Water-Base Systems

Introduction

It is typical for several types of drilling fluid systems to be used in each well.

Many different types of water-base drilling fluid systems (muds) are used in drilling operations. Basic drilling fluid systems are usually converted to more complex systems as a well is deepened and the wellbore temperature and/or pressure increases. It is typical for several types of drilling fluid systems to be used in each well. Several key factors affect the selection of drilling fluid system(s) for a specific well. The most cost-effective drilling fluid for a well or interval should be based on the following criteria:

Application
- Surface interval.
- Intermediate interval.
- Production interval.
- Completion method.
- Production type.

Geology
- Shale type.
- Sand type.
- Permeability.
- Other formation types.

Makeup water
- Type of water.
- Chloride concentration.
- Hardness concentration.

Potential problems
- Shale problems.
- Bit/Bottom-Hole Assembly (BHA) balling.
- Stuck pipe.
- Lost circulation.
- Depleted sands.

Rig/drilling equipment
- Remote location.
- Limited surface capacity.
- Mixing capabilities.
- Mud pumps.
- Solids-control equipment.

Contamination
- Solids.
- Cement.
- Salt.
- Anhydrite/gyp.
- Acid gases (CO_2, H_2S).

Drilling data
- Water depth.
- Hole size.
- Hole angle.
- Torque/drag.
- Drilling rate.
- Mud weight.
- Maximum temperature.

Water-base drilling fluids can usually be placed into one of the following classifications:
- Unweighted clay-water systems.
- Deflocculated, weighted clay-water systems.
- Calcium-treated, weighted, deflocculated clay-water systems.
- Saltwater systems.
- Inhibitive potassium systems.
- High-Temperature, High-Pressure (HTHP) deflocculated systems.
- HTHP polymer systems.
- Encapsulating polymer systems.
- Cationic polymer systems.
- Extended or flocculated clay-based systems.
- Polyglycol enhanced systems.
- Inhibitive silicate systems.

Unweighted Clay-Water Systems

Usually, this system is used to spud a well.

This basic system is essentially M-I GEL® (Wyoming bentonite) and water. Usually, this system is used to spud a well. As drilling continues, formation solids are incorporated into the drilling fluid. Solids-removal equipment is used to remove as much of the formation solids (drill solids) as possible. Some of the native formation solids may be bentonitic in nature and increase the viscosity of the drilling fluid. Therefore, this system is often referred to as a "native mud." Advantages of this system are low cost and high Rate of Penetration (ROP). This system is often extremely shear-thinning.

Unweighted, clay-water systems usually are converted to another system prior to reaching any critical part of the well. Therefore, the solids content should be maintained at low values to facilitate this conversion.

Since this system is not weighted, it has a low buoyancy effect on cuttings. Therefore, hole-cleaning depends on viscosity and flow rate. The plastic viscosity should be low, if the solids content of the system is low, so the carrying capacity must be achieved with higher yield points. Chemical deflocculants reduce the yield point and viscosity dramatically. This can result in inadequate hole cleaning. Therefore, the use of chemical deflocculants in this system should be strictly limited. If a low fluid loss is required, it should be controlled with additions of M-I GEL (prehydrated if used in seawater) and an appropriate Fluid-Loss-Control Additive (FLCA). The FLCA may be MY-LO-JEL™, POLY-SAL™, THERMPAC® UL, CMC or POLYPAC.®

...the use of chemical deflocculants in this system should be strictly limited.

Typical Properties	
Density (lb/gal)	8.5 - 10
Funnel viscosity (sec/qt)	36 - 55
Plastic viscosity (cP)*	5 - 9
Yield point (lb/100 ft^2)*	12 - 25
Initial gel (lb/100 ft^2)	5 - 10
10-min gel (lb/100 ft^2)	10 - 20
pH	8.5 - 10.5
P_m (cm^3 0.02N H_2SO_4)	0.1 - 1.5
P_f (cm^3 0.02N H_2SO_4)	0.1- 1.0
Calcium (mg/l)	40 - 240
Chlorides (mg/l) (freshwater)	0 - 5,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)	3 - 10
MBT (lb/bbl)	See Figure 1

*See Figure 1.

Typical Products	Primary Function
M-I GEL	Viscosity and fluid-loss control
Caustic soda	Increase pH and P_f
TANNATHIN®	Thinner
SAPP	Thinner
POLYPAC	Viscosity and fluid-loss control
THERMPAC UL	Fluid-loss control
MY-LO-JEL	Fluid-loss control
POLY-SAL	Fluid-loss control
POLY-PLUS®	Bentonite extender
CMC	Viscosity and fluid-loss control

Material	Concentration (lb/bbl)
M-I GEL	20 - 35
Caustic soda	0.1 - 0.5
FLCA	As needed
SAPP	0.125 - 0.5

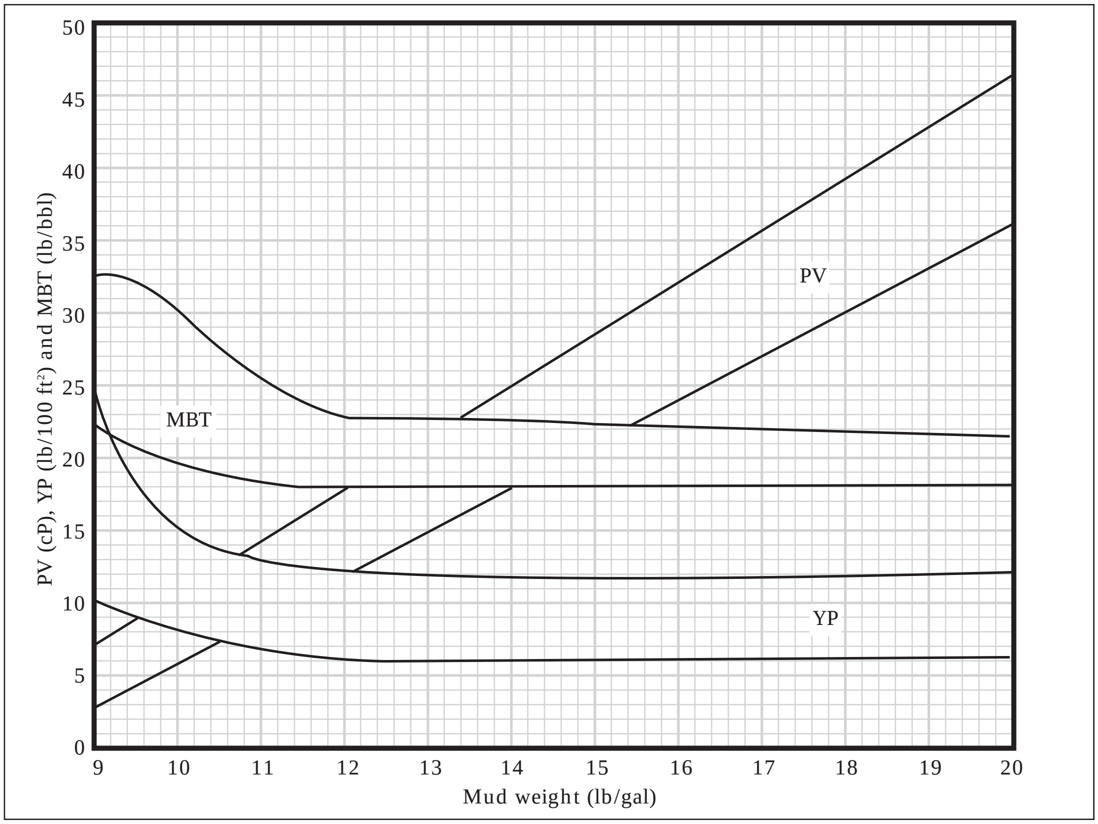

Figure 1: Plastic viscosity, yield point and Methylene Blue Test (MBT) ranges for water-base muds.

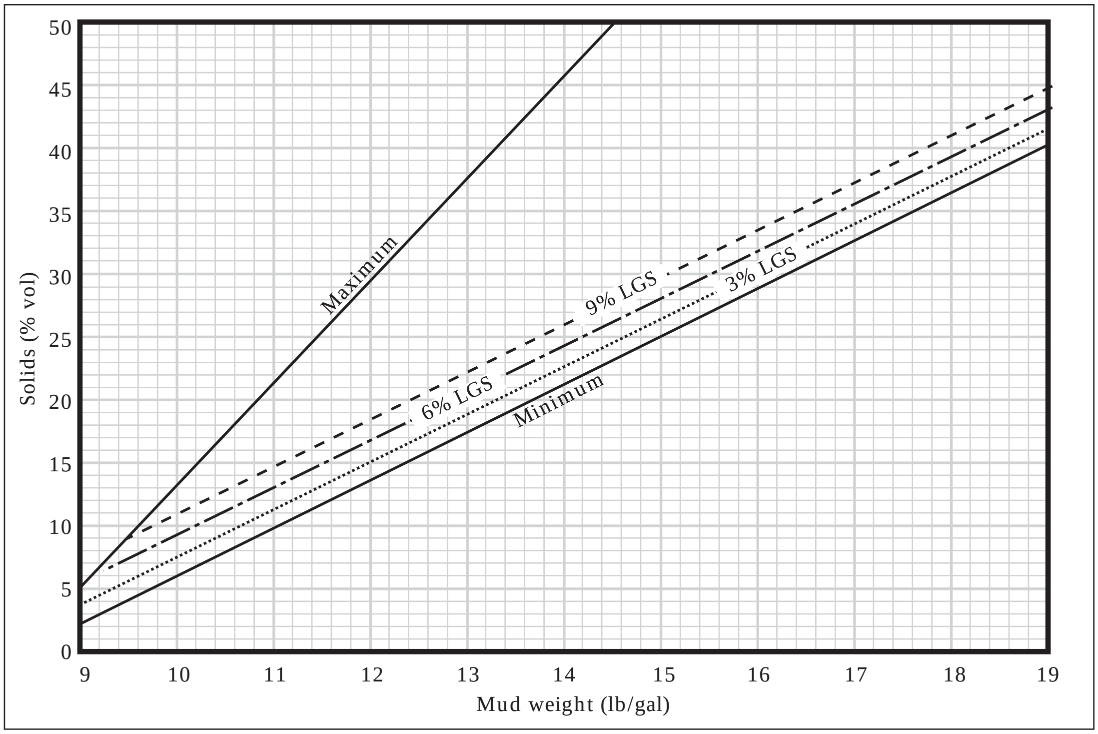

Figure 2: Solids range for barite water-base muds.

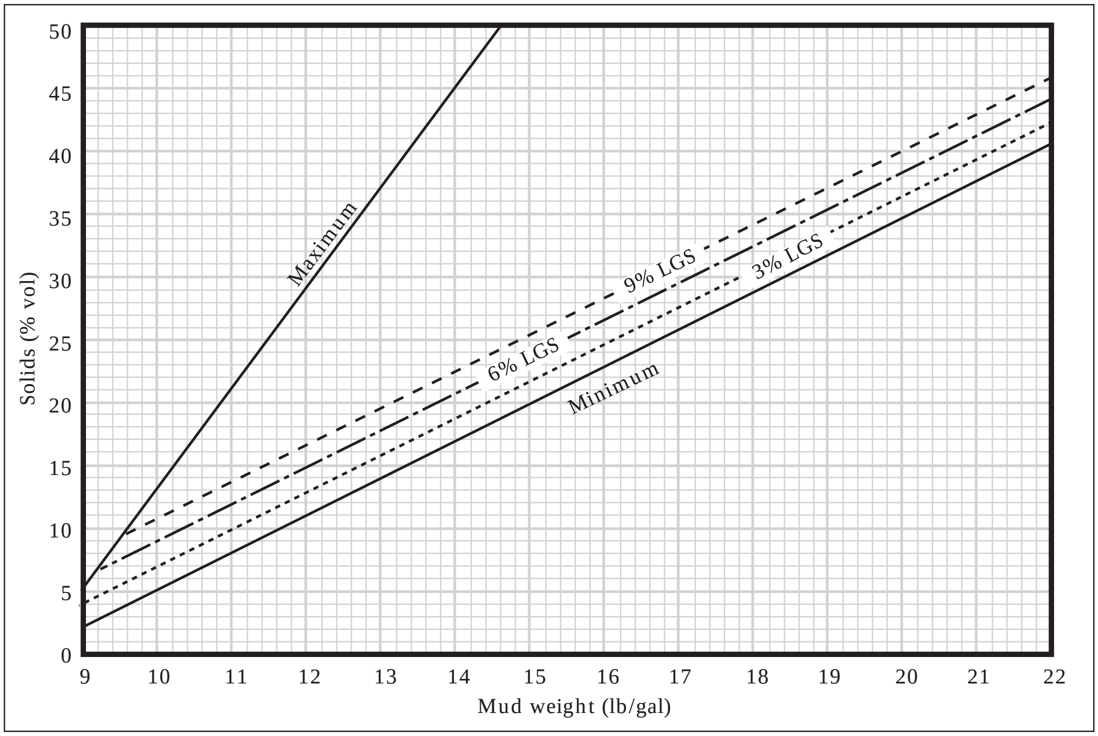

Figure 3: Solids range for hematite water-base muds.

SPERSENE System

The SPERSENE deflocculated system is one of the most common drilling fluid systems used in the industry.

The SPERSENE™ deflocculated system is one of the most common drilling fluid systems used in the industry. The primary thinner in the system is SPERSENE (or SPERSENE CF) lignosulfonate. Lignosulfonates are organic acids that supply anions (negative ions) to the fluid. These anions reduce the yield point and gel strengths by neutralizing the cations (positive ions) on the clay particles, thus deflocculating the clay slurry causing clay particles to repel one another. SPERSENE is very versatile due to its high degree of solubility in both freshwater and saltwater environments. Since it is acidic, SPERSENE requires an alkaline environment in which to solubilize. Therefore, hydroxyl ions are added usually in the form of caustic soda (sodium hydroxide) and lime (calcium hydroxide) to increase the pH.

This system can be treated to have a high degree of tolerance for both solids and chemical contamination by simply increasing the concentration of SPERSENE and TANNATHIN (lignite) or XP-20® (causticized chrome lignite). Lignite is an organic acid that also supplies anions to the fluid, thus causing clay particles to repel one another. In most cases, a ratio of two SPERSENE to one TANNATHIN, or XP-20, is a very effective combination for treatments, but the ratio can be varied.

Materials like SPERSENE, TANNATHIN and XP-20 are deflocculants, but are also referred to as dispersants and thinners, because they allow discrete clay particles to disperse, and they reduce the yield point, gel strength and “n” value of the drilling fluid.

SPERSENE systems are usually converted from unweighted, clay-water suspensions or “spud muds.” A typical treatment to convert to a lightly treated SPERSENE system would be

(Spersene system continued)

about 4 lb/bbl M-I Gel, 2 lb/bbl Spersene, 1 lb/bbl of either Tannathin or XP-20 and 1 lb/bbl caustic soda.

Comparing the drilling fluid properties at the flow line with those in the pits indicates the degree to which wellbore contaminants are affecting the drilling fluid properties. This is also a reflection of the stability of the system. In most cases, a significant difference in the properties between the flow line and the pits indicates an unstable fluid. The stability of a Spersene system can be increased by increasing the concentration of Spersene and Tannathin (or XP-20). Lightly treated Spersene systems contain 2 to 6 lb/bbl Spersene and 1 to 3 lb/bbl of Tannathin (or XP-20), while a fully inhibitive Spersene system may contain 8 to 12 lb/bbl Spersene and 4 to 6 lb/bbl of Tannathin or (XP-20).

Maintenance of a Spersene system (and other drilling fluids systems) while drilling means maintaining the properties at predetermined, near-constant values. These values are controlled by the concentration of materials in the drilling fluid. As water is added to the drilling fluid to maintain an acceptable drilled solids concentration, products must be added to maintain the desired concentration of additives. Therefore, the volume of dilution water should be measured or estimated to use as a basis for product additions. The amount of dilution required depends on the hole size, rate of penetration, type of formation, solids-control equipment and the optimum concentration of drill solids in the drilling fluid.

The temperature limitation of this system is approximately 320°F (160°C) due to the increased rate of thermal degradation of lignosulfonate above this temperature. The temperature limit of this system can be increased significantly by increasing the concentration of lignite and reducing the concentration of lignosulfonate. Lignite has a temperature limitation of about 450°F (232°C).

NOTE: Spersene and XP-20 contain chrome and may not be allowed under some environmental regulations. When chrome is not permitted, Spersene CF and Tannathin should be used.

Lignite has a temperature limitation of about 450°F...

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3.5 x mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	2 - 8
10-min gel (lb/100 ft^2)	2 - 14
pH	9.5 - 11.5
P_m (cm^3 0.02N H_2SO_4)	2.0 - 5.0
P_f (cm^3 0.02N H_2SO_4)	0.5 - 1.5
Calcium (mg/l)	40 - 240
Chlorides (mg/l)	0 - 20,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	5 - 7
MBT (lb/bbl)	See Figure 1

*See Figures 2 and 3.

Typical Products	Primary Function
M-I Bar	Increase density
M-I Gel	Viscosity and fluid-loss control
Caustic soda	Increase pH and P_f
Lime	Increase P_m and treat out CO_3
Gyp	Treat out CO_3
Spersene (CF)	Thinner
Tannathin	Fluid loss and thinner
XP-20	HT thinner and fluid-loss control
Polypac	API fluid-loss control and viscosity
Resinex®	HTHP fluid-loss control
Duo-Vis®	Increase low-shear viscosity

Material	Concentration (lb/bbl)
M-I Bar or Fer-Ox	0 - 550
M-I Gel	5 - 30
Caustic soda	0.3 - 2
Lime	0 - 1
Spersene (CF)	2 - 12
XP-20 or Tannathin	1 - 12
Polypac	0.50 - 2
Resinex	2 - 6
Duo-Vis	0.25 - 0.50

Calcium-Treated Drilling Fluids

When calcium is added to a clay-water slurry, a base exchange occurs as the calcium (Ca^{2+}) cation, which has higher bonding energy, replaces the sodium (Na^+) cation on the clays, converting them to calcium-base clays. Figure 4 shows the amount of calcium adsorbed by Wyoming bentonite and native clays. This cation exchange results in partial dehydration of the hydrated clay particles, reducing the size of the water envelope around the clay particles (see Figure 5). The reduction in the size of the water envelope allows the clay particles to come into contact with one another, resulting in flocculation. Flocculation causes an increase in the yield point and gel strengths. If a deflocculant is not used, the size of the flocs of clay eventually will increase and may precipitate out, resulting in a gradual decrease in the plastic viscosity.

Flocculation causes an increase in the yield point and gel strengths.

If a deflocculant is used, then the clays will still have the reduced water envelope, but the flocs of clay will be dispersed.

This phenomenon occurs when calcium contamination occurs while drilling then is subsequently treated, or when a fluid is converted (“broken over”) to a calcium-base drilling fluid such as a SPERSENE/gyp or a SPERSENE/lime system.

The concentration of reactive solids in the drilling fluid determines the viscosity increase (viscosity hump) encountered when calcium is added to the system (see Figure 6). Therefore, prior to converting to a calcium-base system, or before drilling into formations that contain calcium (such as anhydrite), the reactive solids content of the drilling fluid should be reduced by dilution while the viscosity is maintained with additions of polymers.

The concentration of reactive solids in the drilling fluid determines the viscosity increase encountered when calcium is added to the system.

Calcium systems provide soluble and reserve calcium in a drilling fluid.

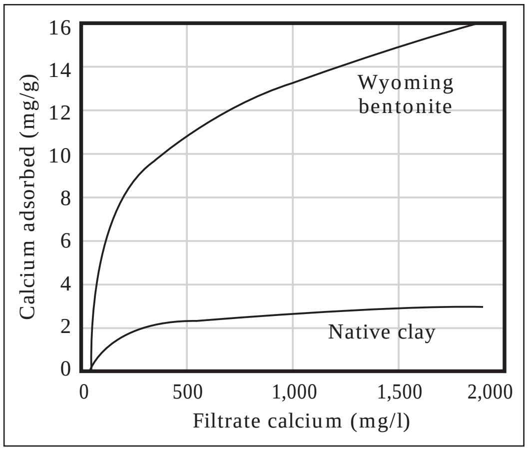

Figure 4: Adsorption of calcium by clays.

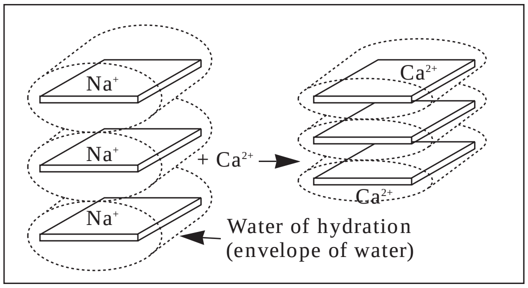

Figure 5: Reduction in water of hydration for sodium clay during base exchange with calcium.

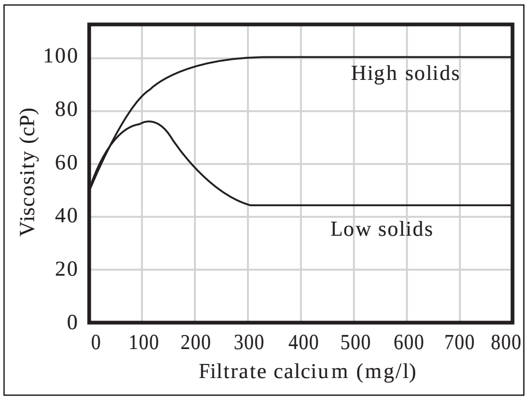

Figure 6: Effect of solids concentration on viscosity with calcium additions.

Soluble calcium performs several functions. It provides wellbore inhibition by minimizing the hydration of drill solids and exposed shales through base exchange into calcium-based clays. It makes a drilling fluid compatible with formations that contain high

(CALCIUM-TREATED DRILLING FLUIDS CONTINUED)

concentrations of calcium, such as anhydrite. It precipitates carbonate ions (CO_3^{2-}) which result from carbon dioxide (CO_2) contamination.

Materials that have a low hardness tolerance should* not *be used in this system.

The solubility of calcium is inversely proportional to the pH of the drilling fluid. It is nearly insoluble at a pH above 12.5, but is very soluble at a low pH. This is illustrated in Figure 7 where, on Line A (when only lime is added), the pH does not increase above 12.5, but on Line B (with added caustic), the pH increases above 12.5 and the soluble calcium decreases rapidly. Therefore, calcium as lime ($Ca(OH)_2$) helps to buffer the pH when acid gases such as CO_2 or hydrogen sulfide (H_2S) are encountered.

Calcium solubility is also directly related to salinity or chloride (Cl^-) concentration. The soluble calcium in seawater is often around 1,200 mg/l and will increase as the salinity is increased, as shown in Figure 8. Figure 8 shows the soluble calcium from gyp added to increasing concentrations of salt.

SPERSENE/GYP SYSTEM

The SPERSENE/gyp (gypsum) system is designed to drill anhydrite ($CaSO_4$) and/or provide inhibition while drilling water-sensitive shales by using gypsum ($CaSO_4 \cdot 2H_2O$) as the source of calcium. To maintain a sufficient amount of soluble calcium, the pH of the SPERSENE/gyp system should be kept low (9 to 10.5). The normal concentration of soluble calcium in this system is in the 600 to 1,200 mg/l range. Since the solubility of calcium is affected by pH and salinity, the actual level will depend on these properties.

When converting an existing untreated or lightly treated system to a SPERSENE/gyp system, the MBT and low-gravity solids content should be reduced to minimize the "break-over viscosity hump." Then, about 8 lb/bbl gyp, 8 lb/bbl SPERSENE and 2 lb/bbl caustic soda should be added simultaneously over one or two circulations. After the initial conversion, properties such as fluid loss, pH and alkalinity should be refined by the additions of the proper materials. Materials that have a low hardness tolerance should *not* be used in this system. Since soluble calcium increases the hardness of the water phase, treatments with about 2 lb/bbl SURFAK-M™ are beneficial for reducing the surface tension of the water phase, and improving the performance of the chemical additives.

In addition to the maintenance procedures previously described, the "excess gyp" test should be used to

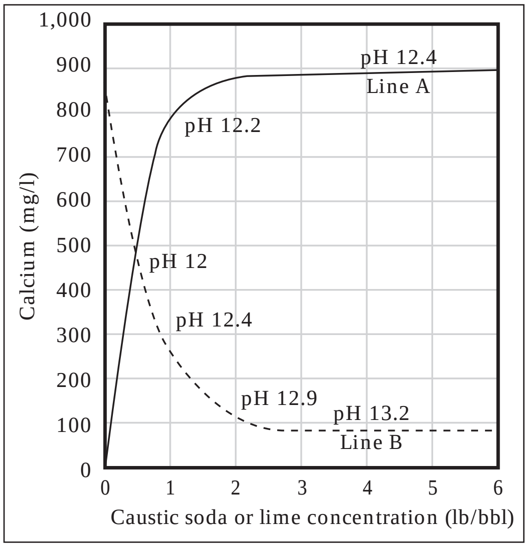

Figure 7: Line A - soluble calcium vs. lime concentration; Line B - Soluble calcium of 4 lb/bbl of lime added to caustic solutions.

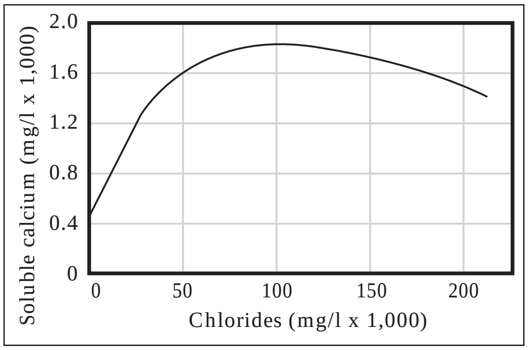

Figure 8: Solubility of calcium vs. chlorides.

(SPERSENE/GYP SYSTEM CONTINUED)

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3.5 x mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	1 - 10
pH	9.0 - 10.5
P_m (cm^3 0.02N H_2SO_4)	0.5 - 2.5
P_f (cm^3 0.02N H_2SO_4)	0.2 - 1.6
Calcium (mg/l)	600 - 1,200
Chlorides (mg/l)	0 - 20,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	4.5 - 7
MBT (lb/bbl)	See Figure 1
Excess gyp (lb/bbl)	3 - 12

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL (prehydrated)	Viscosity and fluid-loss control
Caustic soda	Increase pH and P_f
Gyp	Calcium source
SPERSENE	Thinner
TANNATHIN	Fluid-loss control
POLYPAC	API fluid-loss control
RESINEX	HTHP fluid-loss control
SURFAK-M™	Surface-acting agent

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 550
M-I GEL	7.5 - 25
Caustic soda	0.2 - 1.5
Gyp	8 - 12
SPERSENE	5 - 15
TANNATHIN	2.5 - 10
POLYPAC	0 - 2
RESINEX	3 - 6
SURFAK-M	0 - 2

monitor the concentration of excess gyp in the system. Mass-balance equations cannot accurately monitor excess gyp, because gyp is removed from the system on drilled solids due to base exchange.

Excess gyp procedure

The excess gyp content can be determined by measuring the "whole mud Versenate total hardness" (V_t) and the total hardness of the filtrate (V_f) using this procedure and the calculation which follows:

Procedure to determine the gyp content (see API RP13B-1, Appendix A.8):

1. Add 5 ml whole mud to 245 ml distilled water.
2. Stir for 30 min at room temperature or 15 min at 150°F.
3. Filter the solution with the API filter press. Discard the first cloudy portion of the filtrate. Collect the clear filtrate.
4. Pipette 10 ml of the collected clear filtrate into a titration dish and add 1 ml strong buffer and 4 to 6 drops Calmagite Indicator.
5. Titrate with Standard Versenate to a blue or blue-green end point, record the number of ml of Standard Versenate as V_t.
6. To 1 ml of mud filtrate from the standard API filtrate test, add 1 ml strong buffer and 4 to 6 drops Calmagite Indicator, titrate with Standard Versenate from wine-red to blue, record the number of ml of Standard Versenate as V_f.

Total calcium sulfate (lb/bbl) = $2.38 \times V_t$

Excess calcium sulfate (lb/bbl) = $2.38 \times V_t - (0.48 \times V_f \times F_w)$

Where:

F_w = Water fraction from retort

NOTE: A simplified field method titrates 1 ml of whole mud in 150 to 350 ml distilled water in a quart jar, using 2 to 3 ml strong buffer and 1 to 2 ml Calmagite Indicator. Record the ml of Standard Versenate as the V_m. The color change may be hard to see due to *the dark brown color of the lignosulfonate and lignite. This color change may appear to be from the original color of the solution with a red tint to only a slight green or blue-green tint. The rule-of-thumb calculation for this procedure is:*

Excess gyp (lb/bbl) = $(V_m+V_f) \div 2$

SPERSENE/LIME SYSTEM

Generally, SPERSENE/lime systems are used to reduce the effects of acid gases such as CO_2 or H_2S and/or to reduce the hydration of formation clays. SPERSENE/lime systems use lime ($Ca(OH)_2$) as their source of calcium. Since lime has a high pH (12.4), the pH of the system will be high. The pH of the system depends on the concentration of lime and caustic soda (NaOH). Lime muds maintain a concentration of excess lime which is not in solution, since the solubility of lime is an inverse function of pH. Therefore, this excess (reserve) lime goes into solution only as the pH of the system is reduced by reactions with acidic contaminants incorporated into the system during drilling operations. This results in the excess lime having a buffering effect on the pH, which provides greater stability to the system.

Generally, SPERSENE/lime systems are used to reduce the effects of acid gases...

Lime muds are subdivided into low-, medium- and high-lime categories according to the amount of excess lime that they contain. This level of excess lime is chosen based on the anticipated severity of contamination and on local practice. Typical alkalinities and excess lime concentrations for the low-, medium- and high-lime categories are shown below. These systems are more stable if the P_f is kept roughly equal to the excess lime content (lb/bbl). Lime muds generally are not used when mud densities are below 10 lb/gal because it is difficult to maintain rheological properties sufficient to clean the wellbore. Temperatures in excess of 300°F (149°C) may cause severe gelation or cementation of medium- and high-lime drilling fluids. This severe gelation, or cementation, is caused by high alkalinity, high concentrations of reactive solids and high temperature which combine to form alumino-silica cement.

Alkalinities		
Low-lime	P_f (cm^3 0.02N H_2SO_4)	0.5 - 1
	P_m (cm^3 0.02N H_2SO_4)	2.4 - 4.8
	Excess lime (lb/bbl)	0.5 - 1
Medium-lime	P_f (cm^3 0.02N H_2SO_4)	1 - 4
	P_m (cm^3 0.02N H_2SO_4)	4.8 - 19
	Excess lime (lb/bbl)	1 - 4
High-lime	P_f (cm^3 0.02N H_2SO_4)	4 - 10
	P_m (cm^3 0.02N H_2SO_4)	19 - 46
	Excess lime (lb/bbl)	4 - 9.4

When converting an existing untreated or lightly treated system to a SPERSENE/lime system, the MBT and low-gravity solids content should be reduced to minimize the “break-over viscosity hump.” Then a treatment of 1 to 10 lb/bbl lime, 2 to 12 lb/bbl SPERSENE and 2 lb/bbl caustic soda should be added simultaneously during one or two circulations. After the initial conversion, properties such as fluid loss, pH and alkalinity should be refined by the additions of the proper materials.

In addition to the maintenance procedures previously described, the “excess lime” should be calculated as often as required to monitor the concentration of excess lime in the system. Mass-balance equations cannot accurately monitor excess lime, because lime is removed from the system on drilled clays as the result of base exchange. The equation for calculating excess lime is:

Excess lime (lb/bbl) = $0.26 (P_m - P_fF_w)$

(SPERSENE/LIME SYSTEM CONTINUED)

Typical Properties	
Density (lb/gal)	10 - 16
Funnel viscosity (sec/qt)	± (3.5 mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	1 - 10
pH	11.5 - 13.5
Calcium (mg/l)	40 - 200
Chlorides (mg/l) (freshwater)	0 - 5,000
Chlorides (mg/l) (seawater)	20,000
Low-gravity solids (%)*	4.5 - 7
MBT (lb/bbl)	See Figure 1
Excess lime (lb/bbl)	1 - 10

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL (prehydrated)	Viscosity and fluid-loss control
Caustic soda	Increase P_f
Lime	Excess lime and increase P_m
SPERSENE	Fluid loss and thinner
TANNATHIN	Fluid-loss control
XP-20	HTHP thinner and fluid-loss control
POLYPAC	Viscosity and API fluid-loss control
MY-LO-JEL	Fluid-loss control
POLY-SAL	Fluid-loss control
RESINEX	HTHP fluid-loss control

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 550
M-I GEL	15 - 30
Caustic soda	0.5 - 1.5
Lime	0.5 - 10
SPERSENE	2 - 15
XP-20 or TANNATHIN	3 - 8
RESINEX	0 - 6

SPERSENE/XP-20 Seawater System

Seawater and brackish-water systems are used in offshore and coastal drilling operations due to the endless supply of that type of water at the drillsite. Other benefits derived from using sea or brackish water in drilling fluids include a lesser degree of hydration of drilled clays than when using freshwater.

An understanding of seawater drilling fluids requires an understanding of seawater, and how mud components react in it. The pH of seawater is buffered against changes by a solubility equilibrium with atmospheric CO_2 and sedimentary calcium carbonate. This means that as the pH of seawater is increased through the addition of alkaline materials, atmospheric CO_2 will be absorbed into the seawater in an effort to buffer the pH. Since the buildup of these carbonates is detrimental to drilling fluid properties, an excess concentration of lime (which is not in solution) is maintained in the system. The lime prevents the build-up of carbonates and buffers the pH in the desired range. So, a seawater mud should be run as a "low-lime system" (see lime muds).

...a seawater mud should be run as a "low-lime system".

The cost-effectiveness of XP-20 and TANNATHIN in seawater is minimized due to their reduced solubility; therefore, in environments where chlorides exceed 15,000 mg/l, the use of lignites should be minimized and the use of SPERSENE increased.

The temperature limitation of this system is approximately 320°F (160°C). If bottom-hole temperatures greater than 320°F (160°C) are anticipated, freshwater should be added to reduce the chlorides to less than 15,000 mg/l so that XP-20 will be more soluble. Or, displace with a synthetic- or oil-base system.

Since this system is similar to a SPERSENE/low-lime system, conversion and maintenance are the same as with a SPERSENE/low-lime system.

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3.5 x mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	1 - 10
pH	10.5 - 11.5
P_m (cm^3 0.02N H_2SO_4)	3.0 - 6.0
P_f (cm^3 0.02N H_2SO_4)	1.0 - 1.5
Calcium (mg/l)	40 - 200
Chlorides (mg/l)	20,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	5 - 7
MBT (lb/bbl)	See Figure 1

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL (prehydrated)	Viscosity and fluid-loss control
Caustic soda	pH and P_f
Lime	Treat out carbonates
SPERSENE	Thinner and fluid-loss control
XP-20	HTHP thinner and fluid-loss control
TANNATHIN	Fluid-loss control, thinner
POLYPAC	Stability, fluid-loss control
THERMPAC UL	Fluid-loss control
THERMEX	HTHP fluid-loss control
RESINEX	HTHP fluid-loss control
DUO-VIS	Low-shear viscosity

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 550
M-I GEL	10 - 30
Caustic soda	0.2 - 1.5
Lime	0.2 - 1.5
SPERSENE	5 - 15
XP-20 or TANNATHIN	3 - 8
POLYPAC	0.5 - 2.0
THERMEX	5 - 10
RESINEX	0 - 6

Saturated Saltwater System

Saturated saltwater systems are designed to prevent the enlargement of the wellbore while drilling salt sections.

Saturated saltwater systems are designed to prevent the enlargement of the wellbore while drilling salt sections. This enlargement results from the salt in the wellbore dissolving into the "unsaturated salt" water phase of the drilling fluid. Saturation is achieved by adding salt (sodium chloride) to the mud system until the saturation point is reached. Saturation is about 190,000 mg/l chlorides, depending on temperature. See the Drilling Salt chapter.

To convert an existing freshwater, brackish water or seawater system to a saturated saltwater system, the following procedure should be followed. On the initial break-over, add as quickly as possible: 2 to 3 lb/bbl caustic soda, 1 to 2 lb/bbl soda ash, 4 to 6 lb/bbl SPERSENE and 110 to 125 lb/bbl salt. The salt will flocculate the reactive solids in the system, increasing the viscosity. Therefore, the MBT and low-gravity solids content should be reduced to minimize the viscosity increase during conversion. This viscosity hump is shown in Figure 9. Pilot tests should be made prior to conversion to determine the dilution rate and quantities of products required for a trouble-free conversion. After all the salt has been added, 2 lb/bbl SURFAK-M also should be added. Initially, the salt may cause an increase in viscosity, but this will diminish after several circulations through the hole. This should be followed by 0.5 to 1.0 lb/bbl of POLYPAC UL, which should reduce the viscosity to the desired range. If not, further dilution with saturated saltwater and additions of SPERSENE should be made. Treatments of SPERSENE are more effective when mixed with caustic in drill water then added to the system.

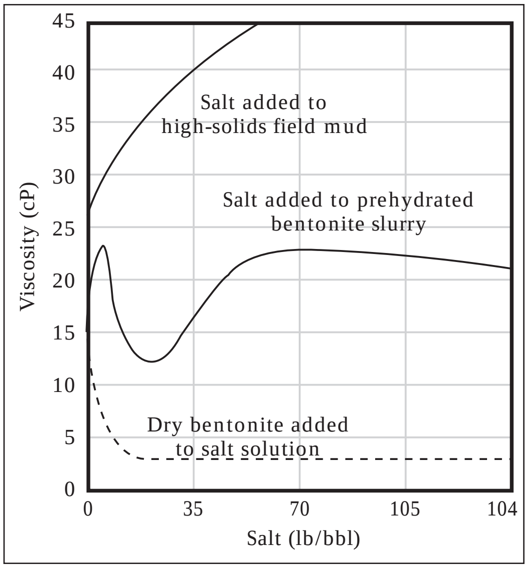

Figure 9: Effect of solids content on viscosity with salt additions.

To mix a saturated saltwater system, 20 to 25 lb/bbl M-I GEL should be prehydrated in freshwater and added to the saltwater. Then, other materials can be added as described above. SALT GEL® can be used instead of M-I GEL if the rig mixing system develops good shear. SALT GEL requires shear to develop viscosity and does not assist with fluid loss or filter-cake quality.

When saturated saltwater is added to the drilling fluid to maintain an acceptable drilled solids concentration, products must be added to maintain the desired concentration of additives. Therefore, the volume of dilution water should be measured or estimated to use as a basis for product additions. Materials must be based on the added saltwater. The amount of dilution depends on the hole size, ROP, type of formation, solids-control equipment and the optimum concentration of drilled solids in the drilling fluid. Frequent chloride checks should be made to monitor the salt content for saturation.

Frequent chloride checks should be made to monitor the salt content for saturation.

(SATURATED SALTWATER SYSTEM CONTINUED)

Provisions should be made to ensure that all dilution water is saturated prior to being added to the active system. In areas where humidity is high, salt absorbs water, becomes lumpy and is almost impossible to mix through mud hoppers fast enough to keep the drilling fluid saturated. If salt is mixed directly into the mud, about half the salt may become coated by the mud and settle to the bottom of the pits. It is far more cost-effective to mix the salt into the water.

When considering the use of a saturated salt drilling fluid in low-density environments, it is important to be aware that the natural weight of saturated sodium chloride is 10 lb/gal. The minimum density of a saturated sodium chloride drilling fluid is about 10.5 lb/gal.

The temperature limitation of this system is less than 300°F (149°C). If bottom-hole temperatures greater than 300°F (149°C) are anticipated, alternative high-temperature water-base products must be used or the system should be displaced with a synthetic- or oil-base drilling fluid.

Typical Properties	
Density (lb/gal)	10 - 16
Funnel viscosity (sec/qt)	± (3.5 x mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	1 - 10
pH	10.5 - 12
P_m (cm^3 0.02N H_2SO_4)	3 - 5
P_f (cm^3 0.02N H_2SO_4)	1 - 2
Calcium (mg/l)	<200
Chlorides (mg/l)	190,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	4 - 6, adjust for salt
MBT (lb/bbl)	See Figure 1

*See Figure 2.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL (prehydrated)	Viscosity and fluid-loss control
Caustic soda	pH and P_f
Salt	Increase chloride
Soda ash	Control calcium <200 mg/l
SPERSENE	Thinner and fluid-loss control
MY-LO-JEL	Fluid-loss control
POLY-SAL	Fluid-loss control
POLYPAC UL	Stability and fluid-loss control
SP-101	HTHP fluid-loss control
DUO-VIS	Low-shear-rate viscosity
SURFAK-M	Surface-acting agent

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 550
M-I GEL	10 - 30
Caustic soda	0.2 - 2.5
Soda ash	0.2 - 1
Salt	110 - 125
SPERSENE	5 - 15
POLYPAC UL	0.5 - 2
SURFAK-M	0 - 2
DUO-VIS	0.25 - 1

Inhibitive Potassium Systems

Potassium is one of the most effective ions available to minimize shale hydration.

Potassium is one of the most effective ions available to minimize (inhibit) shale hydration. The inhibitive nature of potassium is achieved by the ionic base exchange of potassium for sodium and/or calcium ions between clay layers, and by fixation of the potassium ion in the crystalline lattice of swelling clay minerals.

Many swelling clays are selective to potassium and will adsorb potassium ions in preference to sodium ions. In other clays, the "mass action" effect applies, which means that ion exchange from sodium to potassium occurs most readily when the potassium-to-sodium ratio in the drilling fluid exceeds 3:1. The low hydration energy of the potassium ions contributes to the inhibition of clay hydration in potassium-based, exchanged clays.

Fixation of the potassium ions occurs in clay platelets with a higher-than-average negative charge. This ion fixation occurs because the 2.66 Å diameter of the potassium ion fits snugly into the 2.80 Å lattice space of the clay structure. This provides an ideal condition for crystalline compaction. The low hydration energy of the potassium ion also contributes to inter-layer dehydration, resulting in the formation of a compact, tightly held structure. This structure resists hydration and cation exchange. When ion fixation occurs, the clay platelet contains less water in the inter-layer space, and is very stable. See Clay Chemistry chapter.

The potassium chloride polymer system was developed to stabilize water-sensitive shales...

POTASSIUM CHLORIDE POLYMER SYSTEM

The potassium chloride polymer system was developed to stabilize water-sensitive shales by means of potassium ion inhibition. The inhibitive nature of this system minimizes the hydration of shales, which minimizes hole enlargement, bit and stabilizer balling, sloughing shale, and reduction of permeability in productive zones. The potassium chloride system uses potassium chloride salt (KCl) as the primary source of potassium ions for ionic inhibition. This system works best when polymers are used for encapsulation. Either Polyanionic Cellulose (PAC) (POLYPAC) or Partially Hydrolized Poly Acrylamide (PHPA) (POLY-PLUS) polymers can be used for encapsulation. These polymers coat cuttings and exposed shales, limiting interaction with water.

Since some shales are more water-sensitive than others, the concentration of KCl required to inhibit these shales varies. During drilling operations, shale cuttings should be monitored continuously for inhibition. If the concentration of KCl in the system is insufficient, shale cuttings will be soft and mushy. If the concentration of KCl is sufficient, they will retain their integrity. Older shales usually require about 10 to 15 lb/bbl KCl (3.5 to 5.0%) while younger shales may require 30 to 50 lb/bbl (8.5 to 15%).

KCl and other chemicals should be premixed prior to adding them to the system for optimum cost effectiveness.

(POTASSIUM CHLORIDE POLYMER SYSTEM CONTINUED)

When using hard makeup water, the hardness should be treated to less than 300 mg/l with soda ash prior to adding polymers that are hardness-sensitive. Since potassium chloride systems are very solids-sensitive, it is best to mix the system from scratch instead of converting an existing drilling fluid (containing drill solids) to a potassium chloride system. The first step in mixing a potassium chloride system is to treat the hardness with soda ash, then prehydrate the M-I GEL in freshwater. Then, add the KCl, KOH, POLY-PLUS, POLYPAC, DUO-VIS and M-I BAR.

This system is very sensitive to solids and calcium contamination and generally is more expensive than other water-base systems.

Rheological properties and filtration rates in this system are controlled by polymeric materials, which are not temperature-stable above 300°F. The temperature limitation of the system is about 300°F. This system is very sensitive to solids and calcium contamination and generally is more expensive than other water-base systems.

In addition to potassium chloride, a variety of other non-chloride potassium sources are available. These include potassium carbonate, potassium sulfate, K-52™ (potassium acetate), caustic potash (KOH) and more. All of these non-chloride potassium chemicals have been used to formulate inhibitive potassium mud systems.

Typical Properties	Old Formations	Young Formations
Density (lb/gal)	10 - 16	10 - 16
Plastic viscosity (cP)	See Figure 1	See Figure 1
Yield point (lb/100 ft^2)	20 - 30	20 - 30
Initial gel (lb/100 ft^2)	5 -10	10 - 15
10-min gel (lb/100 ft^2)	15 - 20	15 - 20
Fluid loss (cm^3/30 min)	10 -15	5 - 10
Potassium (mg/l)	15,000 - 25,000	55,000 - 100,000
Calcium (mg/l)	<200	<200
pH	9.5 - 10	10 - 11
Low-gravity solids (%)*	2 - 4	3 - 5
MBT (lb/bbl)	<25	<20

*See Figure 2.

Typical Products (lb/bbl)	Old Formations	Young Formations	Primary Function
Potassium chloride	10 - 15	35 - 70	Potassium source
POLY-PLUS	0.5 - 1	0.5 - 2	Encapsulation
M-I GEL	8 - 10 (prehydrated)	2 - 5	Viscosity and filter cake
DUO-VIS	0.5 - 1	0.5 - 1.5	Low-shear viscosity
POLYPAC	0.5 - 2	0.5 - 3	Fluid-loss control and encapsulation
Caustic potash (KOH)	0.5 - 1	0.75 - 1.5	pH and potassium
Soda ash	0.5	0.5	Control calcium
M-I BAR	As required	As required	Density

The K-MAG system is designed to provide inhibition, wellbore stability and improved production...

K-MAG SYSTEM

The K-MAG™ system is designed to provide inhibition, wellbore stability and improved production by means of potassium inhibition in areas where potassium chloride systems are not environmentally acceptable. The sources of potassium are K-17® (potassium lignite), XP-20 (KOH chrome lignite), K-52 (potassium acetate) and caustic potash (KOH). The system limits the amount of added sodium. The system is designed to perform in a freshwater or seawater alkaline environment. Since the primary deflocculant in this system is lignite, the system is not as cost-effective in environments where the chlorides are above 15,000 mg/l since the solubility of lignite decreases as the chlorides increase. Benefits of the system are non-dispersed cuttings, improved solids removal and better wellbore stability. A reduction in sloughing shale, bridges and fill on trips, and expensive cement jobs due to hole enlargement are added benefits.

The K-MAG system can be mixed from scratch or converted from an existing system. To convert an existing system to a K-MAG system, add approximately 3 to 5 lb/bbl prehydrated M-I GEL, 4 lb/bbl of either K-17 or XP-20, and 1 to 2 lb/bbl caustic potash in one circulation. Adjust the potassium ion concentration with additions of K-52 or additional K-17. Add 4 to 6 lb/bbl SHALE CHEK™ on a later circulation for additional shale stabilization and to minimize bit and stabilizer balling.

Low-gravity solids should be maintained at less than 5% and the MBT at less than 25 lb/bbl. Dilution rates should be monitored to assure that proper material concentrations are maintained. The potassium ion concentration should be monitored separately because the potassium reacts with, and is depleted by, drill solids. The potassium ion concentration usually is controlled between 1,000 to 10,000 mg/l.

Typical Properties	
Density (lb/gal)	10.0
Funnel viscosity (sec/qt)	± (3.5 x mud weight)
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	1 - 10
pH	9.5 - 10.5
P_m (cm^3 0.02N H_2SO_4)	0.5 - 1
P_f (cm^3 0.02N H_2SO_4)	1.0 - 1.8
Calcium (mg/l)	0 - 300
Potassium (mg/l)	1,000 - 10,000
Chlorides (mg/l)	0 - 20,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	4 - 5
MBT (lb/bbl)	<25

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR or FER-OX	Increase density
M-I GEL (prehydrated)	Viscosity and fluid-loss control
K-17 or XP-20	Thinner and potassium source
KOH	pH, P_f and potassium source
K-52	Potassium source
POLYPAC	Fluid-loss and encapsulation
RESINEX	HTHP fluid-loss control
DUO-VIS	Low-shear-rate viscosity
SHALE CHEK	Shale stabilization

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 550
M-I GEL	5 - 15
KOH	0.5 - 2.0
K-17 or XP-20	8 - 10
SHALE CHEK	4 - 6
K-52	0 - 3
POLYPAC	0.5 - 1.5
DUO-VIS	0.5 - 1.5
RESINEX	0 - 6

DURATHERM System

The DURATHERM system is a water-base system designed for drilling in HTHP environments.

The DURATHERM™ system is a water-base system designed for drilling in HTHP environments. The system is stable in the presence of contamination from soluble calcium, salts and acid gases, and can be used at temperatures in excess of 500°F (260°C). The stability of the system is due to its low colloidal-solids content and chemicals that are stable at high temperatures. This system also is used as a high-temperature packer fluid.

The low reactive-solids content of the DURATHERM system is achieved by reducing bentonite and the drill-solids content as fluid density and wellbore temperatures increase. Polymeric materials are used in place of bentonite to provide viscosity and gel strengths. This minimizes problems caused by flocculation of reactive clay solids at high temperatures and viscosity increases resulting from chemical contamination.

Most deflocculated water-base systems can be converted to the DURATHERM system by substituting XP-20 for SPERSENE; reducing the reactive-solids content and using POLYPAC or DUO-VIS for viscosity and solids suspension; and using THERMEX or RESINEX for HTHP filtration control. Proper solids control is an absolute necessity for this system.

Proper solids control is an absolute necessity for this system.

This drilling fluid should be monitored carefully for temperature stability. One good way to accomplish this is to heat-age the fluid frequently at 25°F (15°C) above the estimated bottom-hole temperature. The reactive-solids content of the fluid should be monitored closely and controlled within recommended ranges. If a closed-loop, solids-control unit is used, the solids particle size and plastic viscosity should be monitored closely and controlled within the proper range. Monitor dilution rates to assure that proper chemical concentrations are maintained (see HTHP chapter).

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3 x mud weight)
Plastic viscosity (cP)	~Barite/water line (see Figure 1)
Yield point (lb/100 ft^2)	6 - 10
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	2 - 10
pH	10.5 - 11.5
P_m (cm^3 0.02N H_2SO_4)	2.0 - 5.0
P_f (cm^3 0.02N H_2SO_4)	0.5 - 1.5
Chlorides (mg/l)	0 - 10,000
Calcium (mg/l)	0 - 200
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	0.5 - 2.5
MBT (lb/bbl)	2.5 - 12.5

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL	Filter cake and fluid-loss control
Caustic soda	Increase pH and P_f
XP-20	Thinner and fluid-loss control
Lime	Treat out CO_3 and pH
Gyp	Treat out CO_3
POLYPAC	Viscosity/gel strengths
THERMEX	HT fluid loss and stabilizer
RESINEX	HT fluid-loss control

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 600
M-I GEL	1 - 10
Caustic soda	0.5 - 1.5
Lime or gyp	0 - 2
XP-20	15 - 20
POLYPAC	0.5 - 1.5
THERMEX	0 - 12
RESINEX	0 - 6

ENVIROTHERM System

The ENVIROTHERM system is a chrome-free... system designed to drill in HTHP environments...

Proper solids control is a necessity for this system.

The ENVIROTHERM™ system is a chrome-free, environmentally acceptable water-base system designed to drill in HTHP environments, making it similar to the DURATHERM system. The system is stable in the presence of contamination from soluble calcium, salts and acid gases, and can be used at temperatures in excess of 400°F (204°C). The stability of the system is due to its low reactive-solids content and temperature-stable, chrome-free materials. The low reactive-solids content is achieved by reducing bentonite and drill solids as fluid density and wellbore temperatures increase. Polymeric materials like POLYPAC and CMC are used to replace the bentonite to provide viscosity and gel strengths. This minimizes problems caused by flocculation of reactive clay solids at high temperatures and viscosity increases resulting from chemical contamination. SPERSENE CF® (chrome-free lignosulfonate) promotes overall fluid stability by preventing high-temperature gelation and flocculation while providing supplemental API and HTHP fluid-loss control. TANNATHIN (lignite) is the primary fluid-loss-control additive and serves as a secondary deflocculant in this system. Thermal stability is achieved through the addition of THERMEX (a polymeric resin). The resin appears to function synergistically with SPERSENE CF to provide stable viscosity and fluid-loss control.

Most chrome-free, water-base systems can be converted to the ENVIROTHERM system by reducing the reactive-solids content to an MBT <10 lb/bbl and then adding 4 to 12 lb/bbl SPERSENE CF, 4 to 6 lb/bbl TANNATHIN, 4 to 12 lb/bbl THERMEX, 0.5 to 2 lb/bbl POLYPAC and about 2 lb/bbl caustic soda. THERMEX and SPERSENE CF work synergistically to provide stable properties. Proper solids control is a necessity for this system.

(ENVIROTHERM SYSTEM CONTINUED)

This drilling fluid should be monitored carefully for temperature stability. One good way to accomplish this is to heat-age the fluid at 25°F (15°C) above estimated bottom-hole temperature. The drill-solids content of the fluid should be monitored and maintained within recommended ranges. If a closed-loop, solids-control unit is used, the solids particle size and plastic viscosity should be monitored and maintained within the proper range. Monitor dilution rates to ensure that proper chemical concentrations are maintained (see the HTHP chapter).

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3 x mud weight)
Plastic viscosity (cP)	~ Barite/water line (see Figure 1)
Yield point (lb/100 ft^2)	6 - 10
Initial gel (lb/100 ft^2)	1 - 5
10-min gel (lb/100 ft^2)	2 - 10
pH	9.0 - 11.0
P_m (cm^3 0.02N H_2SO_4)	2.0 - 5.0
P_f (cm^3 0.02N H_2SO_4)	0.5 - 1.5
Chlorides (mg/l)	200 - 20,000
Calcium (mg/l)	40 - 600
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	0.5 - 2.5
MBT (lb/bbl)	2.5 - 12.5

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR	Increase density
Caustic soda	Increase pH and P_f
Lime	Treat out CO_3 and pH
SPERSENE CF	Thinner and fluid-loss control
TANNATHIN	Fluid-loss control
THERMEX	HT stabilizer and fluid-loss control
POLYPAC	Viscosity/gel strengths
M-I GEL	Filter cake and fluid-loss control

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 600
M-I GEL	1 - 10
Caustic soda	0.5 - 1.5
Lime or gyp	0 - 2
POLYPAC	0.5 - 2.0
THERMEX	4 - 12
SPERSENE CF	4 - 12
TANNATHIN	4 - 6

POLYSTAR 450 System

This chrome-free...system consists, is formulated with DURASTAR and RHEOSTAR.

The POLYSTAR™ 450 system is M-I's polymer system for HTHP applications. Its thermal stability is provided by new synthetic polymers developed specifically for deflocculating clays and controlling fluid loss at high temperatures. This chrome-free, environmentally acceptable system is formulated with DURASTAR™ and RHEOSTAR™.

RHEOSTAR is a stand-alone rheological stabilizer designed to deflocculate clays at temperatures of up to 450°F (232°C). It contains no chrome, lignosulfonates, lignites or gilsonites. RHEOSTAR also reduces high-shear-rate viscosity, which results in a low plastic viscosity, and higher solids tolerance. RHEOSTAR does not require the use of other products to be effective. It performs well in makeup water that contains high concentrations of hardness and/or high salinity.

DURASTAR…is a stand-alone, fluid-loss-control stabilizer that does not require the use of other products to be effective.

(POLYSTAR 450 SYSTEM CONTINUED)

DURASTAR provides filtration control in water-base drilling fluids at temperatures up to 450°F (232°C). It is a stand-alone, fluid-loss-control stabilizer that does not require the use of other products to be effective. DURASTAR provides some viscosity and resists shear degradation. It does not require a high concentration of bentonite to achieve a low fluid loss. DURASTAR is a liquid product in a low-toxicity, environmentally acceptable carrier.

RHEOSTAR and DURASTAR, with a small quantity of GEL SUPREME™ (non-treated bentonite), are the effective components of the POLYSTAR 450 system.

The POLYSTAR 450 system should be mixed from scratch, since it is not compatible with the chemicals in other systems. The first step in mixing this system is to prehydrate 4 to 10 lb/bbl GEL SUPREME (depending on the mud density). Then, add about 10 lb/bb RHEOSTAR, 1.5 lb/bbl caustic soda, 6 lb/bbl DURASTAR and the weight material required to increase the density.

The POLYSTAR 450 system should be monitored carefully for temperature stability. One good way to accomplish this is to heat-age the fluid frequently at 25°F (15°C) above estimated bottom-hole temperature. The clay/solids content of the fluid should be monitored and controlled at recommended concentrations. If a closed-loop, solids-control unit is used, the solids particle size and plastic viscosity should be monitored and maintained to within the proper range. Monitor dilution rates to assure that proper chemical concentrations are maintained.

Typical Properties	
Density (lb/gal)	10 - 18
Funnel viscosity (sec/qt)	± (3 x mud weight)
Plastic viscosity (cP)	~ Barite/water line (see Figure 1)
Yield point (lb/100 ft^2)	5 - 20
Initial gel (lb/100 ft^2)	3 - 10
10-min gel (lb/100 ft^2)	5 - 20
pH	8.5 - 12.0
P_m (cm^3 0.02N H_2SO_4)	0.5 - 2.0
P_f (cm^3 0.02N H_2SO_4)	0.2 - 1.0
Chlorides (mg/l)	0 - 40,000
Calcium (mg/l)	0 - 600
API fluid loss (cm^3/30 min)	2 - 6
HTHP fluid loss	<15 in freshwater <20 in seawater
Low-gravity solids (%)*	<4
MBT (lb/bbl)	2.5 - 12.5

*See Figures 2 and 3.

Typical Products	Primary Function
M-I BAR or FER-OX	Increase density
Caustic soda or KOH	Increase pH and P_f
Lime or gyp	Treat out CO_3^{2-}
RHEOSTAR	HTHP deflocculant
DURASTAR	HTHP fluid-loss control
GEL SUPREME	Filter cake and fluid-loss control

Material	Concentration (lb/bbl)
M-I BAR or FER-OX	0 - 600
GEL SUPREME	3 - 10
NaOH or KOH	0.5 - 1.5
Lime or gyp	0 - 2
RHEOSTAR	2 - 8
DURASTAR	1 - 4

POLY-PLUS System

POLY-PLUS systems are designed to provide shale stabilization and viscosity control in water-base muds.

POLY-PLUS systems are designed to provide shale stabilization (inhibition) and viscosity control in water-base muds. These systems use POLY-PLUS (a high-molecular-weight PHPA polymer), which has multiple applications and benefits. POLY-PLUS is used in a variety of systems and special applications for encapsulation.

POLY-PLUS is used in the following applications:

1. In clear-water drilling, POLY-PLUS acts as a total flocculant in bentonite-free systems by removing the drill solids at the surface. Benefits from this application include improved ROP, improved efficiency of solids-control equipment and improved wellbore stability.
2. In low-solids, non-dispersed systems where POLY-PLUS is used primarily to extend M-I GEL. Benefits of this application are lower solids content, increased ROP, improved efficiency of solids-removal equipment and minimized hole enlargement. Concentrations of 0.1 to 0.5 lb/bbl POLY-PLUS are added to these systems, which contain 8 to 12 lb/bbl bentonite, to increase the yield point and minimize the plastic viscosity. Conventional systems that do not contain POLY-PLUS usually contain 25 to 35 lb/bbl bentonite.
3. The true low-solids POLY-PLUS systems are used primarily for shale stabilization. This is achieved by encapsulation, through viscosifying the water phase, and by the free water being absorbed by the polymer. Encapsulation is the process by which POLY-PLUS wraps around the clay platelets, preventing water from entering the interlayer structure of the clays. POLY-PLUS also increases the viscosity of the liquid phase, which slows the movement of the fluid into the interlayer structure of the clays. POLY-PLUS also adsorbs water from the liquid phase, reducing the amount of water available to enter the structure of the clays. In this system, the concentration of active polymer (POLY-PLUS) is maintained at 1 to 2 lb/bbl. At this concentration, the anionic sites on the polymers exceed the available cationic sites on the bentonite and drilled clays, resulting in the encapsulation of reactive clays in the mud and on the wall of the wellbore. This condition is often referred to as “controlling the viscosity over the hump.” The stability of this system depends on keeping the polymer concentration within the proper range and controlling the clay-solids content of the system at less than 6%. If the polymer concentration gets too low or the solids concentration gets too high, anionic deflocculants (thinners) will be required to stabilize flow properties. If deflocculants are used, shale stabilization and encapsulation are both reduced as the strong anionic sites of the deflocculants compete with those of the POLY-PLUS for the cationic sites on the clays. Therefore, if deflocculants are required, TACKLE® should be used, since it does not reduce the yield point as much as lignosulfonate or lignite. The maximum density of a true POLY-PLUS system is 12 to 13 lb/gal due to solids intolerance, unless deflocculants are used to stabilize the flow properties.
4. For shale stabilization. POLY-PLUS may be added to any low-pH, freshwater or KCl-treated system to reduce sloughing and heaving shale. POLY-PLUS also will reduce torque and drag, and prevent bit- and BHA-balling.

(POLY-PLUS SYSTEM CONTINUED)

Typical Properties	
Density (lb/gal)	9 - 13
Funnel viscosity (sec/qt)	32 - 45
Plastic viscosity (cP)	6 - 10
Yield point (lb/100 ft^2)	10 - 20
Initial gel (lb/100 ft^2)	3 - 6
10-min gel (lb/100 ft^2)	5 - 10
pH	8.5 - 10
P_m (cm^3 0.02N H_2SO_4)	0.2 - 1
P_f (cm^3 0.02N H_2SO_4)	0.1 - 0.5
Calcium (mg/l)	<300
Chlorides (mg/l)	0 - 190,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	3 - 10
MBT (lb/bbl)	7.5 - 17.5

*See Figures 2 and 3.

5. POLY-PLUS sometimes is added to a part of the active system to increase the viscosity and then sweep the hole. This procedure is used in areas of fast ROP, such as when drilling gumbo and soft shale, and in the riser assembly on offshore floaters. POLY-PLUS may be added in concentrated amounts directly to the suction pit or can be added to the drill pipe on connections.

Most existing drilling fluid systems can be converted to POLY-PLUS systems, but it is far more desirable to mix a clean POLY-PLUS system from scratch. To mix an unweighted POLY-PLUS system, the following formulation can be used as a guide:

Chemical	Amount (lb/bbl)
Prehydrated M-I GEL	2.5 - 5
Caustic soda or KOH	0.25
POLY-PLUS	1 - 2.5
POLYPAC	0.5 - 2

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL	Viscosity and fluid-loss control
POLY-PLUS	Inhibition and gel extender
Caustic soda and KOH	pH and P_f
POLYPAC	Fluid-loss control
SP-101	Fluid-loss control
POLY-SAL	Fluid-loss control
Soda ash	Control hardness
DUO-VIS	Control low-shear-rate viscosities
TACKLE	Reduce gel strengths
KCl and NaCl	Ionic inhibition

Material	Concentration (lb/bbl)
M-I BAR	300
M-I GEL	2.5 - 10
Caustic soda	0.5 - 1
POLY-PLUS	0.5 - 1.5
POLYPAC	0.5 - 2
SP-101	0.5 - 2.5
TACKLE	0.1 - 1
DUO-VIS	0.5 - 1

To mix a weighted POLY-PLUS system, the following formulation can be used as a guide:

Chemical	Amount (lb/bbl)
Prehydrated M-I GEL	1 - 5
Caustic soda or KOH	0.25
POLY-PLUS	1 - 2.5
DUO-VIS	0.2 - 1
POLYPAC	0.5 - 2
TANNATHIN or RESINEX	2 - 5

(POLY-PLUS SYSTEM CONTINUED)

When displacing an existing system with a POLY-PLUS system, the shaker screen size should be increased to prevent loss of mud. The mud will be flocculated and the polymer unsheared for the first circulation or two after displacement. Fine shaker screens should be replaced as soon as possible. A thick, M-I GEL/POLY-PLUS spacer should be pumped ahead of the POLY-PLUS system to achieve a clean displacement. Pumping at a high rate (in turbulent flow) will also help remove old wall cake and aid in a clean displacement. If a POLY-PLUS system is used to displace a current system at a casing point, drill the cement and get a positive shoe test on the formation before displacing with the POLY-PLUS system. Cement and high pH are very detrimental to the polymer. If cement must be drilled with the POLY-PLUS system, pretreatment and disposal of contaminated mud must be done to prevent depleting the polymer content.

The primary concerns of maintaining a POLY-PLUS system are to monitor and maintain the proper polymer concentration and control the solids to within the proper ranges. The POLY-PLUS concentration should be monitored through the use of the Ammonia Extraction Test (the procedure for this test is in the Testing chapter of this manual). The MBT value should be limited to 17.5 lb/bbl.

MCAT Polymer System

The MCAT polymer system is designed to provide shale inhibition through the use of two cationic polymers.

...cationic polymers provide better shale stabilization than anionic polymers.

The MCAT® polymer system is designed to provide shale inhibition through the use of two cationic polymers. MCAT-A, a low-molecular-weight cationic polymer, is used to suppress shale hydration, while MCAT, a high-molecular-weight polymer, is used for encapsulation.

Hydration of swelling clays can be suppressed by using MCAT-A, which penetrates the lattice space of the clay structure. This results in the displacement of exchangeable cations and water molecules which reduces swelling. While this polymer adsorption is similar to the exchange reaction of common cations, the adsorbed cationic polymers cannot exchange with other common cations because of their multisegment attachment on clay surfaces. This multisegment attachment provides a stronger bonding between the layers, similar to the potassium fixation, in that it is irreversible.

MCAT has a large molecular size that does not allow it to penetrate the clay layers as effectively as low-molecular polymers. As a result, adsorption occurs primarily on the exterior surfaces and forms a protective coating (encapsulation). Although anionic polymers also can encapsulate shales, cationic polymers are more effective because of the abundance of negatively charged surface areas on the clay minerals. Therefore, cationic polymers provide better shale stabilization than anionic polymers.

Cationic polymers are not compatible with anionic polymers in freshwater. So, if freshwater is used, non-ionic materials like starch must be used for filtration control. However, with the addition of salt (sodium chloride or potassium chloride), certain anionic polymers are compatible with the cationic polymers.

(MCAT SYSTEM CONTINUED)

This system is sensitive to solids and is more expensive than traditional water-base systems. The temperature limitation is about 275°F.

When displacing an existing system with an MCAT polymer system, the shaker screen size should be increased to prevent loss of mud. The mud will be flocculated and the polymer unsheared for the first circulation or two after displacement. Fine shaker screens should be replaced as soon as possible. A thick, M-I GEL/MCAT spacer should be pumped ahead of the MCAT polymer system to achieve a clean displacement. Pumping at a high rate (in turbulent flow) also will help remove old wall cake and aid in achieving a clean displacement.

Typical Properties	
Density (lb/gal)	8.8 - 16
Funnel viscosity (sec/qt)	36 - 85
Plastic viscosity (cP)	5 - 55
Yield point (lb/100 ft^2)	5 - 40
Initial gel (lb/100 ft^2)	2 - 15
10-min gel (lb/100 ft^2)	5 - 35
pH	8.0 - 9.5
P_m (cm^3 0.02N H_2SO_4)	0.2 - 1.0
P_f (cm^3 0.02N H_2SO_4)	0.1 - 0.5
Fluid loss (cm^3/30 min)	As needed
Chlorides (mg/l)	>30,000
Low-gravity solids (%)*	<5

*See Figure 2.

Typical Products	Primary Function
M-I BAR	Increase density
DUO-VIS	Low-shear-rate viscosity
NaOH and KOH	Increase pH and P_f
POLYPAC	Fluid-loss control
POLY-SAL	Fluid-loss control
MCAT	Encapsulation
MCAT-A	Swelling suppression
LUBE-167™	Lubricity and bit balling

Material	Concentration (lb/bbl)
NaOH and KOH	0.5 - 2
NaCl and KCl	>30,000 mg/l
MCAT	1 - 3
MCAT-A	3 - 6
POLY-SAL	3 - 6
POLYPAC	0.5 - 2
LUBE-167	1 - 2%

Mixed Metal Hydroxide System

The MMH system… provides excellent hole-cleaning and solids-suspension characteristics.

The Mixed Metal Hydroxide (MMH) system is a low-solids, flocculated, cationic drilling fluid system which provides excellent hole-cleaning and solids-suspension characteristics. The key product in this system is the cationic MMH (inorganic polymagnesium aluminum hydroxyl). Two MMH-type products are Polyvis II™ from SKW and Drill-Out™ from Drilling Specialties Co. The viscosity and suspending capability of an untreated gel slurry is increased significantly by using MMH. The basic MMH/gel slurry has a low plastic viscosity, a high yield point, high fragile gel strengths and a high fluid loss.

Viscosity and gel strengths in this system are achieved by flocculating fully hydrated bentonite with MMH. This mechanism relies on the cationic charges of the MMH to react with the anionic charges on the bentonite to form a flocculated slurry. For this reason, anionic materials cannot be used in this system without sacrificing its unique rheological characteristics. Only after pilot-testing should any materials be used, including all starch additives. Even small amounts of an anionic material will drastically reduce the yield point, low-shear-rate viscosity and gel strengths. This leaves specialized starches as the only filtration-control materials that are compatible with the system. Starch is subject to fermentation; therefore, a pH of 11.0 to 11.5 and treatments with a non-ionic biocide are recommended to prevent fermentation.

The pH of MMH systems should be maintained at 10.5 to 11.5. Rheology is reduced a pH levels <10.

This system is very solids-sensitive, so low-gravity solids must be controlled at 5% or less by mechanical removal and/or dilution. The maximum mud weight for this system is about 13 lb/gal.

Typical Properties	
Density (lb/gal)	8.8 - 13
Funnel viscosity (sec/qt)	36 - 55
Plastic viscosity (cP)	Minimum value Figure 1
Yield point (lb/100 ft^2)	15 - 60
Initial gel (lb/100 ft^2)	10 - 60
10-min gel (lb/100 ft^2)	10 - 60
pH	10.5 - 11.5
P_m (cm^3 0.02N H_2SO_4)	0.7 - 1.8
P_f (cm^3 0.02N H_2SO_4)	0.6 - 1.5
Calcium (mg/l)	<80
Chlorides, freshwater (mg/l)	100 - 15,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	<5
MBT (lb/bbl)	10 - 20

*See Figure 2.

Typical Products	Primary Function
M-I BAR	Increase density
GEL SUPREME	Viscosity
Caustic soda	Increase pH and P_f
MMH	Viscosity
Starch (non-ionic)	Fluid-loss control

Material	Concentration (lb/bbl)
M-I BAR	0 - 350
GEL SUPREME	8 - 12
MMH	0.8 - 1.2
Starch (non-ionic)	3 - 8

GLYDRIL System

The GLYDRIL system…uses polyglycol technology to provide a high degree of shale inhibition, wellbore stability, HTHP fluid-loss control and lubricity.

The GLYDRIL™ system is an enhanced-polymer, water-base system that uses polyglycol technology to provide a high degree of shale inhibition, wellbore stability, HTHP fluid-loss control and lubricity. This system also is ideal for drilling depleted sands where differential pressure-sticking is a major concern, in deepwater operations, and drilling high-angle wells in reactive formations where wellbore stability and torque and drag are major concerns. Other benefits include enhanced cuttings integrity, improved filter-cake quality, lower dilution rates, less hole enlargement, greater solids tolerance, better performance of PDC bits, reduced bit-balling and increased ROP. The GLYDRIL system also is environmentally acceptable due to its low toxicity and reduced disposal rates.

Although the GLYDRIL enhanced polymer system achieves some inhibition by chemical adsorption, the cloud-point phenomenon is the primary mechanism for inhibition and stabilization. The cloud-point is the temperature at which polyglycol changes from being totally soluble to insoluble. At temperatures above the cloud point, polyglycols form colloidal droplets, or micelles, which results in a microemulsion. This phenomenon is often referred to as a “Thermally Activated Mud Emulsion” (TAME). This TAME effect provides wellbore stability in three distinct ways:

- Through chemical adsorption.
- Through microemulsion and precipitate pore-plugging.
- By providing a thinner, less-porous filter/wall cake.

These polyglycol polymer systems are more effective when used with an inhibitive salt, such as KCl, for ionic inhibition and an encapsulating polymer such as POLYPAC or POLY-PLUS. So, it is recommended to maintain sodium chloride or potassium chloride salt in the system. Maximum benefits are obtained by matching the cloud point of the polyglycols with the bottom-hole temperature or the temperature of the formation being drilled. This results in the adsorption of insoluble polyglycols onto the wellbore and into the filter/wall cake. This adsorption of insoluble polyglycols onto the clay/shale formation forms a protective barrier against water and its damaging effects. Adsorption of insoluble polyglycols into the filter/wall cake on permeable formations reduces the thickness of the filter/wall cake and the filtration loss rates. Since the insoluble polyglycol has an affinity to surfaces, it can coat solids and exposed surfaces, it provides lubrication and reduces balling. Most polyglycol polymer systems are designed for the polyglycol to become totally soluble as it cools while being pumped up the annulus to the surface. However, some polyglycol polymer systems are designed to keep the polyglycol insoluble at all times. Several glycols are available with a wide range of cloud points to achieve the one desired. However, polyglycol polymer systems usually are designed prior to drilling the well, so only the proper glycol is sent to the wellsite. These polyglycols are listed below.

GLYDRIL GP	Broad-range-clouding PAG blend, low salinity
GLYDRIL LC	Low-salinity-clouding PAG, <30,000 mg/l Cl^-
GLYDRIL MC	Moderate-salinity-clouding PAG, 30,000 to 90,000 mg/l Cl^-
GLYDRIL HC	High-salinity-to saturated-clouding PAG, >90,000 mg/l Cl^-

(GLYDRIL SYSTEM CONTINUED)

Polyglycol polymer systems, like other polymer systems, should be mixed from scratch. If a polyglycol polymer system follows another mud system in a well, the previous system should be displaced by a pre-mixed polyglycol polymer system rather than being converted from the previous system.

The primary concerns involved in maintaining a polyglycol polymer system are to monitor and maintain the proper polymer concentration; to control the solids in the proper ranges; and to maintain the proper concentration and type of polyglycol in the system to obtain the TAME effect. The POLY-PLUS concentration should be monitored through the use of the Ammonia Extraction Test (the procedure for this test is contained in the Testing chapter of this manual). The polyglycol concentration can be monitored by a two-stage retort or by using a hand refractometer. After distilling the water off at 300°F (149°C), the sample is distilled at 950°F (510°C) to distill and measure the glycol. The MBT value of the mud should be limited to 20 lb/bbl.

Typical Properties	
Density (lb/gal)	9 - 15
Funnel viscosity (sec/qt)	36 - 55
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	2 - 25
10-min gel (lb/100 ft^2)	5 - 50
pH	8 - 10
P_m (cm^3 0.02N H_2SO_4)	0.2 - 2
P_f (cm^3 0.02N H_2SO_4)	0.1 - 1
Calcium (mg/l)	100
Chlorides (mg/l)	0 - 190,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	<5
MBT (lb/bbl)	<20

*See Figure 2.

Typical Products	Primary Function
M-I BAR	Increase density
M-I GEL	Viscosity and fluid-loss control
Caustic soda or KOH	Increase pH, P_f
POLY-PLUS	Encapsulation and inhibition
DUO-VIS	Viscosity and suspension
POLYPAC	Fluid-loss control and encapsulation
GLYDRIL GP, LC, MC or HC	Inhibition and lubricity
NaCl or KCl brine	Ionic inhibition

Material	Concentration (lb/bbl)
M-I BAR	0 - 350
M-I GEL	2.5 - 12.5
KOH or soda ash	0.25 - 1.5
POLY-PLUS	0 - 2
DUO-VIS	0.25 - 1.5
POLYPAC	1 - 5
GLYDRIL	2 - 5%
NaCl or KCl brine	0 - 20%

SILDRIL System

The SILDRIL system…was developed to provide shale inhibition and wellbore stability in problem areas…

The SILDRIL™ system is a salt/polymer system utilizing sodium silicate for improved inhibition. The system was developed to provide shale inhibition and wellbore stability in problem areas where oil- or synthetic-base fluids normally would be used. Formations such as microfractured shale, chalk or formations with interbedded dispersive clays are the applications where a SILDRIL system should be considered.

Inhibition and wellbore stability are achieved as the soluble silicates precipitate to form an insoluble silicate film which prevents water contact with the wellbore shale (clay) or invasion into permeable formations. As the soluble silicates come in contact with the surface of the low-pH shales (clays), a reduction in the pH and a reaction with the divalent cations (Ca^{2+}; Mg^{2+}) on/in the shale occur to form a calcium and/or magnesium silicate coating. Soluble silicates are stable only at pH values above 10.4 and in the absence of divalent cations. Silicates precipitate when pH values are less than 10.4 or in the presence of divalent cations. Therefore, the pH should be controlled at 11.0 or greater and multivalent cations should be precipitated with soda ash. The optimum concentration of 50% active silicate is about 30 lb/bbl. It is very important to monitor the silicate concentration in the system because the depletion rates of silicate can be high when drilling reactive shales. For the SILDRIL system to provide good inhibition, the silicate concentration must be monitored and maintained within the proper range.

It is very important to monitor the silicate concentration in the system…

The silica-to-sodium ratio also is very important. It describes the ratio of SiO_2 to Na_2O for a particular silicate. Research has shown that the best ratio between silica and sodium for shale inhibition ranges from 2.0:1 to 2.65:1. Higher SiO_2 to Na_2O ratios do not improve inhibition and can result in unstable flow properties.

Dispersion tests show that the inhibition of the SILDRIL system is comparable to that of oil- or synthetic-base systems. Shale inhibition can be further enhanced by additions of GLYDRIL and potassium or sodium salts. GLYDRIL is glycol with a low-cloud-point temperature that reduces the coefficient of friction of the fluid and extends the thermal stability of the system to 250°F. Therefore, glycol should be added to the system once the bottom-hole temperature exceeds 190°F, or as required to reduce excessive torque and drag.

Caution should be used when drilling reservoirs where the formation water contains high concentrations of Ca^{2+} or Mg^{2+}. If the formation water is high in Mg^{2+} or Ca^{2+}, or the pH of the invaded filtrate is reduced over time, damage could occur due to precipitation of calcium silicate (cement) or solidification of sodium silicate within the pore throat of the rock matrix. However, if the completion will include cemented casing and perforations, this should not present a problem.

When mixing a SILDRIL system, freshwater — or water that has been treated with soda ash and caustic to remove any divalent ions (Ca^{2+} and Mg^{2+}) —

(SILDRIL SYSTEM CONTINUED)

should be used. If not, these ions will precipitate the silicate out of solution as it is added to the makeup water.

The SILDRIL system is not as solids-tolerant as most other inhibitive mud systems and is not recommended for applications where densities of more than 13.5 lb/gal are required. Since the SILDRIL system is solids-sensitive, high dilution rates would be required to provide stable flow properties in high-density SILDRIL applications. Since SILDRIL is an expensive, high-performance system, it is recommended only for difficult wells that contain water-sensitive shales. The temperature stability of the SILDRIL system is about 275°F (135°C).

Typical Properties	
Density (lb/gal)	8.8 - 13.5
Funnel viscosity (sec/qt)	36 - 55
Plastic viscosity (cP)	See Figure 1
Yield point (lb/100 ft^2)	See Figure 1
Initial gel (lb/100 ft^2)	2 - 25
10-min gel (lb/100 ft^2)	5 - 50
pH	11.0 - 12.5
P_m (cm^3 0.02N H_2SO_4)	1.0 - 3.0
P_f (cm^3 0.02N H_2SO_4)	0.8 - 2.5
Calcium (mg/l)	<100
Chlorides (mg/l)	60 - 120,000
Fluid loss (cm^3/30 min)	As needed
Low-gravity solids (%)*	<5
MBT (lb/bbl)	<15

*See Figure 2.

Typical Products	Primary Function
M-I BAR	Increase density
SILDRIL	Inhibition
Caustic soda or KOH	Increase pH and P_f
Soda ash	Precipitate hardness
DUO-VIS	Viscosity and suspension
POLYPAC (UL)	Fluid-loss control
GLYDRIL	Inhibition and lubricity
NaCl or KCl brine	Base fluid and activity

Material	Concentration (lb/bbl)
M-I BAR	0 - 300
SILDRIL	4 - 7%
Caustic soda or KOH	1 - 2
Soda ash	0.5 - 1.5
DUO-VIS	0.5 - 1.5
POLYPAC (UL)	1.0 - 3.0
NaCl or KCl brine	18 - 68/22 - 37
GLYDRIL	2 - 5%