



On the physical and chemical stability of shales

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Abstract

The stability of clay-rich shales is profoundly affected by their complex physical and chemical interactions with drilling fluids. In this paper, an attempt is made to clarify the intricate links between transport processes (e.g. hydraulic flow, osmosis, diffusion of ions and pressure), physical change (e.g. loss of hydraulic overbalance due to mud pressure penetration) and chemical change (e.g. ion exchange, alteration of shale water content, changes in swelling pressure) that govern shale stability. It is shown that shale–fluid interactions can be manipulated to enhance cuttings and wellbore stabilization as well as improving hole-making ability in shale formations. The mode of shale-stabilizing action of a wide variety of water-based fluid additives is discussed and the merits of various mud systems are ranked. It is shown that shale stabilization normally achieved using oil-based/synthetic-based muds is now becoming achievable with economical and environmentally friendly water-based drilling fluids.

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1. Introduction

The problem of wellbore stability in shales has frustrated oil-field engineers from the start of oil and gas well drilling. Wellbore instability is in fact the most significant technical problem area in drilling and one of the largest sources of lost time and trouble cost (van Oort et al., 1996a). A typical example of problems encountered in the field is given in Fig. 1. The 8 1/2 in. section of this well, drilled with a water-based mud, was enlarged up to 25 in. despite the presence of additives used especially for shale-stabilization purposes. Operational problems that derive from such instabilities may range from high solids loading of the mud requiring dilution, to hole cleaning problems due

to reduced annular velocities in enlarged hole sections, to full-scale stuck pipe as a result of well caving and collapse.

Wellbore stability is almost a trivial issue with oil-based and synthetics-based muds. Once mud weight and invert emulsion salinity are properly established, stability can virtually be guaranteed (except for a few cases such as fractured shale formations, which may be rapidly destabilized by such muds when they penetrate the fracture network, lubricate fracture surfaces, and equilibrate pore pressure with wellbore pressure). Moreover, oil and synthetic based muds in general drill wells much faster than water-based muds as they are much less prone to cause bit balling.

Much more problematic and enigmatic have been the adverse interactions of shales with water-based fluids. Such muds are potentially attractive alternatives for oil and synthetic muds from an environ-

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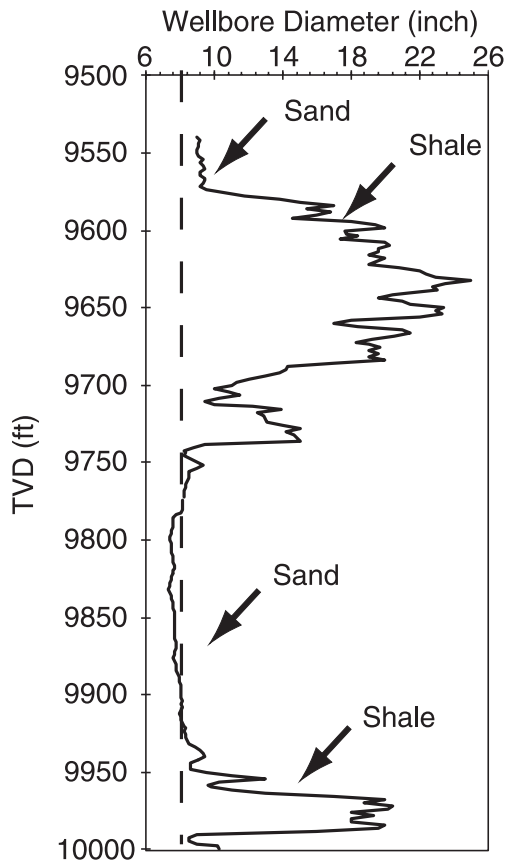


Fig. 1. Typical caliper example of shale instability and wellbore problems. This 8 1/2 in. hole (dotted line) was enlarged up to 25 in. in the shale sections, whereas the sands are near-gauge to slightly under-gauge due to the presence of a poor quality filtercake.

mental point-of-view, but they are still outmatched by the latter in overall drilling performance (exclusive focus in this paper is on shale stability—note that additional factors, such as fluid loss control, lubricity, mud rheology, etc., need to be considered also when comparing differences in drilling performance between mud types).

The central issue explored in this paper is: “which means can be exploited to achieve shale stabilization and improve operational drilling performance with water-based drilling fluids?” The fundamentals of the shale instability problem must be understood first in order to answer this question. This requires appreciation of: (1) transport processes in shales, (2) physio-chemical changes caused by this transport,

and (3) implications of these changes for mechanical and chemical shale stability.

2. Fundamentals of shale behavior

2.1. A balance of forces

Fig. 2 gives a simplistic but practical model for the forces acting on a shale system containing clays and other minerals (primarily quartz) at silt size. They can be subdivided into mechanical and physio-chemical forces. The former include:

- the in-situ vertical (overburden) and horizontal stresses;
- the pore pressure;
- the stress acting at intergranular contact points, e.g. at cementation bonds.

The latter, acting primarily in the clay fabric, include:

- the van der Waals attraction;
- the electrostatic Born repulsion;
- short-range repulsive and attractive forces that are derived from hydration/solvation of clay surfaces

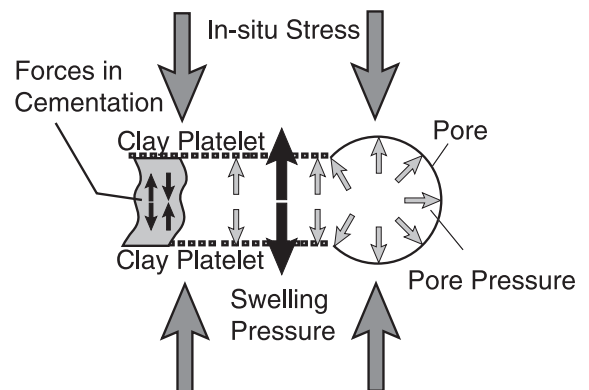


Fig. 2. A schematic representation of downhole forces acting on a shale system, simplified as a single set of clay platelets connected to a pore. The forces include the in-situ vertical and horizontal stresses, the pore pressure, the swelling pressure acting between the clay platelets, and tensile or compressive forces in the cementation developing upon compressive or tensile loading of the shale material, respectively.

and the ions that are present in interlayer spacings (adsorbed or free).

The latter forces are usually lumped together to form the “hydration stress/pressure” or “swelling stress/pressure”, since they are responsible for the characteristic swelling behavior of clays and shales. The term “swelling pressure”, well-accepted in oil-field practice, will be used exclusively below.

2.2. The swelling pressure

The van der Waals attraction and Born repulsion were combined successfully in DLVO theory (van Olphen, 1977), which has worked well in explaining the behavior of clay colloidal suspensions. However, DLVO is a continuum theory that breaks down at small clay interplatelet distances (i.e. distances < 20 Å) present in most well-consolidated shales encountered in the field. At such distances, short-range repulsive forces that bear the mark of the discrete, quantized nature of matter become dominant.

Fig. 3a shows the results of a molecular dynamics (MD) study to simulate the swelling pressure in sodium montmorillonite (Karaborni et al., 1996).

The pressure profile displays oscillations that relate to the layering of water between the clay platelets. The density distributions in Fig. 3b show that Na-montmorillonite during swelling jumps from two water layers at a platelet spacing of 9.7 Å, to three layers at 12.0 Å, to five layers at 15.5 Å, to seven layers at 18.3 Å, etc. The states in-between, i.e. four, six and eight water layers, were all found to be strongly repulsive and therefore unstable. The simulation results show good correlation with experimental determinations of the equilibrium states of Na-montmorillonite (Karaborni et al., 1996). This example shows the complicated nature of the swelling pressure and explains why attempts to explain clay–shale swelling behavior on the basis of simplistic models (such as the osmotic model of swelling) have met with little success.

For decades, the standard oil-field solution to clay–shale problems has been “inhibition”, a term originally derived from the ability of certain additives, most notably salts, to “inhibit” yielding of bentonite in water (Darley and Gray, 1988). The term is confusing since the colloidal behavior of clays and swelling in well-consolidated shales are two separate and, to a large extent, unrelated issues. For instance, the effi-

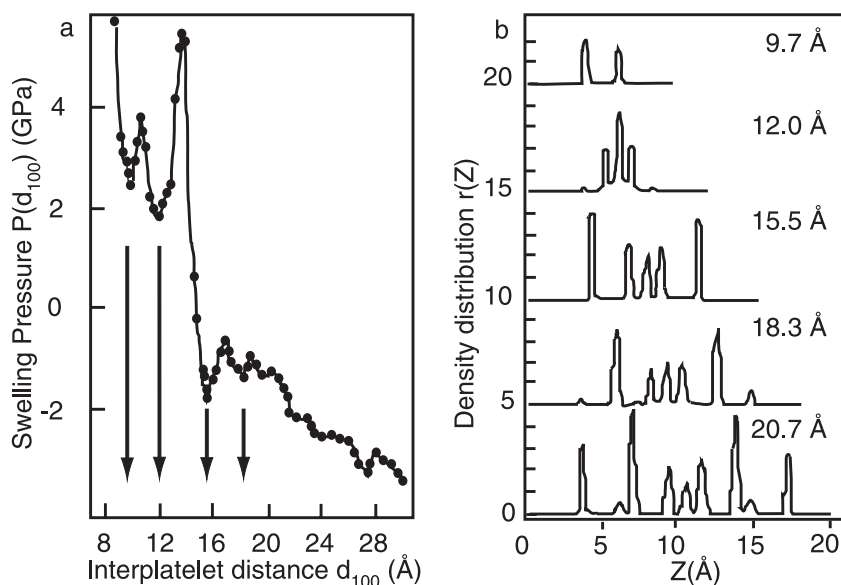


Fig. 3. (a) Swelling pressure in Na-montmorillonite as a function of interplatelet distance/basal spacing d_{100} . Contribution of DLVO forces is not included. Stable states are indicated by arrows. (b) Density distribution of oxygen atoms in water as a function of the distance Z from the octahedral sheet. Results are shown for the stable states with spacings at 9.7, 12.0, 15.5, 18.3 and 20.7 Å.

ciency of clay flocculation governed by DLVO forces decreases with ion valence (the well-known Schulze–Hardy rule, see e.g. van Olphen, 1977). By comparison, swelling pressure governed by non-DLVO forces such as ion hydration follows quite the reverse trend, e.g. K^+ is much more effective than Ca^{2+} or Mg^{2+} in reducing the swelling pressure in montmorillonite. In the following, the well-accepted oil-field terms “inhibition” and “inhibitor” will apply strictly to additives that are aimed at reducing the swelling pressure. “Inhibition”, however, is not necessarily a synonym for “shale-stabilization” as we shall see.

The effectiveness of K^+ ions in minimizing swelling pressures in montmorillonite is believed to be related to the small degree of hydration of these ions in water, resulting in low ion repulsion (Karaborni et al., 1996). The effects of ion hydration, however, are non-trivial. Fig. 4 shows the results of oedometer experiments, measuring the degree of swelling of a pre-loaded montmorillonite-rich shale sample that was immersed in concentrated solutions of KCl and KCOOH. Swelling was measured during an unloading sequence and was quantified in terms of a swelling index. At low salt concentrations, i.e. <20% w/w, a reduction in swelling (showing as a reduced swelling index) was seen with an increase in K^+ content. At high salt levels, however, swelling was again seen to

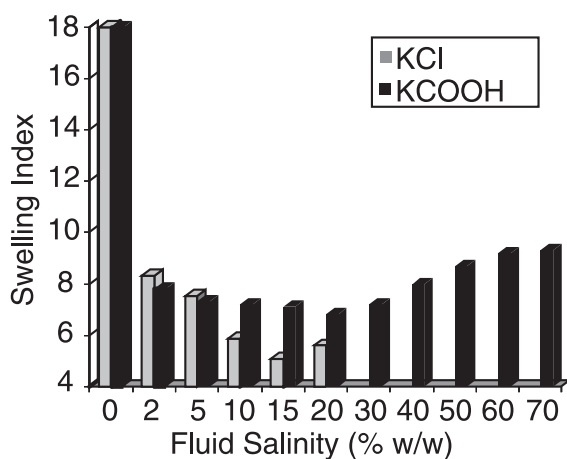


Fig. 4. Oedometer test result for a shale containing 68% total clay, of which 76% montmorillonite, immersed in solutions of KCl and KCOOH of increasing salinity. The test shows an initial decrease in swelling for increase in salinity (note that the swelling index does not go to zero, i.e. there always is a residual swelling pressure), after which swelling increases again with the increase in salt content.

increase. Similar effects have been documented in open literature (e.g. Christenson et al., 1987; Israelachvili, 1991).

These contra-intuitive results are explained by considering the increased ion repulsion that derives from the introduction of an excess of hydrated ions in the interplatelet clay spacings. At first, the introduction of low concentrations of potassium salt is beneficial in lowering the swelling pressure due to K^+ ions replacing “less-inhibitive”, more hydrated ions at the clay surface. However, the swelling pressure will increase when an excess of hydrated cations and anions with increased mutual repulsion builds up in the interplatelet clay spacings.

Note that the above results were both obtained for a shale system with very high-salinity brine as the only fluid between the clay platelets. Such situations will hardly ever occur in actual field practice, where transport of solutes from the mud to the shale (e.g. diffusion of ions) dilutes the concentration of solutes. These results should therefore not be used as an argument to discard concentrated KCl or KCOOH brines as base fluids for shale muds. The results just serve to place swelling pressure in a different light and to highlight the complexity of ion repulsion phenomena.

A full discussion on other unique features of the swelling pressure, most of which are ill-understood in current oil-field practice, falls beyond the scope of this paper. An excellent review can be found in Israelachvili (1991) for interested readers. Important to the present discussion are the following:

1. The swelling pressure is always present in clay-rich shales, acting as a tensile force on clay platelets: it does not suddenly develop when the shales are contacted by water-based drilling fluids. However, chemical changes caused by shale-drilling fluid interactions may change its magnitude (either beneficially or adversely).
2. Even the best inhibitors cannot bring the swelling pressure down to zero (see Fig. 4 and Israelachvili, 1991; Bol, 1986; Bol et al., 1992); there will always be residual repulsion between the platelets due to hydration of the clay surfaces and sterical interference between hydrated ions and water molecules, unless complete dehydration and platelet collapse occurs. Studies claiming otherwise (Steiger, 1993) usually do not take into account the fact that

swelling pressure can be compensated by forces in the cementation bonds, such that no net swelling will be apparent in macroscopic experiments.

- Swelling pressures are highly clay-specific. Thus, the effectiveness of “inhibitors” in reducing swelling pressures will be different for different clays. For instance, whereas potassium has a strong effect on swelling of montmorillonite, it has hardly any effect on illite and may actually increase the swelling of kaolinite.

In our attempt to stabilize shales we should be aiming to control and reduce the swelling pressure. This, however, may not be enough to guarantee stability, as shown in the following discussion on transport in shale and the requirements for shale stability.

3. Transport in shales

An overview of direct and coupled flows that can occur in shales and their driving forces is given in Table 1. Well-known direct flows are Darcy flow of water, driven by hydraulic gradients, and diffusion of solutes, driven by chemical potential gradients between the drilling fluid and the shale. In previous publications (van Oort et al., 1995, 1996a) it was shown that shale–fluid systems may act as “leaky

Table 1
Overview of flows in shales driven by gradients in hydraulic pressure, chemical potential, electric potential and temperature

Driving force flow	Hydraulic pressure gradient	Chemical potential gradient	Electric potential gradient	Temperature gradient
Fluid (water)	Convection (Darcy's Law)	Chemical osmosis	Electro-osmosis	Thermo-osmosis
Solutes/ions	Advection	Diffusion (Fick's Law)	Electrophoresis	Thermal diffusion (Soret Effect)
Current	Streaming current	Diffusion current	Electric conduction (Ohm's Law)	Thermo-electricity (Seebeck Effect)
Heat	Isothermal heat transfer	Dufour effect	Peltier effect	Thermal conduction (Fourier's Law)

Table 2

Results of transport experiments determining permeability, membrane efficiency and ion diffusion rates in Pierre type I shale

Test	Permeability (nD)	Membrane efficiency (%)	Cation diffusion rate
35% CaCl ₂	2.0	5.0	D(Ca ²⁺) = 2.6 × 10 ⁻¹⁰ m ² /s
21% NaCl	1.9	3.8	D(Na ⁺) = 2.9 × 10 ⁻¹⁰ m ² /s
26% KCl	2.2	2.2	D(K ⁺) = 1.9 × 10 ⁻¹⁰ m ² /s
72% KCOOH	1.5	7.9	D(K ⁺) = 1.3 × 10 ⁻¹⁰ m ² /s
21% NaCl–7.5% Na–silicate mud	5.4 ^a (before mud exposure), <0.1 (after mud exposure)	61	D(Na ⁺) = below detection limit ^b

^a The permeability of the shale was determined before and after exposure to the silicate drilling fluid—a dramatic drop in permeability was observed after exposure, consistent with the mechanism of pore blocking caused by silicate gelation and precipitation.

^b The diffusion coefficients were below the experimental detection limit of 0.5 × 10⁻¹⁰ m²/s.

osmotic membranes” that sustain chemical osmosis, which is the flow of water driven by chemical potential gradients. The membrane character derives from by the mobility difference of water and hydrated solutes that exists in the clay-rich, low-permeability matrices of shales. Using high-salinity fluids, it is possible to stimulate osmotic backflow of shale pore water towards the wellbore in order to (partially) offset the hydraulic inflow of mud filtrate. All direct and coupled flows combined give rise to exchange of water and solutes/ions that will change the swelling pressure, water content and pore pressure.

Let us assume that we are drilling a shale at hydraulic overbalance, such that we comply with the mud weight requirements for mechanical stability (see below). The drilling fluid's ion content exceeds that of the shale pore fluid slightly. Diffusion of ions from the mud to the shale will occur due to the chemical potential gradient. For simplicity it is assumed that no coupled flows occur. The question now is: “what will the shale pore pressure, ionic content and water content look like after some time, and how will the changes affect stability?”

Contrary to the behavior in permeable media, diffusion is a more prominent, faster process than Darcy

flow in low-permeability shales. Ion diffusion coefficients in shales have been shown to be typically in the range of $1-10 \cdot 10^{-10} \text{ m}^2/\text{s}$ (see e.g. Ballard et al., 1992, 1993 and Table 2 for examples). For shales with permeability in the nano-Darcy range ($k = 10^{-9} \text{ D} - 10^{-21} \text{ m}^2$), ion diffusion is then one to two orders of magnitude faster than hydraulic flow (see Appendix A).

There is, however, another important process that takes place faster than ion diffusion. The Darcy flow of virtually incompressible water into a high-stiffness shale matrix will have a profound effect on pore-pressure. Because of their low base permeability, shales cannot dissipate pore pressures fast enough to the far field. As a result of the water influx, pore-pressure will be elevated in an extended zone around the wellbore. We thus see that drilling with a water-based mud at overbalance will “charge” the near-wellbore pore pressure in time.

For low-permeability shales, the pore-pressure front is expected to exceed the ion diffusion front by one to two orders of magnitude (see Appendix A and Fig. 5). The situation depicted in Fig. 6 is created where the mud filtrate invasion front is preceded by an ion diffusion front, which in turn is preceded by a

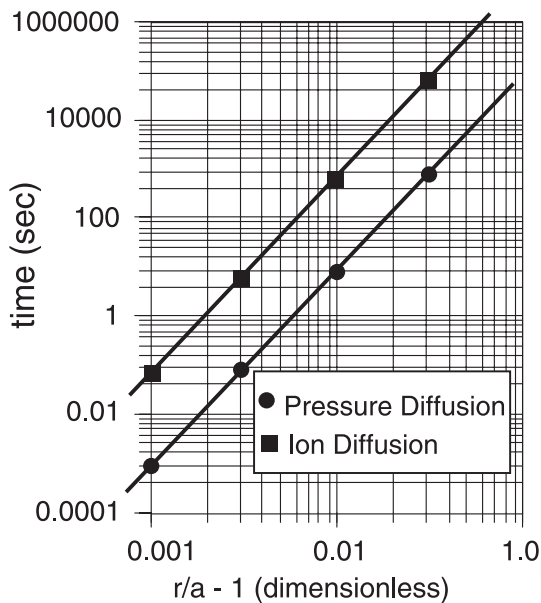


Fig. 5. Pressure penetration and ion diffusion in shale. Profiles were obtained by applying an approximation to Eq. (A4) for short time frames and using a diffusion constant of $1 \times 10^{-8} \text{ m}^2/\text{s}$ for pressure diffusion and $1 \times 10^{-10} \text{ m}^2/\text{s}$ for ion diffusion.

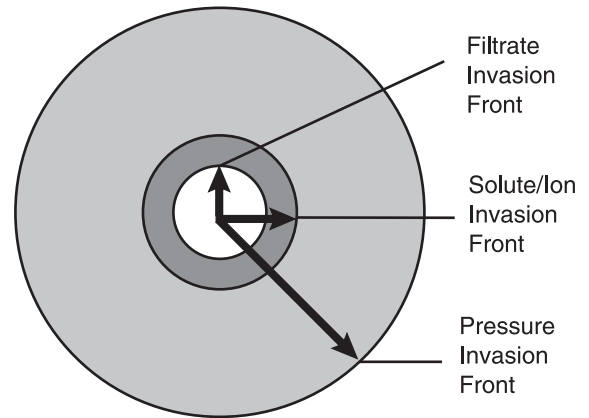


Fig. 6. Schematic overview of the development of various fronts around a wellbore in a shale in time. From the central wellbore going out into the formation, the filtrate invasion front is preceded by a solute/ion invasion front, which in turn is preceded by the mud pressure invasion front. There is one to two orders of magnitude difference in penetration depth between the various invasion fronts.

pore-pressure diffusion front. A good rule-of-thumb is that where bulk water invasion proceeds at millimeters a day, ion diffusion will diffuse over centimeters a day and pressure will diffuse over decimeters a day.

Ions diffusing into shales will exchange at clay sites, altering the swelling pressure. Invading mud pressure will elevate the pore pressure. If osmosis occurs, the shale may be dehydrated in the near-wellbore zone. Such changes will all affect the stress state and/or the strength of a freshly drilled shale in time. Their implications for wellbore stability are now discussed.

4. Requirements for stability

Fig. 7 shows a Mohr–Coulomb representation of the stress state of shale after drilling (dotted curve). The stresses on the vertical axes are inter-granular stress, also known as effective stresses. In an extension to Terzaghi’s (1943) concept of effective stress, these are denoted as:

$$\sigma_i^{\text{eff}} = \sigma_i - P_{\text{pore}} - P_{\text{swelling}} \quad (1)$$

where σ are the in-situ formation stresses and P_{pore} and P_{swelling} denote the pore and swelling pressure, respectively. Note that the swelling pressure and pore pressure have been completely decoupled here. This approach remains to be validated. The Mohr–Cou-

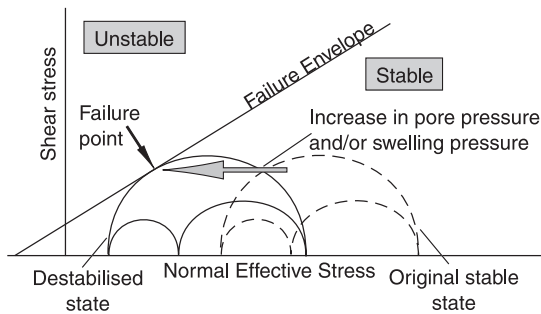


Fig. 7. Mohr–Coulomb representation of shale failure: the increase in pore pressure and/or swelling pressure will reduce all effective normal stresses (note that shear stresses remain unaltered) until the stress state touches the failure envelope and the shale fails for a given orientation around the wellbore.

lomb failure envelope, which reflects the shale's strength, is defined as (Jaeger and Cook, 1979):

$$\tau = \sigma \tan \phi + C \quad (2)$$

where τ represents shear stress, ϕ is friction angle and C denotes cohesion. It is assumed that the shale is stable initially after drilling, meaning that the applied stresses, pore pressure, hydration stress and cementation forces are all balanced in the shale and do not overcome its strength. This requires first of all the application of the proper radial support on the wellbore wall, i.e. the right mud weight (Aadnoy and Chenevert, 1987; Wong et al., 1991). If the mud weight is too low, then immediate (local) tensile or shear failure will occur. Tensile fracturing may occur on the other hand if the mud weight is too high. Note that such immediate failures are not dependent on mud type (be they oil-based, synthetic or water-based muds), but are governed solely by the magnitude of the mud weight. Mud weight is therefore the main tool at the driller's disposal to guarantee initial shale stability. However, having the right mud weight initially does not necessarily guarantee stability over time, as we shall see.

There are basically three mechanisms by which exposure to the drilling fluid can lead to instability in time. These are:

1. Elevation of the pore pressure due to mud pressure invasion, reducing the effective stresses.
2. Elevation of the swelling pressure (e.g. due to unfavorable cation exchange at clay sites), reducing the effective stresses.
3. Chemical alteration and weakening of the cementation bonds. This effect cannot be accounted for in the present representation of effective stress. It may be taken into account by adjusting the shale strength and failure parameters (e.g. cohesion and friction angle), thus shifting the position and the slope of the failure envelope in time.

Note that the opposite holds true also: a more stable situation may arise when pore pressure or hydration stress are reduced, or if chemical alteration strengthens the shale.

Fig. 7 shows what happens to our initially stable state when the effective stresses are reduced in time: the stress state will move towards the failure envelope until for a specific point around the wellbore (i.e. a specific combination of normal and shear stresses) the envelope is reached and failure occurs (see solid curve in Fig. 7). To maintain stability, there is only one option available: to increase mud weight in order to change the stress state (i.e. shift the Mohr circle back to the right) and keep the hole open. This, however, is only a temporary fix as the process that is reducing the effective stresses will continue to move the stress state towards failure. Moreover, progressively weighting up the mud will eventually erode the available drilling margin (=difference between fracture gradient and mud weight required for well control and borehole stability), ultimately leading to exceeding the fracture gradient, tensile wall fracturing and mud losses.

We now pose the following question: “can the elevation of pore-pressure by mud pressure penetration be compensated by lowering the swelling pressure by an equivalent amount using the appropriate inhibitors?” At a more basic level, this becomes a frequently asked question in oil-field practice: “can inhibiting mud additives be used effectively to prevent shale problems, and if yes, what kind of additives should be used?” Reviewing Eq. (1), we are asking if an increase in P_{pore} can be offset by a reduction in P_{swelling} .

Invoking the earlier arguments on transport, the answer to the above questions should be that there are cases in which shale instability cannot be prevented

whatever kind of inhibitors are used (remark that inhibitors were defined earlier as agents that reduce the swelling pressure). The reason for this is that in intact, non-fractured shales, the inhibitor-diffusion front lags behind the pore-pressure front. As shown in Figs. 5 and 6, instability cannot be prevented in the zone with elevated pore-pressure between the two fronts *as the inhibitor will not have reached this zone yet*. Assuming that the pore-pressure has been equilibrated to the mud pressure (i.e. $P_{\text{pore}} = P_{\text{m}}$) in the mud pressure invasion zone not yet reached by inhibitor diffusion, the effective radial stress acting in this zone becomes:

$$\sigma_r^{\text{eff}} = -P_{\text{swelling}} \quad (3)$$

which means that the full native swelling pressure, not in any way attenuated by inhibitors which are lagging behind, is acting in tension on the clay fabric. However, even when inhibitors would be present, the swelling pressure cannot be brought down to zero (see above), such that there will always be an effective tensile force remaining. When this net tensile force overcomes the shale's tensile strength (which is normally low in shales anyway) than yielding will be imminent at the weakest sites in this zone, which may trigger subsequent full-scale failure. Particularly detrimental in this respect are annular pressure fluctuations (e.g. during swab and surge events) which, by changing the hydraulic radial support, may deliver the "final blow" to an already weakened and yielding shale, failing the material and dislodging shale fragments from the wellbore wall.

The time-lag in the transport of inhibitors is regarded as one of the main reasons behind their short-comings as shale-stabilizers. "Inhibition" will only be effective if mud pressure penetration and inhibitor diffusion can go side-by-side, and if the nature of the shale and the inhibiting agent are such that the swelling pressure can indeed be reduced to an extent that offsets the pore-pressure increase. Note that such conditions will only be satisfied for shales with significant amounts of "swellable" clays such as smectites. For low to non-reactive clays such as kaolinites, inhibitors will almost never provide any solution, which explains why inhibitive muds have historically performed poorly when used in drilling of such clays.

It is concluded that a strategy for shale stabilization based solely on the use of inhibitors can only be partially successful. Clearly, something more than "inhibition" is needed for shale stability, which ties in with field experience. As emphasized in a number of previous papers (van Oort, 1994; van Oort et al., 1995, 1996a), the prevention of water/mud filtrate influx in shale and concomitant prevention of mud pressure penetration in shales holds the key to shale stabilization. The recipe for achieving physio-chemical shale and wellbore stability is as follows:

(1) Apply radial support stress to the wellbore wall by using the appropriate mud weight to achieve mechanical stability. Without the right mud weight, any formation may yield and fail whatever mud system is used.

(2) Maintain this radial support in time by preventing mud filtrate invasion and concomitant pore pressure elevation by:

- reducing shale permeability, e.g. by blocking off pore throats;
- increasing filtrate viscosity, thus reducing the rate of hydraulic inflow from the mud to the shale;
- balancing hydraulic inflow from the mud to the shale by an induced osmotic backflow from the shale to the mud.

(3) Attempt to improve stability by:

- stimulating osmotic backflow of pore fluid to reduce the shale's near-wellbore water content and pore-pressure so that strength and effective stress increase (Colback and Wiid, 1965);
- using solutes in the drilling fluid that have the ability to diffuse into the shale, exchange at clay platelets and reduce the swelling pressure effectively;
- using solutes in the drilling fluid that invade shales and chemically react with shale components to increase the cementation forces.

5. Shale problems and solutions

Three types of shale problems and their unique solutions are now discussed: (1) cuttings disintegration, (2) wellbore instability and (3) bit balling. From a mud engineering standpoint, the challenge is to

devise an overall drilling fluid strategy that satisfies the requirements for cuttings and wellbore stability and the prevention of bit-balling at the same time.

5.1. Cuttings disintegration

Fig. 8 demonstrates the effects of drilling on our model shale system. With the release of the cutting from the rock matrix, the in-situ stresses are suddenly removed and replaced by the uniform mud pressure. A single radial effective stress/pressure will be acting on the cutting, given by:

$$\sigma_r^{\text{eff}} = P_{\text{mud}} - P_{\text{pore}} - P_{\text{swelling}} \quad (4)$$

Note that this stress/pressure acting on the cutting's cementation will be in compression when the mud pressure exceeds the combination of pore pressure and swelling pressure, but will shift to tension if the latter combination exceeds the mud pressure. Direct local failure at weak sites within the cutting followed by hydration and dispersion may occur if the stress overcomes the tensile strength of the shale.

Let us assume that the mud pressure and the cutting's cementation are able to control failure and dispersion initially, i.e. right after drilling. The mud pressure may invade the cutting and equilibrate its pore pressure in time, but this is a relatively slow process which will not reach its full effect if cuttings are

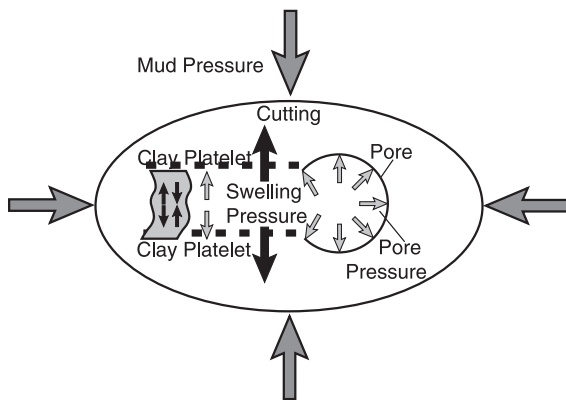


Fig. 8. Pressures acting on cuttings. When a shale is drilled, cuttings experience relief of in-situ stress. The combination of mud pressure and cementation forces will need to contain swelling pressure and pore pressure to avoid disintegration.

quickly circulated out of the hole. A bigger problem is the reduction in hydrostatic pressure (i.e. reduction in P_{mud}) experienced by the cutting as it travels up the annulus. This reduction in the compressive force acting on the cutting reduces the stronghold on the swelling pressure, which may now overcome the cementation's strength and separate the clay platelets by drawing water from the mud. The material will lose its integrity as water invades radially inward, typically creating an "union type" pattern of a hard, dry interior and progressively softer outer shells of more dispersed material.

There essentially two approaches to cuttings instability:

1. Inhibition and encapsulation. Inhibitors have been applied with good success in stabilizing cuttings. Indeed, what is called for is control over the detrimental effects of the swelling pressure, which is usually achieved by the combined action of an inhibitor that targets the swelling pressure directly and an "encapsulator" polymer (the term may not be entirely accurate as there is hardly ever any real encapsulation/coating of the cuttings) that may hold shale material together and prevent it from disintegration. The matter is treated in more detail in the discussion on salt/PHPA muds below.
2. Shut-off of the water influx by filtrate viscosity enhancement, pore blocking, or stimulated osmotic backflow of pore fluid. The idea is simple: when there is no water available to satisfy the demand of the swelling pressure, then there will be no swelling and disintegration (which is essentially the way oil and synthetic mud stabilize cuttings; moreover, in those muds the invasion of bulk mud into the shale fabric is prevented by capillary entry pressures). Any cavitation of pores within the cutting itself will be counteracted by capillary pressures in the pores, which can attain very high values in shales (on the order of several hundred bars).

Preferably, these approaches should be run in parallel to maximize the stabilizing effect on cuttings.

5.2. Wellbore instability

Cuttings and shale stability have historically been equated to being one-and-the-same problem. How-

ever, there are essential differences that necessitate a separate approach to wellbore instability. Two of these differences are:

1. The in-situ stress conditions and geometrical effects.
2. The timing. Normally, wellbores are exposed for much longer times to drilling fluids than cuttings are, unless the latter are not cleaned out of the hole effectively and are, e.g. buried in a cuttings bed. As transport proceeds with time, different modes of failure are encountered.

The strategy for ensuring wellbore stability was outlined in the previous section.

5.3. Bit balling

Bit balling strongly affects rate-of-penetration (ROP) and hole-making ability, concomitantly affecting drilling costs. Despite its obvious importance, it is still a poorly understood phenomenon that is usually approached on a trial-and-error basis by empirically testing additives for their effect on ROP (Cheatham and Nahm, 1990; Cheatham et al., 1985). An attempt is made here to explain the drilling fluid aspects of bit balling on the basis of the shale model presented in Fig. 2, and to offer ways of minimizing bit balling and maximizing ROP through improved water-based mud design.

After drilling, the stress experienced by the cutting is given by Eq. (4). The stress release may immediately trigger hydration. The swelling pressure is like an unloaded spring which is in need of water to effect the separation of the clay platelets. The cuttings will draw water from any available source, which may be the water layers on top of the steel surface of the bit or water from other nearby cuttings. Cuttings are in close contact right after drilling due to the relatively small bit clearances and the mechanical “kneading” action by the bit. In drawing water inwards, cuttings may “vacuum” themselves onto the bit and onto each other, causing the bit to ball. The likelihood that the cuttings are going to remain attached to the bit, i.e. persist in sticking and cause a problem, will depend on their strength and plasticity which is a function of their water and clay content.

The concept of clay plasticity is well known from soil mechanics (Mitchell, 1993), where it is conveniently captured in terms of the so-called Atterberg limits. Increasing the water content of an initially dry clay will first lead to a dry zone below the plastic limit (see Fig. 9). In this zone, the material is too dry to have significant tendency to stick. Above the plastic limit at higher water contents, however, sticking tendency rapidly increases. If the water content is increased even further, the liquid limit is reached such that the material has very limited inherent strength and will disperse. The material may readily wash off the bit by the agitation of the fluid circulation. In this view, it is seen that there is a clear “danger zone” for bit balling: the plastic zone, at intermediate water contents. This position of this zone will depend on the type of shale, its specific clay type and clay content, and therefore its swelling pressure.

If a shale with pronounced balling tendency is drilled one should design the drilling fluid so that (see Fig. 9):

1. The cuttings are dehydrated, such that they are taken from the plastic zone into the dry zone whereby their tendency to stick disappears. This may be accomplished by using mud systems that can build membranes and can osmotically dehydrate the shale. Note that electro-osmosis (i.e. the

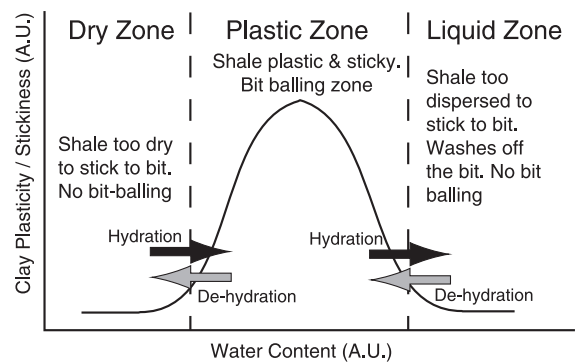


Fig. 9. Model for bit balling. Shales in the plastic zone will have a tendency to ball the bit and BHA, causing ROP reduction. The tendency to ball disappears when the shale is either dehydrated (taken over to the dry zone) or hydrated (taken over to the liquid zone).

flow of shale pore water stimulated by a negative potential applied at the bit, see Table 1) which has been shown to minimize bit balling and improve ROP works in a similar way (Roy and Cooper, 1993).

2. The cuttings are hydrated, such that they enter the liquid zone, disperse, and are easily washed of the face of the bit. This may be accomplished using dispersive mud systems. Note that these systems may give problems with wellbore stability as well as overall mud rheology due to their solids dispersing tendency.
3. The cuttings are coated (e.g. made oil-wet) at their outer periphery to prevent them from sticking together and latching onto the steel surface of the bit. Old oil-field practice dictated the use of a few percent of base oil or synthetic in the mud to overcome balling problems. More recently, special ROP enhancing additives were developed (for a much more detailed discussion, see van Oort et al., 2000) that can beneficially wet cuttings and steel surfaces, and help to brake up cuttings strands (e.g. the typical cuttings “ribbons” generated by PDC bits) to help cleaning of cuttings around the bit-face.

Care is advised for approaches (1) and (2): they can only be applied confidently if the water content and sticking tendency of the shale is known upfront, i.e. one would typically apply these strategies when there is an apparent balling problem and the shale drilled is known to be in the plastic zone. If not, then:

- (i) Using the approach of cuttings hydration, one may take cuttings initially in the dry zone over to the plastic zone, thus creating a bit-balling problem where there first was none. This situation may happen in the field when well-consolidated, low-reactivity shales are drilled with dispersive muds (e.g. lignosulphonate-based).
- (ii) Using the approach of cuttings dehydration, one may take initially wet cuttings from the liquid zone over to the plastic zone, again creating a problem where there was none to start with. This situation may happen in the field when young, high-reactivity shales are drilled with very inhibitive muds or muds with strong osmotic dehydration tendencies.

Of course there are other factors that play an important role in (the prevention of) bit balling problems, like weight-on-bit, bit rotation, hydraulics, the clearance around the bit available for cuttings removal, the sharpness and finish of PDC cutters, etc. These issues fall outside the scope of this paper (see, e.g. Roy and Cooper, 1993 and references therein).

6. Shale stabilizing additives and systems

Now that the framework for the behavior of shales, their interactions with water-based drilling fluids and the problems that derive from these interactions has been outlined, we can start to address the action of specific additives and systems used throughout the industry for shale stabilization. The number of commercial shale stabilizers is impressive; rather than discussing each of them individually they are generically grouped together.

6.1. Salts

6.1.1. Potassium chloride

Potassium chloride (KCl) is probably the best-known inhibitor in the oil-industry. Its popularity derives mainly from its ability to reduce swelling pressures in smectite clays. It has therefore been applied very effectively in drilling young, reactive “gumbo”-type shales which usually contain extensive amounts of these clays. Together with PHPA (partially hydrolyzed poly-acrylamide) a system is formed that is highly effective in stabilizing cuttings (Clark et al., 1976).

The main performance shortcoming of KCl is its inability to prevent filtrate invasion and mud pressure penetration in shales. The viscosities of KCl solutions are close to that of water, even at salt-saturation levels. KCl cannot plug pore throats or modify shale permeability. Thus, the hydraulic conductivity governing the extent of Darcy flow into shales is unaltered by KCl (see Fig. 10). In addition, osmotic pressures generated by concentrated KCl solutions are moderate (typically <20 MPa) and membrane efficiencies are low (typically 1–2%) due to the relatively high mobility of KCl in shale. Thus, osmotic backflow of shale pore fluid induced by

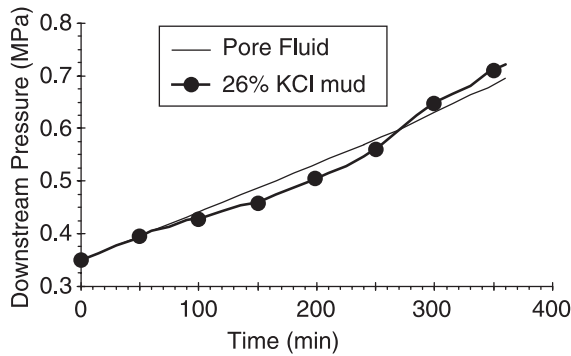


Fig. 10. Pressure transmission result for a saturated KCl mud, tested on Pierre type I shale at $T=65$ °C. Note that the rate of pressure transmission is the same as the pore fluid standard curve, i.e. KCl does not in any way retard mud pressure penetration.

KCl muds (with effective osmotic pressures in the range 0.1–1.0 MPa) will be negligible. As a result, KCl-based mud systems usually are not suitable for drilling older, less-reactive shales. First, ion diffusion is lagging behind mud pressure diffusion. Secondly, these shales have gone through a process of diagenesis which has changed the smectites into less swellable clays such as illites. Concomitantly, there is less swelling pressure in these shales for KCl to act upon. These shales will typically fail due to the effects of mud pressure penetration at prolonged exposure to the invading mud filtrate.

In conclusion, KCl is recommended for primarily for cuttings-stabilization of relatively young, more reactive shale types that contain significant amounts of smectites.

6.1.2. Sodium chloride

Na^+ is not as “inhibitive” as K^+ . Use of sodium chloride (NaCl) for shale control, however, does have certain advantages over use of KCl. NaCl solutions near saturation have elevated base viscosities and have lower water activities than concentrated KCl solutions, giving rise to higher osmotic pressures. Therefore, they are better equipped to reduce filtrate invasion in shales. Although concentrated NaCl solutions do not make good shale drilling fluids by themselves, they are very effective when run in combination with systems that can enhance shale membrane efficiency (such as silicates, polyols and methylglucoside, see below) by

providing the osmotic gradient for shale dehydration.

6.1.3. Calcium/magnesium/zinc chloride/bromide (CaCl_2 , CaBr_2 , ZnCl_2 , MgCl_2 , MgBr_2 , ZnBr_2)

Concentrated brines of Ca^{2+} , Mg^{2+} and Zn^{2+} are popular as base fluid for high-density, low-solids drilling and completion fluids. Two factors make them suitable for shale drilling: (i) their filtrate viscosities are high which will slow down hydraulic flow, and (ii) they can generate very high osmotic pressure (on the order of 1000 bars; however, membrane efficiencies are on the order of 1–10% so that the effective osmotic pressure acting is attenuated to 10–100 bars) that may be used to (partially) offset the hydraulic mud overbalance. There is downside also, however. Divalent ions will diffuse into the shales since the fluid–shale membrane is leaky and allows for ion transport from the mud to the shale. When these ions exchange at clay sites for more inhibitive ions such as K^+ , then the swelling pressure may increase, leading to shale instability. When these muds are used, one should carefully balance their beneficial effect on shale water content and pore pressure, and their potentially detrimental effect on the swelling pressure.

6.1.4. Formate and acetate salts (MCOOH , MCH_3COOH . $M=\text{Na}^+$, K^+ , Cs^+)

The above also holds true to a large extent for concentrated formate and acetate brines; their filtrate viscosities are high and they generate very large osmotic pressures. These monovalent salt systems, however, may have a much more beneficial effect on the swelling pressure. Especially potassium formate (KCOOH) seems especially suitable for shale drilling (see also van Oort et al., 1996a) by reducing swelling pressure, shale water content and pore pressure at the same time. This claim is supported by field experience (Howard, 1995). Note that the above-mentioned benefits will only be obtained for highly concentrated salt solutions.

6.2. Polymers with special shale affinity (e.g. cationics, amines, PHPA)

Several polymer alternatives, among them cationics, amines, etc., have been developed essentially

as alternatives for KCl (Beihoffer et al., 1990; Retz et al., 1991). The fact that K^+ ions could be exchanged only at single clay sites was perceived as a disadvantage that could be remedied using a polymer with functional groups that adsorbed onto clay surfaces at multiple sites (Himes et al., 1991). Such multiple-“anchored” polymers would be much more resistant to exchange than a single K^+ cation. Also, environmental legislation prohibits the use of KCl in several drilling areas in the world either by environmental sensitivity to potassium (e.g. offshore Gulf of Mexico) or to chlorides (e.g. onshore Canada, Thailand, etc.).

The argumentation given for the action of KCl essentially also holds for these polymers. They are good inhibitors of clay swelling, especially those of low molecular weight (<10,000 a.w.u.) that can enter the pore system and penetrate the clay fabric. The higher-molecular-weight species (>10,000 a.w.u.) will have lost this ability to penetrate shales and modify the swelling pressure due to size restrictions, but they may latch onto the outer surfaces of the shale. Well known in this respect is the action of PHPA, which adsorbs onto multiple sites on the clay surfaces and may thereby combat disintegration of shale material.

Fig. 11 shows the spreading of PHPA on a surface of calcite, as imaged using transmission electron microscopy. The image reveals a “spider-like” web formed by PHPA showing as an elevation above the shale surface.

Fig. 11 also clarifies the deficiencies of high-molecular weight shale stabilizing polymers like PHPA: their coverage of the shale surface and pore-blocking efficiency is minimal. As a result, mud pressure penetration is not in any way retarded by them as shown in Fig. 12. For low-molecular-weight polymers actually entering shales, their diffusion rates are much lower than pore-pressure diffusion rates, i.e. they are lagging behind the pore-pressure front. Following this argumentation, the recommended use for these additives is cuttings stabilization.

6.3. Asphaltenes, gilsonites, graphites

Asphaltenes, gilsonites and graphites are used for a variety of purposes, among them shale stabilization. These types of additives have no effect on the swelling pressure. Also, their significant bulk size prevents them from entering shales and effectively blocking pore

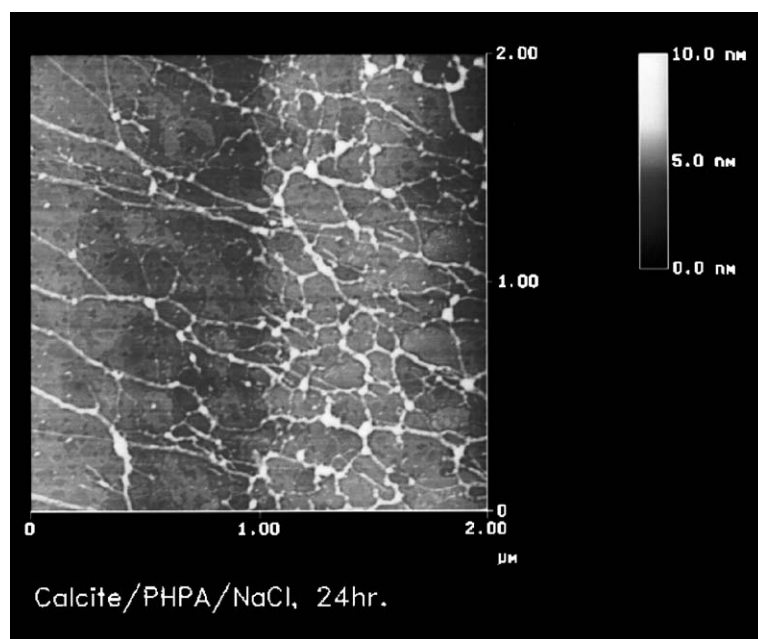


Fig. 11. TEM image of PHPA spread out on a calcite surface. Lighter areas are elevated above the shale surface (scale is from 0 to 10 nm). PHPA is seen to form a web-like structure that “encapsulates” the formation.

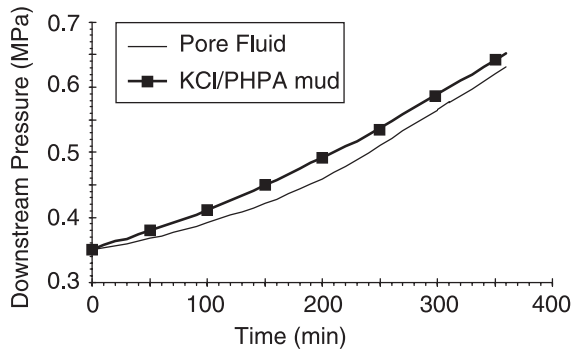


Fig. 12. Pressure transmission result for a 10 ppb KCl/PHPA mud, tested on Pierre type I shale at $T=65$ °C. Note that the rate of pressure transmission is the same as the pore fluid standard curve, i.e. PHPA does not retard mud pressure penetration.

throats. Thus, filtrate invasion and mud pressure penetration will proceed unretarded. Fig. 13 shows the result of a pressure transmission test, in which the rate of mud pressure penetration in shale is measured. Evidently, the gilsonite mud used had no effect on retarding the rate by which water invades. The effect of such additives on shale stability is therefore concluded to be very limited. Note that the 8 1/2 in. hole section shown in Fig. 1 was drilled using a gilsonite as the sole shale stabilizing agent in the drilling fluid. These additives are best applied the help seal (micro-)cracks in fractured formations.

6.4. Sugars and sugar derivatives

Saccharides (sugars) are well known low-molecular-weight viscosifiers which have the advantage of being very environmentally friendly. They viscosify mud filtrates effectively when used at appropriate concentrations, thus reducing the hydraulic flow of water in shales (van Oort, 1994). In addition, they lower water activities and therefore generate osmotic pressures that may be utilized to dehydrate the shale. These sugar systems are vulnerable to attack by biological organism, which may make preservation of mud and base additives at the rigsite difficult. Most of these problems were circumvented using methylglucoside, a methylated saccharides-species that is less sensitive to biological attack (Simpson et al., 1994). Methyl glucoside essentially works by the same token as other saccharides.

Saccharides are recommended for cuttings-and wellbore stabilization. A restriction to their use is that relatively high product concentrations (typically >30% w/w) are necessary to achieve the desired benefits, which may affect the economics of these systems and lead to high base mud viscosity. When systems are formulated that can dehydrate shales effectively, they may also be applied in reducing bit balling and increasing ROP. Systems that stand the best chance of achieving this are mixed glucoside–salt systems (see below).

6.5. (Poly-)glycerols and (poly-)glycols

(Poly-)glycerols and (poly-)glycols (although not entirely accurate, they are denoted in the following simply as glycerols and glycols) have been widely applied in shale drilling fluids (Chenevert, 1989; Bland, 1991, 1992; Bland et al., 1995; Reid et al., 1993; Downs et al., 1993; Cliffe et al., 1995; Twynam et al., 1994). Low-molecular weight (<10,000 a.w.u.) polymers viscosify filtrates and retard thereby filtrate invasion in shales. Fig. 14 shows the measured reduction in pressure penetration rates versus the increase in mud filtrate viscosity, as measured in pressure transmission tests for various glycols. There is a one-to-one relationship. Note that even small increases in filtrate viscosity can be significant for shale stability: when filtrate invasion is causing shale instability, then an increase in filtrate viscosity by a factor 2 will increase troublefree open-hole time by the same

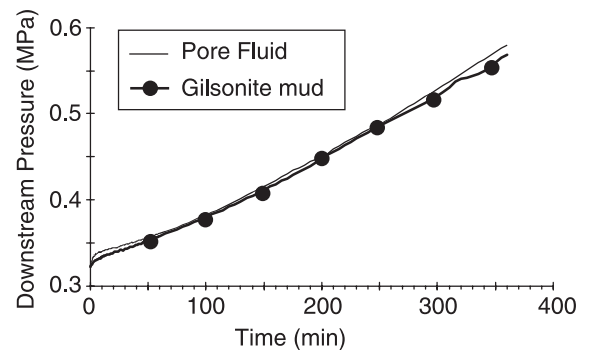


Fig. 13. Pressure transmission result for a mud containing 5% w/w gilsonite, tested on Pierre type I shale at $T=65$ °C. The rate of pressure transmission is the same as the pore fluid standard curve, i.e. gilsonite does not retard mud pressure penetration.

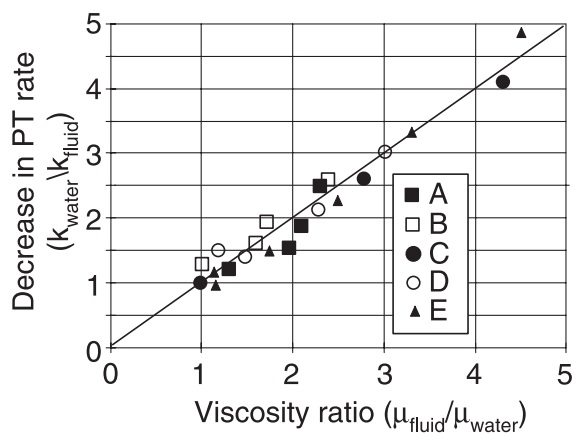


Fig. 14. Pressure transmission results for solutions of five types of (poly-)glycols, varying in concentration. The retardation of mud pressure penetration is directly related to the reduction in rate of Darcy flow due to the filtrate enhancement by these (poly-)glycols.

factor. This may “buy” enough time to run casing and cement before operational problems become significant.

High-molecular weight glycerols and glycols (>10,000 a.w.u.) are screened out on the surfaces of shales. Surface coverage and pore blocking will not be very effective, similar to PHPA (see Fig. 11). Consequently, such additives have little merits as wellbore stabilizers.

Clouding-or TAME (thermally activated mud emulsion) glycols (Bland et al., 1995; Downs et al., 1993) have an additional mechanism by which they can stabilize shales (see Fig. 15). These glycols display reverse solubility and cloud-point behavior in water. This means that they are water-soluble below a certain temperature known as the cloud-point temperature (CPT), but will phase-separate forming an emulsion above this temperature. This effect is utilized in stabilizing shales. In a normal drilling situation the mud will be at bottom-hole circulating temperature (BHCT), drilling a shale initially at bottom-hole static temperature (BHST). The mud is engineered such that the CPT (which is a function of glycol-type and mud salinity) and

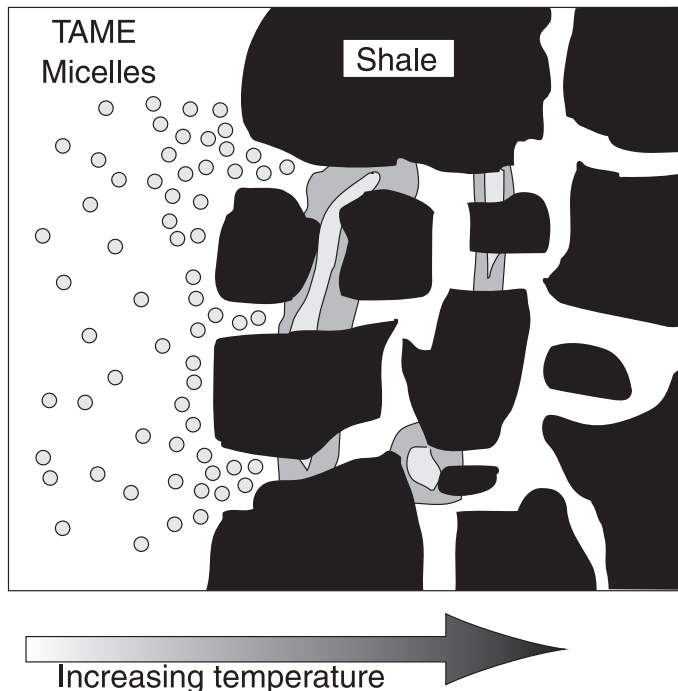


Fig. 15. Thermal activation mechanism for TAME muds: polyglycols in solution (present as small micelles) invade shale pores, experience temperature elevation, cloud-out and form emulsion barriers in the shale that prevent further mud filtrate and pressure invasion.

BHCT coincide. Thus, at the bit the glycols are just on the verge of clouding. Water-soluble glycols will now invade the shale and experience temperature elevation due to the higher BHST. This will trigger phase-separation and emulsification. The emulsion-block thus created will hamper further fluid invasion and mud pressure penetration, stabilizing the shale.

An alternative explanation of the shale-stabilizing action of (non-clouding) glycols has been presented (Cliffe et al., 1995). Water is displaced from clays as certain polyglycols are adsorbed to form ordered mono- or bilayer complexes (depending on the presence of potassium ions), thus lowering swelling pressures. Although the mechanism is not contested here, it is not clear how this could play a major role in shale stabilization:

1. Shales are inhomogeneous media that contain other materials besides clays (e.g. quartz silt) and have pores ranging from nanometer up to microns (see Fig. 17 for a SEM image of shale fabric). Molecular mono- or bilayers of glycol adsorbed onto clay surfaces would not be able to exclude mud filtrates and prevent pressure penetration.
2. Solute transport (glycol diffusion) into shales will be slower than pressure penetration. Thus, the reduction in swelling pressure effected by the glycols lags behind the increase in pore-pressure effected by the overbalance.

Low-molecular-weight glycerols and glycols are recommended for cuttings and wellbore stabilization. Direct spotting of high-concentration glycol pills has been shown to improve ROP in the field also (Twyman et al., 1994).

6.6. Mixed polyol–salt systems

Combinations of various polyols (including polyglycerols, polyglycols, and methylglucoside) and salts (e.g. NaCl, CaCl₂) are far more effective in stabilizing shales than their individual base components (van Oort et al., 1995). It was found that these systems work by synergy through increasing the shale–fluid membrane efficiency. Through the osmotic pressure generated by the salinity (i.e. lowering of the drilling fluid's water activity), shales can be effectively dehydrated.

6.7. Silicates

Silicate-based drilling fluids were reintroduced in the oil-field industry (van Oort et al., 1996b; Ding et al., 1996; Ward and Williamson, 1996) in the 1990s. These inexpensive and environmentally benign muds combine a set of unique characteristics that make them excellently suited for shale stabilization. Soluble silicates will invade shales and rapidly react with available polyvalent ions in the shale pore fluid (e.g. Ca²⁺ and Mg²⁺) to form insoluble precipitates. Also, the neutral-to-acidic pH of pore fluids will trigger silicate gelation. The barrier formed by gelled and precipitated silicates will prevent any further mud filtrate invasion and pressure penetration, as shown in Fig. 16.

Fig. 17 shows a SEM image of a shale after treatment with a silicate-based mud: a 10- μ m-thick silica barrier is clearly visible on the surface exposed to the mud. In fact, the gelation/precipitation mechanism has been shown to seal small cracks and fractures in shales (van Oort et al., 1996b). Thus, silicate-based muds can stabilize formations that are in-situ fractured, or where fractures have been either induced by mechanical action of the drillstring or by annular pressure swabs that have (locally) failed the shale.

An additional feature of the silicate barrier is that it constitutes a highly efficient osmotic membrane (see Table 2, note that the barrier restricts hydraulic flow of

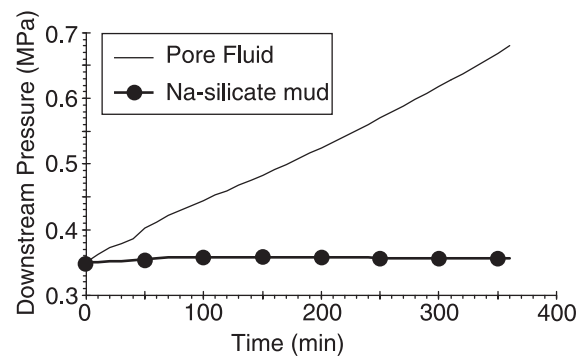


Fig. 16. Pressure transmission result for a sodium silicate mud, tested on Pierre type I shale at $T=65$ °C. The pore system was plugged by the silicates, preventing mud filtrate invasion and mud pressure penetration completely.

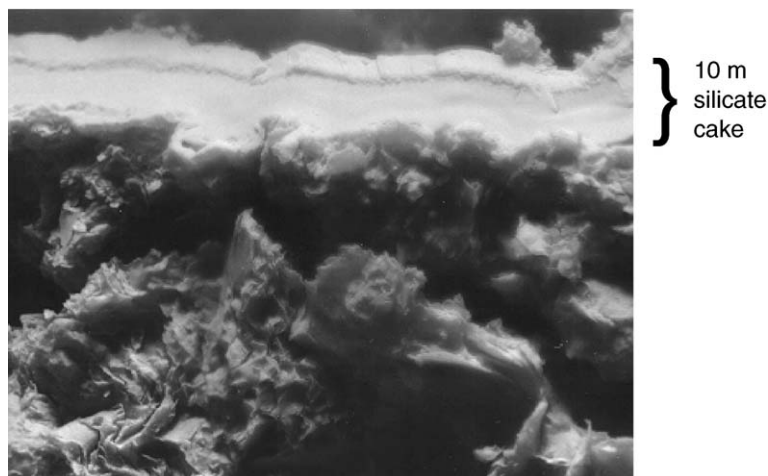


Fig. 17. SEM photograph of Pierre type I shale after exposure to a silicate-based drilling fluid. The picture shows a silicate-“cake” of 10 μm thickness on the shale’s surface. This cake prevents mud filtrate invasion and pressure penetration, and at the same time acts as a leaky membrane with high efficiency (typically 30–80%) that enables osmotic transport. Using a high-salinity/low water-activity brine as base fluid, it is possible to dehydrate a shale using this silicate membrane.

water but not diffusive/osmotic transfer of water) that can be exploited to dehydrate the shale and improve stability. To this extent, the water activity of the drilling fluid should be lowered to generate an effective osmotic pressure. This can be done by using various monovalent salts (e.g. NaCl, KCl) in the mud formulation.

Silicate muds are recommended for all shale-stabilization uses.

7. Classifying mud systems

Specific shale drilling fluid formulations are now classified based on the effect of these mud systems on water content (WC), swelling pressure (SP) and pore-pressure (PP) for the three invasion zones introduced previously: the filtrate invasion (FI) zone, the solute-invasion (SI) zone, and the pressure invasion (PI) zone. Fig. 18 represents the qualitative changes in WC, SP and PP that will have occurred after the shale has been exposed for some time to the mud systems. The changes are shown as increases or decreases from native shale values. It will be a challenge to future R&D to properly quantify the effects of transport and chemical change in shales on rock-mechanical stability.

The shale-stabilizing ability of the various drilling fluid systems is regarded to increase with type as

follows: Type I < Type II < Type III \leq Type IV \leq Type V. Type V fluids are regarded to be most suited to protect cuttings, to stabilize wellbores and to minimize bit balling/maximize ROP.

7.1. Type I: non-inhibitive, dispersed/dispersive WBMs

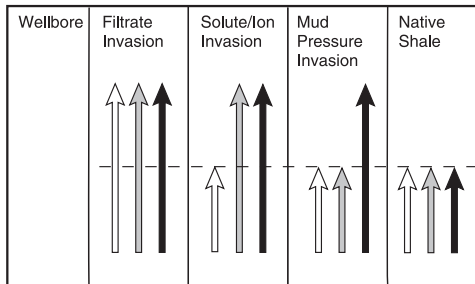
Examples: lignosulphonate mud, gypsum mud, lime mud.

These muds in general offer little to counteract shale instability in general. Over time, the WC, SP and PP will all be increased in the FI zone; SP and PP will be increased in the SI zone; and there will be increased PP in the PI zone. As a result, there will be rapid dispersion of cuttings and progressive enlargement of wellbores over time. The dispersion of solids, however, may have a beneficial effect on bit balling and ROP, as explained previously. Note that lime mud may be an exceptional case. Although the above is expected to hold true, lime mud may have a beneficial effect by promoting in-situ cementing of the shale fabric (Hale and Mody, 1993).

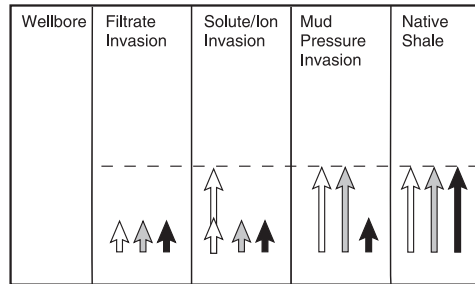
7.2. Type II: conventional inhibitive WBMs

Examples: KCl/PHPA mud, high-KCl mud, amine/cationic muds.

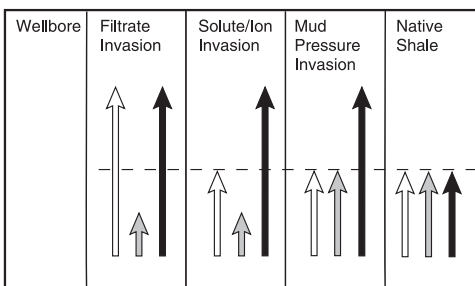
Type I : Non-inhibitive WBM (e.g. Lignosulphonate mud)



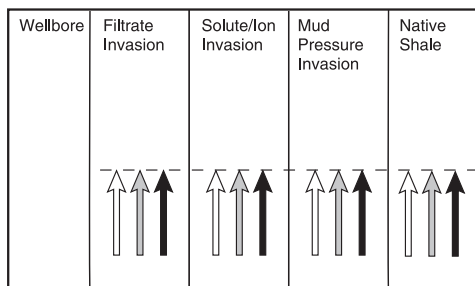
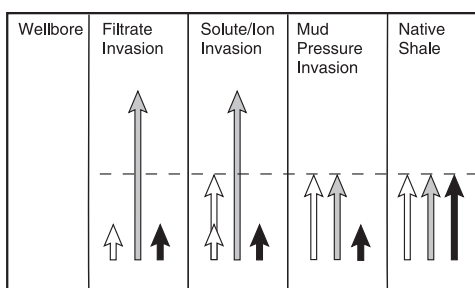
Type IIIb Osmotic WBM with more inhibitive ions (e.g. KCOOH mud)



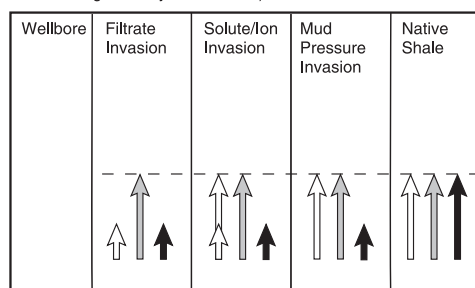
Type II : Inhibitive WBM (e.g. KCl/PHPA mud)



Type IV : Low-/non invading WBM/OBM: e.g. (all-oil, TAME mud (ideally formulated), low-salinity silicate mud)

Type IIIa : Osmotic WBM with less inhibitive ions (e.g. CaCl₂ mud)

Type V : Low-/non invading, osmotic WBM/OBM (high-salinity IOEM, high-salinity silicate mud)



Water Content = Swelling Pressure = Pore Pressure =

Fig. 18. Qualitative effect of drilling fluids on water content, swelling pressure and pore pressure in shales for the filtrate invasion (FI) zone, the solute/ion (SI) invasion zone and the mud pressure invasion (PI) zone. Changes are shown relative to the properties of the native shale, indicated by the dotted lines.

These muds are definitely a step in the right direction when reactive shale formations (i.e. shales with a high smectite content and concomitant high swelling pressure) are drilled. PP will be enhanced in all three invasion zones, but SP may be reduced due to the action of the inhibitive solutes diffusing into the shale and exchanging at clay sites. When mud

pressure diffusion and solute diffusion run approximately in parallel, the PP and SP effects may cancel out, resulting in a more-or-less stable situation.

These muds also offer satisfactorily solutions to cuttings stability. The inhibitive solutes will reduce the SP and the high-molecular-weight polymers that are run in conjunction (e.g. PHPA) may hold material

thereby avoiding disintegration. However, these muds clearly fall short when older, less-reactive shales are drilled as explained earlier. Their primary use, therefore, is for cuttings stabilization.

7.3. Type III: osmotic WBMs

Examples: $\text{CaCl}_2/\text{MgCl}_2$ -based mud, KCOOH mud, methylglucoside mud.

The “leaky membrane” action of shale–fluid systems is exploited in osmotic WBMs (van Oort et al., 1995, 1996a). These drilling fluids employ low-mobility solutes to generate the membrane efficiency and to depress the water activity such that an osmotic pressure gradient, directed from the shale to the mud, is generated. The effective osmotic pressures generated have been shown to be strong enough to offset the hydraulic mud over-balance altogether, leading to dehydration of the shale. As shown in Fig. 18, the WC and PP are expected to be reduced, resulting in a more stable situation.

This type is subdivided based on the effect of the mud on SP. Type IIIA will elevate the SP in the FI and SI zones, due, e.g. to unfavorable exchange of clay cations, which may undo some of the beneficial effect of WC and PP, possibly leading to instability. Type IIIB will lower the SP in the FI and SI and provide additional stability. Note that Fig. 18 displays the most favorable scenario for type IIIB muds, in which osmotic back-flow of pore water overtakes the hydraulic inflow of mud filtrate completely.

7.4. Type IV: low/non-invading WBM/OBM

Examples: TAME mud, balanced-activity silicate mud, balanced activity oil/synthetic mud, all-oil/all-synthetic mud.

These drilling fluids act through a specific mechanism that prevents them from invading shales and changing WC, HS and PP; these properties are therefore essentially left unchanged. Examples are all-oil/synthetic systems, which are restricted from invasion due to capillary entry pressures (van Oort, 1994; van Oort et al., 1996a). TAME polyglycol muds create temperature activated in-situ emulsions that plug pore throats; silicates do likewise by creating in-situ precipitates and gels. When the water-activities of the shale and the mud are similar

(i.e. they are balanced), then there will be no osmotic water transport.

7.5. Type V: low/non-invading osmotic WBM/OBM

Examples: low-activity silicate mud, low-activity invert emulsion mud, mixed polyol–salt induced membrane muds.

Type V drilling fluids are formed by combination of Type III and IV muds. First of all, the mechanism that prevents filtrate invasion in shales is exploited, such as the capillary entry pressure mechanism with invert emulsion muds and the plugging mechanism in silicate muds. Secondly, the ability of these systems to generate highly efficient osmotic membranes is used to enhance stability. This is accomplished by lowering the drilling fluid water activity to generate an osmotic pressure that may stimulate the osmotic flow of water from the shale pores to the mud. This water flow may reduce near-wellbore WC and PP (it is unclear at present what actually happens to the SP: it will probably not be significantly affected). These muds are highly effective in dealing with all types of shale problems, as demonstrated by high-salinity IOEMs (oil or synthetic muds) being the industry standard for drilling troublesome shales.

8. Conclusions

1. Swelling pressures in clays at small platelet separations are governed by complicated non-DLVO forces such as ion hydration. Simplistic models cannot be used to accurately predict the behavior of the swelling pressure.
2. Pressure transmission in intact, non-fractured shales is at least one to two orders of magnitude faster than solute/ion diffusion, which in turn is one to two orders of magnitude faster than Darcy flow of mud filtrate.
3. Shale failure due to the effects of mud pressure penetration cannot be prevented by inhibitive solutes/ions when these lag behind the invading pressure front.
4. Shale cuttings and wellbores can be stabilized by controlling the water flow into shales. The best shale-stabilizing muds currently available accomplish this by either viscosifying filtrates, plugging

pore throats, stimulating osmotic backflow of shale pore water, or a combination of the above. Examples of these mud systems are silicate muds and mixed polyol–salt muds.

5. High-molecular weight ($\geq 10,000$ a.w.u.) additives such as PHPA, gilsonites, graphites, etc., are screened out on the surfaces of shales and cannot prevent filtrate invasion and mud pressure penetration. Their ability to promote wellbore stability is therefore limited.
6. The mechanism of bit balling has been explained on the basis of a soil-mechanics model. Bit balling may be minimized and ROP may be enhanced by either dehydration or hydration of balling shales, such that they will lose their tendency to stick. Moreover, it has now become possible to use special ROP enhancing additives that minimize the sticking of cuttings to BHA components and to each other.
7. A summary on the action of various additives used throughout the drilling industry for shale-stabilizing purposes has been given based on the new understanding of transport processes in shales.
8. Shale drilling fluids have been qualitatively classified in five categories of increasing shale-stabilizing ability based on their effect on shale water content, swelling pressure and pore pressure.

Nomenclature and units

σ	stress [Pa]
P	pressure [Pa]
τ	shear stress [Pa]
ϕ	friction angle [radians]
C	cohesion [Pa]

Subscripts

eff	effective
pore	relating to pore pressure
i	stress indicator (radial, tangential, vertical)
swelling	relating to swelling pressure
mud	relating to mud pressure
r	in radial direction

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Appendix A

The basic equations governing pressure diffusion, ion diffusion and mud filtrate invasion around a cylindrical wellbore are summarized here. The low-permeability medium in which transport occurs is regarded to be semi-infinite bound internally by a cylinder (the wellbore) with radius $r=a$. The diffusion equation for pressure P is given by:

$$\frac{\partial P}{\partial t} = K \left[\frac{\partial^2 P}{\partial r^2} + \frac{1}{r} \frac{\partial P}{\partial r} \right] \quad (\text{A1})$$

with K given by:

$$K = \frac{k}{\mu\beta\phi_e} \quad (\text{A2})$$

where k represents permeability, μ is fluid viscosity and ϕ_e is effective porosity given by:

$$\phi_e = \phi + \frac{\beta_r - (1 + \phi)\beta_s}{\beta} \quad (\text{A3})$$

with ϕ being true porosity, β , β_r and β_s denoting the compressibility of the fluid, bulk rock and grains, respectively.

Solutions to Eq. (A1) are given by (Carslaw and Jaeger, 1959):

$$\frac{P(t) - P_0}{P_m - P_0} = 1 + \frac{2}{\pi} \int_0^\infty e^{-u^2 T_d} \times \frac{J_0(uR_d)Y_0(u) - Y_0(uR_d)J_0(u)}{J_0^2(u) + Y_0^2(u)} \frac{du}{u} \quad (\text{A4})$$

where P_m and P_0 are mud pressure and pore pressure, respectively, T_d and R_d represent dimensionless time and radius given by:

$$T_d = \frac{Kt}{a^2}, \quad R_d = \frac{r}{a} \quad (\text{A5})$$

and the Bessel functions $J_x(u)$ and $Y_x(u)$ ($x=0, 1, 2, \dots$) are defined by:

$$J_x(u) = \sum_{n=0}^{\infty} \frac{(-1)^n \left(\frac{1}{2}u\right)^{x+2n}}{n! \Gamma(x+n+1)},$$

$$Y_x(u) = \frac{J_x(u) \cos x\pi - J_{-x}(u)}{\sin x\pi}. \tag{A6}$$

The solute diffusion equation takes the same form as Eq. (A1):

$$\frac{\partial C}{\partial t} = D^* \left[\frac{\partial^2 C}{\partial r^2} + \frac{1}{r} \frac{\partial C}{\partial r} \right] \tag{A7}$$

where D^* is the apparent diffusion coefficient. The solution to Eq. (A7) is similar to Eq. (A4), only with the dimensionless time given by:

$$T_d = \frac{D^* t}{a^2}. \tag{A8}$$

To calculate the position of the fluid invasion front in time, we evaluate the flux F at the wellbore wall ($r=a$):

$$F = \frac{kA}{\mu} \left[\frac{\partial P}{\partial r} \right]_{r=a}. \tag{A9}$$

Substituting Eq. (A4) in Eq. (A9) we find:

$$F = \frac{4kA(P_m - P_0)}{a\mu\pi^2} \int_0^{\infty} e^{-u^2 K t} \frac{du}{u[J_0^2(ua) - Y_0^2(ua)]}. \tag{A10}$$

The total volume V that has penetrated the formation after time t is given by:

$$V = \int_0^t F(t) dt. \tag{A11}$$

Substituting $A=2\pi rh$ and reformulating in terms of dimensionless time T_d we obtain:

$$V = \frac{8a^2 h \beta \phi_e (P_m - P_0)}{\pi} \int_0^{T_d} \times \left[\int_0^{\infty} \frac{e^{-u^2 T_d} du}{u(J_0^2(u) + Y_0^2(u))} \right] dT_d. \tag{A12}$$

The radius of filtrate invasion r_i can now be determined by substituting $V=\pi(r_i^2 - a^2)h\phi_e$ in Eq. (A12). For the dimensionless radius of invasion $R_{di}=r_i/a$ we obtain:

$$R_{di}^2 = 1 + \frac{8\beta(P_m - P_0)}{\pi} \int_0^{T_d} \times \left[\int_0^{\infty} \frac{e^{-u^2 T_d} du}{u(J_0^2(u) + Y_0^2(u))} \right] dT_d. \tag{A13}$$

Example: For a shale with 1 nD ($\sim 10^{-21} \text{ m}^2$) permeability, 20% effective porosity at a temperature of 65 °C (150 °F) (water viscosity is $4.34 \times 10^{-4} \text{ Pa s}$, water compressibility is $4.48 \times 10^{-10} \text{ Pa}^{-1}$), we obtain a pressure diffusion coefficient K of $2.5 \times 10^{-8} \text{ m}^2/\text{s}$. With ion diffusion coefficients in the range $1-10 \cdot 10^{-10} \text{ m}^2/\text{s}$ (see Table 2) it is seen that pressure diffusion is some two order of magnitude faster than ion diffusion.

SI Metric Conversion Factors

bb1	× 1.589 873 e-01 = m ³
cP	× 1.0 e-03 = Pa s
inch	× 2.54 e00 = cm
ft	× 3.048 e-01 = m
psi	× 6.894 757 e-03 = MPa
lbf	× 4.448 222 e00 = N
lbf/100 ft ²	× 4.788 026 e-01 = Pa
D	× 0.986 9 e-12 = m ²
Å	× 1.0 e-10 = m
°F	(°F - 32)/1.8 = °C

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