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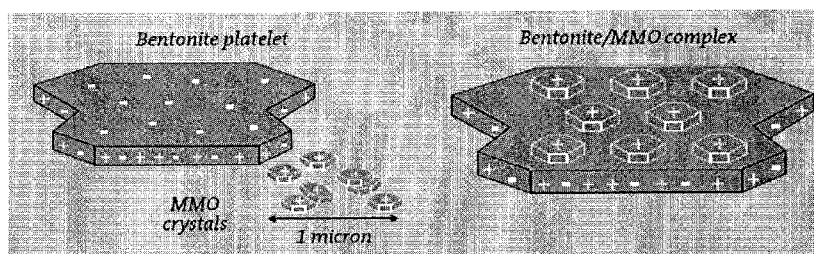


Figure 1

(57) Abstract: A water-based wellbore fluid including an aqueous fluid, a mixed metal oxide- clay complex, and an anionic suppressant, where the anionic suppressant includes a Lewis acid and a lubricant and where the lubricant includes a sulfur containing compound and at least one pH agent, where the at least one pH agent is in an amount sufficient to obtain a pH ranging from about 9 to 13 is disclosed.



LUBRICANT FOR WATER-BASED MUDS AND METHODS OF USE THEREOF

BACKGROUND OF INVENTION

Field of the Invention

[0001] Embodiments disclosed herein relate to components of wellbore fluids (muds). More specifically, embodiments relate to water-based muds and components thereof.

Background Art

[0002] During the drilling of a wellbore, various fluids are typically used in the well for a variety of functions. The fluids may be circulated through a drill pipe and drill bit into the wellbore, and then may subsequently flow upward through the wellbore to the surface. During this circulation, the drilling fluid may act to remove drill cuttings from the bottom of the hole to the surface, to suspend cuttings and weighting material when circulation is interrupted, to control subsurface pressures, to maintain the integrity of the wellbore until the well section is cased and cemented, to isolate the fluids from the formation by providing sufficient hydrostatic pressure to prevent the ingress of formation fluids into the wellbore, to cool and lubricate the drill string and bit, and/or to maximize penetration rate.

[0003] In most rotary drilling procedures the drilling fluid takes the form of a “mud,” i.e., a liquid having solids suspended therein. The solids function to impart desired rheological properties to the drilling fluid and also to increase the density thereof in order to provide a suitable hydrostatic pressure at the bottom of the well.

[0004] Drilling fluids are generally characterized as thixotropic fluid systems. That is, they exhibit low viscosity when sheared, such as when in circulation (as occurs during pumping or contact with the moving drilling bit). However, when the shearing action is halted, the fluid should be capable of suspending the solids it contains to prevent gravity separation. In addition, when the drilling fluid is under shear conditions and a free-flowing near-liquid, it must retain a sufficiently high enough viscosity to carry all unwanted particulate matter from the bottom of the wellbore to the surface. The drilling fluid formulation should also allow the cuttings and other

unwanted particulate material to be removed or otherwise settle out from the liquid fraction.

[0005] There is an increasing need for drilling fluids having the rheological profiles that enable wells to be drilled more easily. Drilling fluids having tailored rheological properties ensure that cuttings are removed from the wellbore as efficiently and effectively as possible to avoid the formation of cuttings beds in the well, which can cause the drill string to become stuck, among other issues. There is also the need from a drilling fluid hydraulics perspective (equivalent circulating density) to reduce the pressures required to circulate the fluid, reducing the exposure of the formation to excessive forces that can fracture the formation causing the fluid, and possibly the well, to be lost. In addition, an enhanced profile is necessary to prevent settlement or sag of the weighting agent in the fluid; if this occurs it can lead to an uneven density profile within the circulating fluid system, which can result in well control (gas/fluid influx) problems and wellbore stability problems (caving/fractures).

[0006] To obtain the fluid characteristics required to meet these challenges the fluid must be easy to pump, so it requires the minimum amount of pressure to force it through restrictions in the circulating fluid system, such as bit nozzles or down-hole tools. In other words the fluid must have the lowest possible viscosity under high shear conditions. Conversely, in zones of the well where the area for fluid flow is large and the velocity of the fluid is slow or where there are low shear conditions, the viscosity of the fluid needs to be as high as possible in order to suspend and transport the drilled cuttings. This also applies to the periods when the fluid is left static in the hole, where both cuttings and weighting materials need to be kept suspended to prevent settlement. However, it should also be noted that the viscosity of the fluid should not continue to increase under static conditions to unacceptable levels. Otherwise when the fluid needs to be circulated again this can lead to excessive pressures that can fracture the formation or lead to lost time if the force required to regain a fully circulating fluid system is beyond the limits of the pumps.

[0007] Drilling fluids are typically classified according to their base material. The drilling mud may be either a water-based mud having solid particles suspended

therein or an oil-based mud with water or brine emulsified in the oil to form a discontinuous phase and solid particles suspended in the oil continuous phase.

[0008] On both offshore and inland drilling barges and rigs, drill cuttings are conveyed up the hole by the drilling fluid. Water-based drilling fluids may be suitable for drilling in certain types of formations; however, for proper drilling in other formations, it is desirable to use an oil-based drilling fluid. With an oil-based drilling fluid, the cuttings, besides ordinarily containing moisture, are coated with an adherent film or layer of oily drilling fluid which may penetrate into the interior of each cutting. This is true despite the use of various vibrating screens, mechanical separation devices, and various chemical and washing techniques. Because of pollution to the environment, whether on water or on land, the cuttings cannot be properly discarded until the pollutants have been removed.

[0009] Thus, historically, the majority of oil and gas exploration has been performed with water-based muds. The primary reason for this preference is price and environmental compatibility. The used mud and cuttings from wells drilled with water-based muds can be readily disposed of onsite at most onshore locations and discharged from platforms in many U.S. offshore waters, as long as they meet current effluent limitations guidelines, discharge standards, and other permit limits. As described above, traditional oil-based muds made from diesel or mineral oils, while being substantially more expensive than water-based drilling fluids, are environmentally hazardous.

[0010] As a result, the use of oil-based muds has been limited to those situations where they are necessary. The selection of an oil-based wellbore fluid involves a careful balance of both the good and bad characteristics of such fluids in a particular application. An especially beneficial property of oil-based muds is their excellent lubrication qualities. These lubrication properties permit the drilling of wells having a significant vertical deviation, as is typical of off-shore or deep water drilling operations or when a horizontal well is desired. In such highly deviated holes, torque and drag on the drill string are a significant problem because the drill pipe lies against the low side of the hole, and the risk of pipe sticking is high when water-based muds

are used. In contrast oil-based muds provide a thin, slick filter cake which helps to prevent pipe sticking.

[0011] Oil-based muds typically have excellent lubricity properties in comparison to water-based muds, which reduces sticking of the drill pipe due to a reduction in frictional drag. The lubricating characteristics (lubricity) of the drilling mud provide the only known means for reducing the friction. Additionally, the use of oil-based muds is also common in high temperature wells because oil muds generally exhibit desirable rheological properties over a wider range of temperatures than water-based muds.

[0012] Thus, components or additives imparting a lubricating effect on water-based muds are desirable. There exists a continuing need for water-based muds having improved properties including lubricity.

SUMMARY OF INVENTION

[0013] In one aspect, embodiments disclosed herein relate to a water-based wellbore fluid including an aqueous fluid, a mixed metal oxide-clay complex, and an anionic suppressant, where the anionic suppressant includes a Lewis acid and a lubricant and where the lubricant includes a sulfur containing compound and at least one pH agent, where the at least one pH agent is in an amount sufficient to obtain a pH ranging from about 9 to 13.

[0014] In another aspect, embodiments disclosed herein relate to a method of treating a wellbore, including mixing an aqueous fluid, a mixed metal oxide-clay complex, an anionic suppressant, a lubricant, and at least one pH agent, to form a water-based wellbore fluid, where the anionic suppressant includes a Lewis acid and where the lubricant includes a sulfur containing compound and where the at least one pH agent is in an amount sufficient to obtain a pH ranging from about 9 to 13, and using the water-based wellbore fluid during a drilling operation.

[0015] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

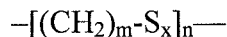
[0016] Figure 1 shows an interaction between mixed metal oxide and bentonite in accordance with some embodiments of the invention.

DETAILED DESCRIPTION

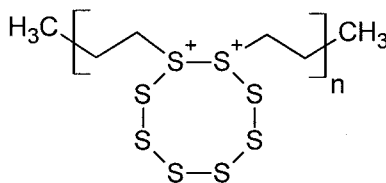
[0017] In one aspect, embodiments disclosed herein relate to lubricants used in water-based wellbore fluid formulations. In particular, embodiments described herein relate to the use of lubricants having sulfur compounds therein capable of imparting lubricity upon a wellbore fluid without negatively interacting with other components of the wellbore fluid. Such embodiments may find particular use in water-based fluids containing, *inter alia*, mixed metal oxide, clay complexes, anionic suppressants, lubricants, and pH adjusting agents. One of ordinary skill in the art will recognize that drilling or wellbore fluids may also comprise various other additives such as viscosifiers, gelling agents, bridging agents, and fluid loss control agents, as known in the art. The lubricant may be formed from several components including at least one sulfur compound.

[0018] Figure 1 shows an interaction between mixed metal oxide and bentonite in accordance with some embodiments of the invention. In mixed metal oxide fluid systems, the rheological properties are derived from interaction between mixed metal oxides and clay particles. Addition of conventional lubricants to the fluid may cause the lubricant to undesirably interact with the mixed metal oxide-clay complex to result in a sudden drop in viscosity and render the fluid unsuitable for its intended purpose. As a more specific example, conventional lubricants or fatty acids, such as oleic acid, if added alone, may interact with other components of the wellbore fluid, *e.g.*, a surface-charged clay such as bentonite, and prevent such component from properly interacting with other fluid components, *e.g.*, a mixed metal oxide component (also referred to as a “bentonite extender”). Thus, reducing the presence and/or availability of fatty acids and other anions may be beneficial to such water-based fluid systems while simultaneously increasing the lubricity of the fluid.

[0019] In some embodiments, lubricants described herein may be comprised of sulfur-containing compounds. In more specific embodiments, lubricants may be sulfide/polymer blends, such as:



[0020] For example, such sulfide/polymer blends may include a polysulfide such as a hydrocarbon chain with an eight membered ring formed therein:



[0021] sulfur-sulfur bonds in such sulfur-containing compounds may break and thus provide sulfide anions at high temperatures, which are available to react with iron to form iron sulfide. Formation of iron sulfide on iron surfaces may impart the desired lubricity effect.

[0022] One exemplary lubricant formulation may include (by volume) about 40-80 percent mineral oil and about 20-60 percent of a sulfide/polymer blend. In some embodiments, the lubricant may be EP LUBE (available from M-I Drilling Fluids, Pocr Quay, Aberdeen).

[0023] Yet sulfide ions available in the fluid may further react with available hydrogen to form hydrogen sulfide and anions, for example, hydrogen sulfide ions (HS⁻). However, sulfide and hydrogen sulfide ions act similar to free fatty acids ("FFAs") (or other anionic contaminants), in that the anions alter the ionic bonds between mixed or metal oxides in water-based fluids and thereby cause undesirable changes to the viscosity/rheological profile of the water-based fluids.

[0024] Therefore, at least one anionic suppressant may be included with the sulfur containing compound, to minimize the effect of the lubricant on the fluid viscosity. Specifically, such an anionic suppressant may preferentially react with available anions in the fluid to prevent or minimize the interaction of the anions with the mixed metal oxides. In some embodiments, anionic suppressants may be comprised of Lewis acids. Examples of Lewis acids include, but are not limited to, magnesium carbonate, aluminum carbonate, iron carbonate, zinc carbonate, zinc chloride,

diborane, boron trifluoride, dialuminum hexachloride, aluminum fluoride, silicon tetrafluoride, phosphorus pentachloride, and sulfur tetrafluoride.

[0025] Thus, the anionic suppressants may act as Lewis acids to precipitate anions, for example sulfide ions, out of the wellbore fluid, thus preventing anions from undesirably altering the ionic interactions between mixed metal oxides and clay particles and thereby preserving the rheological properties of the wellbore fluid.

[0026] As mentioned above, the anionic suppressant may include a Lewis acid to which the anion may be attracted, reducing or preventing the negatively charged anion from interacting with the charged surface of the clay (and displacing the mixed metal oxide). By increasing the cationic charge, the effect of an anionic lubricant on the charged clay surface may be reduced or minimized, which thus reduces or minimizes the effect on the fluid rheology.

[0027] In some embodiments, anionic suppressants may include any chemical substance which is added and which can react with one or more sulfide components, FFAs or any other anionic contaminants, to form inert compounds. It may be appropriate to add anionic suppressants to the wellbore fluid in excess in relation to the amount of anions present, or expected amount of anions, to ensure minimal effect on fluid rheology. Additives based on zinc, such as zinc carbonate, zinc hydroxide and organic zinc compounds may provide sulfide absorption and give irreversible reactions with the sulfides to form solid zinc sulfide.

[0028] However, the addition of the anionic suppressant and lubricant may cause a decrease in the pH of the fluid. In some embodiments, pH agents described herein may be added to the fluid formulation to adjust the pH by increasing or lowering the pH of the wellbore fluid, as appropriate. For example, pH agents may be added to obtain a pH of the wellbore fluid ranging from about 9 to 13, or at least about 11.5 in other embodiments.

[0029] In some embodiments, pH agents may include, for example, sodium hydroxide (*i.e.*, caustic soda), sodium carbonate (*i.e.*, soda ash), potassium hydroxide and potassium carbonate, or other hydroxides or carbonates. In particular embodiments, a potassium-containing pH-adjusting agent may be used to simultaneously adjust the pH and provide clay inhibition and a lower dispersion effect to minimize an overload

of low-gravity solids and high-gravity solids from dispersing into the fluid system. In other embodiments, sodium carbonate may be used to increase the pH, or sodium hydroxide may be used when salt or seawater is present in the wellbore fluid. In yet other embodiments, sodium bicarbonate may be used to decrease the pH. In some embodiments, pH agents may include alkali agents, including basic agents.

[0030] In some embodiments, the alkalinity of wellbore fluids may be tested using alkaline indicators P_f and M_f . The ratio of these, P_f/M_f , is a measurement of filtrate alkalinity. As used herein, P_f is the phenolphthalein end point of a filtrate sample using N/50 sulfuric acid and M_f is the methyl orange or brom cresol green-methyl red end point of a filtrate sample using N/50 sulfuric acid. For example, one method of obtaining P_f and M_f is to pipette 1 ml of filtrate into a titration dish and add more than 2-3 drops of phenolphthalein, while watching for a color change to pink. If no color develops, the P_f is zero and the pH is less than 8.3. If a pink color develops, N/50 sulfuric acid is added until the pink color is discharged. The P_f is the amount of N/50 sulfuric acid (in ml) required to discharge the pink color and the sample is titrated to the P_f end point.

[0031] Continuing with the example, to determine M_f , 2-3 drops of bromocresol green-methyl red is added to the same sample used to determine P_f . N/50 sulfuric acid is added until the sample turns a light blue color initially, and then to an apple green color, indicating the M_f end point (and a pH of about 4.0 to 4.5). The M_f is the total volume of N/50 sulfuric acid required to reach the M_f end point, including the volume required to reach the P_f end point. A P_f value indicates the presence of carbonate and hydroxide ions. A M_f value indicates the presence of bicarbonate ions. The ratio of P_f to M_f may indicate the alkalinity of the filtrate sample by estimating the carbonate, bicarbonate, and hydroxyl present in the filtrate. Table 1 shows one example of how to estimate the concentrations of these ions using P_f and M_f values (as described by DiCorp Procedure © Diversity Technologies Corporation 2002, Canamara United Supply Ltd.):

Table 1. Carbonate, Bicarbonate, and Hydroxyl Concentrations

P_f and M_f Measurements	Bicarbonate (mg/l HCO₃)	Carbonate (mg/l CO₃)	Hydroxyl (mg/l OH)
P _f = 0	1220*M _f	0	0
P _f = M _f	0	0	340*M _f
2*P _f = M _f	0	1200*P _f	0
2*P _f > M _f	0	1200*(M _f - P _f)	340*(2*P _f - M _f)
2P _f < M _f	1220*(M _f - P _f)	1200*P _f	0

[0032] As another example, if the filtrate sample is too dark to see a color change to pink, the sample's pH may be checked for a titration endpoint of 8.3 for phenolphthalein and 4.3 for methyl orange to determine P_f and M_f values.

[0033] Applicants have surprisingly found that by adjusting the pH of the wellbore fluid when adding lubricity components and anionic suppressant components, the rheology of the fluid is improved. Further, it has surprisingly been found that in some embodiments, a P_f/M_f ratio of about 1:2 may advantageously impart improved shear properties to the wellbore fluid compositions. In addition, use of pH agents in such a ratio may advantageously reduce air encapsulation and foaming. In some embodiments, in such a ratio, the lubricants and/or anionic suppressants may increase the tendency of the wellbore fluid to foam and a P_f/M_f ratio of about 1:2 may advantageously control foaming. Further, small additions of sodium hydroxide may improve air encapsulation.

[0034] Wellbore Fluid Formulation

[0035] As mentioned above, the lubricants of the present disclosure may find particular use in a water-based wellbore fluid that includes a mixed metal oxide-clay complex and an aqueous fluid.

[0036] The aqueous fluid of the wellbore fluid may include at least one of fresh water, sea water, brine, mixtures of water and water-soluble organic compounds and mixtures thereof. For example, the aqueous fluid may be formulated with mixtures of desired salts in fresh water. Such salts may include, but are not limited to alkali

metal chlorides, hydroxides, or carboxylates, for example. In various embodiments of the wellbore fluid disclosed herein, the brine may include seawater, aqueous solutions wherein the salt concentration is less than that of sea water, or aqueous solutions wherein the salt concentration is greater than that of sea water. Salts that may be found in seawater include, but are not limited to, sodium, calcium, aluminum, magnesium, potassium, strontium, and lithium, salts of chlorides, bromides, carbonates, iodides, chlorates, bromates, formates, nitrates, oxides, phosphates, sulfates, silicates, and fluorides. Salts that may be incorporated in a given brine include any one or more of those present in natural seawater or any other organic or inorganic dissolved salts. Additionally, brines that may be used in the wellbore fluids disclosed herein may be natural or synthetic, with synthetic brines tending to be much simpler in constitution. In one embodiment, the density of the wellbore fluid may be controlled by increasing the salt concentration in the brine (up to saturation). In a particular embodiment, a brine may include halide or carboxylate salts of mono- or divalent cations of metals, such as cesium, potassium, calcium, zinc, and/or sodium.

[0037] Additionally, the water-based wellbore fluid may include a mixed metal oxide-clay complex. Such clays may include those having surface charges thereon, including, for example, bentonite, saponite, hectonite, and kaolinite. One commercial example of such a clay source is GELPLEX™, an untreated bentonite, which is available from M-I L.L.C. (Houston, TX). Clay flakes are made up of a number of crystal platelets each being called a unit layer. The unit layers stack together face-to-face and are held in place by weak attractive forces between the ionic surfaces of the unit layer. The distance between corresponding planes in adjacent unit layers is called the d-spacing. Clay swelling is a phenomenon in which water molecules surround a clay crystal structure (based on attraction to the ionic surface) and position themselves to increase the structure's d-spacing, thus resulting in an increase in volume. Two types of swelling may occur. Surface hydration is one type of swelling in which water molecules are adsorbed on crystal surfaces. Hydrogen bonding holds a layer of water molecules to the oxygen atoms exposed on the crystal surfaces. Subsequent layers of water molecules align to form a quasi-crystalline structure between clay's unit layers which results in an increased d-spacing. Various types of clays swell in

this manner. Osmotic swelling is a second type of swelling. Where the concentration of cations between unit layers in a clay mineral is higher than the cation concentration in the surrounding water, water is osmotically drawn between the unit layers and the d-spacing is increased. Osmotic swelling results in larger overall volume increases than surface hydration. However, only certain clays, like sodium montmorillonite (bentonite), swell in this manner.

[0038] The ionic surfaces of such clays are usually attractive to cations such as sodium or potassium. However, when exposed to other cations, the unit layer can serve as cation exchange sites for other cations available in the system. When metal cations, such as in the form of mixed metal oxides are added to a fluid, the metal cations may replace the sodium or potassium cations. However, as these metal ions are polyvalent, the metals may more strongly associate with the clay surface and/or with neighboring clay platelets. Such phenomenon is described in more detail in U.S. Patent Nos. 5,232,627 and 4,664,843, for example. One commercial example of a mixed metal oxide is DRILPLEX™ Mixed Metal Oxide, also available from M-I L.L.C. (Houston, TX). It is postulated that the interaction between clay and a mixed metal oxide not only increases the viscosity of the fluid by swelling of the clay as well as formation of a unique electrostatic environment through association of the clay and mixed metal oxide, but the particle complex may also act as a bridging agent to help plug pores of a formation and reduce filtration losses. As mentioned above, the ionic interaction between clay and a mixed metal oxide may be disturbed by anions. For example, the negatively charged anion components may attract the cationic mixed metal oxides, thereby interrupting the electrostatic environment and bridging ability.

[0039] In addition to these components, the wellbore fluids may also include other conventional additives known in the art of wellbore fluids, including conventional bridging agents, weighting agents, viscosifiers, gelling agents, fluid loss control agents, foaming agents, etc. For example, conventional viscosifiers, such as water soluble polymers and polyamide resins, may also be used. The amount of viscosifier used in the composition can vary upon the end use of the composition. However, normally about 0.1% to 10% by weight range is sufficient for most applications.

- [0040]** In one embodiment, the water-based wellbore fluid may include a weighting agent. Weighting agents or density materials suitable for use the fluids disclosed herein include galena, hematite, magnetite, iron oxides, illmenite, barite, siderite, celestite, dolomite, calcite, and the like. The quantity of such material added, if any, may depend upon the desired density of the final composition. Typically, weighting agent is added to result in a wellbore fluid density of up to about 24 pounds per gallon. The weighting agent may be added up to 21 pounds per gallon in one embodiment, and up to 19.5 pounds per gallon in another embodiment.
- [0041]** Conventional bridging agents may include bridging materials suitable for use in the present disclosure include graphite, calcium carbonate (preferably, marble), dolomite ($\text{MgCO}_3 \cdot \text{CaCO}_3$), celluloses, micas, proppant materials such as sands or ceramic particles and combinations thereof.
- [0042]** Foaming agents may include various ester-, alcohol-, or hydrocarbon-based compounds as known in the art. Two commercial examples of defoaming agents include DEFOAMTM-A and DEFOAMTM-X, both of which are available from M-I L.L.C. (Houston, Texas).
- [0043]** A variety of fluid loss control agents may be added to the wellbore fluids disclosed herein and are generally selected from a group consisting of synthetic organic polymers, biopolymers, polysaccharide derivatives, and mixtures thereof. In one embodiment, the fluid loss control agent should be selected to have low toxicity, compatibility with additional wellbore fluid components, and water-solubility. Fluid loss control agents may include, for example, FLO-PLEXTM which is available from M-I L.L.C. (Houston, TX), a water-soluble polysaccharide derivative which is effective in salt-containing wellbore fluids, resistant to bacterial degradation, and which provides fluid loss control without lowering the yield-point value or destroying the low-end rheology of other components of the wellbore fluid.
- [0044]** Other additives that may be included in the wellbore fluids disclosed herein include for example, wetting agents, organophilic clays, soda ash, surfactants, shale inhibitors, filtration reducers, dispersants, interfacial tension reducers, pH buffers, mutual solvents, thinners (such as lignins and tannins), thinning agents and cleaning agents.

[0045] The water-based fluids described herein may be used during a drilling operation. The fluid may be pumped down to the bottom of the well through a drill pipe, where the fluid emerges through ports in the drilling bit, for example. In one embodiment, the fluid may be used in conjunction with any drilling operation, which may include, for example, vertical drilling, extended reach drilling, and directional drilling. One skilled in the art would recognize that water-based wellbore fluids may be prepared with a large variety of formulations. Specific formulations may depend on the state of drilling a well at a particular time, for example, depending on the depth and/or the composition of the formation. The wellbore fluid compositions described above may be adapted to provide improved water-based drilling muds under conditions of high temperature and pressure, such as those encountered in deep wells.

[0046] Sample Formulations

[0047] The following examples were used to test the effectiveness of water-based wellbore fluids that contain lubricants, anionic suppressants, and pH agents, as disclosed herein. In the following examples, various additives commercially available from M-I L.L.C. (Houston, Texas) are used, including: GELPLEX™, a gelling agent comprising untreated sodium bentonite; DRILPLEX™, a mixed metal oxide; FLO-PLEX®, a water-soluble polysaccharide derivative used to control filtration and to control fluid loss, and DUO TEC™, a viscosifier. Referring to Table 2, below, the formulations of the water-based wellbore fluids for Samples 1 and 2 are shown.

Table 2. Wellbore Fluid Formulations

Sample #	1		2	
GELPLEX™ : DRILPLEX™ ratio	9.0:0.95		9.0:0.95	
Water, pounds per barrel (ppb)	243.31		243.31	
Soda Ash, ppb	0.25		0.25	
Prehydrated GELPLEX™, ppb	105.00		105.00	
DRILPLEX™ Mixed Metal Oxide, ppb	0.95		0.95	
FLO-PLEX™, ppb	4.00		4.00	
Zinc Carbonate, ppb	0.70		0.70	
EP LUBE™ (vol %)	-		3.0	
Mud Weight, pound per gallon (ppg)	8.4		8.4	
Treatment	BHR	AHR	BHR	AHR
Treatment Temperature (°F)	RT	150	RT	150
Treatment Time (hours)	-	16	-	16
Rheology Temperature (°F)	120	120	120	120
VG RPM 600 Θ	53	53	46	24
VG RPM 300 Θ	42	47	33	18
VG RPM 200 Θ	38	44	28	15
VG RPM 100 Θ	33	39	23	11
VG RPM 6 Θ	27	33	17	9
VG RPM 3 Θ	26	32	16	7
PV (centiPoise (cP))	11	6	13	6
YP (lb/100ft ²)	31	41	20	12
10 Second Gel	28	36	18	10
10 Minute Gel	19	23	14	17
pH	10.3	10.1	10.5	10.0
Benchtop CoF	0.338	-	0.107	-

[0048] In Table 2, the rheological properties were tested using a Fan 35 viscometer. The 10 second gel is the strength of the gel ten seconds after application. The 10 minute gel is the strength of the gel ten minutes after application. The treatments

include before hot rolling (BHR) and after hot rolling (AHR), with some treatments performed at room temperature (RT). The rheological properties were further measured using plastic viscosity (PV), yield point (YP) and benchtop coefficient of friction (CoF).

[0049] Advantages of the embodiments disclosed herein may include enhanced rheological properties of the wellbore fluids that incorporate lubricants, anionic suppressants, and pH agents as described herein. The sulfur component of the lubricant may impart beneficial lubricity to the wellbore fluid. The wellbore fluids including lubricants, anionic suppressants, and pH agents as described herein advantageously provide for improved rheological properties of the fluid. Further, it has surprisingly been found that in some embodiments, fluids described herein having a P_f/M_f ratio of about 1:2 advantageously impart improved shear properties. In addition, use of pH agents may advantageously reduce air encapsulation and foaming. In some embodiments, a P_f/M_f ratio of about 1:2 may advantageously control foaming.

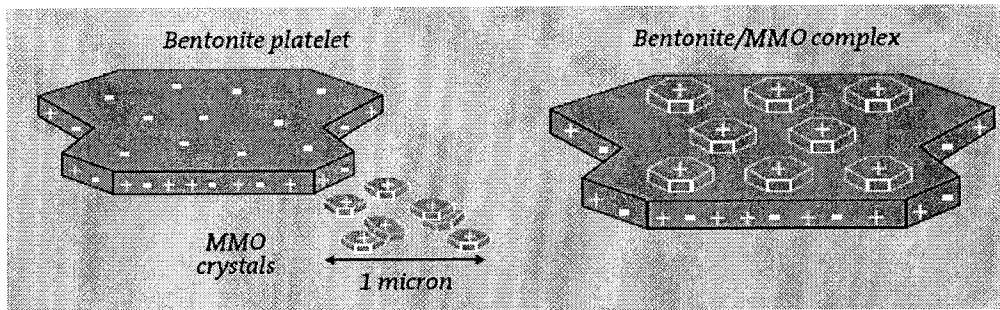
[0050] While the invention has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments can be devised which do not depart from the scope of the invention as disclosed herein. Accordingly, the scope of the invention should be limited only by the attached claims.

CLAIMS

What is claimed:

1. A water-based wellbore fluid, comprising:
an aqueous fluid;
a mixed metal oxide-clay complex;
an anionic suppressant, wherein the anionic suppressant comprises:
a Lewis acid;
a lubricant, wherein the lubricant comprises:
a sulfur containing compound; and
at least one pH agent, wherein the at least one pH agent is in an amount sufficient to obtain a pH ranging from about 9 to 13.
2. The wellbore fluid of claim 1, wherein the Lewis acid comprises magnesium carbonate, aluminum carbonate, iron carbonate, zinc carbonate, zinc chloride, diborane, boron trifluoride, dialuminum hexachloride, aluminum fluoride, silicon tetrafluoride, phosphorus pentachloride, and sulfur tetrafluoride, or combinations thereof.
3. The wellbore fluid of claim 1, wherein the sulfur containing compound is:
$$-[(CH_2)_m-S_x]_n-$$
4. The wellbore fluid of claim 1, wherein the mixed metal oxide-clay complex comprises at least one surface charged clay.
5. The wellbore fluid of claim 4, wherein the at least one surface charged clay comprises at least one of bentonite, saponite, hectonite, or kaolinite.
6. The wellbore fluid of claim 1, further comprising:
at least one of a gelling agent, a viscosifier, a bridging agent, a fluid loss control agent, a foaming agent, a wetting agent, a surfactant, a shale inhibitor, a filtration reducer, a dispersant, an interfacial tension reducer, a pH buffer, a mutual solvent, a thinner, a thinning agent, a cleaning agent, soda ash, or combinations thereof.

7. The wellbore fluid of claim 1, wherein the at least one pH agent is added to the wellbore fluid to give a P_f/M_f ratio of about 1:2.
8. A method of treating a wellbore, comprising:
 mixing an aqueous fluid, a mixed metal oxide-clay complex; an anionic suppressant, a lubricant, and at least one pH agent, to form a water-based wellbore fluid, wherein the anionic suppressant comprises:
 a Lewis acid; and
 wherein the lubricant comprises:
 a sulfur containing compound; and
 wherein the at least one pH agent is in an amount sufficient to obtain a pH ranging from about 9 to 13; and
 using said water-based wellbore fluid during a drilling operation.
9. The method of claim 8, wherein the Lewis acid comprises magnesium carbonate, aluminum carbonate, iron carbonate, zinc carbonate, zinc chloride, diborane, boron trifluoride, dialuminum hexachloride, aluminum fluoride, silicon tetrafluoride, phosphorus pentachloride, and sulfur tetrafluoride, or combinations thereof.
10. The wellbore fluid of claim 1, wherein the sulfur containing compound is:
 $-\text{[(CH}_2\text{)}_m\text{-S}_x\text{]}_n-$.
11. The method of claim 8, wherein the mixed metal oxide-clay complex comprises at least one surface charged clay.
12. The method of claim 11, wherein the at least one surface charged clay comprises at least one of bentonite, saponite, hectonite, or kaolinite.
13. The method of claim 8, wherein the at least one pH agent is added to the wellbore fluid to give a P_f/M_f ratio of about 1:2.

**Figure 1**