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Studies Dispel Myths, Give Guidance on Formulation of Drilling Fluids for Shale Stability

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Abstract

Shale instability problems when using water-base drilling fluids have remained unresolved for decades because of a lack of knowledge and understanding of the shale hydration mechanisms. The industry has relied upon hydrocarbon-base drilling fluids for combating shale problems, but misconceptions have kept even those fluids from being utilized to their fullest advantage. With the use of hydrocarbon-base fluids now being curtailed because of environmental concerns, costs due to shale problems could escalate.

The understanding of shale instability problems has been hindered by inadequate laboratory means of simulating contact of drilling fluid and shale under downhole conditions of stress and temperature. To address this situation Gas Research Institute has conducted a project in which laboratory equipment and procedures were developed to permit preserved specimens of downhole shale (cored in hydrocarbon-base mud) to be restored to in situ axial stress, horizontal stress, pore pressure and temperature prior to being drilled at a selected borehole pressure. Provisions were made for measurement of fluid transport in either direction between the circulating drilling fluid and the shale during an extended period of exposure. The borehole pressure was then reduced incrementally to observe for borehole failure and obtain a measure of effect of the drilling fluid on the relative stability of the shale.

The above procedures have been used to study a well-known troublesome Cretaceous shale cored using oil-base mud at a depth of about 5,500 ft in Block 4 of the U.K. sector

of the North Sea. This paper presents data showing that the aqueous activity of either a water-base or hydrocarbon-base emulsion drilling fluid can be adjusted to develop osmotic pressure that will cause water to enter or be extracted from a low-permeability shale. The hydraulic differential between the borehole pressure and far-field shale pore pressure is also shown to be a driving force affecting the transfer of water.

Discussion of these test results dispels several existing myths and provides guidelines for more effective use of current drilling fluids. The results also provide guidance for development of new environmentally acceptable water-base systems for combating shale problems where the use of hydrocarbon-base fluids is not permitted.

Introduction

Borehole instability in shales has been recognized for over 50 years to be a major cost factor in the drilling and completion of oil and gas wells, with current world-wide costs estimated at \$500 million per year. Typical problems caused by an unstable borehole include:

- High torque, drag, bridging and fill
- Stuck pipe
- Lost circulation
- Cementing failures and high cementing costs
- Failure to get logs and poor log interpretation

Hydrocarbon-base fluids have been used to combat the most troublesome shales. However, environmental concerns are causing the use of oil-base and even synthetic-base fluids to be curtailed. Without hydrocarbon-base systems or environmentally acceptable replacements, the cost of borehole instability could be 50 percent greater.

Resolution of borehole instability problems has been hindered by lack of knowledge and understanding of the interaction between drilling fluid and shale. To remedy that situation Gas Research Institute (GRI) undertook research to study the transfer of water between drilling fluids and shale and to determine the resulting effects on borehole stability. Obtained using the best equipment and procedures available for laboratory investigation of drilling fluid/shale interactions, the results dispel several misconceptions regarding both water-base and hydrocarbon-base fluids.

The results not only explain why hydrocarbon-base systems have been so effective in avoiding shale problems but

also suggest guidelines for optimizing composition of such fluids. The studies confirm the almost contradictory concept that water-base fluids can dehydrate shale, but caution that ion diffusion can still create problems when using various salts to obtain the desired drilling fluid composition.

Most importantly, the studies show that a nonionic polyol monomer can be used as the principal component of a water-base fluid that is very similar to hydrocarbon-base fluids in avoiding shale problems. These results provide guidance for the development of environmentally acceptable water-base replacements for hydrocarbon-base drilling and completion fluids.

A complete report of this GRI research project can be found in Reference 1.

Two Forces Drive Fluid/Shale Interaction

Shales have been thought of as being impermeable, with destabilizing hydration caused only by reactions at the borehole surface. Studies in recent years^{2,3} have indicated that shales are not only permeable to water but, to a lesser extent, permeable to hydrated solutes. This suggests two fundamental driving forces controlling the transfer of water between drilling fluid and shale. One is the hydraulic differential between the drilling fluid pressure in the borehole and the pore pressure in the shale formation (ΔP). The second is an osmotic pressure customarily calculated using the ratio of water activity⁴ of the shale to that of the drilling fluid as described in the Appendix.

Transfer of water into the shale should cause an increase in shale pore pressure near the borehole surface, weakening of the shale, and a reduction in borehole stability. Transfer of water in the opposite direction (from the shale to the drilling fluid) should improve borehole stability, although an ionic water-base drilling fluid might allow ion diffusion as a counter flow into the shale to cause some detrimental changes in the clay structure.

Effective design of drilling fluids to maintain borehole stability in shale requires meaningful data on drilling fluid/shale interactions and the resulting effects on borehole stability. Most prior laboratory studies are flawed because of inadequate simulation of contact of drilling fluid and shale under downhole conditions of temperature and stress. Commonly used procedures for tests of shale cuttings or weathered cores are made with air or water vapor at the drilling fluid/shale interface, introducing capillary effects which would not be present when drilling water-saturated shale at depth⁵. Misleading information also results from the use of water-saturated outcrop shale which is then subjected to downhole stresses with no opportunity for drainage of the pore fluid. Essentially such shale becomes supersaturated, with high aqueous activity and pore pressure, and does not accurately represent the pore sizes of a shale which has been compacted at depth over geologic time.

Faulted test procedures have led to erroneous conclusions such as:

- Water-base fluids can not draw water from shale osmotically.
- When shale problems are encountered while using water-

base mud, raising mud weight might help and can not make the problem worse.

- Hydrocarbon-base fluids simply provide an oil film on shale that prevents hydration and weakening, with no osmotic pressure involved.
- A hydrocarbon-base emulsion fluid having a very high salt content and an ambient activity lower than that of a shale will cause dehydration and destabilization of the shale.

Test Methods Developed to Correct Inadequacies

To avoid the artifacts of commonly used test methods, laboratory equipment and procedures were developed⁶ to allow preserved specimens of downhole shale cored in hydrocarbon-base fluid to be restored to in situ axial stress, horizontal stress and temperature prior to being drilled with a 1 1/4 inch mill-tooth bit at a selected borehole pressure. This Downhole Simulation Cell (DSC) equipment, located in the OGS Laboratory, was later modified⁷ to permit a pore pressure to be established and monitored in a shale specimen being tested. A schematic of the DSC equipment is shown in Figure 1. The equipment permitted measurement of transport of water into the shale, but could not measure water being drawn from the shale to the drilling fluid.

A key to the GRI studies was a modification of the DSC test procedures. A sandpack at the outer periphery of the shale specimen (see Figure 2) was filled with simulated shale interstitial water adjusted to have our ambient activity equal to that of the shale. Volume of fluid drained or pumped into the sandpack to maintain constant pressure provided a measure of fluid transport in either direction between the drilling fluid and shale. Although contact of the shale specimen with the sandpack fluid at the outer periphery and the drilling fluid at the borehole surface resulted in unstable fluid transfer during the first 10 to 20 hours of circulation, quite steady rates were observed thereafter. The fluid transfer, therefore, was taken to be the average rate following the equilibration period.

It is important to note that the fluid transfer rates observed in these studies would not be detectable in field operations. The maximum rate measured, 0.42 cm³/hr for a six-inch section of 1 1/4-inch diameter hole, would correspond to only 0.37 bbl/hr for a 100-ft section of 12 1/4-inch hole.

Solids-free drilling fluids were used to avoid changes in shale permeability caused by plugging of shale pore throats. After 60 hours of exposure of the shale to the circulating drilling fluid, the borehole pressure was reduced incrementally 100 psi each 30 minutes to observe for borehole failure as indicated by abrupt changes in axial stress and axial strain. A very simple method was used to delineate the effect of the exposure on borehole stability, as follows: Relative Shale Stability = Axial Stress - Borehole Pressure at Specimen Failure.

Further evidence of the effects of transport of water and ions was obtained by examination of samples of the shale taken at 1/4, 1 and 2-inch distances from the borehole surface, determining mineralogy, cation exchange capacity, moisture and penetrometer hardness. A photograph of the exposed shale specimen was taken when possible.

All tests of the GRI study used Cretaceous Speeton shale

from Block 4 of the North Sea, one of the most troublesome shales of that region when drilled with a water-base mud. The shale was cored at a depth of about 5,500 ft using an oil-base mud and the cores were preserved to maintain water saturation. DSC tests were made with core specimens subjected to the following:

Axial Stress	5,394 psi
Confining Pressure	4,350 psi
Sandpack Pressure (Pore Pressure)	2,720 psi
Borehole Pressure	
$\Delta P = 0$	2,720 psi
$\Delta P = 400$	3,120 psi
Temperature	150°F

The axial stress was adjusted slightly as necessary to minimize changes in axial strain of the shale specimen during the drilling fluid circulation period.

Observations of Osmotic Force in Ionic Water-Base Fluids

When this study was started it was assumed that a drilling fluid in contact with a shale having the same activity would develop no osmotic force. As the work progressed it became apparent that a fluid and shale having the same activities at ambient conditions did not have equal activities at downhole stresses and temperature. For example, the tests showed that a simulated interstitial water having an ambient activity of 0.89 showed no evidence of osmotic force when in contact with the Cretaceous shale at downhole conditions, even though the ambient activity of the shale was 0.78. The activity of the compressible shale was probably affected more by increased pressure than that of the relatively incompressible water-base fluid. At this time there is no simple method of measuring aqueous activities of shales at elevated pressure and temperature. The drilling fluid activities (a_f) given in this paper are ambient values.

Fresh Water ($a_{df} = 1.00$) - When the Cretaceous shale was exposed to fresh water drilling fluid with no hydraulic differential, water was transported into the shale osmotically at a fairly steady rate of 0.13 cm³/hr (Table 1, Figure 3). The specimen failed after only 42 hr of exposure, showing that relative stability had been reduced from >5,000 psi (value for shale tested when drilled with oil and no circulation period) to a calculated value of 2,430 psi (Table 1). With a hydraulic differential of 400 psi, the shale withstood 60 hr of drilling fluid exposure before failing. However, the rate of fluid transport into the shale was 0.42 cm³/hr (more than three times that for the zero ΔP test) and the relative stability of the shale was actually lower. Both tests showed an increase in moisture content of the shale near the borehole (Table 2).

In field operations, a common practice is to raise mud weight (increase ΔP) when shale problems are encountered. The results of the above tests, and other tests conducted in this study, indicate that raising mud weight higher than that calculated to be necessary for unaltered rock might give temporary relief but ultimately cause worse shale problems.

Calcium Chloride Brine ($a_{df} = 0.78$) - Fluid was extracted from the shale osmotically at a very low rate of 0.04 cm³/hr

when it was exposed at zero ΔP to this 25 percent by weight brine. The relative shale stability was much higher than that for the similar test using fresh water, but the specimen broke into rubble when the borehole pressure was reduced to 1,220 psi. (See photograph in Figure 4A.) Calcium was found to have replaced sodium in the exchange sites of the shale as far as one inch from the borehole surface (Table 3). Ion diffusion counter to the osmotic flow apparently caused ionic reactions detrimental to borehole stability.

When the shale was tested with a ΔP of 400 psi, this brine caused fluid to be transported into the shale at a rate of 0.25 cm³/hr, substantially lower than that for fresh water. Analysis of the shale showed calcium ions to have penetrated about an inch into the shale.

Although the membrane efficiency can not be calculated because the activities of the shale and drilling fluid at downhole pressure and temperature are not known, the two DSC tests show that the 400 psi hydraulic differential pressure was sufficient to overcome the osmotic pressure developed.

Calcium Chloride Brine ($a_{df} = 0.40$) - The extremely low activity of this 40% by weight brine created an osmotic pressure great enough to extract fluid from the shale at a substantial rate of 0.17 cm³/hr even when opposed by a hydraulic differential pressure of 400 psi. In spite of the fluid extraction, there was no change in the moisture content of the shale. The water being removed at the borehole was apparently being replaced by water from the far-field. The relative stability of 4,500 psi noted in this test was greater than that observed for ionic water-base fluids having higher activities, but was less than the reference value of <5,000 psi obtained when the borehole pressure was reduced immediately after drilling the shale with oil. Calcium was found to have replaced sodium in the exchange sites of the shale, indicating ion diffusion into the shale even though fluid was being extracted at the borehole.

This test shows that an ionic water-base drilling fluid having a very low ambient activity can be used to develop sufficient osmotic pressure to oppose a typical hydraulic differential pressure and extract fluid from shale. In spite of the fluid extraction, ion diffusion into the shale can still be detrimental to the stability of the borehole.

Observation of Osmotic Force in Oil-Base Emulsion Fluids

Oil With Emulsified Fresh Water ($a_{df} = 0.99$) - When shale was exposed at zero ΔP to an oil-base emulsion containing fresh water, fluid was transported into the shale at a steady rate (Table 1, Figure 3). The specimen broke into rubble when the borehole pressure was reduced, resulting in a relative shale stability of only 3,400 psi. Analyses of particles near the borehole surface revealed transfer of water into the shale but no transfer of ions (Tables 2 and 3), showing that the oil-base emulsion provided a highly efficient semipermeable membrane. When tested with a ΔP of 400 psi, the fluid transport rate more than doubled, and the relative stability was only 3,030 psi.

These tests clearly show that capillary forces preventing entry of oil into water-wet shale did not prevent water entry from the oil-base emulsion. They also show that hydraulic

pressure differential supplemented the osmotic force transporting water into shale. Moisture contents in the shale were substantially higher for the ΔP of 400 psi.

Oil With Emulsified Calcium Chloride Brine ($a_{df} = 0.78$)

Water was extracted from the shale when it was tested with ΔP of either zero or 400 psi, showing that the efficient oil-base emulsion membrane allowed development of an osmotic force that exceeded the 400 psi hydraulic force. There was no substantial change in the moisture content or exchangeable bases of the shale. In both tests the relative stability of the shale was maintained above 5,000 psi. The photograph for the $\Delta P = 0$ test showed the specimen to be in excellent condition. (See Figure 4B.)

Oil With Emulsified Calcium Chloride ($a_{df} = 0.40$) - Water was transferred from the shale to the drilling fluid when the test was performed at either ΔP of zero or 400 psi, but there was no substantial reduction in the water content of the shale near the borehole. Apparently the water removed was being replenished by transport of water from the far-field as noted above with calcium chloride brine having an activity of 0.40. In contrast to the brine, the oil-base emulsion having an activity of 0.40 allowed no ion diffusion into the shale and maintained the relative shale strengths at greater than 5,000 psi. Photographs showed the specimens to be in excellent condition.

These tests refute the often expressed notion that an oil-base emulsion drilling fluid having an activity lower than that of a shale would extract water, reduce moisture content and cause borehole instability.

Observation of Osmotic Force in Nonionic Water-Base Fluids

The tests previously discussed showed ion diffusion to have some detrimental effects on borehole stability. Such effects should be avoided if nonionic materials could be used to reduce the activity of fresh water. A nonionic organic solute that became adsorbed in the exposed shale pore spaces might provide an efficient osmotic membrane; i.e., the water solvent would be free to move while the solute molecules were retained.

Two nonionic polyol monomers were selected for testing based on ability to reduce the ambient activity of water to less than that of the Speeton shale. The monomers were considered to have the small size necessary to enter the pores of shale confined at downhole pressure. Glycerol is a commercially available monomer having a straight chain configuration with three hydroxyl units. Methyl glucoside (MEG) has a two-tiered cyclic structure with a very compact grouping of four hydroxyl units. Both of these materials are environmentally acceptable, having low toxicity and being readily biodegradable.

Fresh Water/Glycerol ($a_{df} = 0.78$) - When tested with $\Delta P = 400$ psi, this 50 percent by weight solution caused water to be extracted from the shale at a very slow rate for about 28 hr. However, the transfer then reversed and was from the drilling fluid to the shale at a similarly slow rate for the remainder of the 60-hr test. The relative shale strength was reduced to

4,000 psi. Examination revealed that the specimen had broken into pieces and the bedding planes at the borehole had exfoliated. The tests indicate that a somewhat efficient membrane had formed initially, but the glycerol later caused expansion of the lattices of the clays, loss of membrane efficiency, hydration of the shale and reduction of borehole stability.

Fresh Water/Methyl Glucoside ($a_{df} = 0.78$) - When tested at a ΔP of either zero or 400 psi, this 68 percent by weight solution extracted water from the shale at a very slow steady rate and maintained the relative shale stability at greater than 5,000 psi. The stability of the borehole is indicated by the bit marks that are clearly evident in the photograph in Figure 4C. As shown in Figures 3 and Tables 1 and 2, the performance of the methyl glucoside fluid was very similar to that of the oil-base emulsion having the same 0.78 activity.

Conclusions from the GRI Studies

1. Osmotic pressure is a driving force affecting the transfer of water between a drilling fluid and a low-permeability shale. The aqueous activity of either a water-base or oil-base emulsion drilling fluid can be adjusted to cause water to enter or be extracted from a shale.
2. The magnitude of the osmotic pressure developed is determined by the relative activities of the drilling fluid and shale at downhole stresses and temperature. Calculations based on activities measured at ambient conditions will give misleading results. At this time there are no methods for normalizing for the effects of changes in stress and temperature on the relative activities of drilling fluids and shales.
3. The hydraulic differential between the borehole pressure and the far-field shale pore pressure is a driving force affecting the transfer of water between either a water-base or oil-base emulsion drilling fluid and a low-permeability shale. The hydraulic pressure can either support or oppose an osmotic pressure.
4. If the borehole pressure exceeds the pore pressure of a shale, commonly used ionic water-base drilling fluids permit water entry and weakening of the shale unless the activity as measured at ambient conditions is far less than that of the shale. Even if water is extracted from the shale by use of a brine having a very low activity, borehole stability has been found to be reduced when soluble salts alone are used to adjust the activity of the drilling fluid.
5. In contrast to ionic water-base systems, oil-base emulsion drilling fluids extract water from a shale and maintain borehole stability if the ambient activity is equal to or less than that of the shale and the hydraulic pressure differential is within reasonable limits.
6. The use of a nonionic polyol monomer (methyl glucoside) to reduce the ambient activity of fresh water to a value equal to or less than that of a shale provides a drilling fluid that is very similar to an oil-base emulsion in extracting water from the shale and maintaining borehole stability.

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SI Metric Conversion Factors

bbl	x	1.589 873	E-01	=	m ³
cm ³	x	1.0*	E-06	=	m ³
ft	x	3.048*	E-01	=	m
°F	(°F - 32)/1.8			=	°C
in.	x	2.54*	E + 00	=	cm
psi	x	6.894 757	E + 00	=	kPa

Appendix - Osmosis in a Wellbore

Osmosis occurs when a solvent and a solution are separated by a membrane permeable only to the solvent. The solvent passes through the membrane, diluting the concentration of the solution on the other side. Low-permeability shale in the borehole wall acts as a semipermeable membrane and is selective about what it allows to pass through and what it prevents from passing. Water is typically present on both sides of the borehole wall "membrane," with each side having a different concentration of dissolved material. The water will pass very easily because of its molecular size, while larger molecules or dissolved ions will not pass so easily. Since the

water in the less concentrated solution seeks to dilute the more concentrated solution, water will pass through the membrane from the lower concentration side to the higher concentration side. A lower concentration of ions or molecules in the drilling fluid results in osmotic movement of water into the shale. A higher concentration of solute tends to draw water out of the shale. Eventually, osmotic pressure (illustrated in Figure A-1 as the pressure created by the difference in water levels) will counter the diffusion process exactly, creating an equilibrium in a closed system. Water transfer can be sustained, however, when the difference in solute concentrations is maintained while a large volume of drilling fluid is being circulated through the borehole and water in the shale is free to move to or from the far field region of the formation. The osmotic pressure is dependent upon the efficiency of the membrane. This efficiency is very low for ionic water-base drilling fluids, but is high for oil-base emulsion or certain nonionic water-base fluids.

Water Activity

The theoretical osmotic pressure for an ideal membrane is customarily calculated as:

$$\text{Osmotic Pressure} = -RT/V \times \ln(a_1/a_2)$$

where R is the gas constant (mL²/t²T), T is temperature (K), V is the partial molar volume of water (L³/mol) and a₁ and a₂ are the activities at ambient conditions of the solutions on each side of the membrane. For drilling fluid in contact with shale, a₁ is the activity of the drilling fluid and a₂ the activity of the shale.

Activity can be thought of as the "escaping tendency" of water. It is defined as the ratio of the fugacity of water in a system to the fugacity of pure water. The fugacity ratio is essentially equal to the vapor pressure ratio, which means that the relative humidity of the vapor phase above a drilling fluid or shale at ambient temperature and pressure provides a measure of the water activity.

It should be noted that there is an inverse relationship between solute concentration and water activity. Water activity decreases as solute concentration increases.

**TABLE 1 - FLUID TRANSPORT DATA AND RELATIVE STABILITY MEASUREMENTS
FOR A VARIETY OF DRILLING FLUIDS**

Drilling Fluid	Activity (a_{df})	ΔP (psi)	Water Transport (cm ³ /hr)	Relative Stability (psi)
Fresh Water	1.00	0	0.13 into shale (42 hr)	2430
		400	0.42 into shale	2180
CaCl ₂ Brine (25%)	0.78	0	0.04 from shale	4100
		400	0.25 into shale	4100
CaCl ₂ Brine (40%)	0.40	0	0.15 from shale	4280
		400	0.17 from shale	4500
Oil/Fresh Water	0.99	0	0.09 into shale	3400
		400	0.19 into shale	3030
Oil/25% CaCl ₂ Brine	0.78	0	0.15 from shale	>5000
		400	0.07 from shale	>5000
Oil/40% CaCl ₂ Brine	0.40	0	0.25 from shale	>5000
		400	0.34 from shale	>5000
Fresh Water/Glycerol	0.78	400	0.02 from shale (28 hr)	4000
			0.17 to shale (32 hr)	
Fresh Water/MEG	0.78	0	0.07 from shale	>5000
		400	0.06 from shale	>5000

TABLE 2 - EFFECTS OF DRILLING FLUIDS ON WATER CONTENT OF SHALE

Drilling Fluid	a_{df}	ΔP	Initial Shale	Water Content, % by Wt After 60-hr Exposure	
				Inner Inch	1/4 Inch at Borehole
Fresh Water *	1.00	0	6	8	11
Fresh Water	1.00	400	6	8	12
25% CaCl ₂ Brine	0.78	0	6	6	7
25% CaCl ₂ Brine	0.78	400	6	7	8
40% CaCl ₂ Brine	0.40	400	6	6	6
Oil/Fresh Water	0.99	0	6	7	14
Oil/Fresh Water	0.99	400	6	10	21
Oil/25% CaCl ₂ Brine	0.78	0	7	6	6
Oil/25% CaCl ₂ Brine	0.78	400	6	7	7
Oil/40% CaCl ₂ Brine	0.40	0	6	6	6
Oil/40% CaCl ₂ Brine	0.40	400	6	6	6
Fresh Water/Methyl Glucoside	0.78	0	7	7	7
Fresh Water/Methyl Glucoside	0.78	400	6	7	7

* Shale specimen failed after only 42 hr of circulation.

**TABLE 3 - EFFECTS OF DRILLING FLUIDS ON EXCHANGEABLE BASES OF SHALE
(meq/100g)**

	Na	Ca	Mg	K
25% CaCl₂ Brine ($\Delta P = 0$)				
Initial Shale	5.3	22.0	2.2	1.6
Inner Inch After 60-hr Exposure	1.8	23.3	2.3	1.5
25% CaCl₂ Brine ($\Delta P = 400$)				
Initial Shale	5.1	30.8	2.4	1.6
Inner Inch After 60-hr Exposure	3.2	32.8	2.5	1.6
40% CaCl₂ Brine ($\Delta P = 400$)				
Initial Shale	6.1	15.2	2.1	1.1
Inner Inch After 60-hr Exposure	3.3	22.3	2.5	1.3
Fresh Water Emulsified In Oil ($\Delta P = 0$)				
Initial Shale	5.7	39.6	2.4	1.8
Inner Inch After 60-hr Exposure	6.2	39.7	1.9	1.8
25% CaCl₂ Emulsified In Oil ($\Delta P = 0$)				
Initial Shale	5.4	19.8	2.7	1.9
Inner Inch After 60-hr Exposure	5.9	20.1	2.3	1.8
40% CaCl₂ Emulsified In Oil ($\Delta P = 400$)				
Initial Shale	4.5	18.1	2.3	1.5
Inner Inch After 60-hr Exposure	4.9	21.2	2.6	1.5

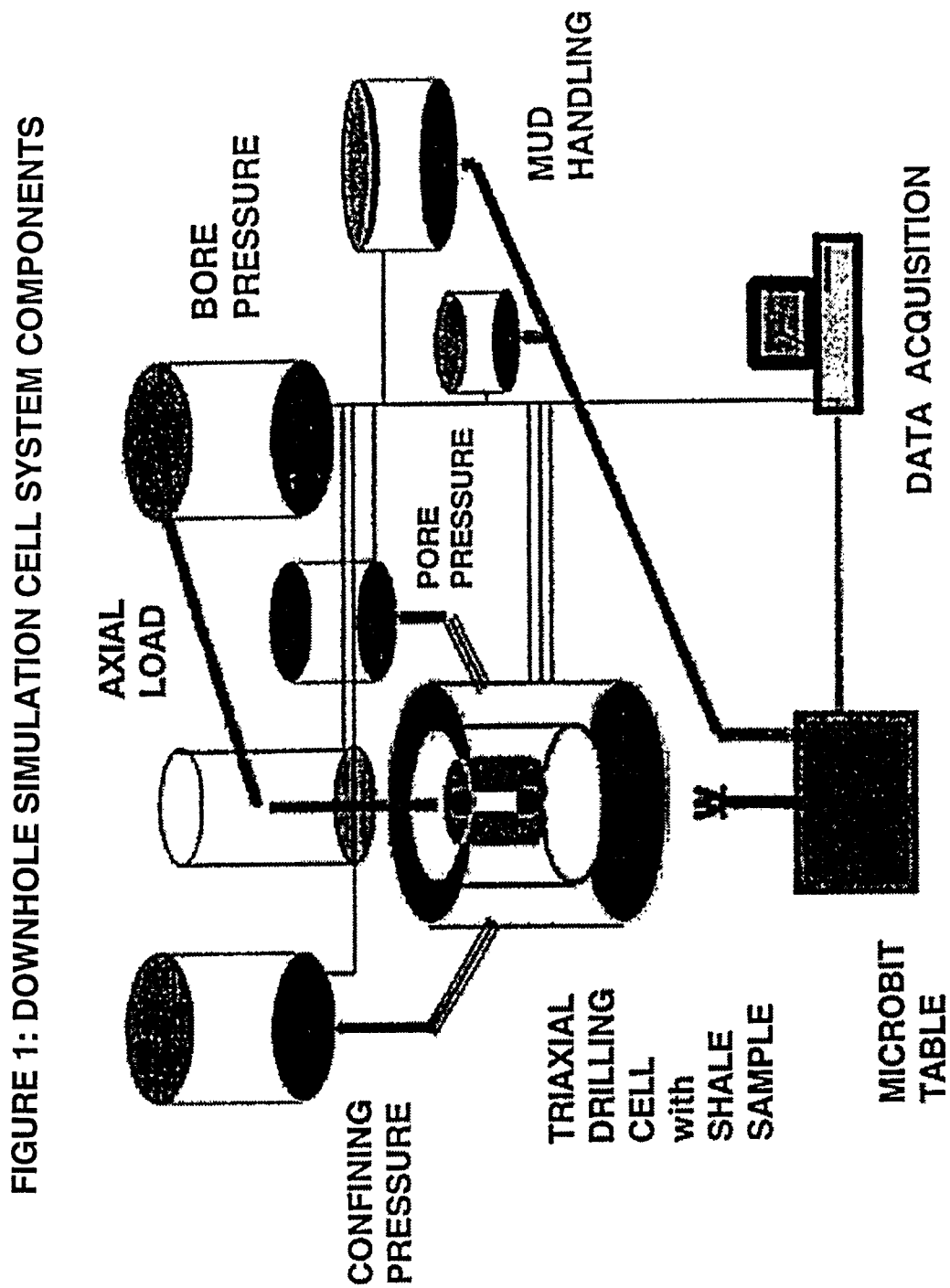


FIGURE 2: TRIAXIAL CELL CROSS SECTION

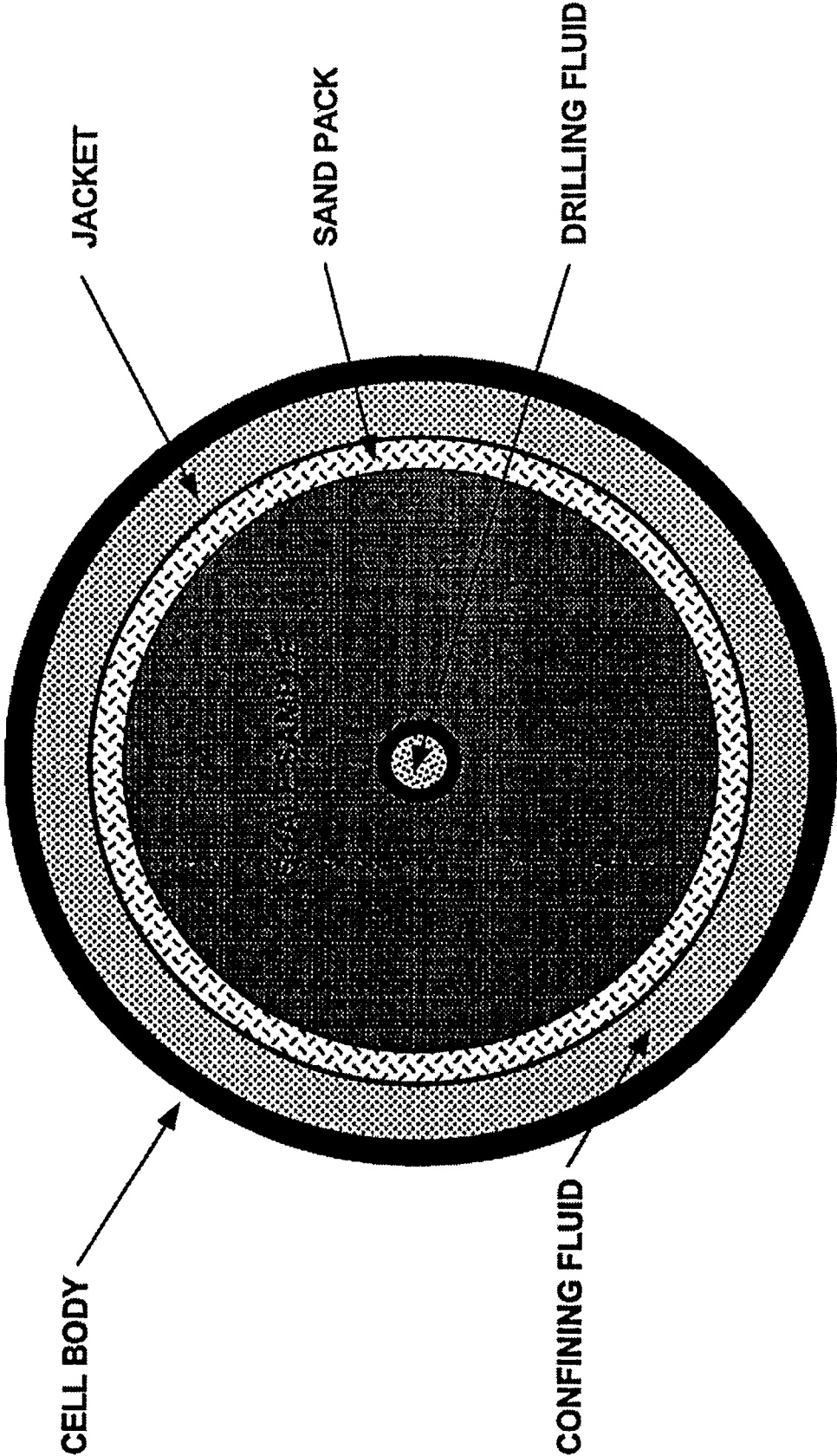


FIGURE 3: EFFECTS OF DRILLING FLUIDS ON FLUID TRANSPORT

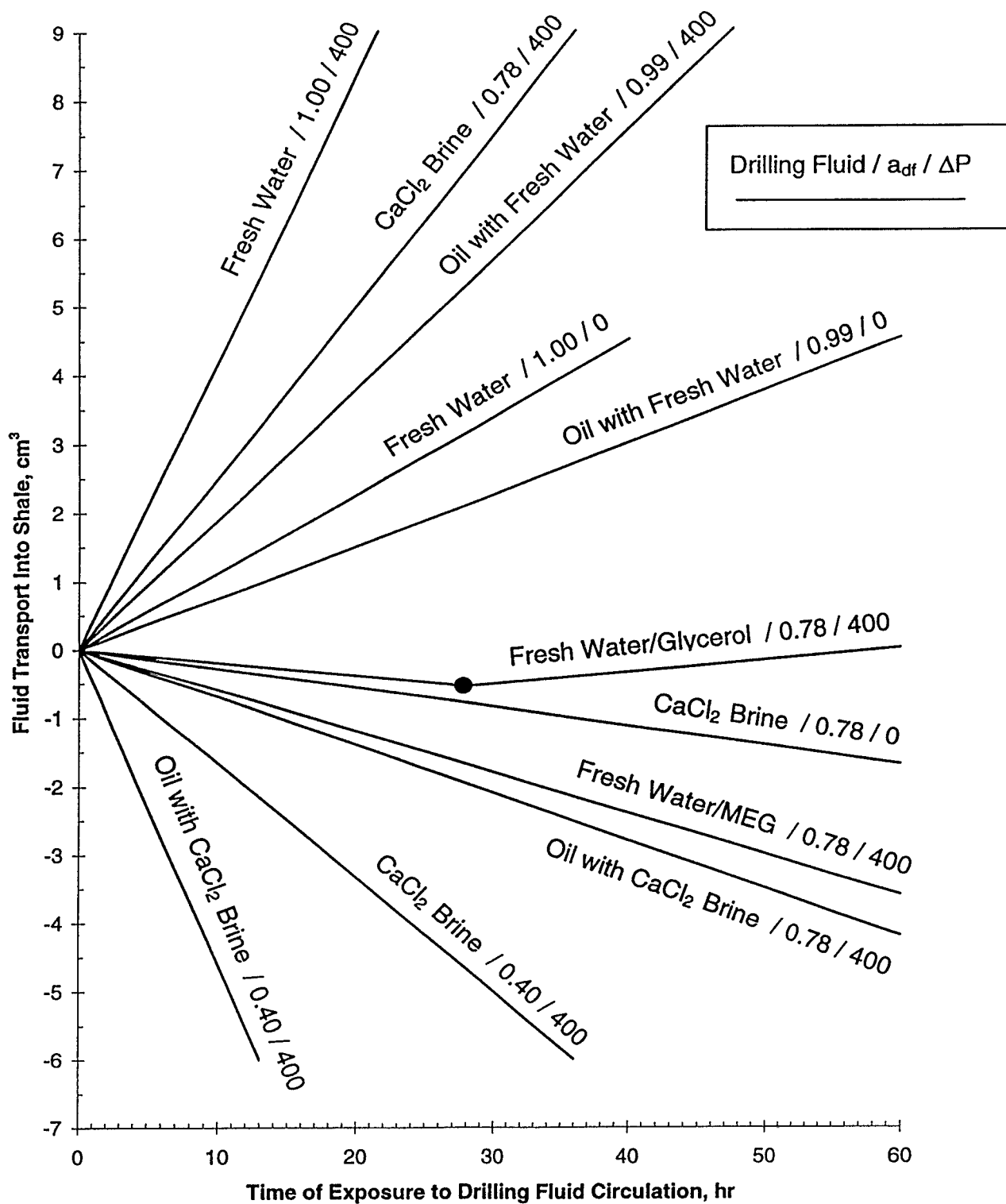


FIGURE 4: SHALE SPECIMENS EXPOSED AT ZERO ΔP TO DRILLING FLUIDS HAVING 0.78 AMBIENT ACTIVITIES

Top View



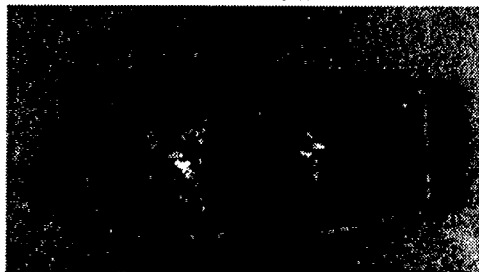
**A. IONIC WATER-BASE DRILLING FLUID
(CaCl_2 BRINE)**

Top View



**B. OIL-BASE EMULSION DRILLING FLUID
(Oil with CaCl_2 BRINE)**

Side View



**C. NONIONIC WATER BASE DRILLING FLUID
METHYL GLUCOSIDE IN FRESH WATER**

FIGURE A-1: OSMOTIC MECHANISM