Shale and Wellbore Stability

Introduction

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Maintaining a stable wellbore is one of the major challenges when drilling a well. Studies indicate that unscheduled events relating to wellbore instability account for more than 10% of well costs, with estimates over $1 billion in annual cost to the industry. Preventing shale instability is a high priority to every phase of the drilling fluids industry, from research and development efforts to field implementation by the mud engineer. New technologies are continually being developed and applied and earlier technologies refined.

Wellbore instability is caused by a radical change in both the mechanical stress and the chemical and physical environments when a hole is drilled, exposing the formation to drilling mud. Hole instability is seen most often as sloughing and caving shale, resulting in hole enlargement, bridges and fill. The most common consequences are stuck pipe, sidetracks, logging and interpretation difficulties, sidewall core recovery difficulties, difficulty running casing, poor cement jobs, and lost circulation. All contribute to increased costs, the possibility of losing part of the hole or the entire well, or reduced production.

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Wellbore instability is caused by:

- **Mechanical stress.**
  - Tension failure — fracturing and lost circulation.
  - Compression failure — spalling and collapse or plastic flow.
  - Abrasion and impact.
- **Chemical interactions with the drilling fluid.**
  - Shale hydration, swelling and dispersion.
  - Dissolution of soluble formations.
- **Physical interactions with the drilling fluid.**
  - Erosion.
  - Wetting along pre-existing fractures (brittle shale).
  - Fluid invasion — pressure transmission.

Understanding shale and wellbore instability is of primary importance if the drilling fluids engineer is to skillfully assess a situation and implement a remedial plan. A systematic approach integrating several disciplines is necessary for the evaluation and remedy of wellbore instability. In other words, a mud engineer's expertise is not limited to drilling fluids alone. A good working knowledge of all areas of the operation, as well as a basic background in mechanics and geophysics, and water and clay chemistry, are necessary. A number of possible causes must be evaluated in resolving wellbore instability. By evaluating these interrelated conditions, the most likely failure mode can be determined and an appropriate response can be applied to resolve or tolerate the instability.

These include mechanical conditions such as:

- Hole cleaning problems.
- Wellbore erosion.
- Physical impact damage.
- Mud weights and pore pressures.
- Surge and swab pressures.
- Wellbore stresses.

Chemical conditions also must be evaluated such as:

- Reactivity of the failing formation.
- Chemical compatibility of the mud system.
- Possible wellbore dissolution.

Quite often, simple and economical solutions do not exist. In these cases, a combination of good drilling practices, the most inhibitive "acceptable" mud system and symptomatic remedies must be used to complete the well. While oil- and synthetic-base systems frequently provide a more stable wellbore and generally solve shale problems, they may be restricted or cause other problems.

A number of restrictions may be placed on the types of mud systems and products that can be used. These restrictions include:

- The need to obtain specific formation evaluation (minimally altered cores or a particular log).
- Local health, safety and environmental regulations.
- Cost, logistics and availability of materials.
- Other problems that override wellbore stability concerns (lost circulation, for example).

Before discussing the individual causes of wellbore instability, it is important to review: (1) shale deposition and sedimentary rocks, (2) clay chemistry, and (3) the earth's stresses.

Shale Deposition and Sedimentary Rocks

Sedimentary processes tend to sort these particles so that sand is deposited at one location, silt in a second area and clay in a third area.

Sedimentary rocks are materials that have been deposited over geologic time in a basin of deposition. Sedimentary rocks can be divided into two major groups: clastic (pronounced *CLÁSS-tick*) and non-clastic. The non-clastic sedimentary rocks include organic precipitates such as coal and chemical precipitates such as salt. By definition, clastic sedimentary rocks consist principally of particles that have been eroded from one location on the earth's surface, transported to another location and deposited as a sediment. The agent of transport for clastic sedimentary rocks may be water, ice, wind or gravity.

Clastic sedimentary rocks are further classified according to the size of the particles that make up the rock. The important size classes of the sedimentary particles and the corresponding rock types are: gravel/conglomerate, sand/sandstone, silt/siltstone and clay/shale (see Table 1 in the Solids Control chapter).

The formation of a clastic sedimentary rock can be divided into two important phases: sedimentation and diagenesis (pronounced *DIE-ah GENesis*).

Sedimentation is the process that occurs at the surface of the earth and allows particles or grains to accumulate as a sediment (see Figure 2 in the Pressure Prediction chapter). For example, within a group of particles undergoing transport by flowing water, a slowing of the flow velocity allows the larger particles in the transported population to be sedimented. The flow of a stream or river into a large body of water such as a lake, bay or ocean ultimately allows all the transported particles to settle out with the coarser fraction accumulating nearest the mouth of the stream and finer fraction settling out away from the mouth.

Typically rivers and streams bring sand, silt and clay into sedimentary basins. Sedimentary processes tend to sort these particles so that sand is deposited at one location, silt in a second area and clay in a third area. As the basin fills, as the level of water in the sedimentary basin changes or as the location of the mouth of the river changes, the location of sand, silt and clay deposition changes. These changes in the location of sand, silt

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and clay sediment accumulation occur over time, and the vertical section at any one location reflects the history of previous deposition at that location and may be divided into layers of sand, silt and clay. As a general rule, sedimentation processes determine the grain size of the sediment as well as certain features that may be present in the sediment, such as bedding planes.

Diagenesis encompasses all of the processes that change a sediment *after* it is deposited. These processes include consolidation, dissolution of some minerals, precipitation of other minerals and changes in the composition of certain minerals. Diagenesis changes sand, silt and clay sediments into sandstone, siltstone and shale rock. Diagenesis begins immediately after the sediment has been deposited as the weight of more recently deposited sediments begin to consolidate and squeeze water out of sediment below the sedimentation surface. Diagenesis continues as the sediment becomes buried more deeply and temperature causes changes to occur in certain minerals. Water being squeezed out of more deeply buried sediments passes through and causes some minerals to be dissolved and others to be precipitated. Often the minerals precipitated in sand, silt and shale act to bind the sedimentary grains together and act as a cementing agent, giving the sedimentary rock a more rigid nature. As diagenesis proceeds with time, temperature and pressure, the changes in the sediment become larger and larger, and eventually grade into metamorphic processes.

It is important to keep in mind that all sedimentary rocks that are drilled have been the result of both sedimentation and diagenesis processes.

Shale is the clastic sedimentary rock composed primarily of particles that are in the clay-size class (on average, smaller than 4 microns). To understand the nature of clay sediments and shale rock, it is important to understand that the term "clay" has two definitions. One definition of clay is as a *size class* of sedimentary particles. The other definition refers to a *class of minerals* known as clay minerals. As a general rule, the clay minerals occur as particles that fall within the clay-size class, but other non-clay minerals — such as quartz and feldspar — may also occur as particles small enough to be classified as clay from a particle size point of view. Clay is a sediment, and shale is a rock composed of clay-sized particles.

In oil and gas drilling, most, but not all, of the clay or shale formations drilled were sedimented in a marine basin. The particles making up the shale or clay were initially eroded from a land mass and transported to the marine basin by rivers. The nature and composition of the particles entering the sedimentary basin depend somewhat on the composition of the rock and soils being eroded in the land mass that acts as a source area for the sediment. The variability of terrain in these source areas is one of the reasons that shales in different sedimentary basins may differ. To give an example, temperate climate soils typically contain more smectite than kaolinite clay minerals and the sedimentary particles eroded from these temperate-climate soils contain less kaolinite than smectite. In tropical soils, more silica has been leached from the soil, and the soils typically contain more kaolinite than smectite.

The reason that clay accumulates as sediment instead of sand or silt is almost always related to flow velocity of the water suspending the clay. In water flowing with any significant velocity or turbulence, clay-sized particles remain suspended. In quiet water with little or no flow velocity or turbulence, clay-sized particles can settle and accumulate. These quiet-water environments occur in water offshore

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Bioturbation is disturbance of the sediment by organisms that live in the sediment.

below wave base (the bottom of waves on the water surface) and in bays or lagoons. Additional nonmarine sites of clay deposition may include lakes and river flood plains.

There are two features of marine sedimentation of clays that may have significance: *flocculation* and *bioturbation*. Flocculation of clay-sized particles may occur when dispersed clays transported by a freshwater river enter the saline marine environment. Whether flocculation occurs may depend on such factors as the nature and amount of clay present in the water. When flocculation occurs, clay-sized particles become aggregated into a larger particle that is more easily sedimented than dispersed clay. The flocculated clay material is often sedimented along with substantial quantities of silt-sized particles of quartz and feldspar. The result is a silty clay sediment that often has a somewhat permeable "cardhouse" fabric. One practical consequence of flocculation is that most marine clay sediments and marine-deposited shale formations contain substantial amounts of silt-sized quartz grains.

Bioturbation is disturbance of the sediment by organisms that live in the sediment. Organisms including mollusks and worms obtain nutrients by digesting the sediment. This bioturbation destroys or modifies the original fabric of the sediment and, in some cases, may pelletize the sediment. The pelletized sediment may have a higher permeability than clay that has not been pelletized. While most marine shale formations are not pelletized, bioturbation processes have obscured or destroyed the laminated or fine bedding structure of most marine clay sediments.

One type of shale that has *not* been bioturbated is carbonaceous shale — shale with a high organic content. Carbonaceous shale was sedimented on an oxygen-depleted surface (as occurs in certain lagoons) that prevented oxidation of the organic material. Carbonaceous shales typically show laminations and the shale can easily be split along these laminations.

Clay sediments are dramatically altered by diagenesis. At the ocean bottom the clays sediments are often called mud because they lack any degree of cohesion. In the initial stages of consolidation, the clay sediments become somewhat firmer but are still easily dispersed into water or water-base mud. As simple consolidation continues, the clays may become less permeable and may develop the ability to trap pressure. Consolidation of clay sediments is one of the mechanisms for generating geopressures. With greater depth of burial and increased temperature, mineralogical changes in the clay formations begin. The clay sediment may retain plastic or gumbo character or it may transform into a better cemented, more rigid and brittle shale. There are two types of diagenetic mineralogical change that alter the nature of clay sediments and shale: (1) the transformation of smectite clay minerals to a mixed-layer illite-smectite and (2) the precipitation of mineral cements.

The transformation of smectite into illite-smectite clay results in the clay minerals in the clay sediment or shale becoming less chemically active. Over geological time (on the order of a million years or more) at temperatures approaching 200°F, at least part of the smectite clay in clay sediments becomes chemically unstable. It alters into a mixed-layer illite-smectite mineral. With temperatures increasing above 200°F and increased geological age, these mixed-layer minerals become more illitic in nature. Geologically old (Paleozoic age — older than 250 million years) shale formations rarely contain significant quantities of smectite clay.

As a general rule, deeper, hotter and older shale is less chemically reactive than younger, shallower and cooler clay sediment.

Another factor is the precipitation of mineral cements that give shale its rigid and brittle character. A few shale formations are cemented by carbonate cements such as calcium carbonate or dolomite, and this carbonate cement typically imparts both strength and mechanical durability. Carbonate cemetation, however, is much less common in shale than silica cementation. Silica, or SiO_2, is a reaction product of the smectite-to-illite transformation discussed above. Silica cementation makes shale brittle. The amount of silica cementation in shale can vary. Partial cementation of the shale, makes shale brittle but weak and possibly dispersible, while increased amounts of silica cementation may make the shale brittle but prone to sloughing. The ability of fluids or filtrates to penetrate into cemented shale formations appears to be an important factor in their stability when exposed to drilling fluids. Formations that allow penetration of water into the shale cause clay materials in the shale to develop swelling pressures that can break apart the cementation binding the shale together.

There are several types of “shale-like” formations that fall outside the marine and nonmarine shale discussed above. One is volcanic tuff. While volcanic tuff is not a sedimentary rock, beds of volcanic tuff can occur in a sequence of sedimentary rock materials. Tuff is the accumulation from a volcanic ash eruption. The volcanic ash, when it falls to the surface of the ocean or sedimentary basin, is primarily composed of silicate glass. Over geological time, this volcanic glass is chemically unstable and it crystallizes to form clay materials. The bed of altered volcanic ash is sometimes called a *bentonite bed*. Wyoming bentonite is mined from a deposit of altered volcanic ash. Geologically important volcanic ash deposits include the Balder Tuff in the North Sea and various tuff formations in Indonesia.

Tuff is the accumulation from a volcanic ash eruption.

Because of the wide variability in shale formations in different areas of the world, techniques and solutions to shale drilling and stability problems that work in one area may not always work in other areas.

Shale formations are easy to identify using commonly run gamma ray logging tools. These tools measure the natural gamma rays emitted by formations penetrated by the borehole. Gamma rays originate by the disintegration of an isotope of potassium with an atomic weight of 40 and by disintegration of atoms in the uranium and thorium series of elements. Minute quantities of thorium are present in clay minerals, and potassium is a common component of shale. By convention, the gamma ray log appears on the leftmost column of an electric log. When the gamma ray line is deflected to the right, it denotes a shale formation. Deflection to the left indicates a sand or limestone formation.

Mud loggers are an invaluable source of information to the onsite mud engineer when attempting to reconstruct the lithology sequence of the formations being drilled. Daily logging reports give a breakdown (into matrix percentages) of each sample taken at a particular depth. These mud logs can help anticipate a known problematic formation and evaluate the reactivity and relative stability of a particular formation. Table 1 lists the standard geologic codes and descriptions that are used on mud logging reports as well as the grain sizes of particular sedimentary rock types.

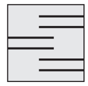
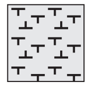
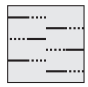
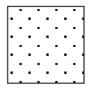
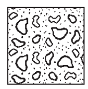
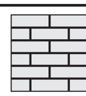
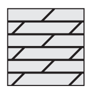
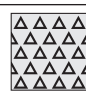
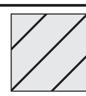
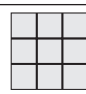
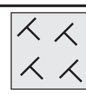
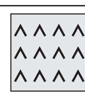
Rock Type	Abbreviation	Symbol	Grain Size	Description
Shale and claystone	Sh CLst		<4 microns	Rocks formed from the accumulation of clay minerals and silt-sized particles. Compressive strength: Sh: 4,000 - 10,000 psi
Marl	Mrl		<4 microns	Rocks formed from the accumulation of clay minerals and calcite (calcium carbonate).
Siltstone	SLst		4 to 60 microns	Rocks formed by the accumulation of silt and sand-sized quartz.
Sandstone	Sst		60 to 2,000 microns	Compressive strength: Sst: 5,000 - 15,000 psi
Conglomerate	Cgl		>2,000 microns	Rocks formed by the accumulation of gravel-, pebble- and boulder-sized particles.
Limestone	Ls		Precipitated rocks	Rocks deposited by precipitating calcite (calcium carbonate) and dolomite (calcium-magnesium carbonate).
Dolomite and chalk	Dol Chk			Compressive strength: Ls: 6,000-15,000 psi, Dol: ~24,000 psi Chk: ~6,000 psi Cht: ~83,000 psi
Chert	Cht			
Gypsum and anhydrite	Gyp Anhy		Evaporate rocks	Rocks deposited by precipitation during the evaporation of water.
Salt	Sa			
Basement	Bm		Igneous rocks	Volcanic rocks formed by the cooling of molten magma.
Volcanics	Volc			
Fault	Flt		n/a	Broad geological fracture and displacement of rocks along a fault plane.
Oil	O		Formation fluids	Oil (5 - 7 lb/gal)
Gas	G			Natural gas (~2.3 lb/gal)
Water	Wtr			Water or brine (8.3 - 11.7 lb/gal)

Table 1: Rock types, mud logging codes and description (after the Amoco TRUE® handbook).

Shale, sandstone and limestone make up the... majority of sedimentary rock...

Shale, sandstone and limestone make up the overwhelming majority of sedimentary rock, with at most a few percent consisting of other rock types. In most oil and gas basins, shale makes up 50 to 75% of rock drilled. The approximate percentage of shale, sandstone, and limestone in several areas is shown in Table 2.

Different rock types have definable characteristics and associated drilling problems. Table 3 lists some of the different characteristics of rock types.

Basin	Shale (%)	Sandstone (%)	Limestone (%)
Gulf of Mexico	60	30	10
Permian Basin	10	30	60
Trinidad	50	50	—

Table 2: Relative distribution of rock types for several areas (after the Amoco TRUE handbook).

Rock Type	Subdivision	Characteristic
Shale	Soft (ductile)	• Generally occurs in shallower depths (~10,000 ft). • Soft and pliable due to high porosity (15 - 60%) and high water content (25 - 70%). • Fracture pressure approximately same as injection pressure. • Pliable texture allows formation fractures to heal to original strength. • Methylene Blue Test (MBT) 20 - 40 (meq/100 g). • Semectite + illite clays. • Associated with swabbing, lost circulation, hole washout and hole packoff.
	Hard (brittle)	• Generally occurs in deeper depths (>10,000 ft). • Hard and brittle due to low porosity (4 - 15%) and low water content (3 - 10%). • Fracture pressure higher than injection pressure. • MBT 3 - 10 (meq/100 g). • Illite, kaolinite and chlorite clays. • Brittle texture prevents formation fractures from healing. • Associated with hole packoff/bridging.
Sandstone	Unconsolidated	• Generally occurs in the surface hole section (surface to ~5,000 ft). • High porosity (>25%). • High permeability (>2 darcies). • Associated with lost circulation, hole washout and hole packoff.
	Consolidated	• Occurs mostly in middle to deep hole sections (>4,000 ft). • Porosity range (1 - 25%). • Permeability range (10 millidarcies - 2 darcies). • Associated with differential sticking and undergauge hole when abrasive.
Limestone dolomite	Soft (chalk)	• Low compressive strength. • High porosity (~40%). • Permeability range (10 millidarcies - 2 darcies). • Chalk (calcium carbonate) will disperse in freshwater mud. • Associated with hole washout and calcium contamination of mud.
	Hard	• High compressive strength. • Usually fractured by natural forces. • High porosity (20 - 40%). • Permeability range (500 millidarcies - 4 darcies). • Associated with hole packoff/bridging, differential sticking and lost circulation.

Table 3: Relative characteristics of sedimentary rocks (after the Amoco TRUE handbook).

Clay Chemistry

From a sedimentation point of view, clay was defined as a particle size term, but from a chemical and mineralogical point of view, the term clay refers to specific clay minerals. These clay minerals are crystalline materials with a layered structure of silica and alumina. The common clay minerals found in shale are smectite, illite, chlorite and kaolinite. These minerals occur as tiny crystalline particles that fall within the clay-size range. Analysis of the types of clay minerals present in a shale is accomplished with X-Ray Diffraction (XRD) techniques.

Clay minerals have the ability to adsorb water and cations on their surfaces.

Clay minerals have the ability to adsorb water and cations on their surfaces. As noted above, clay minerals have a small particle size and a layered, or sheet-like, structure. This gives clay minerals a large specific surface area (specific surface area = surface area per gram of material). Illite, chlorite and kaolinite are tiny crystals that adsorb water and cations to their external surfaces. Smectite, in addition to adsobing water and cations on external surfaces, adsorbs water and cations to surfaces between layers in its crystalline structure. The ability of smectite to adsorb water is much greater than other clay minerals.

The standard unit for reporting cation exchange capacity of dry clay is meq per 100 g of dry clay.

The ability to adsorb water, the ability of the clay to exchange cations and the specific surface area of clay are closely related phenomena that are sometimes termed *colligative properties* of clay. These colligative properties are basically measures of the reactivity of the clay. Because Cation Exchange Capacity (CEC) is easy to measure, it is an practical method to assess clay or shale reactivity. The CEC of dry clay can be measured with methylene blue titration. The standard unit for reporting cation exchange capacity of dry clay is millequivalents (meq) per 100 g of dry clay. When measuring the cation exchange capacity 0.01 N methylene blue solution is used, so the number of milliliters of methylene blue solution needed to reach the end point is equal to meq/100 g. The range of CEC for pure clay mineral materials is:

Clay	CEC (meq/100 g)
Smectite	80 - 150
Illite	10 - 40
Chlorite	10 - 40
Kaolinite	3 - 10

Smectite is clearly much more reactive than other clay mineral materials. Shales containing smectite are the most water-sensitive and hydrate the most. Shales containing other clay minerals have less ability to hydrate but still may be water-sensitive. Most shales contain several types of clay in varying amounts. The reactivity of a shale depends on the types and amounts of clay minerals present in the shale. Often the CEC is a better measure of clay reactivity than the mineralogical analysis inferred from XRD analysis.

The crystal structure of illite and smectite are similar, with a repeating three-layer unit composed of an alumina sheet sandwiched between two silica sheets. In smectite, there is a layer of adsorbed ions and water between the three-layer units making up the crystal. In illite, there is a layer of potassium ions but no water between the three-layer units. In addition, illite has substantial substitution of aluminum atoms for silica atoms in the silica sheets and smectite does not. The potassium atoms in the illite structure are not exchangeable ions but are a fixed part of the crystal structure; only ions on external surfaces of illite are exchangeable. In smectite, the ions between the layers are exchangeable and may be composed of sodium,

...some layers contain exchangeable ions and water while other layers are "collapsed," with potassium atoms between the layers.

calcium, magnesium or potassium (note that potassium exchanged smectite is not the same as illite).

As noted in the discussion of diagenesis, smectite and illite clay often occur as a mixed-layer mineral. In a mixed-layer mineral, some layers contain exchangeable ions and water while other layers are "collapsed," with potassium atoms between the layers. Most of the smectite and illite present in marine sediments and sedimentary rock occur as mixed-layer clay. Many "old-timers" and others involved with drilling use the terms *montmorillonite* or *bentonite* instead of the term *smectite* to mean clay that contains water in its layer structure. This situation arises because specialists who study clay have refined the nomenclature applied to clay materials over the years and continue to refine or redefine terms as additional detail regarding the nature of clay materials are discovered. To help with the nomenclature the following definitions are offered:

- Smectite — a group of clay minerals having the sandwich-type structure discussed above and containing water between the aluminosilicate layers. This group of minerals includes montmorillonite, hectorite, saponite, nontronite and a number of other specific minerals.
- Illite — a specific clay mineral with an aluminosilicate backbone structure similar to smectite but without the interlayer water. The specialists have not subdivided illite into a group of minerals yet, but some are probably working on it.
- Montmorillonite — a common mineral that belongs to the smectite group of minerals. Most of the smectite clay in sediments in the Gulf Coast of the United States actually is montmorillonite. This may not be true in other sedimentary basins.
- Bentonite — geologically, bentonite is a bed of altered volcanic ash. In commerce, the term bentonite is used for commercially mined sodium montmorillonite that is used as an additive for drilling mud. Bentonite clay mined in Wyoming actually comes from a geological bentonite bed, but bentonite clay mined in other areas of the world may be from other types of geological deposits.

Chlorite clay minerals are similar to illite clay in reactivity. Chlorite is a group of specific clay minerals. In general, the chlorite minerals contain a layer of alumina sandwiched between two layers of silica and a layer of magnesium or iron oxide. Chlorite does not contain interlayer water. Some older shale rocks that have experienced a high degree of diagenesis contain only chlorite and illite as clay components. Most of these shales are relatively unreactive but some of them can hydrate and slough.

Kaolinite clay is less reactive than other clay minerals. Its basic structure consists of alternating layers of silica and alumina. The crystallite size of kaolinite is typically larger than the crystallite size of smectite or illite, and it has a smaller specific surface area, cation exchange capacity and ability to adsorb water. Kaolinite clay can be dispersed in water-base drilling fluids.

The types of clay present in a rock formation are analyzed using X-ray diffraction analysis. XRD measures the spacing between planes of atoms in a crystalline substance. For common clay types, the following table gives the thickness of the unit layers in Angstrom (Å or 10^{-8} cm) units:

Clay	Layer Thickness (Å)
Na-smectite	12
K-smectite	12
Ca-smectite	14
Ethylene-glycol-treated smectite	17
Chlorite	14
Illite	10
Kaolinite	7

It is worth noting that the layer thickness of smectite clays depends on the type of ion. One of the classic methods for identifying smectite if there is some question about its presence is to treat the clay with ethylene glycol and determine if the spacing expands to 17 Å units.

Refer to the Clay Chemistry chapter for additional information on the mechanisms involved in base exchange and clay swelling or dispersion.

The Earth's Stresses

It is important to understand the relationship of the earth's stresses to evaluate wellbore instability. Overburden pressure, pore pressure and tectonic forces, described below, all contribute to the instability that occurs when a hole is drilled in the subsurface environment.

Overburden pressure

Overburden is the volume and weight of all formations and fluids above a given formation.

Overburden is the volume and weight of all formations and fluids above a given formation. The total stress imposed by the overburden that a subsurface formation is subjected to is called the geostatic, lithostatic or total overburden pressure (P_O). It can be calculated as follows:

$$P_O = \rho_B \text{ x TVD}$$

Where:
ρ_B = Bulk density of the sediments
TVD = Total Vertical Depth

Overburden pressure (P_O) is equal to the total pressure from the weight of the sediments (P_S) plus the pressure from the weight of the fluids (P_F) that exist above a particular formation and which must be mechanically supported by the formation or $P_O = P_S + P_F$. For English units, the overburden pressure can be calculated by the following equation:

$$P_O \text{ (psi)} = 0.052 \text{ x } \rho_B \text{ (lb/gal) x TVD (ft)}$$

Where the units conversion factor 0.052 is 12 in./ft ÷ 231 in.^{3}/gal.

Pressure/depth relationships are commonly referred to in terms of a "gradient," which is the pressure divided by depth. The overburden pressure gradient (P_{OG}) can be calculated by:

$$P_{OG} \text{ (psi/ft)} = 0.052 \text{ x } \rho_B \text{ (lb/gal)}$$

Since sediment bulk densities vary with location and depth due to compaction, bulk density is usually taken as 144 lb/ft^3 (19.25 lb/gal or SG 2.3) so the geostatic or overburden gradient is 1 psi/ft (0.23 kg/cm^2/m).

Sediment bulk densities are most accurately obtained from bulk density logs. Logs are not always available for this information, but gradients can be calculated. The average geostatic gradient plotted against depth for the Gulf of Mexico is closer to 0.83 psi/ft (~16 lb/gal) near the surface and 1.0 psi/ft (~20 lb/gal) near 20,000 ft. If the overburden gradient is not known, assume that it is 1.0 psi/ft, or use the nearest offset known value.

...total overburden pressure is equal to the sum of the intergranular pressure and the pore pressure...

Abnormal pressured conditions are caused by some form of geological seal...

Pore pressure and intergranular pressure

Total overburden pressure is supported by the rock in two ways. The first is through intergranular pressure (P_I), a matrix stress due to the force transmitted through grain-to-grain mechanical contact. Secondly, when the sediments are not compacted enough to form grain-to-grain contact, the overburden is supported in part by the pore pressure (P_P), causing abnormal pressure. Pore pressure is the pressure of the formation fluids (water, oil and gas) which must be balanced with mud weight. Therefore, the total overburden pressure is equal to the sum of the intergranular pressure and the pore pressure or $P_O = P_I + P_P$ (see Figure 1).

Just as bulk density gradients vary due to compaction, normal pore-pressure gradients vary due to the salinity of the formation waters. As shown in Table 4, for a given salinity and density, the normal pore pressure can be calculated by:

$$P_P \text{ (psi)} = 0.052 \times \text{pore fluid density (lb/gal)} \times \text{TVD (ft)}$$

A normal pore-pressure gradient is generally considered to be 0.465 psi/ft. When the pore pressure is greater than the theoretical hydrostatic pressure for a given TVD, the formation is abnormal or geopressured. Abnormal pressured conditions are caused by some form of geological seal which traps formation fluids and gases from percolating to shallower zones as the mass of overburden increases. Seals may consist of dense shales, limestone, dolomite, salt or other impermeable formations.

An analogy for the three types of pressure — overburden, intergranular and pore pressure — would be a water tower. The overburden would be the total weight acting on the base of the water tower, the weight of the water plus the weight of the tower itself. The intergranular pressure would be the

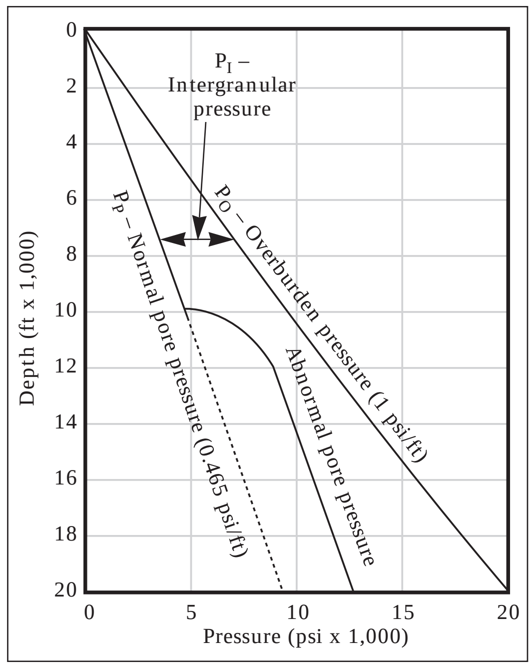


Figure 1: Overburden pressure profile, typical Gulf of Mexico.

Area	Average Pore Fluid Density (lb/gal)	Pore-Pressure Gradient (psi/ft)
West Texas	8.33	0.433
Gulf of Mexico	8.95	0.465
North Sea	8.70	0.452
Malaysia	8.50	0.442
Mackenzie Delta	8.50	0.442
West Africa	8.50	0.442
Anacardo Basin	8.33	0.433
Rocky Mountains	8.39	0.436
California	8.45	0.439

Table 4: Pore-pressure gradients for various areas.

weight of the structure acting through the framework of the structure. The pore pressure would be the hydrostatic water pressure.

ORIENTATION OF STRESSES

The overburden exerts a vertical stress to the formation with a resulting outward horizontal stress, depending on the mechanical properties of the rock. Subsurface stresses are resolved into the orientation (direction) of the three principal stress planes in three-dimensional space which are all perpendicular to each other (see Figure 2). These are (1) maximum principal stress (σ_{MAX}), (2) intermediate principal stress (σ_{INT}) and (3) minimum principal stress (σ_{MIN}).

The fracture gradient is essentially equal to the minimum principal stress.

The fracture gradient is essentially equal to the minimum principal stress. In a non-tectonic stressed environment, the maximum stress is in the vertical direction (σ_Z), due to the overburden, and the intermediate and minimum principal stress (σ_X and σ_Y) are in the horizontal plane and equal.

When a well is deviated from vertical, these stresses tend to make the wellbore less stable and more mud weight is generally required, depending on the rock strength. To evaluate the stress in a deviated well, it is useful to resolve the principal stresses into a different orientation, so that they are radial (σ_R), tangential (σ_T) and axial (σ_A) to the well path, as shown in Figure 3.

Using this orientation, the mechanical stability of the formation can be calculated for a given set of conditions using

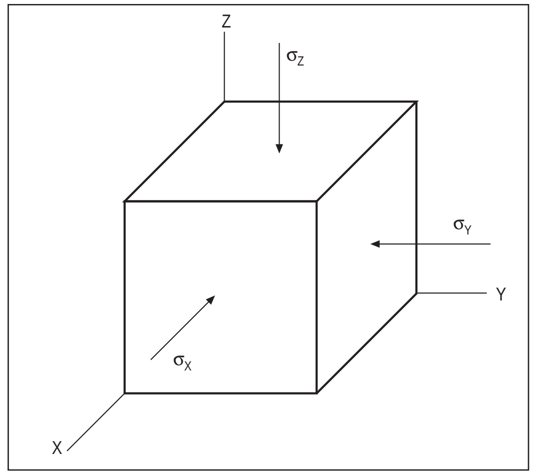


Figure 2: Principal stress orientation.

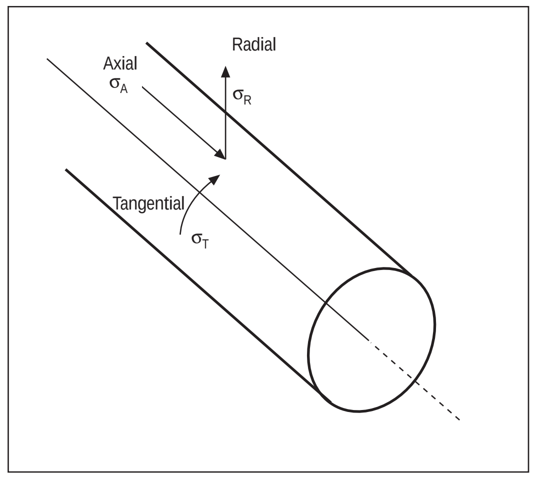


Figure 3: Stress orientation, deviated wellbore.

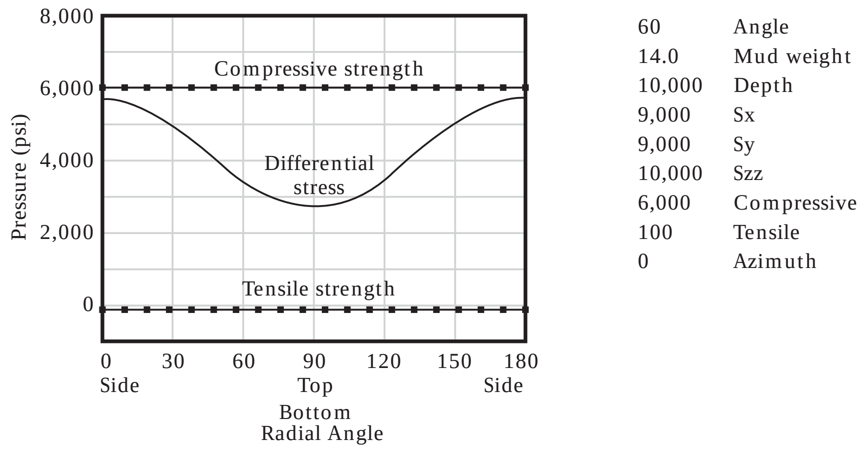


Figure 4: Differential stress, deviated well.

M-I's stresses computer program. As shown in Figure 4, a plot can be made of the effect of the hydrostatic pressure on total differential stress (tangential minus radial) of the rock. Various radial angles around the wellbore are shown from one side (at 0°) to the bottom (at 90°) and on to the other side (at 180°). If the differential stress is less than the rock's tensile strength (shown as a negative number), tensile failure or fracture will occur. If the mud weight is less than the fracture gradient, the fracture or failure will die out near the wellbore. If the mud weight exceeds the fracture gradient, lost circulation will occur. If the differential stress is greater that the rock's compressive strength, spalling and wellbore collapse or plastic intrusion (salt) will occur.

Once this analysis is done, a safe operating range for the mud weight can be calculated for various hole angles and pore pressures as the well is drilled. The resulting stable operating window for mud weights will be considerably less than if the well was vertical, as shown in Figure 5.

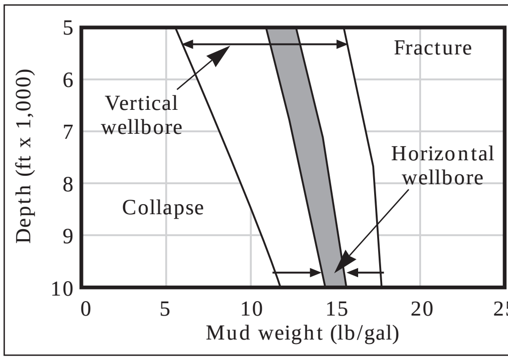


Figure 5: Stable mud weight range.

Tectonic stresses are stresses that deform rock materials in nature.

TECTONIC FORCES

Tectonic stresses are stresses that deform rock materials in nature. The regional contact and movements of the earth's crustal plates and other geological forces cause these stresses. Tectonic forces cause the two horizontal stresses to have different values. Folds and faults are the result of tectonic stresses. Compressional tectonic stress will cause problems due to compression where brittle rocks may spall into the hole or plastic formations like salt to squeeze the hole closed. Extensional tectonic stress will cause problems where formations fracture due to tension, resulting in lost circulation.

Fold belt mountainous areas are built by regional compressive tectonic stress. A fold belt consists of anticlines and synclines formed by tectonic compression (maximum stress) in the direction perpendicular to the fold axes (or colliding crustal plates). Both the maximum and minimum stresses are usually in the horizontal plane with the intermediate stress being mostly vertical.

Extensional tectonic stresses are responsible for faulting in basin- and range-type mountainous regions. The minimum horizontal stress is perpendicular to the fault traces (or retreating crustal plates) while the intermediate principal stress is parallel to the fault traces, with the maximum principal stress in the vertical direction.

Near salt structures such as domes and sheets, stresses are modified by the upward intrusion and migration of the salt through the rock. It is difficult to assess how salt structures modify the in-situ stress field. Higher mud weights are frequently needed to provide a stable wellbore. Lost circulation and wellbore-control problems are often experienced in these complex environments because nearby structures have very little fracture resistance.

Mechanical Stress Failure

...unconsolidated sand or fractured formations have a tensile strength of zero.

Wellbore failure due to mechanical stress is most often caused by one of two situations. First, the mud weight is too high, inducing a fracture (rock in tension) that causes lost circulation. Second, the mud weight is too low, causing the rock to cave in (spalling) or collapse (rock in compression) as shown in Figure 6. Mechanical abrasion and impact from the drillstring can also cause wellbore enlargement and lead to instability in brittle rocks.

Tensile failure-fracturing

Rocks have weak tensile strengths. In fact, unconsolidated sand or fractured formations have a tensile strength of zero. Sandstones tend to have lower tensile strength than shale. Hard rocks may have tensile strengths of 300 to

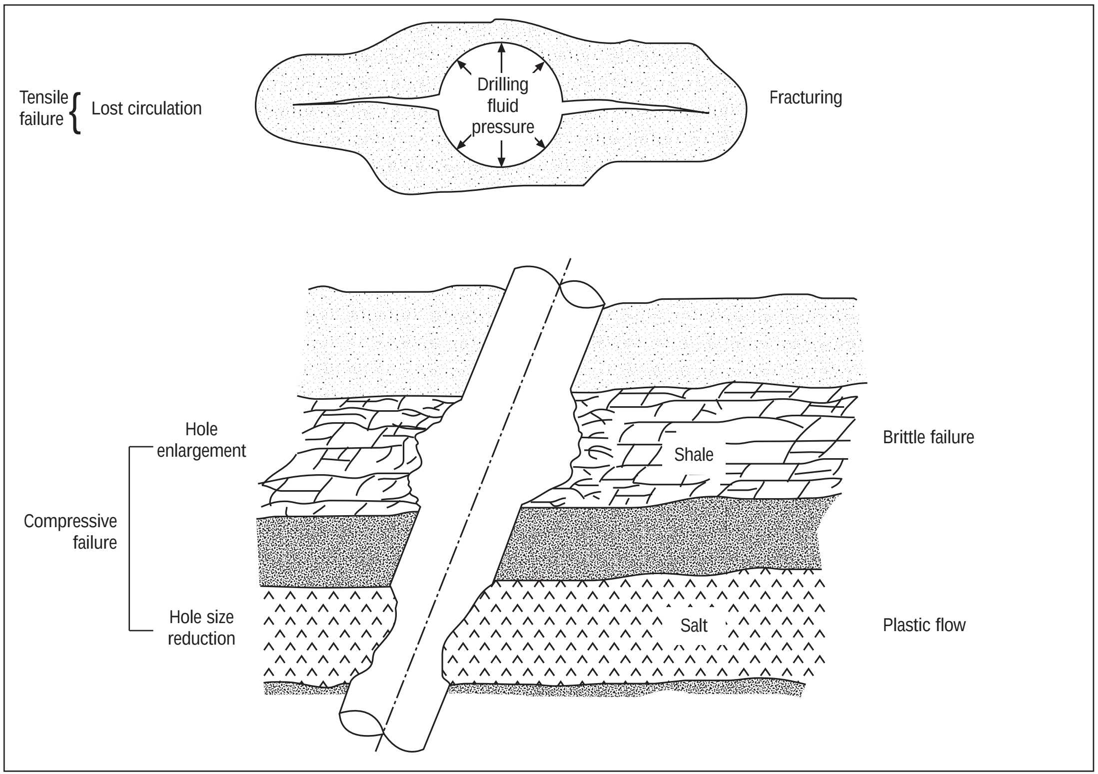


Figure 6: Mechanical wellbore instabilities (after Bradley).

If the mud pressure exceeds the fracture gradient of the rock, a fracture is initiated...

600 psi. Mud weight is usually increased to control the flow of gas and liquids into the well by maintaining a slightly higher hydrostatic pressure than the pore pressure. If the mud pressure exceeds the fracture gradient of the rock, a fracture is initiated, and lost circulation will occur. The fracture will be oriented in a plane parallel to the direction of the maximum principal stress and perpendicular to the minimum stress, usually resulting in a vertical fracture opening toward the least principal stress. Fracturing and lost circulation will have a detrimental effect on wellbore integrity and stability, particularly in medium to hard formations.

There is one school of thought that some "soft" shales and high-water-content gumbos can deform plastically, causing an increase in the size and volume of the hole (ballooning). The ballooning theory is that if the mud weight is excessive, the hole can be enlarged (ballooned) and trap pressure like a pressure vessel. This situation in turn can lead to indications of a kick and allow mud to flow back to the surface without having formation fluids flow into the well. This concept is somewhat controversial and poorly understood. It is not clear whether ballooning symptoms are caused by opening and closing fractures or by plastic deformation of the wellbore. In any case, well-control situations should be handled in the safest possible manner.

COMPRESSIVE FAILURE/COLLAPSE OR PLASTIC FLOW

Rocks have compressive strengths that generally range from 4,000 to 15,000 psi. If the mud weight is insufficient to balance this maximum allowable stress of the rock, one of two failure mechanisms will occur:

1. Wellbore enlargement due to spalling or collapse in brittle rocks.
2. Wellbore deformation and tight hole due to plastic flow in plastic formations, like salt, squeezing the hole closed.

Stressed shales and pressured shales are two special wellbore-stability problems that occur because there is insufficient mud weight to satisfy compressive strengths. Because they are not readily identifiable with an increase in gas, the need for higher mud weights is more difficult to identify. When these types of shale problems are encountered, an increased amount of cavings will be observed at the shale shaker. Often a change in the size and shape (larger and more splintery or angular) of the cavings accompanies the increased volume. Many words are used to describe shale failing in compression, including heaving, sloughing, caving and spalling. These shale fragments are usually much larger than the drill cuttings, are angular or splintery in shape and may have a concave appearance.

Mud weights are usually increased to control the flow of gas and liquids into the well.

STRESSED SHALES

Mud weights are usually increased to control the flow of gas and liquids into the well. If the formation is stressed due to tectonic forces, then mud weight may be needed to prevent wellbore instability.

Shale of this type may be described as shale that does not hydrate appreciably but sloughs into the hole when penetrated. These shales are found in areas where diastrophic or tectonic movements (the process by which the earth's crust is deformed, producing continents, oceans, mountains, etc.) have occurred. The shales may be inclined considerably from the horizontal, in steeply dipping bedding planes. Forces may be acting upon the formations which, when relieved, cause the shale to fall into the hole. The problem may be further aggravated if the bedding planes become wet with water or oil, as discussed later. The Atoka and Springer shales of the mid-continent are examples of this type shale.

Formation stresses induced by diastrophic movement or tectonic stress make these shales vulnerable to sloughing. In addition, the natural material cementing these shales may be relatively weak.

Some stressed shale can never be fully controlled with mud weight because lost-circulation (and other) problems can occur. For these situations, there will always be a tendency for some shale to slough into the wellbore. Occasionally the best method is to treat the problem symptomatically with improved hole cleaning and try to tolerate the problem without allowing a significant drilling problem to occur.

To improve hole cleaning, a highly shear thinning mud system with a low "n" value and high, fragile gel strengths should be used, in addition to maintaining good filter-cake characteristics and low fluid loss. The low "n" value will help prevent stressed sloughing by maintaining a streamlined flow profile and will help clean the wellbore. The high gel strengths will suspend shale that sloughs when the drillstring is out of the hole. This will prevent the shale from falling down the wellbore and creating a bridge. In this situation, it is often better not to wash and ream the troubled section unless absolutely necessary. Leaving the interval undisturbed will allow gelled mud and suspended sloughings to remain quiescent in enlarged intervals. Once disturbed, these zones will typically become more of a problem that will persist for some period of time.

Unusual wellbore instability problems can be encountered while drilling in tectonically active regions. The usual operational responses might be entirely inappropriate if the physical mechanism of the hole deterioration is not properly understood. When drilling in areas that exhibit unusual tectonic conditions, the typical approach to determining mud weights and fracture gradients must be changed to more mechanical criteria and should not rely on indications of pore pressure, such as gas-cut mud. Also, managing to live with some instability may be necessary rather than trying to cure the condition completely.

Experiences in such areas has led to the following observations:

- Tectonic instability is strictly mechanical and not related to, or solved by, chemical incompatibilities.
- Mechanical instability is related to stress-induced failure of weak, often fractured or faulted, formations.

Pressure transmission and mud invasion away from the wellbore tends to destabilize.

- Fracturing causes lost circulation and wellbore instability when mud pressures approached the magnitude of the minimum stress.
- Wellbore breakout and collapse will occur when mud pressures are too low to maintain the rock below its compressive strength.
- Orientating the well path with respect to tectonic forces may help relieve problems.
- Pressure transmission and mud invasion away from the wellbore tends to destabilize the hole.
- Poor drilling practices can contribute to destabilizing the hole, while good drilling practices can help tolerate some instability.
- Good communication and teamwork are critical to cost-effective and timely solutions.

Some recommendations are:

- Monitor hole conditions and shale shaker for signs of instability and the need to improve hole cleaning to relieve symptoms of instability (fill and bridges).
- Use fast but smooth drilling techniques to reduce exposure time and minimize mechanical disturbances.
- Select casing depths to isolate problem intervals.
- Minimize reaming to reduce mechanical disturbance, unless absolutely necessary.

Thermal differences between the colder mud flow and hotter formation can also cause wellbore stresses and wellbore instability. This is not a common problem, but should be considered when evaluating wellbore failure in high-temperature wells.

PRESSURED SHALES

Mud weights are usually increased to control the flow of gas and liquids into the well. If the formation is impermeable with no adjacent permeable formation, like a massive shale or salt body, then it may be difficult to identify an increase in pressure due to the lack of background/connection gas or the influx of pore fluids.

Troublesome shales associated with geo-pressures have generally been restricted geographically to areas of more recent geology, usually post-Cretaceous. Shales of this type are normally massive, but not homogeneous. They are principally marine shales and are probably the source beds for oil and gas. One can logically explain the existence of pressure in shale bodies. During geologic time, sea-level changes such as those that occurred in the glacial and inter-glacial periods may explain localized deposition of foreign sediments in large sedimentary basins. Such climate changes would be enough to permit the development of sandbars near shore, which in later geologic time, could become isolated, permeable sand lenses in an otherwise massive shale.

In the progression of geologic time, the silts and shales compress and become compacted due to the growing mass of the overburden. In the process of compaction, fluids within the shale are forced out and into more porous and permeable sand lenses. The sand lenses are both porous and permeable and do not compress or compact to any degree. Any fluids entering these lenses are thus trapped and completely isolated by the surrounding shale, as shown in Figure 7. In the passage of geologic time, the pore space would become completely filled, and the fluid that is trapped could reach a pressure equal to the overburden.

There may not be an indication of high pressure or flow of gas or liquids

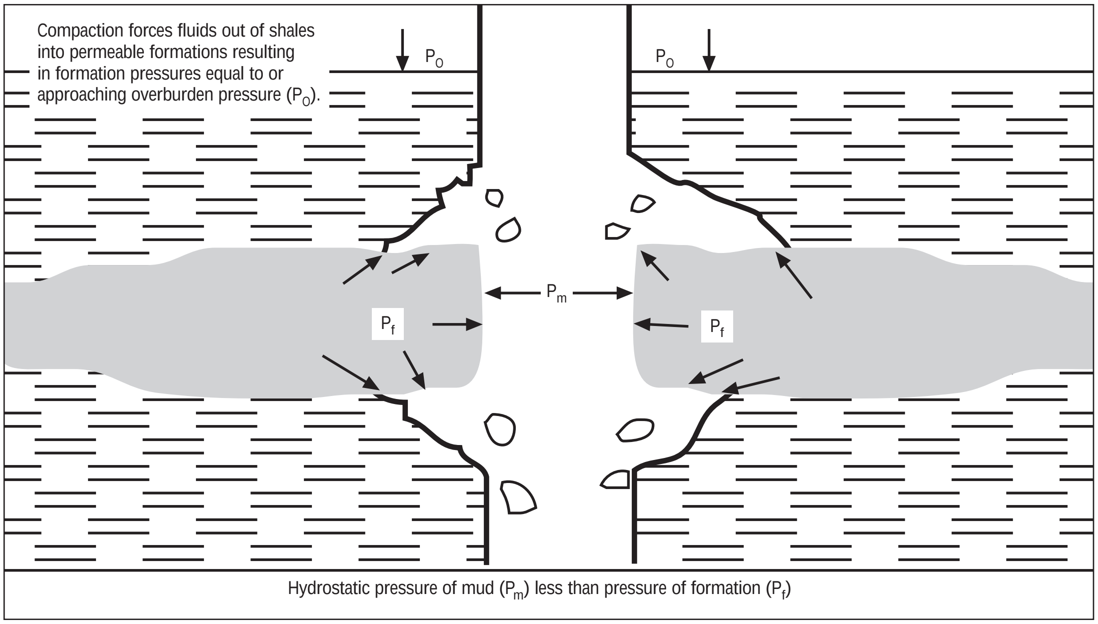


Figure 7: Pressured shale.

into the well if permeable formations are not present. The mud weight is usually not increased without an indication of increasing pressure, resulting in the hydrostatic pressure of the mud column being much less than that of the pressured shale. This pressure differential will attempt to relieve itself along the path of least resistance. It is believed it will do so along the bedding planes separating the sand and shale, causing the shale to flake off and fall into the hole. Shales thus weakened will continue to slough until the mud weight is increased to the point where the hydrostatic head balances the shales' pressure.

Other pressured shales may actually contain gas.

Other pressured shales may actually contain gas. These are often referred to as gas-bearing shales or high-pressure/low-volume gas formations. Wellbore stability may not be compromised depending on the rock strength, and the cause of the problem will be obvious by gas-cut mud. It may not be necessary to increase the mud weight to a point where all shale-gas is contained, as this has led to lost circulation, but only to a point where the formation is not failing.

Solving such a shale problem caused by pressure is relatively simple, i.e. increase the mud weight to create sufficient hydrostatic pressure to contain formation pressure. Besides increasing density, there are other practices that aid in controlling the problem by minimizing further reduction in hydrostatic pressure: (1) Keep the hole full of mud while pulling out of the hole. This keeps the hydrostatic pressure at the highest value possible at all times. (2) Low viscosity, low gel strengths of the mud will aid in the prevention of swabbing. Thinner wall cakes obtained by lower filtration will also avoid swabbing the hole. (3) Pull slowly through the section giving the problem.

Wellbore deformation and tight hole can occur in plastic-yielding rocks like salt.

PLASTIC FLOW

Wellbore deformation and tight hole can occur in plastic-yielding rocks like salt. Salt is a material that will flow (creep) under pressure and squeeze into the wellbore, causing tight hole or possibly closing the hole or sticking the drill pipe. Salt is ductile and transmits most of the overburden into the horizontal directions, so the three stresses are equal. Salt is more plastic at high temperatures, above 225°F (107°C). Salt creep is more of a problem for deep salt formations below 10,000 ft. Figure 8 shows the required mud weight to control the plastic flow of salt for a given depth and temperature.

In many parts of the world, salt formations are drilled with lower mud weights than are required to prevent salt creep, but with undersaturated salt muds which allow dissolution to prevent tight hole. This is most applicable in shallow to intermediate salt formations with temperatures below 225°F (107°C).

"Soft" shales and high-water-content gumbos may also deform plastically due to insufficient mud weight, causing tight hole and swabbing on trips. While there are often a combination of factors which affect tight hole, such as swelling and filter-cake thickness, increasing the mud weight usually alleviates tight hole and swabbing symptoms in soft shales and gumbo-type formations.

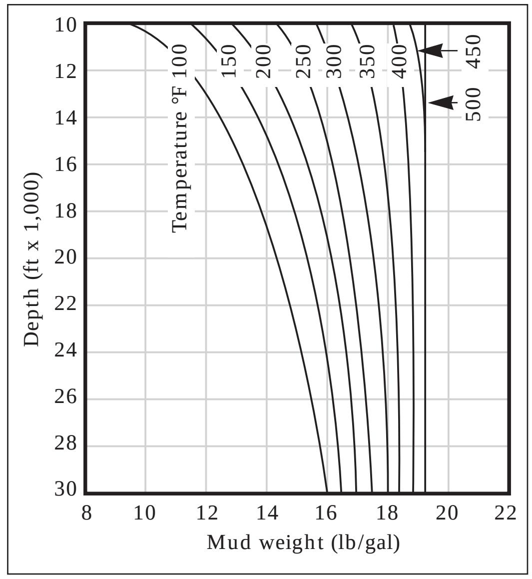


Figure 8: Mud weight required to control salt creep (<0.1% per hr).

Chemical Interactions

Hydration by water is one of the most significant causes of wellbore instability.

WATER-SENSITIVE SHALE

Wellbore instability and enlargement are also affected by the chemistry of the water-base drilling fluid and its effect on shale. Numerous classification schemes have been devised to attempt ranking shales according to their reactivity. These schemes usually assign a letter or number to each category of shale according to its reactivity. Most often, water-sensitive or hydratable shales contain high concentrations of montmorillonite clay. Therefore, ranking systems usually use the montmorillonite content as the primary measure of reactivity with water-base muds. Other useful measurements are the CEC, total clay content, water content, surface area and hardness. Even the shales containing clays that hydrate less — such as the illite-, chlorite- or kaolinite-type shales — are affected to some degree by the interaction with water-base mud chemistry. M-I does not use any single-shale-classification scheme, because no one system has proven to be universally applicable to all areas of the world.

Hydration by water is one of the most significant causes of wellbore

Shale becomes unstable when altered in any way...

instability. Hydration takes two forms in water-sensitive shales: surface and osmotic adsorption. Surface hydration occurs when a small volume of water is strongly adsorbed onto the planar surfaces of the clays which causes little softening or swelling, but can lead to excessive stresses if the swelling is confined. Osmotic swelling occurs when a large volume of weakly held water is attracted to the clay surfaces by electrostatic forces. Osmotic swelling causes softening and significant swelling as the adjacent clay layers hydrate water and expand. Osmostic swelling does not generate excessive stresses, even when confined, and can be substantially reduced if a low-activity salt mud is used.

Shales that contain montmorillonite may adsorb water from the drilling fluid and hydrate or disperse. The mode of failure is usually either a constriction of the hole from a softened swollen zone or spalling of relatively firm fragments. Osmotic adsorption and hydration will soften and swell the exposed wellbore in soft, dispersible shales, causing a tight hole and increasing the potential for dispersion. Brittle failure of relatively firm fragments occurs with salt-saturated fluids in soft, dispersible shales and with older, firmer, “brittle” shales in non-saturated water-base muds. In older, firmer shales, surface hydration leads to an increase in near-wellbore stress (due to the internal stress from confined swelling), causing firm, brittle, angular cavings and sloughings. It appears that water penetrates these shales along partially cemented pre-existing fracture lines. This leads to high internal stress from surface swelling, resulting in rock failure along the fracture lines.

Permeability tests indicate that shales are relatively impermeable. Ions enter the shales to cause either dehydration or hydration by capillary action, osmosis or bedding plane invasion. Alteration thus occurs by a transfer of water from the mud into the shale or water from the shale into the mud. Shale becomes unstable when altered in any way, whether by hydration or dehydration. It is important to prevent the transfer of water between the drilling fluid and the shale, which causes the shale to be altered. This can be achieved by balancing the activity (ion concentration) of the mud with the shale’s.

Oil and synthetic muds are highly effective at stabilizing wells drilled in water-sensitive shales. First, they oil- or synthetic-wet the exposed formations, preventing interaction with any water. Second, they usually incorporate low-activity, emulsified calcium chloride brine to achieve a balanced activity. Alternative chlorides-free materials have been used in place of calcium chloride for activity balancing, due to environmental reasons. These non-aqueous systems do not penetrate the shale-pore-throat network as readily as water-base fluids due to the surface tension of the water-wet shale.

An ideal drilling fluid would be one that does not alter shale in any manner. Many different types of fluids have been tried such as lime mud, gyp mud, calcium chloride mud, silicate mud, potassium mud, calcium acetate and formate mud, calcium nitrate mud, salt mud, surfactant mud, lignosulfonate mud, Partially Hydrolyzed Poly Acrylamide (PHPA) polymer mud, cationic polymer mud, and oil mud. No one fluid has been completely satisfactory in all cases. One mud may work slightly better than another through a certain shale section, but the opposite may be true in another area. From an overall success standpoint, the potassium-base polymer systems and oil or synthetic systems have been the most successful for problem shales of this type.

All types of chemical environments have been tried to control problem shales. The fundamental theory is to

...polymers work to coat exposed shales and cuttings...

Another factor influencing shale stabilization is pH.

not allow the shales to hydrate. In this respect, muds having a high-electrolyte content are often used because they substantially reduce hydration. Another theory involves converting the shale and clay to less reactive minerals with a base exchange of one ion (such as calcium or potassium) for the existing interlayer cations on the clay, usually sodium to suppress hydration.

The potassium (or salt) polymer systems (like POLY-PLUS®) work so well because they attack the shale-hydration mechanism in several ways. With the potassium systems, base exchange of potassium for interlayer clay cations converts the shale and clay to a less reactive state. In salt systems, the low activity reduces osmotic swelling and limits softening. In a sufficient concentration, polymers work to coat exposed shales and cuttings, "encapsulating" them with a bound layer of polymer. This limits the ability of water to interact with the shale and helps prevent cuttings from dispersing. Polymers also increase the filtrate viscosity of the fluid so the transfer of water will be slowed.

It should be understood that shales do have some permeability, albeit very small. Permeability is on the order of one microdarcy or less to water and even less with respect to oil- and synthetic-base fluids due to the surface tension of water-wet shales. There is a significant benefit to limiting any form of water interaction with water-sensitive shales. Mud composition can be changed to improve inhibition in addition to cation exchange with calcium or potassium to change the nature of the exposed shale and cuttings. Polymers tend to help by coating exposed shales and cuttings, slowing the interaction with water. Polymers also provide viscous filtrates that effectively further decrease the ability of the filtrate to penetrate the shale micropores. In addition, water-insoluble materials and plugging agents can substantially improve wellbore stability. They further reduce water invasion in shales by plugging the micropores. These materials are particularly effective in firm shales that tend to be microfractured.

These additives include:

- Oil and non-aqueous synthetic liquids.
- "Cloud-point" polyglycols (GLYDRIL™).
- Insoluble polyglycols and lubricants (LUBE-100® and LUBE-167™).
- Asphalt (STABIL HOLE®).
- Gilsonite.
- Sulfonated asphalt blends (ASPHASOL™).

Experience also indicates that fewer problems occur when the fluid loss is controlled at lower values. This has helped to maintain borehole stability in many cases. Reducing fluid loss with polymer additives such as starch, Polyanionic Cellulose (PAC) and sodium polyacrylate, increases filtrate viscosity and will reduce the inflow of mud filtrate into shale. However, it is more difficult to stop and control a problem created by allowing high filtrate-loss exposure.

Another factor influencing shale stabilization is pH. Almost all muds are controlled in an alkaline range, i.e., having a pH of 7.0 or more. Controlling the pH of the fluid in the range of 8.5 to 9.5 gives better hole stability with adequate control of mud properties. Abnormally high pH, such as with a lime mud, promotes rather than alleviates problems in some shales. Pressures within the shales and the dip of formations further complicate the problem. There are three fundamental remedies for a shale problem of this nature: (1) sufficient density, (2) correct pH range and (3) control of the fluid loss.

SHALE TESTING

A number of laboratory tests are available to try and quantify this chemical interaction between various water-base

The swellmeter is used most often to evaluate different levels of inhibition from salts or other ionic inhibitors...

muds and a particular shale. These tests include:
- Classification of shales (CEC and clay content).
- Visual immersion testing.
- Hydration (yield) tests.
- Cuttings hardness tests.
- Capillary suction tests.
- Linear swelling tests.
- Dispersion tests.
- Confined-pressure testing.
- Triaxial testing.
- Shale-hardness testing.

One caution about shale-compatibility testing is that these tests are significantly affected by the mud properties, particularly fluid loss, filtrate viscosity and mud viscosity. Comparisons between two mud systems with significantly different fluid loss and viscosity should not be made. The two primary tests which M-I uses is a linear swelling test called the "swellmeter" and hot-rolling dispersion tests.

The swellmeter uses reconstituted shale pellets immersed in a drilling fluid and measures the rate and amount of unconfined linear expansion. The most desirable drilling fluid would produce the least amount of linear swelling which would quickly slow to a near zero rate of swelling. This testing device can compare several different fluid formulations simultaneously. The results are reported as the percent swelling from the original thickness and the final rate of swelling at the end of the test. Typical swellmeter results range from 50 to 150%. The swellmeter is used most often to evaluate different levels of inhibition from salts or other ionic inhibitors (such as calcium and potassium). It is not good for trying to evaluate the effect of plugging agents like asphalt, gilsonite and sulfonated asphalt or encapsulating polymers like PHPA and PAC.

Dispersion tests use sized shale fragments (or cuttings) to measure the amount of dispersion which occurs when immersed in a drilling fluid and hot rolled for a given period of time. The original shale fragments are sized larger than one screen mesh size but smaller than another. At the end of the test, the volume of cuttings that will still be retained on the smaller screen size is measured and reported as the percent recovered. The dispersion test is excellent for evaluating the effectiveness of encapsulating polymers. It is one of the best tests for obtaining an indication of which mud system will be most compatible with a particular shale and its actual field performance.

MINIMIZING WATER-BASE MUD INTERACTIONS WITH SHALE

1. Use the best ionic, inhibited system based on mineralogy and shale test.
2. Use the lowest practical fluid-loss values.
3. Use an encapsulating polymer.
4. Use polymers to increase filtrate viscosity for reducing fluid loss.
5. Use the lowest practical pH for a particular system.
6. Use a water-insoluble liquid additive to aid in plugging shale micropores.
7. Use a deformable plastering agent such as asphalt or gilsonite.

Solubility is a complex phenomenon that is affected by temperature, pressure, salinity and pH.

DISSOLUTION OF SOLUBLE FORMATIONS
Several formations are somewhat soluble in water-base mud. These include salt formations and the calcium sulfates, gypsum and anhydrite. Wellbore stability may be compromised if the soluble formation is allowed to wash out. Other problems may arise such as hole cleaning and obtaining a satisfactory cement job. Solubility is a complex phenomenon that is affected by temperature, pressure, salinity and pH. Salt is readily soluble in any undersaturated water-base mud. It is important to limit wellbore enlargement in mobile salt formations to achieve a good cement job for maximum strength and resistance to point loading so that casing collapse will not occur. Gypsum and anhydrite become more soluble as salinity increases. If wellbore stability and a gauge hole cannot be achieved in a gyp or anhydrite zone, then a gyp or lime-base calcium system should be used.

Physical Interactions

Physical interactions... include erosion..., wetting along pre-existing fracture(s) and fluid invasion...

Physical interactions can also lead to wellbore instability. These include erosion which causes wellbore enlargement, wetting along pre-existing fracture(s) and fluid invasion which causes pressure transmission. A wellbore is most stable when there is sufficient hydrostatic pressure to maintain overbalance acting exactly on the face of the well, and when the maximum stress on the wellbore is less than the formation strength. For this reason, it is important to maintain a gauge hole in order to minimize filtrate losses into permeable formations. It is also important to use plugging or plastering agents to prevent fluid invasion and pressure transmission from occurring radially away from the wellbore.

EROSION
Erosion is caused by fluid turbulence in soft formations. Soft formations that are easily eroded are unconsolidated sandstones, soft chalks, and softer clays and shales. Turbulent flow can lead to erosion in the softest formations. However, recent evidence shows that high bit-nozzle shear rate is the primary cause of fluid erosion. High bit-nozzle shear rates are used to maximize rate of penetration, and this feature may be more important than the resulting wellbore erosion. The amount of erosion that will occur depends on the rock strength; some formations will not be affected. Erosion in shales and sandstones has been shown to be greater if the bit nozzle shear rate is >100,000 sec^{-1}. When drilling unconsolidated sands, it may be necessary to use additional techniques to limit erosion. In these sands, viscous muds with shear-thinning characteristics and high bentonite contents (to form a good filter cake) have been found to be most successful.

WETTING, FLUID INVASION AND PRESSURE TRANSMISSION
Wetting along pre-existing shale microfractures, fluid invasion and equalizing the overbalance pressure all compromise wellbore stability.

As discussed earlier, a principal cause of shale instability is water-wetting along shale microfractures. While these shales do not soften or disintegrate when contacted with water, the filtrate or mud invasion will create weaknesses along bedding planes and cause splitting and sloughing. This is often described as "book-page" or "frayed-edges" fractures.

An ideal filter cake helps provide for a stable wellbore.

While chemical inhibition and higher mud weights may help minimize the problem, they are not as effective as sealing the formation with plugging or plastering agents. To more effectively control these shales, the formation must be sealed against fluid invasion. This can be accomplished by controlling the high-pressure, high-temperature filtration and filter-cake quality with polymers, an adequate concentration of bentonite, and by using water insoluble materials and pore plugging agents.

Fluid invasion equalizes the overbalance pressure away from the wellbore and tends to destabilize the mechanical integrity of the wellbore. This is true whether it is in a permeable formation like sandstone or in a relatively impermeable shale. An ideal filter cake helps provide for a stable wellbore. For water-base muds, there is an advantage to using an insoluble additive to limit filtration through the filter cake on sandstones and into the micropores of water-wet shales. Using low fluid loss obtained with a good-quality filter cake and polymers combined with a pore-plugging additive will reduce fluid invasion and limit pressure transmission.

Asphalt, sulfonated asphalt and gilsonite have been the most widely used and effective additives for this purpose. Pore-plugging and plastering additives include:

- Oil and non-aqueous synthetic liquids.
- "Cloud-point" polyglycols (GLYDRIL).
- Insoluble polyglycols and lubricants (LUBE-100 and LUBE-167).
- Asphalt (STABIL-HOLE).
- Gilsonite.
- Sulfonated asphalt blends (ASPHASOL).

They further reduce water invasion in shales by plugging the micropores.

Wellsite Analysis

Extremely difficult drilling conditions have led to more systematic approaches to analyzing wellbore instabilities. One such approach (from Zausa and Civolani) that can be used as a guideline for the mud engineer involves three basic steps:

1. Monitor and analyze the fundamental failure mechanism.
2. Determine and understand the factors governing this failure mechanism.
3. Model the problem considering impact of proposed changes.

1. MONITOR AND ANALYZE THE FAILURE MECHANISM

Monitoring of data and events on the rig is the first step of the process and involves:

- **Collection, organization and processing of drilling data.** Drilling data such as Rate of Penetration (ROP), Revolutions per Minute (RPM), Weight-on-Bit (WOB), Bottom-Hole Assembly (BHA), torque, overpull Trip In Hole (TIH) and Pull Out Of Hole (POOH), swab and surge, flow rate, mud weight, mud rheology, etc. should be collected, organized and analyzed on a continual basis and compared to the symptoms of wellbore stability being observed. This will help evaluate performance and establish trends or any deviations and measure the effectiveness of treatments and changes.
- **Formation characterization.** The standard procedure in drilling operations is to apply the knowledge gained from previous wells to subsequent wells drilled in similar geologic regions. Wellbore-instability investigation requires evaluation of shales during the drilling process.

Since rigsite shale testing is limited due to equipment and time limitations, most evaluations are performed in a properly equipped laboratory. Laboratory tests are conducted to evaluate shale swelling, dispersibility, cation exchange capacity, hydration capacity, colloidal content, capillary suction time, shale hardness tests and mud compatibility properties. A number of methods have been used to perform rigsite tests. These include tests as simple as the methylene blue test (CEC) measurement of shale; shale hardness measurements; hot-rolled dispersion testing with various mud formulations and additives; and sophisticated analytical measurements of various clay properties. It is particularly important to try and determine the failure mechanism: swelling and softening or brittle spalling.

Information from these tests, current shaker observations and mud logger data are used to evaluate drilling fluid performance, adjust mechanical drilling parameters and making casing design decisions. The primary options to counter shale problems at the rigsite are:

- Change the drilling fluid density.
- Change to an oil- or synthetic-base system.
- Change to a more inhibited water-base mud.
- Reduce fluid loss to very low levels and increase filtrate viscosity.
- Utilize pore-plugging additives, emulsified insoluble materials or plastering agents.
- Adjust mechanical drilling parameters.

- **Evaluation and analysis of instability symptoms.** Instability warning signs such as the presence of excessive cavings on the shakers for a given ROP, fill on connections, tripping difficulties, torque, stuck pipe, etc. indicate that something is wrong downhole. The magnitude or volume of failed rock should be estimated and recorded with the other drilling parameters. The number and location of specific incidents should be recorded, such as pipe sticking, fill or packing-off, reaming and redrilling. All of this information can then be organized and correlated with time and depth to detect the location and quantify the severity of critical sections in the well.

2. Determine and understand failure mechanism

All of the monitored and plotted parameters are then evaluated to identify the most probable mechanism causing the instability. The most useful symptoms used to indicate the mechanism responsible for wellbore instability are:

- Cavings analysis.
- Tripping difficulties.
- Drilling conditions.
- Mud system analysis.
- In-situ conditions.

These symptoms should be evaluated based on an interdisciplinary knowledge of the causes of wellbore instability to determine the most likely failure mechanism.

3. MODEL AND CONSIDERING PROPOSED CHANGES

Once the monitoring and determination steps have produced parameters, organize and analyze this data to obtain qualitative solutions and evaluate proposed changes. One good way to do this is through the use of a decision tree or flowchart approach to evaluate the possible failure mechanism and to identify the most promising remedies. After arriving at a proposed solution, a corrective measure should be applied and the results used as feedback into the method and decision tree method.

A decision tree or flowchart, such as shown in Figure 9 for evaluating the cause of excessive cavings, provides a logical path for identification of the mechanism and a qualitative solution.

Maintaining hole stability while drilling shale sections can be particularly troublesome. Simple solutions do not always exist, but good drilling practices combined with good mud practices are most often successful. Analysis of the mechanical stress/strain relationships has helped to develop the proper density requirements for hole stability.

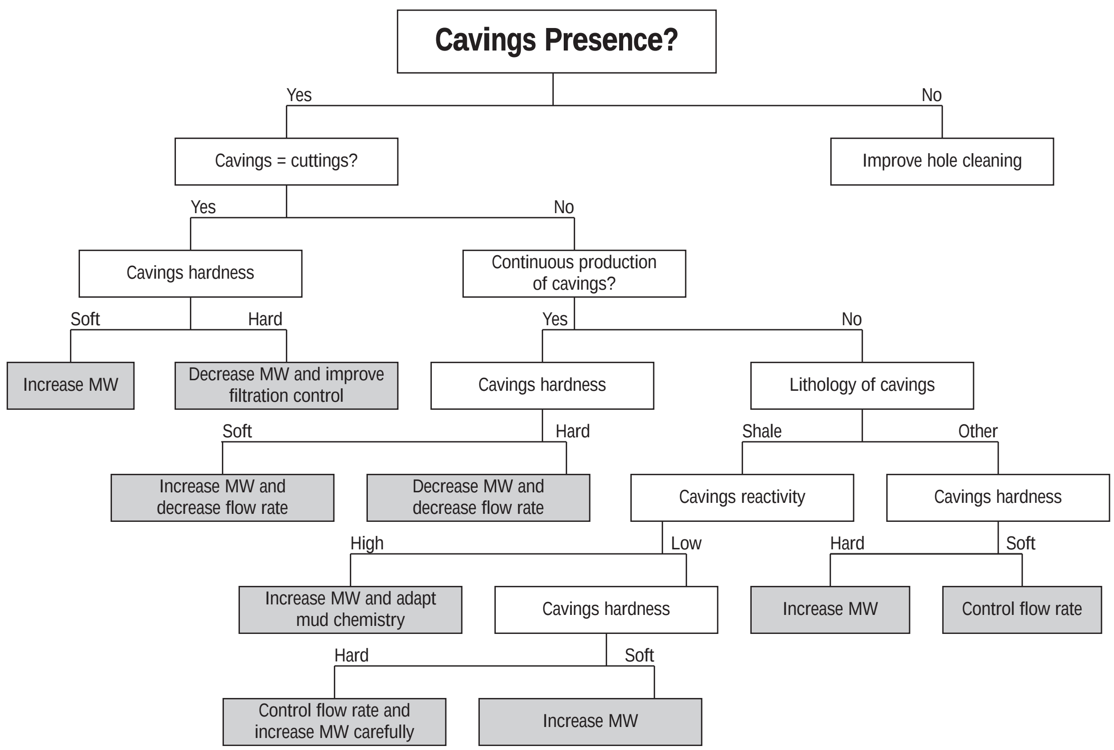


Figure 9: Decision tree for excessive cavings (from Zausa).