



Next Generation Silicate Technology Reduces Cost and Improves Performance

John D. Simpson, The Peak Group; Trevor Hurley, Outlander Oil and Gas; Jay P. Simpson, Newpark Drilling Fluids Laboratory; Wayne Rogers, Newpark Drilling Fluids, LLC

Copyright 2006, AADE Drilling Fluids Technical Conference

This paper was prepared for presentation at the AADE 2006 Fluids Conference held at the Wyndam Greenspoint Hotel in Houston, Texas, April 11-12, 2006. This conference was sponsored by the Houston Chapter of the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individuals listed as author/s of this work.

Abstract

A new anhydrous potassium silicate compound has proven effective in wells in Louisiana and Texas where control of shale hydration is critical to successful drilling operations.

A water-based drilling fluid additive, the anhydrous potassium silicate compound forms a precipitate that coats the drilled cuttings and wellbore with a barrier against water penetration without sacrificing lubricity, rheological control, or solids tolerance. The additive achieves improved cuttings integrity, reduced bit balling and minimized wellbore washout compared to offset wells. Problems historically associated with silicates are avoided by minimizing product concentration combined with its limited rate of solubility.

Tests conducted using a unique downhole simulation cell show the additive reduces the transfer of fluid into shale.

Field usage includes mud densities up to 14.9 lb/gal and temperatures up to 250°F. In addition, primary cementing operations are successful in achieving zonal isolation with no requirement for special procedures or additional chemical treatment of spacers. Polycrystalline diamond compact (PDC) bits are successfully employed and have achieved the elimination of multiple bit runs. The additive has been used in wellbores deviated up to approximately 40 degrees.

Introduction

Formations containing substantial concentrations of clay (shales) cause high costs in oil and gas drilling operations throughout the world. Shale hydration can cause balling, slow drilling rate, poor hole cleaning, stuck pipe, high mud dilution requirements, difficulty with directional control, high cementing costs, failure to fully execute logging programs and poor log interpretation. Such problems can be addressed by use of nonaqueous-based muds such as diesel or synthetic-based systems. However, these nonaqueous-based systems usually cost more per barrel, are more prone to lost circulation and can be subject to stringent health,

safety and environmental regulations. For these reasons, much attention has been given to the development of water-based systems that can combat problems associated with shale hydration.

When considering mud systems for drilling shales, it is helpful to understand the factors affecting shale hydration. One of these is the differential between the borehole pressure and the formation pore pressure. The higher the mud pressure, the higher the rate of water transferred to the shale under a given set of downhole conditions. This tends to be overlooked in typical drilling operations. If shale problems occur, a common practice is to raise the mud weight in an effort to give greater support to the wall of the hole. This might provide temporary help, but eventually often makes the problems worse.

A second factor affecting shale hydration is a chemical osmotic force¹ that is dependent upon the difference between the water activity of the drilling mud and that of the shale pore fluid under downhole conditions. Water transfers from the higher water activity (lower concentration of dissolved ions or molecules) to the lower water activity. The chemical osmotic force is also affected by the efficiency of the osmotic membrane created at the interface between the drilling mud and the shale borehole surface. Water-based muds form a non-ideal membrane at the shale face, allowing transfer of both water and solutes.

A third factor affecting shale hydration is diffusion osmosis², which occurs in the presence of a non-ideal membrane when there is an imbalance in solute concentrations between the drilling mud and the shale pore fluid. Diffusion osmosis results in transfer of solutes and associated water from higher to lower concentrations for each species, opposite to the flow of water in chemical osmosis. Even if the chemical osmotic force predominates and is extracting water from shale, diffusion osmosis can cause dissolved ions from water-based muds to invade the shale structure, alter the structure of the clays in the shale and cause borehole instability.

Treatment of Water-based Muds to Combat Shale Hydration

The above factors affecting shale hydration suggest treatments of water-based muds that can be made to combat shale problems. One approach creates a reaction to coat a shale surface to limit transfer of water from the mud to a shale formation and to limit the disintegration and dispersion of shale cuttings. This serves a second purpose of improving the effectiveness of the osmotic membrane at the shale surface. Water activity of the mud may then be reduced to less than that of the shale pore fluid to obtain a chemical osmotic force tending to oppose shale hydration. Soluble inorganic salts reduce water activity, but also contribute to undesirable diffusion osmosis. For better overall shale inhibition a polyglycerol obtains low water activity without encouraging diffusion osmosis.

Silicate-treated Mud for Combating Shale Problems

It has long been recognized that soluble alkaline silicate solutions can react with shale to cause precipitation of a hydrous silicate gel that seals the surface, protecting against hydration and disintegration. In the 1930's, numerous sodium silicate muds were used on the Texas and Louisiana gulf coast.³ The sodium silicate had a silica-sodium oxide ratio of 2:1. A typical 12 lb/gal composition consisted of:

Water, bbl	0.825
Anhydrous Sodium Silicate, lb	164
Bentonite, lb	15
Sodium Chloride, lb	38

The silicate muds were found to be more effective than the fresh-water muds in combating shale problems. However, the industry lacked additives to thin the mud or to control filtration rates. Only expensive dumping and diluting could offset the accumulation of drilled solids. The systems provided very poor lubricity, and health and safety of personnel were even greater concerns. The muds had a pH of 12.2, requiring protection of the face, eyes and hair of all personnel. The muds also had a solvent action on clothing and leather of most kinds.

Subsequent to those early applications, silicate muds have been used only sporadically. However, attention today focuses upon the utilization of low concentrations of anhydrous silicates to obtain the desired shale stabilizing results without the undesired aspects of high-silicate systems.

Laboratory Tests of Water-based Muds to Combat Hydration of Shale.

Tests were conducted with preserved Pleistocene shale from Block 109 of the West Delta area in the Gulf of Mexico, cored using a synthetic-based mud from a depth between 4,128 and 4,215 ft. The preserved core specimen contained water in the pore spaces and eliminated the need for flushing with a

"simulated pore fluid". Estimated downhole conditions at the average core depth were:

Borehole Pressure	2,200 psi
Temperature	150 °F
Vertical Stress	3,450 psi
Horizontal Stress	2,650 psi
Pore Pressure	2,000 psi

Shale core specimens were restored to these conditions when downhole simulation cell (DSC) tests were made.

The unique DSC equipment and procedures have been discussed in detail in IADC/SPE paper 39376.⁴ A schematic of the DSC equipment is shown in Figure 1. Shale specimens were drilled with a 1.0 -inch drag bit. After drilling, the bit was retracted and a 0.75-inch diameter tube was inserted into the borehole to simulate drill pipe. The drilling mud to be tested was then circulated for 48 hours through the annulus between the drill pipe and shale. The sandpack at the outer periphery of the shale specimen was filled with LVT mineral oil. The pressure in the sandpack was adjusted to the desired initial pore pressure as the shale specimen was subjected to the downhole stresses and temperature. Then the specimen was allowed to equilibrate for 24 hours. During drilling mud circulation, after the specimen was drilled, oil was drained from the sandpack as necessary to maintain constant pressure. The rate of drainage provided a quantitative measure of fluid transported from the drilling mud to the shale.

A Durometer C Penetrometer was used to test the hardness of the shale specimens initially and after exposure to the muds in the DSC tests. Measurements were made at 0.25, 0.75 and 1.5 inches from the borehole surface.

The compositions and properties of the muds tested are given in Table 1. The base mud used in these tests contained humalite solubilized by potassium hydroxide rather than lignosulfonate and sodium hydroxide. This provided reduction in yield point and gel strength of the mud with less dispersion of clay solids. The mud also contained a polyglycerol-based ester as an emulsified nonaqueous phase for better filtration control and good lubricity for fast drilling rate.

The volumes of fluid transferred from the drilling muds to the shale in the DSC tests are plotted in Figure 2. The penetrometer hardness values of the shale specimens exposed to the muds are given in Table 2. Photographs of the shale specimens exposed to the muds are shown in Figure 3.

The base mud allowed substantial transfer of fluid into the shale and resulted in partial collapse of the borehole. There was a reduction in the penetrometer hardness of the shale as far as 1.5 inches from the borehole surface. The inclusion of 4 lb/bbl of potassium silicate in the mud resulted in less transfer of fluid and reduction in the penetrometer hardness of the shale was limited to within 0.25 inch of the borehole surface.

Lowering the water activity of the mud treated with the potassium silicate from 0.97 to 0.88 by inclusion of 30% by volume of polyglycerol in the water phase resulted in about 75% less fluid being transferred into the shale during 48 hours of mud circulation, and the borehole remained in gauge. The penetrometer hardness of the shale remained high throughout the specimen.

In summary, downhole simulation cell tests have shown that anhydrous potassium silicate added to a water-based mud can reduce the hydration and destabilization of shale. A greater reduction in shale hydration and more stable borehole can be obtained when the treatment is accompanied by the addition of a selected polyglycerol to reduce the water activity of the mud to less than that of the shale pore fluid.

Case History Number One, Southeast Louisiana Well, Iberia Parish.

This well was drilled in Iberia Parish of Southeast Louisiana. The fluid initially used was an 11.4 ppg lignite/lignosulfonate type mud system. Numerous shale instability and wellbore problems were experienced, prompting the operator to displace to a more inhibitive water-based fluid system.

The well was initially drilled to a depth of 13,681 ft and the hole was opened to 12-1/4 inches. The 7-5/8 inch casing was stuck at 10,942 ft while running pipe and was cemented in place. This left a 2,739 ft 12-1/4 inch open hole below the 7-5/8 inch casing. A kick-off plug was successfully set at 10,980 ft on the third attempt using the existing lignite/lignosulfonate mud system. The mud was displaced to the new system containing the anhydrous potassium silicate compound at 10,999 ft once surveys gave a positive indication of successful kick-off.

The 6-1/2 inch hole was first drilled with a tri-cone bit to 11,812 ft at an average of 14.4 ft/hr in a combination of rotary and slide drilling. The bit was found to have extensive wear to one bearing when pulled but there was no evidence of bit or BHA balling. The second tri-cone bit drilled 376 ft in 37 hours and was pulled due to low ROP. The bit was found to have one cone locked and most of the middle row teeth broken or worn off. No evidence of bit balling was noted on the two previous runs and a PDC bit was used for the next drilling section.

The PDC bit drilled at an average of 17 ft/hr over 306 feet of hole section and was pulled due to a tendency to drop angle and walk to the right. A correction run was made drilling 241 ft in 20 hours with a tri-cone bit and a second PDC bit was picked up.

The final bit run was with the PDC bit from 12,735 to 13,770 ft in 30 hours of rotating time for an average ROP of 34.5 ft/hr. The drilling fluid was weighted up from 11.4 to 12.1 lb/gal over this course. No balling of the bit or BHA was observed. Cuttings

returned to the surface were found to be separate and discrete, firm, not sticky and having a very hard, dry kernel of shale in the center as seen in Figure 4.

The well was logged on drill pipe after wireline logging had been unsuccessful due to being unable to pass a 7.18° dogleg at 12,584 ft. Logs indicated an average hole size of 8 inches in diameter with minimal filter cake buildup and filtrate invasion across the lower production sands. Target sands were in excellent condition and there was no washout of the interbedded shales.

Case History Number Two, Southeast Louisiana Well, St. Mary Parish.

The circumstances on this well were similar to those on the Iberia well previously noted. A 7-5/8 inch casing had been set at 12,910 ft. A successful shoe test was obtained at 12,950 ft on the third attempt after two cement squeezes using the previous lignite/lignosulfonate system. The existing drilling fluid was then displaced to the drilling fluid system containing the anhydrous potassium silicate compound.

A 6-1/2 inch tri-cone bit on a drill motor was used to effect kick-off and build angle to 8.00°. A trip was made for a new bit. There was no balling of the bit, motor, stabilizers or remaining components of the BHA or the drill pipe tool joints. The next tri-cone bit was run without a mud motor and drilled in rotary mode from 13,367 to 13,911 ft at an average ROP of 7.77 ft/hr. The bit was pulled due to rotating hours used, and the operator decided to make the final bit run with a PDC bit since there was no evidence of bit or BHA balling or presence of sticky shales in the wellbore. An addition of 3.0-4.0% diesel oil was made to enhance ROP. The ROP increased from 5.0 to 15.0 ft/hr.

This section was drilled to total depth at 15,600 ft in one bit run with the PDC bit averaging 13.69 ft/hr. The operator estimates that the use of a PDC bit for one continuous run and the associated increase in ROP with the addition of diesel oil as an enhancer to the system saved the use of three tri-cone bits and associated rig costs for a total savings of \$500,000 in operating time.

Case History Number Three, Southwest Texas Well, Maverick County.

Key objectives of this project were to avoid wellbore instability problems experienced in numerous offset wells in the intermediate section and to minimize hole washout in order to provide high-quality formation evaluation information in the successful execution of the logging program.

The well was spudded in using a fresh water-gel spud mud with anhydrous potassium silicate additive at 1.5-2.0 lb/bbl as a source of inhibition for reduction of clay swelling. High viscosity sweeps were used for hole cleaning. The wellbore was effectively maintained and no large amounts of native clays were incorporated into

the system. No problems were experienced during this interval.

The 12- $\frac{1}{4}$ inch first Intermediate Section from 550 to 1956 ft was drilled with the fresh water system from the surface interval with treatments of polyanionic cellulose for filtrate control with the potassium silicate compound maintained at 1.5-2.0 lb/bbl. There was no evidence of bit or BHA balling, no excessive torque or drag, and no problems setting or cementing casing during this section.

The 8- $\frac{3}{4}$ inch second Intermediate Section was drilled to 4,705 ft. The initial mud weight was 9.3 lb/gal. The final mud weight was 10.5 lb/gal. High viscosity sweeps were utilized for hole cleaning up to the kick off point, then high density sweeps at 2.0-4.0 lb/gal over system mud weight thereafter. The well was kicked off at 3,400 ft. The anhydrous potassium silicate additive was highly effective in inhibiting the reactive shales, ensuring they did not disperse into the mud system. The condition of the drill cuttings returning over the shakers was excellent. They were firm, discrete and competent. Large, blunt pieces of shale returned across the shakers at about 3,800 ft. These large pieces of shale accounted for about one percent per hour of the total solids return across the shakers. A treatment of 5.0 lb/bbl sulfonated asphalt was made to the system and the mud weight was raised from 9.3 to 9.9 lb/gal. The volume of large pieces of shale gradually decreased. Drilled cuttings returning over the shakers at 4,200 ft were soft and mushy due to depletion of the anhydrous potassium silicate in the system. The concentration was raised to 2.0 lb/bbl, which significantly improved the condition of the cuttings. The last survey at 4,633 ft measured an inclination of 39.10 degrees. The mud weight was increased to 10.5 lb/gal. No excessive torque or drag was experienced while rotating or during trips. There was no balling of the bit, BHA or other components of the drill string. All logging runs were accomplished.

Of most significant note is that the hole washout measured by caliper log was to a 9- $\frac{1}{4}$ inch diameter and superior logs were received yielding higher quality geologic data than any others taken from the area for the operator.

Nomenclature

$^{\circ}\text{C}$	=	<i>Degrees Celsius</i>
$^{\circ}\text{F}$	=	<i>Degrees Fahrenheit</i>

<i>API</i>	=	<i>American Petroleum Institute</i>
<i>bbl</i>	=	<i>Barrel, 42 gallons</i>
<i>BHA</i>	=	<i>Bottom Hole Assembly</i>
<i>cP</i>	=	<i>Centipoise</i>
<i>DSC</i>	=	<i>Downhole Simulation Cell</i>
<i>ft/hr</i>	=	<i>Feet per hour</i>
<i>g</i>	=	<i>Gram</i>
<i>hr</i>	=	<i>Hour</i>
<i>HTHP</i>	=	<i>High Temperature, High Pressure</i>
<i>lb</i>	=	<i>Pound</i>
<i>lb/100 ft²</i>	=	<i>Pound per hundred foot squared</i>
<i>lb/bbl</i>	=	<i>Pound per barrel</i>
<i>lb/gal</i>	=	<i>Pound per gallon</i>
<i>Mf</i>	=	<i>Methyl orange end point (mL of 0.2N sulfuric acid required to bring the pH of 1mL of filtrate to 4.3)</i>
<i>mg/L</i>	=	<i>Milligrams per liter</i>
<i>min</i>	=	<i>Minutes</i>
<i>mL</i>	=	<i>Milliliters</i>
<i>PDC</i>	=	<i>Polycrystalline Diamond Compact bit</i>
<i>Pf</i>	=	<i>Phenolphthalein end point (mL of 0.2N sulfuric acid required to bring the pH of 1mL of filtrate to 8.3)</i>
<i>psi</i>	=	<i>Pounds per square inch</i>
<i>rpm</i>	=	<i>Rotations per minute</i>

Acknowledgements

The authors thank The Peak Group and Outlander Oil and Gas for their support and permission to publish this paper.

References

1. Chenevert, M.E. : "Shale Control with Balanced Activity Oil-Continuous Muds" JPT (1970) 1309
2. Simpson, J.P. and Dearing, H.L. : "Diffusion Osmosis – An Unrecognized Cause of Shale Instability." Paper IADC/SPE 59190 presented at the 2000 IADC/SPE Drilling Conference, New Orleans, LA, February 23-25.
3. Rogers, W.F. : "Composition and Properties of Oil Well Drilling Fluids" Gulf Publishing, 1953.
4. Simpson, J.P., Walker, T.O., and Aslakson, J.K. : "GRI Studies Dispel Myths, Give Evidence on Formulation of Drilling Fluids for Shale Stability" paper IADC/SPE 39376 presented at the 1998 IADC/SPE Drilling Conference, Dallas, Texas, March 3-6.

Table 1

Mud Number	1		2		3	
Fresh water, mL	303		303		198	
Bentonite, g	5		5		5	
Xanthan gum, g	0.75		0.75		0.75	
Polyacrylamide, g	1		1		1	
Humalite, g	12		12		12	
Potassium hydroxide, g	3		3		3	
Polyglycerol, mL	-		-		105	
Potassium silicate, g	-		4		4	
Polyglycerol ester, mL	35		35		35	
Low-yield clay, g	30		30		30	
Rheology @ Temp	80°F	120°F	80°F	120°F	80°F	120°F
600 rpm	72	58	70	60	110	85
300 rpm	52	42	49	42	77	59
200 rpm	43	34	39	34	63	47
100 rpm	32	24	29	25	44	33
6 rpm	9	7	9	7	12	9
3 rpm	7	5	7	6	9	6
Plastic viscosity, cP	20	16	21	18	33	26
Yield point, lb/100 ft ²	32	26	28	24	44	33
Initial gel, lb/100 ft ²	7	6	7	6	10	7
10 min gel, lb/100 ft ²	13	15	12	13	17	21
Mud weight, lb/gal	8.7		8.7		8.7	
pH	9.9		10.1		10.5	
Hot rolled @ 150°F for 16 hr						
Rheology @ Temp	80°F	120°F	80°F	120°F	80°F	120°F
600 rpm	70	60	69	59	115	92
300 rpm	50	39	47	40	78	62
200 rpm	40	32	37	33	63	52
100 rpm	29	22	27	23	44	37
6 rpm	9	6	8	7	13	10
3 rpm	6	5	6	5	10	8
Plastic viscosity, cP	20	21	22	19	37	30
Yield point, lb/100 ft ²	30	18	25	21	41	32
Initial gel, lb/100 ft ²	8	5	7	6	11	9
10 min gel, lb/100 ft ²	24	10	22	11	30	27
pH	9.2		9.6		10.2	
API filtrate, mL / 30min	4.1		3.2		1.5	
API filter cake, 1/32nd inch	1		1		1	
HTHP filtrate @ 250°F, mL / 30 min	15.2		13.8		9.2	
HTHP filter cake, 1/32nd inch	2		2		2	
Mud alkalinity, mL	0.8		1.1		3.7	
Pf/Mf, mL	0.2/5.4		0.5/4.2		1.7/8.8	
Chlorides, mg/L	2100		2200		7700	
Water activity, @ °C	0.97 @ 23.1		0.96 @ 23.7		0.88 @ 23.3	

Table 2

Penetrometer Hardness of Shale Specimen

<u>Mud Composition</u>	Inches from Borehole Surface			
	Initial	0.25	0.75	1.5
Base Mud	60	10	25	45
Base Mud with 4 lb/bbl Anhydrous Potassium Silicate	52	5	52	52
Base Mud with 4 lb/bbl Anhydrous Potassium Silicate and 30% by Vol. of Polyglycerol	70	45	68	64

FIGURE 1: DOWNHOLE SIMULATION CELL SYSTEM COMPONENTS

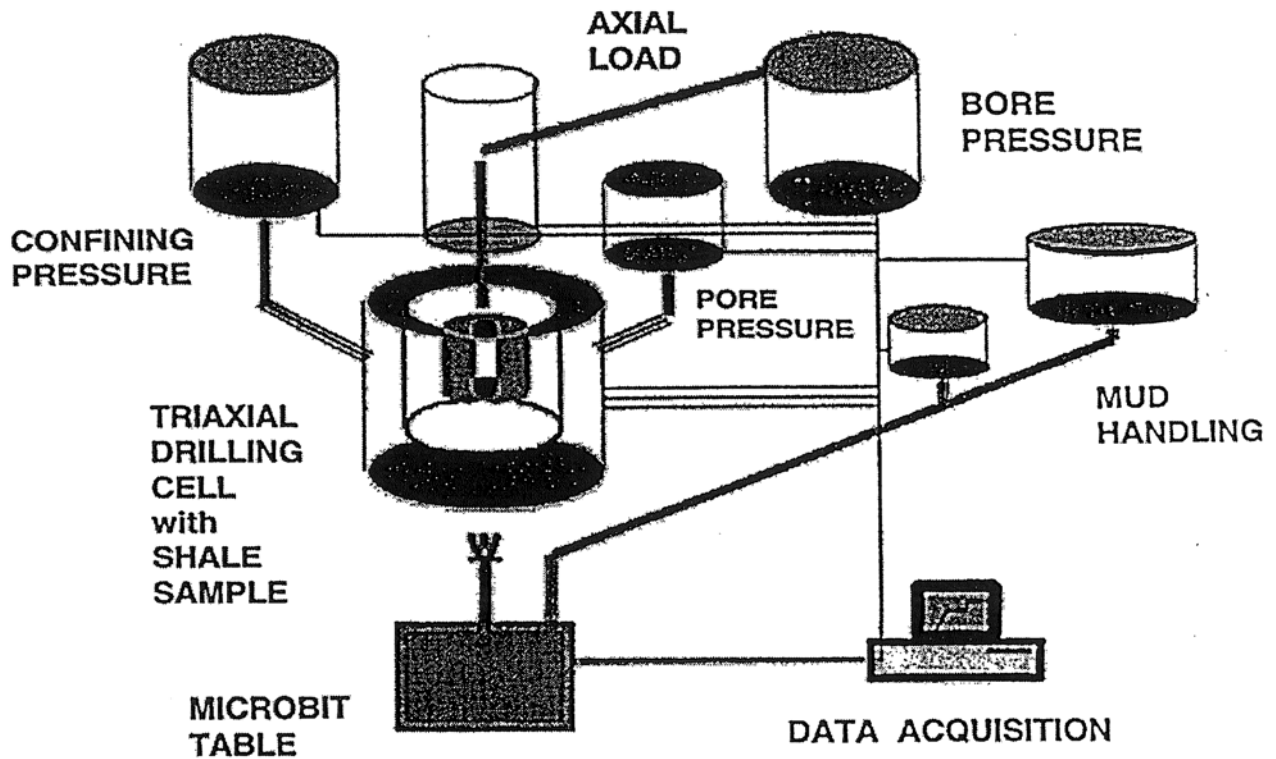


Figure 2
Downhole Simulation Cell Tests
Transfer of Fluid from Borehole to Shale

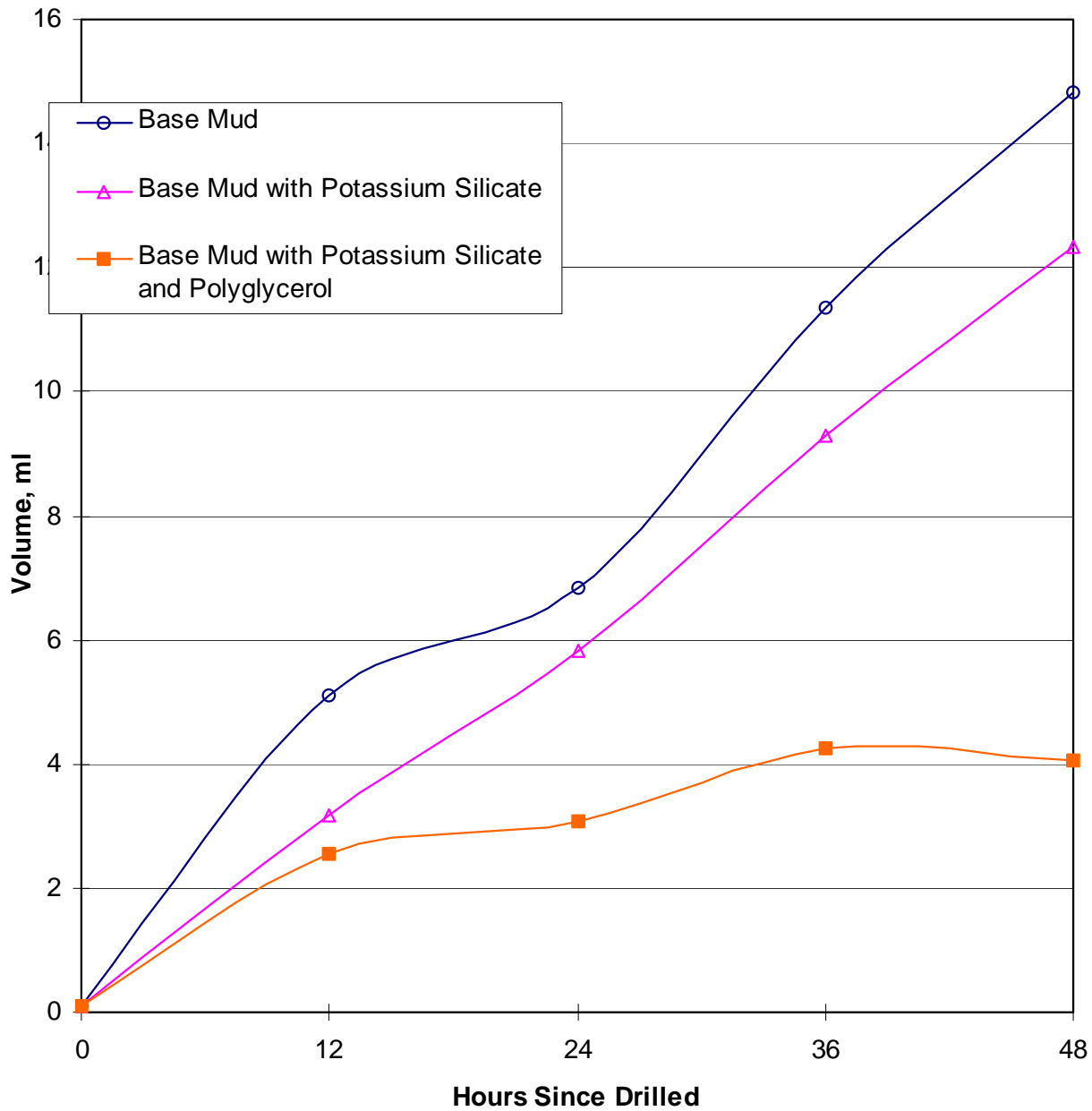
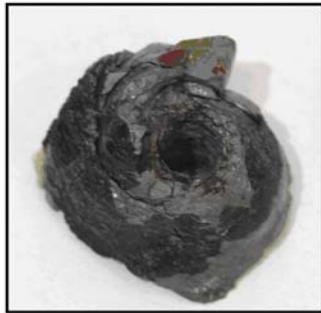


Figure 3
Shale Specimens Exposed to Muds



Base Mud



**Base Mud with
Anhydrous
Potassium Silicate**



**Base Mud with
Anhydrous
Potassium Silicate
and Polyglycerol**

Figure 4
Cuttings from PDC bit run – Southeast Louisiana well, Iberia Parish

