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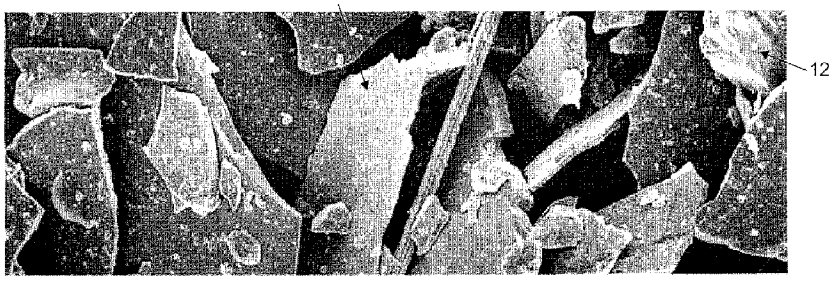


Fig. 1A

(57) Abstract: A wellbore fluid that includes a base fluid; and a lamellar weighting agent is disclosed. A method for drilling a formation with a wellbore fluid that includes a base fluid and a lamellar weighting agent is also disclosed.

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USE OF LAMELLAR WEIGHTING AGENTS IN DRILLING MUDS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to U.S. Patent Application Serial No. 60/890,550, filed on February 19, 2007, which is herein incorporated by reference in its entirety.

BACKGROUND OF DISCLOSURE

Field of the Invention

[0002] Embodiments disclosed herein relate generally to drilling fluids for use in drilling applications. In particular, embodiments disclosed herein relate to the use of lamellar weighting agents in drilling fluids.

Background Art

[0003] When drilling or completing wells in earth formations, various fluids typically are used in the well for a variety of reasons. Common uses for well fluids include: lubrication and cooling of drill bit cutting surfaces while drilling generally or drilling-in (i.e., drilling in a targeted petroliferous formation), transportation of "cuttings" (pieces of formation dislodged by the cutting action of the teeth on a drill bit) to the surface, controlling formation fluid pressure to prevent blowouts, maintaining well stability, suspending solids in the well, minimizing fluid loss into and stabilizing the formation through which the well is being drilled, fracturing the formation in the vicinity of the well, displacing the fluid within the well with another fluid, cleaning the well, testing the well, transmitting hydraulic horsepower to the drill bit, fluid used for emplacing a packer, abandoning the well or preparing the well for abandonment, and otherwise treating the well or the formation.

[0004] Many types of fluids have been used in wellbores particularly in connection with the drilling of oil and gas wells. The selection of an oil-based wellbore fluid involves a careful balance of both the good and bad fluid characteristics in a particular application. The primary benefits of selecting an oil-based drilling fluid include: superior hole stability, especially in shale formations; formation of a thinner filter cake than the filter cake achieved with a water based mud; excellent lubrication of the

drilling string and downhole tools; penetration of salt beds without sloughing or enlargement of the hole as well as other benefits that should be known to one of skill in the art. 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 and thus the use of the oil-based mud can be justified.

[0005] Despite the many benefits of using oil-based muds, they have disadvantages. In general, the use of oil-based drilling fluids and muds has high initial and operational costs. These costs can be significant depending on the depth of the hole to be drilled. However, often the higher costs can be justified if the oil-based drilling fluid prevents the caving in or hole enlargement which can greatly increase drilling time and costs.

[0006] In general, drilling fluids should be pumpable under pressure down through strings of drilling pipe, then through and around the drilling bit head deep in the earth, and then returned back to the earth surface through an annulus between the outside of the drill stem and the hole wall or casing. Beyond providing drilling lubrication and efficiency, and retarding wear, drilling fluids should suspend and transport solid particles to the surface for screening out and disposal. In addition, the fluids should be capable of suspending additive weighting agents (to increase specific gravity of the mud), generally finely ground barites (barium sulfate ore), and transport clay and other substances capable of adhering to and coating the borehold surface.

[0007] 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.

[0008] There is an increasing need for drilling fluids having the rheological profiles that enable these 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, helping to avoid exposing 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, because if this occurs it can lead to an uneven density profile within the circulating fluid system, possibly resulting in well control (gas/fluid influx) and wellbore stability problems (caving/fractures).

[0009] 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. Or 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, alternatively, it can lead to lost time if the force required to regain a fully circulating fluid system is beyond the limits of the pumps.

[0010] Wellbore fluids must also contribute to the stability of the wellbore, and control the flow of gas, oil, or water from the pores of the formation in order to prevent, for example, the flow or blow out of formation fluids or the collapse of pressured earth formations. The column of fluid in the hole exerts a hydrostatic pressure proportional to the depth of the hole and the density of the fluid. High-pressure formations may require a fluid with a specific gravity as high as 3.0.

[0011] A critical property differentiating the effectiveness of various wellbore fluids in achieving these functions is density, or mass per unit volume. The wellbore fluid must have sufficient density in order to carry the cuttings to the surface. Density also contributes to the stability of the borehole by increasing the pressure exerted by the wellbore fluid onto the surface of the formation downhole. The column of fluid in the borehole exerts a hydrostatic pressure (also known as a head pressure) proportional to the depth of the hole and the density of the fluid. Therefore, one can stabilize the borehole and prevent the undesirable inflow of reservoir fluids by carefully monitoring the density of the wellbore fluid to ensure that an adequate amount of hydrostatic pressure is maintained.

[0012] A variety of materials, or weighting agents, are presently used to increase the density of wellbore fluids. These include dissolved salts such as sodium chloride, calcium chloride, and calcium bromide. Alternatively, powdered minerals such as barite, calcite, dolomite, ilmenite, siderite, hausmannite (manganese tetroxide), hematite and other iron ores, and olivine are added to a fluid to form a suspension of increased density. Conventional weighting agents have an average particle diameter (d_{50}) in the range of 10-30 microns. However, despite the general industry disfavor, other approaches have used smaller particles as weighting agents. One approach, disclosed in U.S. Pat. No. 5,007,480, uses manganomanganic oxide (Mn_3O_4) having a particle size of at least 98% below 10 μm in combination with conventional weighting agents such as API grade barite, which results in a drilling fluid of higher density than that obtained by the use of barite or other conventional weighting agents alone.

[0013] One requirement of these wellbore fluid additives is that they form a stable suspension and do not readily settle out. A second requirement is that the suspension exhibits a low viscosity in order to facilitate pumping and to minimize the generation of high pressures. Finally, the wellbore fluid slurry should also exhibit low fluid loss.

[0014] As stated above, conventional weighting agents such as powdered barite exhibit an average particle diameter (d_{50}) in the range of 10-30 microns. A gellant, such as bentonite for water-based fluids or organically modified bentonite for oil-based fluids, is typically required to adequately suspend these materials. A soluble polymer viscosifier such as xanthan gum may be also added to slow the sedimentation rate of the weighting agent. However, as more gellant is added to increase the suspension stability, the fluid viscosity (plastic viscosity and/or yield point) increases undesirably, resulting in reduced pumpability. This is also the case if a viscosifier is used to maintain a desirable level of solids suspension.

[0015] The sedimentation or sag of particulate weighting agents within a drilling fluid becomes more critical in wellbores drilled at high angles from the vertical, in that a sag of, for example, one inch (2.54 cm) can result in a continuous column of reduced density fluid along the upper portion of the wellbore wall. Such high angle wells are frequently drilled over large distances in order to access, for example, remote portions of an oil reservoir. In such instances it is important to minimize a drilling fluid's plastic viscosity in order to reduce the pressure losses over the borehole length. At the same time, a sufficiently high fluid density also should be maintained to counterbalance wellbore fluid ingress and/or a well control incident (blow out).

[0016] Conventional additives may also include bridging agents. Bridging agents within the fluid restrict the flow of fluid into undesirable, overtreated, or depleted areas of the wellbore and diverts the treatment into the primary areas of interest and production potential. Within a fracture, fine particulate fluid loss additives restrict leak-off of the fluid into the formation permeability or hairline fractures exposed at the fracture face. This restriction of leak-off maintains the integrity of the fluid. In other words, solids added to a drilling fluid to bridge across the pore throats or fractures of an exposed rock thereby building a filter cake to prevent loss of whole mud or excessive filtrate. For example, U.S. Patent No. 5,826,669 issued to Zaleski, et al. describes the use of a synthetic graphite additive to prevent or control the loss of well drilling fluid into the pores and fractures of subterranean rock formations. Pores and fractures in shales, sandstones, and the like are effectively sealed with resilient graphitic carbon particles that can be tightly packed under compression in the pores and fractures. The graphitic particles can expand or contract without being dislodged

or collapsing due to changes in the equivalent circulating density or with an increase in fluid weight.

[0017] Currently, while the use of iron oxides, synthetic graphites, and other metal oxides as additives to drilling fluids is well known in the art, there exists room for improvement in a fluid's with barrier, rheological, and anti-settling properties. Accordingly, there exists a continuing need for high density drilling fluids having improved barrier, rheological, and anti-settling properties.

SUMMARY OF INVENTION

[0018] In one aspect, embodiments disclosed herein relate to a wellbore fluid that includes a base fluid and a lamellar weighting agent.

[0019] In another aspect, embodiments disclosed herein relate to a method for drilling a formation that includes mixing a base fluid and a weighting agent, wherein the weighting agent is a lamellar metal oxide compound to form a wellbore fluid, and drilling the formation using the wellbore fluid.

[0020] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0021] FIG. 1A is scanning electron micrograph of lamellar particles according to one embodiment of the present disclosure.

[0022] FIG. 1B is a scanning electron micrograph of conventional non-lamellar weighting agents.

DETAILED DESCRIPTION

[0023] In one aspect, embodiments disclosed herein relate to the use of lamellar weighting agents in wellbore fluids used in drilling applications. In a particular embodiment, the wellbore fluid may include a base fluid and a lamellar metal oxide weighting agent.

[0024] *Lamellar Weighting Agent*

[0025] Weighting agent, as used herein, refers to a finely-divided solid material having a high-specific gravity used to increase density of a wellbore fluid. The type and quantity of a weighting agent used depends upon the desired density of the final drilling fluid composition. Typical weighting agents include, but are not limited to, suspendable solids such as, for example, barite, iron oxide, calcium carbonate, magnesium carbonate, and combinations of such materials and derivatives of such materials and dissolvable solids such as, for example, calcium bromide, calcium chloride, and other salts which may be optionally included in the brine solution with the at least one of calcium bromide and calcium chloride.

[0026] The density of weighting agents generally impacts the density of the wellbore fluid. Generally, the higher the weighting agent density, the greater the impact on the wellbore fluid density and other density-affected properties. Barite, for example, has a minimum specific gravity of 4.20 g/cm^3. Hematite is a more dense material, with a minimum specific gravity of 5.05 g/cm^3, per API and ISO specifications. Calcium carbonate, with a specific gravity of 2.7 to 2.8 g/cm^3, is considered a weighting agent but is used more for its acid solubility than for density. Siderite, with a specific gravity around 3.8 g/cm^3, has been used to densify mud, but can cause problems by dissolving into the mud at high pH. Ilmenite, with a specific gravity of 4.6 g/cm^3 has been used in drilling mud and cement. Those of ordinary skill in the art will appreciate the advantages associated with higher density weighting agents.

[0027] In one embodiment of the present disclosure, lamellar weighting agents may exhibit an increase in density as compared to conventional weighting agents. For example, the specific gravity of lamellar weighting agents suitable for use in the present fluids may be greater than 4.7 g/cm^3, in one embodiment, and may range from 4.8 g/cm^3 to 6.0 g/cm^3, in another embodiment.

[0028] The lamellar shape of the weighting agent, as used herein, refers to a delicate flat, thin, sheet-like particle with a finite lateral dimension. Lamellar particles, or flakes, may be created through a combination of various processes, such as cleavage and fracture, and depend, in part, on crystal habit. Cleavage refers to the splitting of a crystal along a smooth plane. A cleavage plane is a plane of structural weakness

along which a particle is likely to split. The quality of a particle's cleavage refers both to the ease with which the particle's cleaves and to the character of the exposed surface. Fracture takes place when a particle sample is split in a direction which does not serve as a plane of perfect or distinct cleavage. A particle fractures when it is broken or crushed. Fracture does not result in the emergence of clearly demarcated planar surfaces; particles may fracture in any possible direction. The term crystal habit describes the favored growth pattern of the crystals of a particle species. The crystals of particular particle species sometimes form very distinctive, characteristic shapes. Crystal habit is also greatly determined by the environmental conditions under which a crystal develops. Lamellar particles include, but are not limited to, metal oxides, such as micaceous metal oxide. Other examples may include, but are not limited to, dolomite and barite. Those of ordinary skill in the art will appreciate the advantages associated with lamellar particles as used in wellbore fluids.

[0029] Fig. 1A is a scanning electron micrograph of a lamellar particle. Those of ordinary skill in the art will appreciate that Fig. 1A is only exemplary of a lamellar particle and does not limit the present disclosure. Referring to Fig. 1A, lamellar structures 10 may exist alone or in combination with non-lamellar structures 12. As shown in Fig. 1A, lamellar particles 10 may overlap each with each other. Referring to Fig. 1B, a conventional sample of weighting agents containing non-lamellar structures 12 is shown. In one embodiment, the lamellar content of a sample of a weighting agent may range from 65% to 95% of the weighting agent. In another embodiment, the lamellar content of a sample of a weighting agent may range from 75% to 95% of the weighting agent. In yet another embodiment, the lamellar content of a sample of a weighting agent may range from 85% to 95% of the weighting agent. Those of ordinary skill in the art will appreciate that the remaining non-lamellar content may be of various shapes and sizes. In various embodiments, the non-lamellar structures may include conventional weighting agents or micronized weighting agents, such as those disclosed in U.S. Patent Application No. 2005/0277553 and herein incorporated by reference.

[0030] In one embodiment, the lamellar weighting agent may be a lamellar metal oxide. The shape of the lamellar metal oxide may vary significantly. As discussed above, crystal habit, external and internal stresses, areas of cleavage, and resulting

fracture determine each individual flake-like shape. Generally, each lamellar weighting agent particle will have a face, length, and thickness. The length is measured between the two furthest points on a particle's face. The lamellar weighting agent, and lamellar metal oxide in a particular embodiment, may have an average length of less than 100 microns in one embodiment, less than 60 microns in another embodiment, and less than 20 microns in yet another embodiment. In a particular embodiment, the lamellar weighting agent may have an average length ranging from about 40 to 50 microns. The lamellar metal oxides may have an average platelet thickness of less than 10 microns in one embodiment, less than 5 microns in another embodiment, and less than 2 microns in yet another embodiment. Particle size measurements may be performed using laser diffractometry or other methods known in the art.

[0031] In a particular embodiment, the lamellar weighting agent may include micaceous iron oxide (Fe_2O_3). The term "micaceous," as used herein, means thin, flat sheets formed from crystals with one direction of cleavage. Micaceous iron oxide is a naturally occurring lamellar form of ferrous oxide. While micaceous iron oxide is one embodiment of a lamellar weighting agent, those of ordinary skill in the art will appreciate that lamellar weighting agents of the present disclosure may also include any other weighting agent possessing a lamellar crystal habit.

[0032] Examples of products of micaceous iron oxide commercially available from MIOX (Cannock, United Kingdom) are listed in Table 1 below.

Table 1

Product	MIOX® AS	MIOX® SG	MIOX® DB
Color	grey with metallic sheen	grey with metallic sheen	grey with metallic sheen
Particle form	lamellar	lamellar	lamellar
Particle size	fine	standard	coarse
Grade	1	1	1
Type	1	2	3
Iron content (Fe_2O_3)	> 85	> 85	> 85
Density g/cm^3	4.7-4.9	4.7-4.9	4.7-4.9
Water-soluble matter %	< 0.3	< 0.3	< 0.3
pH	9 +/- 1	9 +/- 1	9 +/- 1
Residue on sieve % 100 um 63 um	 trace max. 5 %	 trace 5-15%	 trace 25-35%

[0033] *Drilling Fluid Formulations*

[0034] The drilling fluids that may be mixed according to the embodiments disclosed herein may include water-based fluids, invert emulsions, and oil-based fluids.

[0035] Water-based wellbore fluids may include an aqueous base fluid. The aqueous 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 drilling 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, sulfur, aluminum, magnesium, potassium, strontium, silicon, lithium, and phosphorus salts of chlorides, bromides, carbonates, iodides, chlorates, bromates, formates, nitrates, oxides, 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 drilling 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 drilling 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. One of ordinary skill would appreciate that the above salts may be present in the base fluid, or alternatively, may be added according to the method disclosed herein.

[0036] Oil-based fluids may include an invert emulsion having an oleaginous continuous phase and a non-oleaginous discontinuous phase. The oleaginous fluid may be a liquid and more preferably may be a natural or synthetic oil and more preferably the oleaginous fluid is selected from the group including diesel oil, mineral oil, a synthetic oil, (*e.g.*, hydrogenated and unhydrogenated olefins including polyalpha olefins, linear and branch olefins and the like, polydiorganosiloxanes, siloxanes, or organosiloxanes, esters of fatty acids, specifically straight chain,

branched and cyclical alkyl ethers of fatty acids, mixtures thereof and similar compounds known to one of skill in the art), and mixtures thereof. The concentration of the oleaginous fluid should be sufficient so that an invert emulsion forms and may be less than about 99% by volume of the invert emulsion. In one embodiment the amount of oleaginous fluid is from about 30% to about 95% by volume, and more preferably about 40% to about 90% by volume of the invert emulsion fluid. The oleaginous fluid, in one embodiment, may include at least 5% by volume of a material selected from the group including esters, ethers, acetals, dialkylcarbonates, hydrocarbons, and combinations thereof.

[0037] The non-oleaginous fluid used in the formulation of the invert emulsion fluid disclosed herein is a liquid and may be an aqueous liquid. In one embodiment, the non-oleaginous liquid may be selected from the group including sea water, a brine containing organic and/or inorganic dissolved salts, liquids containing water-miscible organic compounds and combinations thereof. The amount of the non-oleaginous fluid is typically less than the theoretical limit needed for forming an invert emulsion. Thus in one embodiment, the amount of non-oleaginous fluid may be less that about 70% by volume and preferably from about 1% to about 70% by volume. In another embodiment, the non-oleaginous fluid may preferably be from about 5% to about 60% by volume of the invert emulsion fluid. The fluid phase may include either an aqueous fluid, an oleaginous fluid, or mixtures thereof.

[0038] Typically, a number of compounds are added to wellbore fluids. Other additives that may be included in the wellbore fluids disclosed herein include for example, weighting agents, wetting agents, organophilic clays, viscosifiers, fluid loss control agents, surfactants, dispersants, interfacial tension reducers, pH buffers, mutual solvents, thinners, thinning agents and cleaning agents. The addition of such agents should be well known to those of ordinary skill in the art of formulating wellbore fluids.

[0039] Conventional weighting agents may be added to the wellbore fluid in addition to the lamellar weighting agent. The additional weighting agents used in embodiments disclosed herein may include a variety of compounds known to those of skill in the art. In a particular embodiment, the additional weighting agent may be selected from materials including, for example, barium sulphate (barite), calcium

carbonate, dolomite, ilmenite, hematite, olivine, siderite, strontium sulphate, hausmannite, and other minerals such as other metal carbonates and oxides. In some embodiments, these weighting agents may be chemically modified. The quantity of material added, if any, depends upon the desired density of the final composition. Typically, weight material is added to result in a drilling fluid density of up to about 19 pounds per gallon in one embodiment; and ranging from 9.5 to 14 pounds per gallon in another embodiment. Alternatively, the drilling fluid may be formed from a concentrated mud, such as a 16 pound per gallon mud, or heavier which is be blended with additional bore fluid prior to use to the desired formulation. One having ordinary skill in the art would recognize that selection of a particular material may depend largely on the density of the material, as the lowest wellbore fluid viscosity at any particular density is typically obtained by using the highest density particles. However, other considerations may influence the choice of product, such as cost, local availability, the power required for grinding, and whether the residual solids or filter cake may be readily removed from the well.

[0040] Additional bridging agents may be added to the fluid compositions of embodiments of the disclosure for additional functional properties. The addition of such agents should be well known to those of ordinary skill in the art of formulating drilling fluids and muds. However, it should be noted that the addition of such agents should not adversely interfere with the properties associated with the mud's ability to solidify as described herein.

[0041] Deflocculants or thinners that may be used in the drilling fluids disclosed herein include, for example, lignosulfonates, modified lignosulfonates, polyphosphates, tannins, and low molecular weight water soluble polymers, such as polyacrylates. Deflocculants are typically added to a drilling fluid to reduce flow resistance and control gelation tendencies. In a particular embodiment, a deflocculant may be desirable when a drilling fluid is formed from a heavier mud diluted withsea water. TANNATHIN®, an oxidized lignite, is an example of a deflocculant which is available from M-I L.L.C. (Houston, Texas).

[0042] The fluids disclosed herein are especially useful in the drilling, completion and working over of subterranean oil and gas wells. In particular the fluids disclosed herein may find use in formulating drilling muds and completion fluids that allow for

the easy and quick removal of the filter cake. Such muds and fluids are especially useful in the drilling of horizontal wells into hydrocarbon bearing formations.

[0043] Conventional methods can be used to prepare the drilling fluids disclosed herein in a manner analogous to those normally used, to prepare conventional oil-based drilling fluids. In one embodiment, a desired quantity of oleaginous fluid such as a base oil and a suitable amount of polyesteramide surfactact are mixed together and the remaining components are added sequentially with continuous mixing. An invert emulsion may be formed by vigorously agitating, mixing or shearing the oleaginous fluid and the non-oleaginous fluid.

[0044] Advantageously, embodiments disclosed herein provide for at least one of the following. Generally, the embodiments disclosed herein provide a high density weighting agent with the morphological advantages of lamellar particles. The nature of the compounds disclosed herein may allow for fluids with extremely low fluid loss such that the fluid hydraulics allow for reduced pressure required to circulate the fluid. The plate-like structure may also impart useful and improved rheological and anti-settling features to a fluid such that the fluids remove cuttings from the wellbore efficiently and effectively. In addition, the nature of the compounds disclosed herein may allow for fluids with improved bridging properties.

[0045] Additionally, the network of overlapping platelets, or flakes, may settle substantially parallel to each to each other to create a protective barrier over a base. The protective barrier may form over a void in the base caused by a crack or a structural imperfection, thus substantially sealing the void or imperfection from further penetration.

[0046] 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 wellbore fluid comprising:
   a base fluid; and
   a lamellar weighting agent.

2. The wellbore fluid of claim 1, wherein the lamellar weighting agent comprises a lamellar metal oxide compound.

3. The wellbore fluid of claim 1, wherein the lamellar metal oxide comprises micaceous iron oxide.

4. The wellbore fluid of claim 1, wherein the weighting agent has a particle size of less than 60 microns.

5. The wellbore fluid of claim 4, wherein the weighting agent has a particle size of less than 30 microns.

6. The wellbore fluid of claim 1, wherein the weighting agent further comprises at least one non-lamellar weighting agent.

7. The wellbore fluid of claim 1, wherein the base fluid comprises at least one of an oleaginous fluid and a non-oleaginous fluid.

8. The wellbore fluid of claim 7, wherein the base fluid phase comprises the oleaginous fluid, wherein the oleaginous fluid is a continuous phase of the wellbore fluid.

9. The wellbore fluid of claim 7, wherein the base fluid phase comprises the non-oleaginous fluid, wherein the non-oleaginous fluid is a discontinuous phase of the wellbore fluid.

10. The wellbore fluid of claim 7, wherein the base fluid phase comprises the non-oleaginous fluid, wherein the non-oleaginous fluid is a continuous phase of the wellbore fluid.

11. The wellbore fluid of claim 7, wherein the oleaginous fluid comprises at least one of diesel oil, mineral oil, synthetic oil, esters, ethers, acetals, di-alkylcarbonates, olefins, and combinations thereof.

12. The wellbore fluid of claim 7, wherein the non-oleaginous fluid comprises at least one of fresh water, sea water, a brine containing organic or inorganic dissolved salts, a liquid containing water-miscible organic compounds, and combinations thereof.

13. The wellbore fluid of claim 1, wherein the wellbore fluid further comprises at least one of viscosifier, wetting agent, emulsifier, surfactant, depressant, thinner, fluid loss control agent, clay, and combinations thereof.

14. A method for drilling through a formation, comprising:
mixing a base fluid and a weighting agent, wherein the weighting agent is a lamellar metal oxide compound to form a wellbore fluid; and
drilling through the formation using the wellbore fluid.

15. The method of claim 14, wherein the lamellar metal oxide comprises micaceous iron oxide.

16. The method of claim 14, wherein the weighting agent has a particle size of less than 60 microns.

17. The method of claim 16, wherein the weighting agent has a particle size of less than 30 microns.

18. The method of claim 14, wherein the weighting agent further comprises at least one non-lamellar weighting agent.

19. The method of claim 14, wherein the base fluid comprises at least one of an oleaginous fluid and a non-oleaginous fluid.

20. The method of claim 19, wherein the base fluid phase comprises the oleaginous fluid, wherein the oleaginous fluid is a continuous phase of the wellbore fluid.

21. The method of claim 19, wherein the base fluid phase comprises the non-oleaginous fluid, wherein the non-oleaginous fluid is a discontinuous phase of the wellbore fluid.

22. The method of claim 19, wherein the base fluid phase comprises the non-oleaginous fluid, wherein the non-oleaginous fluid is a continuous phase of the wellbore fluid.

23. The method of claim 19, wherein the oleaginous fluid comprises at least one of diesel oil, mineral oil, synthetic oil, esters, ethers, acetals, di-alkylcarbonates, olefins, and combinations thereof.

24. The method of claim 19, wherein the non-oleaginous fluid comprises at least one of fresh water, sea water, a brine containing organic or inorganic dissolved salts, a liquid containing water-miscible organic compounds, and combinations thereof.

25. The method of claim 14, wherein the wellbore fluid further comprises at least one of viscosifier, wetting agent, emulsifier, surfactant, depressant, thinner, fluid loss control agent, clay, and combinations thereof.

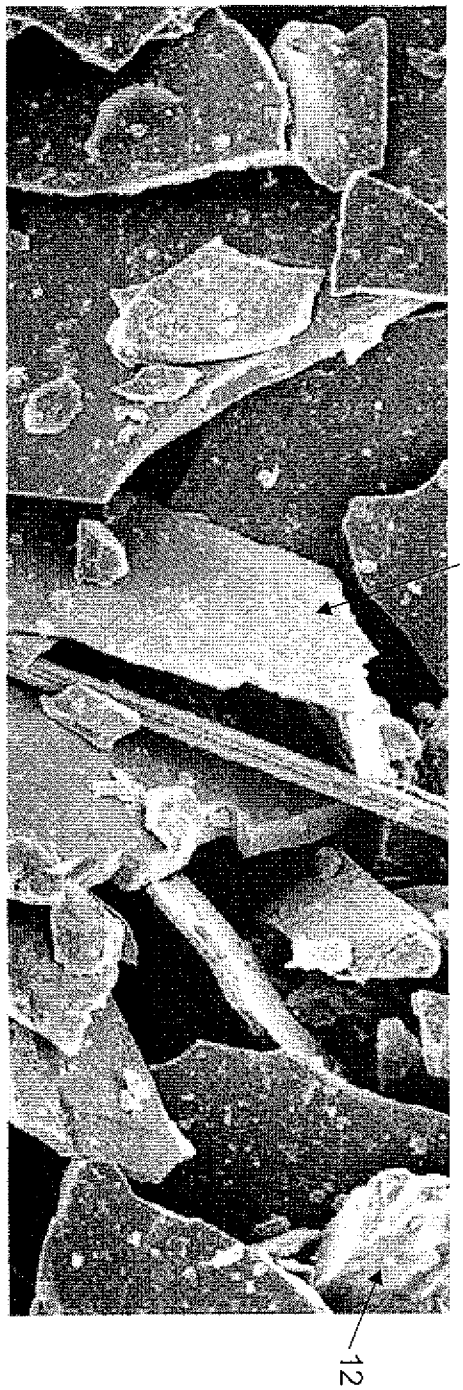


Fig. 1A

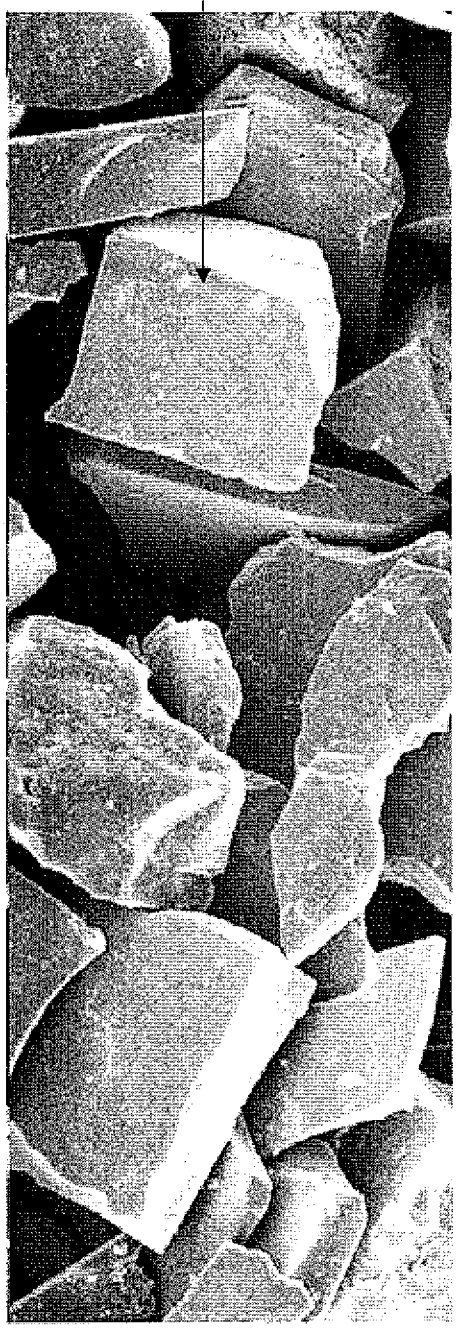


Fig. 1B

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2008/054000

A. CLASSIFICATION OF SUBJECT MATTER

C09K 8/32(2006.01)i, C09K 8/02(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 8 : C09K, E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKIPASS(KIPO internal), Espacenet

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X ----- Y	US 4,541,485 B (BLOCK, JACOB) 17 SEP 1985 See abstract; column 7, lines 1-30; claims 1-24	1-7, 14-19 ---------- 8-13, 20-25
Y ----- A	US 6,790,811 B2 (PATEL, A.D.) 14 SEP 2004 See abstract; column 3, line 41-column 9, line 23; claims 1-17	8-13, 20-25 ---------- 1-7, 14-19
Y ----- A	US 6,770,602 B2 (PATEL, A.D. et al) 3 AUG 2004 See abstract; column 2, line 8-column 7, line 2; claims 1-34	8-13, 20-25 ---------- 1-7, 14-19
A	US 2005/0277553 A1 (MASSAM, JARROD et al.) 15 DEC 2005 See the whole document	1-25

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
31 JULY 2008 (31.07.2008)	**31 JULY 2008 (31.07.2008)**
Name and mailing address of the ISA/KR Korean Intellectual Property Office Government Complex-Daejeon, 139 Seonsa-ro, Seo-gu, Daejeon 302-701, Republic of Korea Facsimile No. 82-42-472-7140	Authorized officer LYU Eun Kyoung Telephone No. 82-42-481-8399

Form PCT/ISA/210 (second sheet) (July 2008)

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

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