CHAPTER

20A Barite Sag

Introduction

Barite sag... causes significant variations in mud density.

Barite sag is the settling of barite, which causes significant variations in mud density. It is a major concern, particularly when weighted muds are used in drilling directional and extended-reach wells. Sag is most often associated with well angles of 50 to 80°, low annular velocities and low viscosity clean muds. Possible consequences include lost circulation, stuck pipe, packoffs, wellbore instability and well-control problems.

Sag is affected by a number of factors related to drilling practices and mud properties, all of which must be properly managed for successful control. Although once thought to occur more often in Oil- or Synthetic-Base Muds (OBMs or SBMs) due to thermal thinning, sag has been found in all types of weighted drilling fluids.

Barite sag occurs when inert weight material particles (barite, hematite, etc.) settle and form an ultra-high-density slurry or a barite “bed” on the low side of the hole. Generally, barite beds can form in wells deviated 30° or more that are drilled with mud weights greater than 12 lb/gal. At angles up to about 75°, the beds can slump (slide or flow toward the bottom of the hole). After a trip, subsequent mud circulation reveals a wide variance in mud weight.

In principle, hole cleaning and barite sag are related. Both are affected by such interdependent factors as: annular velocity; hole angle; interval length; flow regime; mud weight; mud rheology; pipe eccentricity; and rotation, time and drilling practices. Nevertheless, differences require separate control and management methods. For example, cuttings beds which form due to insufficient hole cleaning usually stop sliding (slumping) at angles above 60 to 65°, about 10 to 12° less than the more-fluidized barite beds.

In the field, sag is measured by weighing the mud at the flowline regularly after it has remained uncirculated for a period of time, such as when circulating bottoms-up after tripping, logging or running casing. The typical “fingerprint” of barite sag is a roughly sinusoidal shape (see Figure 1). When circulating bottoms-up, light mud is followed by heavy mud, then by the original-weight mud. The heaviest mud weight usually occurs at bottoms-up.

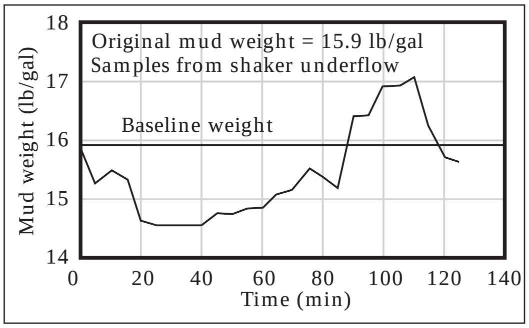


Figure 1: Mud weight variations indicate sag after trip.

In most directional wells, it is highly probable that some degree of sag has occurred. Until recently, however, mud weight typically was measured only on the bottoms-up sample. The heavy mud off bottom frequently was attributed to slugs, dehydration and/or dispersion. In those cases where barite sag was identified, it was simply tolerated, presumably because the incidence of sag-related problems was thought to be low. Sag has been responsible for causing lost circulation in wells with angles of only 30°.

Sag can be minimized by adjusting the rheological properties, composition and formulation of the mud. However, sag is more than just a mud-property problem. It can be induced in almost any directional well by circulating a weighted mud at low flow rates such as while conditioning the mud prior to running casing. General guidelines concerning mud properties and drilling practices are presented later in this chapter.

Sag Basic Concepts

If not properly suspended, weight material will settle out of a static fluid column. In vertical wells, the *hindered* settling that occurs is noticeably slower than the *free settling* rate of a single particle. Settling is further reduced if gel structures develop and improve suspension. However, if the column is on an incline, there is a significant increase in the settling rate. Discovery of this phenomenon is attributed to the physician A.E. Boycott, who reported in 1920 that blood corpuscles settled 3 to 5 times faster in inclined test tubes than in vertical ones.

Boycott settling is best visualized using the M-I Zag Tube, a segmented plastic tube containing viscosified water and glitter. However, a simple test can be performed using a graduated cylinder (or test tube), barite and tap water (see Figure 2). First, add dry barite to fill about a third of the tube. Then, top off with water. Shake vigorously, and place the tube at an angle of about 45°. As the barite settles, observe that the trail of water on the upper side of the tube flows upward, and the solids slide downward. This special movement results when immediate settling on the low and high sides creates a pressure imbalance over the cross section. Low-density fluid is forced upward, while high-density fluid is forced downward along the low side of the hole.

...sag is primarily a dynamic settling problem.

In directional wells, Boycott settling is complicated by several factors, of which fluid dynamics is the most important. At low flow rates, the flow stream moves along the upper side of the hole and increases both the pressure imbalance and bed formation. This is called *accelerated* or *dynamically enhanced* Boycott settling. This settling behavior can be systematically dissipated by higher annular velocities and pipe rotation.

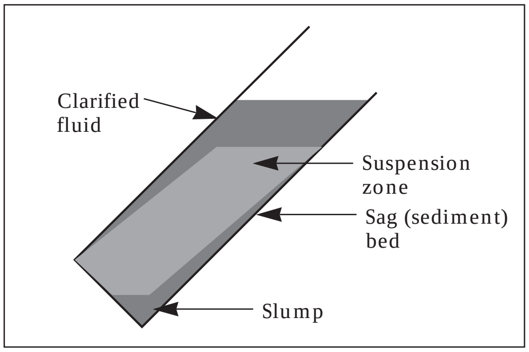


Figure 2: Boycott settling illustration.

It is clear that three key mechanisms are involved in the sag process: *dynamic settling, static settling* and *slumping*. Mud treatments should address the right mechanism. Attempts to solve dynamic problems with static solutions could cause lost circulation or related difficulties. For example, elevated gel strengths can only reduce static settling. At one time, sag was considered a classical static problem, because the symptoms are associated with static conditions in the well. However, since most barite beds are formed while circulating, sag is primarily a dynamic settling problem. Typically, bed growth under static conditions (pumps off) is minimal, although slumping is most likely to occur during static periods. For these reasons, drilling practices prior to and after trips can often prevent sag-related problems.

Sag Measurements

Measuring and recording the flow line mud weight after trips is recommended for all weighted muds used in directional wells. This information is often called a “trip report.” Sag is most severe during the first bottoms-up circulation after a trip. The trip report should include (at 15-min intervals) the following: time and cumulative pump strokes, mud weight, mud temperature, funnel viscosity, and gas units. A pressurized mud balance may be necessary to minimize effects of gas-cutting. If possible, the mud weight should be corrected for temperature.

The definitive measure of sag severity is the difference between the maximum and minimum mud weights observed at the flow line after a trip. For example, these measurements have revealed mud weight differences as high as 4 lb/gal in the Gulf of Mexico and 6 lb/gal in the North Sea.

...the M-I Sag Register is useful in tracking the severity of barite sag.

For comparative purposes, the M-I Sag Register (S_r) is useful in tracking the severity of barite sag. As illustrated in the equation, Sag Register depends on the ratio of the mud weight difference and the circulating mud weight. The exponential function is added to amplify serious sag problems.

$$S_r = e^{\left(10 \text{ x } \frac{W_d}{W_c}\right)}$$

Where:

S_r = Sag Register (dimensionless)
W_d = Maximum mud weight difference (lb/gal)
W_c = Circulating mud weight (lb/gal)

If no sag has occurred, then $S_r = 1.0$. Field data suggest that minimal sag problems should be encountered for $1.0 < S_r < 2.5$. Sr values above 5 indicate severe sag. For reference, the Sag Register — S_r — is 2.55 for the bottoms-up shown in Figure 1. The Sag Register is an open-ended scale. Values in excess of 70 have been calculated for a high density, OBM being pumped at low flow rates on a North Sea well, which is an extreme example of a severe sag problem.

The Sag Register provides two clear benefits. First, it can help monitor sag trends at the well site. Secondly, S_r provides a correlation between field and laboratory results. Data taken on the M-I Sag Flow Loop correlate very well with field results when using the Sag Register. This flow loop simulates actual wellbore angle, drill pipe eccentricity, pipe rotation and annular velocity. Continuous measurement and recording of weight material additions and the circulating mud weight can provide a direct measurement of weight material deposited in the bed.

The M-I Viscometer Sag Test (VST) is a simple test which uses the shear developed by a Fann viscometer rotating at 100 RPM to simulate fluid dynamics. It is easy to run either on location or in a lab. Mud weight changes are measured over time by sampling mud from the bottom of the thermal cup, using a long-needled syringe. The VST procedure is included at the end of this section. The VST cannot simulate all of the well parameters affecting sag in the field. However, various constants have been developed to correct for angle, annular velocity, hole diameter and interval length. In effect, these constants modify the results from the VST to simulate the maximum mud weight difference to be expected in the field, with a calculated value called the “Sag Index.” The Sag Index is useful for correlating data.

Sag Guidelines

Sag is highest during sliding operations.

Fluid control is only one constituent of sag prevention.

Due to its intrinsic complexity, the barite sag mechanism has no analytical solutions. However, practical guidelines have been developed based on field experience and laboratory measurements. These guidelines are listed at the end of this section and are categorized according to: (1) well planning, (2) mud properties and testing, (3) operational practices, and (4) well site monitoring.

Well design may require compromises in order to minimize and control sag. Sag tendency generally increases with hole angle and probably is most critical in extended-reach drilling under High Temperatures and High Pressures (HTHP). High temperatures cause mud thinning and increased settling. HTHP testing may be necessary to ensure that rheological properties are adequate under well conditions. Large annular clearances or low circulation rates promote sag due to low annular velocities. Higher flow rates will reduce sag tendencies, but pressure limits and downhole tools — such as Measurement While Drilling/Logging While Drilling (MWD/LWD) equipment and mud motors — can limit this as an option.

Fluid control is only one constituent of sag prevention. Drilling practices that influence sag include: (1) sliding vs. rotating the drill pipe, (2) displacement techniques, (3) mud conditioning techniques prior to cementing, (4) short trips and rotary wiper trips, (5) trip procedures, (6) techniques for resuming circulation, and (7) well site monitoring procedures.

Barite beds are easily disturbed by tripping and logging operations. This is due primarily to the weak attraction among the inert weight-material particles in the beds. Clearly, then, sag beds are sensitive to pipe rotation and annular velocity. Pipe rotation aids sag bed removal significantly, particularly when the drill pipe is eccentric, and even occasional rotation may help remove beds. Rotating wiper trips also can be used to stir up deposited sag beds and move the particles into the main flow stream.

Bed deposition occurs very rapidly under conditions that are conducive to sag. Sag is highest during sliding operations. Rotating and circulating bottoms-up are recommended after all sliding operations. Staging into the hole may be necessary after being out of the hole for extended periods. Staging in the hole at 1,000- to 2,000-ft intervals (circulating bottoms-up at each stage) reduces mud weight variations to the point that well control, lost circulation, packoff and other sag-related problems are minimized. This is demonstrated in Figure 3, a comparison between two bottoms-up circulations from two consecutive trips on a well in the Gulf of Mexico. On the first trip, when the pipe was not staged into the hole, problems were encountered getting to bottom, the pipe was stuck briefly, and the torque and drag were high. On the second trip, the pipe was staged into the hole without incident. The S_r was reduced from 5.41 for the first trip to 1.45 for the second.

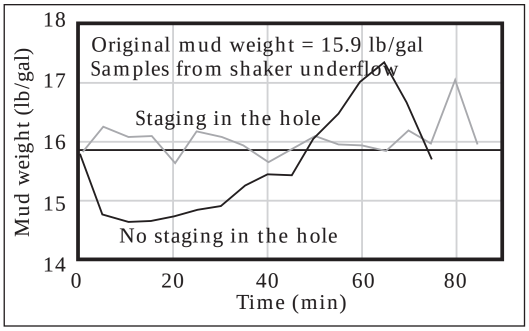


Figure 3: Staging in the hole reduces sag.

Mud conditioning prior to cementing usually involves diluting and thinning the mud. This should only be done once the casing is on bottom. Dilution can reduce the mud's Low-Shear-Rate Viscosity (LSRV) and gels, creating conditions conducive to sag. New muds with few low-gravity drill solids and freshly diluted muds sag more readily than used muds, in which colloidal-sized drill solids have accumulated. Supporting barite during dilution is difficult in conventional water-base muds, but not as difficult in polymer fluids such as FLO-PRO® and POLY-PLUS® systems.

While there is no consensus on a single rheological parameter which has the greatest impact on sag, a close relationship exists between dynamic settling and Low-Shear-Rate Yield Point (LSRYP) (see Figure 4). The LSRYP can be determined using the 3- and 6-RPM readings of a multispeed viscometer. It is calculated using this equation:

$$\text{LSRYP} = (2 \times \Theta_{3\text{ rpm}}) - \Theta_{6\text{ rpm}}$$

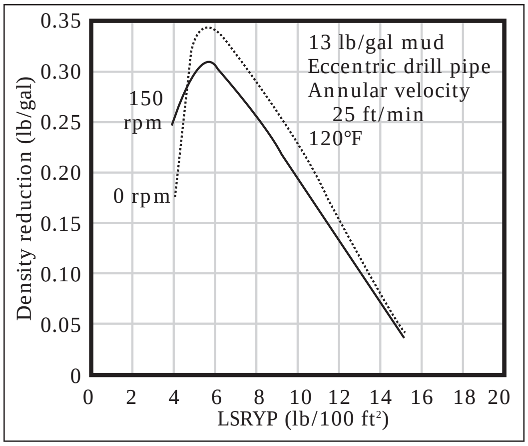


Figure 4: The influence of LSRYP on barite sag.

Minimum LSYP values of 7 to 15 lb/100 ft² have provided adequate barite suspension in many directional wells. In HTHP wells, rheology testing using a Fann Model 50 for water-base muds or Model 70 for oil- and synthetic-base muds is recommended for LSRYP measurements at actual wellbore conditions.

LSRYP in water-base muds is elevated by adding a viscosifying polymer such as xanthan gum (DUO-VIS® or FLO-VIS®). In oil- and synthetic-base fluids, low-shear viscosity is adjusted using a rheology modifier (VERSAMOD™ or NOVAMOD™) or by increasing the organophilic-clay concentration. Regardless of the system, it is important to include both colloidal-sized clays and rheology modifiers (which elevate LSRV) to minimize sag.

Barite sag and its consequences can be minimized only when all of the related factors are under adequate control. The proper fluid rheology and hydraulics must be combined with good sag-reducing drilling practices to prevent sag.

M-I Viscometer Sag Test (VST)

EQUIPMENT REQUIREMENTS

A. Equipment requirements for fluids weighing 17 lb/gal (SG 2.04) or less and using a pocket mud balance:
   1. Fann Model 35A 6-speed viscometer (or equivalent).
   2. Heat cup (i.e., the heated jacket with cup as shown in API *RP 13B-2*: *Recommended Practice Standard Procedure for Field Testing Oil-Base Drilling Fluids*).
   3. Disposable syringe, 50- to 60-cm^3 capacity (i.e., B-D 60 cm^3, #9663, with LeurLoc top).
   4. Biomedical pipetting needle, 6-in. (152 mm) (i.e., Perfectum No. 7942, 14-ga X 6 blunt).
   5. Pocket mud balance (Fann Testing Equipment Part No. 142000001EA).
   6. Timer, 30-min interval.

B. Equipment requirements for fluids weighing more than 17 lb/gal (SG 2.04) or for occasions when the pocket mud balance is not available:
   1. Fann Model 35A 6-speed viscometer (or equivalent).
   2. Heat cup (i.e., the heated jacket with cup as shown in API *RP 13B-2*: *Recommended Practice Standard Procedure for Field Testing Oil-Base Drilling Fluids*).
   3. Disposable syringe, 50- to 60-cm^3 capacity (i.e., B-D 60 cm^3, #9663, with LeurLoc top).
   4. Biomedical pipetting needle, 6-in. (152 mm) (i.e., Perfectum No. 7942, 14-ga X 6 blunt).
   5. Pocket mud balance (Fann Testing Equipment Part No. 142000001EA).
   6. Balance, mechanical beam or electronic, 50- to 100-g capacity, accurate to ± 0.1 g (i.e., a balance similar to those usually included in pilot test kits).
   7. Reusable weighing dish, 50- to 60-cm^3 capacity (any washable and reusable container that will fit on the balance).

NOMENCLATURE

K_a = Factor for hole inclination
K_d = Factor for hole diameter
K_f = Factor for flow regime
K_h = Factor for length of inclined hole section
ΔMW = Mud weight change (lb/gal)
MW_F = Final mud weight (lb/gal)
MW_o = Initial mud weight (lb/gal)
S_i = Sag index
SV = Sample volume (cm^3)
SW = Sample weight (g)
VW_o = Vessel tare weight (g)
VW_t = Total vessel weight (g)

TEST PROCEDURES

A. Test procedure for muds weighing 17 lb/gal (SG 2.04) or less and using a pocket mud balance:
   1. Place the heat cup on the stand of the 6-speed viscometer.
   2. Adjust the cup position vertically until the scribed line on the rotor is slightly below the top edge of the heat cup.
   3. Add drilling fluid to the heat cup up to the scribed line.
   4. Connect the heat cup to an operable electrical outlet.
   5. Adjust the viscometer to 600 RPM and stir the sample while it is heating to 120°F (48.9°C).
   6. While the sample is heating, clean and dry the pocket mud balance.
   7. Attach the clean, dry needle to the clean, dry syringe with a twisting motion.
   8. Once 120°F (48.9°C) has been reached, observe the 600-RPM dial reading until it is stable.
   9. Change the viscometer speed to 100 RPM.

10. Using the syringe/needle combination, remove the desired sample (i.e., 25+ cm^3) from the bottom of the heat cup as nearly under the rotor as possible. Extract slightly more sample than is needed. This allows any air bubbles trapped in the syringe above the mud to remain in the syringe and be excluded from the mud volume to be weighed.
11. Using fresh mud, adjust the mud volume in the heat cup back to the scribed line. Continue to stir at 100 RPM for 30 min. Maintain the sample temperature at 120°F (48.9°C).
12. Dispense the sample into the mud balance and determine the mud weight.
13. Record the initial mud weight (MW_O). Thoroughly clean and dry the mud balance, syringe and needle.
14. At the end of the 30-min stir period, repeat Steps 7, 10 and 12. Record the final mud weight (MW_F).
15. Calculate the mud weight change (ΔMW) using Equation 3. Thoroughly clean and dry all equipment.

B. Test procedure for muds weighing more than 17 lb/gal (SG 2.04) or for occasions when a pocket mud balance is not available.

1. Place the heat cup on the stand of the 6-speed viscometer.
2. Adjust the cup position vertically until the scribed line on the rotor is slightly below the top edge of the heat cup.
3. Add drilling fluid to the heat cup up to the scribed line.
4. Connect the heat cup to an operable electrical outlet.
5. Adjust the viscometer to 600 RPM and stir the sample while it is heating to 120°F (48.9°C).
6. While the sample is heating, weigh the clean, dry dish to obtain the vessel tare weight (VW_O) value. Record this value.
7. Attach the clean, dry needle to the clean, dry 3-cc syringe with a twisting motion.
8. Once 120°F (48.9°C) has been reached, observe the 600-RPM dial reading until it is stable.
9. Change the viscometer speed to 100 RPM.
10. Using the syringe/needle combination, remove the desired sample (i.e., 2+ cm^3) from the bottom of the heat cup as nearly under the rotor as possible. Extract slightly more sample than is needed. This allows any air bubbles trapped in the syringe above the mud to remain in the syringe and be excluded from the mud volume to be weighed.
11. Using fresh mud, adjust the mud volume in the heat cup back to the scribed line. Continue to stir at 100 RPM for 30 min. Maintain the sample temperature at 120°F (48.9°C).
12. Dispense 2 cc of the sample from the syringe into the tared weighing dish. Take extra care to be as precise as the syringes allows in the measurement of the volume dispensed since this measurement is critical! Record the Sample Volume (SV).
13. Weigh the dish and sample on the balance. Record as the total vessel weight (VW_t).
14. Calculate the Sample Weight (SW) and the initial MW (MW_O), using Equations 1 and 2. Record the MW_O. Discard the weighed sample. Thoroughly clean and dry the weighing dish, syringe and needle.
15. At the end of the 30-min stir period, repeat steps 7, 10, 12 and 13.

16. Calculate the final SW, MW_F and the mud weight change (ΔMW), using Equations 1, 2 and 3.
17. Thoroughly clean and dry all equipment.

CALCULATIONS

Equation 1: $SW = VW_t - VW_o$
Equation 2: $MW = SW/SV \times 8.33$
Equation 3: $\Delta MW = MW_F - MW_o$

Sag Index Equation

The Sag Index (S_i) is a method for adjusting the results from the M-I VST for a given set of well conditions in order to better evaluate the possibility of a sag-related problem.

Equation 4: $S_i = \Delta MW \times K_a \times K_d \times K_f \times K_h$

SAG INDEX FACTORS

HOLE INCLINATION (FROM VERTICAL) (K_a)

Hole Angle	K_a
0° - 10°	0.1
10° - 30°	0.2
30° - 40°	0.8
40° - 50°	1.0
50° - 60°	0.7
60° - 90°	0.4

HOLE DIAMETER (K_d)

Diameter	K_d
< 8.5 in. (216 mm)	0.2
8.5 - 12.25 in. (216-311 mm)	0.5
>12.25 - 17.5 in. (311-445 mm)	0.8
> 17.5 in. (445 mm)	1.0

ANNULAR FLOW PROFILE (K_f)

Flow Regime	K_f
Turbulent	0.5
Transitional	0.7
Laminar	1.0

LENGTH OF THE INCLINED SECTION (K_h)

Length	K_h
0 - 1,000 ft (0 - 305 m)	0.5
1,000 - 2,000 ft (305 - 610 m)	0.8
> 2,000 ft (610 m)	1.0

SAG INDEX EXAMPLES

Examples of how well parameters affect S_i are shown below. Three situations are examined.

SITUATION 1

An 18.3-lb/gal (SG 2.20) relaxed-emulsion oil mud is being used to drill a 26°, 9.625-in. (245-mm) diameter borehole. The ΔMW for this mud is 1.9 lb/gal (228 kg/m^3). The angled portion of the hole has 965 ft (294 m) of casing set in place. Hydraulic calculations indicate the mud to be in turbulent flow in this portion of the hole. Referring to the Sag Index factors:

$K_a = 0.2$
$K_d = 0.5$
$K_f = 0.5$
$K_h = 0.5$

Substituting the values into Equation 4 gives:

$S_i = \Delta MW \times K_a \times K_d \times K_f \times K_h$
$S_i = 1.9 \times 0.2 \times 0.5 \times 0.5 \times 0.5$
$S_i = 0.0475$

COMMENT

The modest angle and turbulent flow significantly reduce the probability and severity of sag-related problems for this example, even though a high ΔMW was measured.

SITUATION 2

A 15.3-lb/gal (SG 1.84) polymer mud is being used in a 58°, 12.25-in. (311-mm) hole. The ΔMW for this mud is 1.3 lb/gal (156 kg/m^3). The angled hole length is 450 ft (137 m). The mud is estimated to be in laminar flow. Referring to the previously given Sag Index factors:

$K_a = 0.7$
$K_d = 0.5$
$K_f = 1.0$
$K_h = 0.5$

Substituting the values into Equation 4 gives:

$S_i = \Delta MW \times K_a \times K_d \times K_f \times K_h$

$S_i = 1.3 \times 0.7 \times 0.5 \times 1.0 \times 0.5$

$S_i = 0.2275$

SITUATION 3

An 11.2-lb/gal (SG 1.34) seawater lignosulfonate mud is being pumped through a 1,500-ft (457-m) cased hole with a diameter of 17.5 in. (445-mm). Borehole angle is 45°ΔMW is 0.5 lb/gal (60 kg/m^3). The mud is in laminar flow. Referring to the previously given Sag Index factors:

$K_a = 1.0$

$K_d = 0.8$

$K_f = 1.0$

$K_h = 0.8$

Substituting the values into Equation 4 gives:

$S_i = \Delta MW \times K_a \times K_d \times K_f \times K_h$

$S_i = 0.5 \times 1.0 \times 0.8 \times 1.0 \times 0.8$

$S_i = 0.32$

COMMENT

The S_i results from these examples indicate that the mud system in Situation 3 has a greater potential for sag-related problems than the fluids in the other cases, even though it has the lowest ΔMW. Since it may be difficult to reduce the ΔMW for the last mud, the key to reducing sag-related problems lies with flow rate, rotation and drilling practices.

Barite Sag Guidelines

WELL PLANNING

- **Well type.** Directional wells of >30° inclination drilled with mud densities of >12 lb/gal (SG>1.44) are likely candidates for sag problems. Due to the potentially narrow margin between pore pressure and fracture gradient, extended-reach and directional deepwater wells are particularly critical. The available flow rates for these wells may be limited due to pressure losses and tools.
- **Well environment**. Temperature and pressure affect mud design. High temperatures cause mud thinning and increase sag tendencies. In HTHP wells, rheological measurements are important across the full range of temperature and pressure.
- **Angle and well profile**. The most critical angles for sag are 60 to 75°.
- **Casing design**. Avoid casing designs and situations that give rise to low annular velocities.
- **Hole diameter**. Sag problems have occurred in hole sizes larger than about 6 in. Annular clearance, eccentricity and drill pipe diameter are all key factors.

MUD PROPERTIES AND TESTING

- **Mud type**. Sag can occur in all mud types that use weight material to achieve density. Sag may be noticeably less in water-base muds if reactive formations are being drilled.
- **Mud weight**. Densities >12 lb/gal (SG >1.44) are prone to sag in directional wells.
- **Rheology**. Elevated low-shear rheology and gels help reduce sag. Clay-base rheology modifiers may be more effective than fatty acid products in freshly built OBMs and SBMs. For some muds used in deepwater applications, rheology adjustments to counteract effects of low temperatures can exacerbate sag.
- **Yield stress**. The LSRYP is a good indicator for sag-related rheological properties. For most wells, LSRYP should be maintained above the

7 to 15 lb/100 ft^2 range. Larger hole sizes typically require higher LSRYP values.

- **Testing**. Sag tests should be conducted in the laboratory during well planning and in the lab/field while drilling. HTHP wells may require HTHP testing under expected hole conditions.
- **Oil/water ratio**. Oil/synthetic additions thin OBMs and SBMs, and increase sag potential. Rheology modifiers can compensate for viscosity loss; however, some rheology modifiers require a sufficient amount of water to be available.
- **Surfactant concentration**. Wetting-agent levels in non-aqueous fluids must be sufficient to prevent barite agglomeration. Overtreatment should be avoided to prevent undesirable reductions in viscosity.
- **Fluid-loss additives**. Under certain circumstances, sag problems can be aggravated by viscosity reductions caused by fluid-loss control additives. This reinforces the need to assess specific mud formulations and interactions.

OPERATIONAL PRACTICES

- **Operations at flow rates**. Barite sag is predominantly a dynamic settling problem in which beds are formed during periods of low circulation rates. Long periods at low flow rates exacerbate sag, even if other key variables are within proper limits. Beds should be removed prior to tripping out using high flow rates and rotary speeds.
- **Density variation**. A definite sign that sag has occurred are wide variations in mud density while circulating bottoms-up after a trip. For serious sag — especially when coupled with a low fracture gradient at the casing shoe — it may be necessary to stop circulating, trip out and stage back in. The goal would be to prevent lost circulation when heavy mud from the bottom is above the shoe.
- **Bed disturbance**. Because they are inert, particles in barite beds tend to be only loosely attracted. Barite beds are easily disturbed by operations such as logging and tripping. These perturbations may fluidize the beds and increase slump, slide or flow, even at angles to 75°.
- **Time between trips**. Beds formed under dynamic conditions can slump during static periods. Beds formed at medium angles slump faster, but beds in the 60 to 75° range can be considerably thicker and give more problems. It may be necessary to stage in the hole if there are extended periods between trips.
- **Rotary vs. sliding**. For a given set of conditions, sag is lowest when the pipe is rotating at >75 RPM and eccentric. Sag is worst when the drill pipe is stationary and eccentric. Pipe rotation can minimize bed formation and even help remove existing beds. Rotary wiper trips often are beneficial after extended periods of sliding.
- **Mud conditioning prior to cementing**. Avoid overtreatment of the mud to reduce viscosity prior to running casing and/or cementing. Excessive dilution dramatically increases the likelihood of sag.

WELL SITE MONITORING

- **Mud weight**. After trips, mud weight in and out should be measured (at least every 15 min) while circulating bottoms-up. In HTHP applications, mud-weight adjustment for temperature is necessary. Use of a pressurized balance helps obtain good data with gas-cut mud.

- **Sag indicators**. The mud-weight differential while circulating bottoms-up should be used to calculate and record sag tendencies (Sag Register). Well site monitoring tests such as the M-I Viscometer Sag Test can help with field data correlations to measure the impact of remedial treatments.
- **Standpipe pressure**. Fluctuations in standpipe pressure may occur as slugs of light and heavy mud pass through the bit nozzles and other restrictive parts of the circulating system. Also, higher standpipe pressures may indicate if annular sag packoff is occurring.
- **Torque and drag**. High torque and overpull can indicate that barite beds are forming on the low side of the hole.
- **Mud losses and gains**. Unexpected losses may occur as heavy mud in the annulus reaches near-vertical sections of the well and rapidly increases hydrostatic pressure. The opposite effect can occur with light mud, which could cause the well to flow.

Hole Cleaning

Introduction

Hole cleaning is one of the basic functions of a drilling fluid.

Hole cleaning is one of the basic functions of a drilling fluid. Cuttings generated by the bit, plus any cavings and/or sloughings, must be carried by the mud to the surface. Failure to achieve effective hole cleaning can lead to serious problems, including stuck pipe, excessive torque and drag, annular packoff, lost circulation, excessive viscosity and gel strengths, high mud costs, poor casing and cement jobs, and slow drilling rates. This chapter presents hole-cleaning fundamentals, key parameters and practical field guidelines.

Cuttings transport is affected by several interrelated mud, cuttings and drilling parameters, as shown in Table 1. Hole angle, annular velocity and mud viscosity generally are considered to be the most important. The primary methods used to improve most hole-cleaning problems is to increase the flow rate (annular velocity), mud viscosity and pipe rotation, when in laminar flow. For many difficult hole-cleaning situations, particularly vertical sections, there is some critical, or “threshold,” viscosity required to obtain satisfactory hole cleaning.

Well profile and geometry	• Hole angle (inclination) and doglegs • Casing/hole and drill pipe diameters • Drillstring eccentricity
Cuttings and cuttings-bed characteristics	• Specific gravity • Particle size and shape • Reactivity with mud • Mud properties
Flow characteristics	• Annular velocity • Annular velocity profile • Flow regime
Mud properties	• Mud weight • Viscosity, especially at low shear rates • Gel strengths • Inhibitiveness
Drilling parameters	• Bit type • Penetration rate • Differential pressure • Pipe rotation

Table 1: Parameters affecting hole cleaning.

Cuttings and particles that must be circulated from the well have three forces acting on them...

Cuttings and particles that must be circulated from the well have three forces acting on them as shown in Figure 1a: (1) a downward force due to gravity, (2) an upward force due to buoyancy from the fluid and (3) a force parallel to the direction of the mud flow due to viscous drag caused by the mud flowing around the particle. These forces cause the cuttings to be carried in the mud stream in a complex flow path which is often helical. A simplified illustration of the velocity components acting on a particle is shown in Figure 1b: (1) a downward slip velocity due to gravitation forces, (2) a radial or helical velocity due to rotation and velocity profile, and (3) an axial velocity parallel to the mud flow.

Hole cleaning in vertical wells is perhaps the best understood process and the simplest to optimize. High-angle and extended-reach wells typically present the greatest hole-cleaning challenges. However, other simpler well types can be equally as troublesome under certain circumstances. Successful hole-cleaning practices in one situation do not always apply to another.

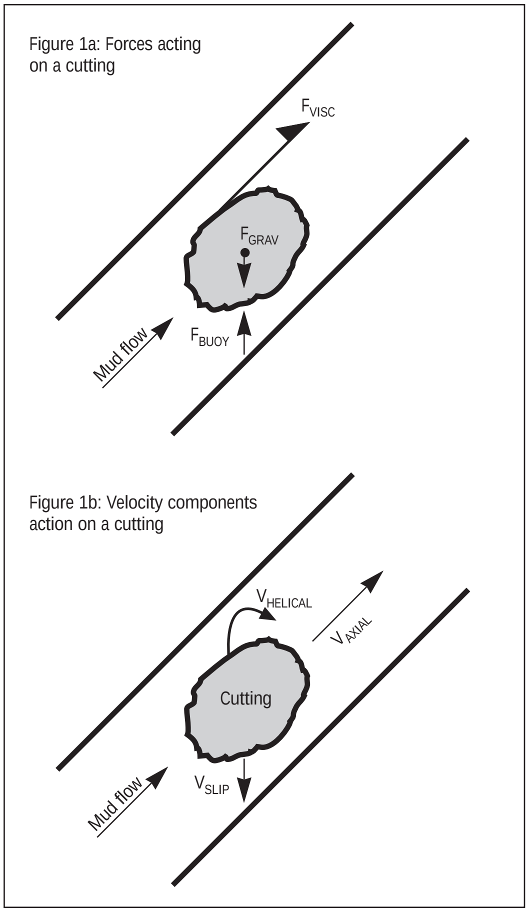


Figure 1: Forces and velocity components acting on a cutting.

Particle-Settling Mechanisms

The hole-cleaning process must counteract gravitational forces acting on cuttings to minimize settling during both dynamic and static periods. Three basic settling mechanisms can apply: (1) free, (2) hindered and (3) Boycott settling. The first two relate to vertical wells, while all three can exist in directional wells.

Basic settling patterns are illustrated in Figure 2, using the M-I Zag Tube, a demonstration device composed of three clear tubes connected by 135° elbows. The fluid in the Zag Tube is slightly viscosified freshwater; the simulated cuttings are aluminum flakes (glitter).

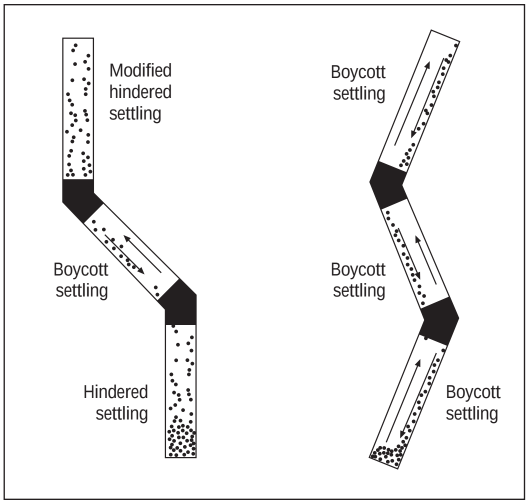


Figure 2: Hindered and boycott settling using Zag Tube.

***Free settling** occurs when a single particle falls through a fluid without interference...*

Free settling occurs when a single particle falls through a fluid without interference from other particles or container walls, similar to what might occur in the center of a large water pit. The so-called "terminal settling velocity" depends on the density difference between fluid and particle, fluid rheology, particle size and shape, and the flow regime around the particle. In turbulent flow, settling velocity is independent of rheology. In laminar flow around the particle, Stokes' law applies for free settling, and was developed for spherical particles, Newtonian fluids and a quiescent fluid. Stokes' law is:

$$V_S = \frac{g_C \; D_S^2 \; (\rho_S - \rho_L)}{46.3\mu}$$

Where:

V_S = Slip or settling velocity (ft/sec)
g_C = Gravitational constant (ft/sec^2)
D_S = Diameter of the solid (ft)
ρ_S = Density of solid (lb/ft^3)
ρ_L = Density of liquid (lb/ft^3)
μ = Viscosity of liquid (cP)

This equation is a mathematical expression of events commonly observed; i.e., the larger the difference between the density of the cutting and the density of the liquid ($\rho_S - \rho_L$), the faster the solid will settle. The larger the particle is (D_S^2), the faster it settles and the lower the liquid's viscosity ($1/\mu$), the faster the settling rate.

Understanding free settling is important because it forms the basis for the relationships which apply to vertical-well hole cleaning. Generally, Stokes' law is modified to incorporate equivalent viscosity for circulating non-Newtonian fluids and non-spherical cuttings. The terminal settling velocity under free settling is called the *slip velocity*.

***Hindered settling** is a more realistic settling mode for near-vertical and near-horizontal intervals...*

Hindered settling is a more realistic settling mode for near-vertical and near-horizontal intervals, particularly in small-diameter holes and where high cuttings concentrations are present with high Rate of Penetration (ROP). Hindered settling occurs when fluid displaced by falling particles creates upward forces on adjacent particles, thereby slowing down their slip rate. The net result is still an overall downward movement, but the settling rate is always less (hindered) than for single, individual particles, hence the name. Interference from the hole walls and drill pipe also slows down the settling rate of nearby particles.

Hindered settling is most important in vertical wells. Coupled with the long settling distance, it helps explain why hole-cleaning is less problematic in vertical wells.

Boycott settling, an accelerated settling pattern which can occur in inclined wellbores, is named after the physician who first reported that particles in inclined test tubes settle 3 to 5 times faster than in vertical ones. Boycott settling is the consequence of rapid settling adjacent to the high (top) and low (bottom) sides of inclined wellbores. This causes a pressure imbalance which drives the lighter, upper fluid upwards and any cuttings beds on the low side downwards. Angles from 40 to 60° are particularly troublesome. At relatively low flow rates, mud flows mainly along the high side and accelerates or enhances the Boycott effect. High flow rates and pipe rotation can disrupt the pattern and improve hole cleaning.

Key Parameters Affecting Hole Cleaning

Four hole-cleaning ranges based on hole angle have been identified...

The effects of different hole-cleaning parameters have been identified in laboratory flow-loop tests. The following comments represent the integration of M-I's experimental results with broad-based, related field observations and measurements.

Well profile and geometry. Four hole-cleaning ranges based on hole angle have been identified:

Range	Angle (degrees)
Near-vertical I	0 - 10
Low II	10 - 30
Intermediate III	30 - 60
High IV	60 - 90

The limits of each range should be considered only as guidelines, since all are affected by bed stability, borehole roughness, cuttings characteristics and drilling fluid properties, among others. Figure 3 illustrates relative hole-cleaning difficulty based on angle. In vertical and near-vertical wells, cuttings beds do not form, but failure to properly transport and suspend cuttings can cause fill on bottom or bridging in doglegs. In directional wells, the build section in the intermediate range typically is the most difficult to clean, because cuttings beds can slide or "slump" opposite the direction of flow. Boycott settling can exacerbate the problem. Sliding tendencies start dissipating at angles greater than about 60°, due to the corresponding decrease in the gravitational force vector.

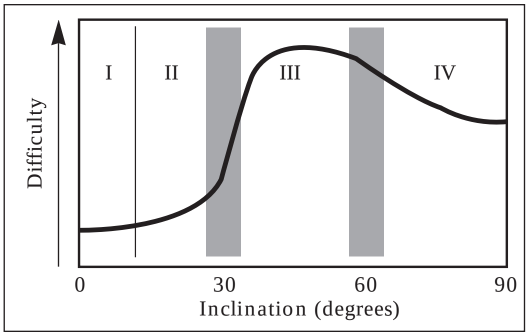


Figure 3: Hole cleaning difficulty vs. inclination.

All four ranges may co-exist in the same directional well. For most cases, fluid properties and drilling practices should strive to minimize problems in the most critical interval. Hole-cleaning factors considered optimum for one interval may be inadequate in another. For example, requirements differ for large-diameter casing (which severely limits annular velocity), the build interval (which promotes cuttings-bed formation and sliding) and the production formation drilled horizontally (which may be shear sensitive and tend to wash out).

Cuttings and Cuttings-Bed Characteristics

Specific gravity, particle size and shape, and reactivity with the drilling fluid are some of the important drill-cutting and cuttings-bed characteristics. Their key consequences are listed here according to angle range:

- Near-vertical and low ranges: cuttings concentration (little to no bed).
- Intermediate range: cuttings concentration, bed thickness and propensity for slumping.
- High range: bed thickness and physical characteristics.

Specific gravity depends on the formations drilled and ranges from about 2.0 to 2.8, somewhat denser than most

If not properly supported, cuttings can accumulate...

muds. Bit type, penetration rate and bottom-hole differential pressure determine initial size and shape. Larger cuttings are generated by long-tooth bits, high penetration rates and lower differential (or underbalanced) pressures. The largest particles are cavings or sloughings created by overpressured shales and unstable wellbores.

Cuttings can be physically altered by reaction with the mud (dispersion), reaction with themselves (aggregation) and mechanical degradation (big cuttings ground down into smaller ones). Cavings, sloughings and other large particles not easily transported out of the well may re-circulate in the annulus until ground by the rotating drillstring into smaller, more easily transported sizes.

If not properly supported, cuttings can accumulate at the bottom of the well (fill), in large-diameter casing strings, in doglegs (bridges), on the low side of inclined intervals (beds), as mud rings in washout zones, and just above the collars or Bottom-Hole Assembly (BHA) (plugs and packoffs). "Plugs" and stuck pipe can be caused by dragging collars and elements up through pre-existing beds. Figure 4 shows a cuttings bed formed in a highly inclined annulus.

Cuttings accumulations can be difficult to erode or re-suspend, so mud properties and drilling practices which minimize their formation should be emphasized. Clearly, cuttings which remain in the flow stream do not become part of a bed or accumulation. Mud suspension properties are important, especially at low flow rates and under static conditions.

During circulation, viscous drag forces acting on cuttings in beds or in washouts often prevent sliding, even at angles less than about 50 to 60°. At pump shut-off, however, the cuttings accumulations can "avalanche," subsequently packing off the annulus.

Cuttings beds, such as those formed in directional wells, can take on a wide range of characteristics that impact hole-cleaning performance. For example, clean sand drilled with a clear brine will form unconsolidated beds which tend to roll rather than slide downwards, and are conducive to hydraulic and mechanical erosion. On the other hand, reactive shales drilled with a water-base mud

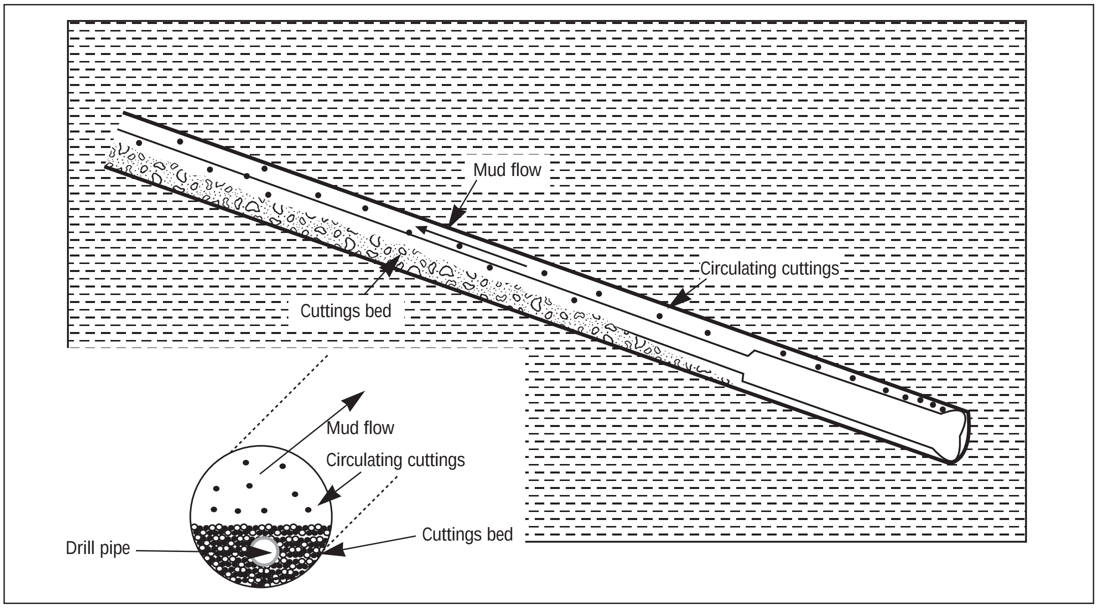


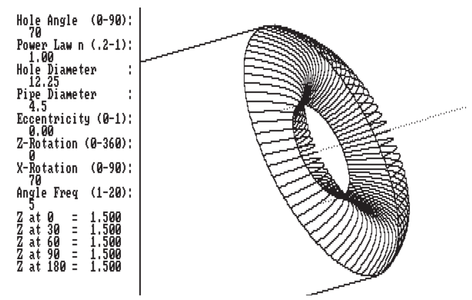
Figure 4: Cuttings bed in highly inclined well.

can form thick filter-cake-like beds which are very difficult to remove without aggressive hydrodynamic and mechanical action.

Flow characteristics. Cuttings transport efficiency is largely a function of annular velocity and the annular velocity profile. ***Increasing annular velocity will always improve hole cleaning,*** though it still must work in concert with other well parameters to ensure good hole cleaning.

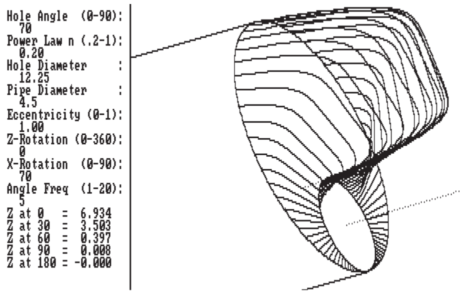
Increasing annular velocity will always improve hole cleaning...

In a fully concentric annulus, flow is evenly distributed around the drillstring as illustrated in Figure 5a. Thus, there is an equal distribution of fluid energy for cuttings transport, regardless of fluid rheology. This profile is generally assumed for vertical intervals. However, the drillstring tends to lay on the low side of the hole in inclined sections, shifting or "skewing" the velocity profile (as shown in Figure 5b), the result of which is not conducive to cuttings transport. Cuttings accumulate on the bottom of the hole adjacent to the drill pipe where the mud flow is minimal. In this situation, pipe rotation is critical to achieve effective hole cleaning. Figure 5b clearly shows that, without pipe rotation, non-Newtonian behavior in laminar flow can exacerbate the skewed profile.



```
Hole Angle  (0-90):
  70
Power Law n (.2-1):
  1.00
Hole Diameter     :
  12.25
Pipe Diameter     :
  4.5
Eccentricity (0-1):
  0.00
Z-Rotation (0-360):
  0
X-Rotation  (0-90):
  70
Angle Freq  (1-20):
  5
Z at 0   =  1.500
Z at 30  =  1.500
Z at 60  =  1.500
Z at 90  =  1.500
Z at 180 =  1.500
```

Figure 5a: Concentric drill pipe and Newtonian fluid.



```
Hole Angle  (0-90):
  70
Power Law n (.2-1):
  0.20
Hole Diameter     :
  12.25
Pipe Diameter     :
  4.5
Eccentricity (0-1):
  1.00
Z-Rotation (0-360):
  0
X-Rotation  (0-90):
  70
Angle Freq  (1-20):
  5
Z at 0   =  6.934
Z at 30  =  3.503
Z at 60  =  0.397
Z at 90  =  0.008
Z at 180 = -0.000
```

Figure 5b: Eccentric drill pipe and non-Newtonian fluid.

Figure 5: Effect of eccentricity and rheology on flow profile.

As illustrated in Figure 6, pipe rotation in fluids with elevated Low-Shear-Rate Viscosity (LSRV), such as FLO-PRO®

1. Rotation moves cuttings from underneath pipe.
2. To the top of the cuttings bed.
3. Up into the mud flow stream.
4 and 5. Transporting the cuttings along the well path.

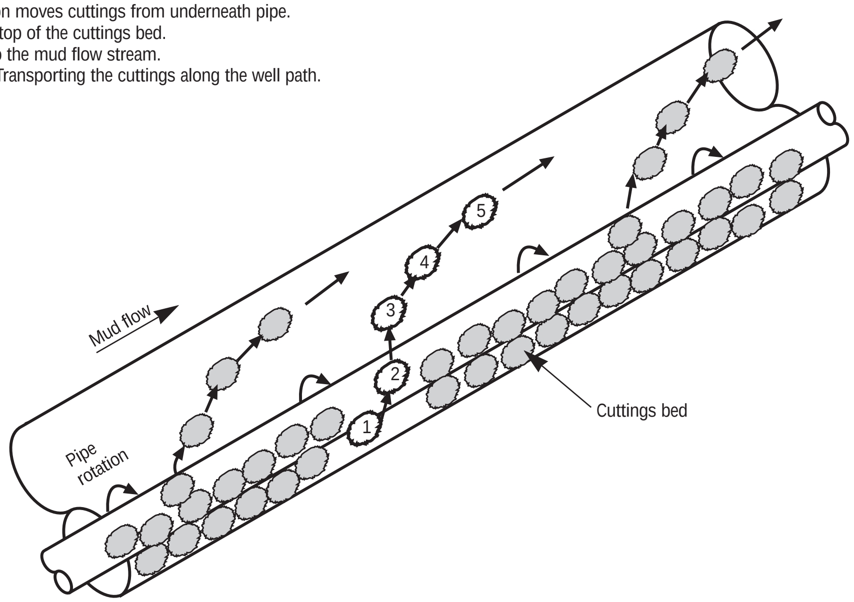


Figure 6: Rotation lifts cuttings into the flow stream.

and Mixed Metal Hydroxide (MMH) systems, can dramatically improve hole cleaning. This rotation lifts cuttings from the low side of the hole back into the flow stream and induces a helical flow pattern which can be very effective for hole cleaning, even at low annular velocities.

Conditions for which the velocity profile is relatively insensitive to pipe rotation include (1) turbulent flow, (2) concentric pipe and (3) low-viscosity fluids, especially clear brines. Furthermore, rotation may not be possible, as in coiled-tubing drilling and slide directional drilling to build angle.

Turbulent flow is considered by some to be a prerequisite for good hole cleaning...

Turbulent flow is considered by some to be a prerequisite for good hole cleaning in some applications, such as small-diameter holes in highly competent formations. Turbulent eddies and high velocities are consistent with good hole cleaning, except when drilling easily eroded formations. Any washouts created by turbulence reduce annular velocity and systematically degrade performance. Unfortunately, turbulence is difficult to achieve and maintain in larger-diameter holes and when using viscosified fluids where suspension is required.

There are many conditions for which full turbulence in an eccentric annulus is not practical to achieve. The open regions above eccentric pipe achieve turbulence at much lower flow rates than those on the low side which contains cuttings beds.

Mud Properties

Generally speaking, different drilling fluid types provide similar cuttings transport if their downhole properties also are similar. However, selection of optimum properties requires careful consideration of all related parameters. Clearly, mud properties must be maintained within certain limits to be effective without being destructive or counter-productive. Properties of particular interest to hole cleaning include mud weight, viscosity, gel strengths and level of inhibition.

Mud weight *helps buoy cuttings and slow their settling rate...*

Mud weight helps buoy cuttings and slow their settling rate (as shown by Stokes' law), but it is really not used to improve hole cleaning. Instead, mud weights should be adjusted based only on pore pressure, fracture gradient and wellbore-stability requirements. Vertical wells drilled with heavy muds normally have adequate hole cleaning as compared to highly deviated directional wells drilled with low-density fluids.

Wellbore instability is a special case where mud weight clearly targets the cause, rather than the symptoms, of hole-cleaning problems. As a rule, formations drilled directionally require higher mud weights to prevent borehole failure and sloughing into the annulus. What can appear as a hole-cleaning problem at the surface, in fact, can be a stress-related problem which should be corrected by increasing the mud weight. Alternative actions to improve cuttings transport may help but will not eliminate the basic problem.

Mud viscosity helps determine carrying capacity. For vertical wells, yield point historically has been used as the key parameter which was thought to affect hole cleaning. More recently, evidence concludes that Fann 6- and 3-RPM values are better indicators of carrying capacity (even in vertical wells). These values are more representative of the LSRV which affects hole cleaning in marginal situations. Coincidentally, most viscosifiers (clays, for example) added to increase yield point also increase 6- and 3-RPM values. One common rule of thumb is to maintain the 3-RPM value so that it is greater than the hole size (expressed in inches) in high-angle wells.

The Low-Shear Yield Point (LSYP), calculated from 6- and 3-RPM values, has also gained broad acceptance for quantifying LSRV:

$$LSYP = (2 \times \Theta_{3rpm}) - \Theta_{6rpm}$$

LSYP can play an even more important hole-cleaning role in directional wells, if it is applied in accordance with the specific well conditions. For example, in laminar flow, there is a clear correlation between improved hole-cleaning performance and elevated LSYP, especially in conjunction with the rotation of eccentric pipe. On the other hand, low LSYP values are preferred for turbulent-flow hole cleaning, because turbulence could be achieved at lower flow rates.

Gel strengths *provide suspension under both static and low-shear-rate conditions.*

Despite its inherent advantage as a general-purpose hole-cleaning indicator, LSYP is not recommended for the FLO-PRO system and other polymer systems which exhibit visco-elastic properties. FLO-PRO viscosity at very low shear rates can be considerably higher than that of fluids with similar 6-RPM, 3-RPM and LSYP values. This unique rheological behavior is the signature characteristic of FLO-PRO fluids and one of the keys to their success as premier horizontal drill-in fluids. Elevated LSRVs make it possible to achieve superb hole cleaning at much lower flow rates than conventional systems.

LSYP is an extrapolated value just like its yield-point counterpart in the Bingham Plastic Model. As such, LSRV for FLO-PRO systems should be measured using a Brookfield viscometer running at 0.0636 sec^{-1} (0.3 RPM with a #2 spindle). Although not a direct measurement of viscoelasticity, Brookfield viscosity correlates well with hole-cleaning performance of FLO-PRO in the field.

Gel strengths provide suspension under both static and low-shear-rate conditions. Although closely related to viscosity, gel strengths sometimes are overlooked with regard to their effects on hole cleaning. Quickly developing gels which are easily broken, as is the case for FLO-PRO systems, can be of significant help. Excessively high and/or progressive gels, on the other hand, should be avoided because they can cause or exacerbate a number of serious drilling problems.

Basic Models

Except for Stokes' law, settling and hole-cleaning mechanisms are quite complex and difficult to model, even if some key parameters are assumed or disregarded. In fact, analytical solutions for annular Boycott settling may not be possible using conventional numerical techniques. It is for this reason that the models provided in this section focus on vertical wells.

There are several good correlations for slip velocity. M-I computer programs use the method developed by Walker and Mayes. The equations which follow are based on their work. They apply in vertical sections, but have reduced application in inclined intervals. Cuttings are considered to be disks falling edgewise through the mud. The resisting shear stress on the

CTR is a useful method for normalizing the rise velocity.

cutting Fp depends on the particle thickness and the density difference between cuttings and mud:

$$Fp\ (lb/100\ ft^2) = 7.4 \times [h_C \times ((8.34 \times Gp) - W)]^{0.5}$$

Where:

h_C = Particle thickness (in.)
Gp = Particle specific gravity
W = Mud weight (lb/gal)

Units for Fp are chosen to allow direct comparison to the mud rheogram plotted from viscometer data. If the entire rheogram curve lies above a shear stress equal to Fp, then cuttings are fully suspended and will not settle. If Fp crosses the rheogram curve, the intersection point is the equivalent particle shear rate Rp (RPM). The slip velocity then depends on whether flow around the particle is laminar or turbulent. The transition shear rate Rc is:

$$Rc\ (RPM) = \frac{109}{dc \times W^{0.5}}$$

Where:

dc = Cutting diameter (in.)

Slip velocity, V_{SLIP} is then calculated by:

$$V_{SLIP} = 1.7 \times Fp \times \left[\frac{dc \times Rp}{W^{0.5}}\right]^{0.5}$$

for laminar ($Rp < Rc$)

or

$$V_{SLIP}\ (ft/min) = 17.72 \times \frac{Fp}{W^{0.5}}$$

for turbulent ($Rp > Rc$)

In a circulating fluid, the difference between the annular velocity (V_{ANN}) and the slip velocity is known as the *transport* or *"rise" velocity* (V_{RISE}):

$$V_{RISE} = V_{ANN} - V_{SLIP}$$

This V_{RISE} equation applies only to vertical intervals because it assumes V_{ANN} and V_{SLIP} exist along the same axis. Perfect hole cleaning occurs as V_{RISE} approaches V_{ANN}. Hole cleaning is poor for low values of V_{RISE} and clearly deficient for negative values ($V_{SLIP} > V_{ANN}$).

***...the difference between the annular velocity and the slip velocity is known as the* transport *or* "rise" velocity**

Cuttings Transport Ratio (CTR) is a useful method for normalizing the rise velocity. This allows hole-cleaning performance in different intervals to be compared directly. CTR (% by volume) values range from 0% for "very poor" and 100% for "perfect" cleaning. Empirical results have suggested that CTR values greater than 50% may be suitable for most vertical wells. This corresponds to an annular velocity twice that of the slip velocity.

$$CTR\ (\%) = 100 \times \frac{(V_{ANN} - V_{SLIP})}{V_{ANN}}$$

Cuttings concentration (C_{conc}) is perhaps the best indicator for cuttings transport in vertical intervals. Experience over the years has shown that drilling problems escalate when the C_{CRIT} exceeds a threshold value (about 5%). C_{conc} is calculated by:

$$C_{conc}\ (\%\ volume) = \frac{1.667 \times ROP \times D_b^2}{(D_h^2 - D_p^2) \times (V_{ANN} - V_{SLIP})}$$

and the critical annular velocity ($V_{ANNCRIT}$) to maintain a specific C_{conc} is defined by:

$$V_{ANNCRIT}\ (ft/min) = \frac{1.667 \times ROP \times D_b^2}{(D_h^2 - D_p^2) \times C_{conc}} + V_{SLIP}$$

Where:

ROP = Penetration rate (ft/hr)
D_b = Bit diameter (in.)
D_h = Hole/casing diameter (in.)
D_p = Pipe OD (in.)
V_{ANN} = Annular velocity (ft/min)
V_{SLIP} = Slip velocity (ft/min)

NOTE: Pipe eccentricity and rotation have minimal effects in vertical intervals and are not considered.

Relationships for directional intervals are not straightforward. Some models are available, but most are incomplete. The danger is that exclusion of factors, such as gel strength, pipe rotation, eccentricity, low-shear viscosity, interaction among different intervals and others, can lead to wrong conclusions.

Fuzzy logic technology (the basis for artificial intelligence) is emerging as the best approach to evaluate hole-cleaning performance at all angles and is the method of choice for M-I software. Fuzzy logic works well with missing and incomplete data, both common to hole-cleaning analysis. Performance is described using words (poor, fair, good and very good) rather than numbers.

Hole-Cleaning Criteria

Clearly, ratios below 1.0 indicate that a hole-cleaning problem exists.

Opinions vary on what constitutes "good" hole cleaning. From a practical perspective, hole cleaning is adequate if no operational problems are encountered. This implies that hole-cleaning requirements vary among different wells and even different intervals in the same well.

Poor cleaning would naturally be assumed if cuttings were not observed on shaker screens. Drilling reactive shales using a highly dispersive water-base mud will limit cuttings observed at the shaker. Other physical indicators of poor cleaning include hole fill in vertical wells, cuttings beds in directional wells, mud rings, bridges and packoffs. Unfortunately, high cuttings volumes on the screens do not automatically signal excellent cuttings transport.

Comparison between the volume of cuttings generated by the bit to the volume of hole drilled is one of the field techniques available to measure hole-cleaning efficiency. Zero-discharge and no-cuttings-discharge operations are examples where cuttings volumes are monitored because they must be boxed and transported for disposal. Typically, the ratio of surface to downhole cuttings volume varies from about 1.5:2.2, but the ratio should only be used as a trend to highlight potential problems. Clearly, ratios below 1.0 indicate that a hole-cleaning problem exists. A drawback to this technique is its inability to identify large cuttings which remain downhole until they grind down into particles that are small enough to be carried to the surface.

There are several techniques for predicting downhole cleaning performance when direct measurements are not possible. In vertical sections, minimum annular velocity, slip velocity, rise velocity, cuttings transport ratio and cuttings concentration are the most common. In directional wells, cuttings-bed thickness also is a good, although not definitive, indicator. Unlike hole fill in vertical wells, cuttings-bed thickness cannot be measured.

At one time, minimum annular velocity was the traditional criterion for "good" hole cleaning. Velocities from 100 to 120 ft/hr were considered adequate, although dependence on hole size was evident. For very large holes (>17½ in.) where 100-ft/min velocity was not achievable, mud yield point was increased significantly to provide adequate hole cleaning. A flocculated gel fluid is a common system used for this purpose.

Minimum Transport Velocity (MTV) is a recent technique applicable to directional wells. This concept presumes that a hole interval can be efficiently cleaned if all cuttings are either suspended in the flow stream or in beds moving upwards in the direction of flow. The annular velocity should meet or exceed a calculated MTV value for both conditions. It would appear that MTV values are conservative, but the concept has been refined by field data and has been used successfully.

Hole-Cleaning Guidelines

When establishing hole-cleaning guidelines, it is important to review relationships among the parameters in Table 1 and to recognize that some can be both independent and dependent variables. Often, one parameter, such as formation type, will determine how to approach hole cleaning. For example, a typical horizontal well drilled through a very competent Austin Chalk formation might use a brine drill-in fluid. It follows that these parameters would be appropriate — turbulent flow, high annular velocity, low fluid viscosity and gels, with minimal effects from pipe eccentricity and rotation. On the other hand, an unconsolidated-sandstone, horizontal interval would dictate tight filtration control and laminar flow. Elevated low-shear rheology and flat gels would be suitable, especially if the eccentric pipe can be rotated.

Listed below are practical hole-cleaning guidelines aimed at field use. They are grouped according to general (all wells), vertical/near-vertical wells and directional wells (including horizontal).

GENERAL

1. Use the highest possible annular velocity to maintain good hole cleaning, regardless of the flow regime. Annular velocity provides the upward impact force necessary for good cuttings transport, even in directional and horizontal wells.
2. Rely on mud rheology and gel strengths for suspension and transport capabilities.
3. Control drill to manage difficult hole cleaning situations only as a last resort. Penetration rate determines the annular cuttings load. The negative implications of limiting drill rate are self-evident.
4. Take advantage of top drives, if available on the rig, to rotate and circulate (backream) when tripping out.
5. Continually monitor parameters affecting hole-cleaning, and react accordingly. Always consider the consequences of changes on other operations.
6. Measure mud rheology under downhole conditions, especially in deepwater and High-Temperature, High-Pressure (HTHP) applications.
7. For deepwater wells with a large-diameter riser, add a riser pump to increase riser annular velocity.
8. Avoid using highly dispersive muds that might help cleaning, but can create a mud solids problem.

VERTICAL AND NEAR-VERTICAL WELLS

1. Keep cuttings concentration less than 5% (by volume) in order to minimize drilling problems.
2. For efficiency and cost considerations, use a mud viscosity selected based on hole size and slip velocity calculations. Further increase yield point and LSYP only when hole-cleaning problems have been encountered or are imminent.

3. Maintain LSYP between 0.4 and 0.8 times the hole diameter in inches unless hole conditions dictate otherwise. Yield point and LSYP for highly dispersed muds typically are low, so higher annular velocities may be required.
4. Use periodic high-density/high-viscosity sweeps to correct cleaning problems. Do not run sweeps unless hole conditions warrant. Sweeps should be >0.5 lb/gal heavier than the mud and should be combined with vigorous fluid and mechanical agitation, if possible.
5. Monitor the hole for symptoms of cuttings accumulation, fill and bridges.
6. Do not expect pipe rotation to help hole cleaning, especially in larger-diameter holes.

DIRECTIONAL WELLS

1. Use hole-cleaning techniques to minimize cuttings-bed formation and subsequent slumping which can occur in 30 to 60° hole sections.
2. Utilize elevated-viscosity fluids from the start, because cuttings beds are easy to deposit, but difficult to remove.
3. Maintain LSYP between 1.0 and 1.2 times the hole diameter in inches when in laminar flow.
4. Treat mud to obtain elevated, flat gels for suspension during static and low-flow-rates periods.
5. For optimum performance from FLO-PRO fluids, maintain Brookfield viscosity above 40,000 cP.
6. Schedule periodic wiper trips and pipe rotation intervals for situations where sliding operations are extensive and bed formation is expected.
7. When using FLO-PRO systems for coiled-tubing drilling, periodically run wiper trips to remove cuttings beds. For re-entry wells with large casing, select the best compromise to clean both the horizontal and casing intervals.
8. Rotate pipe at speeds above about 50 RPM if possible to prevent bed formation and to help remove pre-existing beds. Fully eccentric pipe combined with proper LSYP values can provide best results.
9. Increase mud weight to correct well-bore stresses problems masquerading as hole-cleaning problems.
10. Recognize that turbulent flow across the annulus may be difficult to achieve and maintain.
11. Consider drilling small-diameter, competent, horizontal intervals using turbulent flow. Low-viscosity fluids enter a state of turbulence at lower flow rates than viscous ones. Any beds which form can be eroded by the high flow rates required for turbulent flow.
12. Expect little help from viscous sweeps, unless they are accompanied by high flow rates and pipe rotation and/or reciprocation.

Introduction

A displacement occurs when one fluid replaces another in the wellbore.

Fluid displacements are a common procedure in the drilling, completing and workover of wellbores. A displacement occurs when one fluid replaces another in the wellbore. This chapter will discuss two separate displacement categories. The first covers standard fluid displacements including water-base muds, oil-base muds, synthetic-base fluids, completion fluids and workover fluids. The second category covers cementing displacements.

There are a number of different displacement procedures used in wellbore operations. Listed below are some of the more common procedures.

- **Conventional or standard displacement procedure.** The new fluid is pumped down the drill pipe or tubing to displace the existing fluid up and out of the annulus. This is the normal method of wellbore circulation (see Figure 1).

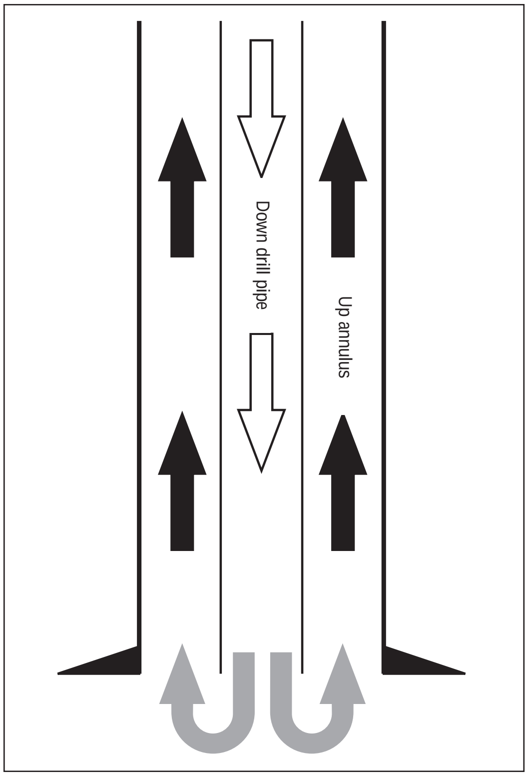


Figure 1: Conventional displacement.

- **Reverse circulation.** The new fluid is pumped down the annulus and the existing fluid is displaced up and out of the drillstring or tubing. This procedure is most commonly used when a lighter fluid is used to displace a heavier fluid (see Figure 2).

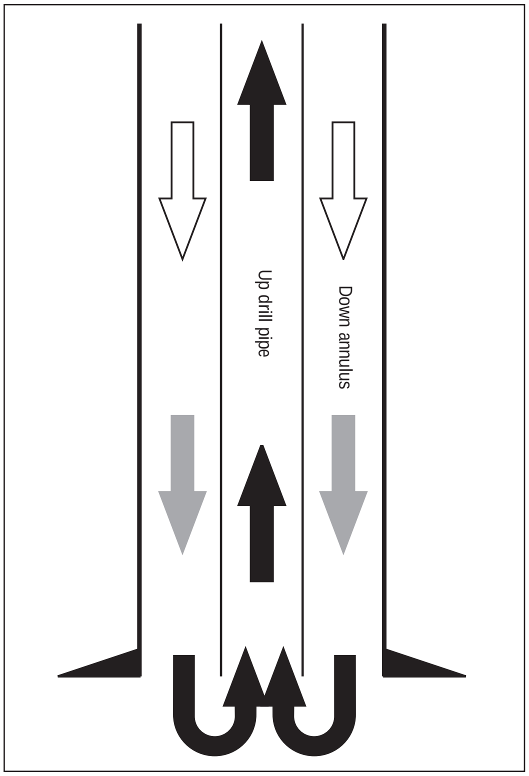


Figure 2: Reverse circulation.

- **Bullhead or squeeze displacement.** The new fluid is pumped down the wellbore and the existing fluid is displaced into the formation with no returns to the surface. This procedure can occur down tubing or between casing strings (see Figure 3).

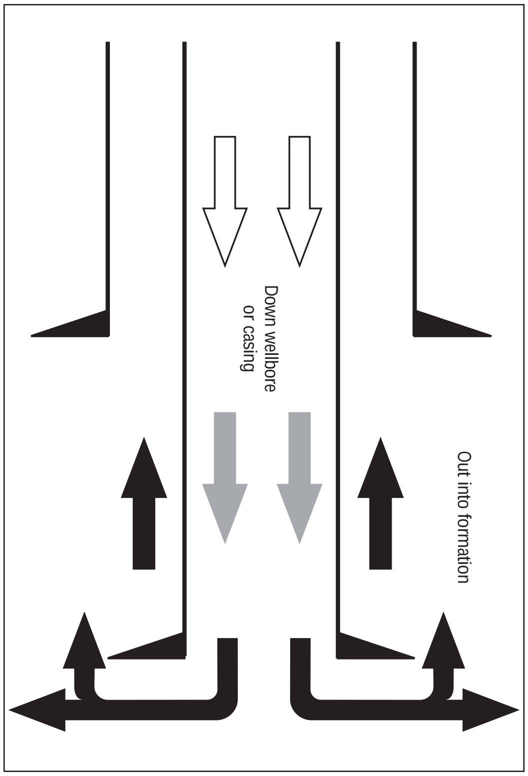


Figure 3: Bullhead displacement.

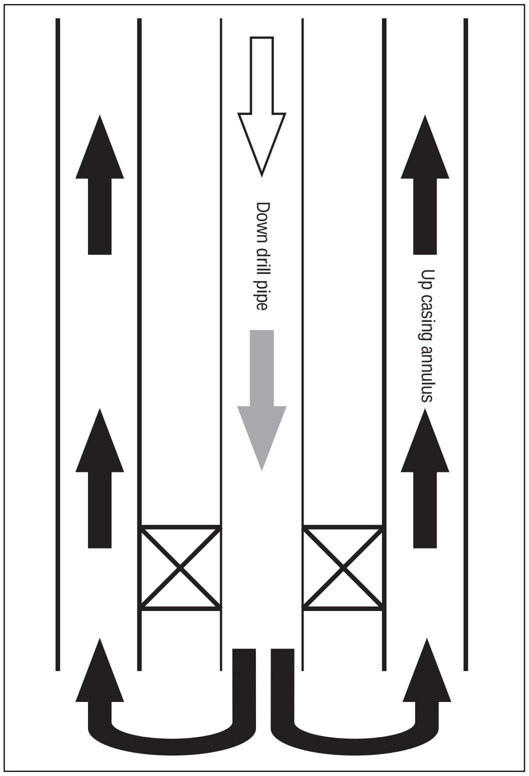


Figure 4: Annular casing displacement.

- **Annular casing displacement.** The new fluid is pumped down the drill pipe or tubing and through a port or collar in the casing string to displace the existing fluid in the casing annulus (see Figure 4).

Factors Affecting Displacements

If a lower-density fluid is displacing a higher-density fluid, it is advantageous to reverse circulate.

Other displacement procedures are used in cementing, gravel packing and fracturing operations.

There are a number of factors that are critical in designing a successful displacement procedure. These factors include the following:

- Fluid density.
- Fluid viscosity.
- Sweeps and spacers.
- Fluid condition.
- Rotation and reciprocation.
- Rig equipment.
- Pumping operations.
- Wellbore deviation.

The impact of these factors must be considered in order to optimize displacement procedures. Each of these factors will be discussed in some detail.

Fluid density. In a standard or conventional displacement procedure, it is desirable to have the displacing fluid heavier than the fluid being displaced. When the heavier fluid reaches the bottom of the well, the heavier fluid will tend to sink while the lighter existing fluid will tend to float or be suspended, thereby aiding in maintaining separation.

If a lower-density fluid is displacing a higher-density fluid, it is advantageous to reverse circulate. In this procedure the lighter fluid should be pumped down the annulus, displacing the heavier fluid up and out of the drill

When isolation spacers are utilized to separate two incompatible fluids, they should be more viscous than either fluid...

It is very important to have a drilling fluid in good condition prior to displacement.

pipe or tubing. Commingling of these fluids may occur in the tubing, but this procedure will minimize the interface when a lighter fluid is displacing a heavier fluid. Wellbore pressures and pressure-drop values should be calculated prior to utilizing the reverse circulation procedure. Improper use of this procedure may cause wellbore damage and/or lost circulation.

It is possible to have effective displacement procedures between fluids with different densities, even when the optimum displacement technique cannot be used. This is accomplished by utilizing the proper spacers, sweeps and flow rates. *NOTE: When displacing fluids with different densities, it is imperative that there is a complete understanding of the downhole pressures throughout the displacement process. Inadequate pressure analysis has caused wellbore-control situations including blowouts and lost circulation.*

Fluid viscosity. Fluid viscosity is important in displacement procedures. The most desirable situation is to displace a thin existing fluid with a viscous fluid. When isolation spacers are utilized to separate two incompatible fluids, they should be more viscous than either fluid, to keep the two incompatible fluids from commingling. In general, the viscosity of the displacing fluid should be higher than the fluid to be displaced.

Sweeps and spacers. Sweeps and spacers serve several different functions in the displacement process. They are used to separate the displaced from the displacing fluid; they are used to clean the wellbore of mud cake; and they are used to change the wettability of the wellbore. Sweeps and spacers can be adjusted to any desired fluid density and fluid viscosity, and they can include surfactants and detergents. Sweeps and spacers must be of sufficient volume so they prevent commingling of the displaced and displacing fluids. They must be of sufficient length to allow enough contact time to clean or change the wettability of the wellbore. Spacers and sweeps can be made from freshwater, brine, oil, synthetic fluid and specialty chemicals. Additional information about spacers can be found in the discussion concerning actual displacement procedures.

The most basic function for all spacer design is to thin the mud in the hole so that it will be removed from the well and to viscosify the mud being placed in the well so that the leading edge of this displacing mud is as viscous as possible. Having the leading edge of the displacing mud as viscous as possible results in plug flow with a flat velocity profile and minimizes the contamination and commingling of the two fluids. Using this concept, if only one spacer is to be used, it is preferred to use water to displace a water-base mud with an oil-base mud or oil to displace an oil-base mud with a water-base mud.

It is frequently beneficial to use some kind of marker to more clearly identify when the leading edge of the displacing mud reaches the shaker. Many times the returning mud is being dumped at the shaker and it is difficult to see the transition from one mud to another. Often a fine to medium lost-circulation material (such as NUT PLUG®) can be mixed into one of the spacers or into the first portion of the displacing mud as a marker.

Fluid condition. It is very important to have a drilling fluid in good condition prior to displacement. A drilling fluid with high solids, high viscosity and high gel strengths will be difficult to remove from the wellbore. When displacing a drilling fluid to a completion brine, it is absolutely essential that the drilling fluid be in good condition for displacement purposes to minimize formation damage and solids contamination of the solids-free completion brine.

Always displace at the highest flow rate possible.

Rotation and reciprocation. The drill pipe or tubing will be in close proximity with the wall of the hole or casing in various parts of the wellbore. When the pipe is not centered, fluids tend to channel up through the larger side of the hole, leaving old fluid behind the drill pipe on the narrow side of the hole. The best way to eliminate this problem is to rotate and reciprocate the pipe during displacement. Rotating and reciprocating forces the mud from poorly circulated areas into the flow stream, allowing for a more uniform displacement. Rotation also increases the degree of turbulence of the fluid. If the pipe remains static, some fluid may be bypassed causing potential contamination. If the pipe cannot be rotated, reciprocation is still beneficial. If displacements are taking place with a coiled tubing unit, special pulling procedures can be utilized to achieve effective displacements.

Rig equipment. In most displacement situations, all rig surface equipment must be thoroughly cleaned prior to displacement. This includes pits, lines, pumps, solids-control equipment, well-control equipment and hoppers. In some displacement scenarios, additional pumping and filtration equipment may be required to maintain fluid cleanliness.

Settling can be controlled by maintaining an elevated Low-Shear-Rate Viscosity.

Pumping operations. Displacement should be at a pump rate high enough to provide turbulent flow. The velocity profile in this case is flat, with a small boundary layer minimizing the commingling of fluids. If turbulence cannot be achieved, better fluid removal is found when maximum flow energy is used, even if the fluid is in laminar flow. Always displace at the highest flow rate possible. *Once displacement has begun, do not stop pumping operations.* If operations are stopped, commingling of fluids will occur. Prior to beginning displacement, all pressures, volumetric and pump-stroke calculations should be made. Prior to commencement of displacement, a rig meeting should be called so that all personnel know their responsibilities.

Wellbore deviation. Many of the factors which influence vertical wellbore displacement become even more critical in deviated wellbores. Results of investigations into deviated wellbore mud displacements indicate that Boycott settling of solids can result in a “bed” or mud and solids channel on the low side of the annulus which is virtually impossible to displace. This type of settling can occur at any time when circulating a high-angle well. Settling can be controlled by maintaining an elevated Low-Shear-Rate Viscosity (LSRV). This value is dependent on wellbore deviation, hole size, fluid type, availability of pipe rotation and solids loading. Effective displacements can still be achieved with the use of high pump rates, adequately sized and properly designed spacers and effective pipe rotation/reciprocation.

Types of Fluid Displacements

There are many different types of fluid displacements that occur during wellbore operations. Listed below are several of the more common types of fluid displacements.

- Water-base mud to water-base mud.
- Water-base mud to oil-base mud.
- Oil-base mud to water-base mud.
- Water-base mud to completion brine.
- Oil-base mud to completion brine.

Each of these displacement types will be discussed, and an example of a displacement procedure will be presented.

Water-base mud to water-base mud. The displacement of one water-base mud to another is a relatively common occurrence in the drilling process. These displacements can occur for a variety of reasons, such as when changing mud systems at casing points or even during an open-hole section. They include but are not limited to:

- Displacements to drill-in fluids.
- Displacements to brine-base muds.
- Displacements for environmental reasons.
- Displacements because of geological reasons.
- Displacements to improve drilling performance.

Cased-hole displacements offer several significant advantages over open-hole...

Cased-hole displacements offer several significant advantages over open-hole displacements. These include known wellbore volumes, improved well control, no problems with wellbore stability and reduced possibility of cross-contamination of displacement fluids. Either conventional displacement procedures or reverse-circulation displacement procedures can be used when the displacement occurs inside casing.

There are normally four different situations where displacements can occur during casing-point operations. The first occurs during casing cementing operations, when the new fluid is used to displace the cement from inside the casing and "bump" the plug. The second situation takes place just prior to drilling the cement, the float collar and the casing shoe. The third occurrence in which displacement can occur is after drilling the cement and float collar, but prior to drilling the casing shoe. The fourth is after the cement, float collar and casing shoe have been drilled. Displacement occurs just before or just after the formation-integrity test.

Open-hole displacements are more difficult than casing-point displacements because of potential hole washouts and the inability to make precise volume calculations. Open-hole displacements with incompatible fluids can cause significant wellbore instability situations. In planning open-hole displacements it is essential to maintain adequate downhole hydrostatic pressure to maintain wellbore control. Open-hole displacements in producing formations must take into consideration the potential for formation damage. Successful open-hole displacements can take place with proper prior planning, proper spacer design and good well site execution.

Displacements from freshwater- to brine-base muds can potentially cause significant problems. These fluids need to be displaced with adequate spacers because detrimental flocculation can occur if the fluids commingle.

Following is an example of a water-base mud to water-base mud conventional displacement (intermediate mud to "bland" coring fluid):

- Hold predisplacement meeting.
- Drill out casing shoe and perform formation integrity test.
- Condition existing water-base mud to reduce viscosity and gels.
- Wash and drain mud pits and flush all lines with water.
- Pump 50 bbl of water with solvent.

- Pump 50 bbl of viscosified water with 3 lb/bbl of a viscosifier such as FLO-VIS.®
- Pump displacing fluid at as high a pump rate as practical.
- Rotate and reciprocate pipe.
- Monitor pump strokes.
- Divert "old" mud for disposal.
- Switch to closed-loop circulation when new fluid returns and circulates over shakers.

Water-base mud to oil-base mud. In many drilling programs, the surface and intermediate casing sections are drilled with water-base muds. The deeper intervals in the well are drilled with oil- or synthetic-base muds. In general, the primary requirements in this displacement situation are to minimize rig time, minimize contamination of the oil- or synthetic-base mud. This is generally accomplished with either one water-base spacer or a water-base followed by a viscous oil-base spacer.

Following is an example of water-base mud to oil-base mud conventional displacement:

- Hold predisplacement meeting.
- Condition water-base mud to reduce viscosity and gels.
- Wash and drain mud pits and lines with water.
- Fill pits with oil-base muds.
- Pump sufficient volume to obtain 200 to 500 linear annular feet of water spacer.
- Pump sufficient volume to obtain 200 to 500 linear annular feet of viscosified oil spacer.
- Pump oil mud.
- Monitor pump strokes.
- Pump at as high a rate as practical.
- Rotate and reciprocate pipe.
- Use large-mesh screens on shakers.
- Divert water-base mud for disposal.
- Switch to closed-loop circulation when oil-base fluid returns and circulate over shaker.

Oil-base mud to water-base mud. An oil-base or synthetic-base mud to a water-base mud displacement usually occurs just prior to the producing interval. This is a situation in which the oil-base or synthetic-base mud provides superior drilling performance in the upper sections of the wellbore above the producing interval, but could damage the producing formation or when a formation evaluation log requires water-base mud.

Another situation that may require displacing an oil- or synthetic-base mud with a water-base mud occurs when lost circulation is encountered. The oil- or synthetic-base fluid may be displaced from the hole with a less expensive water-base mud. Successful spacer design is essential for these displacements to be effective.

Following is an example of oil-base mud to water-base mud conventional displacement:

- Hold predisplacement meeting.
- Condition water-base mud to reduce viscosity and gels.
- Wash and drain mud pits and lines.
- Fill pits with water-base mud.
- Pump sufficient volume to obtain >200 linear annular feet of oil spacer.
- Pump 25 to 50 bbl of viscosified water space with 3 lb/bbl of a viscosifier such as FLO-VIS.
- Pump water-base mud.
- Monitor pump strokes.
- Rotate and reciprocate pipe.
- Divert oil mud returns to storage
- Switch to closed-loop circulation when water-base mud returns and circulate over shaker.

Water-base mud to completion brine. In this type of displacement, it is essential to remove all of the water-base mud and any residual filter cake from the well prior to displacing with the completion brine. This can be accomplished with adequate spacers and surfactant washes. Any residual mud or mud filter cake can cause a reduction in potential production.

Following is an example of the reverse displacement of 10-lb/gal water-base mud to 9-lb/gal completion brine:

- Hold predisplacement meeting.
- Rig up reverse circulate; pumping down annulus and taking returns through drill pipe.
- Clean and drain pits, pumps and lines.
- Pump 50 bbl viscosified spacer with surfactant.
- Pump 50 bbl brine spacer with chemical wash (optional).
- Pump 50 bbl viscosified completion brine.
- Pump completion brine.
- Monitor pump strokes.
- Divert water-base mud to disposal.
- Switch to closed-loop circulation when completion brine returns and circulate and filter completion fluid.

Oil-base mud to completion brine. In this situation, it is important not only to remove the oil-base mud and filter cake but the wellbore needs to be made water-wet rather than oil-wet. This type of displacement creates the potential for an emulsion to form which can negatively impact production potential. Adequate spacers and solvent washes must be utilized if this type of displacement is to be effective.

Following is an example of 10.5-lb/gal, oil-base mud to a 9.2-lb/gal completion brine conventional displacement:

- Hold predisplacement meeting.
- Pump 50 bbl of low viscosity oil-base mud.
- Pump 50 bbl of viscosified brine spacer with surfactant.
- Pump 10 bbl chemical wash.
- Pump 50 bbl viscosified completion brine.
- Pump completion brine.
- Monitor pump strokes.
- Divert oil-base mud to storage.
- Switch to closed-loop circulation when completion brine returns and circulate and filter completion brine.

The following is a checklist of items that should be considered when developing a displacement plan:

- Fluid types, density and viscosity.
- Potential formation damage.
- Environmental.
- Wellbore safety, pressure control.
- Wellbore deviation, geometry.
- Spacer size and composition.
- Flow rates, pump efficiencies.
- Volumetric calculations.
- Ability to rotate and reciprocate.
- Calculated pressure schedule and wellbore pressures.

Cementing Displacement Considerations

Having a drilling fluid with properties optimized for displacement with cement is the single most important factor in obtaining total mud removal.

Extensive studies have shown the foremost factor affecting cement placement is the effective displacement of drilling fluids from the annulus. Cementing studies have determined that a high frequency of cement failures can be attributed to incomplete mud displacement from the annulus which results in mud channels in the cement. These mud channels effectively provide a conduit for the migration of fluids that cause lost production and/or corroded casing and do not allow the cement to form an effective annular pressure seal.

Removal of mud and filter cake is imperative to obtaining a good cement job. The primary factors influencing mud removal are:

- Drilling fluid properties.
- Pipe movement.
- Pipe centralization.
- Flow rate.
- Spacers or flushers.
- Contact time.
- Density differences.
- Hole size and washout.

Drilling fluid conditioning. Having a drilling fluid with properties optimized for displacement with cement is the single most important factor in obtaining total mud removal. Mud removal is influenced by the following factors:

- **Mud properties.** Mud properties need to be adjusted to fluid type, hole angle and wellbore conditions. Mud properties should be adjusted after casing is run. Mud properties required for good cementing may not be the same as those required for successful pipe running. In many areas it is common practice to increase viscosity and gels prior to running casing to provide adequate suspension of any cuttings or cavings. Yet low viscosity fluids are most desirable for obtaining a good drilling fluid displacement and cement job.
- **Fluid loss.** Decreasing filtrate loss results in a thin filter cake. This increases the proportion of mud in the hole which is more easily removed than filter cake. Generally, an API fluid loss of 7 to 8 cm^3/30 min is sufficient. High-Temperature, High-Pressure (HTHP) fluid loss should be not more than twice the API fluid-loss value.
- **Gel strength.** A non-thixotropic mud with low non-progressive gels is desirable for good mud removal. The key parameters governing the ability to remove the mud from the well are low yield point and 10-sec, 10-min and 30-min gel strengths. A well-conditioned mud should have relatively low viscosity, yield point and gel strengths. In addition, these properties allow turbulent flow to be achieved at lower flow rates.
- **Circulation.** Circulate prior to cementing until well-conditioned mud is being returned to the surface. This may take two or more circulations.

Pipe movement helps break up gelled pockets of mud and loosen cuttings that may accumulate within the pockets.

Pipe movement. Following closely behind mud conditioning in importance is the need to employ pipe movement, rotation and reciprocation, both before and during cementing. Pipe movement helps break up gelled pockets of mud and loosen cuttings that may accumulate within the pockets. Pipe movement can also help offset negative effects of poorly centralized pipe. Mechanical scratchers attached to the casing can further enhance the beneficial effects of pipe movement. Reciprocation appears to be the better method when the pipe is well centralized. Rotation appears to be best when the pipe is highly uncentralized.

Pipe centralization. Pipe centralization is another important factor in obtaining high displacement efficiency.

The cement displays a strong tendency to bypass mud where the casing is eccentric. Cement tends to follow the path of least resistance, i.e. the wide side of the annulus. Centralizers improve casing standoff and centralization, thereby equalizing the distribution of forces exerted by the cement slurry as it flows up the annulus.

Generally, a 70% standoff is the objective sought for good centralization. Since perfect pipe centralization (100%) is impossible, it should be used in conjunction with other methods.

Flow rates. There are three flow regimes in which a non-Newtonian fluid (such as cement) may exist: turbulent flow, laminar flow and plug flow.

The highest displacement efficiency occurs under turbulent flow conditions.

- **Turbulent flow.** The greatest displacement efficiencies consistently occur at the highest displacement rates, regardless of the flow regime of the cement slurry. The highest displacement efficiency occurs under turbulent flow conditions. However, if turbulent flow cannot be achieved, displacement is consistently better at the highest flow rate attainable under like conditions for similar slurry compositions. If turbulent flow cannot be achieved, using a preflush should be considered:
  - When mud weights are low, it may be advantageous to use a lightweight scavenger slurry (flush) in turbulence ahead of the primary cement.
  - When mud weights are higher, the use of a spacer or flush which is easily put into turbulence is recommended. Several spacers and flushes can be used. A good general recommendation for a turbulent flush volume is enough for a 10-min contact time, or 1,000 ft of annular volume.
- **Laminar flow.** Viscous non-Newtonian fluids like cement tend to stay in laminar flow over a broad range of shear rate or annular velocity. For many instances, it is impossible to pump cement in turbulent conditions due to concerns for lost circulation and other reasons. When in turbulent flow, fluids exhibit less scrubbing action on wellbore surfaces and do not achieve as good fluid or filter-cake removal.
- **Plug flow.** In theory, plug flow is the second best flow regime. However, studies have shown that if turbulence cannot be achieved, better mud removal is found when maximum flow energy is used, even if the slurry is in laminar flow. Thus, maximum flow rates are always desirable if conditions permit.

Spacers or flushes. Fluids as simple as water or as complex as weighted spacers are beneficial displacement aids because they separate unlike fluids, cement slurry and they remove gelled mud. This promotes a better cement bond, thus helping avoid potential fluid incompatibility.

Many specialized spacer formulations have been designed for specific applications, ranging from well control to reactive spacers that react with chemical components of mud filter cake to improve cement bonding.

Field studies show that a contact time of 10 min with the slurry in turbulent flow enhances the chances of a good cement job.

Contact time. Contact time is the amount of time a fluid flows past a particular point in the annular space. Field studies show that a contact time of 10 min with the slurry in turbulent flow enhances the chances of a good cement job. Studies also show that contact time is not a major factor if the slurry is not in turbulent flow.

Density differences. Density differences do not appear to be a major factor except in extreme cases. A very light cement will not remove a dense mud as well as a dense cement will remove a light mud. The only recommendation regarding density differences is that the cement slurry should have a higher density than the drilling fluid or have a density high enough to maintain well control.

Hole size. The optimum annular space clearance recommended for good mud removal is for the hole size to be 1.5 to 2 in. larger than the casing size. Annular clearances larger than 2 in. can be dealt with, but those smaller than 1.5 in. make cementing significantly more difficult.

Other Cementing Factors

Although gas flow may not be apparent by pressure at the surface, it may occur between zones and damage the cement job.

Another factor to consider in obtaining a good cement job is gas flow. Although gas flow may not be apparent by pressure at the surface, it may occur between zones and damage the cement job. Several methods can be used to help prevent damaging the cement job.

Wiper plugs. Both a top and bottom wiper plug should be used to separate unlike fluids and prevent contamination of the shoe joint.

Waiting-on-cement time. Wait on cement to develop adequate compressive strength before pressure testing the casing or drilling out. Times should be based on the results of cement lab testing, not on the basis of cement samples taken during the cement job itself. Provided that the float equipment is holding, release all pressure on the casing at the conclusion of the cementing job.

Cement fall-back in "rathole." Where casing is to be set off-bottom, a heavy, viscous pill should be spotted in the rathole. The pill will prevent the cement and the "rathole" fluid from trading places due to density differences. The pill should be heavier than the cement to prevent gravity migration.

Cementing deviated wellbores. Many of the factors which influence vertical wellbore cementing become even more critical in deviated wellbores. Conditioning of the drilling fluid is still the most important factor, but different mud qualities are required for good displacements. Results of studies into deviated wellbore mud displacement and cementing indicate that settling of solids from the drilling fluid results in cutting beds and a channel on the low side of the annulus which is virtually impossible to displace.

Clearly there are two requirements in these situations: (1) Circulating cuttings from the well and (2) obtaining good mud removal below the eccentric casing. A special coordinated effort between mud engineer and cementer should be made to achieve an acceptable cement job in high-angle and horizontal wells.