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(57) Abrégé/Abstract:
A method of removing clay compounded on drilling equipment in a well that includes contacting the drilling equipment with a treatment fluid comprising an oxidizing agent. Methods disclosed also relate to drilling a wellbore though a clay-containing formation that includes drilling through the formation with a water-containing drilling fluid; reducing applied weight-on-bit when bit balling detected; emplacing a treatment fluid comprising an oxidizing agent to disrupt clay compounded on drilling equipment; and increasing weight-on-bit to continue drilling through the formation

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(54) **Title**: METHOD OF REMEDIATING BIT BALLING USING OXIDIZING AGENTS

(57) **Abstract**: A method of removing clay compounded on drilling equipment in a well that includes contacting the drilling equipment with a treatment fluid comprising an oxidizing agent. Methods disclosed also relate to drilling a wellbore though a clay-containing formation that includes drilling through the formation with a water-containing drilling fluid; reducing applied weight-on-bit when bit balling detected; emplacing a treatment fluid comprising an oxidizing agent to disrupt clay compounded on drilling equipment; and increasing weight-on-bit to continue drilling through the formation

# METHOD OF REMEDIATING BIT BALLING USING OXIDIZING AGENTS

## BACKGROUND OF INVENTION

### Field of the Invention

**[0001]** Embodiments disclosed herein relate generally to methods for treating drilling equipment in a well. In particular, embodiments disclosed herein relate to chemical treatment of bit balling or clay compounded on a drill bit or other drilling equipment.

### Background Art

**[0002]** Hydrocarbons are found in subterranean formations. Production of such hydrocarbons is generally accomplished through the use of rotary drilling technology, which requires the drilling, completing and working over of wells penetrating producing formations.

**[0003]** To facilitate the drilling of a well, fluid is circulated through the drill string, out the bit and upward in an annular area between the drill string and the wall of the borehole. 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]** The selection of the type of drilling fluid to be used in a drilling application involves a careful balance of both the good and bad characteristics of the drilling fluids in the particular application and the type of well to be drilled. However, historically, water based drilling fluids have been used to drill a majority of wells.

Their lower cost and better environment acceptance as compared to oil based drilling fluids continue to make them the first option in drilling operations. Frequently, the selection of a fluid may depend on the type of formation through which the well is being drilled.

**[0005]** The types of subterranean formations, intersected by a well, include sandstone, limestone, shale, siltstone, etc., many of which may be at least partly composed of clays, including shales, mudstones, siltstones, and claystones. In penetrating through such formations, many problems may be encountered including bit balling, swelling or sloughing of the wellbore, stuck pipe, and dispersion of drill cuttings. This may be particularly true when drilling with a water-based fluid due to the high reactivity of clay in an aqueous environment. When dry, the clay has too little water to stick together, and it is thus a friable and brittle solid. Conversely, in a wet zone, the material is essentially liquid-like with very little inherent strength and can be washed away. However, intermediate to these zones, the shale is a sticky plastic solid with greatly increased agglomeration properties and inherent strength.

**[0006]** When drilling a subterranean well, as the drill bit teeth penetrate the formation, drill chips are generated by the action of the bit. When these cuttings are exposed to conventional water-based muds, they usually imbibe water and are rapidly dispersed. However recent advances in drilling fluid technology have developed highly inhibitive muds which appear to reduce the hydration of shale and in doing so produce sticky, plastic shale fragments. These fragments adhere to each other and to the bottomhole assembly and cutting surfaces of the drill bit, gradually forming a large compacted mass of clay on the drilling equipment. This process, or phenomenon, of accumulation and impacting is generally referred to as "balling" or "packing off" of the drilling equipment.

**[0007]** Clay swelling during the drilling of a subterranean well can have a tremendous adverse impact on drilling operations. Bit balling reduces the efficiency of the drilling process because the drillstring eventually becomes locked. This causes the drilling equipment to skid on the bottom of the hole preventing it from penetrating uncut rock, therefore slowing the rate of penetration. Furthermore the overall increase in bulk volume accompanying clay swelling impacts the stability of the borehole, and impedes removal of cuttings from beneath the drill bit, increases

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friction between the drill bit and the sides of the borehole, and inhibits formation of the thin filter cake that seals formations. Clay swelling can also create other drilling problems such as loss of circulation or stuck pipe and increased viscosity of the drilling fluid that slow drilling and increase drilling costs. There have been advances in drilling fluid technology for the design of shale inhibitive fluids as well as drill bit technology; however, when a shale formation is unexpectedly encountered, or when bit balling nonetheless occurs, the downtime associated with either soaking the bit or tripping the bit is very costly and undesirable.

**[0008]** Thus, given the frequency in which shale is encountered in drilling subterranean wells, the development of methods for reducing or treating clay swelling remains a continuing challenge in the oil and gas exploration industry.

## SUMMARY OF INVENTION

**[0009]** In one aspect, embodiments disclosed herein relate to a method of removing clay compounded on drilling equipment in a well that includes contacting the drilling equipment with a treatment fluid comprising an oxidizing agent. Specifically, the clay compounded on the drilling equipment may be contacted. In a more specific embodiment, the invention relates to a method of removing clay compounded on drilling equipment in a well, comprising: contacting clay compounded on the drilling equipment with a treatment fluid comprising an oxidizing agent, wherein the oxidizing agent comprises at least one of alkali metal perborates, alkali metal persilicates, and perphosphates.

**[0010]** In another aspect, embodiments disclosed herein relate to a method of drilling a wellbore though a clay-containing formation that includes drilling through the formation with a water-containing drilling fluid; reducing applied weight-on-bit when bit balling detected; emplacing a treatment fluid comprising an oxidizing agent to disrupt clay compounded on drilling equipment; and increasing weight-on-bit to continue drilling through the formation.

**[0011]** Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

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## DETAILED DESCRIPTION

**[0012]** Embodiments disclosed herein are directed to methods that enable the removal of clay compounded on a drill bit (or other drilling equipment) in a well. In particular, embodiments disclosed herein are directed to contacting the drilling assembly with a treatment fluid which comprises an oxidizing agent.

**[0013]** Clay minerals are generally crystalline in nature. The structure of the clay's crystals determines its properties. Typically, clays have a flaky, mica-type structure. 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. The distance between corresponding planes in adjacent unit layers is called the c-spacing.

**[0014]** Clay swelling is a phenomenon in which water molecules surround a clay crystal structure and position themselves to increase the structure's c-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 c-spacing. All 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 c-spacing is increased. Osmotic swelling results in larger overall volume increases than surface hydration. However, only certain clays, like sodium montmorillonite, swell in this manner.

**[0015]** Stress increases can induce brittle or tensile failure of the formations, leading to sloughing, cave in, and stuck pipe. Volume increases reduce the mechanical strength of shales and cause swelling of wellbore, disintegration of cuttings in drilling fluid. The swelled excavated earth adheres to the walls of the wellbore and of the drilling equipment and forms a compact hard mass which gradually fills the entire wellbore annulus thus balling up of drilling tools and reducing the effectiveness of the drilling bit.

**[0016]** Once clays have hydrated and compounded on a piece of drilling equipment, to avoid tripping / replacing the bit, various drilling techniques are conventionally attempted, including reducing weight on bit, increasing flow rate, and increasing RPM while the bit is off bottom, while soaking the bit in fresh water (so that the compounded clays can pass into their wet, dispersed state). However, in accordance with embodiments of the present disclosure, a treatment fluid comprised of an

aqueous based fluid in which an oxidizing agent is incorporated prior to delivery to the balled up drilling equipment may be used to expedite remediation of the balled up equipment so that drilling may continue.

**[0017]** According to an embodiment of the present disclosure, the oxidizing agent comprises at least one peroxide. As used herein, "peroxide" refers to any organic and inorganic compounds whose structures include the peroxy-group, -O-O-. The characteristic properties of peroxide compounds are the liberation of oxygen as a result of thermal decomposition and the decomposition into oxygen and water. Inorganic peroxides (such as alkali or alkaline earth metals) first decompose into a metal hydroxide and hydrogen peroxide, prior to the decomposition of hydrogen peroxide into oxygen and water. Their use as an oxidizing agent results from the instability of the peroxy bond. However, one skilled in the art would appreciate that the rate of decomposition is dependent on the temperature and concentration of the peroxide, as well as on the pH and the presence of impurities and stabilizers. Thus, in various embodiments, the oxidizing agent may comprise at least one compound selected from the group consisting of hydrogen, alkali metal and alkaline earth metal peroxides and of inorganic salts of peroxyacids (also referred to as peracids) such as alkali metal percarbonates and perborates. In other embodiments, the oxidizing agent may comprise at least one compound chosen from the group consisting of hydrogen peroxide, sodium percarbonate, and sodium perborate. In a particular embodiment, the oxidizing agent may be sodium percarbonate. Use of sodium percarbonate may be particularly desirable in some embodiments, because when used in a wellbore to aid in the removal of compounded clays from drilling equipment, the byproducts of the reactions may include oxygen, water, and sodium carbonate (soda ash).

**[0018]** Further, while several particular compounds have been described above, one skilled in the art would appreciate that no limitation on the type of peroxy compound is intended by the present disclosure. Rather, similar to the peroxides cited above, which are active oxygen-releasing peroxide compounds, any compound that similarly are a source of hydrogen peroxide (such as by hydrolysis) may be used in the fluids and methods of the present disclosure.

**[0019]** Further, one skilled in the art would also appreciate that when selecting the oxidizing agent(s) for use in the treatment fluids according to the present disclosure, the chemistry of the drilling fluid used for the drilling operations may need to be taken into consideration. Indeed the treatment fluid, during the treatment period, may likely be in contact with the drilling fluid, which may have a very complex chemistry, and comprise a variety of different additives. Further, these additives could potentially react with the various compounds used in the treatment fluid to form by-products that may be undesirable. Thus, the type of oxidizing agent used in the methods of the present disclosure may be chosen depending on the types of additives within the drilling fluid. For example, if biopolymers are contained within the drilling fluid, one skilled in the art may choose an oxidizing agent other than a perborate, as the borate by product may cause undesirable gellation of the biopolymers.

**[0020]** Further, the oxidizing agents used in the fluids and methods disclosed herein may be stored at the drilling site (the rig), so as to be readily available and for immediate use once bit balling has been detected in the well. However, as one with skill in the art would appreciate, rigs' environments are usually humid and, as mentioned above, peroxides are highly reactive to water and moist environments. As a consequence, it may be desirable to prepare the oxidizing agent in such as manner so as to be stable when stored at the rig's conditions (temperature, humidity) in order to provide a long shelf life. Moreover, it may also be desirable to use an oxidizing agent having a delayed activity so that once mixed with the aqueous based continuous phase, the oxidizing agent may be protected so as to prevent it from generating all of the hydrogen peroxide during the mixing process or during emplacement in the wellbore. However, the delay should not be so great so as to prevent rapid release once emplaced. This delay may be achieved by any techniques known from one skilled in the art such by, for example, encapsulation or acid stabilization with conventional compounds used in these techniques and known to those with skill in the art.

**[0021]** According to a particular embodiment of the present disclosure, the oxidizing agent may be an encapsulated oxidizing agent. The use of capsules for the slow or controlled release of liquid or solid active ingredient and for the protection of the

active ingredient from any interactions with the exterior medium is well known in the art. For example, use of encapsulated oxidants is described in U.S. Patent No. 6,861,394, which is assigned to the present assignee.

Typically, capsules may be formed by physical methods

such as spray coating, spray drying, pan coating, rotary disk atomization and the like; and chemical methods such as phase separation, interfacial polymerization and the like. Generally, release rates and solubility of the capsules are governed by the encapsulating material, capsule particle size, the thickness of the wall, the permeability of the wall, as well as external environmental triggers. Thus, for example, the oxidizing agent may be provided with a coating sufficient to control the release of oxidant until a set of conditions selected by the operator occurs. Some general encapsulating materials may include natural and synthetic oils, natural and synthetic polymers and enteric polymers and mixtures thereof. However, many methods of encapsulating may alternatively be used.

However, the encapsulant may be any conventional

compound known to be used in such technique by one skilled in the art. In a particular embodiment, the encapsulant is a styrene-based polymer.

**[0022]** Many methods may be used to cause the release of the oxidant upon the occurrence of specific conditions desired by the operator. For example, the oxidant could be caused to be released by a change in temperature, pressure, pH, abrasion or any number of these or other environmental factors. In a particular embodiment, the method by which the oxidant is released from the encapsulating material for the disturbing compounded clays in a subterranean well is by having the oxidant release upon a change in pH in the downhole environment.

**[0023]** According to another particular embodiment, the oxidizing agent may be an acid stabilized oxidizing agent. As one with skill in the art would appreciate an acidic material may be added to a hydrogen peroxide solution in order to prevent its decomposition in water and oxygen. For example, hydrogen peroxide is typically stabilized with phosphoric acid and/or acetanilide; however, one skilled in the art would appreciate that the present disclosure is not so limited.

**[0024]** Upon formulation, the treatment fluid may comprise from 0.0014 kg/L (0.5 lb/bbl) to 0.1427 kg/L (50 lb/bbl) of the oxidizing agent in some embodiments, and

from 0.0143 kg/L (5 lb/bbl) to 0.1141 kg/L (40 lb/bbl) of the oxidizing agent in other embodiments.

**[0025]** The aqueous based continuous phase of the treatment fluid may be any water based fluid that is compatible with the oxidizing agent disclosed herein. The aqueous based continuous phase may be selected from fresh water, sea water, mixture of water and water soluble organic compounds and mixtures thereof. The amount of the aqueous based continuous phase should be sufficient to form a water based treatment fluid.

**[0026]** The treatment fluid of the present disclosure may comprise a weighting agent known in the art in order to increase the density of the fluid, as required for use in a wellbore. The primary purpose for such weighting agents is to increase density of the treatment fluid so as to give it the density necessary to sit in the region of the compounded clay. That is, if the treatment fluid is not dense enough, it will float up the wellbore. Additionally, if the fluid doesn't have the appropriate density, then the pressures from the formation will be greater (or lower) than the hydrostatic pressure of the fluid against the wellbore walls and could thus induce formation fluids to enter the wellbore (or treatment fluid to enter the formation). The weighting material may be added to the treatment fluid in a functionally effective amount largely dependent on the well being drilled. Weight agents suitable to use in the formulation of the treatment fluid of the claimed subject matter may be generally selected from galena, hematite, magnetite, iron oxides, illmenite, barite, siderite, celestite, dolomite, calcite, and the like or any conventional type or mixture of weighting agents known to one skilled in the art.

**[0027]** Other additives that could be present in the treatment fluids of the claimed subject matter include products such as lubricants, surfactants, corrosion inhibitors, antioxidants and pH buffers. Such compounds should be known to one of ordinary skill in the art for formulating aqueous based fluids for use in subterranean wells. For example, such suitable lubricants may include fatty acid esters or other lubricants known in the art of drilling fluid formulation. Further, such surfactants may include alkoxylated alcohols, such as ethoxylated alcohols having an HLB between 10 and 15, but other surfactants known in the art of drilling fluid formation may alternatively be used.

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**[0028]** The method of use of the above-disclosed treatment fluids is contemplated as being within the scope of the claimed subject matter. The subject matter of the present disclosure is generally directed to a water based treatment fluid for use in subterranean wells that penetrate a subterranean formation that swells in the presence of water. During the drilling of a subterranean well, hydrophilic formations may be encountered. Their swelling may result in the drill bit balling up and being unable to drill further. Thus, according to one embodiment of the present disclosure, clay compounded on a portion of drilling equipment (such as the drill bit or other equipment including drill collars, stabilizers, pipe, etc.) may be contacted with a treatment fluid comprising an oxidizing agent.

**[0029]** Specifically, a treatment fluid may be introduced in the well and brought into contact with the clay of which removal is desired.

**[0030]** This treatment fluid may be administered to the region of the wellbore in which drilling equipment is stuck as a treatment pill. The treatment pill may be prepared by mixing the oxidizing agent and chosen additives with the aqueous based continuous phase. The oxidizing agent is mixed with the aqueous based fluid for sufficient time to insure that it is completely incorporated in the fluid. Once the treatment pill has been prepared, it may be emplaced in the wellbore so that it may be brought into contact with the balled up drilling equipment. This may be achieved by any conventional method known by one skilled in the art and for example by injecting it into a work string, letting it flow to the bottom of the wellbore, and then out of the work string and into the annulus between the work string and the casing or wellbore. This batch of treatment is typically referred to as a "pill". The treatment pill may also be selectively emplaced in the wellbore, for example, by spotting the pill through a coil tube or by bullheading. Various methods of emplacing a pill known in the art are discussed, for example, in U.S. Patent Nos. 4,662,448, 6,325,149, 6,367,548, 6,790,812, and 6,763,888.
However, no limitation on the techniques by which the
treatment fluid of the present disclosure is emplaced is intended on the scope of the present application. After a period of time sufficient, *i.e.*, several days, to allow for disruption or fragmentation of the compounded clay the fluid may be returned to the surface for collection and subsequent recovery techniques.

**[0031]** The amount of treatment fluid contained in a pill used in the practice of the present disclosure may vary over a wide range depending upon the formations penetrated by the drillstring and upon the extent of the bit balling. Therefore, there are no limitations in this regard. Generally, the size of the treatment pill employed in the practice of the invention may range between 10 and 50 bbl; however, one skilled in the art would appreciate that depending on the size of the hole and the severity of bit balling, a larger volume may be used, for example, up to 100 bbls.

**[0032]** Further, the treatment fluid may be allowed to remain in contact with the balled up drilling equipment for a time sufficient to disrupt the clay compounded on the drilling equipment to such an extent that the clay becomes dispersed or a loosely adherent mass on the drilling equipment. The amount of time that the aqueous composition remains in the formation will vary over a wide range depending on factors such as well temperature, extent of the bit balling, etc. Thus, the compounded clay should be sufficiently disrupted in an amount of time less than that required to disperse the clay if only soaked in fresh water (in the absence of an oxidizing agent). However, in particular embodiments, the amount of soak time for sufficient disruption of the bit balling may range from a duration of less than 3 hours. However, one skilled in the art would appreciate that the soak time may depend on factors such as the concentration of the active product, amount of bit balling present, temperature, and pressure.

**[0033]** Further, to reduce the amount of soak time (and thus downtime of the well), the drillstring may be rotated during the soaking period. Specifically, once the treatment fluid is in contact with the clay compounded on the drill bit and anytime during the treatment period, the drillstring may be rotated in order to further mix the downhole mixture, comprising clay, treatment fluid etc., so as to contact the remaining treatment fluid with the residual clay still compounded on the drill bit and aid in disruption and dispersion of the clay.

**[0034]** According to yet another preferred embodiment, the drillstring is rotated after the soaking period. At the end of the treatment period, the drill string may be rotated in order to begin drilling again.

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**[0035]** Optionally, once enough clay has been disrupted sufficiently so as to enable the drilling operator to apply weight on bit (to proceed with drilling), it may be desirable to displace/wash the residual treatment fluid containing dispersed clay particles. For example, the previously balled up equipment and region of the wellbore may be washed with a wash fluid such as by contacting or circulating within the borehole the wash fluid. Such wash fluids may include water, brine or other conventional wash fluids. In this manner, the major components of the clay may be removed from the equipment, and the clay that was compounded on the equipment may then be essentially completely removed from the wellbore. In a particular embodiment, the washing of the residual treatment fluid may be done while rotating the drillstring.

**[0036]** EXAMPLES

**[0037]** The present disclosure is further exemplified by the examples below which are presented to illustrate certain specific embodiments of the disclosure.

**[0038]** Example 1

**[0039]** A sticky clay material (a red clay from Britt ranch (Wheeler county, section 6, block 5, TX)) was balled onto the end of rod stirrers (one for a control and one for a sample treatment fluid) to simulate clay compounded on a drill bit. The stirrers were submerged in and left to soak in treatment fluids for 30 minutes. The test was conducted at room temperature and at a pressure of 6.894 MPa (1000 psi), and after conclusion of the test, the amount of clay remaining on the stirrers was measured. The test details are shown below in Table 1.

Table 1

| | **Control** | **Treatment Sample 1** |
|---|---|---|
| Clay initially deposited (g) | 170 | 151 |
| Rotation speed of the stirrer ($rad.s^{-1}$) | 9.3 (89 rpm) | 11.5 (110 rpm) |
| Treatment fluid | 300 mL water | 300 mL water + 20 g sodium percarbonate |
| Remaining clay after treatment (g) | 169 | 102 |

**[0040]** No removal of clay from the stirrer which was soaked only in water was observed. However, a reduction of 32.5% of the clay deposited on the stirrer contacted with the treatment fluid comprising an oxidizing agent was observed.

**[0041]** Example 2

**[0042]** Similar to Example 1, clay was balled onto the end of rod stirrers (one for a control and one for a sample treatment fluid). The stirrers were submerged and left to soak in the treatment fluids (water or oxidizing agent) for 1 hour. The experiment was conducted at room temperature and at a pressure of 6.894 MPa (1000 psi), and after conclusion of the test, the amount of clay remaining on the stirrers were measured. The test details are shown below in Table 2.

Table 2

| | **Control** | **Treatment Sample 2** |
|---|---|---|
| Clay initially deposited (g) | 148.8 | 169.0 |
| Rotation speed of the stirrer ($rad.s^{-1}$) | 10.5 (100 rpm) | 10.5 (100 rpm) |
| Treatment fluid | 350 mL water | 350 mL water + 20g sodium percarbonate |
| Remaining clay after treatment (g) | 146.2 | 83 |

**[0043]** A slight reduction (1.7%) of the clay deposited on the stirrer was observed after the treatment with water. A higher decrease (51%) of the clay deposited on the stirrer contacted with the treatment fluid comprising an oxidizing agent was observed.

**[0044]** Example 3

**[0045]** Two different treatment fluids (Samples 3 and 4) were prepared. Sample 3 included 350 mL of water, 5 g of sodium percarbonate, 0.1 g of D-limonene and ~2-3 g of DAWN®, available from Procter & Gamble (Cincinnati, OH). Sample 3 was compared to Sample 4, which was comprised of 350 mL of water and 10g of OXICLEAN® (sodium hypochlorite with potassium and sodium hydroxide), available from Church and Dwight Co. (Princeton, NJ). Similar to Example 1, clay was balled onto the end of rod stirrers (one for each sample). The stirrers were submerged in and left to soak in the treatment fluids. The experiment was conducted at 150°F and at a pressure of 1 atm.. The stirrers were rotated while soaking in the treatment fluids for 1 hour, and after conclusion of the test, the amount of clay remaining on the stirrers were measured. The test details are shown below in Table 3.

Table 3

| | Treatment Sample 3 | Treatment Sample 4 |
|---|---|---|
| Clay initially deposited (g) | 113.8 | 111.7 |
| Rotation speed of the stirrer (rad.s$^{-1}$) | 6.8 (65 rpm) | 6.8 (65 rpm) |
| Remaining clay after treatment (g) | 57.7 | 75.5 |

**[0046]** A higher decrease (49.2%) in clay is observed for Sample 3 (sodium percarbonate) than for Sample 4 (sodium hypochlorite) for which a decrease of 32.4% was observed.

**[0047]** Example 4

**[0048]** Similar to Example 1, clay was balled onto the end of rod stirrers (one for a control and one for a sample treatment fluid). Sample 5 was formed with BIOADD™ 1105, an acid stabilized hydrogen peroxide available from Shrieve Chemical Products, Inc. (The Woodlands, Texas). The stirrers were submerged and left to soak in the treatment fluids (water or oxidizing agent) for 45 minutes in rheology heating cups. The experiment was conducted at 65.5°C (150°F) and at a pressure of 6.894 MPa (1000 psi). The stirrers were maintained static during the experiment and, after conclusion of the test, the amount of clay remaining on the stirrers was measured. The test details are shown below in Table 4.

Table 4

| | Control | Treatment Sample 5 |
|---|---|---|
| Clay initially deposited (g) | 42.8 | 44.9 |
| Treatment fluid | 180 g water | 140 g water + 40 g BIOADD™ 1105 |
| Remaining clay after treatment (g) | 43.8 | 25.5 |

**[0049]** In the case of the treatment with an oxidizing agent, a reduction of 57% of clay compounded on the stirrer is observed, while the control showed a gain in weight. While visual inspection of the control showed a loss of clay from the stirrer (some clay is observed to be in bottom of control cup), the increased weight of the control clay remaining on the stirrer may be explained by absorption of water by the remaining clay.

**[0050]** To shorten the effect of clay absorbing water during the experiment, the clay was soaked in water for 10 minutes at 65.5°C (150°F), weighed and then subjected to experiment. The experiment was conducted at 65.5°C (150°F) and at a pressure

of 1 atm. The stirrers were maintained static and soaked during 45 minutes, and after conclusion of the test, the amount of clay remaining on the stirrers was measured. The test details are shown below in Table 5.

Table 5

| | Control | Treatment Sample 6 |
|---|---|---|
| Clay initially deposited after soaking (g) | 59.7 | 56 |
| Treatment fluid | 100 mL water | 80 mL water + 20 g BIOADD™ 1105 |
| Remaining clay after treatment (g) | 55.7 | 30.4 |

**[0051]** A loss of 45.7% was observed on the stirrer treated with the oxidizing agent compared to a loss of 5.7% on the control stirrer.

**[0052]** Example 5

**[0053]** In the example, an active composition of EMI-1995, available from M-I LLC (Houston, Texas), that contains a mixture of oxidizing agent, surfactant, and lubricant was tested in Sample 7. Clay (40g wet, 25.38g dry) was balled onto the end of rod stirrers (one for a control and one for a sample treatment fluid), dried at 65.5°C (150°F) for 16 hr and weighed (to determine the amount of clay material present with the moisture removed). The stirrers were then submerged in bottles containing the treatment fluids (water or oxidizing agent) for 55 minutes. The experiment was conducted at room temperature and at a pressure of 1 atm. The stirrers were maintained static during the experiment. After the treatment period, the remaining clay on the stirrers was dried at 65.5°C (150°F) for 16 hours and weighed for comparison against the initial amounts of clay on the stirrers. The test details are shown below in Table 6.

Table 6

| | Control | Treatment Sample 7 |
|---|---|---|
| Clay initially deposited after drying (g) | 25.38 | 25.38 |
| Treatment fluid | 350 mL water | 280 mL water + 70 mL active composition |
| Remaining clay after treatment and drying (g) | 23.5 | 14.32 |

**[0054]** A decrease of 43.57% was observed on the stirrer soaked in the treatment fluid comprising the active composition while only a 7.91% decrease was observed on the control stirrer.

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**[0055]** Advantageously, embodiments of the present disclosure may provide for at least one of the following. Methods of the present disclosure allow for efficient removal of compounded clays such that tripping of the bit is not required each time bit balling occurs. Thus, use of the treatment fluids is less costly and time consuming as compared to conventional remedial techniques. Further, the treatments fluids may be selected to be non-toxic, resulting in natural by-products such as oxygen, water, and carbonate.

**[0056]** 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.

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CLAIMS:

1. A method of removing clay compounded on drilling equipment in a well, comprising:

contacting clay compounded on the drilling equipment with a treatment fluid comprising an oxidizing agent, wherein the oxidizing agent comprises at least one of alkali metal perborates, alkali metal persilicates, and perphosphates.

2. The method of claim 1, wherein the oxidizing agent is an encapsulated oxidizing agent.

3. The method of claim 2, wherein the encapsulant is a styrene polymer.

4. The method of claim 2, wherein the encapsulated oxidizing agent is released upon a change in pH in the downhole environment.

5. The method of any one of claims 1 to 4, wherein the oxidizing agent is an oxidizing agent stabilized by the addition of an acidic material.

6. The method of any one of claims 1 to 5, wherein the treatment fluid comprises from 0.0014 kg/L (0.5 lb/bbl) to 0.1427 kg/L (50 lb/bbl) of the oxidizing agent.

7. The method of claim 6, wherein the treatment fluid comprises from 0.0143 kg/L (5 lb/bbl) to 0.1141 kg/L (40 lb/bbl) of the oxidizing agent.

8. The method of any one of claims 1 to 7, further comprising:

soaking the drilling equipment for a period of time sufficient to disrupt the compounded clay.

9. The method of claim 8, further comprising:

rotating the drilling equipment during the soaking.

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10. The method of claim 8, further comprising:

rotating the drilling equipment after the soaking.

11. The method of any one of claims 1 to 10, further comprising:

washing the remaining treatment fluid at the end of the treatment period.

12. The method of claim 11 wherein the washing of the remaining treatment fluid is done while rotating the drilling equipment.

13. A method of drilling a wellbore through a clay-containing formation, comprising:

drilling through the formation with a water-containing drilling fluid;

reducing applied weight-on-bit when bit balling detected;

emplacing a treatment fluid comprising an oxidizing agent to disrupt clay compounded on drilling equipment; and

increasing weight-on-bit to continue drilling through the formation.

14. The method of claim 13, further comprising:

soaking the drilling equipment for a period of time sufficient to disrupt the compounded clay.

15. The method of claim 13 or 14, further comprising:

rotating the drilling equipment without applied weight-on-bit.

16. The method of any one of claims 13 to 15, wherein the oxidizing agent comprises at least one of alkali metal perborates, alkali metal persilicates, and perphosphates.