyp mud is fairly tolerant up to a maximum of 100,000 mg/L chlorides. The temperature limitation of a gyp mud is 350°F and will depend on the amount of low-gravity solids in the mud system.

Principal Additives of Gyp Mud

Principal additives of gyp muds are similar to the lime muds. Exceptions are that concentrations of deflocculants and fluid loss additives are higher. Table 16 lists the principal additives used in formulating and maintaining gyp muds.

Additive	Concentration, lb/bbl	Function
Bentonite	20 - 24	Viscosity Filtration Control
Lignosulfonate	4 - 8	Deflocculant
Gypsum	4 - 8	Inhibition Alkalinity Control
Caustic Soda	pH 9.5 - 11.0	Alkalinity Control
Caustic Potash		Inhibition
DESCO	2 - 3	Deflocculant
Starch	2 - 6	Filtration Control
PAC	0.25 - 1.5	Viscosity Filtration Control
Barite	as required for density	Weighting Agent

Bentonite - Prehydrated bentonite is added to increase viscosity and control filtration.

Gyp - Gypsum provides Ca⁺⁺ ion for base exchange of clays from Na⁺ to Ca⁺⁺ for inhibition. Calcium ion level is maintained from 200-1200 mg/L.

Lignosulfonate - Mixed-metal lignosulfonates provide excellent deflocculation of gypsum-based muds as well as good filtration control by their dispersive action upon the clays.

Caustic Soda/Caustic Potash - Caustic is added when needed to control calcium solubility and to stabilize mud properties.

DESCO - DESCO, a sulfonated tannin, is an effective deflocculant in gyp muds. It can be added either as a primary or secondary deflocculant.

Starch - Starch is added for filtration control. A preserved starch (starch with biocide already added) should be used; however, if unpreserved starch is used, then a biocide should be added along with the starch.

Polyanionic Cellulose - PAC provides additional filtration control. Low-viscosity PAC is used when no increase in yield point is desired.

Barite - Barite is added to increase density.

Other Additives - Gilsonite, asphalt, DMS, and cellulosic materials can be added for additional well-bore stabilization.

Typical Properties of Gyp Muds

Gyp muds typically have higher yield point, gel strengths, and soluble calcium compared to other calcium-based inhibitive fluids. Table 17 lists typical properties for 9 lb/gal and 12 lb/gal gyp muds.

Table 17 Typical Properties of Gyp Muds									
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10 min (lb/100 ft ²)		Excess Gyp (lb/bbl)	P _F	pH	Ca ⁺⁺ (mg/L)	API Filtrate (cm ³)
9	12-15	6-10	2-4	8-12	10-15	0.2-0.7	9.5-11.0	600-1200	8-12
12	15-20	2-15	0-5	2-15	10-15	2-3	11.0-12.0	200-600	6-8

System Conversion/Maintenance

A procedure for converting to gyp mud is similar to the lime muds; however, the source of calcium is gypsum instead of lime. Native or lightly-treated freshwater low pH muds are preferred for conversion; however, any water-based mud can be converted to a gyp mud. If high pH or lime muds are to be converted, more water dilution will be required to lower solids and more gypsum will be required to control alkalinity. Caustic soda is usually not required in this instance.

A typical breakover from a lightly-treated freshwater mud may be performed by first reducing Marsh funnel viscosity to 30-35 sec/qt with water. Water is added prior to breakover to prevent excessive viscosity during conversion. The amount of water will depend upon the solids content and previous chemical treatment. Add four to eight lb/bbl of gypsum through the hopper over one or more circulations. Three to six lb/bbl of lignosulfonate may be necessary to add along with the gypsum to control excessive rheology. Caustic soda, lime, or both, can also be added (through a chemical barrel) during the gypsum additions to control the pH between 9.5 and 11.0 (P_F is normally maintained between 0.2 and 0.7 cm³). Caustic soda minimizes the viscosity increase during conversion. The amount required will depend on the desired P_F and the pH of the mud prior to converting. Normally, 1/2 to 1-1/2 lb/bbl caustic soda is required for the breakover. If starch is used for fluid loss control, a preservative must be used to prevent fermentation. Foaming may occur during or following conversion, but generally is a surface phenomena and is not detrimental to drilling. Remedial measures should be taken to avoid mechanical entrapment of air; for example, submerge the surface guns. If foaming becomes excessive, defoamer is recommended.

Maintenance - A gyp mud is easy to maintain. Due to high calcium hardness of gyp muds, bentonite additions must be prehydrated before adding to the system. The system usually must be supplemented with a polymer to achieve low filtrate control, 8 cm³ or less (API). Rheology control is accomplished by addition of lignosulfonate. Alkalinity control is maintained with NaOH or KOH. A tourly treatment for each additive can be prescribed by calculating the amount of hole to be drilled, water addition required, and mud density to be maintained.

Advantages/Disadvantages of Gyp Muds

Gyp muds have many of the same advantages and disadvantages as lime and lime/Mor-Rex muds; however, gyp muds are slightly more temperature stable. Table 18 lists both advantages and disadvantages of gyp muds.

Table 18 Advantages/Disadvantages of Gyp Muds	
Advantages	Disadvantages
Low viscosities and gel strengths.	High ECD during conversion may cause hole damage.
High solids tolerance.	High temperature gelation may occur when temperature exceeds 300°F
Easily weighted to 18.0 lb/gal.	
Inhibits hydration of shales and clay-bearing sands.	
Resistant to contamination such as: cement, anhydrite, salt (100,000 mg/L Cl ⁻).	
Borehole stabilization.	

Troubleshooting and Contamination - Gyp Muds

Gyp muds are fairly resistant to contamination. Salt and cement contamination do not greatly affect mud properties and when flow properties increase, generally deflocculant treatments will usually restore properties. Table 19 lists common contaminants, indicators of contamination, and principal treating strategies for each. The table also includes troubleshooting for problems such as poor product quality and foaming.

Table 19
Contaminant Treating of Gyp Muds

Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, 10-minute, gel strength, MBT.	Major dilution. Improve solids removal. Centrifuge mud.
Salt/Saltwater	Increasing chlorides, Marsh funnel viscosity, yield point, gel strengths, fluid loss. Decreasing P_M , P_F , pH.	Increase density to kill flow. Dilute with freshwater. Add deflocculant, caustic to control rheology. When rheology stabilizes, add starch, PAC to decrease fluid loss. If more salt will be drilled, consider converting to a saturated salt mud or displace with oil-based mud.
Carbonates/ CO ₂ Influx (Not likely to cause a problem in Lime muds.)	Increasing M_F , 10-min gels. Decreasing P_M , pH. Increase in mud density causes thick mud. If CO ₂ influx is continuous, normal treatments with lime can result in a build up of fine solids.	Add lime to control P_M and KOH to control P_F . Ensure solids are at low end of acceptable range.
Poor Product Quality	Change in product packaging. Increased treating amounts. Erratic mud properties.	Document product quality history through supplier. Arrange for regular sampling and testing.
Foaming	Foam on pits. Air entrapment. Decreasing pump pressure.	Add non-toxic, non-sheening defoamer. Locate cause of foam and eliminate.
Temperature	Increasing pressure to break circulation after trip. Thick mud on bottoms-up after trip. High flowline viscosities.	Reduce low-gravity solids. Add lignosulfonate if BHT < 300°F. Add high-temperature polymeric deflocculant if bottomhole temperature exceeds 300°F.

Salt-Based Muds

To eliminate confusing terminology, any references to the term “salt” in this manual will herein refer to sodium chloride, unless otherwise stated. Therefore, salt-based muds are muds containing varying amounts of **predominantly** sodium chloride ranging from 10,000 mg/L NaCl up to saturation,

315,000 mg/L NaCl. However, when referring to chloride ion concentration which is colorimetrically titrated and reported on the Drilling Mud Report, chlorides will mean chlorides from **any** source such as calcium chloride, magnesium chloride, sodium chloride, potassium chloride, etc. Thus, 10,000 mg/L salt is approximately equivalent to 6000 mg/L chlorides. Other confusing terms are: parts per million (ppm) and milligrams per liter (mg/L). Parts per million refers to a weight per specified weight measurement versus milligrams per liter, which refers to a weight per volume measurement. Titrations routinely performed on drilling fluids at the rigsite are done on a weight per volume and reported as milligrams/liter (mg/L).

The effect that salt has on a drilling mud is dependent on the amount of salt in the fluid and the type and quantity of solids.

Salt acts as a contaminant in freshwater mud systems. Even when encountered in small amounts, salt contamination can cause an increase in viscosity, gel strengths, and fluid loss. As salt concentrations increase to greater than 10,000 mg/L, mud properties become increasingly more difficult to control. Muds are usually called salt-based muds if the sodium chloride content is greater than 10,000 mg/L NaCl. There are three basic salt-based muds:

Salt-Based Muds Classification	NaCl, mg/L
Saturated Salt Muds	315,000
Saltwater Muds	25,000-315,000
Brackish-Water Muds	10,000-25,000

Saturated Salt Muds may be prepared purposely or evolve from drilling into salt.

Saltwater Muds are most often the result of using field brine or seawater as makeup water, or incorporating salt that is encountered while drilling.

Brackish-Water Muds are the result of using water from sources such as: bay water, inland canals, or water from swamps or marshes.

Saturated Salt Muds

Saturated Salt Muds are used to prevent excessive hole enlargement while drilling massive salt beds. They can also be used to reduce dispersion and hydration of shales and clays. High viscosity problems in Saturated Salt Muds are unusual; however, solids content (percent by volume) should be maintained within a desired range by mechanical removal or dilution with saturated salt water to prevent unacceptable increases in gel strengths and viscosity.

Saturated saltwater contains approximately 13 volume % dissolved solids; therefore, to obtain "true" brine content of Saturated Salt Muds, multiply the "retort liquid" volume percent of the mud by 1.13 and subtract that from 100 to obtain actual volume percent suspended solids content. Volume increase due to lower concentrations of salt can also be calculated. Equations for calculating solids are located in Section 5, *Solids Calculations*.

The chloride content of saturated salt muds is 192,000 mg/L (315,000 mg/L NaCl) at saturation. As the temperature of the mud increases, more salt is able to go into solution. This means that a fluid which is saturated under surface conditions may not be saturated at downhole temperatures and can cause substantial washout in a salt zone due to increased salt solubility.

Control of the pH of saturated salt muds varies widely. These muds do not require pH to function. Many low- solids, attapulgate/starch muds are used without adding caustic soda. In other areas, it is a

common practice to maintain the pH of the mud from 11-11.5 with additions of caustic soda. Saturated salt muds require larger additions of caustic soda to maintain a higher pH than do freshwater muds. Maintaining an 11 to 11.5 pH offers several advantages:

- Deflocculants are more effective
- Corrosion is reduced
- Lower concentrations of filtration control additives are required when Ca⁺⁺ and Mg⁺⁺ solubility is reduced
- Foaming tendency is lessened
- Mud is generally more stable

Saturated salt muds will normally contain soluble calcium due to the formations penetrated and the type of makeup water used. Also, the sodium ions from the salt will undergo a base exchange and release calcium ions from the clay platelets, thereby contributing to the free calcium. Generally, the presence of calcium does not produce detrimental effects on the mud; except when the pH is increased beyond 12.0 and then the fluid loss will be difficult to control.

Saturated salt muds are characterized by foaming. Foaming is generally restricted to surface foam and is not troublesome unless aggravated by mechanical agitation. The degree of foaming may sometimes be decreased by increasing the alkalinity of the mud (P_M). Also, the addition of bentonite can be successful in reducing the foaming. A defoaming agent may be necessary. Unless Mg⁺⁺ sensitive additives are used, a Saturated Salt Mud is less prone to foam and air cut with a 9.0-9.5 pH.

The temperature limitation of Saturated Salt Mud is around 250°F and is normally dictated by the filtration control additive used. Ca⁺⁺ and Mg⁺⁺ hardness do not adversely affect filtration control in Saturated Salt Mud when using starch; however, when PAC is used, hardness should be below 400 mg/L.

Principal Additives of Saturated Salt Mud

Saturated Salt Mud are generally inexpensive to maintain and contain few additives. System complexities are greatly reduced due to the limited selection of additives that will function effectively in a saturated salt mud. Table 20 lists typical additives, function, and concentration for Saturated Salt Mud.

Table 20 Principal Additives of Saturated Mud		
Additive	Concentration, lb/bbl	Function
Prehydrated Bentonite	10 - 25	Viscosity Filtration Control
Starch	4 - 6	Filtration Control
Caustic Soda	for pH 9.0 - 11.0	Alkalinity Control
Soda Ash	1 - 3	Calcium Removal
PAC	0.25 - 1.5	Filtration Control Viscosity
Salt (NaCl)	125	Weight Material Inhibition

Bentonite - Viscosity can be controlled to a limited degree with the addition of prehydrated bentonite. The positive sodium ion (from the salt) acting on the swelled clay causes flocculation, giving viscosity with a minimum of clay added. In time, the mass action of the sodium ion on the hydrated bentonite shrinks the hydration water shell around the clay platelet releasing free water and causing a rapid drop in viscosity. This rate of drop in viscosity can be decreased by adding prehydrated bentonite that has been treated with caustic and a deflocculant such as lignosulfonate. Continued additions of prehydrated bentonite are necessary to maintain desired viscosity. Although very little filtration control is provided with prehydrated bentonite, the particle size distribution may aid in filtration control. Attapulgate can be used as an alternative viscosifier when freshwater is unavailable to prehydrate bentonite.

Attapulgate - Attapulgate, a clay which yields through shear rather than hydration, is commonly used in saturated salt muds to develop viscosity. Attapulgate will not be affected by either chlorides or hardness. Due to its brush-heap structure, attapulgate does not provide filtration control. Normal concentrations of attapulgate are 10-20 lb/bbl.

Starch - Starch is the most common fluid loss additive in saturated salt muds. It is not affected by high levels of hardness (2000-3000 mg/L) and does not adversely affect rheology unless drill solids concentrations are outside acceptable limits. Starch has a thermal limit of approximately 250°F. Normally it will not ferment as long as the system is salt-saturated or the pH is above 11.5.

Caustic Soda - Caustic soda is added to increase the alkalinity of a Saturated Salt Mud. The pH range is from 9.0 - 11.0 to minimize corrosion of the drill string and prevent starch fermentation. Saturated salt muds usually require large additions of caustic soda to maintain a high pH because the base exchange of the sodium on clays tends to release free hydrogen ions which lower pH.

Soda Ash - Soda ash is added to precipitate hardness to allow calcium-sensitive materials such as PAC to function efficiently. The amount of soda ash required will depend on the amount of soluble calcium in the system. The total hardness should be checked to determine the amount of calcium present in order to avoid overtreating with soda ash. Too much soda ash will contribute to high gel strengths. The addition of soda ash is not feasible where hard brines are continuously used as makeup water.

Polyanionic Cellulose - PAC is added for viscosity and filtration control. PAC functions more efficiently when low-gravity solids are under 6 volume % and hardness is below 400 mg/L. If increases in viscosity of the mud are not desired, low-viscosity PAC can be used to control filtration.

Typical Properties of Saturated Salt Mud

Saturated Salt Mud typically exhibit high yield point values and gel strengths. Gel strengths, although high, are generally fragile. Table 21 lists typical properties for unweighted (10.5 lb/gal) and weighted saturated salt muds.

Table 21
Typical Properties of Saturated Salt Mud

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		API Filtrate (cm ³ /30 min)
10.5	8 - 12	12 - 15	6 - 8	8 - 12	8 - 12
12.5	15 - 20	15 - 18	8 - 10	10 - 14	6 - 8

System Conversion/Maintenance - Conversion

A freshwater mud is usually used to drill down to the top of a salt section. Conversion to a saturated salt mud is made prior to drilling into the salt. Some operators have drilled salt sections allowing the drilled salt to saturate the freshwater mud; however, this is not a recommended practice due to the excessive hole enlargement where large sections of salt are drilled.

Usually there are no problems associated with saturated salt mud conversions. Conversion can be accomplished in two circulations. The mixing hopper discharge should be located away from the main pump suction to reduce foaming and air cutting. When a freshwater mud is to be converted to a saturated salt mud, it is desirable to use as much of the old mud as possible. This will provide a source for building viscosity and density and will save on the amount of saltwater clay (attapulgate) or prehydrated bentonite required. Additions of salt to a freshwater clay-based mud will cause severe flocculation and excessive viscosity. It is therefore necessary to water back the old mud. Usually 30% to 50% dilution is required, depending on solids concentration. The amount of salt required to saturate the system should be calculated and then added through the hopper. It requires approximately 125 lb/bbl of NaCl to saturate one barrel of water. This will result in 1.13 bbl of saturated fluid or an 0.13 volume increase. A saturated salt mud will generally weigh 10.4 to 10.5 lb/gal without weight material addition. Next, a fluid loss additive is added through the hopper while the mud is circulated. Starch is generally used for fluid loss control and as a supplementary viscosifier. Normally, four to six lb/bbl starch will be required to obtain a fluid loss of approximately 6 cm³/30 minutes. If a higher density is required, barite may be used. When weighting up with barite, a lignosulfonate deflocculant is recommended to avoid excessive viscosity and high gel strengths. Caustic soda is usually added along with the deflocculant.

Maintenance - In many cases, saturated salt muds are maintained throughout the drilling of the well without additions of anything other than water, a viscosifier and a fluid loss control additive. Viscosity can be increased with prehydrated bentonite or attapulgate and decreased by dilution with saturated salt water. In some cases, the use of a deflocculant may be needed to lower the yield point, gel strengths, or viscosity. Lignosulfonates can be used to deflocculate saturated salt muds; however, polymeric thinners have demonstrated greater effectiveness at higher temperatures and do not require caustic soda in order to function properly.

Advantages and Disadvantages of Saturated Salt Muds

Saturated Salt Muds are fairly easy to run and are highly resistant to most contaminants. Table 22 lists some of the advantages and disadvantages of using Saturated Salt Muds.

Advantages	Disadvantages
Inhibitive	Filtration control difficult - dependent on starch or polymers.
Resistant to contaminants such as cement, anhydrite, salt and saltwater flows.	Tendency to foam and air cut.
Lower solids - uses dissolved solids for density.	Corrosive if below saturation.
Good hole cleaning capability.	Maximum temperature limitation of 280°F.
Resistant to contamination such as: cement, anhydrite, salt (100,000 mg/L Cl ⁻).	
Borehole stabilization.	

Troubleshooting and Contamination - Saturated Salt Muds

Saturated saltwater muds generally are resistant to contamination from salt, cement, gyp, or anhydrite. Since these muds are highly resistant to contamination, Table 23 lists only a few areas that require specific troubleshooting and treatment strategies.

Contaminant	Indicators	Treating Strategy
High Solids	Increasing PV, YP, gel strength, viscosity, fluid loss, MBT. Foaming and air entrapment	Major dilution. Improve mechanical solids control. Centrifuge mud.
Saltwater Flow	Decreasing PV, YP, gel strengths. Increasing filtrate. Possible decrease chlorides and density (depending on salinity of mud).	Raise mud density to control saltwater influx. Add salt to saturate. Add starch to decrease filtrate. Add attapulgite or prehydrated bentonite to increase viscosity.
Poor Product	Material performance poor even though adequate treatment concentrations added. Product package change.	Pursue history of material manufacture. Set up sampling and testing program.

Saltwater Muds

Saltwater muds are often prepared from fresh water or bentonite-water muds. These muds normally contain low solids concentrations, have low densities, have minimal chemical treatment, and possess low viscosities and high fluid losses. Saltwater muds may be prepared intentionally with salt to drill troublesome shale sections. They are used as an inhibitive mud to decrease dispersion and viscosity build-up from drilled solids. These muds may range from approximately 25,000 mg/L salt up to nearly saturation. Produced brines are commonly used in workover and completion operations. Swelling of formation clays or shales are reduced. They are also used as low solids fluids to control pressures that are normally encountered in workover and well completion operations. Seawater can also be used to formulate a saltwater mud. Frequently in offshore drilling, seawater is used as the makeup water to avoid the expense and problems of transporting fresh water to the wellsite. Typical seawater composition contains approximately 35,000 mg/L NaCl and 1500 to 2500 mg/L total hardness. The temperature maximum for Seawater Muds is 280-300°F, depending upon the clay content of the mud.

Principal Additives of Saltwater Muds

Saltwater Mud formulations are more complex than Saturated Salt Muds because their salinity range does not limit selection of additives. Table 24 lists typical additives, their function, and normal concentration ranges for Saltwater Muds.

Table 24 Principal Additives of Saltwater Muds		
Additive	Concentration, lb/bbl	Function
Prehydrated Bentonite	15 - 25	Viscosity Filtration Control
Caustic Soda/ Caustic Potash	0.5 - 1.5	Alkalinity Corrosion Control
Starch	3 - 6	Filtration Control
PAC	0.5 - 1.0	Filtration Control
Lignosulfonate	3 - 6	Deflocculant
Lignite	2 - 4	HTHP Filtration Control

Bentonite - Viscosity can be controlled to a limited degree with the addition of prehydrated bentonite. The positive sodium ion (from the salt) acting on the swelled clay causes flocculation, giving viscosity with a minimum of clay added. In time, the mass action of the sodium ion on the hydrated bentonite shrinks the hydration water shell around the clay platelet releasing free water and causing a rapid drop in viscosity. This rate of loss in viscosity can be decreased by adding prehydrated bentonite that has been treated with caustic and a deflocculant such as lignosulfonate. Continued additions of prehydrated bentonite are necessary to maintain desired viscosity. Although very little filtration control is provided with prehydrated bentonite, the particle size distribution may aid in filtration control. Attapulgite can be used as an alternative viscosifier when freshwater is unavailable to prehydrate bentonite.

Attapulgite - Attapulgite is sometimes added for viscosity in Saltwater Muds; however, prehydrated bentonite or polymers are preferred. Attapulgite is neither affected by chlorides nor hardness. Due to its brush-heap structure, it does not provide filtration control. Normal concentrations are 10-20 lb/bbl. Use of attapulgite is sometimes prohibited due to local environmental regulations.

Starch - Starch is added for filtration control. Three pounds per barrel will give approximately 12-15 cm³/30 min. fluid loss and 5 lb/bbl will give approximately 6 to 8 cm³/30 min. fluid loss. A preservative should be added prior to starch additions and maintained at recommended concentration in the system. The more expensive preserved starches can be used in lieu of the unpreserved starches.

Caustic Soda/Caustic Potash - NaOH or KOH is added for pH, alkalinity, and corrosion protection. When lignosulfonate is used in a saltwater mud it functions more efficiently when the environment is alkaline. Caustic soda is used to maintain the pH of Saltwater Muds within the range 9.0 to 11.0.

Polyanionic Cellulose - PAC is added for filtration control. There may be a noticeable increase in viscosity and gels in the suction pit as the PAC is mixed; however, as the mud is circulated through the hole, the viscosity and gels should be back to normal at the flow line. Hardness should be maintained below 400 mg/L. If increases in viscosity of the mud are not desired, low-viscosity PAC can be used to control filtration.

Lignosulfonate - Lignosulfonates are the most effective deflocculant in Saltwater Muds (especially Seawater Muds) and also contribute to fluid loss control.

Lignite - Lignite is added to improve HTHP filtration control, but is ineffective as a deflocculant. It is recommended to presolubilize the lignite in causticized fresh water (pH 10.5-11.0).

Soda Ash - Soda Ash may be used to precipitate calcium from salt water. This will maximize the effectiveness of most fluid loss additives.

Corrosion Inhibitor - Corrosion is more severe in Saltwater Muds than in freshwater muds or Saturated Salt Muds. Controlling the pH in the upper ranges is usually adequate; however, corrosion inhibitors such as filming amines are frequently used. An oxygen scavenger may also be used.

Preservatives - Preservatives are used in Salt Muds to prevent starch and XC polymer from fermenting. Several different types of preservatives or biocides are currently available. Testing has shown that the isothiazoline-based biocides are more effective in limiting bacterial degradation of starches. Biocides are usually not necessary in muds with a pH above 11.5

Defoamers - Defoamers are always needed for Saltwater Muds. Pilot testing is recommended.

Another popular saltwater mud is the Seawater-Lime Spud mud, which consists of prehydrated bentonite, lime, and seawater; however, starch and/or PAC (regular grade or low-viscosity) can be added if additional filtration control is required. If both starch and PAC are used, a ratio of 5 sacks starch to 1 sack PAC usually gives optimum performance. The mud starts out with 30-40 lb/bbl prehydrated bentonite in fresh water and then uses seawater and lime (1-4 lb/bbl) to maintain and control viscosity. In addition, the calcium ions from lime react with the sodium-based clays to minimize dispersion hydration of formation clays. Lime also reduces bit and BHA balling while drilling gumbo. When drilling gumbo, the pH should be maintained at 9.0-10.0. If bit balling occurs, increase the mud alkalinity (P_M) to 5 or more with lime. If shales are difficult to control, KOH may be used instead of lime, but not NaOH.

Typical Properties of Saltwater Muds

Saltwater Muds range in salinity from 25,000 mg/L salt up to nearly saturation. Generally, these fluids do not exhibit the high viscosities and fragile gel strengths of the Saturated Salt Muds. Table 25 lists typical properties for a Saltwater Mud.

<i>Table 25 Typical Properties of Saltwater Muds</i>						
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		Chlorides mg/L	API Filtrate (cm ³ /30 min)
9	16 - 18	10 - 14	2 - 4	5 - 8	25,000 - 300,000	6 - 10
12	22 - 24	12 - 16	2 - 4	5 - 8	25,000 - 300,000	6 - 8

System Conversion/Maintenance - Conversion

These muds generally present the same problems for conversion and maintenance as Saturated Salt Muds. Many of the problems associated with Saltwater Muds, particularly seawater muds, are due to the high concentrations of total hardness. Magnesium ion hardness (magnesium carbonate) is relatively soluble; therefore, treating with soda ash for reduction of total hardness in seawater is not effective. Magnesium is; however, insoluble at a pH of 10; therefore, caustic soda is effective in removing magnesium ion from seawater muds. Supplementary additions of lime may be used to maintain hydroxyl ion concentration. Also, soda ash may be used to precipitate the calcium ion to obtain better mud properties. Ca⁺⁺ ion contamination does not severely affect these muds, but the Ca⁺⁺ should be treated and kept under 400 mg/L. Conversion to a Saltwater Mud is performed according to some very simple guidelines. First, the solids content of the mud to be converted should be in an acceptable range. If the solids are too high, reduce concentration with solids removal equipment and/or dilute with available makeup water to obtain acceptable concentration. If the viscosity of the mud is too low, add prehydrated bentonite that has been treated with deflocculant and caustic soda. After rheological properties are adjusted, then adjust the filtrate with starch or PAC, if necessary. If starch is used and pH is below 11.5, add biocide.

Maintenance - To maintain a Saltwater Mud, the solids should be monitored and controlled in an acceptable range. These muds are quite solids tolerant, but they will run more economically if low-gravity solids are less than 6% by volume. Bentonite should be prehydrated and added as indicated by MBT analysis. The clay content of the mud should be decreased as density is increased to minimize downhole gelation problems.

Advantages and Disadvantages of Saltwater Muds

Table 26 lists some of the advantages and disadvantages of Saltwater/Seawater Muds.

Table 26 Advantages/Disadvantages of Saltwater Muds	
Advantages	Disadvantages
Inhibitive	Increased additive concentration, decreased efficiency.
Reduces freshwater consumption.	Filtration control difficult.
Minimal adverse effects of contaminants such as anhydrite, cement, salt, saltwater flow.	Requires bentonite to be prehydrated.

Troubleshooting and Contamination - Saltwater Muds

Contamination in Saltwater Muds is more evident than in Saturated Salt Muds. Saltwater muds contain more additives and the range of salinity and hardness affects fluid performance. Treating strategies for contaminants in Saltwater Muds are listed in Table 27.

Table 27 Contaminant Treating of Saltwater Muds		
Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, YP, gel strength. Mud thick on bottoms-up after trip.	Massive dilution. Centrifuge mud. Improve mechanical solids control.
Saltwater Flow	Increasing YP, fluid loss, chlorides. Possible decrease in density.	Increase density to control water flow. Increase deflocculant to control rheology. Add starch or PAC for filtration control.
Poor Product Quality	Increased treating frequency. Product package change.	Pursue history of material manufacture. Set up sampling and testing program.
Cement	Increasing PV, YP, pH, P_M , P_F and fluid loss. Possible increase in Ca^{++} .	Add bicarb or SAPP to treat out cement. Dilute with freshwater or seawater. Mix additional deflocculant to control rheology. Mix starch and/or PAC to reduce filtrate.
Carbonates	Increasing gels, YP. Rheology erratic. Thick mud on bottoms up after trips.	Increase pH to 10.7 or higher to convert bicarbonates to carbonates. Treat with lime or gyp to remove carbonate ion.

Brackish-Water Muds

In many areas, because of economics or lack of sufficient fresh water, brackish water often is used as the makeup water for drilling fluids. These muds generally are termed brackish-water if their salt content is between 10,000 to 15,000 mg/L. They are usually found in inland bay areas or marshes.

Principal Additives of Brackish-Water Muds

Although additives and concentrations are essentially the same as for Saltwater Muds, Brackish-Water Muds generally are not as difficult to maintain because of their lower makeup water salinity. However, because of the nature of brackish water environments, both organics and bacteria may cause increased consumption of additives.

<i>Table 28 Principal Additives of Brackish-Water Muds</i>		
Additive	Concentration, lb/bbl	Function
Prehydrated Bentonite	15 - 25	Viscosity Filtration Control
Caustic Soda/ Caustic Potash	0.5 - 1.5	Alkalinity Corrosion Control
Starch	3 - 6	Filtration Control
PAC	0.5 - 1.0	Filtration Control
Lignosulfonate	3 - 6	Deflocculant
Lignite	2 - 4	HTHP Filtration Control

Bentonite - bentonite is added for viscosity and filtration control in brackish-water muds. The bentonite should be prehydrated in fresh water and then added to the mud system. In time, the mass action of the sodium ion on the hydrated bentonite shrinks the hydration water shell around the clay platelet releasing free water and causing a rapid drop in viscosity. This rate of loss in viscosity can be decreased by adding prehydrated bentonite that has been treated with caustic and a deflocculant such as lignosulfonate. Continued additions of prehydrated bentonite are necessary to maintain desired viscosity. As an alternative viscosifier, when freshwater is unavailable to prehydrate bentonite, Attapulgite can be used.

Attapulgite - Although attapulgite is occasionally added for viscosity, prehydrated bentonite is preferred as it also aids in filtration control. Attapulgite is not affected by chlorides and hardness. Due to the brush-heap structure, it does not provide filtration control. Normal concentrations are 10-20 lb/bbl.

Caustic Soda - Caustic soda is used to maintain the pH of brackish-water muds within the range 9.0 to 11.0.

Starch - Starch is added for filtration control. A preservative should be added prior to starch additions and the recommended concentration maintained in the system.

Polyanionic Cellulose - PAC is added for filtration control. Hardness must be maintained below 400 mg/L.

Lignosulfonate - Lignosulfonates are the most effective deflocculants in Brackish-Water Muds and contribute to fluid loss control.

Lignite - Lignite is added to improve HTHP filtration control, but may not be an effective deflocculant, depending on makeup water quality.

Soda Ash - Soda Ash may be used to precipitate calcium from brackish water. This not only allows better hydration of clays, but also will maximize the effectiveness of fluid loss additives.

Corrosion Inhibitor - Corrosion is more severe in Brackish-Water Muds than in freshwater muds. Controlling the pH in the upper ranges is usually adequate. An oxygen scavenger may also be used. Lignite and lignosulfonates if present in sufficient quantity will also act as oxygen scavengers.

Typical Properties of Brackish-Water Muds

Table 29 lists typical properties for Brackish-Water Muds.

Table 29 Typical Properties of Brackish-Water Muds							
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		pH	Chlorides mg/L	API Filtrate (cm ³ /30 min)
9	16	10 - 18	2 - 4	5 - 10	10.5 - 11.0	10,000 - 25,000	6 - 10
12	22	12 - 15	2 - 3	5 - 8	10.5 - 11.0	10,000 - 25,000	6 - 8

System Conversion/Maintenance - Conversion

Brackish-Water Muds are generally not converted, but formulated from scratch. The reason for this is that brackish-water is used when freshwater is either scarce or not available.

Maintenance - To maintain a Brackish-Water Mud, the solids should be monitored and controlled in an acceptable range. These muds are quite solids tolerant, but they will run more economically if low-gravity solids are less than 6%. Bentonite should be prehydrated and added as indicated by MBT analysis. The clay content of the mud should be decreased as density is increased to minimize down-hole gelation problems.

Advantages and Disadvantages of Brackish-Water Muds

Table 30 lists some advantages and some disadvantages of using Brackish-Water Muds compared to freshwater muds.

Advantages	Disadvantages
Provides some inhibition.	Increased additive concentration, decreased efficiency.
Reduces freshwater consumption.	Requires prehydrated bentonite.

Troubleshooting and Contamination - Brackish-Water Muds

Contamination and troubleshooting Brackish-Water Muds are essentially the same as for Saltwater Muds. Table 31 lists contaminants and treating strategies.

Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, YP, gel strengths. Mud thick on bottoms up after trips.	Massive dilution. Centrifuge mud. Improve mechanical solids control.
Saltwater Flow	Increasing YP, fluid loss, chlorides. Possible decrease in density.	Increase density to control water flow. Increase deflocculant to control rheology. Add starch or PAC for filtration control.
Poor Product Quality	Increased treating frequency. Product package change.	Pursue history through manufacturer.
Cement	Increasing PV, YP, pH, P_M , P_F and fluid loss. Possible increase in Ca^{++} .	Add bicarb or SAPP to treat out cement. Dilute with freshwater or brackish water. Mix additional deflocculant to control rheology. Mix starch and/or PAC to reduce filtrate.
Carbonates	Increasing gels, YP. Rheology erratic. Thick mud on bottoms up after trips.	Increase pH to 10.7 or higher to convert bicarbonates to carbonates. Treat with lime or gyp to remove carbonate ion.

Potassium-Based Muds

Potassium-based muds are used in areas where inhibition is required to limit chemical alteration of shales. Potassium performance is based on cationic exchange of potassium for sodium or calcium ions on smectites and interlayered clays. The potassium ion compared to calcium ion or other inhibitive ions, fits more closely into the clay lattice structure, thereby greatly reducing hydration of clays. Potassium-based muds perform best on shales containing large quantities of smectite or interlayered clays in the total clay fraction. Shallow shales, containing large amounts of montmorillonite, however, still swell in a potassium-based system. The benefits may not justify the cost of using a potassium-based mud in this type of environment.

Potassium interactions with clay surfaces can be traced to two effects: ionic size and hydrational energy. Potassium ions are of the proper size to fit snugly into the spaces between the two silica tetrahedral layers which contact each other in the formation of a three-layer clay packet. The ionic diameter of potassium is 2.66 Å, very close to the available distance of 2.8 Å in the lattice space of the clay structure. A cation slightly smaller than 2.8 Å is desirable to allow for crystalline compaction.

Stabilization of problem shales by potassium ions appears to take place in the following manner. When montmorillonite is present, potassium exchanges for sodium and calcium and results in a more stable, less hydratable structure. When illites are present, the potassium replaces any exchangeable cation impurities in the structure. The potential for further base exchange is substantially reduced after K⁺ substitution, and the shale is more stable. In mixed-layered clays, potassium works both on the illite and the montmorillonite and reduces the amount of differential swelling that occurs. Therefore, potassium cations stabilize shales which have a larger percentage of illite or illite/smectite layer combinations.

Several general statements can be made regarding whether a potassium-based mud should be used on a particular shale. These generalizations are based on the results of laboratory and field tests. The potassium cation performs best on shales containing large quantities of illite or inter-layered clays in the total clay fraction. This is true as long as the shale is not an extremely hard, brittle variety with a matrix containing numerous microfractures. In these cases, a small percentage of the total swelling potential may be sufficient to jeopardize the wellbore. Intrusion of fluid along the microfractures helps to accelerate swelling. Even an 80% reduction in hydration may not be enough to stabilize the formation. However, these shales have been drilled successfully with potassium-based muds containing asphaltites and asphaltenes. Potassium-based muds have also been used to drill very hard illitic shales. Ideally, shales of this type should be tested before a definite recommendation is made.

Shales that contain large amounts of montmorillonite will still swell, to some extent, in a potassium-based mud system. The degree of inhibition required for these shales may not be sufficient to justify the cost of using a potassium-based system, particularly since most shales of this type appear at shallow depths (gumbo). Extremely large potassium treatments are required for the base exchange to occur, particularly in large holes with a high penetration rate. Again, testing of the particular shale should be done to decide whether the degree of inhibition justifies the costs. If cuttings dispersion, rather than hole erosion, is the main concern, then a potassium-based mud system may reduce the problem significantly.

The benefit of laboratory testing before using a potassium-based inhibitive fluid in a problem shale zone cannot be overemphasized. If core material is available from an offset well, an entire series of laboratory tests, including x-ray analysis, absorption isotherm, swelling, and dispersion studies should be performed. If cores are not available, then dispersion tests on cuttings from a previous well in the area can be used to obtain information. Without samples of any kind, an estimate as to the type of shale to be encountered must be based on the depth of burial, geologic correlation, and available logging data.

Base exchange reactions with cations in the shale, cuttings, and wellbore (also with cations on the surfaces of clay added to the drilling fluid), effectively reduce the potassium level in the mud as drilling proceeds. Since a sufficient concentration must be maintained at all times to guarantee inhibition, an excess of potassium should be maintained in the system.

The theory of ionic inhibition of each of the systems is essentially the same; however, selection of the particular system to use will depend on one or more of the following factors: operator's preference, mud densities required, types of formations to be drilled, temperatures expected, fluid loss required, rig equipment, and available solids control equipment. The importance of proper solids control also cannot be overemphasized.

The main concern when using any of these systems is that enough potassium be available for base exchange with an excess remaining in solution. If the potassium level ever falls below the required amount, the clays or shales will begin hydrating, leading to borehole instability and mud problems. If sufficient remedial treatment is not made quickly, the entire advantage of potassium-based mud systems could be lost.

Basically, there are four types of potassium-based muds:

- KCl-Polymer (KCl-PHPA)
- KOH-Lignite Muds
- KOH-Lime Muds
- KCl-Cationic Polymer Muds

KCl-Polymer (KCl-PHPA) Muds

KCl-Polymer Muds were developed to provide wellbore stability and minimize cuttings dispersion. When properly formulated, benefits such as low formation damage and high return permeability encourage their use for drilling water-sensitive formations. Potassium chloride (KCl) muds not only use a wide variety of potassium chloride concentrations from 3 to 15 wt%, but also a wide variety of types and concentrations of polymers. For KCl muds to be economical, drill solids concentrations should be low and efficient solids control practices must be used. For additional information on KCl-PHPA muds, see Appendix C.

Principal Additives of KCl - Polymer Muds

KCl-Polymer Muds with low KCl concentrations (typically 3-5 wt%) and low densities are easy to maintain when drilling harder formations. However, when increased densities are required, mud composition is more complicated and mud properties are more difficult to control. Materials and concentration ranges for KCl-Polymer Muds are listed in Table 32. Not listed is poly (propylene glycol), or PPG, such as DCP-208, which is gaining increasing popularity as an inhibitor aid. This low-molecular weight polymer is usually added at levels up to 15 lb/bbl.

Table 32
Principal Additives of KCl-Polymer Mud

Additive	Concentration, lb/bbl	Function
Prehydrated Bentonite	5 - 15	Viscosifier, Filtration Control
Potassium Chloride	5 - 60	Inhibition Source of K ⁺ ion
Caustic Potash	0.25 - 0.75	Alkalinity Control, Source of K ⁺ ion
Starch	3 - 6	Filtration Control
PAC	0.5 - 1.0	Filtration Control
Lignosulfonate	3 - 6	Deflocculant
Lignite	2 - 4	HTHP Filtration Control

Bentonite - Prehydrated bentonite is used to viscosify KCl-Polymer Muds. Bentonite also provides a colloidal solid that can improve filter cake quality in freshly- prepared muds. Since bentonite will dehydrate from the high salt content of the mud and lose viscosity over time, constant additions of bentonite may be needed. When feasible, API "Nontreated" bentonite is recommended because it provides a noticeable reduction in material requirements and also provides better mud performance. Typically, concentrations of 5-15 lb/bbl of prehydrated bentonite are adequate for mud viscosity and filtration control. Dry bentonite additions will not give adequate viscosity for suspension in high chloride and hardness environments, but small additions in the range of 1-3 lb/bbl may enhance particle size distribution of the mud and improve filtration control, particularly at temperatures in the 225-275 °F range.

Potassium Chloride (KCl) - Potassium chloride is used to inhibit clay hydration. The amount of KCl actually needed for inhibition is difficult to determine. Older formations which contain nonswelling clays, require KCl levels in the 3 to 5 wt% range; whereas, younger shales containing hydratable clays, require KCl levels up to 15 wt%. Other sources of K⁺ may also be used - especially if there are environmental restrictions on chlorides - with little or no effect on performance, e.g., KNO₃, KC₂H₃O₂, K₂CO₃, and K₄P₂O₇.

Caustic Potash - Caustic potash (KOH) is added for alkalinity control in a KCl-Polymer Mud rather than caustic soda because it provides pH control without introducing potentially destabilizing sodium ions. Generally, a pH range of 9.5-10.5 is considered optimum for running KCl-Polymer muds since high pH has a detrimental effect on polymer adsorption. However, in some cases, particularly in coring applications, a neutral pH (7-8) is desired.

Xanthan Gum - Biopolymers such as XC or XCD are used for viscosifying KCl-Polymer Muds either by replacing or supplementing prehydrated bentonite. Although KCl-Polymer Muds may display a high yield point, they may not be capable of adequately suspending barite; therefore, small quantities of xanthan gum are added to provide the required suspension properties.

Polyanionic Cellulose/Carboxymethylcellulose (PAC/CMC) - Cellulosic polymers are added for filtration control. When chloride concentrations are below 50,000 mg/L, either technical-grade or regular-grade CMC are used for filtration control rather than PAC. High-viscosity CMC is generally not used because it can have a deflocculating effect; therefore, pilot testing should always be performed prior to treatment.

Starch - Starch is added for filtration control in KCl muds. A modified starch (starch treated with a biocide) is preferred. Modified starches are generally potato-based rather than corn-based and have a thermal stability of approximately 250°F. Conventional pregelatinized corn starch may be used. However, it has a slightly lower thermal stability and can bacterially degrade.

PHPA - Partially hydrolyzed polyacrylamide (PHPA) is primarily added to encapsulate solids and provide inhibition. Since PHPA purities vary from vendor to vendor, actual PHPA concentration should be ascertained to prevent over or undertreatment of the mud. PHPA is sensitive to calcium and magnesium ions. Calcium hardness should be less than 400 mg/L before adding PHPA.

Gilsonite - A mined asphalt-like powder, gilsonite is used to plug microfractures and bridge depleted sands.

Operating Parameters

The most common cause of problems in a KCl-Polymer Mud is inadequate polymer concentration. If the polymer concentration is too low, it allows shale cuttings to disperse thus causing viscosity increases and making polymer additions difficult. Solids control is essential for running KCl-Polymer Muds.

Table 33 lists typical properties for KCl-Polymer Muds.

Table 33 Typical Properties of KCl-Polymer Muds					
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft²)	Gels 10 sec/10min (lb/100ft²)		API Filtrate (cm³/30 min)
9 - 10	12 - 25	10 - 20	6 - 8	8 - 20	10 - 12
10 - 11	15 - 25	10 - 20	2 - 8	8 - 15	5 - 8
11 - 12	15 - 35	7 - 15	2 - 8	5 - 15	3 - 6
12 - 14	20 - 40	6 - 15	2 - 6	5 - 15	2 - 4
14 - 16	25 - 45	6 - 15	2 - 6	5 - 12	2 - 4
16 - 18	30 - 45	6 - 8	2 - 5	5 - 9	1 - 3

System Makeup

KCl-Polymer Muds should be built from scratch as follows:

1. Treat makeup water with 0.25 lb/bbl soda ash and 0.12 lb/bbl caustic potash to remove calcium and magnesium. However, if the makeup water does not contain magnesium, the caustic potash may be omitted.
2. Prehydrate bentonite in fresh water.
3. To mix polymers, start with the viscosifying polymers first. If the mud becomes too thick to efficiently pump, add potassium chloride. The salt will reduce the viscosity. Adjust pH range to 9.0-9.5. After the viscosity has been reduced, add the remaining polymers.

- Add barite and allow mud to stir until needed. Check viscosity and density frequently as the viscosity may drop after initial mixing. If settling occurs, add additional viscosifying polymers or prehydrated bentonite.

Table 34 gives typical KCl-Polymer Mud materials concentrations for different mud densities. Since this type of system is rarely converted from a spud mud only one concentration for each product is given.

Concentration, lb/bbl										
Mud Density (lb/gal)	Water (bbl)	Bentonite	Caustic Potash	KCl	Xanthan Gum	LV	PAC Reg	Starch	Barite	ACTIVE PHPA
10.0	0.92	15.0	0.25	35.0	1.0	---	1.5	4.0	0	1.0
12.0	0.84	15.0	0.25	31.0	1.0	---	1.5	4.0	124	1.0
14.0	0.76	12.5	0.50	28.0	0.75	1.5	---	4.0	238	1.0
16.0	0.73	10.0	0.50	27.0	0.50	1.0	---	3.0	295	1.0
18.0	0.69	7.5	0.50	25.0	0.50	1.0	---	3.0	354	1.0

Note: These product additions should only be used as a guide or starting point. Final formulations should be pilot tested before mixing on the rig.

Maintenance - KCl-Polymer Muds are maintained by controlling low-gravity solids below 6 volume % and maintaining adequate polymer concentration. While drilling, constant additions of PAC and PHPA are required to keep the mud in good condition. Because PHPA degrades as it is sheared through the drill bit, new PHPA must be continually added to replenish the high-molecular-weight fraction, which is thought to be responsible for inhibiting reactive clays via encapsulation. Monitoring the appearance of the cuttings and the MBT of the mud can indicate when additional PAC and PHPA polymer are needed. Starch may be added for additional filtration control.

Both PHPA and PAC are thought to adsorb on solids (especially clays), although only PHPA appears to inhibit shale dispersion (this process is known as encapsulation). Since PHPA and PAC are continually depleted by adsorption, it is crucial to remove drill solids as quickly as possible. Incorporating solids into the mud will require more dilution and higher concentrations of PHPA and PAC, hence higher mud costs. As with most muds, low-gravity solids should be maintained at or below 6 volume %. To compensate for loss of PHPA via adsorption and degradation through the bit, the rule of thumb used in the field is to add 1 lb/bbl of PHPA for every 110 ft drilled.

Troubleshooting - Major problems associated with KCl-Polymer Muds are attributed to: high solids, cement contamination, and poor product quality. High solids should immediately prompt the examination of solids control practices and/or equipment.

Drilling cement can have a drastic effect on mud properties. If the solids concentration is high, the viscosity of the mud will generally increase; however, if the solids concentration is low and the mud contains few reactive solids, the viscosity of the mud will decrease. Small amounts of cement can be treated with sodium bicarbonate; however, if large amounts of cement are to be drilled, treatment with

bicarb and lignite can be used to reduce mud alkalinity. Table 35 lists several contaminants, properties affected and treating strategies.

Table 35 Contaminant Treating of KCl-Polymer Muds		
Contaminant	Indicators	Treating Strategy
High Solids	Increasing PV, YP, retort solids, MBT. Mud thick on bottoms-up after trips.	Major dilution. Improve solids removal. Centrifuge mud.
Cement	Increasing P_M , P_F , pH, YP gels, fluid loss, and funnel viscosity.	Minor dilution. Treat with bicarb and/or SAPP. When rheology stabilized, add starch or PAC to control filtration properties.
Poor Product Quality	Change in product packaging. Increased treating amounts or frequency. Erratic mud properties.	Document product quality history through supplier. Arrange for regular sampling and testing.
Saltwater/Salt	Increasing chlorides, Marsh funnel viscosity, yield point, gel strengths, fluid loss.	Increase density to kill flow. Convert to Saturated Salt Mud if massive salt to be drilled.
Gyp/Anhydrite	Increasing Ca^{++} , YP, gel strengths, fluid loss. Decreasing pH, P_M , P_F .	Treat with SAPP, soda ash, or potassium carbonate. Add deflocculant to control rheological properties, if necessary.
Carbonates	Increasing M_F , YP, gel strengths. Decreasing pH, P_M , P_F . Thick mud on bottoms-up after trip. High flow-line viscosity.	Run GGT for accurate analysis. Raise pH above 10.7 with KOH. Add lime to treat out carbonates. Ensure low-gravity solids are maintained in acceptable range.

Shearing of PHPA Muds: Cutting Down on Problems

Problems in the field - "fish eyes," excessive viscosities, extensive mixing times and coating, and/or plugging of shaker screens - often arise when attempting to mix some types of dry (powdered) PHPA through conventional mixing hoppers.

A mixing and shearing system which minimizes these problems consists of a Flo Trend Jet Shear Mixer coupled to an Echols Homogenizer, which is capable of preparing a pre-mix of 3-6 lb/bbl PHPA in a 50,000 mg/L chloride brine. This concentrate can be added to the active system as required to maintain the desired PHPA concentration and molecular weight distribution.

The need for moderate shear, such as that provided by the Jet Shear Mixer/Homogenizer system, arises from the high molecular weight of some brands of PHPA, such as ASP-700, POLY PLUS DRY, ALCOMER HD, and MON PAAL. Although high molecular weight is beneficial for flocculation of clays and inhibition of shales, it also poses handling and mixing problems like the ones described above. Brands of PHPA such as ALCOMER 120, PA 469, and ALCOMER 120CC, have considerably lower molecular weights. Although these lower molecular weight polymers appear to present few handling and mixing problems, they do not inhibit shales very well. In the course of our research, we found that

we could produce a PHPA polymer that would both be easy to handle and provide substantial inhibition.

The answer lies in subjecting high-molecular-weight PHPA to moderate shear. Long polymer molecules are susceptible to physical degradation in a shear field, i.e., the polymer chains actually break to form lower molecular weight material. The degree of degradation increases with increase in shear and molecular weight. With the Jet Shear Mixer/Homogenizer system (or an equivalent), high-molecular-weight PHPA is degraded sufficiently to permit easy handling and mixing, but not so much that its molecular weight is too low to provide shale inhibition. On the other hand, the shear experienced in a drill bit nozzle is generally so high (100 to 1000 times greater than the Jet Shear Mixer/Homogenizer) that the polymer is degraded to a molecular weight too low to provide much, if any, inhibition. Consequently, it is necessary to continually add extra pre-mix while drilling, i.e., PHPA is added not only to compensate for the amount adsorbed on the wellbore and cuttings, but also for the amount degraded through the drill bit. In this regard, care must be exercised in interpreting the results of the Amoco test method for measuring the concentration of PHPA in the mud (CRON 91003ART0090); this test gives a value for the total amount of PHPA, without regard for the molecular weight distribution.

It is theoretically possible to synthesize PHPA with a molecular weight distribution that has good handling/mixing properties and also gives a high level of shale inhibition. But until that "new and improved" PHPA comes to market, the method described above will have to suffice. There is another product, however, that may fill that need. Recently Allied Colloids began to market a high-molecular-weight dry PHPA which is coated with a crystalline material that is purported to delay polymer hydration long enough for the powdered polymer to disperse. Initial experiences with ALCOMER 110RD in Canada have been positive.

KOH-Lignite Systems

In areas where high chloride ions may be objectionable (logging, environmental considerations, etc.) KOH-lignite systems should be considered. Potassium lignite muds offer inhibition and are flexible enough to be tailored to meet desired drilling requirements. Polymers can be used for viscosity and fluid loss control. Lignosulfonates are added if additional deflocculation is needed. The desired pH should be maintained with caustic potash and additional potassium ion concentration with potassium lignite.

KOH-lignite muds are designed as low pH, not highly dispersive mud systems. The pH is usually maintained around 10. This system will not tolerate either high chlorides or calcium. The upper limit for chlorides is 5000 mg/L, while the upper limit for calcium ion is 250 mg/L. KOH-Lignite Mud is temperature stable up to 400°F.

Principal Additives of KOH-Lignite Muds

Table 36 lists principal additives for KOH-Lignite Muds. The muds are very similar to freshwater lignite-based muds in their composition and maintenance except for using caustic potash (KOH) rather than caustic soda (NaOH) for pH and alkalinity control.

Table 36 Principal Additives of KOH-Lignite Muds		
Material	Concentration, lb/bbl	Function
Bentonite	15 - 25	Viscosity Filtration Control
Lignite	5 - 8	Deflocculation Filtrate Control
Caustic Potash	0.5 - 1.5	Alkalinity Control Potassium
PAC/CMC	0.5 - 1.0	Filtration Control Viscosity
Barite	as needed for density	Weighting Agent

Bentonite - Bentonite is used in KOH-Lignite Muds for viscosity and filtration control. It can be added dry through the hopper or prehydrated in a separate pit and then, bled into the system.

Lignite - Lignite is used to lower the filtrate and deflocculate the mud. It is not a strong deflocculant and will not function well in the presence of large amounts of low-gravity solids.

Caustic Potash (KOH) - KOH provides alkalinity control and is the primary source of K⁺ ion for inhibition.

Carboxymethylcellulose (CMC) - CMC can be added for filtration control.

Polyanionic Cellulose (PAC) - PAC is used to aid in filtration control and as a secondary viscosifying agent.

Barite - Barite is added as needed to increase density.

Typical Properties of KOH-Lignite Muds

These muds exhibit much of the same properties as the Lignite/Lignosulfonate Muds. These muds provide inhibition of shale by the addition of KOH rather than NaOH to control alkalinities and pH. Table 37 lists typical properties for KOH-Lignite Muds.

Table 37 Typical Properties of KOH-Lignite Muds						
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft²)	Gels 10 sec/10min (lb/100ft²)		pH	API Filtrate (cm³/30 min)
9	12 - 14	9 - 12	2 - 4	4 - 8	10.0	10 - 12
12	16 - 20	11 - 18	2 - 6	6 - 12	10.0	6 - 8

System Conversion/Maintenance - Conversion

KOH-Lignite Muds are normally formulated as new muds, but can be converted from a spud mud. The existing mud must be diluted and pilot tested before conversion to a KOH-lignite mud. Conversion to a KOH-lignite mud would be as follows. First, the solids content of the mud which is being converted must be in the proper range either through mechanical removal or dilution with fresh water or both. If the viscosity of the mud is too low, it can be increased by adding dry bentonite through the hopper or by adding bentonite that has been prehydrated. Lignite and KOH are added to the mud while adding bentonite. To control the fluid loss, polymers such as PAC or CMC can be added. Generally, 0.25-0.5 lb/bbl is sufficient for conversion. Barite is added to increase fluid density; however, 0.7 gal of water should be added for each sack of barite to properly water-wet the barite.

Maintenance - To maintain a KOH-Lignite system, the solids should be controlled in an acceptable range. Carbonates will have a more detrimental effect on the mud if clay solids are high. The K^+ ion concentration should be monitored and maintained in the desired range. The calcium ion and chloride ion content of mud should be maintained in an acceptable range for additives to function efficiently. KOH-Lignite muds can be weighted up to 18 lb/gal providing low-gravity solids, particularly clay solids, are on the low side of the acceptable range.

Advantages-Disadvantages of KOH-Lignite Muds

KOH-Lignite Muds are fairly inexpensive, easily maintained inhibitive fluids. Table 38 lists some of their advantages and disadvantages.

Table 38 Advantages/Disadvantages of KOH-Lignite Muds	
Advantages	Disadvantages
Inhibitive	Intolerant of contaminants such as salt, Ca^{++} , cement, carbonates, and anhydrite.
Economical. Filtrate control is achieved from lignite and bentonite.	Low-gravity solids must be kept low.
Simple - limited number of additives	
Thermal stability to 400°.	

Troubleshooting and Contamination - KOH-Lignite Muds

KOH-Lignite Muds are treated in the same manner as are the Lignite/Lignosulfonate (Deflocculated) Muds. Table 39 lists contaminants, indicators, and treating strategies.

Table 39
Contaminant Treating of KOH-Lignite Muds

Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, YP, and gels. Thick mud on bottoms-up after trips. Increased treating concentrations of additives.	Major dilution. Improve solids removal. Centrifuge mud.
Saltwater/Salt	Well flow. Increasing funnel viscosity, chlorides, YP, fluid loss.	Increase density to kill flow. Dilute with freshwater and increase deflocculant to control rheological properties. When rheology stabilized, add PAC/CMC to restore fluid loss control. Convert to Saturated Salt Mud if massive salt to be drilled.
Cement	Increasing pH, P_M , P_F , YP, gel strengths, fluid loss. Possible increase in hardness.	Treat out cement with bicarb and/or SAPP. Dilute with freshwater. Increase P_F to limit Ca^{++} solubility. Add deflocculant to control rheological properties. Breakover to a Lime Mud, if necessary.
Anhydrite Gypsum	Change in drilling rate, increase in Ca^{++} . Decreasing P_M , pH, P_F .	Raise pH with KOH to suppress Ca^{++} . Treat out calcium ion with bicarb or soda ash. Add deflocculant to control rheological properties or convert to gyp mud.
Poor Product	Increased treating frequency.	Document product's history through. Arrange for regular sampling and testing. Pilot test against good material.
Carbonates	Increasing gel strengths, YP & M_F . Erratic flow properties. Thick mud on bottoms-up after trips. High flowline viscosity. Decreasing pH, P_M , P_F .	Run GGT for accurate analysis. Raise pH above 10.7 with KOH. Add lime and/or gyp to treat out carbonates. (Avoid overtreatment). Ensure low-gravity solids are maintained in acceptable range.
Temperature Gelation	Increasing pump pressure to break circulation. Thick mud on bottoms-up after trips.	Reduce low-gravity solids and MBT. Use a thermally stable deflocculant. Check for carbonate contamination.

KOH-Lime Muds

KOH-Lime Muds are parallel to the Lime Muds previously described in this Section, except that KOH is used - instead of NaOH - to control alkalinity and to limit lime solubility. A KOH-Lime Mud provides two types of shale-inhibitive ions: Ca^{++} and K^+ . It can be run as: low lime, intermediate lime or high lime, as previously defined. Fluid loss control is provided with starch, CMC or PAC. The KOH-Lime Muds can be run in a pH range of 11-13. They are usually run as a high lime mud with a P_M of 17-20 and a P_F of 5-6. The calcium range is from 200-400 mg/L. Their high pH suppresses much of the calcium. These muds can tolerate chlorides to 15,000-17,000 mg/L fairly well. High chlorides will make the muds less economical because of the reduced efficiency of the additives. The temperature limitation of KOH-Lime Muds is determined by the amount of clay in the system. A mud which contains a small percentage of clay will have a higher temperature tolerance than a mud which has a high clay content. The temperature limitation is generally considered to be 320°F.

KOH-Lime/MOR-REX System - This mud system parallels the Lime/MOR-REX muds described earlier in this Section. MOR-REX deflocculates the mud to stabilize flow properties during temperature cycles. MOR-REX also solubilizes lime to allow more Ca^{++} ion to exist in solution.

Principal Additives of KOH-Lime Muds

Material	Concentration, lb/bbl	Function
Bentonite	15 - 25	Viscosifier Filtration Control
Lignosulfonate	4 - 8	Deflocculation Filtrate Control
Lime	4 - 10	High pH Source of Ca^{++}
Caustic Potash (KOH)	2 - 3	Alkalinity Control Source of Ca^{++}
DESCO	2 - 3	Deflocculant
PAC-Starch	1 - 2	Filtration Control
Barite	as needed for density	Weighting Agent
MOR-REX	3 - 5	Deflocculant

Bentonite - Bentonite is added for viscosity and filtration control. Filtration control is created by the deflocculating action of lignosulfonate/deflocculants on bentonite. Bentonite is prehydrated before being added.

Lignosulfonate - Lignosulfonate is added as a deflocculant to control rheology and provide some filtration control.

Lime - Lime is added to provide pH and a source of calcium. It is also added to control the P_M and stabilize rheological properties.

Caustic Potash - KOH is added for alkalinity and as a source of potassium ion.

DESCO - Desco is added as a deflocculant in lime muds and was developed exclusively for this purpose.

MOR-REX - Mor-Rex is a biodegradable polysaccharide which is added to deflocculate Lime/Mor-Rex Muds.

Starch - Starch is added to control filtration. High starch concentrations, however, can cause viscosity problems.

Polyanionic Cellulose - PAC can be added as a supplementary filtration control additive.

Barite - Barite is added to increase density. As density is increased, the bentonite content should be reduced to prevent excessive rheological properties and temperature gelation.

Typical Properties of KOH-Lime Muds

KOH-Lime Muds exhibit similar rheological and filtration properties to Lime Mud. Table 41 lists typical properties for an unweighted and weighted KOH/Lime Mud.

Table 41 Typical Properties of KCl-Polymer Muds					
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft²)	Gels 10 sec/10min (lb/100ft²)		API Filtrate (cm³/30 min)
9	10 - 12	8 - 12	4 - 6	6 - 10	6 - 9
12	16 - 18	16 - 20	4 - 6	6 - 12	14 - 19

System Conversion/Maintenance - Conversion

KOH-Lime Muds are usually formulated from scratch. A freshwater spud mud can be “broken over” to a KOH-Lime Mud; however, a spud mud with high chlorides should not be converted to a KOH lime mud because of increased product consumption. To convert a freshwater spud mud to KOH-lime mud, the mud density, gel strengths, and solids content of the mud should be low. If the solids are too high, dilute with fresh water and/or use mechanical solids removal to reduce solids. The mud should be converted prior to increasing mud density because 10-25% dilution is generally recommended prior to the breakover. Conversion is usually accomplished in two circulations. Water additions should be added before adding any chemicals. Turn off all mud guns except in the suction pit to prevent flocculating mud in the other pits. Add KOH, deflocculant, and lime at the same time to minimize the viscosity hump. KOH should be added through the chemical barrel while adding lime and deflocculants through the mud mixing hopper. Add 1/2 of the lime and all of the deflocculant and caustic over one circulation. Add the remainder of the lime in the second circulation. The degree of viscosity increase “breakover hump” will depend upon the solids concentration. If the mud is too thick, add more deflocculant or water, or both. Adjust P_M, P_F, and excess lime after breakover has been accomplished. Fluid loss additives are added after conversion. As mud density is increased, lime additions will needed to be increased to maintain the desired amount of excess lime in the mud.

Maintenance - To maintain a KOH-Lime Mud, low-gravity solids must be continually monitored and controlled in the proper ranges. In most situations this means less than 8% low-gravity solids and less than 6% drill solids. PAC or CMC can be added to control fluid loss; however, adding lignite or lignosul-

fonate along with prehydrated bentonite is more economical. If the viscosity of the mud is too low, prehydrated bentonite can be added. Prehydrated bentonite can be added to the mud to prevent barite settling in lower weight muds; however, in higher weight muds, barite settling can be rectified by small additions (1/8-1/4 lb/bbl) of PAC. If the mud becomes too viscous, additional deflocculant can be added. Regular tourly treatments of lignosulfonate, KOH, and lime should be added based on dilution rates. Lignosulfonate concentration should be maintained at 4-5 lb/bbl and low-gravity solids should be maintained at a low level. Pilot testing is recommended to determine optimum quantities of materials for addition.

Advantages-Disadvantages of KOH-Lime Muds

KOH-Lime Muds offer many of the same advantages as Lime Muds. Both KOH-Lime Muds and conventional lime muds have low viscosities and low gel strengths and are solids tolerant.

<i>Table 42 Advantages/Disadvantages of KOH-Lime Muds</i>	
Advantages	Disadvantages
Inhibitive.	Not shear-thinning
Solids tolerant.	Decreased penetration rates in hard formations
Resistant to contaminants such as anhydrite, cement, carbonates, and salt.	Complex - many additives.
	High temperature gelation.
	Bentonite must be prehydrated

Troubleshooting and Contamination - KOH-Lime Muds

Table 43
Contaminant Treating of KOH-Lignite Muds

Contaminant	Indicators	Treating Strategy
High Solids	Increasing retort solids, PV, MBT 10-minute gel strength.	Massive dilution. Improve solids removal. Centrifuge mud.
Saltwater/Salt	Increasing chlorides, funnel viscosity, YP, gel strengths, fluid loss. Decreasing pH, P_M , P_F	Increase density to control water flow. Dilute chlorides with freshwater. Increase deflocculant, caustic to control rheology. When rheology stabilized, add PAC, starch to control filtration. If more salt must be drilled, consider converting to saturated salt mud or displace with oil-based mud.
Carbonates CO ₂ (Not likely to cause problem in KOH-Lime Muds.)	Increasing MF, gels, especially 10-minute gel. Rheology hard to control. Decreasing P_M , pH.	Add lime to control P_M and KOH to control P_F . Ensure clay solids are at low end of acceptable range.
Poor Product Quality	Change in product packing. Increased treatment required for same properties. Erratic mud properties.	Document product quality history through supplier. Arrange for regular product sampling and testing.
Temperature Gelation	Thick mud on bottoms-up after trips. Thick mud at flowline, not at suction. Increasing pressure to break circulation after trip.	Reduce low-gravity solids. Increase lignosulfonate concentration if temperature <325°F. Add high-temperature deflocculant if bottomhole temperature >325°F.
Foaming	Foam on pits and at shaker. Air entrapment. Decreasing pump pressure.	Add non-toxic, non-sheening defoamer. Locate cause of foam and eliminate.

KCl - Cationic Polymer Muds

One of the most recent advances in drilling fluid technology has been the development of cationic muds, which use a cationic (positively charged) polymer along with a potassium salt to inhibit reactive shales. KCl-Cationic Polymer muds are generally considered to be the most inhibitive water-based muds, although even they cannot perform as well as oil-based muds. The chemistry of these muds is quite different, in that everything in the mud that is surface active is cationic, nonionic or at most only weakly anionic. The cationic polymers are high-molecular weight versions of the cationic surfactants that are used to make clays organophilic for oil-based muds. The cationic polymer, along with K^+ from KCl (or other potassium salt), adsorb on clays to reduce the repulsion between clay particles and reduce the adsorption of water. This makes the clays in shales resistant to swelling and dispersion.

The salt makes slightly anionic polymers, like XCD (xanthan gum) compatible with the cationic polymer; without it, the oppositely charged polymers would react with each other and remove themselves from the mud.

The Amoco cationic mud, called Cationic Brine Fluid (CBF), is maintained with 2 to 10 lb/bbl of excess (or active) cationic polymer, 5 to 10% KCl, 4 lb/bbl of biocide-treated starch for fluid loss control, and XCD or BIOZAN (welan gum) as required to provide adequate suspension of weighting material and hole cleaning. Another additive that has recently been introduced to the KCl-Cationic Polymer formulation is low-molecular-weight poly (propylene glycol), or PPG. A nonionic polymer, PPG appears to act synergistically with both K^+ and the cationic polymer to enhance the inhibition of shale.

As is the case for KCl-PHPA muds, the key to maintaining KCl-Cationic Polymer muds is to keep an excess of cationic polymer and maintain a fixed concentration of K^+ in the mud. Fortunately, KCl-Cationic Polymer muds have the attribute that the concentrations of excess cationic polymer and K^+ can be monitored directly. The Amoco Bead Test, used to measure the excess concentration of cationic polymer, and the Ion Specific Electrode (ISE), used to measure the level of K^+ , are described in Appendix C along with other features of the CBF system.

KCl-Cationic Polymer muds are among the most expensive to maintain. The strong reaction between the cationic polymer and shales leads to rapid depletion of the polymer. Although the initial cost of the mud is relatively high, it is not excessive. The cost of maintaining excess polymer in the system is, however, higher than that of any other water-based mud. The use of PPG can mitigate the net drilling fluid cost, as can the addition of lubricants to reduce torque and drag on the drill string and the addition of ROP (Rate of Penetration) enhancers.

POLYMER FLUIDS

Introduction

Polymer fluids contain polymers which greatly diversify their application. These fluids contain polymers to viscosify, polymers to control filtration, polymers to deflocculate, polymers to provide high-temperature stabilization, etc. Polymer fluids generally contain only minor amounts of bentonite to build viscosity. Primary viscosification is provided by high molecular weight polymers such as PHPA, PAC, XC polymer, etc. Because these fluids contain only small quantities of bentonite or clay solids, they are less prone to rheological and filtration property fluctuations resulting from the effects of contaminants on the clay structure. Polymer fluids also reduce cuttings dispersion and stabilize the wellbore through encapsulation. Usually these fluids contain less than 5% by volume total low-gravity solids and can be divided into two general polymer mud categories:

- Non-Dispersed Polymer Mud
- High-Temperature Deflocculated Polymer Mud

Non-Dispersed Polymer Mud

In many areas clear water cannot be used as a drilling fluid because of its effect on formations and the lack of sufficient viscosity to properly clean the hole. In these circumstances Non-Dispersed Polymer Mud may be used to closely simulate the drilling characteristics of clear water. Non-dispersed Polymer muds have found their best application in areas where formations are hard and penetration rates are slow. These polymer muds contain fewer than 5% low-gravity solids and hence are sometimes referred to as low-solids non-dispersed (LSND) muds. LSND muds do not perform well in areas with

long intervals of reactive shales because of their intolerance to solids contamination. Also, salt, saltwater flow, gyp/anhydrite, and cement contamination will severely limit the use of these muds.

Most Non-Dispersed Polymer MudS are composed of water with varying quantities of bentonite and polymers. Polymers are added to the system to build viscosity either through flocculation of the solids or by viscosifying the water phase. They are also added to provide filtration control. Some of the more commonly used Non-Dispersed Polymer MudS are:

- BEN-EX MudS
- Low-Solids PAC/CMC MudS
- Low-Solids PHPA MudS

BEN-EX MudS

BEN-EX is a powdered water-dispersible polymer packaged in 2-lb bags. It is used to increase the yield of bentonite and to flocculate drilled solids. The addition of 0.05 lb/bbl BEN-EX will approximately double the yield of bentonite. This is an advantage because fewer solids are used to produce the same viscosity. The application of BEN-EX for extending bentonite is confined to water containing less than 5000 mg/L chlorides.

Low-Gravity solids should be kept below 5% by volume. Best drilling rates are obtained in the 2-3 volume % range. Water dilution and use of mechanical separation equipment is recommended. BEN-EX acts as a flocculant for non-bentonitic clays. If settling pits are available, solids will settle out. Deflocculants should not be added unless absolutely necessary. Deflocculants should be added very cautiously because BEN-EX muds respond quickly to very small treatments.

BEN-EX can be economically used for mixing large volumes of spud mud or fresh mud when lost circulation occurs. The BEN-EX system can easily be converted to any type system as drilling progresses.

Principal Additives for BEN-EX MudS

<i>Table 44 Principal Additives of BEN-EX MudS</i>		
Material	Concentration, lb/bbl	Function
Bentonite	10 - 14	Viscosifier Filtration Control
BEN-EX	0.05 - 0.1	Bentonite Extender
Sodium Polyacrylate	0.25 - 0.5	Selective Flocculant
Soda Ash	0.25 - 0.75	Calcium Removal
Barite	as needed for density	Weighting Agent

Bentonite - Bentonite is added for viscosity and filtration control. The concentration of bentonite is generally around 10-14 lb/bbl. Less bentonite and polymers will be required if the bentonite is prehydrated prior to adding it to the active mud system.

Bentonite Extender - BEN-EX is a bentonite extender which doubles the yield of good quality bentonite and functions as a selective flocculant. It is sensitive to both Cl⁻ and Ca⁺⁺ contamination.

Sodium Polyacrylate (SPA) - Sodium polyacrylate (SPA) is added for filtration control. It is also added to control rheological and filtration properties and acts as a selective flocculant.

Soda Ash - Soda Ash is used to treat out Ca⁺⁺ from makeup water since most polymer additives are Ca⁺⁺ sensitive. Continued use of heavy concentrations of soda ash can cause viscosity problems due to "ash gels".

Barite - Barite is used to increase density. For each sack of barite, 0.7 gal of water should be added to properly water-wet the barite.

Typical Properties for BEN-EX Muds

BEN-EX Muds are typified by low PV and high yield point and gel strength. Table 45 lists typical properties for an unweighted and weighted BEN-EX Mud.

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		Chlorides (mg/L)	API Filtrate (cm ³ /30 min)	Hardness (mg/L)
9	4 - 8	8 - 12	4 - 8	8 - 10	2000	10 - 12	40 - 80
12	8 - 10	10 - 15	6 - 12	10 - 15	2000	6 - 8	80 - 100

System Conversion/ Maintenance - Conversion

BEN-EX muds are generally not converted from an existing fluid, but prepared from scratch. First, clean the pits and build volume with fresh water. The makeup water should be treated with soda ash to remove hardness. Add 0.25 lb/bbl soda ash to remove calcium from makeup water. The sodium polyacrylate is added to reduce fluid loss. The pH of the water should be adjusted with either soda ash or caustic soda. To obtain proper viscosity bentonite and BEN-EX through hopper at the rate of one 2-lb bag BEN-EX for each 5 100-lb bags bentonite until reaching a sufficient bentonite concentration of 10-14 lb/bbl. Barite can be used to increase density; however, BEN-EX must be added along with barite additions. One 2-lb bag of BEN-EX must be added only with each 40 100-lb bags of barite when increasing density. Also, add 0.7 gallons of water for each sack of barite. The upper limit for mud weight for this type of mud is usually 14.0-14.5 lb/gal.

Maintenance - To maintain a BEN-EX mud, a stream of water is required while drilling to maintain volume and to dilute solids. Solids control is crucial to the success of running these muds. The pits should be jetted and cleaned when necessary to remove settled solids. Soda ash is added to maintain calcium below 200 mg/L. For flocculating drill solids, BEN-EX is normally injected with clean water in a chemical barrel below the shale shaker. See Table 45 for quantities of BEN-EX required for flocculation.

Hole Size (in.)	6" - 7"	8" - 10"	11" - 13"
lb/100 ft of hole	4	6	8

If the system is to be weighted, 5 lb of BEN-EX per 100 sacks of barite are required to provide proper support of the barite. Fluid loss, yield point, and gel strengths can be adjusted using 0.2-1.0 lb/bbl of sodium polyacrylate, either CYPAN or WL-100.

Low Solids PAC/CMC Muds

Low-solids PAC/CMC muds use cellulose-based polymers rather than sodium polyacrylate polymers. The cellulosic polymers have greater tolerance to calcium and salt than do the acrylate polymers. Hardness needs to be less than 400 mg/L as compared to 250 mg/L for acrylate polymers. Cellulosic polymers can function in a chloride environment up to saturation; whereas, acrylate sodium polymers do not function well above 5000 mg/L chloride. The availability of different viscosity PAC/CMC allows flexibility in treating muds.

Principal Additives of Low Solids PAC/CMC Muds

Table 47 lists principal additives for formulating Low Solids PAC/CMC Muds. These muds just as Ben-Ex Muds, contain few additives and are relatively easy to maintain. Low Solids PAC/CMC Muds are also relatively inexpensive compared to other LSND polymer fluids.

<i>Table 47 Principal Additives of Low-Solids PAC/CMC Mud</i>		
Material	Concentration, lb/bbl	Function
Bentonite	5 - 10	Viscosity Filtration Control
Caustic Soda	for pH 9.0 - 9.5	Alkalinity
Soda Ash	0.25 - 0.5	Calcium Removal
Regular PAC/CMC	0.5 - 1.5	Filtration Control
Barite	as needed	Weight Material

Bentonite - Bentonite is added to increase viscosity and provide filtration control. To optimize of the quality of bentonite and polymer required to achieve sufficient viscosity, it is recommended to prehydrate the bentonite in fresh water.

Caustic Soda - Caustic soda is used to create an alkaline environment. Also, premium untreated bentonite will reduce the amount of materials required. Caustic soda can be used to increase the pH to 9.7 or higher. This higher pH will precipitate magnesium ions which would interfere with polymer.

Soda Ash - Soda ash is added to makeup water to precipitate Ca⁺⁺. The polymers in LSND fluids function more efficiently when hardness is less than 250 mg/L.

Polyanionic Cellulose (PAC) - PAC is added for viscosity and filtration control in LSND muds. PACs have a high salt tolerance; however, they function more efficiently when hardness is below 400 mg/L.

Carboxymethylcellulose (CMC) - CMC is another cellulose based polymer added for viscosity and filtration control. CMC, however, does not have a high tolerance for salt (50,000 mg/L max) as compound to PAC. It also performs best when hardness is below 250 mg/L.

Barite - Barite is added to increase density as needed. When adding barite, low-gravity solids must be kept below 6 volume %. Water and PAC/CMC should be added with the barite to avoid excessive rheologies.

Typical Properties for Low-Solids PAC/CMC Mud

Typical properties for Low-Solids PAC/CMC Muds are very similar to both the Ben-Ex and Low Solids PHPA Muds. Table 48 lists typical property ranges for 9 lb/gal and 12 lb/gal Low Solids PAC/CMC Muds.

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		Chlorides (mg/L)	API Filtrate (cm ³ /30 min)	Hardness (mg/L)	pH
9	4-6	8-12	4-8	6-10	<2000	10-12	<200	9.0-9.5
12	8-10	10-15	6-12	10-15	<2000	6-8	<200	

System Conversion/Maintenance - Conversion

As with Ben-Ex Muds, Low Solids PAC/CMC Muds are not generally converted from an existing fluid, but prepared from scratch. First the pits must be cleaned. Volume should build with fresh water. Hardness should be treated below 200 mg/L with soda ash before adding any of the polymers. Then, gradually add desired amount of bentonite (10-14 lb/bbl). Let hydrate at least 24 hours if possible. Then, add PAC for desired viscosity and filtration properties. Regular and low viscosity can be used interchangeably when rheology dictates. CMC can be used for viscosity and filtration control or along with PAC to supplement. Maintain pH with caustic soda, or soda ash at pH 9.0-9.5. Density can be increased with barite; however, this Low Solids PAC/CMC muds are generally not run with mud weight above 12.5-13.0 lb/gal because of difficulty controlling rheological properties within acceptable ranges.

Low-Solids PHPA Muds

Low-Solids PHPA Muds (partially hydrolyzed polyacrylamide) are used to inhibit shale. These acrylate/acrylamide polymers absorb onto clay surfaces. Thus, because PHPA is a long-chemical molecule, it can effectively link a number of clay platelets together creating viscosity with a minimum concentration of low-gravity solids. Therefore, as with Low Solids PAC/CMC Muds and with BEN-EX Muds, a minimum solids fluid can be formulated to maximize ROP and provide good hole cleaning capability. In addition, the inhibitive nature of these fluids is easily increased by the addition of KCL or poly (propylene glycol). They provide viscosity, solids encapsulation and limited fluid loss control. Small amounts of bentonite should be used when these systems are initially built. PHPA is used to viscosify drilling fluids with a minimum quantity of clay and to assist in borehole stabilization. The main component of this system is a high molecular weight, long-chained PHPA polymer (partially hydrolyzed polyacrylamide). This system is sensitive to contamination from chlorides, Ca⁺⁺, and solids. Solids must be kept to a minimum through dilution and mechanical separation, otherwise the mud can become rheologically unstable (high viscosity and gel strengths).

Principal Additives of Low-Solids PHPA Muds

<i>Table 49 Principal Additives of Low-Solids PHPA Mud</i>		
Additive	Concentration, lb/bbl	Function
Bentonite	10 - 14	Viscosity Filtration Control
Caustic Soda/ Caustic Potash	for pH 9.0 - 9.5	Alkalinity
PHPA	1.0	Solids Encapsulation Borehole Stability, Viscosity
SPA	0.25 - 0.5	Filtration Control
Soda Ash	0.25 - 0.75	Teat out Ca ⁺⁺

Bentonite - Bentonite is added for viscosity and filtration control. Since PHPA polymer effectively encapsulates bentonite particles and limits hydration. It is recommended to prehydrate bentonite before adding PHPA.

Caustic Soda/Caustic Potash - NaOH or KOH is added sparingly for pH and corrosion protection. The pH of the mud should not exceed 9.5 unless conditions dictate otherwise. At this pH all hardness will be precipitated out. Magnesium hardness has a very detrimental effect on polymer performance and should be eliminated from the system.

PHPA - PHPA is added to provide inhibition through encapsulation of the drill cuttings. Further inhibition is thought to take place by polymer plugging of small micro fractures along the borehole wall, which prevents hydration of clays. PHPA is also a secondary viscosifier and can provide some filtration control.

Sodium Polyacrylate - Sodium polyacrylate (SPA) is added for filtration control. Calcium hardness should be less than 400 mg/L in order for SPA to function effectively and economically.

Soda Ash - Soda ash is added to precipitate calcium from makeup water. This not only allows better hydration of clays, but also will maximize the effectiveness of fluid loss additives.

Typical Properties of Low-Solids PHPA Muds

Low-Solids PHPA Muds have similar properties to the Low-Solids PAC/CMC Muds and Ben-Ex Muds. Table 50 lists typical properties for 9 lb/gal and 12 lb/gal Low-Solids PHPA mud.

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft²)	Gels 10 sec/10min (lb/100ft²)		API Filtrate (cm³/30 min)
9	4 - 6	10 - 14	5 - 8	6 - 10	10 - 12
12	8 - 10	12 - 20	6 - 12	10 - 15	6 - 8

Advantages/Disadvantages of Non-Dispersed Polymer Muds

Table 51 Advantages/Disadvantages of Polymer Muds	
Advantages	Disadvantages
High ROP in hard formations	Limited Use
Shear thinning/lower ECD	Irreversible adsorption of the polymer on clays
Good hole cleaning	Low temperature stability
Easy to run	Solids intolerant
Easily converted to a deflocculated system	Requires more dilution than deflocculated systems
Does not disperse solids	Fluid loss control not economical
	More corrosive than deflocculated systems
	Sensitive to contaminants/carbonate contamination difficult to treat
	Density increase difficult
	Not inhibitive

Contamination - Non-Dispersed Polymer Muds

Table 52
Contaminant Treating of Non-Dispersed Polymer Muds

Contaminant	Symptom	Treating Procedure
High Solids	Increasing retort solids, PV, YP, gels, MBT. Thick mud on bottoms-up after trips. High flowline viscosity.	Major dilution. Improve solids removal. Centrifuge mud.
Cement	Increasing funnel viscosity, pH, P _M , P _F , Ca ⁺⁺ , YP, gels, fluid loss.	Treat out cement contamination (Ca ⁺⁺) bicarb, and/or SAPP. Dilute with freshwater. Increase P _F to limit Ca ⁺⁺ stability. May require deflocculant or breakover to lime mud.
Salt/Saltwater	Well flow. Increasing Chlorides, Marsh funnel viscosity, YP, gels, fluid loss. Top water separation. Decreasing pH, P _M , P _F . Possible decrease in mud density.	Increase mud density to stop flow. Dilute with freshwater to reduce chlorides. May need deflocculant depending on severity of problem. Add PAC for filtration control. Consider converting to Saturated Salt Mud if massive salt to be drilled.
Gypsum/ Anhydrite		Treat out Ca ⁺⁺ with soda ash, bicarbonate, SAPP. Add freshwater. May require deflocculant.
Carbonates CO ₂ (Not likely to cause problem in KOH-Lime Muds.)	Increasing MF, gels, especially 10-minute gel. Rheology hard to control. Decreasing P _M , pH.	Add lime to control P _M and KOH to control P _F . Ensure clay solids are at low end of acceptable range.
Poor Product Quality	Increased treating amounts-frequency. Product packaging change. Inability with standard treatments.	Document product's history through supplier. Set up sampling and testing program. Pilot test against good material.

High-Temperature Deflocculated Polymer Muds

High-Temperature Deflocculated Polymer Muds were developed to extend the temperature stability of conventional polymer muds. They are designed to tolerate, in addition to contaminants the inclusion of inhibiting ions such as KCl or NaCl. These muds are required to provide stability along the same lines as an oil mud yet still be economical. If the high-temperature deflocculated polymer mud can be used in place of an oil-base mud, then it becomes very attractive for reasons of environmental and safety considerations. The major drawback to the high-temperature deflocculated polymer muds is that they become difficult to control at densities above about 14.0 lb/gal. Viscosity can become difficult to control when the solids loading is high and when the mud contains polymeric fluid loss additives. This is especially true of freshwater muds; however, sodium chloride can inhibit the viscosity increase contributed by the fluid loss additives. An important consideration, however, is that the consumption rate of the fluid loss additives will increase as a result of adding sodium chloride. It should also be noted that consumption of fluid loss additives is higher for muds formulated with KCl.

At temperatures above 375°F synthetically-manufactured deflocculants is preferred since most deflocculants such as lignosulfonate and lignite rapidly degrade. Synthetic deflocculants are more expensive, but offer overall economical benefits.

For mud densities in excess of 16 lb/gal, bentonite levels should be maintained at less than 10 lb/bbl. This concentration should be decreased as mud density increases above 16 lb/gal. The pH should be controlled in the range of 9-11 with KOH or NaOH. Drill solids must be kept to a minimum and controlled with high-speed shakers, centrifuges, and dilution. Excessive solids will cause gelation of the mud or even solidification in high-temperature environments.

To increase the lifting capacity of the low-density, deflocculated polymer muds, an additive such as Aqualon HP-007 can be used. Bentonite additions in high temperature muds is not recommended because it can cause severe gelation and difficulty in initiating circulation; however, cellulosic polymers can be used as they will not cause high-temperature gelation. It should be noted that adequate mixing such as that from auxiliary mixing devices described in Section 10 will be required to fully disperse and mix the cellulosic viscosifiers. Cellulosics provide viscosity and suspension and are not affected by contaminants such as chlorides and carbon dioxide.

Some of the more commonly used High-Temperature Deflocculated Polymer Muds are:

- THERMA-DRIL
- PYRO-DRILL
- DURATHERM
- POLYTEMP

THERMA-DRIL

THERMA-DRIL is a high-temperature polymer drilling fluid system sold by Baroid. This mud system utilizes prehydrated bentonite for suspension and some filtration control. THERMA-THIN, a liquid polyacrylate/terpolymer, is used as a deflocculant and to control high-temperature gelation. THERMA-CHECK, a vinyl-sulfonate co-polymer, is used to control filtrate up to 425 °F. NaOH or KOH is used for alkalinity control. Oxygen scavengers are used to reduce corrosion and add temperature stability.

Principal Additives for - High-Temperature Therma Drill

Table 53
Principal Additives of THERMA-DRIL Muds

Additive	Concentration, lb/bbl	Function
Bentonite	8 - 10	Viscosity
Therma-Thin	1 - 4	Deflocculant
Therma-Check	2 - 8	Filtration Control
Caustic Soda	for pH 9 - 10	Alkalinity Control
Oxygen Scavengers	1 - 2	Corrosion Control Temperature Stability

THERMA-THIN - THERMA-THIN is a liquid polyacrylate terpolymer used to reduce the viscosity of the mud and functions extremely well in reducing high-temperature gelation. THERMA THIN is also effective in the presence of chlorides and aids in filtration control. It is used to pretreat the mud system prior to drilling cement. This product does not contain any chrome.

THERMA-CHECK - THERMA-CHECK is a vinylsulfonate co-polymer used to control HTHP fluid loss up to 425°F. It has good salt stability and will tolerate moderate levels of calcium contamination. Therma check is somewhat sensitive to high pH environments as it will tend to hydrolyze. Higher consumption rates may be expected at pH above 11.0. The normal usage rate is from 2-8 lbs/bbl. At high concentrations of chlorides and temperatures approaching 400°F, the usage rate will be from 6 to 8 lb/bbl.

Bentonite - Bentonite is prehydrated for best results for use in salt environments to provide viscosity and suspension and filter cake quality. Bentonite is used initially at concentrations up to 8-10 lb/bbl. Sepiolite can be used to replace bentonite in high salt environments. Dry bentonite can be added to aid in HPHT fluid loss without increase in viscosity.

Oxygen Scavengers - Oxygen Scavengers will reduce oxygen corrosion and increase the thermal stability of the mud. Sodium sulfite is used most commonly in this system.

Caustic Soda - The alkalinity is obtained from sodium hydroxide to provide a pH from 9.0 to 10.0.

Typical Properties for High-Temperature Deflocculated - THERMA-DRIL Muds

Table 54
Typical Properties of THERMA-DRIL Mud

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels		HTHP (cm ³ /30 min)	API Filtrate (cm ³ /30 min)
			10 sec/10min (lb/100ft ²)			
9	10 - 12	10 - 14	4	6	12 - 15	4 - 6
12	14 - 16	8 - 12	4	6	10 - 12	4 - 6

PYRO-DRIL

PYRO-DRIL is a high-temperature mud system sold by Milpark. This system uses a MILTEMP, a sulfonated, styrene maleic anhydride, as a high-temperature deflocculant. PYRO-TROL is an acrylamide-acrylamido methyl propane sulfonic acid. This material is used as a high-temperature filtration control agent. PYRO-VIS is a sugar beet extract and is used to provide carrying capacity without addition of bentonite. KEM-SEAL, an acrylate-acrylamide compound, provides filtration control in saltwater brines and high hardness environments.

Principal Additives for High-Temperature Deflocculated PYRO-DRIL Muds

Table 55
Principal Additives of PYRO-DRIL Mud Systems

Additive	Concentration, lb/bbl	Function
PYRO-VIS	as needed	Supplemental Viscosifier
MIL-TEMP	1 - 2	Deflocculant
PYRO-TROL	1 - 3	Filtration Control
KEM-SEAL	0.5 - 2	Filtration Control, Viscosity
CHEMTROL X	2 - 6	Filtration Control

PYRO-VIS - PYRO-VIS is a sugar beet extract which acts as a supplemental viscosifier to increase carrying capacity without the addition of bentonite. This product requires a shearing device to fully develop viscosity. PYRO-VIS is not affected by chlorides or other contaminants such as carbon dioxide and calcium from anhydrite.

MILTEMP - MILTEMP is sulfonated styrene maleic anhydride. This product is a powdered deflocculant used to reduce viscosity and high temperature gelation.

PYRO-TROL - PYRO-TROL is an amps copolymer which provides high-temperature fluid loss control in high salt content muds. PYROTROL is not compatible in high hardness or when pH is greater than 11.0 as it will be chemically modified and give off ammonia. PYROTROL has shown some shale stability and lubrication benefits.

KEM-SEAL - KEM-SEAL is an amps/aam copolymer which provides high-temperature filtration control in salt water brines and high hardness environments. KEM-SEAL can be used for filtration control in

environments where PYRO-TROL is not used. KEM-SEAL will increase viscosity in freshwater systems, but will not increase viscosity in higher chlorides environments.

CHEMTROL X - CHEMTROL X is a lignite-polymer blend high temperature fluid loss additive used in the Pyro-Dril system when the chlorides are less than saturation and the hardness level is low (< 500 mg/L). CHEMTROL X should be presolubilized in fresh water containing caustic soda if the CHEMTROL X is to be added to salt water mud systems. CHEMTROL X added to a salt water mud system directly will be ineffective as a fluid loss additive.

Table 56
Typical Properties of PYRO-DRIL System

Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels		HTHP (cm ³ /30 min)	API Filtrate (cm ³ /30 min)
			10 sec/10min (lb/100ft ²)			
9	8 - 12	12 - 20	4 - 6	6 - 12	12 - 15	4 - 6
12	16 - 25	12 - 20	7 - 10	8 - 14	10 - 12	4 - 6

DURATHERM

DURATHERM is a high-temperature mud system sold by M-I Drilling Fluids. This mud system uses small concentrations of bentonite for suspension. XP-20, a modified chrome lignite containing potassium, is used as a fluid loss additive and viscosity stabilizer. XP-20 is used primarily in fresh water systems. MELANEX-T, a melanin polymer derivative, is used as a high-temperature deflocculant to reduce viscosity and high-temperature gelation. RESINEX, a resin polymer, is used for HTHP filtration control and can be used to replace the XP-20 in salty environments.

Principal Additives for High-Temperature Deflocculated DURATHERM Mud Systems

Table 57
Principal Additives of DURATHERM Mud Systems

Additive	Concentration, lb/bbl	Function
Bentonite	5 - 14	Viscosity
Melanex-T	1 - 2	Rheology Control Deflocculant
Resinex	5 - 6	Fluid Loss Control
XP-20	10 - 20	Fluid Loss Control Deflocculant

Bentonite - Bentonite is used for fluid loss control and suspension. The bentonite content at mud densities greater than 14.0 lb/gal should not exceed 10 lb/bbl.

MELANEX-T - MELANEX-T is a melanin polymer derivative deflocculant used to reduce viscosity and high temperature gelation.

RESINEX - RESINEX is a resin polymer fluid loss control additive that can be used to replace some of the XP-20 especially in salty environments.

XP- 20 - XP-20 is a modified chrome lignite containing potassium. This product provides fluid loss control and is also used to control viscosity at high temperatures. It is normally used in fresh to seawater system. Higher concentrations of salt will require a more salt resistant fluid loss control additive such as Resinex.

Typical Properties of DURATHERM Systems

<i>Table 58 Typical Properties of DURATHERM System</i>						
Density (lb/gal)	Plastic Viscosity (cPs)	Yield Point (lb/100 ft ²)	Gels 10 sec/10min (lb/100ft ²)		HTHP (cm ³ /30 min)	API Filtrate (cm ³ /30 min)
9	8 - 12	10 - 18	4 - 6	6 - 12	12 - 15	4 - 6
12	12 - 20	10 - 20	7 - 10	8 - 14	10 - 12	4 - 6

POLY TEMP

The IDF POLY TEMP mud system uses POLY TEMP, a vinyl sulphonate-vinyl amide co-polymer of low to medium molecular weight, to reduce filtrate. Bentonite is used for suspension. POLY TEMP can be used in a seawater or freshwater system. IDF HITEMP, a resin compound, is used to aid in HTHP filtrate control. The mud system has been reported to be stable with bottomhole temperatures up to 400°F.

Principal Additives for High-Temperature Deflocculated PolyTemp Muds

<i>Table 59 Principal Additives of POLY TEMP Mud Systems</i>		
Additive	Concentration, lb/bbl	Function
Bentonite	8 - 10	Viscosity, Filter Cake
Hi-Temp II	4.0 - 8.0	Fluid Loss Control
PTS-200	4.0 - 8.0	Temperature Stabilizer
PolyTemp	2.0 - 4.0	Fluid Loss Control
Idsperse XT	1.0 - 4.0	Deflocculant

Bentonite - Bentonite is prehydrated for best results for use in salt environments to provide viscosity and suspension and filter cake quality. Bentonite is used initially at concentrations up to 8-10 lb/bbl. Sepiolite can be used to replace bentonite in high salt environments. Dry bentonite can be added to aid in HPHT fluid loss without increase in viscosity.

HI-TEMP II - HI-TEMP II is a polyanionic lignin fluid loss additive used in low salinity mud systems. It is also not sensitive to calcium. For better performance however, the calcium should be treated out with soda ash.

PTS-200 - PTS-200 is an alkaline pH buffer and temperature stabilizer used to increase the temperature stability of the system by removing oxygen. PTS-200 is a liquid product and is added at a rate of 4-8 lb/bbl. This additive will raise the pH to around 10.0 and should be handled with care since it is a caustic type material.

POLYTEMP - POLYTEMP is a high temperature polymeric fluid loss additive designed to function in high salt environments.

IDSPERSE XT - IDSPERSE XT is a high temperature stable liquid polymer used to control the viscosity of the system especially in the presence of salt. This product does not contain any chrome and will minimize high temperature gelation of the mud system.

Section 9 Oil-Based Muds

Introduction

An oil base fluid can be defined as a drilling fluid which has oil as its continuous or external phase and the water, if present, is the dispersed or internal phase. The solids in an oil base fluid are oil wet, all additives are oil dispersible and the filtrate of the mud is oil. The water, if present, is emulsified in the oil phase.

There are two basic classifications of oil-based fluids; invert emulsions and all-oil muds. The amount of water present will describe the type of oil base fluid. The oil used in these types of oil base fluids can range from crude oil, refined oils such as diesel or mineral oils, or the non-petroleum organic fluids that are currently available. The latter type fluids - variously called inert fluids, pseudo oils, nonaqueous fluids and synthetic fluids - are now considered more environmentally acceptable than diesel or mineral oils.

Conventional all-oil muds have oil as the external phase but they are designed to be free of water when formulated or in use. Since water is not present, asphaltic type materials are required to control the fluid loss and viscosity. Since there is no water added to this system during the formulation and water additions are avoided if possible while drilling, there is only a minimum requirement for emulsifiers. All-oil muds can withstand small quantities of water; however, if the water becomes a contaminating effect, the mud should be converted to an invert emulsion. If the water is not quickly emulsified, the solids in the mud can become water wet and will cause stability problems. The water wet solids will blind the shaker screens and loss of whole mud will occur.

Invert emulsions are oil muds that are formulated to contain moderate to high concentrations of water. Water is an integral part of the invert emulsion and can contain a salt such as calcium or sodium chloride. An invert emulsion can contain as much as 60% of the liquid phase as water. Special emulsifiers are added to tightly emulsify the water as the internal phase and prevent the water from breaking out and coalescing into larger water droplets. These water droplets, if not tightly emulsified, can water wet the already oil wet solids and seriously affect the emulsion stability. Special lignite derivatives or asphaltites are used as the fluid loss control agents, and bentonite derivatives are used to increase the viscosity and suspension properties of the system. Invert emulsions are usually tightly emulsified, low fluid loss oil muds. An improvement in drilling rates has been seen when the fluid loss control of the system is relaxed, thus the name "relaxed" invert emulsion. Also, the relaxed invert emulsions fluids do not use as much emulsifier as the regular invert emulsion systems.

Detailed information on oil-based muds is available in the "Handbook of Oil-Based Mud Technology," published by the Fluid Mechanics and Chemistry Group at Amoco Production Research (Tulsa, OK), December 1992.

Oil Mud Applications

Oil muds offer many advantages over water based muds. The high initial cost of the oil based mud can be a factor in not selecting this type of mud system. However, if the overall drilling costs are considered, the costs accompanying the use of an oil mud are usually less than that for a water mud. Some of the applications of oil-based muds will be described below.

Shale Stability - Oil muds are most suited for drilling water sensitive shales. Formulated with the proper salinity, oil muds can prevent water movement from the mud into the shale. In some cases, water can actually be drawn from the shale and could result in strengthening. However, it is also possible to draw too much water from the shale (with too high a salinity) and cause a shale to be less stable. It is desirable to have enough salinity to prevent water migration into the shale but not to allow dehydration of the shale. This is the "balanced activity" concept. The required salinity is usually determined through field experience. Shale cores that have not been altered by the oil mud are necessary to accurately determine the salinity requirements.

Penetration Rates - Oil-mud formulations can usually drill faster than water muds and still provide excellent shale stability. Relaxed filtrate invert emulsions usually have a high oil to water content and some of the additives used to control fluid loss are omitted. These systems do not use the primary emulsifiers, which have been shown to reduce drilling rate, and they do not have the same temperature stability as conventional invert oil muds. The relaxed type oil muds are especially suited to drilling with PCD bits.

High Temperatures - Oil muds have the ability to drill formations where bottom hole temperatures exceed water base mud tolerances, especially in the presence of contaminants. Oil muds have been used at temperatures approaching 550°F. Oil muds can be formulated to withstand high temperatures over long periods of time, unlike water muds, which can break down and lead to loss of viscosity and fluid loss control, as well as corrosion.

Drilling Salts - Invert oil muds will provide gauge hole and do not leach out salt. The addition of salt to the water phase will prevent the salt from dissolving into the emulsified water phase. Water-based mud, even up to saturation and over saturation does not assure that the salts will not be leached out.

Coring Fluids - Special oil muds provide a native state coring fluid with minimum wettability changes. These fluids are usually water-free and thus require only a minimal content of emulsifiers. Oil mud emulsifiers are very strong oil-wetting agents and can cause oil-wetting of the formation. Oil-based coring fluids will not introduce any water into the core, so determination of water saturation can be more accurately determined.

Packer Fluids - Oil mud packer fluids are designed to be stable over long periods of time and when exposed to high temperatures. Oil muds provide long term stable packer fluids under conditions of high temperature since the additives are extremely temperature stable. Since oil is the continuous phase, corrosion is almost negligible compared to water muds under the same conditions. Properly formulated, oil mud packer fluids can suspend weighting material over long periods of time.

Lubricity - The high lubricity offered by oil muds makes them especially suited for highly deviated and horizontal wells. Along with the higher lubricity, the risk of differential sticking is minimized when using oil muds. An oil mud has a thin filter cake and the friction between the pipe and the wellbore is minimized, thus reducing the risk of differential sticking.

Low Pore Pressure Formations -The ability to drill low pore pressure formations is easily accomplished with oil muds since the mud weight can be maintained at a weight less than that of water. Mud weights as low as 7.5 lb/gal can be achieved.

Corrosion Control - Corrosion of pipe is controlled since oil is the external phase and coats the pipe. Oil muds offer exceptional corrosion protection due to the non-conductive nature of the oil, and corrosion cells cannot develop since the metal surfaces are oil wet. The products used in oil mud are very thermally stable and do not degrade to produce corrosive products. Also, bacteria do not thrive in oil muds.

Re-Use - Oil muds are well suited to be used over and over again. The oil mud can be stored for long periods of time, since bacterial growth is suppressed. The oil mud can be conditioned before being

used again by reducing the drill solids content with mechanical removal equipment instead of relying on dilution.

Disadvantages of Oil Muds

- The initial cost of oil mud is high, especially formulations based on mineral or synthetic fluids. The high cost can be offset by oil mud buy-back or leasing from the mud service company.
- Kick detection is reduced when using oil muds (compared to that of water-based muds) due to high gas solubility in oil muds.
- Oil muds are costly when lost circulation occurs.
- Greater emphasis is placed on environmental concerns when using oil muds as related to discharge of cuttings, loss of whole mud and disposal of the oil mud.
- Special precautions should be taken to avoid skin contact which may promote allergic reactions. Inhalation of fumes from oil muds can be irritating.
- Oil muds can be damaging to the rubber parts of the circulating system and preclude the use of special oil resistant rubber.
- Oil muds pose potential fire hazards due to low flash points of vapors coming off the oil mud. Mineral oils and the synthetic fluids have higher flash points than diesel and crude oils. Crude oils should be "weathered" before using in oil muds.
- Additional rig equipment and modifications are necessary to minimize the loss of oil muds.
- Electric logging must be modified for use in oil-based muds. Oil muds are non-conductive therefore resistivity measuring logs will not work in oil muds (SP, resistivity, Dipmeters).
- Oil muds require emulsifiers that are very powerful oil-wetting materials, which can also change the wettability of the rock to an oil-wet condition.
- Oil based muds are more compressible than water muds, and, therefore, the downhole density may vary considerably from that measured at the surface.

Oil Mud Products Description

Oil muds require special products to ensure that the emulsion is extremely stable and can withstand conditions of high temperature and contaminants. Oil mud products must be dispersible in the external oil phase.

Primary Emulsifier - calcium soaps are the primary emulsifier in oil muds. These are made in the mud by the reaction of lime and long chain (C-16 to C-22) fatty acids. Soap emulsions are very strong emulsifying agents but take some reaction time before emulsion is actual formed. Wetting agents prevent solids from becoming water wet while the emulsion is forming. Emulsifiers surround the water droplets and prevent their coalescence.

Secondary emulsifiers - very powerful oil wetting chemicals. Generally these products do not form emulsions as well as the primary emulsifiers, but this oil wet solids before the emulsion is formed. Used to readily emulsify any water intrusions quickly. Typically, these additives are polyamides or imidazolines.

Organophilic lignites - used as high temperature fluid loss additives. They also will aid in the emulsification of water especially at high temperatures. A lignite is treated with an amine to make it oil dispersible. It controls fluid loss by plugging and can be used at high concentrations without causing excessive viscosities (20 lb/bbl +/-).

Asphaltic fluid loss additives - generally consist of gilsonite or asphalt derivatives. Gilsonite has high temperature stability (400°F) whereas asphalt is not as temperature stable (350°F). High concentrations can cause excessive viscosity and gelation of the mud. Treatment level will not usually exceed 15 lb/bbl.

Organophilic gellants - viscosity builders that are made from bentonite, hectorite or attapulgite treated with an amine to make them oil dispersible. Bentonite is most commonly used and is compatible with diesel and mineral oils up to 350°F. For temperatures above 350°F, especially in mineral oil formulations, the hectorite based clay should be used. Organophilic attapulgite is used to improve the suspension properties of packer fluids without appreciably increasing the viscosity.

Wetting agents - supplemental additives to quickly and effectively oil wet solids that become water wet. Drill solids and weighting agents will naturally water wet and the wetting agents will strip off the water and replace it with an oil layer.

Polymeric viscosifiers - additives that increase the viscosity of oil muds in the presence of organophilic bentonite, especially when the organophilic bentonite performance is reduced by high temperatures; they work up to 400°F. A high molecular weight sulfonated polystyrene becomes effective only when the temperature exceeds 250°F.

Rheological modifiers - low molecular weight fatty acid. Provides increase in viscosity at low shear rates (3 and 6 rpm). Barite can "sag" or slide down the hole, especially on deviated wells; these additives will minimize or eliminate this "sag". Increases in total mud viscosity are avoided when using these additives.

Weighting Agents - used to increase the density of the oil mud. The most commonly used weighting agent is barite. A mud weight of around of 21.0 lb/gal is the highest achievable with barite. Hematite, with a S.G. of 5.0 can also be used to increase the density of the oil mud. A mud weight of around 24.0 lb/gal can be achieved with hematite. For the same mud weight, the solids content of the oil mud weighted with hematite will have a lower solids content than weighted with barite because of the higher S.G. of the hematite.

Types of Base Oils Used

In many areas, diesel is used to formulate and maintain oil muds. In remote areas where diesel may not be plentiful, crude oil can be used instead of diesel. Crude oils should be tested prior to their use, since they may pose safety problems. Mineral oils and the new synthetic fluids are replacements for diesel, especially because of their lower toxicity compared to diesel. However these fluids are usually higher in cost compared to diesel.

There are a wide variety of oils available for use in oil muds. The properties of these oils can have a significant effect upon the physical properties of the oil mud. The properties of the oil which are tested are:

- Flash point - a measure of the volatility of the base oil. The higher the flash point of the oil, the less likely the oil mud will catch fire. The flash point of an oil will change with age as the more volatile components of the oil vaporize into the atmosphere. Addition of water will generally cause the flash point of the finished oil mud to be higher than that of the base oil. The flash point of the oil should be greater than 150°F.
- Aniline point - an indication of the relative aromatic content of the base oil. The aromatic components are particularly detrimental to the rubber parts of the circulation system. The aniline point should be at least 140°F. Certain oil mud products such as the organoclay viscosifiers are affected by the amount of aromatic components in the base oil. As the aromatic

content is decreased, more viscosifier will generally be required or a different viscosifier will have to be used.

- Base oil viscosity - a measurement of the viscosity of the base oil and will vary considerably with the type of oil. Crude oils usually have very high viscosities because of higher asphaltic components, whereas the refined oils such as diesel and mineral oils have considerably lower viscosities. Addition of brine and solids to an oil increases its viscosity substantially, but the viscosity of any mud is generally proportional to the viscosity of the base oil. Lower viscosity oil muds will generally cause an increase in penetration rates.
- Aromatic content - a measure of the quantity of aromatics or benzene-like compounds in the oil. These are the compounds that will affect the toxicity of the base oil with the higher content of aromatics, the more toxic the oil mud will be. Most of the mineral oils now used in oil muds have a aromatic content less than 1% by weight.

The types of base oils used in oil-based muds are described below:

Crude Oils - crude oil can be used in place of diesel as the base oil in areas where diesel may not be available in sufficient quantities to formulate and maintain an oil-based mud system. There are some disadvantages with using crude oil as listed below.

- crude oils have lower flash points and fire points compared to diesel or other refined oils.
- crude oil usually has higher base viscosity compared to diesel and the overall viscosity of the oil mud will be higher than that offered by diesel or other refined oils.
- crude oil needs to be weathered before use since the crude has low flash points because of the light ends contained in crude.
- the aniline point of the crude is usually low which can cause the rubber parts of the circulating system to deteriorate.
- crude oil may contain impurities that may require higher concentration of emulsifiers therefore pilot testing with the crude oil is required to design the proper formulation.

Refined Oils- the refined oils are those such as diesel or kerosene which is the most commonly used oil to formulate and maintain oil-based muds.

- check the aniline point of the diesel to determine if it will be damaging to the rubber parts.
- some diesels may contain additives used to "winterize" the diesel and can have an affect on the emulsifier used to formulate oil muds.
- diesels have higher aromatic content than the mineral oils and these components will have a direct effect on the toxicity of the oil mud.

Mineral Oils - the mineral oils have lower aromatic content than diesel and are considered less toxic than diesel.

- mineral oils have higher flash points than diesel and are safer to use especially in high temperature applications.
- mineral oils have a low viscosity compared to diesel and crude oils which will affect the overall viscosity of the oil-based mud.
- mineral oils have a low aromatic content (<1.0%) compared to diesel, which makes them more environmentally acceptable than diesel. Also, the lower aromatic content makes mineral oils more attractive to use and less hazardous to personnel in the event of contact. Low-toxicity mineral oils, like ESCAID110 (Exxon) have aromatic contents of <0.1%.
- mineral oils unlike diesel, do not contain surfactants that could change wettability of the formation.

Synthetic Fluids - The base fluids in synthetic muds are non-petroleum organic compounds that act like petroleum-derived oils in drilling operations but appear to biodegrade readily in the ocean. Like most OBMs, synthetic muds are invert emulsions, with the synthetic fluid serving as the external, or continuous, phase and a brine serving as the internal phase. Several base fluids, mainly in the size range C₁₆-C₂₄, have been introduced in the marketplace during the last few years.

- PETROFREE (Baroid) - an ester made by the reaction of palm kernel fatty acids with a proprietary alcohol. This was the first commercial synthetic fluids. [PETROFREE may be considered a synthetic vegetable oil]
- AQUAMUL (Anchor) - a di-acetal (di-ether) made by condensation of alcohols. [Lower molecular weight diacetals are used as solvents, cosmetics, perfumes and flavoring agents]
- NOVASOL (M-I) - a straight-chain non-aromatic hydrocarbon made by polymerization of ethylene. [Also known as a PAO, for Poly- α -Olefin, this product resembles a highly refined low-toxicity mineral oil not unlike Amoco SUPERLA White Mineral Oil No. 7]. Other synthetic hydrocarbons similar to NOVASOL, like ISOTECH (Chevron) and ULTIDRILL (Dowell) have also been introduced recently.
- BIOMUL (Baker-Hughes Inteq) - a detergent alkylate composed of benzene attached to a saturated hydrocarbon chain. [Detergent alkylates, which are used in the manufacture of detergents, are also called linear alkylbenzenes and might be considered hybrids of diesel and low-toxicity mineral oil]

Properties - In the field, synthetic drilling fluids are thought to perform as well as conventional OBM's. Some differences in their properties remain, however, which may be desirable attributes (+) or which may pose some limitations on handling and use (-):

- a. Synthetic fluids are severalfold more expensive than oils used in conventional OBM's; (-)
- b. Synthetic muds appear to be more biodegradable and disperse in seawater more readily; (+)
- c. Synthetic muds are considerably more viscous at ambient temperatures, but they also thin more readily with increasing temperature; (-)
- d. Synthetic muds are not as thermally stable; (-)
- e. Synthetic muds do not hydrate or dehydrate shales as rapidly; (-)

Comparative Oil Mud Products by Function

FUNCTION	M-I	Baker-Hughes Inteq	Baroid	Dowell	Anchor
PRIMARY EMULSIFIER	VERSA MUL	CARBO TEC L	INVERMUL	EMUL	ANCO-MUL PE
SECONDARY EMULSIFIER	VERSA COAT	CARBO MUL	EZ MUL	FL	ANCO-MUL SE
ORGANOLIGNITE	VERSA LIG	CARBOTROL A9	DURATONE	NA	ANCO-MUL FR-L
ASPHALTIC FLA-GILSONITE	VERSA TROL	CARBO TROL	BARABLOK	TRUDRILL S	ANCO-MUL FR-G
ORGANOPHILIC BENTONITE	VG-69	CARBO VIS	GELTONE II	TRUVIS	ANCO-MUL GEL-B
ORGANOPHILIC HECTORITE	-----	CARBO GEL	BENTONE 38	TRUVISHT	ANCO-MUL GEL-H
WETTING AGENT	VERSA WET	SURF COTE	DRILTREAT	O.W.	ANCO-MUL OWA
RHEOLOGICAL MODIFIER	VERSA MOD	SIX-UP	RM 63	INTERDRILL	LOWRM
POLYMERIC VISCOSIFIER	VERSA HRP	CARBO VISHT	X-VIS	TRUPLEX	ANCO-MUL GEL-P
OIL MUD THINNER	VERSA THIN	SURF COTE	OMC	DEFLOC	ANCO-MUL SPERSE

Oil Mud Formulations

Product requirements are listed for each company over the temperature ranges noted. These formulations are based on lab conditions and will be lower in actual field usage. The field requirement is lower because of the incorporation of drill solids, particle size of the weighting material, and longer periods of shear experienced while drilling. The formulations listed can be formulated in diesel or mineral oils with only small modifications.

BAKER-HUGHES INTEQ - CONCENTRATION OF PRODUCT, LB/BBL

PRODUCT	200°F	300°F	400°F
CARBO-TEC	7	10	13
CARBO-MUL	2	4	6
CARBO-TROL	5	7	15
LIME	5	5	7

CARBO-VIS, an organophilic viscosifier is used at a concentration of 2-3 lb/bbl for O/W ratios of 75/25-80/20. At O/W ratios of 85/15-90/10, CARBO-VIS is used at 3-5 lb/bbl. The concentration of CARBO-VIS will vary with the mud weight. At lower mud weights, the CARBO-VIS requirements will be the higher quantity.

M-I - CONCENTRATION OF PRODUCT, LB/BBL

PRODUCT	200°F	300°F	400°F
VERSA MUL	5	7	10
VERSA COAT	2	3	4
VERSA TROL	2	5	10
LIME	5	5	7

VG-69, an organophilic viscosifier is used at a concentration of 3-4 lb/bbl for O/W ratios of 75/25-80/20. At O/W ratios of 85/15-90/10, VG-69 is used at 4-6 lb/bbl. The concentration of VG-69 will vary with the mud weight. At lower mud weights, the VG-69 requirements will be the higher quantity.

BAROID - CONCENTRATION OF PRODUCT, LB/BBL

PRODUCT	200°F	300°F	400°F
INVERMUL	5	8	10
EZ MUL	2	4	6
DURATONE	5	8	10
LIME	3	5	7

GELTONE II, an organophilic viscosifier is used at a concentration of 3-5 lb/bbl for O/W ratios of 75/25-80/20. At O/W ratios of 85/15-90/10, GELTONE II is used at 4-6 lb/bbl. The concentration of GELTONE II will vary with the mud weight. At lower mud weights, the GELTONE II requirements will be the higher quantity.

DOWELL - CONCENTRATION OF PRODUCT, LB/BBL

PRODUCT	200°F	300°F	400°F
EMUL	3	3	4
FL	3	5	5
S	-	3	8
LIME	7	9	12

TRUVIS, an organophilic viscosifier is used at a concentration of 3-5 lb/bbl for O/W ratios of 75/25-80/20. At O/W ratios of 85/15-90/10, TRUVIS is used at 5-7 lb/bbl. The concentration of TRUVIS will vary with the mud weight. At lower mud weights, the TRUVIS requirements will be the higher quantity.

ANCHOR - CONCENTRATION OF PRODUCT, LB/BBL

PRODUCT	200°F	300°F	400°F
ANCO-MUL PE	5	7	10
ANCO-MUL OWA	2	3	5
ANOC-MUL FR-G	3	5	7
LIME	5	7	10

ANCO-MUL GEL B, an organophilic viscosifier is used at a concentration of 3-5 lb/bbl for O/W ratios of 75/25-80/20. At O/W ratios of 85/15-90/10, ANCO-MUL GEL B is used at 5-7 lb/bbl. The concentration of ANCO-MUL GEL B will vary with the mud weight. At lower mud weights, the ANCO-MUL GEL B requirements will be the higher quantity.

Mixing Procedures

The addition of components in their proper sequence when initial mixing an oil mud will optimize the performance of each product. The order of addition as listed below is the most common procedure for preparation of oil base muds, though each mud system may require some modification of this procedure. The mixing time may vary depending upon the amount of shear either at the rig or at the liquid mud plant. Organophilic viscosifiers require considerable quantity of shear to fully develop their viscosity; therefore, more of this additive may be required on initial mixing. As the oil mud is used over the first couple of days, improvement in the emulsion stability and fluid loss control will vastly improve compared to what the mud was when it was initially mixed.

1. Add the required quantity of base oil to the mixing tank.
2. Add the primary emulsifier and secondary emulsifier as required.
3. Add filtration control additives if required.
4. Add lime as required.
5. Add required amount of water to the above mixture. If brine is to be used, then add brine after the lime additions.
6. Add organophilic viscosifier as required.
7. Add calcium chloride powder if brine is not used. If calcium chloride powder is not available, then mix the calcium chloride flakes into the water and add as a brine.
8. Mix above for several hours to ensure a good emulsion is formed.
9. Add weighting material as required for the desired density.

The viscosity contributed by the organophilic gellant will be higher if it is added to the mud after the water is added and before the calcium chloride is added. If brine is used, then the gellant is added after the brine and the viscosity will generally be lower. The electrical stability of the mud after mixing will be lower initially if brine is used instead of adding calcium chloride to the mud after the water is added.

The electrical stability and fluid loss control will improve after use due to the shear generated during circulation. The above mixing procedure will be suitable for most mud systems. The supplier's mixing procedure should first be reviewed to determine if any variations in the above are to be employed.

Oil Mud Properties

Mud weight of oil muds ranges from 7.5 lb/gal to over 22.0 lb/gal. Downhole density is affected by temperature and pressure more than water base muds. Temperature will decrease the density of oil muds due to expansion and pressure will increase the density due to compression of the oil phase.

Viscosity is affected by temperature and pressure. As the temperature increases, viscosity decreases. Conversely, as the pressure increases, the viscosity increases. The funnel viscosity measurement of an oil mud is greatly affected by temperature. The funnel viscosity of an oil mud is usually used as an indicator and is not normally used for treatment purposes. Rheological properties are usually made with a rotational viscometer. The plastic viscosity, yield point and gel strengths measurements (according to the Pseudoplastic Rheology Model) are made with the rheometer. More accurate descriptions of the rheology of the mud are made with the Yield-Power Law Model. Suspension of cuttings and weighting material is monitored with the gel strength (for static settling) and 3 or 6 rpm reading (for dynamic settling). Run the rheology of oil muds at the same temperature for each test. Plastic viscosity is greatly affected by temperature at which mud is normally tested. The higher the temperature the lower the plastic viscosity. Reduce plastic viscosity by solids control or dilute with base oil. Yield point is somewhat affected at temperatures where mud is normally tested but may be greatly affected by temperatures above 350°F. Increase yield point by additions of organophilic clay, oil polymers or water. Decrease with wetting agents or thinners or dilution with base oil. Gel strengths behaves similar to yield point. Increase with organophilic clay, water or rheological modifiers. Decrease with wetting agents or thinners or even dilution with base oil.

Electrical stability (E.S.) is the increase in voltage across a probe until the emulsion breaks and a current is established. The electrical stability will vary with the amount of water - the more water generally the lower the stability. Presence of conductive solids such as hematite and insoluble salt will result in low E.S. readings. New sine wave E.S. meters are more reproducible and reliable. The readings from these meters are about one-half the value of the previous meters. Falling E.S. readings and the presence of water in the filtrate indicate weakening of the emulsion. Emulsifiers and lime additions are usually required.

HPHT filtration is run at bottom hole temperatures under static conditions to determine condition of emulsion, the filtrate volume and filter cake quality. If water is present in the filtrate, this could indicate emulsion weakening. Thick filter cakes and high fluid loss indicate excessive drill solids content. Lower the filtration rate with filtration control agents, emulsifiers and lime. Increase the fluid loss by dilution with base oil.

Salinity determination of calcium and sodium chloride is done on the whole mud. A new method for this test is now established by the API to determine types of salts present and if any salt is insoluble in the mud. Insoluble calcium chloride can cause water wetting problems and should be reduced by adding water or oil mud with no salinity in the water phase. Insoluble sodium chloride can be reduced in the same manner, but it does not cause water wetting of solids.

Lime analysis determines the amount of excess lime in the oil mud. Lime is essential for the formation of the emulsion when using fatty acid type emulsifiers. Lime content should always be checked since emulsifier additions may not be required due to deficiency in the lime content. A decrease in lime content while drilling may indicate acid gases such as H₂S or CO₂ or high temperature deterioration of products.

Water Activity or relative humidity of the oil mud is determined with a hygrometer. The hygrometer does not determine if any insoluble salt is present.

Oil/Water/Solids ratio in the oil mud is determined with a retort, which is a still that operates at about 650°F. Results need to be accurate, especially for the salinity analysis. Small sources of error in water content can cause large differences in salinity analysis.

Sulfides in the oil mud are measured with the Garrett gas train. A sample of whole mud is used instead of filtrate. Zinc oxide is the preferred compound to treat for soluble sulfides. Increased lime additions are also necessary when H₂S is present.

Trouble Shooting Oil Muds

PROBLEM	SOLUTIONS AND INDICATORS
Low viscosity	Add water and emulsifier, add gellant. If high temperature add polymeric viscosifier. All of these affect the low-shear viscosity, gel strength and yield point more than the plastic viscosity.
High viscosity	Remove low gravity solids with solids control equipment and/or dilution. Increase o/w ratio if water content is too high. Add oil wetting agent to reduce viscosity.
Water wet solids	Remove water wet solids and add oil wetting agent and oil. Ensure that there is no insoluble calcium chloride in the mud. Water wet solids will blind screens and give low E.S. readings. Suspected water wet solids added to water will disperse easily.
Low ES	Water wet solids, undissolved solids, inadequate concentration of emulsifiers, inadequate concentration of lime for emulsifiers, and some weighting agents (such as hematite) generate low electrical stability readings. All except hematite require chemical treatment. Most muds made with mineral oil will have lower electrical stability than those made with diesel. Low viscosity muds usually have low electrical stability readings.
High solids	Mud viscosity will increase and electrical stability readings will decrease even though emulsifier concentration is adequate. Improve solids removal efficiency. Use dual centrifuge to remove drill solids while recovering the barite and oil phase.
High filtrate	Add additional emulsifier if water appears in filtrate. Organolignite will also emulsify water and lower filtrate. Ensure mud has excess lime. Newly formulated mud may have high HPHT until properly sheared. Sometimes small amounts of water will lower HPHT in high O/W ratio muds. Organolignites are not effective when bottom hole temperature is less than about 150°F.
Acid gas	Detected in mud by drop in alkalinity. If H ₂ S is detected by the Garrett Gas Train, alkalinity has decreased so increase lime additions. Maintain lime additions and add sulfide scavenger such as Zinc Oxide. If carbon dioxide is present, add lime.
Mud losses	If loss is not complete, use oil-wettable fibrous material or solid bridging material such as calcium carbonate. Use same technique for seepage losses to minimize thick filter cake and differential sticking. If losses are complete, consider organophilic clay squeeze, cement or displacing to water based mud until loss zone is cased off.
Free top oil	After periods of inactivity, free oil may cover the surface of the pits. Agitate the mud in the pits or add organophilic clay to increase viscosity.

Displacement of Special Equipment

Displacement of Water Mud

- Reduce viscosity and gel strength of water base mud
- Water spacer of at least 500 ft should precede the oil mud
- Use maximum flow rate while rotating the drill pipe
- Highly contaminated mud should be diverted from the active system
- The oil mud/water interface will thicken, so that a gelled spacer will not be needed

Special Equipment

- A mud saver pan installed on top of bell nipple and one installed on rig floor where drill pipe is racked on trips.
- A mud box connected by a flexible hose to the flow line or catch pan
- Use a mud saver sub to reduce losses on connections
- Use pipe wipers to remove oil mud from outside of pipe on trips
- Install covers on pits to prevent rain from getting into pits and lined reserve pits
- Keep water hoses off rig floor to minimize water contamination. Use oil spray system to wash shaker screens.
- Use a rotating head and gas separator for gas entrainment in oil mud
- Disconnect water lines to pits and centrifugal pumps
- Squeegy to clean up oil mud seals and use oil absorbents on rig floor

Oil Mud Calculations

The following set of calculations describe how to either raise or lower the oil/water (O/W) ratio of an oil-based mud. If water enters an oil mud, the O/W ratio will decrease and if the O/W ratio is to be raised, then oil will have to be added. The amount of oil required to raise the O/W ratio can be calculated as follows:

Raise oil/water ratio - add oil

$$\frac{\% \text{ oil} + x}{\% \text{ water}} = \text{O/W (desired)}$$

If the O/W ratio is desired to be lowered, then water must be added based on the following equation:

Lower oil/water ratio - add water

$$\frac{\% \text{ water} + x}{\% \text{ oil}} = \text{O/W (desired)}$$

Example:

retort analysis: 52% oil by vol
 10% water by vol

How much oil is required to increase O/W to 88/12?

Therefore:

$$(52 + x)/10 = 88/12$$

$$(52 + x)/10 = 7.33$$

$$X = 21.3\% \\ = 0.213 \text{ bbl oil/1 bbl mud}$$

Resulting volume = 1 bbl mud + 0.213 bbl oil = 1.213 bbl

To convert to one barrel final volume, divide the mud and the oil volume by the resulting volume.

$$1 \text{ bbl mud} / 1.213 \text{ bbl} = 0.82 \text{ bbl mud}$$

$$0.213 \text{ bbl oil} / 1.213 \text{ bbl} = 0.18 \text{ bbl oil}$$

Electric Logging in Oil Muds

Advantages using oil muds

- Oil muds provide gauge to near gauge holes
- Oil muds provide excellent hole stability
- Oil muds generally produce very little invasion

Disadvantages of using oil muds while logging

- Oil muds are non-conductive so resistivity logs will not work
- Empirical rules for water muds cannot be used in oil muds
- Resistivity measurements using induction logs are not that accurate

Resistivity logs

- Laterolog, SFL, short normal, MSFL do not work in oil muds.
- Resistivity is measured using the induction log.
- Dipmeter with scratchers is still affected when using oil muds.

Porosity logs

- Density (FDC, LDT) is able to see into permeable zones, but invasion could exceed depth of investigation, and response is a combined volume of invaded oil and residual hydrocarbon in place.
- Pe curve is accurate and needs no correction.
- Neutron (CNL) depth of investigation is deeper than that of density logs and neutron would respond less to invaded oil and more to original hydrocarbon.
- Sonic (BHC and long spacing) is least affected by presence of oil muds. Oil filtration may increase transit time close to borehole. If zone is gas bearing, sonic velocity would be lower.

Gas Solubility in Oil Muds

- Gas solubility in oil muds is many times greater than in water muds.
- Gas kick will remain for the most part at the point of entry and will not migrate up the hole like in a water mud.
- When circulating kick out, gas remains in solution and little if any gain in pit level or casing pressure is noted.
- When the gas comes out of solution, a rapid increase in pit level and casing pressure will be observed.
- Gas solubility is a function in the amount of the oil phase, and, once saturation is reached, no further gas will go into solution. Further influx of gas after this point will behave like a gas kick in a water mud.
- Because of the gas solubility in an oil mud, the casing pressure will not be that much higher than the drill pipe pressure. This will depend somewhat on the density differential of the mud and the mud containing the gas. Since gas is not very soluble in water, the casing pressure will be somewhat higher than the drill pipe pressure because of the loss in hydrostatic head with the water mud being displaced out of the hole.
- A reliable pit monitor sensitive to very slight changes in the mud volume is probably the best indicator of a gas kick. Treat all kicks in an oil mud as gas kicks and do not be confused by the somewhat low casing pressure.
- A separator designed for large gas volumes along with a rotating head should be provided if an oil mud is going to be used.

Section 10 Special Fluids

COMPLETION FLUIDS

Introduction

A workover or completion fluid is a fluid used to conduct a workover and/or completion operation. Fluid selection should be based on consideration of the formation characteristics for a particular well. The fluid should be able to control wellbore pressures, as well as be non-damaging to the production interval. Because an over-balanced fluid column exists in most wells during completion and workover operations, fluid selection is critical if formation damage is to be minimized. Non-damaging fluids can be solids free, clay free, acid soluble, water soluble or oil soluble and are used for operations such as: drilling-in, perforating, cleaning out sanded wells, gravel packing, packer fluids, under reaming and well control. While the costs of these fluids are initially high, they are economically justified by the reduction in the time spent remedying or stimulating a production zone, and by the higher production rates attained by using a fluid that is compatible with the formation. For additional information, consult "An Introduction to the Basics of Well Completions, Stimulations and Workovers," by G. E. King at Amoco Production Research (Tulsa, OK), 1993.

Types of Formation Damage from Fluids used in Completion

Formation damage, either chemical or physical, reduces the productivity of a well. The basic causes of formation damage are:

- Hydration of formation clays
- Wettability changes
- Pressure differential
- Water blocking
- Emulsion blocking
- Paraffinic or asphaltic plugging
- Formation of precipitates
- Migration/dispersion of formation clays

One or more of these causes may exist simultaneously in a well. Selecting a properly designed, compatible fluid is a means of mitigating these effects.

Sensitivity Studies

To evaluate reservoir potential, sensitivity studies should be undertaken when possible. In order of preference, pressure cores, conventional cores, sidewall cores, or cuttings should be used to perform the evaluation and sensitivity studies. Tests to be performed should include:

Formation Description

- Pore throat lining and bridging material (XRD, SEM/EDX)
- Thin section - petrographic microscope analysis
- Reservoir fluid analysis
- Porosity and permeability
- Pore throat size and distribution
- Vugularity

Formation Integrity Tests

- Return permeability
- Rock/fluid and fluid/fluid interactions
- Acid solubility
- Matrix strength

Formation Pressure

Determining formation pressure is crucial to fluid selection economics, minimizing formation damage, and maintaining operational safety. Formation damage is greatly reduced by operating under-balanced using a non-damaging, solids-free fluid, but the risks are high. Not only must experienced and trained crews be employed, but also specialized equipment is needed. While it is desirable to maintain 100-200 psi over formation pressure, this is often difficult to achieve. Pressure sensing devices, such as the Hewlett Packard quartz pressure sensor, or a manometer survey tool (Bourdon Tube gauge), are useful for determining formation pressure. However, actual well conditions may dictate adjustments to these determinations in order to maintain well control during operations.

Formation Clay Swelling

The chemical composition of a fluid, formation water, type of clay in the formation, and/or secondary clay deposits lining a pore throat must be carefully considered when selecting a fluid. Rock-fluid and fluid/fluid interactions can result in formation damage such as swelling of the clays, migration of fines, and the formation of precipitates.

Oil Wetting of Reservoir Rock

Most reservoirs are water-wet or preferentially coated with a film of water. Consequently, if oil wetting additives are used in a fluid that comes into contact with the formation, oil movement across the grains becomes severely restricted. This will cause the formation to produce water more readily and may result in the formation of an emulsion block and/or water block.

Mixing Facilities

Rigsite mixing is generally poor for fluids that require shear; however, the problem can be resolved through the use of portable high-shear mixers. If large volumes of fluids are to be mixed, then pre-mixing at a mixing facility should be considered. Safety considerations are another factor that limit the mixing of fluids at the rigsite. Generally, fluids are pre-mixed at a mixing facility, then delivered and maintained at the rigsite.

Corrosion

Some fluids produce high corrosion rates and require pH adjustments and/or the addition of corrosion inhibitors. Consideration must be given to the use of corrosion inhibitors for economics as well as fluid compatibility.

Economics

Proper fluid selection should always consider economics. Remediation, treating or stimulation operations due to an improperly selected fluid can be costly. Contaminants such as cement, salt water, acids or surfactants, along with bacterial growth and safety are important factors to be considered in selecting an economical workover/completion fluid.

Completion Fluid Types

- **Water-Based Fluids** - Drilling muds which contain solids have been modified to be used as completion fluids. Water-based fluids have been used because they are relatively economical, easily maintained, and available. Unless the well is perforated under-balanced and then placed on flowing production, modified drilling muds should be avoided during completion operations, since mud solids can cause permanent formation damage. Barite, for example, a common mud additive used to increase fluid density, is a very damaging solid, as is very difficult to remove chemically.
- **Oil-Based Fluids** - These fluids are generally selected to protect water-sensitive clays against chemical formation damage. Oil-based fluids contain varying amounts of both dissolved and suspended solids. These solids can plug formation pores, form a precipitate, or settle over time. These fluids are less damaging and more expensive than water-based muds, but are often more damaging than solids-free completion fluids.
- **Clear Brine Fluids** - Today, most completion fluids are designed to be solids-free or with a minimum amount of solids. To achieve the higher density fluid for deeper, more hostile environments, clear brines have been formulated using inorganic salts. These solids-free clear brines can minimize formation damage yet control reservoir pressures. Densities can range from 8.5 to 19.2 lb/gal. Higher density brines require special handling. Excessive corrosion and fluid crystallization must also be considered with the use of these fluids.

Water-Based Fluids

Several types of fluids use oil-soluble organic particles such as waxes and resins to act as bridging agents. In some of these fluids, the particles are deformable at temperatures low enough to act as filtration control agents as well as bridging agents. These systems operate best at temperatures between 150°F and 200°F. The particles become too rigid at temperatures below 150°F and too soft at temperatures above 200°F. When needed, HEC and xanthan gum are used for viscosity.

Petroleum hydrocarbon resins are completely soluble in diesel, produced crude oil or condensate. They have a much higher softening point (300°F), provide bridging, but do not control filtration. Starch derivatives and other polymers are used to control filtration, while HEC is used when necessary for carrying capacity.

Acid-Soluble and Clay Free Systems

Ground calcium carbonate is commonly used as a bridging agent in acid-soluble and clay-free systems. It is 98% soluble in 15% HCl, and is available in a wide range of particle sizes (from several millimeters down to a few microns) and may be used at any temperature encountered in the well. It has been found that, if suitable size ranges are selected, suspensions of calcium carbonate alone can be used for short term remedial work in gun perforated wells. However, for most purposes it is necessary to add polymers for filtration control and carrying capacity. Commonly used polymers include: sodium CMC and polyacrylamides, which are not acid-soluble; xanthan gum, which is water soluble, brine soluble and acid degradable; guar gum, which may be degraded with enzymes; starch derivatives; and HEC, which is almost completely acid soluble. Magnesium oxide stabilizes the viscosifying action of HEC to provide temperature stability to about 275°F. Calcium lignosulfonates are used as supplementary filtration control agents when needed. Guar gum, HEC and xanthan gum have low PV/YP ratios, are non-thixotropic, and are advantageous for increased efficiency in separating gas and extraneous solids. For applications requiring high carrying capacity and suspending properties, however, xanthan gum provides superior characteristics.

Water Soluble Clay-Free Systems

A completion or workover fluid can use sized grains of sodium chloride, potassium chloride, sodium bromide, calcium bromide or any other water soluble salt as bridging and weighting agents. The grains are dispersed insoluble solids, suspended in saturated brine by a polymer and a dispersant. Densities up to 14.0 lb/gal are attainable. When the well is brought into production, the salt grains are removed by formation water, or the well may be cleaned by flushing with under-saturated brines. This fluid is especially suitable for water injection wells.

Oil-Based Fluids

Oil-in-Water Emulsion for Gun Perforating

A solids-free emulsion, specifically for use when gun perforating, typically consists of 40% oil emulsified in sodium chloride, potassium chloride or calcium chloride brine. The oil phase is either kerosene or diesel, but may contain other types of refined oils. To minimize cost, emulsion slugs are pumped into the well and spotted opposite the interval to be perforated, the density having been previously adjusted so that it does not migrate in the wellbore. Field results show that oil-in-water emulsions cause no significant impairment either when perforating or during workover operations with exposed perforations unless the wells are shot with a high-pressure overbalance.

Oil-Based Muds

Under most conditions, conventional oil-based muds are excellent for drilling through a production interval. Low mud spurt loss minimizes particle invasion and the filtrate, being oil, does not cause water-block or damage water-sensitive formations. Both laboratory and field tests have shown that oil muds are less damaging to water-sensitive formations than conventional water-based muds. Oil muds can cause wettability changes, however, and are unsuitable for use in dry gas reservoirs.

Oil muds are designed for maximum stability while drilling; any water that they contain, or pick up while drilling, is tightly emulsified by powerful surfactants. Thus, there is a danger of emulsion blocking if bridging fails and whole mud is lost to the formation. Thus, oil muds containing colloidal asphalt for filtration control are preferable to invert emulsions, which have much higher water-to-oil ratios. Since the asphalt is soluble in aromatic oil, any impairment it causes will automatically be removed in reservoirs

with aromatic crudes. Otherwise, it may be removed by washing with aromatic solvents. Asphalt muds should not, however, be used in condensate reservoirs because asphalt is precipitated by light hydrocarbons, such as hexane.

A degradable water-in-oil emulsion is available for situations which require an oil-based fluid with filtration and rheological properties. The emulsion droplets are stabilized by a skin of finely divided chalk particles instead of by organic surfactants. The chalk particles are dissolved by acid and the emulsion breaks to oil and water, leaving no residue. The composition is particularly suitable for use in workover wells because it is available in sack form and may be mixed with lease crude and water or brine to form an emulsion.

Clear Brine Fluids

Solids-Free Brine Fluid Systems

These fluids are made from fresh water or are solutions made with water and the addition of one or more electrolytes. These fluids do not contain either suspended particles or viscosifiers, which means neither filtration control nor viscosity control are provided. Some brines are corrosive and when corrosion inhibitors are required, compatibility studies should be performed. Some brines are toxic and precautions should be taken to prevent contact with unprotected skin. Brine solutions can be prepared to give good inhibition of clays or shales in producing formations. In addition, common contaminants do not affect the brines.

Fluid densities can be prepared from fresh water (8.33 lb/gal) to saturated calcium chloride solution at 11.7 lb/gal. Higher densities may be achieved by the use of other electrolytes, but they may cause corrosion problems. The main salt solutions are calcium chloride, potassium chloride, mixtures of calcium chloride and calcium bromide, and mixtures of zinc bromide, calcium bromide and calcium chloride. Sodium bromide and sodium chloride are used in special circumstances where required densities are low and contamination is a problem. The most commonly-used brines are sodium chloride, and calcium chloride.

Density Range (lb/gal)	Salt Solutions
8.3 - 9.7	Potassium Chloride
8.3 - 9.9+	Sodium Chloride
10.1 - 11.1	Sodium Chloride/Calcium Chloride
8.3 - 11.7	Calcium Chloride
12.0 - 16.0	Zinc Chloride/Calcium Chloride
9.8 - 10.9	Potassium Bromide/Potassium Chloride
10.0 - 12.4	Sodium Bromide/Sodium Chloride
11.7 - 15.1	Calcium Bromide/Calcium Chloride
15.0 - 19.2	Zinc Bromide/Calcium Bromide/Calcium Chloride

Sodium Chloride - Sodium chloride brines have been used extensively for a number of years as completion fluids. The brines are readily available in most active producing areas with densities up to 10 lb/gal. In areas where brine solutions are not readily available, they can be prepared by adding common salt to fresh water.

Table 2
Requirements for Preparing Sodium Chloride Salt Solutions (60° F)
(Final Barrel Based on 100% Material Purity)

Density (lb/gal)	Fresh Water (gal/final bbl)	Sodium Chloride (lb/final bbl)
8.33	42.0	0
8.6	41.2	16
8.8	40.5	28
9.0	40.0	41
9.2	39.5	54
9.4	39.0	68
9.6	38.5	82
9.8	38.0	95
10.0	37.5	110

Salt solutions were formerly considered too corrosive to be used as workover or completion fluids or as packer fluids. The corrosion problem can be solved by adjusting the pH of the solution to above 10.5; however, pH measurements may be less important than measuring and controlling the p-alkalinity of the filtrate; this value should be kept above 1 cc. Lime or caustic soda may be used for pH control.

Adjustment of pH, or alkalinity, does not necessarily ensure the solution to be corrosion resistant. It may be necessary to use a corrosion inhibitor to achieve lower corrosion rates. In some cases, an oxygen scavenger might be used in conjunction with a filming amine inhibitor.

Calcium Chloride

Calcium chloride solutions can be prepared to a density of 11.8 lb/gal. Dry calcium chloride gives off heat when added to water. For this reason, the amount of calcium chloride necessary to obtain the desired density should be determined prior to preparing the solution. The resulting density will be lower at elevated temperatures. Calcium chloride solutions are mildly alkaline and are considered non-corrosive; however, some operators prefer to add a corrosion inhibitor.

Effect of Temperature on Solution Density

As the temperature of the brine solution increases, the volume increases with a resultant decrease in density. A very important consideration in the use of brines is the crystallization temperature (freezing point). The mixing chart to be used must be chosen with care so that the crystallization temperature of the brine is above the lowest temperature expected on the location during completion operations.

Determining Fluid Cleanliness

Clarity

Clarity is defined as a lack of turbidity due to the presence of suspended insoluble or immiscible particulate matter. Brine clarity is important in the following determinations:

- Formation damage potential
- Isolation of a contamination source in the course of manufacture, transport, storage or rig-site use
- Specifications or limits to be placed on concentration and/or type of solids found in water or brines

Clarity is considered to be the most important measure of filter aid filtration efficiency. A high quality filter aid is most important for uniform results day after day. Selection of the particular type and grade having a correct particle size and distribution is a major factor. Tests must be performed using the actual fluid to determine the type and quality of filter aids to be used as well as determining their efficiency.

Clarity measurements involve the most difficult aspect of filtration technology. The significance of accurate clarity measurements is obvious when evaluating a series of any type of filter aid. Many variables can influence results; therefore, it is imperative that comparative tests duplicate, as nearly as possible, actual plant conditions. While it is possible to calculate the average pore size of a filter cake, particles much smaller than the calculated pore diameter are readily retained by diatomite and perlite filter aids. Filter aid filtration gives high solids removal efficiencies, but not 100%.

Turbidity

Turbidity is defined as the “. . . expression of the optical property that causes light to be scattered and absorbed rather than transmitted in straight lines through a sample.” This scattering and absorption are caused by the interaction of light with particles suspended in the sample medium. Turbidity can be caused by suspended solids, including silt, clay, algae and other plankton, microbes, organic matter, and fine insoluble particles. Particles interfering with light transmittance cause the sample to take on a hazy or cloudy appearance. Turbidity is the opposite of clarity.

Turbidity originally was determined by measuring the depth of a column of liquid required to cause the image of a candle flame at the bottom to diffuse into a uniform glow. This was known as *Jackson Candle Turbidimeter*. Calibration was based on suspensions of silica from Fuller's or diatomaceous earth. The turbidity caused by one part per million (ppm) of suspended silica was defined as one Jackson Turbidity Unit. The method was based on the attenuation of light transmitted through a sample; however, because the attenuation is too small at low turbidities, the Jackson Candle Turbidimeter has limited application. Today, turbidity usually is measured by a technique called nephelometry which measures the level of light scattered by particles at right angles to the incident light beam. When light hits a particle, the energy is scattered in all directions. The scattered light level is proportional to the particulate concentrations and can be measured by an electronic photodetector. Photodetectors can be made which are very sensitive to low light levels to allow measurement of low turbidities.

Turbidity of a liquid is important for many reasons. It can be caused by fine suspended particulates that may damage the formation, or it can be caused by particles that are vital to the make-up of a product. Turbidity can also be used as a quality control measure to monitor the efficiency of a filter aid.

Turbidimeters are calibrated in Turbidity Units (TU). Originally, one TU was equal to the turbidity caused by one ppm of suspended silica. The Nephelometric Turbidity Unit (NTU), the most common

unit in use, provides reference to the nephelometric measurement technique. Today the primary turbidity standard is Formazin. It can be synthesized in the laboratory with 1% or better repeatability. Serial dilutions of Formazin are universally accepted now as primary standards for calibrating turbidimeters. More convenient and economical secondary standards are available for routine calibration of turbidimeters on a day-to-day basis. Secondary standards are much more stable as compared to dilute Formazin standards which must be prepared fresh daily. Secondary Standards can also be checked periodically against Formazin to assure accuracy.

There are three features of a turbidimeter which affect its response to a sample: (1) light source, (2) the photodetectors, and (3) the physical configuration between the photodetectors and the sample cell (optical geometry). Different light sources have different spectral outputs. Photodetectors also have different spectral characteristics, some are sensitive to near infrared while others have peak sensitivity to the ultraviolet band. In addition, optical geometry between detectors and the sample cell affects factors such as sensitivity and linearity. As a result, turbidimeters may respond differently to a sample, even though they are calibrated with the same primary standard.

Turbidity levels rise and fall as the suspended solids concentration increases and decreases. However, the amount and color of light scattered by any particle is dependent on the particle size, shape, composition and refractive index. Solutions of equal suspended solids concentration, but different composition, may not scatter the same amount of light. Thus, turbidity relates to suspended solids, but the relationship can not be quantified.

Visual Observations

Clean fluids should be solids-free or contain particles no greater than 2 microns. In the field, a drinking glass can be used to determine fluid clarity. If the sample is not crystal clear, regardless of color, the fluid must be either filtered or discarded. Clean operational practices and on-site filtration are essential to minimizing formation damage. However, determining whether a fluid is clean enough at the rigsite can often be difficult unless a special laboratory has been established at the rigsite to perform solids analysis. The turbidimeter can be used to identify changes in fluid turbidity; however, more precise measurement must be performed in the laboratory.

Total Suspended Solids

Laboratory analysis is required to determine economics and technical feasibility of a filter aid system before, during and after final filtration. To check filter aid performance, total suspended solids determined gravimetrically need to be performed both upstream and downstream of the filter aid, to determine whether the system is performing adequately.

Particle Size Analysis

Solids content of a liquid is quantified in terms of amount and size of particles present. Particle size distribution must be determined by instrumentation designed specifically for the purpose. Several methods of determining particle size are currently in use. Some equipment measures the change in electrical resistance across an orifice as different size particles pass through, while others use laser scattering and diffraction, optical imaging, and methods which measure light blockage.

Other Tests

Oil content, pH, ash determination, chemical analysis and scanning electron microscopy (SEM/EDX) are useful in identifying and/or quantifying completion fluid contamination.

So, How Clean is Clean Enough?

1. Hole Information

- Casing size: 7 in. (26lb/ft, 6.276 I.D.)
- Tubing: 2 7/8 in.
- Perforations: 4 shots per foot (total interval 260 in.), 1/2 in. Diameter, 12 in. avg. depth.
- Brine: 11.8 lb/gal CaCl₂ (650 bbl) containing 0.5% solids with an ASG of 2.4 to 2.6

2. Specific Gravity Information

- Specific Gravity of Water: 1.0 @ 68°F
- Density of Water: lb/gal = 8.33
- Specific Gravity of Drill Solids: 2.4 - 2.6
- Density of Drill Solids: (8.33) (2.4) = 19.99 lb/gal

3. Conversion Information

1 bbl	=	42 gal = 5.61 ft ³ = 9702 in. ³
1 gal	=	231 in. ³ = 0.13368 ft ³ = 0.0238 bbl = 3.785L
1 ft ³	=	7.48 gal = 1728 in. ³ = 0.781 bbl
1 yd ³	=	201.97 gal = 27 ft ³ = 4.81 bbl:
Vol.%		PPM
2.0 = 0.02	=	20,000
1.0 = 0.01	=	10,000
0.5 = 0.005	=	5000
0.25 = 0.0025	=	2500
0.1 = 0.001	=	1000
0.01 = 0.0001	=	100

Is it possible to have solids settling on top of a packer if you have 650 bbl of 11.8 lb/gal CaCl₂ which contains only 0.5% solids?

Determine how many barrels of solids are actually in 650 bbl of 11.8 lb/gal CaCl₂.

$$650 \text{ bbl} \times 0.005 = 3.25 \text{ bbl of solids}$$

Then convert the number of barrels of solids to cubic inches of solids.

$$(3.25 \text{ bbl solids}) \times 9702 \text{ in.}^3/\text{bbl} = 31,531.5 \text{ in.}^3 \text{ solids.}$$

This then translates into 136.5 gal or 2728 lb of solids.

$$\frac{31,531.5 \text{ in.}^3}{231 \text{ in.}^3/\text{gal}} = 136.5 \text{ gal of solids}$$

$$(136.5 \text{ gal}) (19.99 \text{ lb/gal}) = 2728 \text{ lb of solids}$$

So, 650 bbl containing only 0.5% solids left in the hole will leave 108 ft of solids to settle on top of the packer, as shown below:

$$\frac{ID^2 - OD^2}{231 \text{ in}^3/\text{gal}} = 136.5 \text{ gal of solids}$$

$$= \text{bbl/ft} = \frac{(6.276)^2 - (2.875)^2}{1029}$$

$$= 0.0302454 \text{ bbl/ft}$$

$$\frac{3.25 \text{ bbl}}{0.03 \text{ bbl/ft}} = 108 \text{ ft}$$

Another way of evaluating the cleanliness of a fluid is to evaluate the effect of 0.5% solids in 60 barrels of fluid lost on one perforation. Perforations generally are 1/2 in. in diameter and penetrate an average depth of 14 in. The volume of an average perforation can be visualized as being roughly cylindrical.

$$\begin{aligned} \text{Volume Cylinder} &= (D^2)(A)(0.7854) \\ &= (0.5^2)(14)(0.7854) = 2.75 \text{ in}^3 \end{aligned}$$

Sixty bbl of fluid lost on one perforation contains 0.30 bbl of solids. So, when 60 bbl of fluid containing only 0.5% solids is lost, 2910 in.³ of solids are also lost!

$$60 \text{ bbl} \times 0.005 = 0.30 \text{ bbl solids}$$

$$(0.30 \text{ bbl}) (9702 \text{ in.}^3/\text{bbl}) = 2910.6 \text{ in.}^3 \text{ solids}$$

Sixty bbl of fluid will occupy 1984 ft of space in the wellbore. Since there are 1040 perforations in a 260 ft interval (four perforations per foot), the result of only 0.5% solids in 60 bbl lost will plug a total of 1058 perforations.

$$\frac{60 \text{ bbl}}{0.0302454 \text{ bbl/ft}} = 1984 \text{ ft}$$

$$\frac{2910.6 \text{ in.}^3 \text{ solids}}{2.75 \text{ in.}^3 \text{ per perforation}} = 1058 \text{ holes}$$

It should be evident now why cleanliness is extremely important and measures should be taken to assure that only clean completion fluids are used!

Displacement

Complete displacement of the fluid in the hole is critical to the success of every completion/workover operation. Proper displacement procedures should be followed to remove all solids from the hole and to avoid mixing brine fluid with the fluid in the hole.

Indirect versus Direct Displacement

Two different displacement procedures are outlined: the indirect displacement and the direct displacement. The choice of procedure depends on casing-tubing strengths and cement bond log results.

If the bond logs and casing strength data indicate that the casing will withstand a calculated maximum pressure differential, the indirect displacement procedure should be used ($P = \text{BHP} - \text{HH}$ due to seawater). This procedure uses large volumes of seawater or drillwater to flush the well and results in a clean, solids free displacement with reduced spacer and filtration costs. When applying the indirect method, always be sure that pressures do not exceed the burst strength or fall below the collapse strength of the casing.

If the bond logs and pressure profile indicate the casing will not withstand the differential pressure, the direct displacement procedure should be used. This method does not obtain a clean displacement and more spacers and expensive filtering are required. However, undesirable pressure differentials are eliminated because this procedure maintains a constant hydrostatic head. If the indirect displacement method can be applied, it is recommended that the initial displacement be done by bumping the plug with water during cement displacement from the casing. If the direct displacement method is to be used, bump the plug with drilling fluid.

Pills and Spacers

Both direct and indirect displacement procedures utilize pills and spacers for effective hole cleaning and separation of fluids. The primary purpose of a spacer is to provide complete separation of two incompatible fluids. The spacer must be compatible with both the displaced fluid and the displacing fluid.

Cleaning pills are used to scour and sweep debris out of the hole. Two types of pills may be used. A basic cleaning pill is composed of viscosified drill water, seawater or brine. A scouring pill, used to remove mud cake and loose cement from the inside casing wall, consists of water, surfactant, caustic soda, and coarse sand. The scouring pill must be preceded and followed by a viscous cleaning pill/spacer to assure hole cleaning and to prevent mixing of fluids.

Indirect Displacement Procedure

Pre-Displacement Steps

1. Run bit and dual or tandem scrapers.
2. Circulate and condition mud. Reduce funnel viscosity as much as possible while maintaining adequate rheological properties to clean hole and prevent settling of solids. Maintain critical annular velocity to assure that liner tops are thoroughly cleaned prior to displacement.
3. Rig up equipment for displacement of completion fluid. All tanks, circulating lines, and pumps to be used in the displacement should be cleared of residual mud.
4. Insure sufficient space is available to store displaced mud.

Displacement (Water-Based Mud)

1. Pump seawater down the annulus and up the tubing no faster than 2 barrels per minute (BPM). Reverse circulation reduces intermingling of the mud and water. Pumping fluid faster than 2 BPM creates turbulent flow and increases intermingling in most wellbore geometries.
2. Prepare a 50-bbl pill of freshwater and caustic soda (pH13). Circulate this pill slowly through the system for two circulations. Rotate and reciprocate the pipe while circulating. The high pH helps dissolve the mud residue left on the casing.
3. Chase the pill with clean seawater and flush until the seawater is clear.

4. Prepare a 20-40 bbl spacer of filtered seawater viscosified to a funnel viscosity of 150-200 sec/qt. Reverse circulate the spacer, pumping at 1-2 BPM. Follow with the desired completion fluid.
5. Pump until density in equals density out at the flowline; dump the spacer.

Displacement (Oil-Based Mud)

1. Prepare a weighted SAM-5 spacer (Halliburton) or DS3001 (Dowell) spacer or equivalent.
 - a. Viscosity and rheological properties should be greater than the drilling mud.
 - b. Density should be at least 0.2 lb/gal heavier than the drilling mud.
2. Pump spacer down annulus and up the tubing no faster than 2 BPM.
3. Chase spacer with seawater or drill water. Divert oil mud and spacer to reserve pits for storage.
4. Prepare and pump a 100-bbl surfactant/caustic pill using 1 drum of surfactant per 10 bbl of fresh water; raise pH to 12.5 -13.0.
5. Chase spacer with seawater or drill water. Pump at critical velocity to attain turbulent scrubbing of casing wall. Flush until water is clear.
6. Prepare a 20-bbl spacer/pill of filtered water viscosified to a funnel viscosity of 150-200 sec/qt. Reverse circulate the spacer, pumping at 1 to 2 BPM. Follow with the completion fluid.
7. Pump until the density in equals the density out at the flowline. Dump the spacer. Note: In highly deviated wells, use Pine Sol, Pine 'O Pine or other material with a distinct aroma to determine when spacer is to surface.
8. Put filtration unit on line.

Direct Displacement

Due to the pressure profile involved, direct displacement is a somewhat tedious procedure. It involves using five spacers in line, each spacer having a specific use.

- **Spacer 1** is viscosified mud used as a plug to push out the mud.
- **Spacers 2 and 4.** Separate the surfactant/ scouring spacer from spacer 3.
- **Spacer 3** is a combination scouring/dissolving spacer. Frac sand is used to scour the casing wall while the surfactant/caustic cleans the casing and disperses any mud left on the casing wall.
- **Spacer 5** is viscosified completion brine to separate the solids-laden fluid from the solids-free heavy completion brine.

Direct Displacement Procedure

Pre-Displacement Steps

1. Run bit and dual or tandem scrapers.
2. Circulate and condition mud. Reduce funnel viscosity as much as possible while maintaining sufficient rheological properties to clean hole and prevent settling of solids. Maintain critical annular velocity to assure that liner tops are thoroughly cleaned prior to displacement.

3. Rig up equipment for displacement of completion fluid. All tanks, circulating lines, and pumps to be used in the displacement should be cleared of residual mud.
4. Insure sufficient space is available to store displaced mud.

Displacement (Water-Based Mud)

1. Pump 20 bbl of mud to the slug pit and increase viscosity to 80 sec/qt with xanthan gum, HEC or other polymer. (Spacer 1)
2. Follow with a 30-bbl viscosified weighted pill. (Spacer 2)
 - a. Viscosity should be equal to or greater than the mud in Spacer 1.
 - b. Density should be at least 0.2 lb/gal heavier than the drilling mud.
 - c. The minimum recommended volume is 30 bbl.
3. Follow with a 10-bbl pill of fresh water mixed with 1 drum of surfactant, caustic soda to a pH of 12.5-13, and 500 lb of coarse frac sand. (Spacer 3)
4. Follow with a 30-bbl viscosified, weighted pill. (See Item B - Spacer 2.)
5. Follow with a 10-bbl pill of heavy completion brine, viscosified to 150-200 sec/qt. (Spacer 5)
6. Chase with clean heavy brine at a pump rate of no more than 2 BPM.
7. Discard all pills.

Note: If an oil mud is to be displaced, use a service company multipurpose spacer (Halliburton SAM 6) in Step 1.

Filtration

Filtration refers to the process of passing a liquid through a porous, permeable media in order to remove any particulate matter suspended in the liquid. The filtering media can be paper, ceramic, fibrous, or packed beds of material such as diatomaceous earth, coal or sand. All of these media are used on occasion depending upon circumstances. In the oil field, we are particularly concerned with filtering clear brines used as workover and completion fluids. It has long been known that even small concentrations of fine particulates can cause formation damage in the form of permeability reduction by plugging formation pore throats. This damage is difficult if not impossible to reverse and economics indicate that prevention, by removing the fine particulate matter prior to contact with the formation, is always the less expensive choice.

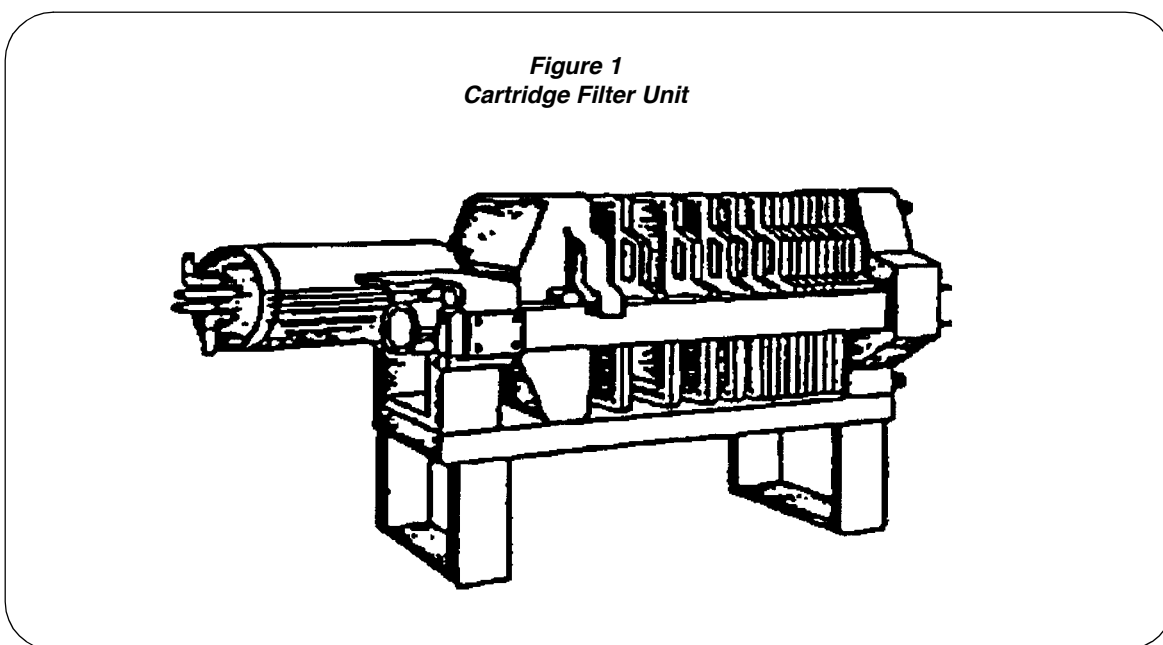
Studies indicate that particles in the range of 1/3 to 1 times the pore throat diameter pose the greatest threat of formation damage. The larger particles will tend to plug off the pore immediately while the smaller particles will tend to enter the pore throat and bridge off deeper into the formation. It appears that particles less than 1/3 the pore throat diameter pose no serious threat to the formation. Based on this data a general recommendation for maximum particle size and concentration has been formulated. It is generally assumed that fluids containing particles less than 2 microns in diameter in concentrations of less than 100 mg/L are relatively safe for use as workover and completion fluids.

The source of the particulate matter varies considerably. Sediment from the water source, particularly if it is from a lake or stream, algae and bacteria present in stagnant water or sea water, impurities in the solid salts used in formulating the brines are all common sources of contamination. In addition, sediment, rust, or remains of other fluids from the tanks used for transporting the brines, as well as similar

contaminants from the tanks or pits at the rig site all add to the difficulty of maintaining a solids free liquid.

Filter Types

The two filter types most often seen in the oil industry are the bed type (usually a bed of diatomaceous earth) and the disposable cartridge type; a washable cartridge type is also available, but less frequently used. The diatomaceous earth filter consists of a rack or frame which supports the beds of filter medium (see Figure 1).

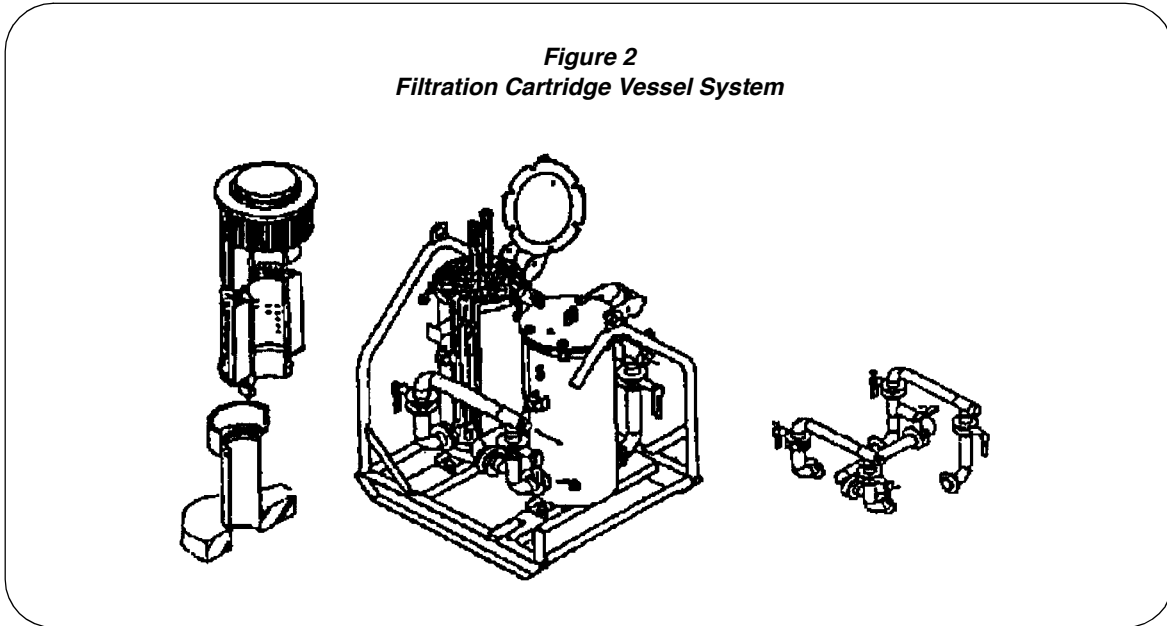


This type of filter works by formation of a filter cake on the surface of the filter bed. Because the filter medium is lightly packed, it can erode or crack and must be replenished periodically. These filters are generally used as pre-filters in series with a cartridge-type filter canister.

The most common cartridge filters are disposable, usually formed by continuous wrapping of a fibrous material around a hollow perforated core. The filters can be designed to have a very positive cut point in terms of solids sizes removed. These filters are rated and described in different terms and it is essential to be familiar with the terms used. A filter may be rated as either a nominal or absolute filter for a certain particle size. A nominal rating means the filter will remove 90% of the particles greater than the rated size. It will remove some smaller particles, but will also leave in suspension some particles larger than the nominal rating. An absolute rating means the filter will remove essentially all particles larger than the rated size. Obviously, the filters with an absolute rating tend to be more expensive than the nominal filters. An example of a cartridge filter set up can be seen in Figure 2.

Usually, for the purpose of filtering clear brines, a diatomaceous earth pre-filter is used, followed by a cartridge type filtering system. The pre-filter will remove particles down to an average of a few microns and is able to handle high flow rates and heavy solids loading. This type of filter medium must be replenished periodically and requires an experienced operator to be present. The cartridge type filter system is fairly low maintenance and easily replaced when dirty. It is recommended that the filters be replaced when the differential pressure across the filters is in excess of 40 psi.

Figure 2
Filtration Cartridge Vessel System



Filter Sizing

As a general rule, the lower the flow rate, the greater the life of the filter. The recommended flow rate is 0.5 to 0.75 gallon per minute (gal/min) per square foot of filter medium. The system should be sized to handle 10% more than anticipated maximum flow rate.

Filtering Procedure

All clear brines should be filtered prior to introducing them into the wellbore. Fluids that are severely contaminated may be treated with rig solids control equipment, specifically the centrifuge, to remove larger sized particles prior to filtering. It may also be necessary to filter the fluid with a series of filters, decreasing the pore size if the fluid has a high concentration of particulate matter. A representative of the service company providing the filtration services can recommend a specific procedure for the individual well.

System Maintenance

Completion fluid maintenance, complexity and cost depend on well conditions and the completion fluid selected. In many cases, simple brines such as sodium chloride (NaCl) and potassium chloride (KCl) brines can be treated simply and effectively. In other circumstances, the expense of the completion fluid or the sensitivity of the reservoir requires careful planning of system maintenance.

Controlling Density

In workover completion fluids, control of the fluid density to prevent influx of formation fluids into the well is of major importance. Maintaining control of the well in most cases depends on the density of the workover fluid. One of the major expenses using clear brine fluids and sized salt water soluble fluids is the maintenance of density at desired levels. In other fluid types such as calcium carbonate based fluids, density control is not a major expense.

Density Control of Calcium Carbonate Based Fluids

Ground calcium carbonate (limestone) is used to control the density of calcium carbonate based fluids. Figure 3 gives a typical particle size distribution for a calcium carbonate weighting material compared to barite. Since the specific gravity of calcium carbonate is 2.8, reasonable fluid properties can be maintained at fluid densities up to 12.5 lb/gal when fresh water is used to formulate the fluid. If saturated sodium chloride (10.0 lb/gal) is used, densities to 14.0 lb/gal can be obtained. When operating within recommended density ranges, sacked calcium carbonate can be added to the fluid through a mixing hopper to achieve desired density. Large density changes of more than 0.75 to 1.0 lb/gal will require pilot testing to determine dilution amounts and treating additive concentrations needed for acceptable fluid properties.

Density Control of Water Soluble Completion Fluids

The concept of a water soluble fluid consisting of a saturated brine and ground salt (NaCl) in combination with polymeric viscosifiers and filtration control agents has been patented by TBC-BRINADD and licensed by a number of workover/completion fluid suppliers. In these systems, the ground salt functions as a weighting agent. Figure 5 gives a typical particle size distribution for a ground salt weighting agent. Due to the 2.18 specific gravity, the typical density range for these formulations is much narrower than most of the other solids-weighted completion fluids. Using 10 lb/gal sodium chloride brine as a base, fluid densities between 10.0 lb/gal and 13.0 lb/gal are practical. Higher density fluids formulated with calcium chloride and other dense brines are also possible, but not typical. The performance of these systems requires maintaining a saturated fluid phase. Any contamination with unsaturated brine will result in loss of soluble salt from the solid phase of the fluid. Adjusting the density of these systems can be accomplished through the addition of the salt weighting material. As with the calcium carbonate material, density changes in the 0.75 to 1.0 lb/gal range should not be too difficult. Pilot testing is recommended before making major changes in density.

Density Control of Solids Free, Clear Brines

Control of brine density requires the addition of water or a lower density brine to reduce density and the mixing of solid salt or higher density brine to increase density. Changing the density of a brine can also change its crystallization temperature. This does not present much difficulty when working with brines such as sodium chloride (NaCl), potassium chloride (KCl) and calcium chloride (CaCl₂). Crystallization temperatures are very important when working with the mixed salt brines such as calcium chloride/calcium bromide brines. Controlling a brine's crystallization temperature is important to prevent the brine from solidifying or precipitating salts from solution when exposed to lower temperatures. Usually, decreasing a brine density with water by as much as one pound per gallon will not cause the crystallization point to increase to a dangerous value. When larger decreases in density are needed, particularly on wells in cold climates or deeper water offshore, they should be made after consulting the supplier of the brine or a knowledgeable completion fluids engineer.

Increasing the density of brines such as sodium chloride, potassium chloride and calcium chloride requires the addition and dissolution of the salt. Most drilling fluids manuals and workover completion fluids manuals include formulations and crystallization temperatures for these brines. When mixing sodium chloride and potassium chloride as coarse salts, achieving saturation can be difficult. Sometimes it may take several hours of stirring and agitation to achieve saturation. Calcium chloride will generate heat as it dissolves, and rapid mixing of calcium chloride can be carried out to the desired density. While densities of calcium chloride greater than 11.4 lb/gal are possible, these brines will crystallize at near room temperatures above the 11.4 lb/gal density. High density mixed salt brines such as calcium chloride/calcium bromide (CaCl₂/CaBr₂) and calcium chloride/calcium bromide/zinc bromide

(CaCl₂/CaBr₂) require special attention. Due to the expense of these brines and their components, any adjustment of density should be carefully considered and formulated. Addition of the wrong salt can cause precipitation of other salts from solution or even cause solidification. In many cases, an increase in density will require the addition of some form of all the salts present in the brine.

Since salt-containing brines are hygroscopic (can draw water from the air), which will cause them to decrease in density, high density brines should be stored in closed tanks. Storage in open pits, particularly when mechanically agitated, will cause high density calcium chloride and mixed brines to absorb water from the atmosphere. If a brine must be stored in an open pit, put the brine into the smallest suitable pit available and eliminate agitation of the brine. All the high density brines pose health concerns to those working with them. Protective clothing should be used when working with these brines.

Viscosification

There are a number of reasons for adjusting the viscosity of a workover/completion fluid. When displacing fluids, adjusting the displacing fluid viscosity higher than the fluid to be displaced usually improves displacement. Cleaning out a well usually requires mixing a viscous pill and pumping it around to remove foreign particles. Milling operations require sufficient fluid viscosity to remove metal cuttings from a well. Gravel packing operations require a fluid that can suspend and transport gravel for placement. Adjustment of viscosity is most often accomplished by addition of a polymer to the completion fluid. Three general types of polymers are available for use in brines and solids containing completion fluids. They are xanthan gum (XC polymer), hydroxypropyl guar, and hydroxyethyl cellulose (HEC).

Xanthan Gum (XC Polymer)

XC polymer is a polysaccharide polymer that can be used in fresh water, sodium chloride, and potassium chloride containing fluids. Of the polymers available, it provides the best solids-suspending characteristics and should be used for viscosifying sodium chloride and potassium chloride brines in preference to the other types of viscosifiers. In situations where mixing capabilities are limited, a liquid product that mixes readily is available.

Hydroxypropyl Guar

Guar-based materials are usually used in fracturing and gravel packing fluids. They can be used in sodium chloride, potassium chloride, and calcium chloride brines. While these materials perform similarly to the xanthan gums, they are not usually used in completion/workover fluids. Raw, unprocessed guar gums should not be used in workover/completion fluids due to formation damage concerns.

Hydroxyethyl Cellulose (HEC)

HEC is a nonionic cellulosic polymer that can impart viscosity to almost all brines, except the higher density zinc-based brines. It is most effective when used in sweeps and for spacers in displacements. The polymer viscosity is drastically reduced by increasing temperature and its low gel strengths reduces the material's effectiveness in suspending weighting materials. For this reason, HEC is used predominantly to viscosify clear brines.

Corrosion Control

Corrosion control in completion fluids is important to protect tubular goods and equipment. In sodium chloride, potassium chloride, and calcium chloride brines (and fluids based on these brines) corrosion

control is relatively simple. Corrosion can be limited by controlling the fluid pH at the neutral or alkaline level, and treating out dissolved oxygen. In severe environments such as high temperature or contamination with acid gases, the addition of filming amines can limit corrosion to acceptable levels.

In the bromide and zinc containing fluids, corrosion control becomes more difficult. Zinc-based brines are moderately acidic, which can cause severe corrosion at elevated temperatures. Most brine suppliers treat their dense brines for corrosion control in their facilities, so rigsite corrosion additives should be compatible with the suppliers' materials. If long-term use of a high density brine is contemplated, selection of a corrosion inhibitor should include testing with long-term exposure to the type of steel used in the tubular goods.

Fluid Losses to the Formation

Losses of brines to formation need to be controlled for economic reasons. Control of downhole pressures and prevention of formation fluid influxes also requires limiting of losses to the reservoir. Formation damage can be limited in many cases by limiting losses of fluid to the formation. In cases where low permeability formations are encountered, losses can be reduced by mixing polymer only pills. HEC polymer is one of the best performing polymers for this use. The polymer pill reduces losses mainly by increasing the flow resistance of the fluid through the formation. In high permeability formations, polymer fluid loss additives with bridging solids are usually needed.

Bridging solids should be non-damaging or capable of being removed from the formation. The bridging agents used must be matched to the formation, workover/completion operation, and type of fluid. Commonly used bridging agents include calcium carbonate, sized salts for saturated brines, calcium aluminosilicate fibers, and oil-soluble resins. These additives need to be tested for bridging effectiveness and optimum concentration requirement. When bridging agents and polymeric additives are used in clear brines, their compatibility with the brine needs to be evaluated. If brine filtering is required, provisions should be made to avoid filter plugging and controlling clear brine contamination.

Crystallization of Brine Completion Fluids

When choosing the lowest cost formulation for a given density one must consider the temperatures at which the brine will be transported, stored and used. The crystallization of the brine formulation selected should be well below these anticipated temperatures to prevent crystallization of the brine before or during use. Generally, in divalent cation brine blends, the more CaCl_2 a brine contains, the higher will be crystallization point and the lower the cost. Conversely, the more CaBr_2 in the blend, the lower the crystallization point and the higher the cost.

The brine formulation tables show crystallization points determined by the last crystal to dissolve (LCTD) method. The method involves cooling the brine sample while stirring below the point where the first crystals appear. Then the sample is warmed slowly until the last crystal dissolves. This LCTD temperature is taken as the crystallization point because it usually occurs at a higher temperature than where the first crystals form. The variability of LCTD values results from the phenomenon that brines formulated in different ways exhibit different crystallization behavior.

Brine Formulations

Section	Brine Density lb/gal	Crystallization Point (LCTD) °F (Experimental Data)	Saturation Crystallization Temp, °F (OSCA Tech. Manual)
NaCl, NaBr	8.4 to 10.0	-1 to 31	23,-
	8.4 to 12.7	-19 to 63	
KCl, KBr	8.4 to 9.7	14 to 60	47,-
	8.6 to 11.5	30 to 75	
KCl/KBr	9.8 to 10.9	23 to 70	-
NaCl/NaBr	10.0 to 12.7	-22 to 45	33
	10.0 to 12.4	-22 to 30	
NaCl/KCl	8.4 to 10.0	-7 to 31	-
	8.4 to 10.0	4 to 55	
NaCl/CaCl ₂	10.1 to 11.1	-42 to 0	-
CaCl ₂	8.4 to 11.6	-57 to 44	34
	11.0 to 14.5	-81 to 35	
CaBr ₂	14.3 to 15.4	25 to 87	57
	14.2 to 15.5	15 to 81	
	11.7 to 15.1	45 to 68	
	11.7 to 14.9	45 to 67	
	11.8 to 14.9	55 to 59	
	11.9 to 14.8	45 to 52	
	11.7 to 15.1	39 to 64	
	11.7 to 14.2	-15 to 39	
	11.6 to 14.5	30 to 40	
	11.8 to 14.4	5 to 15	
	10.7 to 14.2	-54 to 64	
CaCl ₂ /CaBr ₂	10.9 to 14.2	-30 to 15	62
	11.0 to 14.2	-18 to 15	
	11.1 to 14.2	-15 to 15	
	11.2 to 14.2	-11 to 15	
	11.3 to 14.2	-2 to 20	
	11.4 to 14.2	-5 to 32	
	11.5 to 14.2	1 to 41	
	11.6 to 14.2	4 to 50	
	11.7 to 14.2	7 to 55	
	10.7 to 15.1	-58 to 68	
	11.7 to 15.1	45 to 68	
	14.4 to 15.1	-6 to 69	
	14.3 to 15.6	10 to 40	
14.3 to 15.6	10 to 20		
15.0 to 19.2	-8 to 28		
CaCl ₂ /CaBr ₂ /	15.0 to 19.2	3 to 46	10
ZnBr ₂	15.0 to 19.2	20 to 51	
	15.0 to 19.2	-40 to 23	
	14.6 to 19.2	16 to 63	
	15.0 to 19.2	16 to 64	

CORING FLUIDS

Coring fluids are specialty fluids used when coring a production zone. Frequently, the drilling fluid will be used when coring but occasionally it is necessary to substitute a special fluid for the purpose. A cor-

ing fluid is chosen primarily for its lack of interaction with the formation and formation fluids. Ideally, we would like to recover the cores with all the formation fluids and rock properties unchanged. While this ideal is not attainable at this time, it is possible to minimize the effect of the coring fluid on the formation. Since each coring job has special considerations, a universal coring fluid is not practical. Each job should have a fluid designed to meet the needs and requirements of the coring job in question.

Filtration

The single most important consideration of a coring fluid is limiting the filtrate invasion of the formation. This invasion can cause a number of difficulties in analyzing the core. If the filtrate invasion is large, it may flush all the formation fluids out of the core before it is retrieved. At the very least the relative volumes of oil water and gas will be altered. The filtrate can also react chemically either with clays in the formation pore throats or with chemicals in the formation fluids to block pores and change the permeability characteristics of the core. Oil mud filtrates can also be damaging to the cores. The surfactants used to emulsify and water wet solids in conventional oil-based muds can alter the wettability characteristics of the reservoir rocks and, in extreme cases, cause an emulsion blockage of the formation. Waterless oil muds have been used with success in a number of areas, including the North Slope of Alaska. The benefit of the waterless oil muds is that by excluding water entirely we are able to limit the use of the surfactants which are most damaging to the formation.

Other Considerations

There are a number of physical constraints imposed by the use of a core barrel. These are a result of the hole geometry and limited annular flow area. Good hydraulics are a must in order to maintain an adequate pressure loss across the bit face. In addition, the low fluid loss necessary also helps minimize the possibility of sticking the core barrel in the hole, always a problem with large diameter tools. Oil-based muds tend to fit all these requirements and also add to the lubricity of the hole minimizing torque and drag.

Several mud additives can alter wettability and permeability. The need to maintain original rock properties can severely limit the amount and type of additives used in a coring fluid.

Preserving the in situ wettability of a core requires special attention to the coring fluid. Our first choice is to core with produced brine only. The pH should be near neutral (not to exceed 8.5). If higher viscosity is needed, CMC can be added. Mud additives which may alter formation wettability are:

- detergents and surfactants
- lignosulfonate
- phosphates
- deflocculants
- lignite
- caustic soda
- oil
- bactericides (other than formaldehyde used as a starch preservation).
- film-forming amine corrosion inhibitors including chromites although zinc-basic carbonate may be used as an H₂S scavenger.

Precautions to avoid contaminating the coring fluid should be observed. Cleaning surface lines, mud tanks and pumps will help minimize contamination.

Oil Mud Coring Fluid

Oil muds have been developed in recent years as a 100% oil coring fluid. They have been specifically developed to control formation damage caused by conventional drilling and coring fluids. They contain an optimum concentration of oil and particles designed to plug pores of rock, but not penetrate it. The particle size, distribution, and concentration of these solids are tailored to provide low filtration rates, prevent deep mud invasion into potential pay zones, and minimize flushing of core samples.

The system is designed so that rocks in contact with the fluid maintain their water wet nature. Since the fluids are formulated with no water, the fluid system and filtrate are non-reactive with the reservoir rock minerals. Consequently, clay minerals often present in sandstone pore spaces are not disturbed.

These systems do not contain strong surfactant emulsifiers, so the risk of creating emulsion blockage is reduced and the natural wettability characteristics of the reservoir rock or core are preserved.

PACKER FLUIDS

A packer fluid is a fluid left in the casing tubing annulus when completing a well. The purpose of the fluid is to help balance pressures on the tubing and casing strings by providing a hydrostatic pressure on the static side of the tubular goods. The fluid may be either water-based or oil-based. Regardless of the type of fluid used, there are several common properties required for adequate performance. The principal requirement of a packer fluid is stability. A packer fluid will be left static for long periods of time between workover operations. A fluid which solidifies or allows all the solids to settle on top of the packer will significantly increase the maintenance well costs. A good packer fluid will inhibit corrosion of the tubular goods either through oil wetting, as with oil-based muds, or by the use of appropriate corrosion inhibitors. The fluid should be non-damaging to the formation in the event of a packer leak or other downhole communication between the annulus and the wellbore. The fluid should also be of sufficient density to properly balance the anticipated pressures. Several fluids have been found which meet these requirements.

Water-Based Drilling Mud

As a general rule, water-based drilling muds are not suggested for use as packer fluids. Exceptions to the rule are the use of low-density drilling fluids in shallow areas of relatively low temperature. Water-based drilling fluids are susceptible to extremes of temperature and can solidify with long-term exposure to downhole conditions. Lime-based drilling fluids are particularly susceptible to high temperature gelation. Settling and corrosion, whether from electrolytic or bacterial action are other problems associated with the use of water-based drilling fluids as packer fluids. Lignosulfonates and other organic materials used in water-based fluids may release CO₂ and H₂S during thermal degradation. These acid gases can be extremely corrosive and can cause tubing failure in a very short period of time. Table 3 lists several wells completed with a water-based packer fluid and the condition of the fluid upon re-entry at a later date, and Table 4 provides general mixing and performance data for a freshwater packer fluid.

Table 3
Results of Water-Based Drilling Fluids Used as Packer Fluids

Well	Depth Feet	Age Years	Mud pH at Completion	Mud pH at Workover	Sulfide on Tubing	Remarks
1	12,500	5-1/2	10.0	8.4	Positive	Brittle failures of tubing
2	12,980	6-1/2	10.5	8.2	Negative	Casing failure
3	13,600	1-2/3	11.0	9.2	Positive	Casing failure
4	10,200	1-1/2	9.0	8.5	Positive	No failures
5	11,800	1-1/6	8.0	8.0	Negative	Tubing replaced, down-graded
6	4,200	17	8.0	8.0	Negative	No failures
7	9,400	4-1/3	7.5	7.1	Positive	Severe external tubing corrosion
8	9,000	6-1/3	10.0	8.4	Positive	Tubing failure
9	9,650	4	10.0	7.0	Positive	No failure
10	10,000	7	11.4	9.6	Negative	Tubing failure

Table 4
Suggestion Composition of Water-Based Packer Fluid

Mud Density lb/gal	Suggested Fun. Visc. sec/qt	Fresh Water bbl	Caustic Soda	Bentonite lb	CMC lb	Barite lb
11	45-55	0.91	0.36	10.9	1.82	145
12	50-60	0.87	0.35	9.5	1.73	200
13	55-65	0.83	0.33	8.3	1.66	255
14	55-75	0.79	0.32	7.1	1.58	310
15	60-80	0.76	0.30	6.0	1.51	365
16	65-85	0.72	0.29	5.0	1.44	420
17	75-90	0.68	0.27	4.1	1.37	475
18	75-100	0.65	0.33	3.3	1.31	530
19	75-100	0.61	0.43	2.5	1.22	585
20	75-100	0.57	0.46	1.7	1.15	640

Clear Fluids

Clear fluids may be anything from fresh water to a heavy brine depending upon the density required. Clear brines with densities up to 19.2 lb/gal are available. As a general rule the cost per barrel increases with density. One major benefit of the use of these materials is that they are solids free. This eliminates the need for products used to maintain suspension of weight materials, which in turn, elimi-

nates the possibility of settling and high temperature gelation. These fluids tend to be highly corrosive, but this tendency can be reduced by raising the pH and using corrosion inhibitors.

Viscosifying Agents

The material used to maintain viscosity in the packer fluid will vary with the type of fluid used. Bentonite, of course, is a viable and inexpensive choice for use in fresh water fluids. Several polymers are available for use in the clear brines as well as in fresh water. CMC and polyacrylonitriles may be used, but polymers such as xanthan gum, HEC and other starch derivatives are frequently chosen, because they are partially or completely acid soluble. This acid solubility enables the operator to limit or reverse formation damage from the polymers.

Bridging and Fluid Loss Agents

In the event the packer fluid comes into contact with the formation, some filtration control is necessary. This can be a particular problem with the clear brines since they do not have the solids base which forms the filter cake in conventional fluids. While polymers alone can provide substantial filtration control, it is frequently necessary to add a material to serve as a bridging agent to aid in plugging permeable formations. Graded calcium carbonate is frequently used in this application. It is chosen because it is essentially completely soluble in acid which helps minimize formation damage due to solids build-up. Other bridging agents used are powdered, oil-soluble waxes, and resins, which will later dissolve when oil production begins, and graded solid salt which will later dissolve when in contact with fresh water. Filtration control agents used are the CMCs, polyacrylonitriles, xanthan gum, and starches and derivatives.

Weight Materials

Along with the conventional materials such as barite, several other materials are used as weight material. These are calcium carbonate in various grades and certain iron compounds, both of which are acid soluble. The calcium carbonate, being of a lower specific gravity than barite or hematite, has a maximum density limit of about 14 lb/gal. This is true also of graded salt which is also occasionally used for density in oil or saturated salt fluids.

pH Control

pH control is essential in packer fluids. It is accomplished by addition of caustic soda (NaOH) to the fluid. Maintaining a high pH is important because it is the first line defense against corrosion. Since the packer fluids are expected to be in place for years without being disturbed, corrosion is a principal concern. The likelihood of corrosion occurring is worsened in an acidic environment (below pH 7).

Corrosion Inhibition

As mentioned above, the prevention of corrosion is of major concern when designing a packer fluid. There are several methods of corrosion inhibition, all of which should be considered. In addition to elevating the pH as mentioned above, there are specific corrosion inhibitors which may be employed. These are presented in two basic categories: passive and active. The active inhibitors react with corrosive elements in the fluid, for example, sulfites react to remove oxygen from the fluid. The passive inhibitors, on the other hand, form a coating on the steel components and inhibit the current flow necessary to complete an electrochemical corrosion cell. The ultimate corrosion inhibitor is an oil-based fluid used for the packer fluid. When all the steel surfaces are preferentially oil wet, corrosion is minimized.

Oil-Based Muds

Oil-based drilling fluids are frequently used as packer fluids, particularly in deep hot wells. While oil muds are still susceptible to settling, they are very temperature and pressure stable. Oil muds have a very low inherent corrosion factor and are not susceptible to bacterial degradation. Oil muds are probably the most universally applicable fluid for use as a packer fluid. Certain procedures are recommended to convert a drilling fluid for use as a packer fluid. the mud should be cleaned up, most drill solids should be removed mechanically. The carrying capacity of the fluid should be increased substantially to combat the possibility of solids settling. See Table 5 for recommended fluid properties for packer fluids.

Table 5
Recommended Properties for Oil-Based Packer Fluids

Mud Density lb/gal	Min	10	Max	Min	12	Max	Min	14	Max	Min	15	Max	Min	18	Max
Yield Point lb/100 ft ²	30		80	30		100	30		120	30		140	30		150
10-Second Gel lb/100 ft ²	20		50	25		60	25		70	30		90	30		130
10-Minute Gel lb/100ft ²	30		60	30		70	30		80	35		100	35		180
Alkalinity, ml N/ 10H ₂ SO ₄ per ml mud	1.5		6.5	1.5		6.5	1.5		6.5	1.5		6.5	1.5		6.5
Electrical Stability, volts	300			325			350			375			400		
Water Content % by volume	20		35	20		35	15		30	10		25	5		15

Casing Packer Fluids

Casing packs are fluids left behind casing above the cement. They serve a function similar to a packer fluid in protecting the casing from formation fluids. In addition, they allow the retrieval of a portion of the casing in the event the well is dry. Casing packs must be stable at anticipated conditions for long periods of time and assist in corrosion protection of the casing.

Arctic Casing Packs

Casing packs perform a special function in arctic areas. They are applied between strings of casing which penetrate the permafrost layer in these areas. They have an added function of reducing the heat flow from the well to the surrounding environment. Arctic packs are highly gelled to limit the formation of convection currents which increase heat transfer. They should also be non-freezing, which effectively limits them to being oil-based fluids. The freezing restriction is necessary to protect the casing from extremes of pressure generated by ice formation in the annular spaces between casing strings. Refer to DTC Technical Memorandum #87-04 for a complete description of Arctic Casing Packs.

TRACERS

Tracers are compounds used while drilling to differentiate mud filtrate from formation fluids. Tracers are also occasionally used in other applications such as locating lost circulation zones, but we are not concerned with these operations in this chapter. The two most common types of tracers are chemical and radioactive. Chemical tracers may be nitrates, lithium, iodide, chromium or any compound readily soluble but not usually found in formation fluids. Radioactive tracers include tritium and iodine I-131. Both are safe when used properly, but their use is limited due to the stigma attached to use of radioactive materials. Consequently, the chemical tracers are the most frequently used.

Nitrates

Of all the chemical tracers used, nitrates are the most common. This is due mostly to their accessibility and ease of use. Several nitrate sources exist, most of which are available in common fertilizer. Ammonium nitrate, sodium nitrate, potassium nitrate are all acceptable nitrate sources. It is recommended that ammonium nitrate not be used if there is a high concentration of illite clays in the mud. The combination of illite and ammonium ion can result in a highly thixotropic fluid.

Nitrates are used in concentrations of 100 to 200 ppm and the concentration is easily determined with a nitrate test kit which uses a simple colorimetric process to determine nitrate concentration. If the concentration is monitored while drilling it will be possible to determine the relative quantities of filtrate and formation fluid obtained during a drill stem test. Nitrates will deteriorate with time, and there have been cases of bacterial action rapidly reducing nitrate concentrations. Above 200°F, nitrates readily deteriorate with temperature. Nitrates readily reduce to nitrite, nitrous oxide, and finally nitrogen. Therefore, their ability to act as tracers is severely reduced. When wellbore temperatures approach 200°F, it is recommended that an alternate tracer be considered. For these reasons it is necessary to check the nitrate concentration periodically and supplement treatment to maintain the required concentration in the fluid.

Iodide

Potassium iodide is sometimes used as a tracer since the normal iodide content in formation fluids is low. Iodide concentration may also be used to determine the fractional fluid volumes in a test sample. Potassium iodide is strongly caustic and should be handled in a manner similar to caustic soda. Since the recommended concentration is 127 mg/L (0.001 molar) the total fluid volume must be known with some accuracy in order to determine the proper treatment. Iodide concentration is measured with a specific ion meter and an iodide electrode.

Lithium

Lithium ion, as lithium chloride, is also used as a tracer. The use of lithium provides several advantages over the other tracer techniques. Lithium does not undergo a base exchange on the clays; it is temperature-stable and non-biodegradable. Lithium does not affect the drilling fluid properties and can be accurately determined in low concentrations. The major drawback to the use of lithium is the detection process used to determine lithium concentrations. The quantitative determination of the lithium ion must be done by atomic adsorption spectrophotometry. This is a very sensitive process but not one which can be carried out at the rig site. Consequently, there is a lag time between catching a sample and determining the lithium concentration.

Bromides

Sodium bromide and calcium bromide have been used very successfully as tracers, especially in coring operations. One drawback to these tracers is that they can cause mud flocculation in higher concentrations. Recommended mud concentrations range from 0.5 to 1.0 lb/bbl. Pilot testing with bromides is highly recommended prior to additions to any mud systems.

Radioactive Tracers

Radioactive tracers, as mentioned before, are put into use less often than the chemical type although they provide definite benefits. The most common of the radioactive tracers tritiated water, is simply water with one or more of the hydrogen atoms replaced with tritium, a radioactive hydrogen isotope. This is a low energy radioactive emitter of beta radiation, and as a tracer is used in concentrations well below maximum permitted. The half life of tritium is 12.26 years, so no corrections for decay are required over the relatively short test period. The major benefit of the radioactive tracers is that they are relatively unaffected by chemical, temperature or bacterial degradation.

Section 11 Hole Problems

SHALE STABILITY

Introduction

Wellbore instability encountered while drilling shale formations is a worldwide problem. Despite much experience and considerable research, drilling and completion operations continue to be plagued by various hole problems attributed directly to shale formations. Studies and solutions to shale problems are not a simple matter because of the wide variations in clay chemistry.

Shales are sedimentary rocks which were generally deposited in marine basins. They are composed of compacted beds of muds, silts, and clays. In the soft or unconsolidated shale, mud or clay predominates, in the more consolidated formation it is shale or argillite, and in the metamorphic form, slate, phyllite, or mica schist. At increased depth the shales become denser due to the compaction caused by overburden weight. Shales may also be subjected to tectonic stresses, producing further alteration.

When shales contain sand they are called arenaceous shales. If they contain calcium carbonate they are called calcareous shales. Those that contain iron are termed ferrungeneous shales and if large amounts of organic materials are present, they are called carbonaceous shales.

The drilling fluid engineer is very much concerned with the degree of hydration of shales, and with the cementing materials binding shales together. Equally important are the inclination of the bedding planes and the stresses acting within or upon the shale formation.

Shales contain various clay minerals which differ structurally. The more common of these are montmorillonite, illite, chlorite and kaolinite. Some of these clay minerals will hydrate while others will not. Shales containing montmorillonite will hydrate easily. The montmorillonite clay group has a high base exchange capacity, where one cation will replace another and can increase or decrease the shales tendency to hydrate. The degree of hydration is also influenced by the type of cation involved and the pH of the fluid. Mass action by a high concentration of salts will suppress the hydration of clays. Illite is another mineral frequently found in shales. The basic structure of illite is similar to montmorillonite but it does not hydrate readily in fresh water. Both are composed of two silica tetrahedral sheets and a central octahedral alumina sheet. Illite, however, develops a charge deficiency (negative charge) from the replacement of silicon by aluminum on the surface of the silica sheet. This charge deficiency is largely satisfied by potassium ions which fit into the surface oxygen layers. The diameter of the potassium ion allows it to fit the locations in the surface permitting very close association of the clay layers and aiding in resistance to swelling.

Chlorite clay minerals are similar to illite and do not noticeably hydrate. They are composed of the same three layers. Kaolinite is somewhat different from montmorillonite, illite, or chlorite. The clay structure is composed of two layers instead of three: a single silica tetrahedral sheet and an alumina octahedral sheet. There is no charge deficiency and the particles are electrically neutral. Kaolinite does not swell but will readily disperse.

The hydrating-type shales containing montmorillonite are found at shallow depths and are often referred to as gumbo shales. At greater depths their ability to hydrate decreases due to modification of the internal lattice structure. They tend to become a more illitic or chloritic type of clay.

Problems Caused by Shale Instability

Terms frequently used to describe troublesome shales are, sloughing shale, heaving shale, running shale, bentonitic shale, mud-making, plastic-flowing and pressured shale. Besides enlarged hole due to shale sloughing, other problems which occur include:

- Improper mud weight
- Hole cleaning difficulties
- Stuck pipe
- Bridges and fill on trips
- Increased mud volume and treating costs
- Poor cement jobs and increased cement requirements
- Well logging problems
- Limited sidewall core recovery
- Tight hole

Factors Causing Shale Instability

- Tectonically stressed shales
- Abnormally pressured shales
- Erosion due to high annular velocities
- Drill string whipping, knocking shale off the wall of the hole
- While tripping, the drill string dislodges shale, either by direct contact or swabbing action.
- Dissolving salt within the formation
- Mud filtrate or whole mud invasion of the formation is mechanical. The subsequent effect is chemical.
- Annular pressure losses in excess of 50 psi/1000 ft. This can cause wellbore erosion and instability even in laminar flow.

Mechanically Induced Shale Instability

Mechanical instability is generally the end result of excessive, erratic contact of the drill string with the wellbore wall, and/or excessive pressure losses and surges generated by the flowing fluid in the annulus. Proper bottomhole assembly selection and sound fundamental drilling practices will do all that can be done to minimize the first of these causes. Annular pressure loss control involves constantly monitoring annular rheology and hydraulics. As a guide, if the calculated annular pressure loss per 1000 feet exceeds 50 psi, hole stability will be likely to be affected. Even though maintaining laminar flow in the annulus, with certain fluid types and sufficient annular velocity, excessive annular pressure losses may be present.

From a troubleshooting standpoint, all suspected shale and wellbore stability problems should be first examined in light of mechanical causes. Examination of cuttings and analysis of current drilling parameters are of paramount importance.

Note: The time the hole is exposed to the drilling fluid is very important. Since most instability problems are time related, the less time spent drilling with potentially unstable formations open, the lower the possibility of developing a stability problem.

Classification of Problem Shales

Various classification schemes for problem shales have been proposed, but problem shales can be broadly classified by their mechanism of failure: hydratable and dispersing shales, brittle shales, pressured shales and stressed shales.

Table 1
A Suggested Classification of Problem Shales

1	Soft	<ul style="list-style-type: none">• High Dispersion• High in Montmorillonite• Some Illite
2	Moderately Soft	<ul style="list-style-type: none">• Fairly High in Dispersion• Fairly High in Montmorillonite• High in Illite
3	Medium-Hard	<ul style="list-style-type: none">• Moderate-High in Interlayered Dispersion• Sloughing Clays Tendencies• Kaolinite Moderate to High Percentage
4	Hard	<ul style="list-style-type: none">• Little Dispersion• Moderate Illite• Sloughing Tendencies• Moderate Chlorite
5	Very Hard	<ul style="list-style-type: none">• Brittle• High in Illite• No Significant Dispersion• Moderate Chlorite• Caving Tendencies

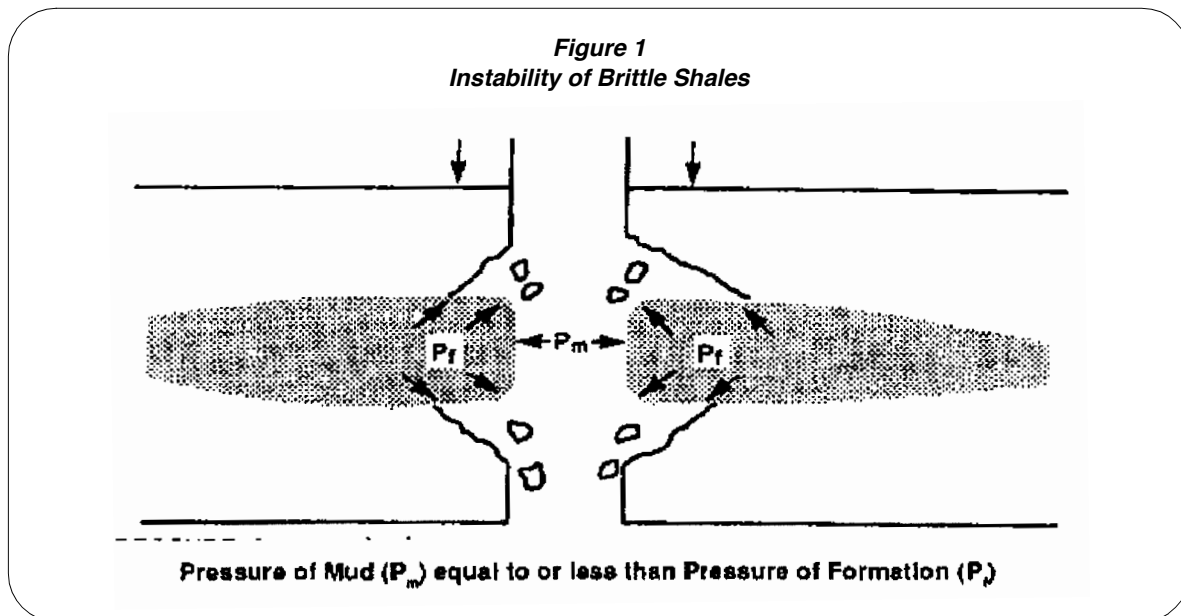
Hydratable and Dispersing Shales

The process of hydration (swelling) and dispersion are related, although each is affected by the amount and type of clays in the shale. Some shales will swell significantly with little dispersion; for oth-

ers, the reverse is true. Hydration results from two distinct mechanisms: surface hydration and osmotic hydration. Surface hydration is a slight expansion between compacted clay particles by the addition of several molecular layers of water on the clay particle surfaces. Osmotic hydration is primarily the expansion of the structure of the clay particle caused by the adsorption of water between the clay platelets. Dispersion is a continual and often rapid disintegration of the shale surface, and results when the strength of the bonds between particles is reduced by the entrance of water. Various clays react differently when exposed to water. As previously stated, the clays that are most commonly found in shales are kaolinites, montmorillonites, illites, and chlorites. Montmorillonites are highly dispersible, disintegratable, and hydratable. Illites are non-swelling in the pure form. Due to leaching and weathering, however, the exchangeable cation (potassium) can be replaced with other cations which may permit some swelling. The chlorite group contains orderly stacks of alternate layers of different types of clays. Disintegration tendencies are high since the layering reduces the number of strong bonds between particles. Non-uniform swelling causes high hydrational stresses and weakens the structure.

Brittle Shales

These shales appear quite firm and competent, but fall to pieces when placed in water. The pieces do not soften or swell in the water. Instability of brittle shales can be caused by either of two mechanisms. The shale can be weakened by hydration of micro-fracture surfaces, and bedding planes, parting within the shale structure. The second mechanism results when a small amount of clay is surrounded by a completely non-swelling quartz and feldspar matrix. Even slight hydration of the clays will cause high differential swelling pressure, and will make the formation unstable (see Figure 1). Many brittle shales have a high percentage of kaolinite. Kaolinite may become unstable in the presence of a high pH environment.



Abnormally Pressured Shales

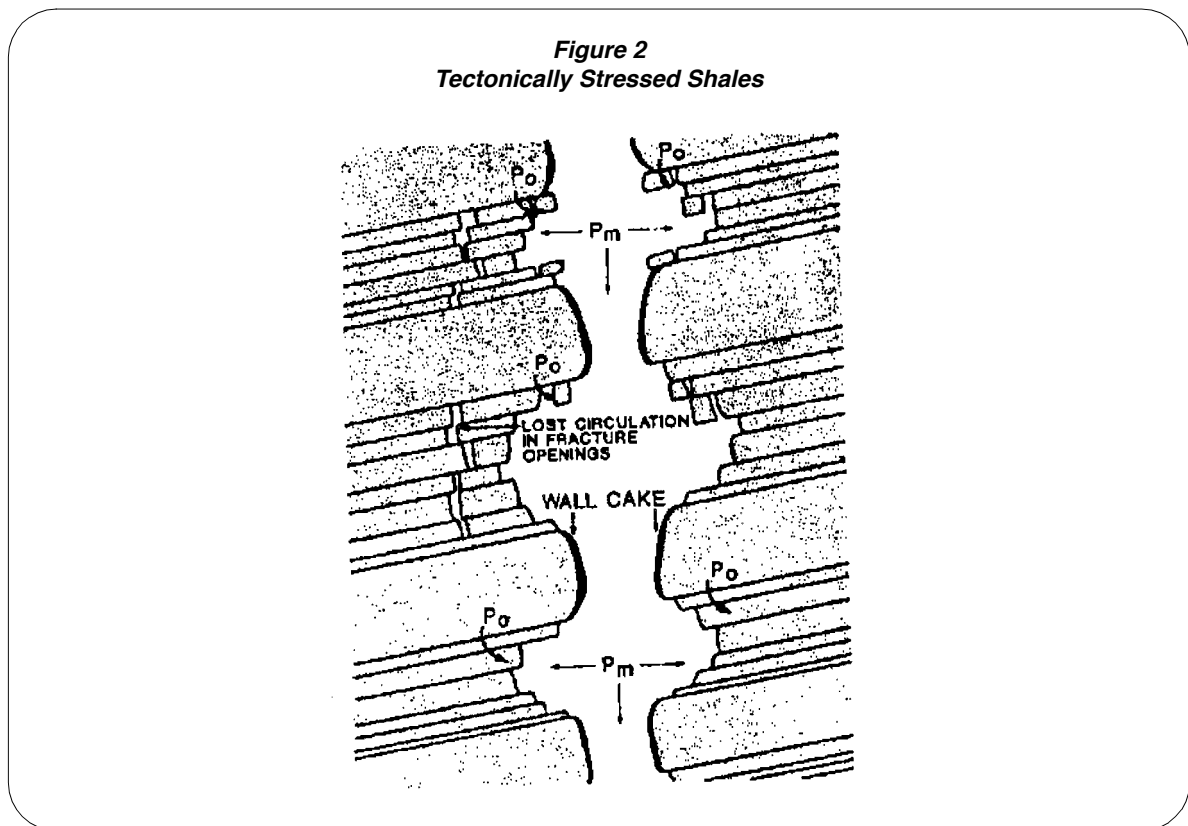
Shales are abnormally pressured when a layer of low-permeability compacted clay develops adjacent to a sand, restricting the flow from the remainder of the clay body. Thus, in a thick clay formation, the rate of expulsion is not able to keep pace with the rate of compaction, and the pore pressure therefore

increases above that normal for the depth of burial. Any sand body, either interbedded or contiguous with the shale, will also be geopressed if it is isolated from the surface either by pinchout or faulting.

Abnormally high pressures may also be found in initially normally pressured formations that have been elevated above deposition level by tectonic forces, and surface layers then eroded. Isolated sand bodies within such formations will then have high pore pressures relative to their depth below the surface.

Tectonically Stressed Shales

Stressed shales occur in areas where diastrophic movement has occurred. (This is the process by which the earth's crust is reshaped, producing continents, oceans, mountains, etc.) The shales may incline considerably from the horizontal, having steeply dipping bedding planes. Forces may be acting upon the formation which, when relieved, cause the shale to fall into the hole (see Figure 2).



The problem may be further aggravated if the bedding planes become wet with water or oil. The Atoka and Springer shales of the American mid-continent are classic examples of shales of this type.

It is agreed that formation stresses induced by diastrophic movement make these shales vulnerable to sloughing. It is also recognized that the natural material cementing these shales is relatively weak. It may be amorphous silica, an aluminum or calcium silicate, or an organic material that is sensitive to oil. There is evidence that chemical inhibition is helpful in minimizing the problem, but it is not the entire answer. There is also evidence that slightly higher mud densities can be helpful, but here again it does not seem to be the entire answer.

To more effectively control these shales, a way has to be found to seal the formation against fluid invasion. This is typically accomplished by carefully controlling the high pressure, high temperature filtration properties of muds. The improvement can be significant, but still does not completely solve the problem.

Blended organic compounds, containing an emulsifier and a sulfonated blown asphalt or modified gilsonites are materials used in plugging the micro-fractures in shale. This minimizes fluid contact along the fractures, and when combined with other remedies will generally reduce the severity of the problem.

Shale Stabilization with Drilling Fluids

Oil-Based Muds

The hydratable, dispersible, and brittle shales are all sensitive to water. Instability can be partially eliminated by preventing the water in the drilling fluid from contacting the shale. One solution is to use an oil-based fluid where water is emulsified in the continuous oil phase.

The interfacial film surrounding the emulsified water droplets in an oil mud can act as a semipermeable membrane and provide a mechanism for osmosis. Osmosis is the flow of water from a less concentrated salt solution into a more concentrated solution through a semi-permeable membrane. Water will migrate from the oil mud into the shale when the salinity of the water phase of the oil mud is lower than the salinity of the water phase of the shale. There is evidence that dehydration of the shale occurs when the reverse is true. No migration occurs when the salinities are equal.

Although maximum shale inhibition is realized with oil muds, their use in some wells may not be considered practical because of other factors. These factors must be carefully evaluated in relation to the severity of the shale instability problem. Oil muds can:

- Reduce the penetration rate in some formations
- Limit the logging program
- Affect cuttings analysis
- Require special preparation and maintenance programs
- Be environmentally unacceptable

Water-Based Muds

Stability is generally obtained in water-based muds from ionic inhibition, encapsulation, and physical plugging. The degree of stability will not be as great as with the oil muds, but properly treated water muds can be successfully used for even the most troublesome shales.

From a drilling efficiency standpoint, the most practical, semi-inhibitive water-based muds are classified as low-solids, non-dispersed fluids. Their stabilizing characteristics are obtained partially from soluble salts and partially from low concentrations of polymer additives. These fluids exhibit good rheological characteristics and generally promote high penetration rates. Proper solids control is a key to using these fluids in the field. High drilled solids content will create rheological problems, reduce the penetration rate, and increase the costs of the mud system and the well.

Ionic Inhibition - Ionic inhibition is effective in reducing the dispersion and hydration of clays, thereby reducing the instability of shales containing swelling clays. The degree of hydration is dependent on the type and concentration of the inhibiting ion in the drilling fluid. For example, montmorillonite will

swell only to about three times its original volume when placed in a saturated NaCl solution. The hydration is greatly reduced, but not eliminated.

The common clays described earlier are all bonded by cations. These cations bond the platelets that make up the clay structure and can greatly affect the degree of hydration of the shale. The cation associated with montmorillonite is usually either Na⁺ (as in bentonite) or Ca⁺⁺ (as in sub-bentonite). Illites contain K⁺ in the pure form, but Na⁺ or Ca⁺⁺ may have replaced the K⁺ through time.

Clays, when placed in water, develop a strong negative charge imbalance on the surface of the platelets. Any cations in the solution will be oriented to satisfy the negative charges. If the concentration of the cation in solution is sufficiently high, a base exchange with the bonding cation of the clay will take place. The various cations behave differently because of ionic size and hydrational energy.

Table 2 shows the unhydrated and hydrated diameters of several common ions. Potassium and ammonium are proposed as the most inhibitive ions for use in a drilling fluid. Their diameters are both very close to the available distance of 2.8 Å between the three-layer packets of montmorillonites and illites. Potassium and ammonium have the lowest hydrational energies (smallest hydrated diameters). The low energies produce inter-layer dehydration and layer collapse, and help in forming a compact, tightly held structure.

Table 2 Ionic Diameters		
Ion	Ionic Diameter (Angstroms)	
	Not Hydrated	Hydrated
Na ⁺	1.96	11.2
K ⁺	2.66	7.6
NH ₄ ⁺	2.86	7.6
Mg ⁺⁺	1.56	21.6
Ca ⁺⁺	2.12	19.2
Ba ⁺⁺	2.86	17.6
Al ⁺⁺⁺	1.14	*
*Not Available		

Potassium cations are expected to perform best as an inhibitive cation on shales having a large percentage of illite. The potassium returns the illite to the pure form which is a non-swelling structure.

Encapsulation -Encapsulation is a chemical and physical interaction with the clay surfaces. Long chain polymers, such as partially hydrolyzed polyacrylamide (PHPA) and modified carboxymethylcellulose, are believed to wrap around the particles. This aids in the control of surface hydration and reduces the tendency to disperse and disintegrate.

Physical Plugging - In some of the brittle shales, ionic inhibition and encapsulation may not sufficiently reduce shale instability. Even slight hydration of micro-fractures will make the formations unstable. Asphaltenes have been effectively used in the field to seal micro-fractures. Their use must be coupled with proper fluid loss control to minimize filtrate invasion into the fractures. The materials that

are purely oil soluble appear to be the most desirable for treatment of brittle shales. The asphaltenes that are water soluble tend to further disperse into the formation water and reduce the sealing effect.

Gilsonite is another mineral product used effectively to maximize shale stabilization. It is thought that these materials minimize shale sloughing by sealing off micro-fractures and pores in the shales and limiting exposure of the shale surfaces due to a plating action on the wellbore. In the most severe cases of brittle shales, not even the use of asphaltenes will prevent instability. The only alternative is to try a balanced activity oil mud.

When shales with abnormal pressure are encountered they must be balanced by hydrostatic pressure or they will become unstable and cause borehole problems. An indication of an overpressured shale is long sharp concave/convex splinters coming from the shale shaker. The amount of cuttings coming over the shaker is also increased. A directional hole will usually require a higher mud density than a straight hole in the same area or field.

Tectonically stressed shales may also require a higher mud density to stabilize the borehole. The amount and configuration of drill cuttings may or may not change. The drag and torque of the drill string may be increased dramatically when geo-pressured shales are encountered without sufficient mud density. Frequently, long sections of hole must be reamed when running the drill string in hole after trips. The borehole can become elliptical due to stress and appear to be under gauge. A good drilling practice is to raise the mud density prior to drilling sections of hole which are tectonically stressed. This will usually allow a lower mud density to run than if the hole is allowed to deteriorate.

STUCK PIPE

Introduction

Stuck pipe during the drilling operation can occur for a variety of reasons such as hole collapse, inadequate hole cleaning, pulling the pipe into an undergauge hole or by differential sticking. Stuck pipe from differential sticking, unlike the others described, usually can not be removed by working the pipe free. Differential stuck pipe usually requires the spotting of specialized fluids across the zone that the pipe is stuck to aid in freeing the pipe. If the spotting fluid is not successful, then a washover job is required to free the pipe. If none of these are successful, then a sidetrack will be required.

Differential Pressure Sticking

Differential pressure sticking is caused by a combination of; poor filtration control, thick filter cake, a positive differential pressure, and a permeable formation.

Differential pressure sticking is usually indicated when the pipe cannot be rotated or reciprocated but full circulation at normal pressure can be established. Conditions contributing to the likelihood of differential pressure sticking are:

- High formation permeability.
- High positive differential pressure.
- Hole angle.
- Poor mud filtration properties.
- The relative geometry of the pipe and the wellbore.
- Period of time the drill string remains immobile.
- The degree of drill collar stabilization. Configuration of drill collars may also be important.

- Poor particle size distribution in the mud leading to formation of a thick high permeability filter cake.

Mechanics

The possibility of differential sticking can be reduced by altering mud properties. Decreasing the mud density to lower the differential pressure is one method; however, this is not always possible. Another method is to lessen the contact area between the pipe and the wall cake. This requires reducing cake thickness. Low filtration rates and minimum solids concentration will contribute to minimizing cake thickness. Good particle size distribution in the fluid will result in low permeability filter cakes which will also reduce the chance of sticking. One point often overlooked regarding low filtration rates is the effect of temperature and pressure. Low API filtrate values do not necessarily mean that filtration rates will be low downhole at increased temperature and pressure. The drilling fluid should be tested routinely at elevated temperatures and pressures to determine filter cake compressibility. For a test conducted at 300°F and 500 psi, the high temperature, high pressure (HTHP) fluid loss should be less than four times the API value for muds having an API fluid loss of two cm³ or more. This is arrived at by assuming that filtrate volume is inversely proportional to the square root of the viscosity of the mud and proportional to (Pressure)^x, when x is no greater than 0.5. Materials that reduce the friction factor between the steel and mud solids are also of value in minimizing wall stuck pipe. Oil emulsion muds, extreme pressure lubricants, and detergents can be beneficial.

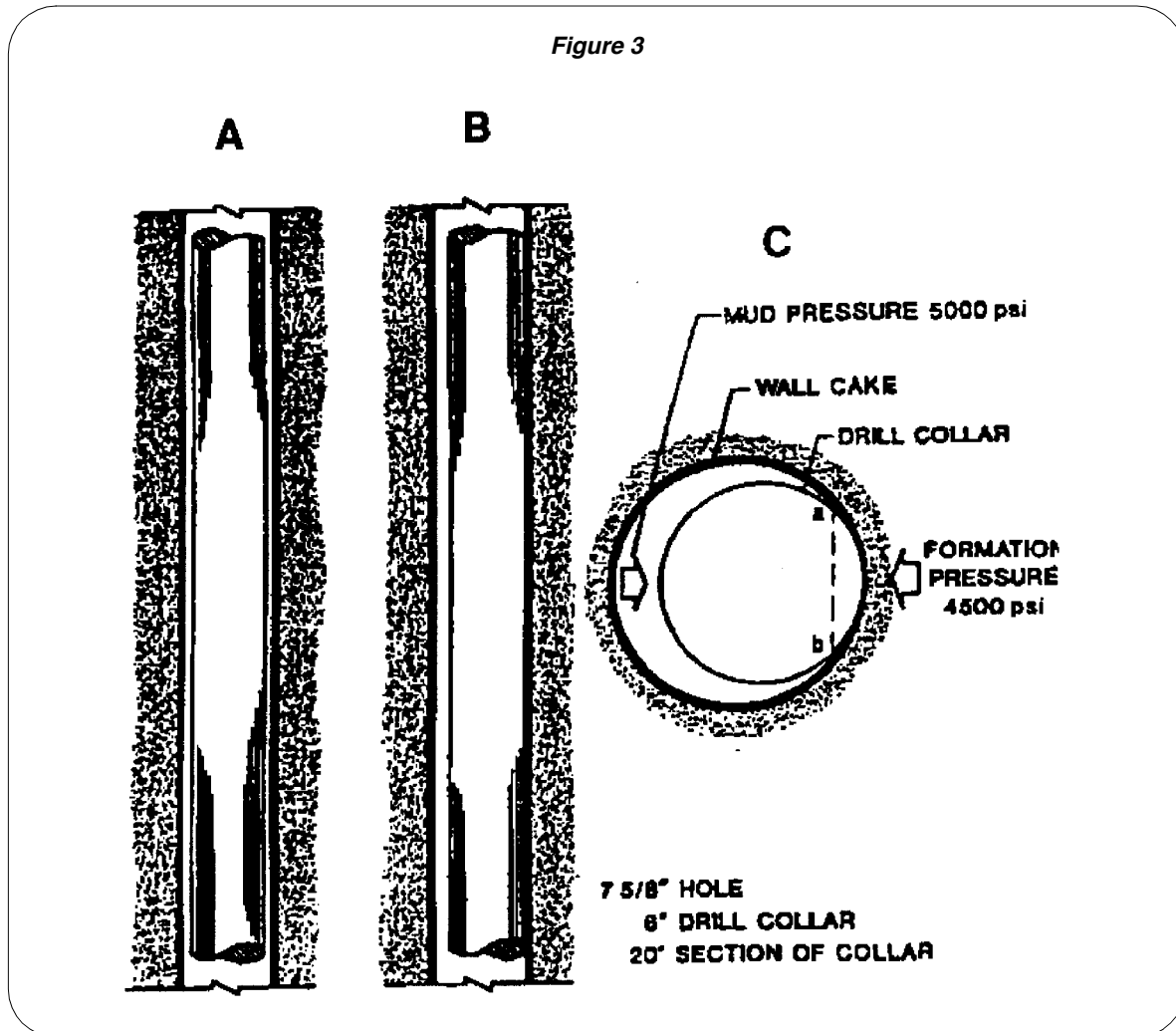
In Figure 3 above, the hydrostatic pressure of the mud is 500 psi greater than formation pressure. In A, the drill collars are centered in the hole and are not stuck. The hydrostatic pressure acts equally in all directions. In B and C, the collars become stuck because they are imbedded in the wall cake opposite the permeable zone. In C the hydrostatic pressure acts across the isolated portion of the collars. This pressure holds the collars firmly against the wall of the hole. The segment this force acts upon is shown by the broken line drawn from a to b which in the following hole geometry will be 3.75 in. in length. For every square inch isolated, there is a confining force of 500 lb. For a 20-ft section of 6- in. collars, in a 7-5/8-in. hole imbedded 1/8-in. into the wall cake, the calculated side thrust is:

$$(500 \text{ psi}) (3.75 \text{ in.}^2/\text{in.}) (12 \text{ in./ft}) (20 \text{ ft}) = 450,000 \text{ lb}$$

The vertical force necessary to pull the pipe free would be somewhat less than this, depending upon friction between the collars and the wall cake.

Prevention

- Drill with mud density as low as practical.
- Keep hole as straight as possible.
- Keep solids content of mud as low as possible.
- Keep static drill string time to a minimum.
- Use extreme pressure (EP) lubricants.
- Avoid long strings of drill collars where the diameter is larger than 65% of the hole diameter and/or
- Use stabilizers or spiral drill collars.
- Use an oil-based mud.



Remedial Measures

In spite of all precautions, stuck pipe still occurs. Recovery may be accomplished by any one of several methods:

- Working/jarring it loose, washing over it, using a taper tap or overshot (fishing tools), etc.
- Reduction of hydrostatic pressure by spotting or u-tubing a column of fluid of lower density than the muds in use, such as water or oil.
- Application of a drill stem test (DST) tool. The pipe is backed off and a DST tool with open-ended drill pipe below is screwed into the fish. When the DST tool is opened, differential pressure is relieved, freeing the pipe. This method depends largely on having a section of hole above the fish where the DST packer will seal properly.
- Spotting of various fluids around the fish, such as oil, oil-based mud, invert oil muds, saturated salt-water, or a special surfactant material (such as Pipe Lax, Freepipe) added to crude oil, mineral oil, or diesel oil, or mixed with an oil-based or invert oil mud. For weighted muds, the surfactant can be mixed with true oil-based or invert emulsion muds correspond-

ing to the density of mud in the hole to prevent the tendency of a short fluid column of less density to migrate up through the denser drilling fluid.

All of the foregoing have been used with varying degrees of success. The spotting method involves placing solutions of the various types around the fish. The most successful method to date has been a soak solution of one of the surfactants in oil, or a soak solution of one of the surfactants in an oil-based mud. Oil alone has been used for years with some measure of success, but the above mixtures have shown a much greater degree of success. Pipe Lax, Freepipe, Skot-Free, Petrocate, and SFT are additives specifically designed to free wall stuck pipe. One gallon is added to each barrel of oil or oil-based mud to be spotted.

When pipe is stuck due to differential pressure sticking, the following remedial measures should be tried:

- Apply torque and tension to try to work the pipe free.
- Determine the stuck point and spot a diesel-oil pill or other surfactant and leave in place.
- Spot soak solution in sufficient volume to cover BHA with 24 BBLs inside the drillpipe.
- It is advisable to raise the pill to approximately the same density as the drilling fluid to minimize migration of the pill in the hole.
- If backoff from the stuck portion has already been effected, a packer may be set above the fish to lower the differential pressure around the stuck portion, thereby freeing the pipe.
- Setting a cement plug and sidetracking may be necessary as a last resort.

Spotting Methods - Most frequently, it is the drill collars that become differentially stuck. Mixing one of the surfactants and an oil solution, and spotting it around the drill collars is relatively easy and frequently very effective. Regardless of where the drill string is stuck, a large enough volume of the solution should be used to cover the complete section of stuck pipe. It may be advisable to spot enough fluid to cover the entire open hole section if practical. Frequently, although initially stuck at the collars, the pipe may become stuck further up hole due to forced inactivity of the pipe. Statistical analysis done by the US MMS shows that spotting fluids placed around the pipe within six hours after becoming stuck have freed the pipe over 60% of the time. Therefore, it is obvious that spotting fluids need to be in place as quickly as possible. A number of drilling fluid companies offer pre-mixed containers of oil-based drilling fluid for no charge storage on the rig site. These fluids may be unweighted or weighted to a specified density. If the spotting fluid is needed it is necessary only to transfer the fluid to the slugging pit, increase the density as needed and add the surfactant before spotting the fluid at the stuck zone. There is generally no charge unless the fluid is used, and it provides a minimum lag time between sticking the pipe and spotting a fluid.

With known hole size and drill collar size, determine the volume of solution to fill the annular space around the collars. Multiplying this value by the number of feet of collars will give the annular volume opposite the collars. For example:

$$500 \text{ ft of } 6\text{-}3/4 \text{ in. collars in } 9\text{-}7/8 \text{ in. hole } (0.5 \text{ bbl/ft}) (500 \text{ ft}) = 25 \text{ bbl}$$

- An extra 25 bbl are added to this figure. The extra volume takes care of hole enlargement and leaves enough solution in the pipe so that a few barrels may be displaced from time to time to keep the collars completely covered.
- The surfactant and oil solution is mixed by adding one gallon of the surfactant per barrel of fluid spotted. The solution should be thoroughly mixed before spotting.
- Determine the pumping time and the volume of fluid to be moved in order to spot the soak solution so it completely covers the drill collars. Spot the slurry, then shut the pump down.

- After the solution is spotted, the pipe should be worked. Work the pipe by putting it in compression. Slack off 10,000 lb below the weight of the pipe and then take 1/2-round of torque/1000 ft with either tongs or rotary table and hold for a few minutes. Release torque and apply tension to the string. Repeat this cycle about once every five minutes. Most of the time the pipe will come free on the compression cycle. It should be pointed out that working the pipe in tension, or hoisting 10,000 to 50,000 lb over the indicated weight of the drill string, could cause the pipe to become stuck further up the hole.
- Displace one half to one barrel of soak solution every half hour to keep the collars covered. Continue to work pipe as outlined above. Allow soak solution to soak a minimum of 24 hours prior to considering alternative operations.

Keyseating

A key-seat is caused by the drill pipe cutting or wearing a slot into the side of the borehole. The drill collars, being larger than the drill pipe, can become wedged into this slot and stuck. The drill string is usually stuck while pulling out of the hole. The drill collars are pulled into the key seat and stuck.

Mechanics of key-seat sticking are:

- The number and severity of dog-legs.
- Length of time that the uncased section of the wellbore is left exposed, especially in terms of rotating hours and number of trips.
- The drillability of the formation.
- The relative size between the drill pipe tool joints and the drill collars. Very large collars are less likely to pull into a key-seat and become stuck than are collars that are just slightly larger than the tool joint outside diameter.
- Rapid transition from a formation that is prone to wash out to one that remains close to gauge, or the reverse. The washed out section no longer provides support for the adjacent formation and thereby concentrates the wall stress exerted by the drill pipe.

Prevention

- Drill with a stiff bottomhole assembly, which tends to minimize the chance of severe dog legs.
- Use key-seat wipers properly positioned in the string.

Remedial Measures

- Sound drilling practices and good preventive measures are most important.
- Working the drill string and attempting to get above the key-seat without getting lodged too tightly may be the only recourse.
- As a last resort, backing off and fishing or sidetracking may be the only solution.

Cuttings Accumulation

Mechanics of Cuttings Accumulation

The drill string can become stuck when drill cuttings are not adequately removed from the hole. This type of sticking is usually accompanied by loss or partial loss of circulation caused by “packing off”.

Prevention

To prevent pipe sticking due to debris or cuttings accumulation and swelling or plastic movement:

- Maintain drilling fluid properties capable of good hole cleaning and general wellbore stability.
- For high-angle holes (>35°), rigs should have top drives, three mud pumps, advanced solids control systems, and well-trained crews.
- Maximize rotary drilling, especially for high-angle holes (>35°).
- A rough guideline for flow rate is that it should be 60 times the hole diameter in inches for high-angle holes and about 1/2 as much for low-angle holes (<35°). Typical annular velocities range from 120 ft/minute for low-angle wells to greater than 200 ft/minute high-angle wells.
- Use the highest mud weight consistent with wellbore stability considerations (lost circulation).
- Both low and high viscosity fluids have provided good hole cleaning in drilling operations. The suitability of a particular rheology mud can be checked using a hole cleaning design program such as Amoco STEP (Solids Transport Efficiency Program). This provides minimum operating flow rates and corresponding maximum ROPs with ECD predictions.
- Use routine hole-cleaning prevention methods such as back reaming, drillpipe rotation and reciprocation, and circulation with bit off bottom. This is especially important in wells with hole angles between 45 and 75° where bed slumping is likely and before tripping out of hole.
- Ensure proper selection of casing points to minimize exposure time of formations to drilling fluids.
- Maintain sufficient mud density in pressured zones.

Remedial

When the stuck pipe is caused by debris or cuttings accumulation and swelling or plastic movement, the following measures should be tried:

- With debris or cuttings in the hole, occasionally rotating, reciprocating and attempting to break circulation may free the pipe.
- If pack-off is severe and circulation cannot be established, a fishing job, or sidetrack, or both, may be the only alternatives.
- If plastic salt flow is sticking the pipe, occasionally attempting to circulate with a freshwater pill may wash the wellbore enough to get the pipe free.

LOSS OF CIRCULATION

Introduction

Lost circulation is best defined as the uncontrolled flow of whole mud into a formation. This can occur in naturally cavernous, fissured, or coarsely permeable beds, or can be artificially induced by hydraulically or mechanically fracturing the rock, thereby giving the fluid a channel in which to travel.

- Induced Losses
- Naturally Occurring Losses

Induced Lost Circulation

Induced lost circulation is the result of an excessive overbalanced condition, where the formation is unable to withstand the effective load imposed upon it by the drilling fluid. Excessive drilling fluid density is the most common cause of this condition. Excessive drilling fluid density can be the result of inadequate or inaccurate well planning (pore pressure and fracture gradient prediction), poor or non-existent solids control, or can be the result of poor rheology or circulating system hydraulics. Any mechanical condition which causes an abnormal pressure surge can cause hole instability, and may cause lost circulation. Examples of these conditions may be: pump surges, bit and stabilizer balling, poor hole cleaning, abnormally high pump flow rates, poorly designed hole geometry, and poor fluid properties, making it difficult to break circulation after the fluid has been static.

Prevention

The key to preventing induced lost circulation lies in controlling static and dynamic pressures, and at all times keeping the sum of these imposed loads below the fracture limit of the rock that is being drilled. This is a well planning problem, and centers around the accurate prediction of pore pressure and fracture gradient. Second, drilling fluid properties must be closely monitored and maintained within acceptable ranges. Solids control is the most important aspect of maintaining acceptable drilling fluid properties, followed by monitoring rheology and hydraulics to minimize fluid gel strengths, annular pressure losses, and equivalent circulating density (ECD). Bit hydraulic optimization will aid in reducing or eliminating bit balling, and thereby reduce abnormal surge and swab pressures. Sound drilling practices designed to improve drilling efficiency (reduce formation exposure time) and improve formation stability must always be employed. Some examples of these are:

- Drill all bridges; do not drive through them.
- Break circulation with caution; if necessary, do so in stages when tripping into the hole. When breaking circulation, commence pipe rotation first and start pumping slowly while moving pipe up.
- Maintain all surface pumping equipment in good working condition.
- The intermediate casing string should be set in a consolidated shale formation as deep as is practical. This ensures the highest possible fracture limit at the casing shoe.

Remedial Measures

When induced loss of circulation occurs, addition of loss circulation materials is not usually very effective. This is particularly true if the mud density is high, 14 lb/gal or greater. Fine loss circulation material which does not adsorb a lot of water should be used in weighted mud. Recommended procedures are:

- Shut down the pump.
- Monitor fluid level in the annulus (the reduction in pressure due to cessation of fluid flow may be sufficient to stabilize a minor loss.)
- If the fluid level is down, fill the hole with water or diesel (base fluid), and monitor the number of barrels required.
- If the loss is severe, the bit should be pulled up into the casing to prevent stuck pipe.
- In the case of minor losses, where the hole appears to be stable after shutting the pump down, an attempt to regain complete circulation at a reduced pump rate is warranted. Do not continue pumping if the loss continues.
- If it is necessary to fill the hole with water or diesel, an estimation of the loss point (generally assumed to be the casing shoe), and the volume of water used will allow a calculation of the effective fluid density which the wellbore can support. This is an important calculation since it helps determine what corrective measures may be applied.

In any lost circulation case, remedial action should center around reducing the effective mud density. This may involve changing fluid or flow properties, or both, to reduce the load applied by the fluid to the formation while pumping. If water or diesel were used to fill the annulus, then the calculation described in 6, above, becomes the key in determining the magnitude of the effective fluid load reduction required. Well control needs must always be taken into consideration prior to reducing the fluid density.

A barite plug can be used to remedy induced loss of circulation. In extreme cases the zone can be cemented to remedy loss of circulation.

The following are recommendations for composition and application of barite plugs.

Formulation Plug Density (lb/gal)	16	17	18	19
Composition per final Bbl				
Water (Bbl)	.71	.68	.64	.60
Chrome Lignosulfonate (lb)	5.7	5.4	5.1	4.8
Caustic Soda (lb)	1.1	1.0	1.0	0.9
Barite (lb)	422	477	533	588

The following procedures are for mixing and placing a heavy barite plug to remedy induced loss of circulation. The placing of a heavy barite plug is usually done in order to stabilize the borehole for running casing. It is not recommended to drill ahead after inducing loss of circulation, unless the losses can be cured.

Settling Plug Mixing Procedure

Cementing Equipment

- Clean and flush all mixing lines to and from cement mixing equipment. Arrange for weight material to be mixed rather than cement. This may require the use of sacked weight material. If sacked weight material is to be used, be sure that weight material sufficient for the plug can be placed near the mixing hopper. Estimate manpower and barite moving requirements (forklift and/or crane).

- Measure mixing water for plug volume (take into account line volumes) into tank. If possible, mix caustic soda and lignosulfonate into mixing water. This may be done by using mud system slugging pit and pumping mixing water to cement mixing equipment. Mix 1-1/2 lb/bbl of caustic soda and 8 lb/bbl of lignosulfonate in mix water (pilot test).
- Mix plug and pump “on the fly” using weight material and mixing water. Avoid mixing slurry below 16 lb/gal for barite weight material and below 20 lb/gal for hematite material as rapid settling could cause plugging of equipment or lines.
- Avoid “chasing” plug with water. Use mud to prevent premature settling of plug.

Mud Tank Slugging Pit

- Empty and clean slugging pit. If unable to dump pit, fill with water and agitate. Pump out dirty water. Repeat, if necessary, to get pit clean.
- Put just enough mixing water in pit to obtain mixing pump suction. Add the total calculated amount of caustic soda and lignosulfonate to the mix water. Note: quantity required and calculate remaining amount of water to be added to bring total volume mix water.
- Begin mixing weight material. Slurry should begin to look viscous when the density nears 16 lb/gal for barite and 20 lb/gal for hematite.
- When slurry density approaches 18 lb/gal for barite and 21 lb/gal for hematite, begin adding remainder of mix water. Add mix water in steps with additional weight material to avoid both too light a slurry that will settle or too heavy a slurry that will lose pump suction. After adding the calculated volume of mix water, bring slurry to final desired density. Allow to mix until weight material is mixed thoroughly.
- Pump plug to mud pump, avoiding water ahead or behind plug. Avoid chasing plug with water. Use mud instead to prevent premature settling of plug.

Naturally Occurring Loss of Circulation

Circulation in a drilling well can be lost into open fractures which are pre-existing. Circulation can be lost into large openings with structural strength such as large pores or solution channels.

When circulation is lost the first step should be diagnosis, where and why the loss is occurring.

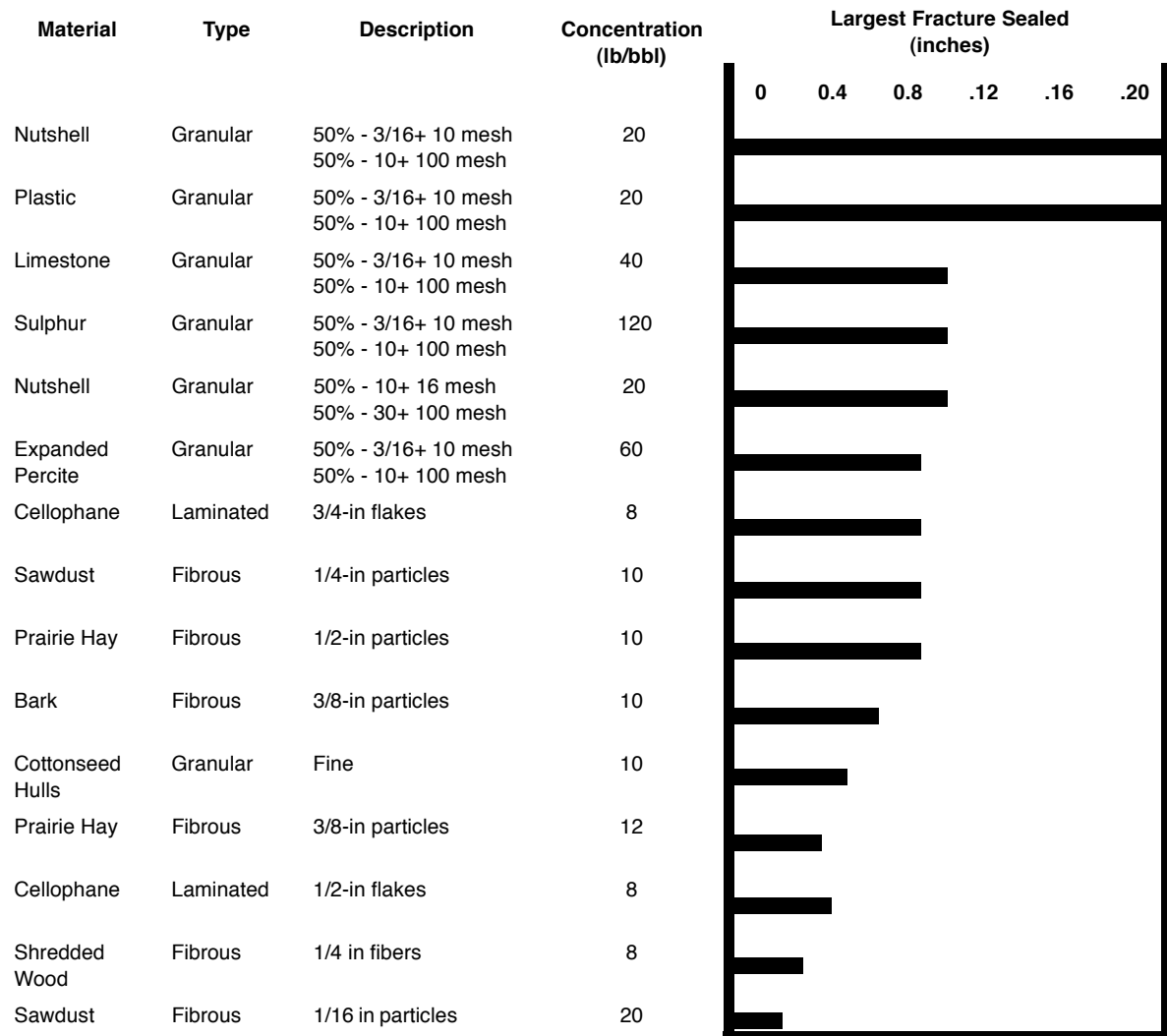
Remedial Measures

1. Shut down the pump.
2. Observe the annulus and monitor the fluid level if it is in sight.
3. If the fluid level is out of sight fill the hole with water and monitor the number of barrels required. If the hole will not stand full, mix 10-15 lb/bbl LCM in the remaining mud in the pits and spot across weak zone if the location of the loss zone is known, or spot a concentrated LCM pill.
4. Pull the pipe into the casing and rebuild mud volume while waiting for the hole to heal.

The action taken will depend on knowledge of the area. In many areas when circulation is lost the drill string can be removed from the hole without danger, while the hole is healing after spotting lost circulation material across the thief zone. There are other areas where the drill string cannot be removed when the fluid is out of sight and cannot be monitored, because of an expected influx of oil or gas. The concentration and type of lost circulation material will depend on the individual situation.

Sealing Materials to Combat Loss of Circulation

There are a great variety of materials available to use as sealing agents for loss of circulation. The following chart gives an indication of the size of fractures scaled by different materials.



Plug Choices and Techniques

When a loss zone cannot be stabilized with sealing materials it may be desirable to try a plug. Several choices and techniques are available; however, in all cases a reasonably accurate estimate of depth of the loss is required prior to setting the plug. Spinner surveys, radioactive traces, and temperature surveys are most commonly used for this purpose.

The following is a typical list of plug choices. These are generally classified as soft, medium or hard plugs:

- a. Soft Plugs
 - DIASEAL M squeeze *

- Attapulgite squeeze *
- b. Medium Plugs
 - Bentonite-diesel oil squeeze (gunk)
 - Cement-bentonite-diesel oil squeeze
 - Invert, bentonite-diesel oil squeeze
- c. Hard Plugs
 - Cement
 - Barite

* Depends on filtration to produce a firm plug.

The following are examples of material combinations for several of the above plugs:

- a. Bentonite-diesel oil (10 bbl - 11.0 lb/gal)
 - 7.5 bbl diesel oil
 - 21 sx bentonite
 - 50 lb coarse mica
 - 50 lb fine mica
 - 10 lb fiber
 - (The density of the mixture can be in-creased with barite.)
- b. Cement-bentonite-diesel oil (10 bbl - 11.2 lb/gal)
 - 6.75 bbl diesel oil
 - 13.5 sx bentonite
 - 13.5 sx cement
 - sealing material (as desired)
 - (The density of the mixture can be in-creased with barite.)
- c. Invert bentonite-diesel oil (10 bbl - 16.4 lb/gal)
 - 5.9 bbl water
 - 10 lb caustic soda
 - 5 lb chrome-lignosulfonate
 - 32.5 sx organic, amine-treated bentonite (oleophilic)
 - 30 sx barite
 - (Mix the caustic and lignosulfonate into the water, then add the oleophilic bentonite, and finally, the barite.)

Note: The invert bentonite-diesel oil (BDO) system reacts with oil or oil-based mud just as the normal BDO system reacts with water.

Squeezes

Formulation of Soft Squeezes - DIASEAL "M" and Attapulgite - DIACEL "M" and attapulgite squeezes depend on lack of filtration control to produce a firm plug. They are sometimes called high water loss squeezes.

An attapulgite or DIACEL "M" squeeze is formulated as follows:

1. Clean mixing pit thoroughly.

2. Add desired volume of water and mix 50 lb/bbl of DIASEAL "M" or attapulgite.
3. Pump down drill pipe and place in suspected loss zone. If annulus is not full, pump mud down annulus while pumping squeeze down drill pipe. When annulus fills and squeeze is in place, apply 150-200 psi on annulus with annular BOP closed. This will "soft squeeze" the material into the loss zone.

Formulation of Diesel Oil-Bentonite and Diesel Oil-Bentonite-Cement Squeeze: The principal underlying diesel oil-bentonite and diesel oil-bentonite cement slurries is that large amounts of bentonite and cement can be readily mixed with diesel oil. When the plug encounters mud or water, the bentonite and cement hydrates, forming a dense plastic plug which can be squeezed into the loss zone.

The following is a formulation procedure for a diesel oil-bentonite or diesel oil-bentonite-cement squeeze:

1. Add desired volume of diesel to a clean pit. Make sure no water is in the pit.
2. Add bentonite or bentonite and cement. Make sure no water is encountered by the mixture.
3. Pump 5 barrels of diesel down drill string ahead and behind the slurry. Displace to the loss zone with mud. Pump and displace at a rate of 3 bbls/min.
4. If the annulus is not full, pump mud down the annulus at a rate of 4 bbls/min while pumping the squeeze.
5. After the plug is placed in the loss zone and if the annulus is full, squeeze with 300-400 psi with the annular preventer closed.
6. Pull the drill string well clear of the squeeze. (Mix and place the squeeze with a cementing unit, if possible.)

CORROSION

Introduction

Metals in their natural state are usually compounds that are thermodynamically stable. When a metal is extracted and refined, the thermodynamics become unstable; exposed to the environment, this metal will corrode and revert to its natural state as a compound.

Although the components of water-based drilling fluids are not unduly corrosive, the degradation of additives by high temperature or bacteria may result in corrosive products. Also contamination by acid gases such as CO₂ and H₂S and formation brines can cause severe corrosion. Oxygen entrapped in the mud can accelerate corrosion. Under adverse conditions, the replacement of corroded drill pipe becomes an economic problem. A more severe problem arises if the corrosion is not detected and the pipe fails while drilling. In this section, the several ways in which corrosion can occur and the necessary corrective measures are briefly discussed.

Types of Corrosion

Corrosion can be classified as either dry or wet.

Dry Corrosion

Dry corrosion results from reaction to high temperature gases. Wet corrosion involves contact by the metal with an electrolyte solution. It is this form of corrosion which concerns the drilling industry.

Wet Corrosion

Wet corrosion is commonly classified into eight types (which are described later in this chapter). The types of corrosion are:

- Galvanic
- Uniform
- Concentration cell
- Pitting
- Intergranular
- Stress
- Dezincification
- Erosion

Wet corrosion is the result of fluids conducting current much like the electrolyte in a lead-acid battery. The more conductive the fluid, the more the electricity flows and the faster corrosion occurs. The electrical current flows between an anode, where corrosion occurs, and a cathode. The anode and cathode can occur on separate pieces of metal, or side by side on the same piece. The corroded area is eaten away, or oxidized.

Anodic Reaction for Iron (i.e., tubular goods in muds, workover completion fluids, or packer fluids) is:

- a. Oxidation Reaction: $\text{Fe} \rightarrow \text{Fe}^{++} + 2\text{e}^{-}$

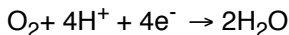
There is no corrosion at the cathode, which is protected by the chemical reactions which take place there.

Various Types of Cathodic Reactions:

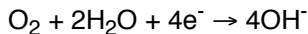
- a. Hydrogen evolution in acid solutions:



- b. Oxygen reduction in acid solutions:



- c. Oxygen reduction in neutral or alkaline solutions:



- d. Hydrogen evolution and oxygen reduction are the most common cathodic reactions.

Basic Requirements

Four basic requirements must be met simultaneously before these forms of wet corrosion can occur:

- A corrodible metal, or metals, such as iron, steel, or copper, which form the anodes and cathodes of the corrosion cell.
- Water or water vapor (electrolyte) in contact with the metal. The electrolyte usually contains dissolved gases such as oxygen, carbon dioxide, or hydrogen sulfide or an acidic substance.
- A completed electrical circuit is necessary between the metal, or metals.

- Current flow between electrodes.

An electrical potential, or voltage, must exist between the anode and cathode area for corrosion to occur. Metals complete the electrical circuit and provide a path for the current flow back to the anode. The source of voltage is the energy stored in the metal by the refining process; however, different metals require different amounts of energy for refining, which results in different tendencies to corrode. The driving force that makes current flow is the potential (voltage) that exists between metals, or between the anode and cathode.

Eight Forms of Wet Corrosion

Galvanic Corrosion - Galvanic corrosion occurs when two dissimilar metals set up a galvanic cell in an electrolyte. The Galvanic Series was developed as a more practical ranking of metals by potential than the EMF Series. The commonly used metals and alloys are listed from the anodic end to the cathodic end in a seawater environment.

Uniform Corrosion - When the entire metal area corrodes uniformly, it is called uniform corrosion. This comes about when anodic and cathodic areas continuously shift because of polarization changes. Of all the forms of corrosion, uniform corrosion is the least damaging. Uniform corrosion can often be seen in a piece of evenly rusted pipe.

Pitting and Crevice Corrosion - When the anodes and cathodes do not shift, pitting and crevice corrosion occurs; the area of the pit or crevice is anodic. This is also an example of localized corrosion. As the anodic area is eaten away, pitting deepens and holes or deep cracks result. This is a common cause of washouts in pins and boxes. Crevice corrosion frequently occurs when rubber pipe protectors are left for too long in the same spot.

Concentration Cell Corrosion - This type of corrosion is often called shielding. Oxygen corrosion sets up concentration cells. Shielding is caused by different parts of the metal being exposed to environments of differing ionic concentrations.

Example - In oxygen concentration, where the drill pipe is shielded by scale, dried mud, or pipe protectors, the area outside the shield, the area of high oxygen concentration, will be cathodic. Pipe under the shield is exposed to less oxygen, is anodic, and will corrode.

Intergranular Corrosion - This is the localized attack of the grain boundaries in a metal. Metals and alloys consist of many grains or crystals. As the metal cools in manufacture, the last metal to solidify is the least pure. The grain boundaries are less pure and tend to be anodic to the remainder of the grain, causing the boundaries to corrode.

Stress Corrosion - Any one of the other types of corrosion which is accelerated by stress is called stress corrosion. Failure is usually by cracking due to the combined effects of corrosion and stress. One of the characteristics of stress corrosion is the absence of visible overall attack.

Dezincification - This is a type of corrosion that occurs in zinc alloys. It is selective dissolution of one element of an alloy. In a copper-zinc combination (brass or bronze alloy), both metals apparently go into solution, then the copper plates back, leaving a porous plug in the metal. Alloying for better corrosion resistance helps in this case.

Erosion Corrosion - This is corrosion accelerated by the erosive effect of a moving fluid, particularly one containing suspended solids. In effect, any protective film is continually swept away, allowing further corrosion to occur. High annular velocities, turbulent flow in the annulus, and air or air-mist drilling all contribute to the effect. To reduce erosion corrosion, slower annular velocities, cleaner muds, and laminar flow profiles are recommended.

Electromotive Force (EMF) Series

All metals have an electrical potential relative to other metals. Using hydrogen as a standard, all metal elements can be arranged in a series based on their potential relative to hydrogen. For standardization purposes, this is done at a constant temperature (250°C), and with a set concentration of ions in the electrolyte solution. This series is called the Electromotive Force (EMF) Series.

The top of the EMF Series is the active or anodic end, and the bottom is the cathodic end. Each metal listed is anodic to any metal listed below it on the scale.

Example - Assume both metals are hydrogen. Since they are the same, the potential is zero and no current flows from one electrode to the other. Now, assume an electrode of iron and one of copper. Iron (Fe) is anodic to copper (Cu), so the current flows from the iron to the copper, and the iron electrode corrodes. The direction of flow (potential) depends upon which electrode assumes the anodic position and which assumes the cathodic. The force of the flow (potential) depends upon the difference in voltage between the metals.

Note: Some metals have the capacity to form a protective film against their environment. This film is formed by corrosion, and acts as a barrier or insulator against further corrosion. This effect is known as passivation. For example, aluminum can form a coating of aluminum oxide which retards further corrosion.

EMF Series

Electrode Reaction					Standard Electrode Potential (Volts), 250°C
K	=	K ⁺	+	e ⁻	-2.922
Ca	=	Ca ⁺⁺	+	2e ⁻	-2.87
Na	=	Na ⁺	+	e ⁻	-2.712
Mg	=	Mg ⁺⁺	+	2e ⁻	-2.34
Be	=	Be ⁺⁺	+	2e ⁻	-1.70
Al	=	Al ⁺⁺⁺	+	3e ⁻	-1.67
Mn	=	Mn ⁺⁺	+	2e ⁻	-1.05
Zn	=	Zn ⁺⁺	+	2e ⁻	-0.762
Cr	=	Cr ⁺⁺⁺	+	3e ⁻	-0.71
Ga	=	Ga ⁺⁺⁺	+	3e ⁻	-0.52
Fe	=	Fe ⁺⁺	+	2e ⁻	-0.440
Cd	=	Cd ⁺⁺	+	2e ⁻	-0.402
In	=	In ⁺⁺⁺	+	3e ⁻	-0.340
Ti	=	Ti ⁺	+	e ⁻	-0.336
Co	=	Co ⁺⁺	+	2e ⁻	-0.277
Ni	=	Ni ⁺⁺	+	2e ⁻	-0.250
Sn	=	Sn ⁺⁺	+	2e ⁻	-0.136
Pb	=	Pb ⁺⁺	+	2e ⁻	-0.126
H ₂	=	2H ⁺	+	2e ⁻	0.000
Cu	=	Cu ⁺⁺	+	2e ⁻	0.345
Cu	=	Cu ⁺	+	e ⁻	0.522
2Hg	=	Hg ₂ ⁺⁺	+	2e ⁻	0.799
Ag	=	Ag ⁺	+	e ⁻	0.8000
Pd	=	Pd ⁺⁺	+	2e ⁻	0.83
Hg	=	Hg ⁺⁺	+	2e ⁻	0.854
Pt	=	Pt ⁺⁺	+	2e ⁻	1.0
Au	=	Au ⁺⁺⁺	+	3e ⁻	1.42
Au	=	Au ⁺	+	e ⁻	1.68

Factors Affecting Corrosion

Metallurgy

To understand corrosion, it is necessary to have some knowledge of metallurgy. Metals and alloys are granular in structure. Variations in this microstructure determine steel properties. Generally, the finer the structure, the harder and stronger the steel. The microstructure and final properties of the steel are determined by type of alloying constituents, temperature, and by the rate and procedure of cooling. Tensile strength and hardness are major factors in the corrosiveness of oil-field tubular goods. Higher strength pipe is harder and more susceptible to hydrogen embrittlement and stress corrosion cracking. Hardness is usually classified according to the Hardness Rockwell C (HRC) scale, and calculated from indentations made in the metal by a diamond-pointed instrument under a given load. Most instruments used in this measurement will give a hardness range rated from 15 up to 70. As a rule of thumb we assume that below an HRC of 23 steels are not subject to embrittlement and cracking. From 23 to 26 some failure will occur, and above 26, in any acid-forming environment, steel is almost sure to be brittle, or fail, or both. Usually, N-80 and lower grade tubular goods are in the safe hardness range, while P-105, P-110 and higher grades are considered in the susceptible range. Often, however, lower grade goods can be work-hardened into a higher range. Also, some goods sold as N-80 were in the past actually downgraded from higher grades because of not meeting all of the higher specifications. API standards have recently set upper limits on hardness of various grade tubular goods.

Drilling Fluids

Salts dissolved in the water phase contribute to the corrosion of metal goods. Salt increases the conductivity of the water and thereby increases the rate of corrosion. For some fluids with high salt concentrations, the corrosion rates will actually be lower since the dissolved oxygen will be lower in these fluids. At saturated brines, the concentration of dissolved oxygen will be at a minimum. As the salt concentration decreases, the amount of dissolved oxygen will increase.

In the acidic range of drilling fluids, the corrosion rate is much greater than in the alkaline ranges. Normally, a pH of 9.5-10.5 is sufficient to reduce most corrosion to an acceptable range.

Temperature

As the temperature increases, the rate of corrosion generally increases since most chemical reactions increase with temperature. As the temperature increases in a closed system, the oxygen cannot escape and thus at higher bottom hole temperatures with more oxygen present, the corrosion rates will increase. In a closed system, the oxygen is less likely to escape than in an open system.

Corrosion in Drilling Fluids

The gases oxygen, carbon dioxide, and hydrogen sulfide, all cause problems in drilling because of their solubility and reactions with steel components. Oxygen has the lowest solubility. By comparison, carbon dioxide and hydrogen sulfide are very soluble, being about 100 times more soluble than oxygen.

The effects of the gases on drilling fluids differ. Oxygen can be measured with difficulty by the oxygen meter, while H₂S and CO₂ effects usually are indicated by a rapid reduction in the alkalinity of the fluid. Oxygen forms iron oxide on pipe or coupons, carbon dioxide forms carbonates, and hydrogen sulfide forms sulfides.

Rate of Metal Loss

The rate at which corrosion proceeds is determined by many factors. Some of the more important are:

- pH. In the presence of oxygen, corrosion rates increase rapidly as the pH decreases from neutral, and decrease slowly as the pH increases from neutral. (Aluminum alloys, however, exhibit increasing corrosion rates at pH values higher than 8.5.)
- Temperature. Most corrosion rates increase with increasing temperature.
- Velocity. In general, corrosion rates are accelerated at high rates of fluid flow.
- Heterogeneity. Localized variations in composition of the metal microstructure may increase corrosion rates. Ringworm corrosion, sometimes found near the upset area of drill pipe is an example of corrosion caused by Non-uniform grain structure. Correct heat treating eliminates this type of corrosion.
- High Stress. Highly stressed areas usually corrode faster than areas of lower stress. The drill stem just above the drill collars often shows greater corrosion damage, in part because of higher stress and bending moments.

Oxygen Corrosion

Many muds today are more corrosive than those used in the past. One reason for this is the lack of lignosulfonates, lignins and tannins in many fluids. Used in sufficient quantities, these materials act as oxygen scavengers. If they are not being used in a mud, it is advisable to monitor the O₂ level in the mud and use a high quality oxygen scavenger. It has been shown that dissolved oxygen levels exceeding one mg/L accelerate corrosion. When associated with CO₂ and H₂S, as little as five parts per billion O₂ can greatly accelerate corrosion. Generally, oxygen corrosion affects the drill pipe, casing, pumps and surface equipment. This corrosion commonly occurs under mud cakes or other shielded areas such as drill pipe protector rubbers. Faulty pipe wipers are often overlooked as a cause of oxygen corrosion, these wipers may leave mud streaks on the drill pipe which dry and set up a potential corrosion cell. Localized cells are formed where steel is in contact with aerated solutions at one place, and with oxygen deficient solutions in another.

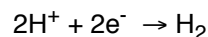
Corrosion Cell

The anode-cathode electrolyte system described earlier is a corrosion cell. The amount of current passing through the cell is directly proportional to the metal loss. It takes very little current to cause substantial metal loss in one year.

Cathodic Depolarization

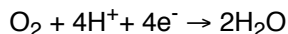
In a corrosion cell with an acid electrolyte, hydrogen molecules (H₂) formed during the reduction reaction can accumulate at the cathode and form an insulating blanket which reduces or stops current flow, and therefore, corrosion.

Hydrogen Evolution in Acid Solution



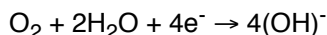
This process is called polarization. Any dissolved oxygen in the electrolyte can unite with the hydrogen at the cathode to form water. This prevents hydrogen polarization from occurring, and allows current to flow and corrosion to continue.

Oxygen Reduction in Acid Solution

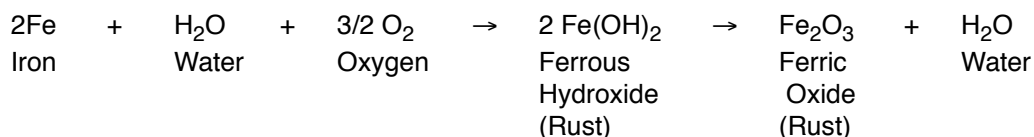


Similarly, in a neutral or alkaline solution, oxygen acts as a depolarizer to prevent an accumulation of hydrogen at the cathode. It will react with the water molecule and free electrons to form the hydroxyl ion and allow continued current flow and corrosion.

Oxygen Reduction in Neutral or Alkaline Solutions

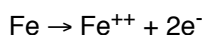


The chemical reaction in oxygen corrosion with respect to iron, oxygen and water can be expressed as follows:

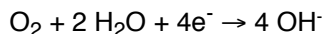


Step by step, the reaction takes place as follows:

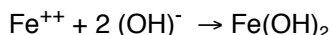
- Oxidation at the anode where the metal is eaten away or destroyed:



- Reduction at the cathode where oxygen combines with water and gains electrons to form the hydroxyl ion:



- The reaction of the ferrous ion with the hydroxyl ion to form ferrous hydroxide (rust) which coats the cathode:



The reaction continues as long as oxygen is present in the system, or until the cathode becomes coated with a rust layer. The removal of the electrons at this cathode (Step 2) prevents cathodic polarization. Under circulating conditions downhole, the erosional effect of the drilling fluid continually sweeps away the protective film of iron rust forming at the cathode.

To treat the cause of oxygen corrosion by preventing corrosion cells from forming, it is necessary to keep the pipe as clean as possible, and either:

- Remove the dissolved oxygen from the fluid with an oxygen scavenger, thereby stopping the reaction described in Step 2; or
- Coat the drill pipe or metal surface with a protective film of corrosion inhibitor to prevent further reaction with oxygen.

Factors Affecting Oxygen Corrosion

Factors affecting oxygen corrosion include O₂ solubility and pH. In general, the colder the water, the greater the solubility. For example, in fresh water, 14.6 mg/L O₂ are soluble at 32°F (0°C) compared to 7.8 mg/L at 86°F. It should be pointed out, however, that recent laboratory studies from a closed loop, dynamic simulation of downhole conditions show that oxygen concentrations downhole are not

reduced by increased temperature. This is because in this type of system the oxygen cannot escape to the atmosphere. Therefore, during the winter months, corrosion rates are normally increased because of increased O₂ solubility due to decreasing temperature at the surface.

Oxygen corrosion can occur at all levels of alkaline pH; however, at high pH, corrosion rates usually are reduced. Tests have also shown that oxygen solubility is reduced in a saturated salt system, so that less oxygen scavenger and scale inhibitor may be necessary in the saturated system.

Oxygen Corrosion Preventive Measures

Any procedure that would reduce the amount of oxygen entrained in the mud should be effective in reducing corrosion. Running degassers, submerging the guns and the hopper discharge should help, along with controlling pH, using plastic-coated drill pipe and treating with filming type corrosion inhibitors.

Recognizing and Monitoring Oxygen Corrosion

Monitoring is accomplished through the use of corrosion rate meters and oxygen sensors. The galvanic probe is used to detect a corrosion rate trend. Examples of corrosion rate meters are the Magna Corrotor and the Petrolite Pair Meters. Oxygen sensors are made by Beckman Instruments, Simplec Corp., Edmont-Wilson and others. Galvanic probes are marketed by Fincher Engineering. By studying carefully kept records from these monitors, it is possible to learn more about the general effect of oxygen scavengers on different fluids.

Oxygen Corrosion Treatment

To reduce corrosion of steel in contact with drilling fluids, the oxygen can be eliminated at the pump suction by treating it out with chemicals. The scavengers are catalyzed sodium sulfite or ammonium bisulfite. To assure the removal of dissolved oxygen, it is usually necessary to maintain a minimum sulfite (SO₃⁼) content in the drilling fluid (measured from filtrate at the flow line). A range of 50-150 mg/L excess sulfite is recommended. In some cases, a higher range is desirable when corrosion rings indicate pitting attack, or unacceptable rates of corrosion. The reaction using a sulfite is as follows:



Use a sulfite test kit to determine excess sulfite. Sodium sulfite is a dry powder and comes in 50 lb (22.7 kg) sacks. To prepare in liquid form, it is recommended mixing one pound of sulfite for each one gallon of water (120 kg/m³). Ammonium bisulfite is a liquid and comes in 55-gal (0.21 m³) drums. Dilution with water is NOT necessary.

Treatment for preventing oxygen corrosion with the scavenger should begin at the pump suction. Visualize the mud circulatory system as a closed, high pressure, high temperature system and disregard the surface pits. Suggested treating methods are:

- Inject the liquid scavenger directly into the pump suction line using a chemical injection pump (if possible). Add continuously while circulating.
- Injection rate is dependent upon the oxygen content and mud circulation rates. Optimum injection rates must be regulated by monitoring (at the flow line) excess sulfite.
- Under normal conditions, 100-150 lb (45.4-68 Kg) of the powder, or 5-10 gal (0.019-0.0383 m³) of the liquid daily should provide sufficient oxygen reduction.

Oxygen Scavengers

Both sulfite scavengers lose some of their effectiveness in high concentrations of calcium (above 1000 mg/L). Tests indicate that increasing the treatment of the scavenger is usually sufficient for high concentrations of calcium. (Economics should be the deciding factor.) In addition, the scavengers should not be used in air or air-mist drilling.

Chromate Inhibitors

When the scavengers cannot be used effectively, there are several inhibitors available for use in drilling fluids. Zinc chromate and sodium dichromate are inhibitors which coat the drill pipe to protect against the corrosive environment. (Use of chromates is prohibited in some areas due to environmental regulation.)

The chromates are in liquid form and come in 55-gal (0.21 m³) drums. Injection of the material is done in a manner similar to the scavengers. When using the chromates, it is recommended that at least 500 mg/L chromate (CrO₄²⁻) be maintained for corrosion protection. The drill string must be completely coated with the chromate or the possibility exists that localized corrosion in the unprotected areas can be accelerated. Use a chromate test kit to determine excess chromate.

Note: The chromate inhibitors and sulfite scavengers should not be used together.

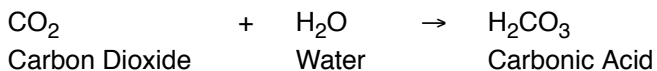
Carbon Dioxide Corrosion (Sweet Corrosion)

Sweet corrosion, as noted in production language, is attributed to carbon dioxide which occurs as a gas kick, or slow bleed-in of gas while drilling. As used here, sweet corrosion refers to a condition where no iron sulfide corrosion product occurs from a result of sour (H₂S) type corrosion. Other sources of CO₂ can be from the atmosphere entrapped in the mud at the surface and circulated down-hole or existing in formation waters as HCO₃⁻ or CO₃²⁻. Carbon dioxide can intrude into the borehole from the formation and reach the surface as a gas, or react completely with the water phase of the drilling fluid before reaching the surface.

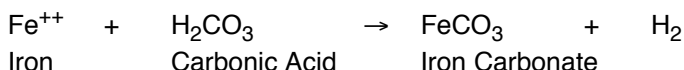
Carbon dioxide corrosion can cause severe pitting and sharp cracks in fatigue areas.

When moisture is present, CO₂ dissolves and forms carbonic acid.

4.3 pH

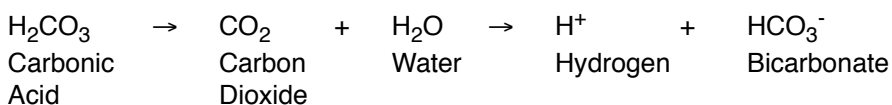


This carbonic acid causes a reduction in pH of the water which makes it quite corrosive to steel.

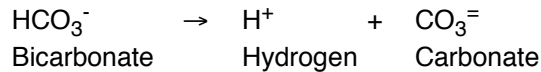


Alkalinity Effect on Carbon Dioxide

4.3 pH



8.3 pH



Generally, increased pressure results in the increased solubility of CO₂ in water. Increases in temperature normally decrease the solubility of CO₂ in water. Dissolved minerals tend to buffer or to prevent the reduction of pH in a water associated with CO₂, thereby influencing the rate of corrosion in a given system.

Determination of Carbon Dioxide in Drilling Muds

Carbon dioxide can be identified in the drill mud by several means:

- Reduction in pH
- Increased corrosion rates
- Increase in rheology value
- Increase in HCO₃⁻ and CO₃⁼ content
- Iron carbonate, magnesium carbonate, or calcium scale on the drill pipe
- Identification by gas detection equipment

Treatment for Carbon Dioxide

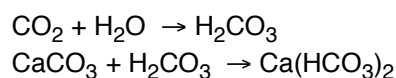
Standard treatment for CO₂ includes use of the degasser to remove the gas, increase the mud density to kill the flow, and re-establish proper alkalinity and pH values with caustic soda or lime, or both. Lime additions should be made sparingly, especially into clear brine solutions, because of resulting scale buildup. Application of filming amines are recommended for corrosion protection, in addition to standard treatment with chemicals.

Scale

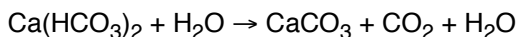
Corrosion tendencies related to drilling fluids and the formation of scale may be summarized as follows:

- In degassed drilling fluids, the pH values can determine the corrosion rates. Rates increase as pH decreases, or as muds become more acid.
- In drilling fluids which do not have sufficient calcium and CO₃⁼ to form scale, the oxygen content of the water can determine the rate. As oxygen contents increase, corrosion rates usually increase.
- In drilling fluids containing CO₂/CO₃⁼ in a low pH environment, the acidity of the fluid dissolves the scale and corrosion rates can be high. If the pH is high, corrosion rates will be low, but scale will form; the shielding area under the scale promotes concentration cell type corrosion.

The solubility of calcium carbonate (CaCO₃) in water is low; however, in the presence of dissolved CO₂ quantities of Ca(HCO₃)₂ (calcium bicarbonate) are formed which are more soluble than CaCO₃ in water.



With increased temperature, the above reaction is reversed, CO₂ is released, and CaCO₃ is precipitated.



Recognizing Scale

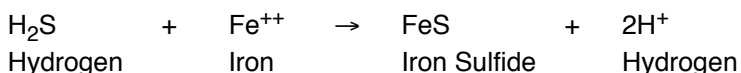
If calcium content is high and the pH is high, there is usually a good chance for scale to form in an HCO₃⁻/CO₃⁼ environment. Further indication would be a noticeable scale deposit on the drill pipe. The use of acid arsenate solution can assist in identifying the scale. Iron carbonate or magnesium carbonate scale will effervesce slowly when contacted with the acid solution. Calcium carbonate will effervesce at a faster rate. Laboratory tests to check corrosion rings are also helpful in the identification of carbonate scale.

Treatment for Scale

A blended, water-soluble, organic phosphate can be used as a scale inhibitor. It effectively prevents the deposition of alkaline earth metal on oilfield tubular goods and associated surface equipment. The organic phosphate comes in 55-gal drums. The rate of injection is determined by maintaining 5-10 mg/L phosphate (PO₄⁼) at the flow line, which should be tested by monitoring the flow line discharge with a Hach Colormetric Phosphate Kit. Excess phosphate can deflocculate the drilling fluids system. Normal injection rates are approximately 3-5 gal/day (0.011-0.019 m³). The inhibitor is compatible with the oxygen scavengers and scale inhibitors for oxygen.

Hydrogen Sulfide Corrosion (Sour Corrosion)

Hydrogen sulfide is sometimes associated with a gas kick or bleed-in. Other sources are makeup waters and microorganisms. Although hydrogen sulfide is relatively noncorrosive in the absence of moisture, the gas becomes corrosive if moisture is present. In the presence of CO₂ or O₂ and water, hydrogen sulfide becomes severely corrosive due to the driving voltage increase of the corrosion cell. Normally, when H₂S corrosion is a severe problem, one of these other gases is present. The chemical mechanism of this type of corrosion can be simply, though not completely, stated as:



This reaction can result in deep pitting of iron or steel. A secondary effect can occur with H₂S corrosion. The hydrogen released in the foregoing reaction enters the steel matrix where it can alloy with the steel to embrittle it. It may form molecular hydrogen which tends to blister ductile steel and crack high strength steel. Steel with yield strengths below approximately 90,000 psi are nearly immune to sulfide cracking. An HRC of less than 22 is usually in this range. The iron sulfide scale produced by this reaction generally adheres to the steel surfaces as a black scale. The scale tends to cause a local acceleration of corrosion which results in deep pitting.

The concentration of H₂S affects the time failure ratio, with delayed failures occurring at very low concentrations in solution, although at a concentration of 0.1 mg/L or less, the time-to-failure is very long. Cracking tendencies are drastically reduced if the pH is maintained above 10.0. Some studies indicate cracking susceptibility decreases after temperatures reach about 150°F (66°C). It is thought that elevated temperatures facilitate the movement of entrained hydrogen through the steel lattice. Where H₂S formations are to be penetrated, attention must be given to the steels in use, and to the amount of torque applied to tool joints. Care should be taken to avoid creating notches with tongs and slips, and

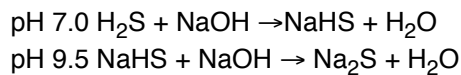
the condition of internally coated pipe should be watched. Regular electronic and visual inspections of the drill string should be made.

The primary hazard resulting from encountering hydrogen sulfide is the loss of human life without warning; the gas is lethally toxic. The threshold limit, or that level at which it is believed that workers may be repeatedly exposed, day after day, is 10 ppm. Concentrations as low as 150 ppm will cause irritation of the eyes and the respiratory tract, and will deaden the olfactory nerves, with loss of the ability to detect odors. Exposure to a concentration of 800 to 1000 ppm for as little as two minutes may result in death.

Frequently referred to as sour gas, H₂S in low concentrations smells like rotten eggs. The smell should not be depended upon as a means of detection, however, because of its effect on the olfactory nerves. It is highly flammable, and forms explosive mixtures with air. It is heavier than air and will accumulate in low areas, such as the cellar beneath the rig floor, or in low lying areas around locations.

H₂S is soluble in drilling muds. The solubility in water is approximately proportional to the pressure up to four to five atmospheres (4.13-5.16 kg/m²); however, in extremely high pressures such as in the hydrostatic pressure of the mud column, hydrogen sulfide may be liquefied and this simple relationship may not hold true.

Solubility data show that the solubility of H₂S is about 0.1 molal or 0.2N or 3400 mg/L at room temperature. When drilling fluids or treating waters are analyzed, somewhat higher figures can be obtained since hydrogen sulfide will react with alkaline compounds in the drilling fluids to form the alkaline salt, sodium sulfide, and water, according to the following equation:



Recognition of H₂S

Hach Test -As the pH increases, the percent of total existing hydrogen sulfide decreases to a very low level. The following chart illustrates the existence of hydrogen sulfide as a gas in various pH ranges. The factor should be used in the Hach test for sulfides, to provide the correct results of H₂S in the mud system.

pH	Factor as H ₂ S
5.0	0.98
6.0	0.83
6.5	0.61
7.0	0.33
7.5	0.14
8.0	0.048
9.0	0.005
10.0	0.0005
11.0	0.00005

The Hach test kit measures H₂S as a gas since the test is performed in an acid environment. Adjustments for pH must be made to accurately report quantity of H₂S in the mud as a gas and as a soluble

sulfide. To do this, check the pH of the mud system prior to performing the test, then multiply the answer determined by the test by the above factor to determine mg/L H₂S as a gas.

Example

pH of mud = 10.0

Hach test: 100 mg/L H₂S (uncorrected)

$$0.0005 \times 10 = \begin{array}{l} 5 \text{ mg/L H}_2\text{S as gas} \\ 95 \text{ mg/L soluble sulfide} \end{array}$$

If the factor is not used, then the results should be reported as H₂S uncorrected for pH.

Hydrogen sulfide is a weak acid and exists as molecular hydrogen sulfide (H₂S), hazardous to humans under acidic conditions. When the pH of the mud approaches the neutral range, there is a transformation from molecular to bisulfide (HS⁻) state, which is associated with hydrogen embrittlement and metal fatigue. Atomic hydrogen is liberated during ionization from H₂S to H⁺ + HS⁻; and in the atomic form enters the molecular matrix of metal, causing structural weakening. Additional hydroxyl ion concentration raises the pH (9.5) and changes the bisulfide radical to its anionic sulfide form S⁼. It is in this state that metallic cations such as sodium (Na⁺) and calcium (Ca⁺⁺) can react with anionic sulfides. Note that reactions are reversible with decreases in pH. The soluble sulfides will accumulate in the drilling fluid, and exist as a potential hazard. If carbon dioxide (CO₂), salt water flow, or additional hydrogen sulfides are encountered, the associated pH drop can convert the sulfide ion (S⁼) back to the dangerous bisulfide (HS⁻), or molecular sulfide (H₂S) state.

The chemistry of hydrogen sulfide is quite complex. It is not unusual for it to form compounds that are entirely unrelated to stoichiometric relations. The most important consideration is that when H₂S enters an alkaline mud it reacts to form an alkaline sulfide, most often sodium sulfide, since sodium is the predominant ion in mud. This is a very good way to keep H₂S from giving trouble under some conditions, but it does not remove the material. A sulfide scavenger must be used to remove the sulfide ion from the mud.

Detecting H₂S Gas

There are several methods commonly used or available to determine the presence of H₂S in drilling fluids. Gas detectors or monitors are used on drilling rigs to detect unreacted H₂S gas at the surface. The Hach test is used to detect H₂S in the acid form, or as soluble sulfides in the makeup water, filtrate or mud. The Garrett Gas Train also analyzes the soluble sulfides in the filtrate of the mud. In addition, both tests can also determine the total sulfides, both soluble and insoluble, in a mud. It is important that the engineer have a complete understanding of the testing procedures and of the test results being reported.

In a slightly acid solution (below 7pH), H₂S gas will ionize and exist as an acid or acid gas; or in a basic solution (above 7pH) as soluble sulfides. These soluble ions can go through filter paper and will be detected in the filtrate. The Hach soluble sulfide test is performed to determine the amount of H₂S present in the drilling fluid in the soluble sulfide form. The test is performed on the mud or mud filtrate in which H₂S gas has been liberated by a CO₂ flow from an Alka-Seltzer tablet. This test determines the amount of H₂S present as an acid, or present as soluble bisulfide or sulfide ions. The initial result is uncorrected for pH. To accurately report the results, corrections must be made for pH of the drilling fluid.

The Garrett Gas Train test for sulfides uses a controlled CO₂ flow from a gas cartridge to force H₂S from an acidized sample of fluid or filtrate. Acidification of the sample ensures all of the sulfides in the sample are in the acid gas (H₂S) form.

If H₂S in the form of an acid gas, or the soluble bisulfide, or sulfide ions, has reacted with a sulfide scavenger (such as zinc carbonate), it will precipitate out as insoluble zinc sulfide. These insoluble sulfides cannot pass through filter paper, and therefore will not be present in the filtrate. Insoluble sulfides revert to soluble ions only at a very low pH (1-3). Therefore, to determine the amount of total sulfides in a mud, it becomes necessary first to change the insoluble sulfides back to soluble sulfides by acidizing the mud to a low pH (1) before running the test.

The test for total sulfides in the drilling fluid indicates what amount of H₂S gas in the acid form or in the soluble sulfide form has reacted with an H₂S scavenger. The test is performed on a mud sample which has been acidized below a pH of one. At this low pH range, all the sulfides in the mud, including those which have reacted with the H₂S scavenger, are made soluble and measured by the test. To determine the amount of insoluble sulfides in the mud, the soluble sulfides are subtracted from the total sulfides.

Use of this procedure gives an engineer relative guidelines as to how much scavenger has reacted with H₂S. For example, if the concentration of excess scavenger has decreased and the insoluble sulfides check indicates no decrease, then it is very likely the scavenger did not react with the H₂S, but was discarded, or diluted, or mechanically settled out in the pits.

Treatment for H₂S

If hydrogen sulfide gas is encountered or expected to be encountered, the pH of the mud should be adjusted above 10 and a scavenger added to the system, either to remove the existing sulfides or as a pretreatment. If a water-based mud system is used, a calcium or lime system is preferred. Basic zinc carbonate is normally used as an H₂S scavenger in water-based systems. If used as pretreatment, in anticipation of H₂S gas, no more than 5 lb/bbl (14.27 kg/m³) should be added to the system. To effectively control the alkalinity from the carbonate added, 0.25 lb/bbl (0.71 kg/m³) lime should be added for every 1.0 lb/bbl (2.85 kg/m³) zinc carbonate. Approximately 1 lb/bbl (2.85 kg/m³) zinc carbonate is needed to remove 500 mg/L of the sulfide ion. Additional amounts of lignosulfonate can help control rheology. Zinc carbonate in excess of 5 lb/bbl (14.27 kg/m³) can cause rheological problems, especially in deep, hot holes (above 250°F, 121°C); therefore, rheological and alkalinity properties should be closely monitored for adverse effects. Other scavengers on the market include zinc chelate, zinc chromate, ironite sponge (Fe₃O₄), zinc oxide and copper carbonate. All these scavengers have certain limitations. Ironite sponge performs best in the lower pH range (below 10.0). At least 5 lb/bbl should be added to the system as pretreatment and maintained as excess, the correct amount to be determined by the ironite-magnetic test. Copper carbonate should not be added to a system as pretreatment; it should only be added after the sulfide ion is measured in the mud system. Zinc chelate should be used in unweighted mud systems, and can be used in weighted mud systems. The zinc chelate does not affect mud properties as do the zinc carbonates. They react quickly with HS⁻ but require more of the product to complete the reaction.

Oil Mud Treatment

For added protection of the drill string in an H₂S environment, an oil-based mud is recommended. The main advantage of a continuous oil phase fluid for drilling acid gas-bearing formations is the prevention of the various types of corrosion listed. Corrosion prevention is mostly due to the oil phase fluid eliminating one of the factors essential for completion of the electrochemical reaction necessary for corrosion to occur. The oil also forms a protective oil film on the drill pipe which is not readily removed by the

oil-wet solids as the fluid is being circulated up the hole. The major precautions taken with the oil phase system are to carry an alkalinity above 1 cm³, and to use special mud gas separator devices which force all the circulating fluid through a mud-gas separator and vacuum degasser. This set-up removes the poisonous gases and protects rig personnel and metal parts.

Even with the precautions, it is still considered good practice to have an ample supply of approved oxygen canister gas masks or pressurized breathing units at strategic locations around the rig perimeter; in addition, several wind socks should be installed to indicate wind direction. H₂S gas monitoring units, alarm devices, drills and educational programs for the crews assist greatly in handling these toxic gas formations safely.

Atomic Hydrogen (Hydrogen Embrittlement)

Steels are permeable to atomic hydrogen (H⁺), but not to hydrogen gas (H₂), according to one theory of hydrogen embrittlement process. The theory further supposes that if impurities or alloying particles in the steel impede the passage of atomic hydrogen through the steel, the atoms of hydrogen will combine to form hydrogen gas (H₂). In the process of combination and expansion, the hydrogen molecules will blister mild steels and crack harder, finer grained steels. Any acidic solution could possibly provide the atomic hydrogen necessary for embrittlement. (Some theorists feel that ionic hydrogen H⁺ will also accomplish the same results as atomic hydrogen H.)

Hydrogen sulfide (H₂S) reacts with iron at the pipe surface to form iron sulfide (FeS), which liberates two hydrogen atoms that penetrate the steel matrix. Carbon dioxide (CO₂) will form carbonic acid (H₂CO₃) in water, and a similar reaction with the steel can take place. Iron carbonate will be formed, and the hydrogen will again be released to enter the steel.

Today, much is being said about corrosivity in oil and gas well annular fluids. The trend is away from highly treated, heavy weight, high pH (11.0-12.0) muds containing diesel oil, and toward the lightly treated, low pH muds containing no oil, which are more conducive to corrosion. The lighter weight water-based muds contain a much higher water fraction than the denser fluids, and the corrosive water phase is in direct contact with the drill pipe and casing. Exacerbating this situation is the increased usage of high tensile strength tubular goods such as the P-grade materials. To achieve strengths required in the tubular goods, ductility is sacrificed. The resulting material is a finer grained, brittle structure which is more susceptible to failure, often accelerated by corrosion.

Bacteria

It has been shown by various investigators that microorganisms can greatly affect corrosion rates. For microorganisms to accelerate corrosion, the environment must be suitable for their growth. Moisture, essential minerals, organic matter, an energy source and a suitable pH must be provided. Microorganisms such as De-sulfovibrio (sulfate reducers) can cause sulfide corrosion in the absence of dissolved oxygen (anaerobic conditions). These organisms utilize hydrogen formed by electrochemical corrosion during their growth, and reduce sulfate (SO₄⁻) to H₂S. Both hydrogen utilization and H₂S formation cause increased corrosion rates. In the case of sulfate-reducing bacteria, alterations of the mud chemistry are required. Increasing the pH to 10.0 or above, along with additions of a bactericide, is recommended.

Corrosion Rates

Corrosion rates are calculated from corrosion coupons and reported in a variety of ways. Rates are reported as weight of material lost per square area in a given period of time. The rate may be reported as pounds per square foot per year (lb/ft²/yr), kilograms per square meter per year (kg/m²/yr), or in mils per year (mpy), which is actually a thickness reduction.

$$\text{Corrosion Rate lbs/ft}^2/\text{yr} = (K^*) \frac{(\text{weight loss in grams})}{\text{Exposure time in hours}}$$

K* = a constant used for the area of the ring exposed and is printed on the shipping envelope.

The significance of weight loss values should be considered along with other features of a drill pipe coupon. For example, if uniform corrosion has taken place, then weight loss numbers may be a valid indicator of corrosion severity; however, pits may completely penetrate a coupon with little weight loss, incorrectly indicating a low corrosion rate. As with many aspects of mud engineering, familiarity with typical corrosion values in the drillsite area enables the mud engineer to interpret the corrosion rates correctly.

The following description of ring coupons and their respective part numbers should be referred to when ordering the correct type and size of drill pipe coupons.

Tool Joint Size & Type

3-1/2" X.H. & F.H.
-1/2" I.F. & X.H.
4" F.H.
4" I.F. & 4-1/2" X.H.
4-1/2" F.H., X.H. & 4" I.F.
4-1/2" I.F., 5" X.H.

Ring Coupon Monitoring Procedure

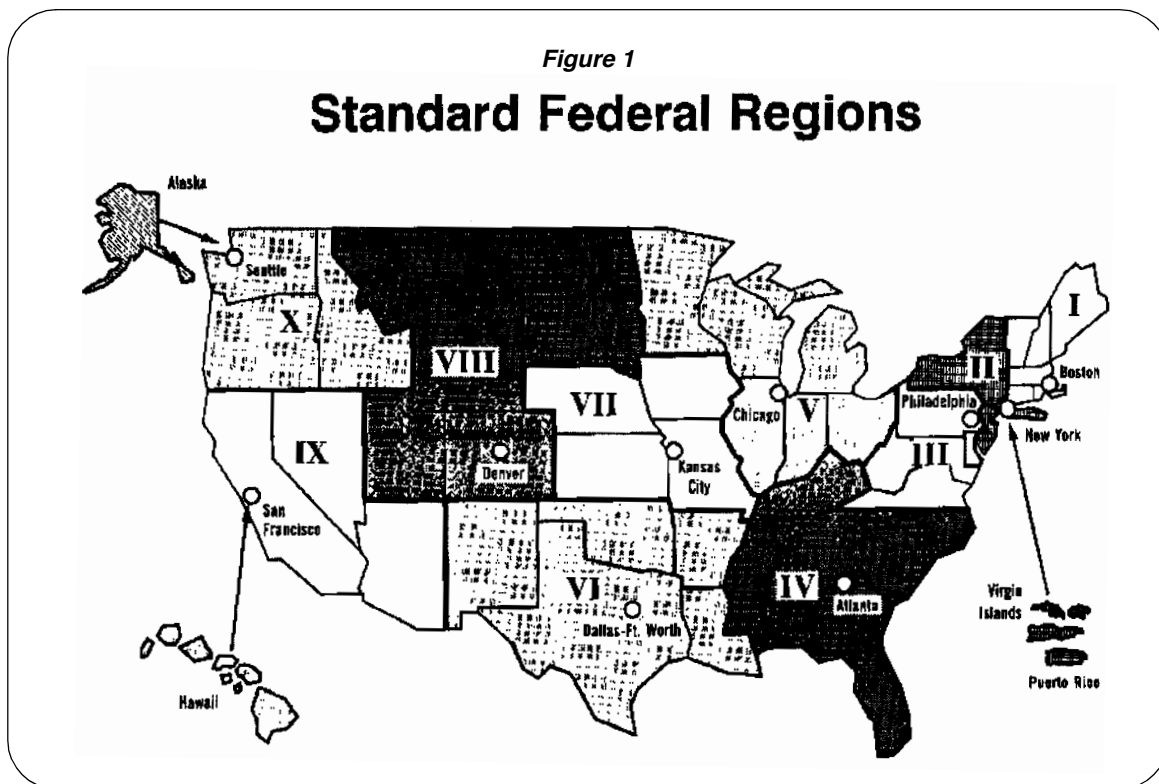
- Drill pipe corrosion rings should be kept in the drill string for a minimum of 40 hours. Exposure periods of less than 40 hours should not be used, because initial corrosion rates are usually high and can give misleading data. Normally, rings are run from five to seven days, to give a more accurate picture of the corrosion rate. The ring is usually placed in the box end of the tool joint, bevel side down, at the top of the first stand above the drill collars, and can be left in the drill string for more than one bit run. An additional ring can be placed in the Kelly saver sub to monitor corrosion at that point. Care should be taken to ensure that the box recess is clean to prevent interference with proper makeup of the joint, and to avoid damage to the ring. In some instances, specially manufactured subs have been used for the ring placement in the string. During installation, the ring should be handled with clean, dry gloves.
- The drill pipe corrosion coupon form should be filled out completely. Each form should have a space for ring material, drilling fluid properties, type of corrosion, location of the ring in the drill string, initial weight, time, depth in, depth out, ring number, color of scale, and any other information of significance in the specific test.

- Following the test period, the drilling fluid residue should be removed from the coupon by wiping with a cloth when the ring is pulled from the drill string. The ring should be examined for severity of corrosion or mechanical damage. If severe corrosion is evident, the cause of the corrosion should be determined promptly so that remedial action can be taken. Place the ring in a plastic bag, or original VPI wrapper, and then in the mailing envelope provided. Do not lubricate the ring using rig pipe dope.

Section 12 Environmental Regulations

Introduction

The National Environmental Protection Act enacted in 1970 was the beginning of numerous federal and state environmental regulations imposed to protect the health and safety of people and to protect the environment. Many of these statutes have had and continue to have a major impact on the petroleum industry, especially on air emission standards, drilling fluid and produced water discharge requirements, waste minimization and disposal, and stringent biological considerations as a result of a growing list of endangered species. These considerations not only direct our way of conducting current operations, but also require considerable pre-planning and interaction/cooperative agreements with regulatory agencies, environmental groups and the communities in which we operate.



The “Environmental Regulations” section of this Drilling Fluids Manual provides an outline of regulations and mud and cuttings disposal considerations for offshore and onshore U.S. operations. It is intended to be used as a general reference guide and can also be used as a guide line for drilling operations in areas which currently do not have established regulations. Environmental laws are complex and the penalties for noncompliance are serious. At the same time, regulations are changing very rapidly and it is difficult to stay current. Nevertheless, both criminal and civil penalties can be levied against individuals as well as corporations; therefore, it is imperative that good communication lines with Amoco EH&S staff be maintained from the onset of drilling operations.

Disposal of oil-based mud cuttings is a special issue not covered in this manual. Various onshore and offshore disposal methods and their applicability throughout the world are discussed in detail in the "Handbook of Oil-Based Mud Technology" compiled by the Fluid Mechanics & Chemistry Group at Amoco Production Research (Tulsa, OK) in December, 1992.

Gulf of Mexico General Permit #GMG28000 General Requirements

There are several options for drilling fluids and cuttings disposal in offshore U.S. areas. One option is to dispose of mud and cuttings by transporting to shore to a proper disposal site. Another option is to discharge from the platform or rig. A third option is to dispose of the drilled waste in the annulus or into a previously abandoned wellbore. In the United States a permit to discharge is required under the authority of the Federal Water Pollution Control Act. The Environmental Protection Agency issues National Pollutant Discharge Elimination System (NPDES) permits governing point source discharges into waters of the United States. These permits limit discharges based on ocean water quality criteria and were initially issued on a per well basis; however, the trend has been toward issuing general permits for each of the outer continental shelf regions (Figures 1 and 2). In some areas, however, special individual permits are required for limited discharge of mud and cuttings.

To determine the relative toxicity of drilling mud and cuttings discharges, a bioassay test for assessing the toxicity of dredged materials was adopted from the Army Corps of Engineers. This drilling fluids bioassay test is a 96-hour acute toxicity test which uses *Mysidopsis bahia* shrimp as the test species and measures the effects caused by that fluid. This effect is called an LC₅₀ or lethal concentration which causes 50% of the test organisms to die. Data generated from the test is used to statistically determine a reportable LC₅₀ for compliance purposes. The 96-hour LC₅₀ acute toxicity test will be further explained in the section on Drilling Fluids Toxicity Testing.

**Figure 2
USEPA Offshore Drilling Regions**

Regions I, II, & III (OCS-A)
II-Mid Atlantic (Baltimore Canyon)

Regions IV & VI (OCS-G)
Gulf of Mexico

Regions IX & X (OCS-P)
California and Pacific N.W.,

The first NPDES permits were granted in 1978 by the United States Environmental Protection Agency, Region II to operators drilling in the Baltimore Canyon. Part of the permit condition required operators to perform a jointly-funded drilling mud bioassay program. This was the beginning of the generic water-based muds. Generic mud formulations were selected for the bioassay program based on the minimum number of muds that covered most systems used by prospective permittees. Thus, eight different generic water-based mud systems were identified. Rather than conducting tests on numerous additives using varying concentrations, estimated usage ranges were allowed for major components in these generic muds. The concentration ranges were sufficiently wide to allow flexibility for most drilling operations; however, specialty additives such as lubricants, defoamers, corrosion inhibitors, etc. were not included. Thus, any additive which was not on the generic mud composition list required prior

approval by the region office. Approval was based on anticipated usage rates, toxicity data and a chemical composition of the additive. If there was a need for continued use of an unapproved additive, bioassay data containing that additive had to be submitted to the appropriate EPA regional office. Once the additive became approved, future discharges would be allowed without conducting additional bioassay tests. This approach, deemed by the industry as the “product clearing house approach”, was accepted for both Region X, Alaska and Region IX, California offshore drilling. However, with the new Gulf of Mexico NPDES general permit issued in July 1986 a completely different approach was taken to approving drilling fluids and additives. The Gulf of Mexico permit #GMG28000 requires a monthly bioassay and an end-of-well bioassay, regardless of whether the mud system is one of the eight basic generic muds.

The specific effluent limitations and monitoring requirements for the Gulf of Mexico permit are shown to illustrate how regulations are applied to offshore facilities. It is important to note that definitions are crucial to understanding environmental laws and their impact upon compliance strategies. Requirements for the Gulf of Mexico can be compared to Alaska and California general permit requirements (refer to Table 1). The last column in Table 1 lists the “New Source Performance Standards” as the direction of future general permits. It is evident that federal offshore effluent requirements will become more stringent in the future; particularly as current permits expire.

Gulf of Mexico General Permit #GMG28000 General Requirements

Controlled drilling fluids discharge rates must be calculated for those discharges within 544 meters of:

- MMS (Minerals Management Service) “no activity” zone
- Live-bottom area
- Territorial waters of Mississippi

In the Central and Western Gulf (EPA Region VI), drilling fluids which are shunted to the bottom as required by MMS lease stipulation are not subject to this discharge rate control requirement. For facilities subject to the discharge rate control, the rate is determined as follows:

$$R = 10^3 \log (d/15) + T_t$$

Where:

R = discharge rate (bbl/hr)

d = distance (meters from boundary of controlled discharge rate area)

T_t = toxicity-based discharge rate

$$T_t = \frac{[\log(\text{LC}_{50} \times 8 \times 10^{-6})]}{0.03657}$$

**Table 1
Cuttings and Discharge for Federal Outer Continental Shelf**

Comparison of Drilling Fluid and Cuttings Discharge Requirements of Proposed or Finalized General NPDES Permits for Federal Outer Continental Shelf Waters				
	ALASKA REGION X COOK INLET FINAL 10/86	CALIFORNIA (REGION IX) S. CALIFORNIA PROPOSED 9/85	GULF OF MEXICO REGION IV & VI FINAL 7/86	FEDERAL NSPS PROPOSED 8/85
Drilling Fluid Oil-Based Mud (BCT)	Discharge Prohibited	Discharge Prohibited	Discharge Prohibited	Discharge Prohibited
Generic Muds (BAT)	Authorized subject to limitations on additives. Combined Generic for- mulas into 6 rather than 8 mud systems.	Authorized based on toxicity of Generic mud #1 of 30,000 ppm.	Requirements based on toxicity of generic muds. Maximum toxicity of 30,000 ppm.	
Additives (BAT)	Approved additives list provided. Minimum 96-hr LC ₅₀ of 30,000.	Approved additive list provided. Additives with LC ₅₀ 's > 100,000 approved. LC ₅₀ 's between 30,000 - 100,000 conditionally approved if, when used with other additives, the total does not exceed 30,000 ppm. Refer- ence mud for testing is Generic mud #7. Nonapproved additives must not increase toxicity of muds 2-8 by a factor of 7 based on a formula given in permit.	No approved addi- tive list.	No approved addi- tive list.
Bioassays (BAT)	Bioassays required prior to drilling with unautho- rized additives. End-of-well bioassay required.	Bioassay required for each mud system used plus end-of-well bioassay. Bioassay on Northern Anchovy also required.	Toxicity of mud plus additives required for a monthly and end-of-well Toxic- ity limit is 30,000 ppm.	Toxicity of dis- charged mud and cuttings must not exceed 30,000 ppm.
Discharge Rate (Sec. 308)	>40 m 1000 bbl/hr 20-40 m 750 bbl/hr 5-20 m 500 bbl/hr <5m No discharge	No limit.	1000 bbl/hr maxi- mum Near biologically sensitive areas the rate is reduced based on distance and toxicity.	Not addressed.
Lubricity Agents (BAT)	Discharge of mud con- taining diesel prohibited.	Allows the discharge of muds containing residual diesel only for spotting operations if pill and minimum of 50 bbl of mud on each side of pill are removed and overall toxicity not violated by remaining mud.	No discharge of muds containing diesel; except if company is part of diesel pill study. Requires pill and minimum of 50 bbl either side of pill removed.	No discharge of muds containing die- sel in detectable amounts. Mineral oil allowed for provided its addition would not cause toxicity to exceed LC ₅₀ limit and no sheen is pro- duced.

Table 1 (Cont'd)
Cuttings and Discharge for Federal Outer Continental Shelf

Limitations or Monitoring Required	ALASKA REGION X COOK INLET FINAL 10/86	CALIFORNIA (REGION IX) S. CALIFORNIA PROPOSED 9/85	GULF OF MEXICO REGION IV & VI FINAL 7/86	FEDERAL NSPS PROPOSED 8/85
Barite (BAT)	Mercury 1 mg/kg Cadmium 3 mg/kg Content of Barite	Mercury 1 mg/kg Cadmium 2 mg/kg Based on barite used in each mud system.	None	Mercury 1 mg/kg Cadmium 1 mg/kg Based on dry weight in the whole mud.
Other Prohibited Mud Components (BAT)	No discharge of: • Halogenated phenols • Trisodium Nitriloacetic acid • Sodium chromate • Sodium dischromate Minimum usage allowed for surfactants, dispersants, and detergents.	No discharge of: • Halogenated phenols • Chrome Lignosulfonates Minimum usage allowed for surfactants, dispersants, and detergents.	No discharge of: • Halogenated phenols Minimum usage allowed for surfactants, dispersants, and detergents.	Not addressed.
Inventory (BCT)	End-of-well inventory of all chemicals used in well; one or more mud samples per well analyzed for metals and oil content and toxicity.	Inventory of all mud constituents. Composition of each mud system used and discharged. (Reported after well completion.)	Inventory of all constituents volumes to be recorded.	Not addressed.
Drill Cuttings Oil Content on Cuttings (BCT)	No discharge of diesel contaminated cuttings. Mineral oil on cuttings <10% by wt. in federal waters. <5% by wt. in state waters.	No discharge of diesel contaminated cuttings. No discharge of free oil on cuttings.	No discharge of diesel contaminated cuttings. No discharge of free oil.	No discharge of diesel contaminated cuttings (detectable). No discharge of free oil.

The oil and grease content of produced water must meet a monthly average of 48 mg/L in addition to a daily maximum of 72 mg/L. The monthly average is an arithmetic mean, or the sum of all sample results divided by the number of samples taken. Thus, if the initial monthly sample is greater than 48 mg/L, additional samples should be taken in an attempt to reduce the average. The flow rate for produced water must also be monitored (estimated).

Drilling Fluid Toxicity

The degree to which a material is considered toxic is determined by the relative danger posed or the unreasonable risk of injury to health or environment. Two major concerns are addressed in the discharge of drilling fluids:

- short term lethal response to organisms (LC₅₀) or alteration of the ecosystem; and
- accumulation of organic compounds and metals which contribute to toxic effects in organisms or travel up the food chain via bioaccumulation.

The terms "toxic" and "hazardous" are often mistakenly used interchangeably. Materials identified as hazardous refer to reactivity with other chemicals and pose an unreasonable risk to health, safety and property when transported in commerce. Material Safety Data Sheets (MSDS) outline the hazards in transportation and handling of various mud additives. The drilling representative should insure that all

MSD sheets are made available for reference at the drilling location. Toxicity, on the other hand, refers to the effect caused by a chemical or effluent on a test population of organisms.

Drilling Fluids Toxicity Testing

The accepted test for determination of relative mud toxicity, while rather complex, may be summarized as follows:

- A sample of the drilling fluid to be tested is transported under controlled conditions to a laboratory for analysis.
- A 200-cm³ aliquot of mud is mixed with 1000 cm³ of filtered seawater. The total volume is then brought to 2000 cm³ for a 1:9 mud-to-seawater ratio.
- The mud/seawater slurry is then stirred with a magnetic stirrer for five minutes and the pH is adjusted back to that of seawater by the addition of 6N HCl. The slurry is then allowed to settle for one hour, at which time it generally separates into two and sometimes three phases:
 - Water Soluble Phase
 - Suspended Particulate Phase
 - Solid Phase
- At the end of the settling period, the suspended particulate phase (SPP) is decanted into a suitable container (see Figure 3).
- The SPP is then further diluted with seawater to obtain 5 or 6 concentrations (usually 1%, 5%, 10%, 25%, 50%, and 100%) plus a control of 0% SPP. The first "range-finder" test should be done following the guidelines outlined in this chapter.
- After a suitable range-finder number is established, a full 96-hour protocol test is run to obtain the LC₅₀.
- At the end of 96 hours the live mysids are counted in each of the test concentrations. These results are then used to statistically determine an LC₅₀ or lethal concentration at which 50% of the test organisms die. See Figure 4.
- This number is then reported as the 96-hour LC₅₀.

The current LC₅₀ minimum for offshore discharges, as designated by various EPA regions is 30,000 ppm of the suspended particulate phase (See Figure 5). The basis for this number was the toxicity study conducted by EPA's Gulf Breeze laboratory on the eight generic mud compositions (See Figure 6). For these muds, Generic Mud #1 was found to have a 96-hour LC⁵⁰ of 27,000 ppm and 30,000 ppm when adjusted for control mortality. Therefore, the toxicity limitation of 30,000 ppm for the suspended particulate phase was based on the most toxic generic mud, which was Generic Mud #1. It is important to understand, however, that the bioassay test results do vary and are dependent on several factors. For this reason, field drilling fluids in offshore environments should not be run at LC₅₀'s below 150,000 ppm.

Although relative amounts of an additive may not appreciably lower LC₅₀ values for a given mud, trends in bioassay test results must be considered. Each EPA Region and some state agencies have varying discharge regulations. Should an LC₅₀ analysis yield results that are out of compliance with regulatory guidelines, a substantial penalty will be levied on a daily basis against the operator from the last date of compliance.

Figure 3

Schematic of Bioassay for Drilling Fluids

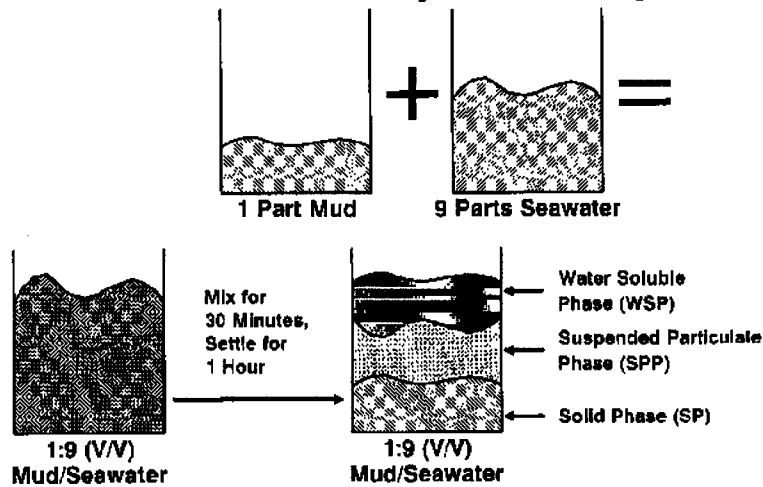
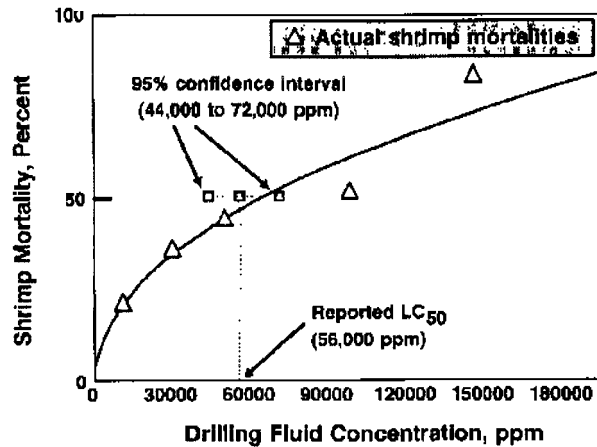


Figure 4
 Toxicity Testing Results



Amoco recommends that the following guidelines for testing all water-based field muds and water-based mud additives. For Amoco's database, either the Amoco 96-hr range finder test or the full 96-hr LC₅₀ protocol test is acceptable.

General

- Use only 5 or 6 day old shrimp in the 96-hr LC₅₀ protocol test (see Figure 7A).
- All range finder tests must be done using 20 shrimp (2 replicates of 10 shrimp each) and a minimum of 6 concentrations plus a seawater control. Use discretion when selecting con-

Figure 5
Acute Toxicity of Generic Drilling Fluids
(SPP - 96-Hr LC₅₀ ppm)

#1	27,000	KCL polymer
#2	516,000	Seawater lignosulfonate
#3	163,000	Lime
#4	>1,000,000	Nondispersed polymer
#5	>1,000,000	Spud Mud
#6	>1,000,000	Seawater/Freshwater gel
#7	654,000	Lightly-treated lignosulfonate
#8	293,000	Freshwater lignosulfonate

centrations for use in the range-finder test. Recommended concentrations are: 1%, 5%, 10%, 25%, 50%, and 100%. If the results are expected to be below 150,000 ppm (15%), then the recommended concentrations are 1%, 3%, 5%, 15%, 25%, 50%.

- Mud samples are to be maintained in cold storage at the lab facility for a minimum of 35 days after testing is completed.
- Use the Amoco “Acute Toxicity Test of Drilling Fluid” (ATDF) form when reporting range finder (see Figure 7A) and 96-hr protocol results.
- If MORE than 4 of the 60 Mysid shrimp die in the full 96-hr LC50 seawater control sample, or if MORE than 2 of the 20 die in the range finder control sample, REPEAT THE TEST.
- It is expected that the ultimate LC50 value is one that is corrected for the control mortality.

Testing Mud Products - To have the results recorded in Amoco’s database in Tulsa, Oklahoma, the test must be a full 96-hr protocol test OR a range finder test using Amoco’s protocol (above) done over 96 hours. Whether the full 96-hr protocol or a 96-hr range finder test is done, the base fluid should be Amoco’s formulation for Generic Mud #7, although other Generic #7 muds can be accepted.

Amoco Formulation for Generic Mud #7 - (Whole mud concentration)

Bentonite	20.0 ppb
Barite	178.5 ppb
Caustic Soda	2.0 ppb
Lignosulfonate	5.0 ppb
Lignite	3.0 ppb
Polyanionic Cellulose (PAC)	0.5 ppb
Drilled Solids	50.0 ppb (Rev Dust etc.)
Soda Ash	1.0 ppb
Seawater/Freshwater Ratio	1/1

Note: After blending the above formulation, add the test mud product and then hot roll for 16 hours at 150°F. The concentrations above are given in terms of **whole mud** and therefore should make up one lab barrel.

Figure 6
Source and Reported Composition of Eight Generic
Drilling Fluids Received at USEPA - Gulf Breeze, Florida

Drilling Fluid	Source	Component	Composition Concentration (lb/bbl)
EPA-83-001 KCl Polymer Mud	Chromalloy	KCl Drispac (Super-Lo) X-C Polymer Barite Starch Seawater	50.0 0.5 1.0 283.2 2.0 0.736 bbl
EPA-83-002 Seawater Lignosulfonate	IMCO Services	Attapulgite Chrome Lignosulfonate Lignite Polyanionic Cellulose Caustic Barite Seawater	30.0 15.0 10.0 0.25 pH 10.5 - 11.0 Mud Weight - 17.0 - 18.0 lb/gal As needed
EPA-83-003 Lime Mud	Hughes	Bentonite Lime Barite Chrome Lignosulfonate Caustic Lignite Distilled Water	20.6 5.01 281.84 15.04 1.00 6.02 0.734 bbl
EPA-83-004 Nondispersed Mud	Newpark Drilling Fluids	Bentonite Acrylic Polymer (for suspension) Acrylic Polymer (fluid loss control) Barite Deionized Water	13.0 0.5 0.25 190.7 299.6
EPA-83-005 Spud Mud	NL Baroid	Bentonite Lime Barite Seawater/Freshwater Caustic	12.5 0.5 50.0 1.0 pH to 10.0
EPA-83-006 Seawater/Freshwater Gel Mud	Milchem	Bentonite Polyanionic Cellulose Sodium Carboxymethyl Cellulose Barite Sodium Hydroxide Seawater/Freshwater 1:1	20.0 0.50 0.25 20.0 pH to 9.5 As needed
EPA-83-007 Lightly Treated Lignosulfonate Mud	Magobar Dresser	Bentonite Chrome Lignosulfonate Lignite Soda Ash Carboxymethyl Cellulose Barite	20.0 5.0 3.0 1.0 0.5 178.5
EPA-83-008 Freshwater Lignosulfonate Mud	Dowell	Bentonite Chrome Lignosulfonate Lignite Carboxymethyl Cellulose Sodium Bicarbonate Barite Deionized Water	15.0 15.0 10.0 0.25 1.0 487.0 0.534

Figure 7A

ACUTE TOXICITY TEST OF DRILLING FLUID
SUSPENDED PARTICULATE PHASE (SPP)



Amoco Production Company
New Orleans, Louisiana

96 hour LC50

Date: _____
Lab Test ID Number: _____

TESTING LAB/ADDRESS: _____

Sample Data: _____ Well Name: CSG- _____ No. _____
Area/Block: _____ Rig: _____
Depth Taken: _____ Mud Type: _____ Wt: _____
Date/Time Sample Taken: _____ Sample Rec'd: _____
Condition of Sample: _____
Date/Time Test Start: _____ End: _____

TOXICITY RESULTS: Method Used: _____

LC50 _____ ppm SPP Lower _____ ppm Upper _____ PI
_____ (95 % Confidence Limits)

TOXICITY DATA:

Test Concentration (ppm SPP)	Exposed	Total Number of Mysids Nc. Dead	Adjusted
Seawater Control	60	_____	_____
_____	60	_____	_____
_____	60	_____	_____
_____	60	_____	_____
_____	60	_____	_____
_____	60	_____	_____
_____	60	_____	_____

Standard Reference Toxicant: _____
LC50 _____ ppm SDS Lower _____ ppm Upper _____ PI
_____ (95 % Confidence Limits)

Other:
Total Dissolved Solids _____ mg/l
Total Suspended Solids _____ mg/l

The toxicity test was conducted according to EPA, "Drilling Fluids Toxicity Test", Federal Register, Volume 50, No. 163, August 26, 1985.

Lab Technician

Lab Supervisor/Manager

Figure 7B

ACUTE TOXICITY TEST OF DRILLING FLUID
SUSPENDED PARTICULATE PHASE (SPP)



Amoco Production Company
 New Orleans, Louisiana

_____ hr RANGE FINDER

Date: _____
 Lab Test ID Number: _____

TESTING LAB/ADDRESS: _____

Sample Data: _____ Well Name: OSG- _____ No. _____
 Area/Block: _____ Rig: _____
 Depth Taken: _____ Mud Type: _____ Wt: _____
 Date/Time Sample Taken: _____ Sample Rec'd: _____
 Condition of Sample: _____
 Date/Time Test Start: _____ End: _____

TOXICITY RESULTS: Method Used: _____

LC50 _____ ppm SPP Lower _____ ppm Upper _____ ppm
 (95 % Confidence Limits)

TOXICITY DATA:

Test Concentration (ppm SPP)	Exposed	Total Number of Mysids	
		No. Dead	Adjusted
Seawater Control	20		
_____	20		
_____	20		
_____	20		
_____	20		
_____	20		
_____	20		
_____	20		

Standard Reference Toxicant: _____
 LC50 _____ ppm SDS Lower _____ ppm Upper _____ ppm
 (95 % Confidence Limits)

Other:
 Total Dissolved Solids _____ mg/l
 Total Suspended Solids _____ mg/l

The toxicity test was conducted according to EPA, "Drilling Fluids Toxicity Test", Federal Register, Volume 50, No. 165, August 26, 1985

_____ Lab Technician

_____ Lab Supervisor/Manager

Free Oil - Sheen

As mentioned previously, definitions are critical in interpreting environmental regulations. The sheen test, for example, is especially pertinent. Note that there are three tests for sheen, each with a slightly different meaning, but with a significant impact on compliance. The Alaska sheen evaluation criteria is based on a bucket test; however, the sheen definition criteria states that the sheen must cover greater than one half of the surface area of the container. On the other hand, the Gulf of Mexico test defines sheen as any increased reflect, etc., but observations are based on the receiving water. [Note: Weintritt et al., in the May 3, 1993, issue of the Oil and Gas Journal (pp. 77-83), points out some of the inadequacies of the new static sheen test for the Gulf of Mexico.] In contrast the minimal cup test, which uses a small laboratory container, defines sheen as any increased reflectiveness, gloss, etc. This test, however, is significantly more stringent than either the Alaska or Gulf of Mexico sheen definitions. Not only is the amount of surface area not mentioned, but also the test has yielded conflicting results, such as detecting oil when none was added. The minimal cup test appears to be the direction that EPA is headed toward future regulations and will have a significant impact upon operations.

Sheen Definitions

Gulf of Mexico

Detection of a silvery or metallic sheen, gloss or increased reflectiveness; visual color; or iridescence on the water surface. These visual observations include patches, sheets, or streaks of such altered surface.

Alaska

Detection of a sheen, color, iridescence, or slick on the water surface of the container which covers greater than one half of the surface area.

Minimal Cup

Detection of a silvery or metallic sheen, gloss, or increased reflectiveness; visual color; or iridescence on the water surface. These visual observations include droplets, patches, sheets, or streaks of such altered surface.

Toxic Components in Drilling Fluids

Because formulations for mud additives are continually undergoing change, the Drilling Representative should be aware of certain additives that are considered toxic. EPA priority pollutants include various trace metals; zinc, chromium, lead, mercury, cadmium, nickel, asbestos, and various phenol compounds. Chromium is a highly controversial issue; the EPA defines toxic chrome as Cr^{+6} (or in a hexavalent state). In drilling fluids, the chrome exists in a trivalent state (Cr^{+3}) and the process to oxidize the absorbed chrome back to a Cr^{+6} state is virtually impossible. Additives that contain chrome in the Cr^{+3} state are: chrome lignite and chrome lignosulfonate.

Aromatic hydrocarbons are among the most toxic to marine organisms and destructive to soils and groundwater. Other hydrocarbon products include: asphalt derivatives, foamers/defoamers, surfactants, emulsifiers and corrosion inhibitors. These can be added in small percentages without significantly reducing LC_{50} values, but the impact of each should be considered prior to treatment of the entire mud system. Bactericides and biocides are highly toxic; however, newer formulations have

shown improved LC₅₀ responses and therefore, greater acceptance in the industry. Completion fluids contain inorganic materials such as: zinc, bromine, chlorine, potassium, etc. and are regulated by most Federal and State Agencies. Completion fluid filtration control additives may contain chrome salts of up to 8.0% by weight.

The use of spotting fluids complicates matters as a fraction of the spot will always become blended with the active mud system, regardless of the amount of buffer zone recovered on either side. Generally, if the retort volume exceeds 2% oil (by volume), the amount absorbed on cuttings will be great enough to leave a visible sheen. Reduced toxicity mineral/vegetable oils may satisfy EPA guidelines, but a visible sheen in the marine environment will still direct unnecessary attention to the discharge and thus prevent discharge.

Because of the information available on drilling fluid toxicity in the marine environment, one can infer that disposal of drilling fluids and solids offshore is environmentally safe if approved by the EPA. Some EPA regions do not allow any discharges overboard, others require bioassay information for the drilling fluid prior to discharge, and some allow almost any discharge into state or federal waters. Many industry experts expect that sooner or later, the Federal EPA and related agencies will require all discharges to be "non-toxic" or hauled to shore for disposal. Moreover, it appears that state waters will follow suit. Thus, the ultimate fate of waste material generated in offshore drilling operations will need to be handled according to onshore disposal regulations.

Onshore Mud and Cuttings Disposal

Waste handling onshore is quite different from offshore. The governing laws, criteria for toxicity, and toxicity tests are considerably different from offshore waste handling. To illustrate this point, the Resource Conservation and Recovery Act or RCRA enacted in 1976 required the Environmental Protection Agency to:

- establish procedures for identifying wastes as either hazardous or non-hazardous, and
- promulgate requirements for the management of both types of waste.

As a part of the ACT, provisions were made for a "Cradle to Grave" tracking of hazardous waste, from generator, to transporter, to treatment, storage and disposal. Determining whether a waste is hazardous or non-hazardous depends to a large degree on definition. First, a solid waste is any material that is discarded or intended to be discarded. It can be either:

- Solid
- Semisolid
- Liquid
- Contained gaseous material

Whether or not the waste is an RCRA waste depends on definition.

An RCRA solid waste is defined as: garbage, refuse or sludge and excludes any solid waste that is listed in the Code of Federal Regulations (CFR) under Section 261.4. An RCRA waste can either be hazardous or non-hazardous. Hazardous wastes are identified as either being a listed toxic waste or by possessing certain characteristics such as:

- Ignitability
- Reactivity
- Corrosivity
- EP Toxicity

EP Toxicity characteristics are based on an acid extraction leachate test with the following criteria for heavy metals:

Arsenic	5 mg/L
Barium	100 mg/l
Cadmium	mg/l
Chromium	5 mg/l
Lead	5 mg/l
Mercury	0.2 mg/l
Selenium	1mg/l
Silver	5 mg/l

Exploration and Production Waste

If a waste is not hazardous, then it is non-hazardous and is controlled under RCRA Subtitle D regulations, if land disposed. So, how are exploration and production wastes classified? Exploration and production wastes can either be exempt or non-exempt from Subtitle C (SARA) regulations. In 1976, exploration and production wastes were listed as high volume, low-toxicity hazardous wastes. When RCRA was amended in 1980, much of these wastes were temporarily exempted and in June 1988, the EPA submitted a list to congress which exempted many exploration and production wastes in their regulatory determination. However, some exploration and production wastes are not exempt and are, therefore, regulated under Subtitle C.

Non-Exempt Wastes

- a. Maintenance of Production Equipment
 - painting wastes
 - used hydraulic fluids
 - used equipment lube oil
- b. Transportation Related Wastes
 - unused frac fluids or acids
 - radioactive tracer wastes
 - Waste solvents
- c. Transportation Related Wastes
 - produced water
 - drilling mud and cuttings
 - reserve pit waste
 - rig washdown water

These wastes are referred to as NOW wastes because of the RCRA exemption, but that does not mean that they are necessarily non-hazardous. An example of how a NOW waste can be classified as a hazardous waste would be to mix something like pipe dope, which contains lead, or a gallon of used hydraulic fluid into the reserve pit. Now, instead of having one gallon of hazardous waste, you now have thousands of barrels of hazardous waste.

Note: The cardinal rule is - DO NOT MIX WASTES.

In the future it appears that regulatory agencies may be moving toward removing the current exemption status for NOW wastes. This would have a tremendous impact on industry waste handling techniques and associated recordkeeping requirements.

Onshore Disposal Methods

There are several methods currently utilized for onshore disposal of mud and cuttings. These methods are:

- Landfarming
- Injection
- Biodegradation
- Incineration
- Solidification

Landfarming

Reserve pits are usually dewatered, with the liquid portion drained off and properly treated for disposal. The solids are often handled by chemical solidification and then the remainder is back-filled using the original walls of the reserve pit. In dryer seasons, the remainder of non-pumpable material is often spread on the location to dry prior to burial and backfilling.

Land farming mud solids and liquids into surrounding soils with tilling equipment is also a commonly accepted method of disposal. Land spreading promotes reduction of organic and inorganic constituents through dilution, biodegradation and adsorption. In some areas, a permit is required in addition to landowner approval. Saline fluids cannot be land farmed due to the destructive effect on vegetation and groundwater purity. Low concentrations of aromatic materials/oils, while damaging to soils in the short term, do not present long term problems and can be effectively landfarmed. Bacteria in soils can biodegrade oils under correct anaerobic conditions; however, areas of high moisture retard this activity and should not be utilized for the surface disposal of oil-laden fluids. Any landfarming operation should avoid excessive application rates resulting in excess drying time and the potential for runoff into surface waters.

Injection

The Operator may elect to pump materials down the casing annulus if conditions allow. A permit is required to do this, usually based on known ground water horizons. The Drilling Representative needs to be aware of the potential for collapsed casing prior to using this method.

Biodegradation

Biodegradation uses microorganisms to biologically degrade petroleum hydrocarbons. It requires a nitrogen source for bacterial growth, continual dilution, additions of an odor suppressant, and the soil/bacteria mixture must be frequently turned over to increase availability of oxygen. The process is relatively slow and volume handling capabilities are relatively low.

Incineration

Thermal systems can be installed on a drilling platform or placed at a convenient onshore site. These units generate air emissions in the form of partially combusted hydrocarbon particulates. The equip-

ment is large, complicated, expensive and requires a central treatment facility to be cost effective. Incineration should be conducted with appropriate permits which specify the type of solid wastes to be incinerated. In addition, air pollution regulatory agency approval is required for this process. Problems associated with this method of waste disposal are the short-term air emissions, safety due to a heat source, and ability to keep up with high ROPs. The units must also achieve a destruction and removal efficiency of 99.99 percent. Incineration technology for drill cuttings is in its infancy stages. New prototypes for use are being built, but are not yet field proven or cost effective.

Solidification

Solidification of reserve pit wastes offers a variety of environmental improvements over burial. Reducing the mobility of potentially hazardous materials, such as heavy metals, decreases the potential for contamination of groundwater from leachate of unsolidified, buried reserve pit wastes. Reserve pit fluids and cuttings are combined with solidification agents such as: commercial cement, flash, or lime kiln dust to form a relatively insoluble concrete-like matrix, which is sometimes used for road construction material. Although it is easier to handle waste in this manner, the practice is not widely used. Federal and state and even local regulations for drilling fluid disposal vary to such a large degree. Therefore, it is the responsibility of each Division to determine what is acceptable. One key point should be emphasized - disposal of drilling wastes at an authorized disposal site does not release the Operator from liability. Because many disposal locations process toxic waste from several industries, long term liability in the event of pollution still rests with the Operator. Again, since laws are constantly changing, it is imperative that you check with your local EH&S representative to ensure you are fully complying with all environmental regulations and completing all of the required paperwork.

Glossary of Environmental Terms

API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BAT	Best Available Technology Economically Achievable
BCT	Best Conventional Pollutant Control Technology
BPT	Best Practical Control Technology
BPJ	Best Professional Judgment
BOD	Biochemical Oxygen Demand
BIA	Bureau of Indian Affairs
BLM	Bureau of Land Management
CASRN	Chemical Abstracts Service Registry Number
COD	Chemical Oxygen Demand
CWA	Clean Water Act
CFR	Code of Federal Regulations
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (SUPERFUND)
DOE	Department of Energy
DOI	Department of Interior
DOT	Department of Transportation
DMR	Discharge Monitoring Report
DO	Dissolved Oxygen
EPA	Environmental Protection Agency
EHS	Extremely Hazardous Substance
LEPC	Local Emergency Planning Committee
DEQ	Louisiana Department of Environment Quality
DNR	Louisiana Department of Natural Resources Office of Conservation
MSD	Marine Sanitation Device
MSDS	Material Safety Data Sheets
EC ₅₀	Median Effective Concentration
LC ₅₀	Median Lethal Concentration
MOGA	Mid-Continent Oil and Gas Association
MMS	Minerals Management Service
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NOW	Nonhazardous Oilfield Waste
OSHA	Occupational Safety and Health Administration
OOC	Offshore Operators Committee
OCS	Outer Continental Shelf
-A	Outer Continental Shelf - Atlantic
-G	Outer Continental Shelf, Gulf

-P	Outer Continental Shelf, PacificRQ Reportable Quantity
RCRA	Resources Conservation and Recovery Act
RRC	Texas Railroad Commission
SDS	Sodium Dodecyl Sulfate
SP	Solid Phase
SRT	Standard Reference Toxicant
SERC	State Emergency Response Commission
SARA	Superfund Amendments and Reauthorization Act
SPP	Suspended Particulate Phase
TCLP	Toxicity Characteristic Leaching Procedure
TPQ	Threshold Planning Quality
TDS	Total Dissolved Solids (filterable residue)
TOC	Total Organic Carbon
TSCA	Toxic Substances Control Act
TSS	Total Suspended Solids (nonfilterable residue)
USCG	United States Coast Guard
USGS	United States Geological Survey

Definitions

Acute Toxicity - Any poisonous effect produced within a short time period following exposure, usually up to 24-96 hours, which results in severe biological harm or death.

Bioaccumulation - The process where toxic substances accumulate in tissues and pose a substantial hazard to human health or the environment.

Bioassay - A toxicity test that measures the effect of a chemical or effluent on a test population of organisms.

Effluent - Anything discharged into a receiving body of water.

Generic Mud - One of eight general mud classifications used to characterize drilling fluids.

Hazardous Materials - A substance or material which has been determined by the Secretary of Transportation to be capable of posing an unreasonable risk to health, safety and property when transported in Commerce.

Hazardous Substances - Elements or compounds other than oil, when discharged in any quantity into or upon the navigable waters of the United States or adjoining shorelines, or the waters of the contiguous zone or in connection with activities on the outer continental shelf, or which may affect natural resources, or present or imminent and substantial.

LC₅₀ - Lethal concentration at which 50% of the bioassay test population dies.

Toxicity - The degree of danger posed by a substance to animal or plant life.

Wetlands - Areas that are inundated or saturated by surface or groundwater and support a prevalence of vegetation adapted for life in saturated soil conditions.

Section 13 Appendix

Known Elements and Atomic Weights

Element	Symbol	Atomic number	Atomic weight	Element	Symbol	Atomic number	Atomic weight
Actinium	Ac	89	227*	Mercury	Hg	80	200.59
Aluminium	Al	13	26.9815	Molybdenum	Mo	42	95.94
Americium	Am	95	243*	Neodymium	Nd	60	144.24
Antimony	Sb	51	121.75	Neon	Ne	10	20.179
Argon	Ar	18	39.948	Neptunium	Np	93	237.0482
Arsenic	As	33	74.9216	Nickel	Ni	28	58.71
Astatine	At	85	210*	Niobium	Nb	41	92.9064
Barium	Ba	56	137.33	Nitrogen	N	7	14.0067
Berkelium	Bk	97	247*	Nobelium	No	102	259*
Beryllium	Be	4	9.01218	Osmium	Os	76	190.2
Bismuth	Bi	83	208.9808	Oxygen	O	8	15.9994
Boron	B	5	10.81	Palladium	Pd	46	106.4
Bromine	Br	35	79.904	Phosphorus	P	15	30.9738
Cadmium	Cd	48	112.41	Platinum	Pt	78	195.09
Caesium	Cs	55	132.9054	Plutonium	Pu	94	244*
Calcium	Ca	20	40.08	Polonium	Po	84	209*
Californium	Cf	98	251*	Potassium	K	19	39.0983
Carbon	C	6	12.011	Praseodymium	Pr	59	140.9077
Cerium	Ce	58	140.12	Promethium	Pm	61	145*
Chlorine	Cl	17	35.453	Protactinium	Pa	91	231.0359
Chromium	Cr	24	51.996	Radium	Ra	88	226.0254
Cobalt	Co	27	58.9332	Radon	Rn	86	222*
Copper	Cu	29	63.546	Rhenium	Re	75	186.2
Curium	Cm	96	247*	Rhodium	Rh	45	102.9055
Dysprosium	Dy	66	162.50	Rubidium	Rb	37	85.467
Einsteinium	Es	99	254*	Ruthenium	Ru	44	101.07
Erbium	Er	68	167.26	Samarium	Sm	62	150.4
Europium	Eu	63	151.96	Scandium	Sc	21	44.9559
Fermium	Fm	100	257*	Selenium	Se	34	78.96
Fluorine	F	9	18.9984	Silicon	Si	14	28.0855
Francium	Fr	87	223*	Silver	Ag	47	107.868
Gadolinium	Gd	64	157.25	Sodium	Na	11	22.9898
Gallium	Ga	31	69.72	Strontium	Sr	38	87.62
Germanium	Ge	32	72.59	Sulphur	S	16	32.06
Gold	Au	79	196.9665	Tantalum	Ta	73	180.9479
Hafnium	Hf	72	178.49	Technetium	Tc	43	98.9062
Helium	He	2	4.0026	Tellurium	Te	52	127.60
Holmium	Ho	67	164.9304	Terbium	Tb	65	158.9254
Hydrogen	H	1	1.0079	Thallium	Tl	81	204.37
Indium	In	49	114.82	Thorium	Th	90	232.0381
Iodine	I	53	126.9045	Thulium	Tm	69	168.9342
Iridium	Ir	77	192.22	Tin	Sn	50	118.69
Iron	Fe	26	55.847	Titanium	Ti	22	47.90
Krypton	Kr	36	83.80	Tungsten	W	74	183.85
Lanthanum	La	57	138.9055	Uranium	U	92	238.029
Lawrencium	Lr	103	260*	Vanadium	V	23	50.941
Lead	Pb	82	207.2	Xenon	Xe	54	131.30
Lithium	Li	3	6.941	Ytterbium	Yb	70	173.04
Lutetium	Lu	71	174.97	Yttrium	Y	39	88.9059
Magnesium	Mg	12	24.305	Zinc	Zn	30	65.38
Manganese	Mn	25	54.9380	Zirconium	Zr	40	91.22
Mendelevium	Md	101	258*				

Atomic weights quoted are the 1969 values based on carbon 12 and include the IUPAC revision 1971.

Values marked * are for the most stable or most common isotope.

PHYSICAL PROPERTIES OF SODIUM CHLORIDE SOLUTIONS

Percent Sodium Chloride of Solution	Density †		Specific Gravity † @ 20° C	Weight of Salt		Yield of Solution	Freeze Point	
	Lbs./Gal.	kg/m ³		Lbs./Bbl. of Water	kg/m ³ of Water		°F	°C
0	---	998	0.998	---	---	1.000	---	---
1	8.34	1005	1.005	3.54	10.1	1.005	30.9	-0.6
2	8.45	1013	1.013	7.15	20.3	1.008	29.9	-1.2
3	8.51	1020	1.020	10.82	30.6	1.011	28.8	-1.8
4	8.57	1027	1.027	14.61	41.1	1.015	27.7	-2.4
5	8.62	1034	1.034	18.42	51.7	1.018	26.2	-3.0
6	8.68	1041	1.041	22.35	62.5	1.022	25.3	-3.7
8	8.70	1056	1.056	30.47	84.5	1.029	22.9	-5.1
10	8.93	1071	1.071	38.92	107.1	1.038	20.2	-6.6
12	9.06	1086	1.086	47.78	130.3	1.047	17.3	-8.2
14	9.18	1101	1.101	57.03	155.4	1.056	14.1	-9.9
16	9.31	1116	1.116	66.73	178.6	1.067	10.6	-11.9
18	9.44	1132	1.132	76.89	203.7	1.077	6.7	-14.0
20	9.57	1148	1.148	87.57	229.6	1.089	2.4	-16.5
22	9.71	1164	1.164	98.81	256.1	1.101	-2.5	-19.2
24	9.84	1180	1.180	110.62	283.3	1.115	1.4*	-17.0*
26	9.98	1197	1.197	123.09	311.3	1.130	27.9**	-2.3*

* Precipitation @ - 17°C, 1.4°F **Precipitation @ -2.3°C, 27.9°F

† Density in kg/L and kg/dm³ is equal in numerical value to specific gravity.

PHYSICAL PROPERTIES OF POTASSIUM CHLORIDE SOLUTIONS

Percent Potassium Chloride by Weight of of Solution	Density of Solution+ Lbs./Gal. Kg/m ³	Sp. Gr.† @ 20°C	Weight of Potassium Chloride		kg of Potassium per m ³ of Water	kg of Chloride per m ³ of Water	Freeze Point	
			Lbs./Gal. of Water	Lbs./Bbl. of Water			°F	°C
0	8.34	0.998	---	---	---	---	---	---
1	8.38	1.005	0.08	3.54	5.27	4.78	31.2	-0.44
2	8.43	1.011	0.17	7.15	10.6	9.6	30.3	-0.94
3	8.48	1.017	0.26	10.82	16.0	14.5	29.5	-1.39
4	8.54	1.024	0.35	14.61	21.5	19.5	28.7	-1.83
6	8.65	1.037	0.53	22.35	32.6	29.6	27.0	-2.78
8	8.75	1.050	0.73	30.47	44.0	39.8	25.2	-3.78
10	8.87	1.063	0.93	38.92	55.8	50.5	23.3	-4.83
12	8.98	1.077	1.14	47.78	67.8	61.4	21.4	-5.89
14	9.10	1.091	1.36	57.03	80.0	72.5	19.3	-7.06
16	9.21	1.104	1.59	66.73	92.6	84.0	17.4	-8.11
18	9.33	1.119	1.83	76.89	105.4	95.5	14.9	-9.50
20	9.45	1.133	2.09	87.57	118.8	107.8	15.0	-9.44
22	9.57	1.147	2.35	98.81	132.1	119.8	32.6	10.33
24	9.69	1.162	2.63	110.62	146.3	132.6	52.0*	11.11*
26.5	9.82	1.178	3.01	126.28	163.7	148.5	78.3*	25.72*

* Precipitates

† Density in kg/L and Kg/dm³ is equal in numerical value to specific gravity.

PHYSICAL PROPERTIES OF CALCIUM CHLORIDE SOLUTIONS

Percent Calcium Chloride by Wt. of Solution	Density of Solution*		Specific Gravity @ 20°C	Weight of Anhydrous Calcium Chloride		kg/m ³ of Water	Yield of Solution	Freeze Point	
	Lbs./Gal.	Kg/m ³		Lbs./Gal. of Water	Lbs./Bbl. of Water			°F	°C
0.	8.34	998	0.998	---	---	---	1.00	32.	0.0
1.	8.41	1008	1.008	0.08	3.54	10.1	1.002	31.1	- 0.5
2.	8.47	1015	1.015	0.17	7.15	20.3	1.004	30.2	- 1.0
3.	8.54	1024	1.024	0.26	10.80	30.7	1.006	29.7	- 1.3
4.	8.61	1032	1.032	0.35	14.61	41.3	1.008	28.4	- 2.0
5.	8.69	1042	1.042	0.44	18.42	52.1	1.012	27.7	- 2.4
10.	9.04	1084	1.084	0.93	38.92	108.4	1.024	22.3	- 5.4
15.	9.44	1132	1.132	1.47	61.74	169.8	1.040	13.5	-10.3
20.	9.82	1178	1.178	2.09	87.57	235.6	1.060	- 0.4	-18.0
25.	10.24	1228	1.228	2.78	116.76	307.0	1.090	-20.6	-29.2
30.	10.69	1282	1.282	3.57	149.94	384.6	1.114	-49.0	-45.0
35.	11.15	1337	1.337	4.49	188.58	468.0	1.151	---	---
40.	11.72	1405	1.405	5.56	233.52	562.0	1.186	---	---

* Density in kg/L and Kg/dm³ is equal in numerical value to specific gravity.

Settling Plug Mixing Procedure

Cementing Equipment

1. Clean and flush all mixing lines to and from cement mixing equipment. Arrange for weight material to be mixed rather than cement. This may require the use of sacked weight material. If sacked weight material is to be used, be sure that weight material sufficient for the plug can be placed near the mixing hopper. Estimate manpower and barite moving requirements (forklift and/or crane).
2. Measure mixing water for plug volume (take into account line volumes) into tank. If possible, mix caustic soda and lignosulfonate into mixing water. This may be done by using mud system slugging pit and pumping mixing water to cement mixing equipment. Mix 1-1/2 lb/bbl of caustic soda and 8 lb/bbl of chrome lignosulfonate in mix water.
3. Mix plug and pump "on the fly" using weight material and mixing water. Avoid mixing slurry below 16 lb/gal for barite weight material and below 20 lb/gal for hematite material as too rapid settling could occur and plugging of equipment or lines can occur.
4. Avoid chasing plug with water. Use mud instead to prevent premature settling of plug.

Mud Tank Slugging Pit

1. Empty and clean slugging pit. If unable to dump pit, fill with water and agitate. Pump out dirty water. Repeat, if necessary, to get pit clean.
2. Put just enough mixing water in pit to obtain mixing pump suction. Add the total calculated amount of caustic soda and chrome lignosulfonate to the mix water. Note quantity required and calculate remaining amount of water to be added to bring to total volume mix water.
3. Begin mixing weight material. Slurry should begin to look viscous when the density nears 16 lb/gal for barite and 20 lb/gal for hematite.
4. When slurry density approaches 18 lb/gal for barite and 21 lb/gal for hematite, begin adding remainder of mix water. Add mix water in steps with additional weight material to avoid both too light and slurry that will settle or too heavy a slurry that will lose pump suction. After adding the calculated volume of mix water, bring slurry to final desired density. Allow to mix until weight material is mixed thoroughly.
5. Pump plug to mud pump, avoiding water ahead or behind plug. Avoid chasing plug with water. Use mud instead to prevent premature settling of plug.

The following are recommendations for composition and application of barite plugs.

Formulation

Plug Density (ppg)	16	17	18	19
Composition per final bbl				
Water bbl	.71	.68	.64	.60
Chrome Lignosulfonate lb	5.7	5.4	5.1	4.8
Caustic Soda lb	1.1	1.0	1.0	0.9
Barite lb	422	477	533	588

Preparation of Oil-Base Plugs

Plug slurries can be prepared with oil and barite. A certain sequence of mixing of products is desirable for optimum performance.

Always mix the wetting agent with the oil thoroughly before adding the weight material. This will aid in keeping the slurry pumpable and tie up any stray water that may be present.

High density slurries settle more slowly than low density slurries because of the high solids concentration and gel strengths. Therefore, the lowest appropriate weight should be chosen, keeping in mind that the slurry volume should be no longer than the distance between the loss zone and the active zone.

Variations and contaminants in weight material, variations in the viscosities and physical properties of available base oils, and the type of wetting agent will require different concentrations of wetting agent to insure an optimum settling rate. It should be kept in mind that too much wetting agent can be just as detrimental as to little wetting agent. Therefore, pilot testing should be done with available materials before use. It is highly recommended that samples of the oil, barite, and available wetting agent be sent to the DTC for testing to determine optimum concentration.

The amount of oil and barite required to make a one-barrel pumpable slurry of desired weight can be estimated from the following table.

Mud Weight (ppg)	Oil (bbl)	Barite (lb/bbl)
14	0.729	362.9
15	0.691	415.4
16	0.653	467.9
17	0.615	520.4
18	0.577	572.9
19	0.539	625.5
20	0.501	678.0

Again, the amount of wetting agent required for optimum settling will depend upon the characteristics of the barite, oil, and type of wetting agent. It cannot be emphasized enough--PILOT TEST.

Recommended Plug Procedures

Length of Plug

Barite plugs are designed to control formation pressures by providing an immovable, impermeable seal at the point of influx. Success depends entirely on the ability to mix the plug slurry with optimum settling properties, spotting the slurry by the recommended displacement procedures, and minimizing the amount of contamination that may adversely affect the settling rate and prevent the formation of a firm plug. In some cases, several attempts must be made to successfully seal off the influx of formation fluids.

The length of the barite plug is a wellsite determination and should be based on the severity of the situation. The maximum slurry length should not exceed the distance between the influx and the lost circulation zone. Long barite plugs are not desirable because of the distance the drill string has to be pulled to withdraw it completely from the slurry.

In cases where formation pressure can be estimated, the length of the plug can be calculated to balance this pressure. Under these circumstances, the plug is used as both a kill fluid and an immovable seal. The length of the plug required to balance a given pressure can be calculated using the following equation.

$$L = \frac{P}{1.8228}$$

where

- L = Required length of plug (ft)
P = Pressure to be balance (psi)
1.8228 = Pressure gradient of compacted barite (psi/ft). S.G. of barite (4.2) x 0.434.

Mud Density

The density (ppg) selected should be 0.5 to 1.0 ppg greater than the fluid in the hole. This will ensure that once the plug is spotted, there will be no movement or migration.

Determine Maximum Slurry Length

Determine maximum slurry length (distance between loss zone and zone of influx) if applicable.

Calculate Total Slurry Volume

The volume of slurry can be calculated using the following equation.

$$V = \frac{L \times Vr \times 1470}{WTM}$$

where

- V = Volume of slurry
L = Plug length
1470 = Weight of 1 bbl of barite
Vr = Hole volume (bbl/ft)
WTM = Barite required to formulate 1 bbl of slurry (from table)

Materials

Calculate amount of material required to formulate plug.

Mixing

There are two different mixing procedures that can be used when mixing the slurry. The first is a mix and displace method, very similar to a cementing operation. The barite is added "on the fly" to the pre-mixed oil and wetting agent and immediately pumped downhole. The alternate method is to "batch mix" the slurry in a tank with sufficient circulation and agitation to prevent settling and then displace downhole.

Displacement

Displacement techniques are similar to those of cementing in that the slurry should be underdisplaced. When calculating the volumes of displacement, adjustments should be made so that the height of the slurry is 2 bbls greater in the drill pipe than in the annulus. This allows the drill string to be pulled with a natural slug. It should be kept in mind that if the slurry is underdisplaced and the drill string left in place, barite will settle, plugging the string and will settle in the annulus, sticking the string. Contamination caused by slurry movement is also minimized. A 2-5 bbl spacer before and after the slurry will minimize contamination by in-situ drilling mud.

The following calculations are required to efficiently displace a barite plug.

1. Find the height at which the total slurry volume (less than 2 barrels) is equalized in the hole.
2. Determine the volume inside and outside the drill collars.
3. Subtract this volume from the total slurry volume and determine the height the remaining volume would occupy inside and outside the drill pipe.

$$\text{Height} = \frac{\text{Remaining Volume}}{\text{Capacity DP (bbl/ft)}}$$

4. Find the height that 2 barrels of slurry will occupy in the drill pipe

$$\text{Height} = \frac{2}{\text{Capacity DP (bbl/ft)}}$$

Add this to the length of the drill collars and the height of the slurry equalized around the drill pipe.

5. Once the total height of the slurry inside the drill string has been determined, the remaining length of the drill string represents the volume of mud required to displace the slurry.

Conversion Tables

Multiply	By	To Obtain
PPG	119.286	kg/m ³
PPG	.052	psi/ft
PPG	.1198	gm/cm ³
PPG	7.48	lb/ft ³
Kg/m ³	.06243	lb/ft ³
PPB	2.853	kg/m ³
PPB	2857	mg/l
Mg/L	.00035	ppb
PPM	SG	Mg/L
Ft	0.3048	m
M	3.281	ft
BBL	5.615	ft ³
BBL	.15899	m ³
BBL	42	gal
Ft ³	7.48	gal
Ft ³	.0283	m ³
Gal	.003785	m ³
Lbs	.454	kg
Lbs	453.6	gm
Kg	2.2046	lb
PSI	.06804	Atm
PSI	703.1	kg/m ²
°C	(°C x 1.9) + 32	°F
°F	(°F - 32) x .556	°C

Common Contaminants and Treating Agents

Contaminant	Treating Agent	lb/bbl of Treating Agent to React with 100 mg/l of Contaminant
Calcium	Soda Ash	0.093
	Sodium Bicarbonate	0.074
Magnesium	Caustic Soda	0.058
Carbonate	Gypsum (if high pH)	0.118
	Lime	0.043
Bicarbonate	Lime	
Sulfide	Zinc Carbonate	0.14
	Zinc Oxide	0.089

Common Oilfield Screens

Mesh	Wire Diameter (in)	Opening		% Open Area	API Designation
		inches	microns		
8x8	.028	.097	2464	60.2	8x8 (2464x2464, 60.2)
10x10	.025	.075	1905	56.3	10x10 (1905, 1905, 5613)
12x12	.023	.060	1524	51.8	12x12 (1524x1524, 51.8)
14x14	.020	.051	1295	51.0	14x14 (1295x1295, 51.0)
16x16	.018	.0445	1130	50.7	16x16 (1130x1130, 50.7)
18x18	.018	.0376	955	45.8	18x18 (955x955, 45.8)
20x20	.017	.033	838	43.6	20x20 (838x838, 43.6)
20x8	.020/.032	.030/.093	762/2362	45.7	20x8 (762x2362, 45.7)
30x30	.012	.0213	541	40.8	30x30 (541x541, 40.8)
30x20	.015	.018/.035	465/889	39.5	30x20 (465x889, 39.5)
35x12	.016	.0126/.067	320/1700	42.0	35x12 (320x1700, 42.0)
40x40	0.10	.015	381	36.0	40x40 (381x381, 36.0)
40x36	.010	.0178/015	381/592	42.5	40x30 (381x592, 42.5)
40x20	.014	.012/.036	310/910	36.8	40x20 (310x910, 36.8)
50x50	.009	.011	279	30.3	50x50 (279x279, 30.3)
50x40	.0085	.0115/.0165	292/419	38.3	50x40 (292x419, 38.3)
60x60	.0075	.0092	234	30.5	60x60 (234x234, 30.5)
60x40	.009	.0077/.016	200/406	31.1	60x40 (200x406, 31.1)
60x24	.009	.007/.033	200/830	41.5	60x24 (200x830, 41.5)
70x30	.0075	.007/.026	178/660	40.3	70x30 (178x660, 40.3)
80x80	.0055	.007	178	31.4	80x80 (178x178, 31.4)
80x40	.007	.0055/.018	140/460	35.6	80x40 (140x460, 35.6)
100x100	.0045	.0055	140	30.3	100x100 (140x140, 30.3)
120x120	.0037	.0046	117	30.9	120x120 (117x117, 30.9)
150x150	.0026	.0041	105	37.4	150x150 (105x105, 37.4)
200x200	.0021	.0029	74	33.6	200x200 (74x74, 33.6)
250x250	.0016	.0024	63	36.0	250x250 (63x63, 36.0)
325x325	.0014	.0017	44	30.0	325x325 (44x44, 30.0)

PUMP DISPLACEMENT

TRIPLEX PUMPS

Liner Diameter (inches)	Barrels per inch of Stroke
3-1/2	0.002376
3-3/4	0.003416
4	0.003986
4-1/4	0.004387
4-1/2	0.004919
4-3/4	0.005480
5	0.006073
5-1/4	0.006895
5-1/2	0.007348
5-3/4	0.008031
6	0.008744
6-1/4	0.009488
6-1/2	0.010283
6-3/4	0.011067
7	0.011902

Generalized Procedure:

Step One

Determine "Barrels per Inch of Stroke" by using the appropriate pump table or the following equations:

$$\text{Barrels per Inch of Stroke} = \frac{(\text{Liner Diameter})^2}{4116} \quad (\text{Triplex})$$

$$\text{Barrels per Inch of Stroke} = \frac{(2 \times \text{Liner Diameter})^2 - (\text{Rod Diameter})^2}{6174} \quad (\text{Duplex})$$

Example:

Duplex pump with 6" liners, 3" rods, 16" stroke length, 92% efficiency
From pump table below: 0.01020 Barrels per inch of Stroke
Pump Displacement = 0.01020 x 16" x 0.92 = 0.1501 Barrels per Stroke (transcribe to Pre-recorded Data Sheet)

Step Two

Calculate actual pump displacement with the following formula:

$$\text{Pump Displacement (Bbls/Stroke)} = \frac{\text{Barrels per Inch of Stroke} \times \text{Stroke Length (inches)} \times \text{Volumetric Efficiency}}{1}$$

Note: Use Volumetric Efficiency in decimal form (eg. 95% = 0.95)

DUPLEX PUMPS

Liner Diameter (inches)	Barrels per Inch of Stroke					Fluid Piston Rod Diameter						
	1-1/2	1-3/4	1-7/8	2	2-1/4	2-3/8	2-1/2	2-3/4	3	3-1/8	3-1/4	
3-1/2	0.00380											
3-3/4	0.00419	0.00406	0.00398	0.00391								
4	0.00482	0.00468	0.00461	0.00453								
4-1/4	0.00548	0.00535	0.00528	0.00520								
4-1/2	0.00619	0.00606	0.00599	0.00591								
4-3/4	0.00694	0.00681	0.00674	0.00666								
5	0.00773	0.00760	0.00753	0.00745	0.00574	0.00564	0.00555	0.00533	0.00510	0.00498	0.00485	
5-1/4	0.00856	0.00843	0.00836	0.00828	0.00811	0.00801	0.00791	0.00770	0.00747	0.00734	0.00721	
5-1/2	0.00943	0.00930	0.00923	0.00915	0.00898	0.00888	0.00878	0.00857	0.00834	0.00821	0.00808	
5-3/4	0.01034	0.02021	0.01014	0.01006	0.00989	0.00979	0.00969	0.00948	0.00925	0.00912	0.00900	
6	0.01129	0.01116	0.01109	0.01101	0.01084	0.01074	0.01064	0.01043	0.01020	0.01008	0.00995	
6-1/4	0.01228	0.01215	0.01208	0.01200	0.01183	0.01174	0.01164	0.01142	0.01119	0.01107	0.01094	
6-1/2	0.01332	0.01318	0.01311	0.01303	0.01286	0.01277	0.01267	0.01246	0.01222	0.01210	0.01197	
6-3/4	0.01439	0.01426	0.01418	0.01411	0.01393	0.01384	0.01374	0.01353	0.01330	0.01317	0.01304	
7	0.01550	0.01537	0.01530	0.01522	0.01505	0.01495	0.01485	0.01464	0.01441	0.01429	0.01416	

