Development of Water-Based Drilling Fluids Customized for Shale Reservoirs

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Summary

Drilling activity has increased dramatically in unconventional shale gas reservoirs. The drilling fluid of choice in these shale plays is often nonaqueous-based fluid (NAF). While NAFs can provide advantages such as shale stabilization, lubricity, and contamination tolerance, environmental consequences and associated costs are an issue. These disadvantages cause operators to seek water-based muds (WBMs) for drilling many of these gas reservoirs.

Despite some operational similarities, a wide variety of unique downhole conditions can be found in the shale plays. Shale mineralogy and bottomhole temperature (BHT) represent just two highly variable critical factors in unconventional gas reservoirs. Therefore, a single water-based solution for addressing shale plays globally is not a realistic option. Instead, a customized approach that delivers WBMs formulated specifically for a given shale play has been pursued.

Customization relies on detailed analysis of the well parameters of a given shale play. This analysis includes not only the shale morphology and lithology but also well drilling program plans, environmental factors, and other reservoir-specific considerations. Applying appropriate drilling-fluid chemistries on the basis of this detailed analysis has led to the successful field deployment of a number of new shale fluids.

Details of the process used for customizing a WBM for a shale play, as well as specific examples of new fluids developed for the Barnett, Fayetteville, and Haynesville shales, are presented in this paper. Full laboratory development and testing are described. Additionally, field-trial results are presented that show that specially designed WBMs can provide performance comparable to that of NAFs, but with enhanced environmental and economic benefits. Application of the customization process to develop WBMs for other shale plays around the globe is also discussed.

Introduction

Estimated gas reserves in North America have risen dramatically in the past few years largely because of the contribution from unconventional shale plays that are only now being fully defined (Mauawd 2009). These new shale plays have been unlocked in recent years by the application of modern horizontal-drilling techniques and hydraulic fracturing (Arthur et al. 2009). While these unconventional gas reserves maintain similarities in the manner in which they are drilled and produced, in truth there are a number of fundamental differences between plays and sometimes even within a given play. These differences may include physical distinctions such as the mineralogy of the formation, the BHT of the well, and petrophysical values (e.g., Young's modulus, Poisson's ratio) (Passey et al. 2010). Additional differences can be seen in economic expectations for a given play as well as the quality of the equipment available in the region in which the play resides. From the perspective of drilling-fluid design and deployment, these variations among shale plays are of paramount importance.

NAFs are often the drilling fluid of choice in unconventional shale plays. Despite the differences among shale plays, NAFs are flexible enough and generally economical enough to be applied across the majority of the unconventional gas reserves. In addition to the near universality with which NAFs can be applied, they also offer top-notch performance and reliability. Excellent shale stabilization, lubricity, and contamination tolerance are just a few of the benefits of an NAF (Darley and Gray 1988). Despite these advantages, the undesirable environmental consequences of using base oils (generally diesel oil for North American operations) as well as unwanted costs associated with the use of base oils led operators to seek WBMs as alternatives. With water as the continuous phase, WBMs generally offer an improved environmental profile over NAFs (particularly a diesel-based NAF). Additionally, costs can often be lower overall with WBM because of the reduction of ancillary costs. These ancillary costs, which include such burdens as base-oil transportation, cuttings transportation, and cuttings remediation, are usually greatly reduced when WBMs are used.

While NAFs could be applied in nearly all shale plays despite the often substantial differences, WBMs cannot. WBMs are much more chemically active than NAFs. WBMs are significantly more sensitive to changes in conditions than NAFs, including changes in temperature, salinity, pH, and contaminants such as CO_2. Shale stabilization in reactive shales should always be considered and addressed when employing a WBM. In short, the differences between the shale plays are significant enough that a single WBM cannot be expected to show broad-spectrum global utility in unconventional shales. Appreciating this fact led to the development of an approach for designing water-based drilling fluids customized for a given shale play. In this customized approach, the fluid is designed from the bottom up to meet the challenges of a given play. Each challenge of a play is considered (e.g., reactive shale, high BHT, CO_2-influx potential) and dealt with by the application of chemistry appropriate for the task. This bottom-up design allows for optimal matching of the chemistry of the WBM to the chemistry of the shale reservoir. Not surprisingly, developing WBMs specially designed for an individual shale play has proved to be superior to early attempts at simply "force fitting" an established WBM system into the unconventional shales.

Significant success has been observed in the development and deployment of customized WBMs through this method. Subsequent sections illustrate the customization process and the successes it has produced in the context of three North American shale plays: Haynesville, Fayetteville, and Barnett. For each play, the process used to develop the appropriate WBM, the laboratory-testing results, and a field-application summary are discussed. A discussion of application of the customization process to other unconventional shale plays globally is presented before the concluding remarks.

Haynesville Shale

The Haynesville shale play is a large natural-gas play covering approximately 9,000 sq miles in northwestern Louisiana and eastern Texas. Recent estimates indicate 251 Tcf of technically recoverable resources in the play, easily making it one of the largest shale plays in North America (GWPC 2009). The Haynesville shale itself is a black, organic-rich shale from the Upper Jurassic. The Haynesville play is extremely active, with 128 wells currently being drilled and 883 currently producing wells on the Louisiana side alone (State of Louisiana Department of Natural Resources 2011).

The Haynesville separates itself from the majority of other North American shale plays by virtue of its remarkably harsh bottomhole conditions. The Haynesville shale comes in deep with

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TABLE 1—REPRESENTATIVE XRD DATA FROM HAYNESVILLE AND BOSSIER SHALES				
Component (wt%)	Haynesville	Haynesville	Bossier	Bossier
Quartz	19	24	27	23
Plagioclase feldspar	2	2	3	3
Calcite	7	13	6	6
Pyrite	–	17	21	27
Illite	67	42	40	37
Dolomite	5	–	1	2
Chlorite	trace	trace	2	2
Smectite	–	–	trace	trace

true vertical depths in the 10,500- to 14,000-ft range, depending on location within the play, and BHTs that can exceed 380°F. In addition to the high BHTs observed in much of the Haynesville, CO_2 influx is common in the play and the deep location of the Haynesville often necessitates high mud weights. Designing a WBM suitable for these harsh conditions is no small task. The high BHTs observed in the Haynesville exclude many of the traditional WBM additives from being used because of thermal degradation. For example, biopolymers—workhorse additives for a variety of functions such as suspension and fluid-loss control in WBM—are essentially useless at the temperatures seen in the Haynesville. CO_2 historically wreaks havoc on WBMs. In order to address this demanding play, a customized WBM was needed.

Haynesville Shale WBM Design and Development. The customization process began with a thorough evaluation of the Haynesville mineralogy by use of X-ray diffraction (XRD) analysis of cuttings and core samples. Mineralogy of the Bossier shale was also examined. The Bossier shale sits above the Haynesville shale, and current drilling practices leave the Bossier exposed while the Haynesville is drilled. This results in long-term exposure of the Bossier to the drilling fluid.

Results of our XRD analysis (representative data shown in **Table 1**) indicate the Haynesville and Bossier to be composed of clay, carbonate, pyrite (frequently), and quartz.

From the perspective of designing a water-based drilling fluid, the crucial information is the clay content and, more importantly, the identity of the clay. Our data shows that the clay content in both the Haynesville and Bossier samples studied was nearly exclusively illite with virtually no smectite detected. In illitic clays, potassium substitutes for sodium in the lattice structure of the clay. This seemingly small change makes a substantial difference because the illitic clays are not as prone to swelling as the smectites are (Salles et al. 2007). Illite is, however, prone to dispersion. With this information in hand, it was felt that concerns of shale swelling with the water-based fluid could be set aside. Focus could then be turned to the thermal demands of the play.

Freshwater formulations were devised that consisted solely of additives designed for high thermal stability **(Table 2).** Common drilling-fluid additives, including clay, barite, and water, were used in addition to specialized thinners/deflocculants to control thermal flocculation of the system clays. Surfactant chemistry was employed to reduce interparticle forces and allow for high mud weights and high loadings of low-gravity solids. Sulfonated acrylamide-based terpolymers were used to control fluid loss to the formation. Finally, a buffer agent was added to combat the effects of CO_2 influx, which, as mentioned previously, is common in the Haynesville. This buffer agent allowed for adequate control of CO_2 without the potential for hydrolyzing the synthetic polymers, a common effect of lime.

TABLE 2—CUSTOMIZED WBM FOR HAYNESVILLE SHALE		
Products (lbm/bbl)	15.5 lbm/gal	17.5 lbm/gal
Water	243	216
Clay	10	10
High-temperature deflocculant	3	4
Surfactant	2	3
Thinner	5	5
Shale stabilizer	5	5
Fluid-loss control polymer	2	2
Caustic soda	0.5	0.5
Buffer agent	1.5	1.5
Barite	380	490

Haynesville Shale WBM Laboratory Testing. With a formulation in hand, attention was turned toward laboratory testing. Static aging of Haynesville formulations weighted to 17.5 lbm/gal was conducted at 400°F for 48 hours according to standard American Petroleum Institute (API) procedures (API RP 13I 2009). These harsh conditions of temperature and time were chosen in an effort to emulate the worst-case scenario. After aging, standard rheological and fluid-loss properties were measured. **Table 3** provides mud-testing data for the 17.5-lbm/gal base formulation, the base formulation after aging, the base formulation after aging with CO_2 (pressurized to 200 psi with CO_2), and formulations with 6 and 12% low-gravity solids (LGSs). As a key part of the customized approach, the LGSs used for these studies were made from cuttings from the Haynesville and Bossier shales (Red River Parish) ground to a D_{50} of less than 10 µm. For these studies, a 50:50 mixture of ground Haynesville and Bossier cuttings was used. Use of actual core/cuttings samples for the formulations further emphasizes the customized approach that was sought and allows for a more seamless transition from the laboratory to the field.

The data in Table 3 clearly indicate that the customized fluid handles the rigors of temperature quite well. No progressive gelation is seen in any of the samples, even in the presence of CO_2. Plastic viscosities and shear strengths remained remarkably low, given the aging protocol and solids contents of the muds. The mud retains functional properties even at what is considered to be an unrealistically high 12% LGSs. Also of note, the API and high-temperature/high-pressure (HT/HP) fluid-loss values are quite low for a high-temperature WBM. These results clearly demonstrate that a thermally stable WBM tolerant of CO_2 and of high loadings of LGS has been formulated using the customized approach.

Further laboratory testing revealed the rheological performance of the customized Haynesville formulation under more-realistic downhole conditions of temperature and pressure. A test matrix was developed that used a Fann 75 HT/HP rheometer to follow the rheology of the fluid as the temperature/pressure was ramped up from 120°F/0 psig to 400°F/10,000 psig. Upon reaching the peak temperature and pressure, the sample was then held at temperature and pressure for 24 hours. After this time, the temperature and pressure were ramped down back to 120°F/0 psig. The results of this testing **(Table 4)** show that even under extreme temperatures and pressures, no signs of thermal gelation were present. Following the tau0 value (a measure of suspension characteristics) throughout the ramp-up/ramp-down cycle is clearly demonstrative of a very stable fluid.

With thermal stability firmly established, the compatibility of the designed formulation with the highly illitic shales common in the Haynesville and Bossier formations was examined. As mentioned previously, illitic clays are substantially less prone to

TABLE 3—CUSTOMIZED HAYNESVILL E WBM: FLUID PROPERTIES					
17.5 lbm/gal	Base	Base (Aged)	Base + CO_2	Base + 6% LGS	Base + 12% LGS
Rolled at 150°F (hr)	3	3	3	3	3
Static aged at 400°F (hr)	–	48	48	48	48
pH	10.5	9.1	8.7	9.0	8.9
API fluid loss (mL)	4.0	4.4	5.0	4.6	3.4
HTHP fluid loss at 400°F (mL)	–	20	20	18	16
Shear strength (lbm/100 ft^2)	–	75	95	90	135
Fann 35 Data					
Temperature			120°F		
Plastic viscosity (cp)	55	37	42	49	74
Yield point (lbm/100 ft^2)	12	11	5	18	34
10s/10m/30m gel (lbm/100 ft^2)	5/7/9	4/5/6	3/5/7	6/7/8	10/16/18
600 rev/min	122	85	89	116	182
300 rev/min	67	48	47	67	108
200 rev/min	47	34	32	49	80
100 rev/min	27	19	18	29	49
6 rev/min	5	4	3	6	12
3 rev/min	3	3	2	4	9

TABLE 4—CUSTOMIZED HAYNESVILLE WBM: HT/HP RHEOLOGY									
17.5 lbm/gal	120°F 0 psig	200°F 5000 psig	300°F 7500 psig	400°F 10,000 psig		400°F 10,000 psig	300°F 7500 psig	200°F 5000 psig	120°F 0 psig
Tau0	12	10	12	14	24 Hours 400°F 10,000 psig	12	10	10	10
600 rev/min	146	104	84	71		87	97	125	169
300 rev/min	85	62	51	43		53	60	77	102
200 rev/min	63	49	42	36		43	48	60	78
100 rev/min	40	33	31	28		31	34	40	50
6 rev/min	11	12	13	13		13	12	13	15
3 rev/min	11	10	12	13		12	11	11	12

swelling than smectite but can be prone to dispersion. To address potential concerns, a shale-erosion study was conducted. In this study, Bossier core was ground and sized so that the pieces would pass through a 5-mesh screen but would be retained on a 10-mesh screen. Approximately 30 g of sized shale was added to 350 mL of sample of customized Haynesville WBM. The mass of shale retained on a 10-mesh screen after hot rolling for 16 hours was compared to the mass before aging to calculate percent recovery **(Table 5).** Shale samples were thoroughly dried before weighing after hot roll. The data show near-complete recovery of the shale after the aging protocol, indicative of minimal dispersion and disintegration of the shale samples in the customized Haynesville WBM.

Further evidence of shale integrity can be seen in **Figs. 1 and 2.** Fig. 1 shows Haynesville shale after a shale-erosion test in the customized Haynesville WBM, while Fig. 2 depicts a similar shale-erosion test with Haynesville shale in a diesel-based oil-based mud (OBM). The similarity in the photos is indicative of equivalent shale integrity with the customized WBM and OBM, a strong testament to the customized approach.

Application of a bottom-up approach allowed for the formulation of a WBM that displays excellent properties under conditions likely encountered in the Haynesville shale. The designed fluid is remarkably stable in the daunting thermal environment of the Haynesville and is tolerant to solids and CO_2. Successful field application remained for final validation of the system and the design principles employed for its preparation.

TABLE 5—CUSTOMIZED HAYNESVILLE WBM: SHALE EROSION	
Fluid Density (lbm/gal)	% Recovery
15.5	98.0%
16.5	98.7%
17.5	98.5%

Haynesville Shale WBM Field Application. The customized WBM for the Haynesville shale was used in Red River Parish in Louisiana. This particular region of the Haynesville shale is one of the most thermally demanding. The customized system was introduced into the wellbore at the top of the Bossier shale at 10,700 ft and used to total depth in the Hayneville shale at nearly 17,800 ft. Because of a complex well design, the fluid was in open hole for

Fig. 1—After shale erosion test in customized WBM.

Fig. 2—After shale erosion test in OBM.

45 days. Along the way, substantial and nearly constant CO_2 influx was observed (> 8,000 ppm). The mud handled these influxes well, with minimal effect on the rheology. At the peak influxes (gas-removal equipment was out of service), there were some increases in mud rheology, but they were easily treated with base additives from the formulation. BHTs greater than 350°F were encountered. Little or no trouble returning to bottom after trips was observed. Rates of penetration (ROPs) were found to be comparable to those of offset wells, and, upon completion of drilling, washout was calculated to be very respectable at 8.5%. Typical properties measured for the field mud can be seen in **Table 6.**

Ultimately, it was felt that in a challenging wellbore in a challenging region of the Haynesville, the customized WBM system performed extremely well. Properties observed in the field were highly similar to those observed in the laboratory, and the customized design approach showed merit.

Fayetteville Shale

The Fayetteville shale is black, organic-rich Mississippian rock that resides in the central portion of the Arkoma basin (North central Arkansas). The estimated reserves of natural gas are approximately 42 Tcf. The Fayetteville shale generally comes in at a depth of approximately 4,000–8,000 ft. BHTs in the play range from 120 to 220°F. While the temperatures are not as harsh as those seen in the Haynesville, little success was historically seen in drilling the lateral sections of the Fayetteville shale with WBM. OBM was frequently the most successful and reliable option and, hence, the option of choice. The success of WBMs in the play was sporadic, primarily because of unusual mineralogy of the Fayetteville shale. The Fayetteville shale (and the Morrow shale that lies above it) contains a high percentage of smectite/chlorite mixed-layer clays. To adequately deal with the unusual mineralogy of the Fayetteville/Morrow shale and to ultimately provide a successful and reliable WBM solution for the play required a customized approach.

TABLE 6—CUSTOMIZED HAYNESVILLE WBM: TYPICAL FIELD PROPERTIES

	Depth (ft)	
	12,442	14,864
Fluid density	15.0 lbm/gal	16.6 lbm/gal
pH	10.4	9.3
API fluid loss (mL)	5.0	2.0
HTHP fluid loss at 300°F (mL)	16.2	14.0
Fann 35 Data		
Temperature	120°F	
PV (cp)	41	49
YP (lbm/100 ft^2)	19	17
10s/10m/30m gel (lbm/100 ft^2)	7/13/16	8/12/13
600 rev/min	101	115
300 rev/min	60	66
200 rev/min	45	48
100 rev/min	30	30
6 rev/min	8	8
3 rev/min	7	7

Fayetteville Shale WBM Design and Development. As was the case with Haynesville WBM, the development of a customized WBM for the Fayetteville shale began with XRD analysis of cuttings and core samples. The XRD data (representative data shown in **Table 7**) revealed that although there were disparities in the exact percentages, both the Fayetteville and Morrow proved to be primarily quartz and clay.

The predominant clay minerals were illite, a nonswelling clay present in the Haynesville samples, and the aforementioned smectite/chlorite mixed-layer clay. The smectite/chlorite mixed-layer clay is not frequently encountered, particularly in shale gas reservoirs. While it is not an osmotically swelling clay such as smectite, the smectite/chlorite does undergo reaction with water. Smectite/chlorite is prone to fissuring or delamination in aqueous systems. This delamination, if left unchecked, can lead to wellbore-stability issues and drilling-fluid issues such as rheological and particle-size-distribution problems. In the absence of extreme thermal conditions downhole, addressing the troublesome delamination of the smectite/chlorite became the top priority for WBM-system design.

A freshwater formulation was devised that was expected to seal and protect the smectite/chlorite from delamination. Application of solid-silicate chemistry (in relatively small concentrations compared with previous silicate systems) along with sulfonated asphaltenes was expected to adequately prevent/remedy the shale's penchant for delamination. Other additives for shale stability, fluid-loss control, and pH control were combined with xanthan gum for aid in suspension **(Table 8).**

TABLE 7—REPRESENTATIVE XRD DATA FROM FAYETTEVILLE AND MORROW SHALES

Component (wt%)	Morrow	Fayetteville
Quartz	31	40
Plagioclase feldspar	2	1
Potassium feldspar	trace	trace
Calcite	trace	–
Pyrite	–	trace
Smectite/Chlorite mixed-layer	35	24
Illite	21	24
Dolomite	2	10
Chlorite	3	1
Kaolin	6	–

TABLE 8—CUSTOMIZED WBM FOR FAYETTEVILLE SHALE

Products (lbm/bbl)	9 lbm/gal
Water	329
Silicate	5
Sulfonated asphaltenes	6
Modified lignite	8
Polyanionic cellulose	2
Starch	2
Xanthan Gum	0.5
Barite	15
Bridging agent	10
Glycol	10

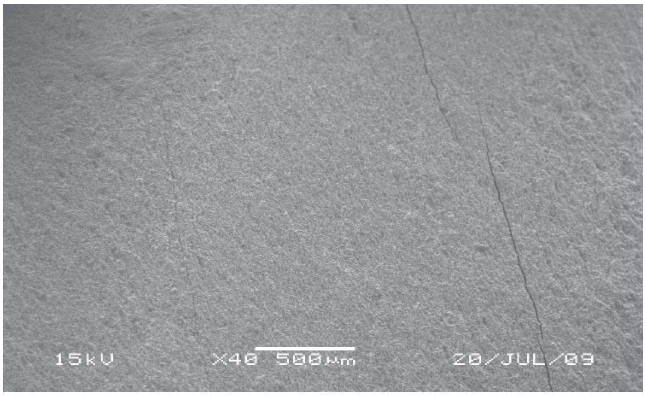

Fig. 3—Initial Fayetteville/Morrow shale.

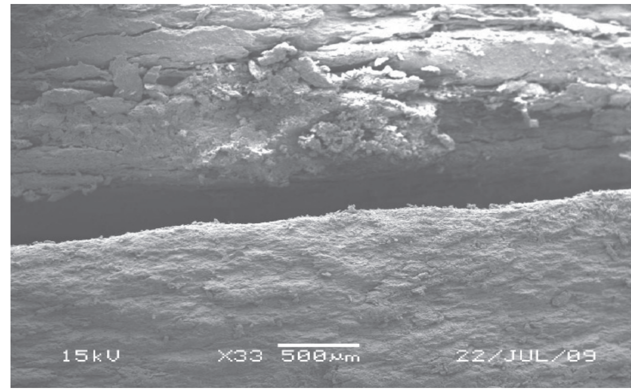

Fig. 4—Fayetteville/Morrow Shale after 24-hour soak in fresh water.

Fayetteville Shale WBM Laboratory Testing. The crux of laboratory testing on the WBM customized for the Fayetteville shale was determining if the chemistries of the fluid system (specifically, the silicate and sulfonated asphaltenes) could prevent the delamination of the native shale. Efforts to make this determination were initiated at the microscopic level. **Figs. 3 through 6** show scanning-electron-microscope (SEM) photos of Fayetteville/Morrow shale.

Fig. 3 shows a micrograph of the native shale, and Fig. 4 shows the native shale after soaking in water for 24 hours. A clear fissure has formed in the Fig. 4 sample as the water has facilitated the delamination of the smectite/chlorite mixed-layer clay. Fig. 5 illustrates the shale sample after a 24-hour soak in a typical inhibitive mud. Some degree of fissure prevention/healing has occurred, but it can be easily seen that the customized WBM in Fig. 6 does a far superior job of preventing/healing the delamination of the smectite/chlorite. With the sealing capabilities of the customized formulation clearly demonstrated at the microscopic level, further proof at the macroscopic level was sought.

Fig. 7 shows representative results from linear-swell-meter (LSM) testing against the Fayetteville/Morrow shale. The newly designed fluid was tested against three other inhibitive fluids for the ability to inhibit swelling of Fayetteville/Morrow shale samples. The customized fluid is easily the best performer because virtually no swelling is observed.

Standard fluid data including Fann 35 rheology and API fluid loss were also obtained for the customized Fayetteville WBM, and excellent properties were observed **(Table 9).**

Laboratory testing showed that, through the use of appropriate chemistry, the primary issue in drilling the Fayetteville shale with a WBM could be addressed and controlled. The next subsection summarizes a field application of the customized system in the Fayetteville shale.

Fayetteville Shale WBM Field Application. The customized WBM for the Fayetteville shale was applied in Van Buren County in Arkansas. This organically rich region of the Fayetteville shale is particularly prone to severe delamination, high LGSs content, and high torque and drag. The customized system was introduced into the wellbore at the bottom of the Morrow shale at 3,500 ft and used to total depth in the Fayetteville shale at nearly 10,000 ft. While drilling, the problems seen with traditional WBMs were not observed and trips were made without incident. The ROPs seen while drilling were comparable to those of the NAFs traditionally used in the region, with rates of 30–50 ft/hr while sliding and 100–250 ft/hr while rotating. These ROPs were achieved because of proper customization allowing for maximum lubricity and shale inhibition. Typical field properties are shown in **Table 10.**

Barnett Shale

Considered to be the first of the shale plays to be developed in the recent North American shale play boom, the Barnett shale is composed of Mississippian sedimentary rocks. Situated in the Fort Worth basin, the Barnett covers approximately 5,000 sq miles spanning 21 counties in north Texas. The Barnett play is purported to contain approximately 44 Tcf of technically recoverable resources (GWPC 2009). The depth of the Barnett ranges from 7,000 to 10,000 ft, and BHTs are in the range of 125–225°F. As was the case with the Haynesville and Fayetteville, OBM is generally used for drilling the production zone in the Barnett shale. While not thermally demanding like the Haynesville nor possessing an unusual clay mineral like the Fayetteville, the Barnett proved a troublesome play for application of a WBM because of its reactive clays. In order to provide operators with an effective alternative to OBM for the Barnett, the customization protocol was undertaken.

Barnett Shale WBM Design and Development. As with the other systems, the design of the WBM system customized for the Barnett shale was begun with the XRD analysis of core/cuttings samples from the Barnett shale. XRD analysis shows a large fraction of

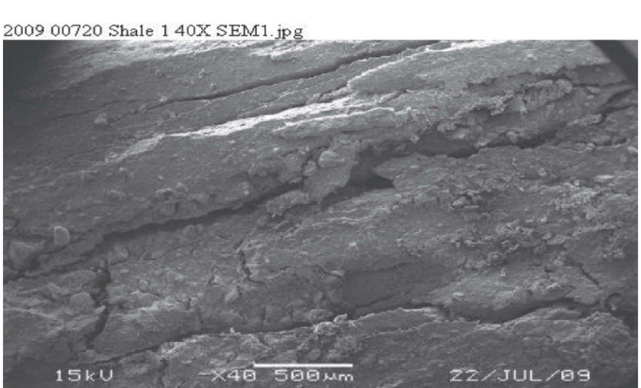

Fig. 5—Fayetteville/Morrow Shale after 24-hour soak in typical inhibitive WBM.

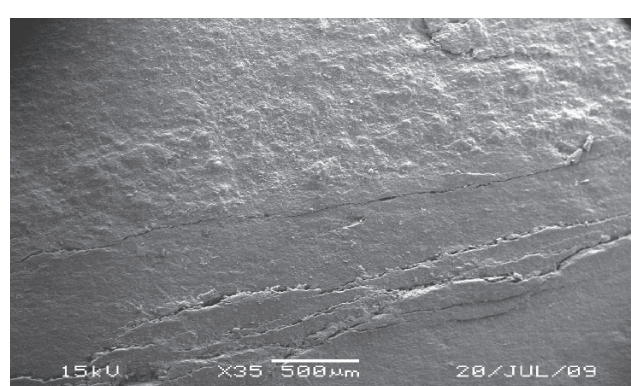

Fig. 6—Fayetteville/Morrow Shale after 24-hour soak in customized WBM for Fayetteville shale.

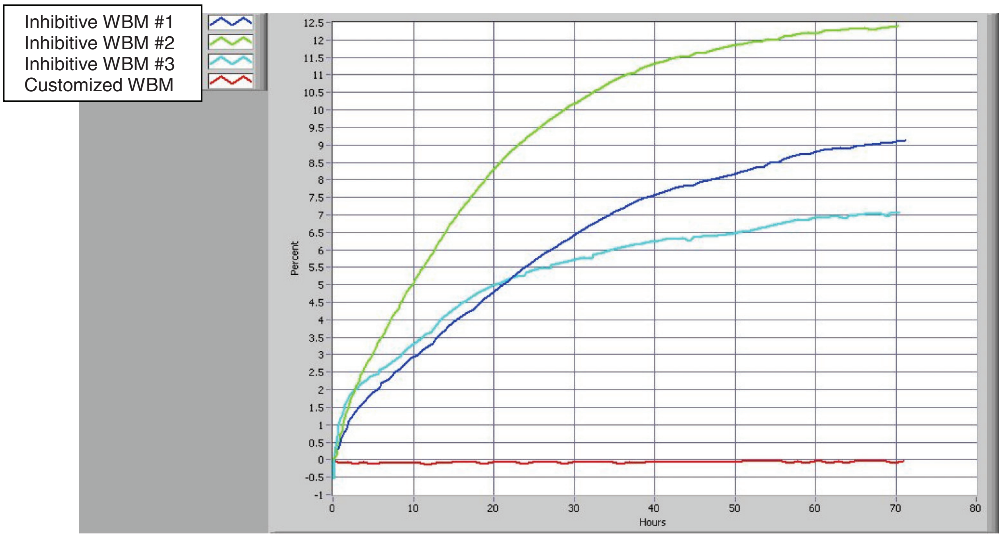

Fig. 7—LSM results for customized Fayetteville WBM.

TABLE 9—CUSTOMIZED FAYETTEVILLE WBM: FLUID PROPERTIES

Properties	9 lbm/gal
API fluid loss (mL)	6.2
Fann 35 Rheology	
Temperature	120°F
Plastic viscosity (cp)	17
Yield point (lbm/100 ft^2)	15
10s gel (lbm/100 ft^2)	3
10m gel (lbm/100 ft^2)	5

TABLE 10—CUSTOMIZED FAYETTEVILLE WBM: TYPICAL FIELD PROPERTIES

	Depth (ft)	
	5,663	7,537
Fluid density	9.0 lbm/gal	9.0 lbm/gal
pH	10.7	10.9
API Fluid Loss (mL)	4.8	4.8
Fann 35 Data		
Temperature	120°F	
Plastic Viscosity (cp)	21	22
Yield Point (lbm/100 ft^2)	35	38
10s/10m/30m gel (lbm/100 ft^2)	9/12/14	9/13/15
600 rev/min	77	82
300 rev/min	56	60
200 rev/min	47	47
100 rev/min	36	35
6 rev/min	10	10
3 rev/min	9	9

clay minerals in the Barnett samples (representative data shown in **Table 11**).

The identity of the clay minerals was dependent on the county in which the well was drilled. In Denton County, the clay minerals are essentially equally divided between illite, which was encountered previously in both the Haynesville and Fayetteville mineralogies, and illite/smectite mixed-layer clay. Illite/smectite mixed-layer clay is a commonly seen reactive clay that represents a intermediate point in the diagenetic pathway from smectite to illite. The clay is much more reactive than illite (Darley and Gray 1988; Salles et al. 2007) and, hence, must be addressed when the intent is to drill with a water-based fluid. Samples from Cooke County were highly illitic, with no illite/smectite mixed layer present. With the BHTs and representative Barnett shale mineralogy now known, a formulation could be prepared. The relatively mild BHT allowed great flexibility in formulation, but preventing the illite/smectite clay from swelling and the illite clay from dispersing had to be addressed at a chemical level with the mud additives. A highly inhibitive formulation, similar in additives but not concentration to the Fayetteville formulation, was devised to combat the reactive shale of the Barnett. The formulation was heavy on potassium ions and used glycol chemistry along with the solid silicate and sulfonated asphaltenes for optimum inhibition (**Table 12).**

TABLE 11—REPRESENTATIVE XRD DATA FROM BARNETT SHALE

Component (wt%)	Denton County	Cooke County
Quartz	29	35
Plagioclase feldspar	5	5
Potassium feldspar	–	1
Siderite	5	–
Halite	–	6
Illite/Smectite mixed-layer	28	–
Illite	33	45
Chlorite	trace	6
Kaolin	trace	2

TABLE 12—CUSTOMIZED WBM FOR BARNETT SHALE

Products (lbm/bbl)	9 lbm/gal
Water	329
Silicate	5
Sulfonated asphaltenes	5
Lignite	6
Polyanionic cellulose	1
Starch	1
Xanthan gum	0.5
Barite	15
Bridging agent	10
Glycol	10
Lubricant	7

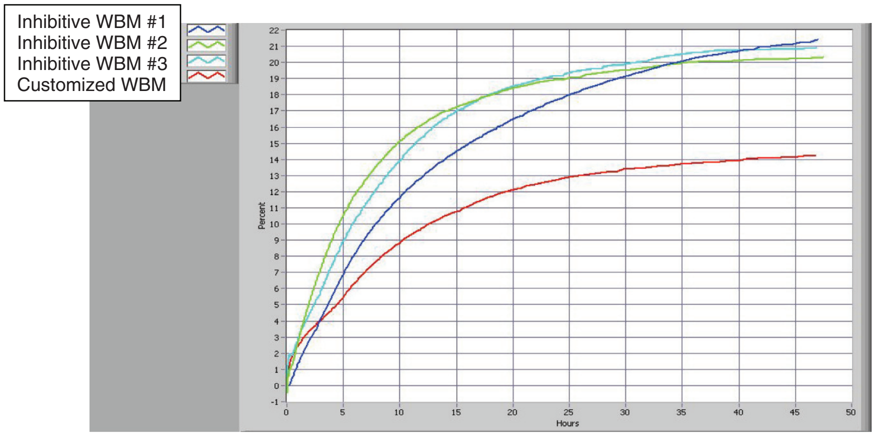

Fig. 8—LSM results for customized Barnett WBM.

Barnett Shale WBM Laboratory Testing. The formulation was designed to handle the swelling shales seen in some regions of the Barnett as well as the dispersive clays that appear throughout the Barnett. The customized Barnett WBM was subjected to LSM testing with a sample of the smectite-containing Denton County shale (Table 11). LSM results (**Fig. 8**) from the customized Barnett WBM and three other inhibitive WBMs indicate that the shale is indeed quite reactive. Of the fluids tested, however, the customized Barnett WBM was clearly the superior performer, resulting in 5–6% less swelling over the 48-hour test.

With satisfactory performance demonstrated in the Denton County high-smectite clay, testing switched focus to the highly illitic shale seen in Cooke County. Shale-erosion tests were conducted to gauge the degree of dispersion of the illitic clays in the customized Barnett WBM. These tests involved rolling Cooke County shale samples of a specific size range (retained on a 10-mesh screen) in a test fluid at 150°F for 16 hours. The weight of the shale samples before rolling and after rolling (dried) was used to calculate a percent of shale that was retained. A larger percent retained corresponds to a lesser degree of shale dispersion. **Table 13** provides fluid-property data as well as shale-erosion data for the customized Barnett WBM and other inhibitive fluids.

The performance advantage of the customized Barnett WBMs is seen in the substantially higher percent shale retentions shown in Table 13. Dispersion of the illite is effectively controlled by means of the inhibitive and sealing chemistry of the customized WBM. The customized WBM for the Barnett had demonstrated the ability to handle the reactive clays commonly seen in the Barnett. With adequate laboratory testing complete, field validation was now required.

Barnett Shale WBM Field Application. The customized WBM for the Barnett shale was used in Denton County in Texas. This tectonically stressed region of the Barnett shale is highly microfractured and prone to hole instability, high LGSs content, and high torque and drag. The customized system was introduced into the wellbore out from under surface at ±1,000 ft and used to total depth in the Barnett shale at nearly 9,000 ft. While drilling, no problems were seen with trips and casing was run to bottom with no issues. The ROPs seen while drilling were comparable to those of the fluids traditionally used in the region, with rates of 24–80 ft/hr while sliding and 100–250 ft/hr while rotating. These ROPs were achieved because of proper customization allowing for maximum lubricity and shale inhibition. Thus, allowing minimal operational issues and no liquid mud haul off were two of the criteria for success with this operator. Representative field properties of the customized WBM for the Barnett shale can be seen in **Table 14.**

Broader Application of Shale WBM Customization

The data of this paper are focused on customized WBM development for three of the major unconventional gas plays in North America: the Haynesville, Fayetteville, and Barnett shales. While these specific plays were addressed with a customized WBM,

TABLE 13—FLUID-PROPERTY COMPARISON: CUSTOMIZED BARNETT WBM

	Inhibitive Fluid 1	Inhibitive Fluid 2	Customized Barnett WBM 1*	Customized Barnett WBM 2**
API fluid loss (mL)	3.6	2.8	5.0	5.4
		Fann 35 Data		
Temperature			80°F	
Plastic viscosity (cp)	30	20	33	35
Yield point (lbm/100 ft^2)	15	15	16	17
10s/10m gel (lbm/100 ft^2)	5/8	5/6	6/8	6/8
600 rev/min	75	55	82	87
300 rev/min	45	35	49	52
6 rev/min	7	6	8	8
3 rev/min	5	5	6	6
% Shale Retained†	62	79	93	99

* Customized Barnett WBM containing 5 lb/bbl silicate

** Customized Barnett WBM containing 10 lb/bbl silicate

† % Shale retained = (mass of shale retained on 10-mesh screen after hot rolling/mass of shale retained on 10-mesh screen before hot rolling)*100

TABLE 14—CUSTOMIZED BARNETT WBM: TYPICAL FIELD PROPERTIES

	Depth (ft)	
	6,970	11,694
Fluid density	9.1 lb/gal	9.2
pH	11.2	11.1
API fluid loss (mL)	6.0	5.4
Fann 35 Data		
Temperature	120°F	
Plastic viscosity (cp)	20	19
Yield point (lbm/100 ft^2)	21	24
10s/10m gel (lbm/100 ft^2)	9/25	7/16
600 rev/min	61	62
300 rev/min	41	43
200 rev/min	32	34
100 rev/min	22	24
6 rev/min	9	8
3 rev/min	7	6

a major thrust of this paper is the conveyance of the bottom-up approach to designing WBMs for shale plays. It is felt that, while the formulations described this paper are useful in the context of the shale play they were designed for, the customization approach can be made universal. In order to efficiently develop customized systems for other shale plays, a process was developed in which specific information about a shale/shale play was gathered. This information includes

- XRD data on core/cuttings samples
- Logging data
- Key wellbore factors
  - BHT
  - Fluid density
  - Saltwater flows
  - CO_2
  - Typical wellbore schematic
  - Problematic formations such as salt stringers or anhydrite
- Environmental factors/limitations

The XRD data are of utmost importance because they will reveal the nature of the clays present in the formation. These clays can roughly be divided into reactive [essentially water-swelling (i.e., smectite)] or nonreactive [does not swell in water (i.e., illite)]. Once this distinction is made, a series of tests can be recommended to evaluate the behavior of the shale **(Table 15).**

With the critical information described previously and the results of shale testing in hand, a customized WBM for any shale play can be produced. The chemistry required in the WBM system will be dictated by both the well details and the results of the shale testing. The systematic, bottom-up approach described herein brings an enhanced rationality to the process of designing a drilling fluid. This rational approach should easily allow for customization of shale-play WBMs globally.

Conclusions

Customized WBMs have been developed for three major North American shale plays: Haynesville, Fayetteville, and Barnett. The WBMs were customized with a rational, bottom-up approach that allowed for precise matching of the chemistry of the fluid to the formation being drilled. Excellent laboratory data and field performance for the fluids customized for these three shale plays have validated the effectiveness of the fluid-design approach. The success of these fluids gives operators an environmentally advantageous and potentially economically advantageous alternative to NAFs, which had previously dominated the unconventional shale drilling market.

TABLE 15—RECOMMENDED TESTS BY SHALE TYPE

Reactive Shale	Nonreactive Shale
Capillary suction test	Methylene blue test
Linear swell meter	Fracture development test
Methylene blue test	Brinell hardness test
Shale erosion test	Shale erosion test
SEM Imaging	SEM Imaging

The principles used to develop the customized WBMs involved gathering of key well and formation data as well as specific laboratory testing of formation samples. From this information, it is felt that a customized WBM can be developed and deployed for any shale play globally.

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