(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
8 October 2015 (08.10.2015)

WIPO | PCT

(10) International Publication Number
WO 2015/153406 A1

(51) International Patent Classification:
C09K 8/487 (2006.01) *C09K 8/36* (2006.01)

(21) International Application Number:
PCT/US2015/023253

(22) International Filing Date:
30 March 2015 (30.03.2015)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:

61/972,755	31 March 2014 (31.03.2014)	US
61/972,805	31 March 2014 (31.03.2014)	US
61/972,871	31 March 2014 (31.03.2014)	US

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(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

(54) Title: SMART LCM FOR STRENGTHENING EARTHEN FORMATIONS

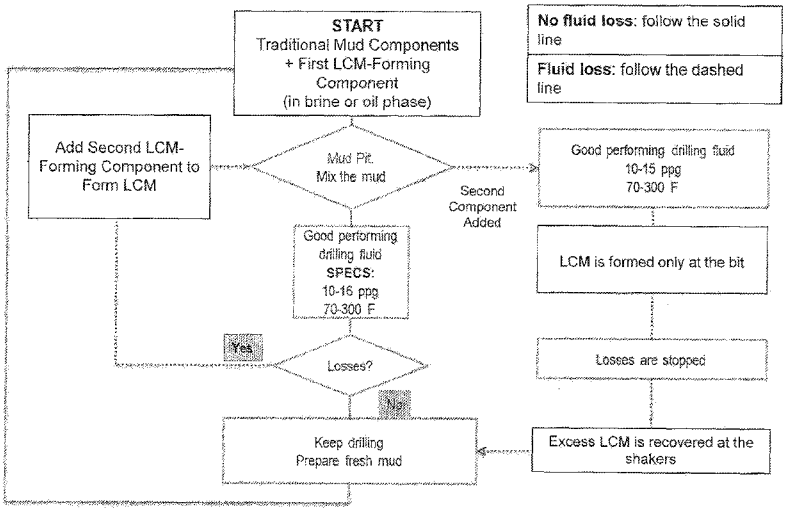


FIG. 1

(57) Abstract: Methods for treating an earthen formation may include: drilling at least a section of a wellbore using a first wellbore fluid containing a first base fluid, and a first LCM-forming component; injecting, upon experience of a fluid loss, a second wellbore fluid containing a second base fluid, and a second LCM-forming component; and reacting the first LCM-forming component with the second LCM-forming component to form an LCM that reduces the fluid loss. A fluid system may include a first component containing a first base fluid and a first LCM-forming component; and a second component containing a second base fluid and a second LCM-forming component, wherein the second LCM-forming component is capable of reacting with the first LCM-forming component to form a LCM.

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SMART LCM FOR STRENGTHENING EARTHEN FORMATIONS

RELATED APPLICATION

[0001] This application claims priority to and the benefit of U.S. Provisional Patent Application having Serial No. 61/972871, filed 31 March 2014; U.S. Provisional Patent Application having Serial No. 61/972755, filed 31 March 2014; and U.S. Provisional Patent Application having Serial No. 61/972805, filed 31 March 2014, which are all incorporated by reference in their entirety.

BACKGROUND

[0002] During the drilling of a wellbore, various fluids may be 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] Wellbore fluids may also be used to provide sufficient hydrostatic pressure in the well to prevent the influx and efflux of formation fluids and wellbore fluids, respectively. When the pore pressure (the pressure in the formation pore space provided by the formation fluids) exceeds the pressure in the open wellbore, the formation fluids tend to flow from the formation into the open wellbore. Therefore, the pressure in the open wellbore is often maintained at a higher pressure than the pore pressure. However, when wellbore pressures are maintained above the pore pressure, the pressure exerted by the wellbore fluids may exceed the fracture resistance of the formation and fractures and induced mud losses may occur. Further, formation fractures may result in the loss of wellbore fluid that decreases the hydrostatic pressure in the wellbore to decrease, which may in turn also allow formation fluids to enter the wellbore. As a result, the formation fracture pressure

may define an upper limit for allowable wellbore pressure in an open wellbore while the pore pressure defines a lower limit. Therefore, one constraint on well design and selection of drilling fluids is the balance between varying pore pressures and formation fracture pressures or fracture gradients though the depth of the well.

[0004] As stated above, wellbore fluids are circulated downhole to remove rock, as well as deliver agents to combat the variety of issues described above. Fluid compositions may be water- or oil-based and may contain weighting agents, surfactants, proppants, viscosifiers, and fluid loss additives. However, fluid loss may impede wellbore operations, as fluids escape into the surrounding formation. During drilling operations, variations in formation composition may lead to undesirable fluid loss events in which substantial amounts of wellbore fluid are lost to the formation through large or small fissures or fractures in the formation or through a highly porous rock matrix surrounding the borehole. While fluid loss is often associated with drilling applications, other fluids may experience fluid loss into the formation including wellbore fluids used in completions, drill-in operations, productions, *etc.* Lost circulation may occur naturally in formations that are fractured, highly permeable, porous, cavernous, or vugular.

[0005] Lost circulation may also result from induced pressure during drilling. Specifically, induced mud losses may occur when the mud weight, which is often tuned for well control to maintain a stable wellbore, exceeds the fracture resistance of the formations. A particularly challenging situation arises in depleted reservoirs, in which the drop in pore pressure effectively weakens a wellbore through permeable, potentially hydrocarbon-bearing rock formation, but neighboring or inter-bedded low permeability rocks maintain their pore pressure. This can make the drilling of certain depleted zones impossible because the mud weight employed to support lower permeability rocks such as shale may exceed the fracture resistance of high permeability sands and silts. Another unintentional method by which lost circulation can result is through the inability to remove low and high gravity solids from fluids. Without being able to remove such solids, the fluid density can increase, thereby increasing the hole pressure, and if such hole pressure exceeds the formation fracture pressure, fractures and fluid loss can result.

[0006] Various methods have been used to restore circulation of a drilling fluid when a lost circulation event has occurred, particularly the use of "lost circulation materials" (LCM) that seal or block further loss of circulation. These materials may generally be classified into several categories: surface plugging, interstitial bridging, and/or combinations thereof. In addition to traditional LCM pills, crosslinkable or absorbing polymers, and cement or gunk squeezes have also been employed to combat fluid loss downhole.

SUMMARY

[0007] In one aspect, embodiments disclosed herein relate to methods for treating an earthen formation that include: drilling at least a section of a wellbore using a first wellbore fluid containing a first base fluid, and a first LCM-forming component; injecting, upon experience of a fluid loss, a second wellbore fluid containing a second base fluid, and a second LCM-forming component; and reacting the first LCM-forming component with the second LCM-forming component to form an LCM that reduces the fluid loss.

[0008] In another aspect, embodiments disclosed herein relate a fluid system that includes: a first component containing a first base fluid and a first LCM-forming component; and a second component containing a second base fluid and a second LCM-forming component, wherein the second LCM-forming component is capable of reacting with the first LCM-forming component to form a LCM.

[0009] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter. Other aspects and advantages of the disclosure will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0010] FIG. 1 is a flowchart illustrating an embodiment of a method of drilling incorporating a smart LCM of the instant disclosure.

DETAILED DESCRIPTION

[0011] Embodiments disclosed herein relate to methods of treating fluid loss in downhole formations. Methods and chemical systems in accordance with the present disclosure are directed to treating lost circulation, wherein a multi-component system capable of reacting to form a lost circulation material (LCM) is employed. In one or more embodiments described herein, LCM-forming components that react to form an LCM material may be combined to form an LCM on demand when treatment of fluid loss is experienced during a wellbore operation. LCM-forming components may be isolated in separate fluids, in separate phases of a single fluid, or individual components may be isolated within a wellbore fluid in which one or both components is encapsulated.

[0012] Embodiments of the present disclosure may be particularly suitable for drilling through depleted sandstone formations, as well as other depleted formation types. Depleted formations pose numerous technical challenges, including wellbore instability, severe lost circulation, etc., which generally make further development uneconomical. Uncontrollable drilling fluid losses frequently are unavoidable in the often large fracture characteristics of these formations. While conventional wellbore strengthening techniques often involve the use of particulates to create a hoop stress and thus increase the strength of the formation through formation of a stress cage, such techniques involve the formation of new fractures, which may be undesirable for a depleted formation. Thus, embodiments of the present disclosure seek to strengthen the formation through the multi-component system capable of reacting to form LCMs *in situ*. The chemical reaction of the fluid components may be selectively activated to prevent or at least reduce premature reaction within the drill string and also achieve reaction in the near-bit area, when desired. Thus, to achieve such selective activation, multiple components may be incorporated into the wellbore fluid(s). To avoid or reduce premature reaction, one of the components may be encapsulated or otherwise rendered chemically non-reactive. Upon activation and

exposure to a second component, with which the first component is reactive, the two (or more) components may react to form the LCM.

[0013] In one or more embodiments, a first LCM-forming component may be provided with a first wellbore fluid during normal wellbore operations and, upon experiencing fluid loss into the formation, a second LCM-forming component is introduced into the wellbore as needed. Once injected, the second LCM-forming component may contact the first LCM-forming component in the wellbore, which in turn results in the formation of a LCM that seals or otherwise impedes the flow of wellbore fluids into intervals of the wellbore experiencing fluid loss. For example, in particular embodiments, drilling operations may be commenced with a first LCM-forming component dormant in a drilling fluid, while a second LCM-forming component is added at the pit when losses are registered downhole. The second LCM-forming component may be activated at the bit by shear or pressure drop and react with the first LCM-forming component in the wellbore fluid, forming a LCM material *in situ* that serves to reduce fluid loss.

[0014] With particular respect to FIG. 1, a method of drilling in accordance with the present disclosure is shown in which a multi-component system is used to treat fluid loss. In the initial stage, drilling mud components are mixed together with a first LCM-forming component that remains inactive or substantially inactive during drilling. When fluid loss is detected, such as by a reduction in fluid pressure, a second wellbore fluid is prepared containing a second LCM-forming component and introduced into the wellbore near the source of fluid loss. During the injection of the second component, the first and second LCM-forming components react to form a LCM that enters into sites of fluid loss including, for example, fractures, vugs, and highly permeable zones, and reduces fluid loss. Further, because the LCM material is formed at the site of injection when delivered from a drill bit and/or drill string, use of wellbore fluid components and damage to the formation from excess LCM is minimal. During drilling operations using methods in accordance with the present disclosure, any excess LCM formed may be recovered from returned wellbore fluids and drill cuttings and removed by techniques known in the art, such as mechanical shakers and other separation methods. As fluid loss is reduced and fluid pressures return to suitable levels for drilling, the injection of the second wellbore fluid

containing the second LCM-forming component may be stopped and drilling operations may resume.

[0015] In one or more embodiments, the first LCM-forming component may be within a wellbore fluid in a well and the second LCM-forming component may be injected as needed in a fluid loss pill. As used herein, the term "pill" is used to refer to a relatively small quantity (often around 200 bbl or less) of a special blend of wellbore fluid to accomplish a specific task that the regular wellbore fluid cannot perform. In some embodiments, the lost circulation pill may be used to plug a "thief zone," which simply refers to a formation into which circulating fluids can be lost. For example, operators on a rig may notice a decrease or cessation in the flow of fluid returning and a volume of a wellbore fluid containing a second LCM-forming component may be prepared and pumped downhole to produce a LCM material that plugs the zone where fluid is being lost. In some embodiments, the volume of the second wellbore fluid applied as a pill may range from 1 to 30 m^3, from 3 to 20 m^3, or from 5 to 16 m^3.

[0016] In one or more embodiments, one or more of the components of the LCM system may be encapsulated. In particular embodiments, components may be released from an encapsulating coating in response to an external stimulus or triggering event, which may include changes in temperature or pH; degradation of the encapsulant by enzymes, oxidants, or solvents; or physical disruption of the encapsulant, such as by shearing, grinding, or crushing.

[0017] In particular embodiments, the encapsulant may be designed such that the encapsulant releases a LCM-forming component when exposed to shear forces such as those that occur during injection of a wellbore fluid downhole. For example, an encapsulated component may be injected into a wellbore and as the wellbore fluid containing the encapsulated reagent is exposed to shear forces that occur as the fluid exits an opening in a tubular, drill string, or drill bit, the shear forces may disrupt the encapsulating material and release a reagent such as an LCM-forming component into the surrounding fluid. Thus, the release and delivery of an encapsulated component may be obtained by tuning the shear pressure of the fluid injection in the wellbore.

[0018] Shear forces are closely related to the pressure drop experienced by a wellbore fluid passing through constrictions in various pumps, pipes, and drill-bits that may be

present during a particular wellbore operation. This phenomenon is also known as the Venturi effect, which describes the physical process in which a fluid's velocity increases as it passes through a constriction to satisfy the principle of continuity, while its pressure decreases to satisfy the principle of conservation of mechanical energy. The greater the pressure differential between two particular stages that a wellbore fluid passes through (*e.g.*, a change in diameter of a length of pipe or tubing), the greater the proportional pressure drop and shear force the fluid experiences. For example, shear forces may be highest when a fluid passes through narrow openings or nozzles on a drill bit or a port of completion string downhole.

[0019] In one or more embodiments, an encapsulant coating may be designed such that the coating ruptures, thereby at least partially activating the LCM-forming component, when exposed to shear forces that may range from 10,000 to 30,000 s^{-1} in some embodiments, or from 12,000 to 25,000 s^{-1}. In other embodiments, activation of the encapsulated component may occur at shear forces of at least 15,000 s^{-1} or at shear forces of least 20,000 s^{-1} in yet other embodiments.

[0020] In some embodiments, the multi-component system may react to form a LCM by simply contacting the individual components of the LCM-forming system together. In other embodiments, the components may be selected such that the reaction is optimized to preferentially react at downhole temperatures or when exposed to heat using one of the various downhole heating tools known in the art. In yet other embodiments, reaction of the multi-component system to form an LCM may be activated or accelerated by exposing the components to electromagnetic radiation generated from a downhole tool, including gamma, ultraviolet, microwave, and radio wave radiation, for example.

[0021] **LCM-Forming Components**

[0022] In one or more embodiments, the multi-component LCM system may form silicate polymers from the reaction of a silicate with an alcohol, polyol, amine, or polyamine. As described above, in some embodiments, a wellbore fluid may be formulated with either component and the second component may be added as fluid loss is experienced, creating LCM on demand and as needed to combat fluid loss. Other possible embodiments include providing a single wellbore fluid in which one or both components is encapsulated and then forming the LCM by exposing the fluid to

the proper stimulus, *e.g.*, a change in temperature or pH, or in response to mechanical stress such as shear.

[0023] While not bound by a particular theory, it is believed that the combination of the silicate species and the alcohol or amine initiates a series of hydrolysis and condensation reactions that serve to generally increase the molecular weight of the silicate species and in some instances crosslink the silicate monomeric units. The increase in molecular weight and crosslinking of the silicate species serves to generate a viscous gel which may form a more robust chemical seal in the filter cake where the encapsulated particles were first embedded.

[0024] An LCM-forming silicate component in accordance with the present disclosure may be present within a wellbore fluid as a liquid or solid, or an encapsulated fluid or solid in some embodiments. For example, silicates may be selected from one or more of sodium silicate, potassium silicate, lithium silicate, quaternary ammonium silicates, and the like.

[0025] In one or more embodiments, a silicate may be combined with a small molecule or polymer having one or more hydroxyl groups in order to produce a LCM. Fore example, a LCM may be prepared from the reaction of a silicate and a hydroxyl-containing compound such as a polyol containing 2 to 8 carbon atoms, including ethylene glycol, 1,2-propylene glycol, 1,3-propylene glycol, 1,4-butylene glycol, 1,5-pentanediol, 1,7-heptanediol, and the like. Other potential alcohols included are polyoxyalkylene glycols and water-soluble mono-alkyl ethers of glycols and polyoxyalkylene glycols, polyoxyalkylene glycols such as polyoxyethylene glycols and polyoxypropylene glycols, monoalkyl ethers of glycols include monomethyl ether of ethylene glycol, monoethyl ether of ethylene glycol, monobutyl ether of ethylene glycol, mono-methyl ether of propyleneglycol, monobutyl ether of propylene glycol, monomethyl ether of diethylene glycol, mono-ethyl ether of diethylene glycol, monobutyl ether of diethylene glycol and the like.

[0026] Suitable hydroxyl-containing polymers also include saccharides such as xanthan gum, guar gum, carboxymethylated polysaccharides, hydroxypropyl polysaccharides, carboxymethyl, hydroxyproply polysaccharides, and similarly derivatized starches. Other examples include guar gum, cellulose, arabic gum, guar gum, locust bean gum, tara gum, cassia gum, agar, alginates, carrageenans, chitosan,

scleroglucan, diutan, or modified starches such as n-octenyl succinated starch, porous starch, and hydroxypropyl- and/or carboxymethyl-derivatives of any of the above. Other suitable hydroxyl-containing polymers may be selected from synthetic polymers such as polyvinyl alcohol, partially hydrolyzed polyvinyl acetate, and copolymers containing vinyl alcohol or other monomers containing hydroxyl-substituted side chains. Further, suitable crosslinkable polymers may be branched or linear polyols with available hydroxy and/or amino groups.

[0027] Suitable amines may include small molecules and polymers capable of reacting with a silicate to form a LCM such as, for example: methylamine, ethylamine, propylamine, isopropylamine, butylamine, amylamine, hexylamine aniline, toluidine amine, xylidine amine, naphthylamine, benzylamine, di- and polyamines such as C_6-C_{12} diamines, phenylenediamine, ethylenediamine, tetramethylenediamine, pentamethylenediamine, hexamethylenediamine, octamethylenediamine, decamethylenediamine, xylylenediamine, diphenylamine, piperazine and other compounds such as aminocaproic acid, polyamines, alkylene polyamines, vinyl amines, diethylenetriamine, triethylenetetramine, tetraethylenepentamine, and the like. Other possible components include species that contain heterogeneous functional groups such as aminoacetaldehyde diethyl acetal, aminoacetic acid, aminobenzoic acid, 2-amino-1-butanol, 2-aminoethanol, 1-amino-2-propanol, O-aminophenol, p-aminophenol, 1-amine-2-propanol, 6-amino-2-picoline, 2-amino-4-nitrophenol, aminosuccinic acid (DL Aspartic acid), 2-aminopyridine, and mixtures thereof. In one or more embodiments, suitable amino-containing components may include polyetheramines such as the series of Jeffamines® available from Huntsman Corporation (Dayton, TX).

[0028] In some embodiments, one or more of the LCM-forming components may be encapsulated. In one or more embodiments, the encapsulated component may include a sodium or potassium silicate either in solid or solution form. In order to create an effective chemical seal, the encapsulated silicate may be combined with a second component, such as an amine, alcohol, or an alcohol or amine produced from the corresponding hydrolyzed ester or amide.

[0029] In other embodiments, silicates may also be reacted with multivalent cations (e.g., Ca^{+2}, Mg^{+2}, Al^{+3}, Fe^{+3}, *etc.*) to produce insoluble metal silicates or metal silicate

gels. For example, upon addition of divalent calcium ions, a monovalent silicate may react with the calcium to form a hydrated calcium silicate. Multivalent cations may be derived from the corresponding salts such as bicarbonates, phosphates, polyphosphates, sulfates, *etc.* Such inorganic setting agents may be included in the external phase of the fluid (or in a second emulsion) so that, during emplacement of a fluid in a wellbore, the setting agent is kept separate from silicate internal phase to avoid premature crosslinking of the silicates and setting of the fluid.

[0030] In other embodiments, the corresponding component that initiates LCM-formation with a silicate may be an inorganic salt such as calcium chloride ($CaCl_2$), aluminum sulfate ($Al_2(SO_4)_3$), or strontium chloride ($SrCl_2$). When the LCM-forming component is an inorganic salt, the reaction with the sodium or potassium silicate first component will result in precipitation of a calcium, aluminum, or strontium silicate LCM, respectively, which may then treat formation defects that are the source of fluid loss.

[0031] Water solubility of such silicates is due to the presence of alkali metal oxides (M_2O) which maintain the pH at a level where silica (SiO_2) can be dissolved. However, if the pH is neutralized or lowered, the solubility of the silica is reduced and it gels or polymerizes. Silicate gelation refers to the self-polymerization or condensation of soluble silicate structures to form a hydrous, amorphous gel structure of silicate, which rapidly occurs at a pH below 10.5. Thus, in one or more embodiments, pH may be used to control the deposition of silica as a LCM. For example, a decrease in pH may be used to trigger the precipitation of a silica LCM at the site of fluid loss when a drop in fluid pressure is detected. In order to effect a pH change in some embodiments, a mineral acid such as HCl or formic acid may be encapsulated and deployed downhole. When production of the LCM is desired, the encapsulated acid may then be activated by rupturing the surrounding encapsulant by applying the appropriate triggering mechanism, *e.g.*, shearing, grinding, or temperature.

[0032] Other potential mechanisms for decreasing the pH of the surrounding fluid and precipitating a silica LCM include injection of an ester that hydrolyzes to produce the corresponding carboxylic acid. Suitable esters may include formic or acetic acid ester of a C_4-C_{30} alcohol, which may be mono- or polyhydric. Other esters that may

find use in triggering gelation of the silicates of the present disclosure include those releasing C_1-C_6 carboxylic acids, including hydroxycarboxylic acids formed by the hydrolysis of lactones, such as δ-lactone and γ-lactone). In another embodiment, a hydrolyzable ester of C_1 to C_6 carboxylic acid and a C_2 to C_{30} poly alcohol, including alkyl orthoesters, may be used.

[0033] It is also within the scope of the present disclosure to use any one of the aforementioned inorganic salts, amines, alcohols, esters, or amides as an encapsulated component. In these instances, the sodium or potassium silicate component may be added and/or emulsified into the non-aqueous wellbore fluid, and the respective encapsulated component may be added when fluid loss is registered in an on-demand fashion. In one or more other embodiments, as a preventative measure against fluid loss the LCM-forming components may be directly combined together in a single wellbore fluid formulation and used during wellbore operations before a fluid loss event is registered.

[0034] **Encapsulation Materials**

[0035] In one or more embodiments, LCM-forming components may be released from an encapsulating coating in response to an external stimulus or triggering event, which may include changes in temperature or pH; degradation of the encapsulant by enzymes, oxidants, or solvents; or physical disruption of the encapsulant, such as by grinding or crushing. It is also envisioned that encapsulants susceptible to triggered release may also be used in conjunction with passive diffusion encapsulants, and combined with any of the strategies disclosed above.

[0036] In particular embodiments, the encapsulant may be designed such that the encapsulant releases a reagent when exposed to shear forces such as those that occur during injection of a wellbore fluid downhole. For example, an encapsulated reagent may be injected into a wellbore and as the wellbore fluid containing the encapsulated reagent is exposed to shear forces that occur as the fluid exits an opening in a tubular, drill string, or drill bit, the shear forces may disrupt the encapsulating material and release the reagent into the surrounding fluid. Thus, the release and delivery of an encapsulated reagent may be obtained by tuning the shear pressure of the fluid injection in the wellbore.

[0037] The encapsulant coating may be designed such that the encapsulated reagent is initially inactive, meaning that the encapsulating reagent is not able to chemically interact with any components external to the coating. Once exposed to shear forces, the coating ruptures and at least partially activates the encapsulated reagent, such that the reagent may chemically interact with a secondary component. The coating may rupture when exposed to shear forces that may range from 10,000 to 30,000 s^{-1} in some embodiments, or from 12,000 to 25,000 s^{-1}. In other embodiments, activation of the encapsulated reagent may occur at shear forces of at least 15,000 s^{-1} or at shear forces of least 20,000 s^{-1} in yet other embodiments.

[0038] In one or more embodiments, a component may be encapsulated in an organic coating prepared from cellulose acetate, cellulose acetate butyrate, ethyl cellulose, hydroxymethyl cellulose, hydroxyethyl cellulose, and the like. Other encapsulants include polystyrene, copolymers of polystyrene with other vinylic monomers, polymethylmethacrylate, copolymers of methylmethacrylate with other ethylenically-unsaturated monomers, acrylic resins, polyolefins, polyamides, polycarbonates, polystyrene, vinyl polymers such as vinyl acetate, vinyl alcohol, vinyl chloride, vinyl butyral, and copolymers, terpolymers, and quaternary polymers thereof. Examples of pH-sensitive polymers include poly(hydroxethyl)methacrylate- co-methacrylic acid) and a copolymer of N,N,dimethylaminoethyl methacrylate and divinyl benzene.

[0039] In yet another embodiment, LCM-forming components may be encapsulated in a coating that releases the component or components in response to an external stimulus or triggering event, which may include temperature, pH, enzymatic degradation, oxidants, solvents, or physically disrupted, such as by grinding the encapsulated components. It is also envisioned that encapsulants susceptible to triggered release may also be used in conjunction with passive diffusion encapsulants, and combined with any of the strategies disclosed above.

[0040] The encapsulation material may be a heat-activated material that remains intact prior to exposure to elevated temperatures, such as those present in a downhole environment, and upon heating, slowly melt and release the molecules or ions contained within. In some embodiments, the coating may melt at a temperature greater than 125°F (52°C). Examples of such materials are vegetable fat, gelatin, and vegetable gums, and hydrogenated vegetable oil. Other coatings may include

materials selected from lipid materials such as, but not limited to, mono-, di-, and tri-glycerides, waxes, and organic and esters derived from animals, vegetables, minerals, and modifications. Examples include glyceryl triestearates such as soybean oil, cottonseed oil, canola oil, carnuba wax, beeswax, bran wax, tallow, and palm kernel oil. Heat-activated materials may also include those disclosed in U.S. Pat. No. 6,312,741, which is incorporated herein by reference in its entirety.

[0041] In a particular embodiment, the encapsulating material may include enteric polymers, which are defined for the purposes of the present disclosure, as polymers whose solubility characteristics are pH dependent. Here, this means that component release is promoted by a change from conditions of a first predetermined pH value to a second predetermined pH condition.

[0042] Enteric polymers are commonly used in the pharmaceutical industry for the controlled release of drugs and other pharmaceutical agents over time. The use of enteric polymers allows for the controlled release of a component under predetermined conditions of pH, or a combination of pH and temperature. For example, the Glascol® family of polymers are acrylic based polymers (available form Ciba Specialty Chemicals) are considered suitable enteric polymers for the present disclosure because the solubility depends upon the pH of the solution. In an illustrative embodiment of the present disclosure, an enteric polymer may be selected as an encapsulating material that is substantially insoluble at pH values greater than about 7.5 and that is more soluble under conditions of decreasing pH.

[0043] Encapsulating materials may also include enzymatically degradable polymers and polysaccharides such as galactomannan gums, glucans, guars, derivatized guars, starch, derivatized starch, hydroxyethyl cellulose, carboxymethyl cellulose, xanthan, cellulose, and cellulose derivatives. Enzymatically degradable polymers may include glycosidic linkages that are susceptible to degradation by natural polymer degrading enzymes, which may be selected from, for example, carbohydrases, amylases, pullulanases, and cellulases. In other embodiments, the enzyme may be selected from endo-amylase, exo-amylase, isoamylase, glucosidase, amylo-glucosidase, malto-hydrolase, maltosidase, isomalto-hydrolase or malto-hexaosidase. One skilled in the art would appreciate that selection of an enzyme may depend on various factors such as the type of polymeric additive used in the

wellbore fluid being degraded, the temperature of the wellbore, and the pH of wellbore fluid

[0044] While a number of encapsulating compositions and release mechanisms have been discussed, many methods of encapsulating and releasing components described herein may alternatively be used without departing from the scope of the present disclosure.

[0045] Lost circulation treatments in accordance with the present disclosure may employ a base fluid and LCM-forming components, weighting agents, natural or synthetic fibers, and/or bridging agents. In yet other embodiments, the pills may include a number of other additives known to those of ordinary skill in the art, such as wetting agents, viscosifiers, surfactants, dispersants, interfacial tension reducers, pH buffers, mutual solvents, thinners, thinning agents, rheological additives and cleaning agents.

[0046] LCM-forming components may be added to a wellbore fluid in an amount ranging from 0.5 ppb to 80 ppb in some embodiments; however, more or less may be desired depending on the particular application. The amount of LCM-forming components employed may depend on the fluid loss levels, the anticipated fractures, the density limits for the pill in a given wellbore and/or pumping limitations, *etc.*

[0047] **Base Fluids**

[0048] Base fluids described herein may be oil-based wellbore fluids or invert emulsions in one or more embodiments. Suitable oil-based or oleaginous fluids may be a natural or synthetic oil and in some embodiments, in some embodiments the oleaginous fluid may be selected from the group including diesel oil; mineral oil; a synthetic oil, such as 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.

[0049] In other embodiments, the wellbore fluid may be an invert emulsion having a continuous oleaginous phase and a discontinuous aqueous (or non-oleaginous liquid) phase, among other substances and additives. Non-oleaginous liquids may, in some

embodiments, include at least one of fresh water, sea water, brine, mixtures of water and water-soluble organic compounds, and mixtures thereof. In various embodiments, the non-oleaginous fluid may be a brine, which 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, sulfates, silicates, phosphates and fluorides. Salts that may be incorporated in a 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.

[0050] The amount of oleaginous liquid in the invert emulsion fluid may vary depending upon the particular oleaginous fluid used, the particular non-oleaginous fluid used, and the particular application in which the invert emulsion fluid is to be employed. However, in some embodiments, the amount of oleaginous liquid may be sufficient to form a stable emulsion when used as the continuous phase. In some embodiments, the amount of oleaginous liquid may be at least about 30, or at least about 40, or at least about 50 percent by volume of the total fluid. The amount of non-oleaginous liquid in the invert emulsion fluid may vary depending upon the particular non-oleaginous fluid used and the particular application in which the invert emulsion fluid is to be employed. In some embodiments, the amount of non-oleaginous liquid may be at least about 1 percent by volume of the total fluid, or at least about 3 percent, or at least about 5 percent. In some embodiments, the amount may not be so great that it cannot be dispersed in the oleaginous phase. Therefore, in certain embodiments, the amount of non-oleaginous liquid may be less than about 90, or less than about 80, or less than about 70 percent by volume of the total fluid.

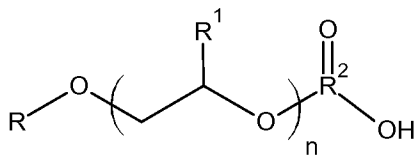
[0051] Conventional methods can be used to prepare the drilling fluids disclosed herein, in a manner analogous to those normally used to prepare conventional oil-based drilling fluids. In one embodiment, a desired quantity of oleaginous fluid such as a base oil and a suitable amount of a surfactant are mixed together and the remaining components are added sequentially with continuous mixing. An invert emulsion may also be formed by vigorously agitating, mixing or shearing the oleaginous fluid and the non-oleaginous fluid.

[0052] **Wellbore Fluid Additives**

[0053] Other additives that may be included in the wellbore fluids disclosed herein include for example, wetting agents, organophilic clays, viscosifiers, 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 one of ordinary skill in the art of formulating drilling fluids and muds.

[0054] Emulsifiers that may be used in the fluids disclosed herein include, for example, fatty acids, soaps of fatty acids, amidoamines, polyamides, polyamines, oleate esters, such as sorbitan monoleate, sorbitan dioleate, imidazoline derivatives or alcohol derivatives and combinations or derivatives of the above. Additionally, lime or other alkaline materials may be added to conventional invert emulsion drilling fluids and muds to maintain a reserve alkalinity.

[0055] In some embodiments, the invert emulsion may be a high internal phase ratio (HIPR) emulsion, wherein the aqueous or non-oleaginous fluid within the oleaginous fluid is present in a volume amount that is more than the non-oleaginous fluid. While a number of possible emulsifiers may be used, one exemplary class of emulsifiers is alkoxylated ether acids. In one or more embodiments, an alkoxylated ether acid is an alkoxylated fatty alcohol terminated with an carboxylic acid, represented by the following formula:



where R is C_6-C_{24} or $-C(O)R^3$ (where R^3 is C_{10}-C_{22}), R^1 is H or C_1-C_4, R^2 is C_1-C_5 and n may range from 1 to 20. Such compound may be formed by the reaction of an

alcohol with a polyether (such as poly(ethylene oxide), poly(propylene oxide), poly(butylene oxide), or copolymers of ethylene oxide, propylene oxide, and/or butylene oxide) to form an alkoxylated alcohol. The alkoxylated alcohol may then be reacted with an α-halocarboxylic acid (such as chloroacetic acid, chloropropionic acid, etc.) to form the alkoxylated ether acid. In a particular embodiment, the selection of n may be based on the lipophilicity of the compound and the type of polyether used in the alkoxylation. In some particular embodiments, where R^1 is H (formed from reaction with poly(ethylene oxide)), n may be 2 to 10 (between 2 and 5 in some embodiments and between 2 and 4 in more particular embodiments). In other particular embodiments, where R^1 is $-CH_3$, n may range up to 20 (and up to 15 in other embodiments). Further, selection of R (or R^3) and R^2 may also depend on based on the hydrophilicity of the compound due to the extent of polyetherification (*i.e.*, number of n). In selecting each R (or R^3), R^1, R^2, and n, the relative hydrophilicity and lipophilicity contributed by each selection may be considered so that the desired HLB value may be achieved. Further, while this emulsifier may be particularly suitable for use in creating a fluid having a greater than 50% non-oleaginous internal phase, embodiments of the present disclosure may also include invert emulsion fluids formed with such emulsifier at lower internal phase amounts.

[0056] Wetting agents that may be suitable for use in the fluids disclosed herein include crude tall oil, oxidized crude tall oil, surfactants, organic phosphate esters, modified imidazolines and amidoamines, alkyl aromatic sulfates and sulfonates, and the like, and combinations or derivatives of these. However, when used with the invert emulsion fluid, the use of fatty acid wetting agents should be minimized so as to not adversely affect the reversibility of the invert emulsion disclosed herein. FAZE-WET™, VERSACOAT™, SUREWET ™, VERSAWET™, and VERSAWET™ NS are examples of commercially available wetting agents manufactured and distributed by M-I L.L.C. that may be used in the fluids disclosed herein. Silwet L-77, L-7001, L7605, and L-7622 are examples of commercially available surfactants and wetting agents manufactured and distributed by General Electric Company (Wilton, CT).

[0057] Organophilic clays, normally amine treated clays, may be useful as viscosifiers and/or emulsion stabilizers in the fluid composition disclosed herein. Other viscosifiers, such as oil soluble polymers, polyamide resins, polycarboxylic

acids and soaps can 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 6% by weight range is sufficient for most applications. VG-69™ and VG-PLUS™ are organoclay materials distributed by M-I, L.L.C., Houston, Texas, and VERSA-HRP™ is a polyamide resin material manufactured and distributed by M-I, L.L.C., that may be used in the fluids disclosed herein. In some embodiments, the viscosity of the displacement fluids is sufficiently high such that the displacement fluid may act as its own displacement pill in a well.

[0058] Conventional suspending agents that may be used in the fluids disclosed herein include organophilic clays, amine treated clays, oil soluble polymers, polyamide resins, polycarboxylic acids, and soaps. The amount of conventional suspending agent used in the composition, if any, may vary depending upon the end use of the composition. However, normally about 0.1% to about 6% by weight is sufficient for most applications. VG-69™ and VG-PLUS™ are organoclay materials distributed by M-I L.L.C., and VERSA-HRP™ is a polyamide resin material manufactured and distributed by M-I L.L.C., that may be used in the fluids disclosed herein.

[0059] One skilled in the art would appreciate that depending on components present in the fluid, the pH of the fluid may change. In particular embodiments of the present disclosure, the pH of the LCM treatment fluid may be less than about 10, and between about 7.5 and 8.5 in other embodiments. However, in other embodiments, a greater pH may be desired, and may be achieved by including an alkaline material such as lime to the pill.

[0060] In one or more embodiments, wellbore fluids in accordance with the present disclosure may include at least one fiber additive to aid in suspension and to provide additional compressive strength to the resulting plug or seal. However, other embodiments may use other LCM materials, where the addition of the fiber may restore at least a portion of the strength loss due to the incorporation of a weighting agent. As used herein, the term “fiber” refers to an additive that has an elongated structure. The fiber may be inert with respect to the base fluid and the LCM-forming components.

[0061] Various embodiments of the present disclosure may use a fiber that has an elongated structure, which may be spun into filaments or used as a component of a composite material such as paper. In a particular embodiment, the fibers may range in length from greater than 3 mm to less than 20 mm. While some embodiments may use a synthetic fiber, other embodiments may include either a naturally occurring fibrous (such as cellulose) material, and/or a synthetic (such as polyethylene, or polypropylene) fibrous material.

[0062] Synthetic fibers may include, for example, polyester, acrylic, polyamide, polyolefins, polyaramid, polyurethane, vinyl polymers, glass fibers, carbon fibers, regenerated cellulose (rayon), and blends thereof. Vinyl polymers may include, for example, polyvinyl alcohol. Polyesters may include, for example, polyethylene terephthalate, polytriphenylene terephthalate, polybutylene terephthalate, polylatic acid, and combinations thereof. Polyamides may include, for example, nylon 6, nylon 6,6, and combinations thereof. Polyolefins may include, for example, propylene based homopolymers, copolymers, and multi-block interpolymers, and ethylene based homopolymers, copolymers, and multi-block interpolymers, and combinations thereof. The fiber may be added to the pill in an amount ranging from 0.5 ppb to 10 ppb in some embodiments; however, more or less may be desired depending on the particular application.

[0063] A natural fiber may optionally be used with the LCM materials (including silicate particles or other LCM materials) to aid in suspension and viscosification of the slurry, as well as provide additional compressive strength to the resulting plug or seal. As used herein, the term "natural fiber" refers to an additive formed from a naturally occurring material that has an elongated structure, which may be spun into filaments or used as a component of a composite material such as paper. Similar to the synthetic fiber described above, the natural fiber may be inert (does not react with) with respect to the base fluid and to the LCM materials. When included, natural fibers may be present in an amount up to 50 percent by weight of the pill.

[0064] Natural fibers generally include vegetable fibers, wood fibers, animal fibers, and mineral fibers. In particular, the natural fibers include cellulose, a polysaccharide containing up to thousands of glucose units. Cellulose from wood pulp has typical chain lengths between 300 and 1700 units, whereas cotton and other plant fibers as

well as bacterial celluloses have chain lengths ranging from 800 to 10,000 units. In other embodiments, cellulose fibers may be either virgin or recycled, extracted from a wide range of plant species such as cotton, straw, flax, wood, *etc.*

[0065] Further, as mentioned above, the pills of the present disclosure may optionally include at least one weighting agent to provide the desired weight to the pills. As is known in the art, control of density may be desired to balance pressures in the well and prevent a blowout. To prevent a blowout, the fluid in the well may have a density effective to provide a greater pressure than that exerted from the formation into the well. However, fluids having a density that place pressures on the formation that exceed the fracture strength of the formation may cause further lost circulation. Thus, it is often desirable to modify the density of a wellbore fluid with weighting agents to balance the pressure requirements of the well. Weighting agents may be selected from one or more of the materials including, for example, barium sulfate, calcium carbonate, dolomite, ilmenite, hematite or other iron ores, olivine, siderite, manganese oxide, and strontium sulfate. Additionally, it is also within the scope of the present disclosure that the fluid may also be weighted up using salts (either in a water- or oil-based pill) such as those described above with respect to brine types. Selection of a particular material may depend largely on the density of the material. The lowest wellbore fluid viscosity at any particular density is obtained by using the highest density particles. Weighting agents may be added to the pill in an amount such that the final density may range from 6.5 pounds per gallon (ppg) to 20 ppg in some embodiments.

[0066] In addition to the above materials within the scope of the present disclosure tja that bridging agents may also be incorporated into a wellbore fluid. Particulate-based treatments may include use of particles frequently referred to in the art as bridging materials. For example, such bridging materials may include at least one substantially crush resistant particulate solid such that the bridging material props open and bridges or plugs the fractures (cracks and fissures) that are induced in the wall of the wellbore. As used herein, "crush resistant" refers to a bridging material is physically strong enough to resist the closure stresses exerted on the fracture bridge. Examples of bridging materials suitable for use in the present disclosure include graphite, calcium carbonate (such as marble), dolomite ($MgCO_3 \cdot CaCO_3$), celluloses, micas, proppant

materials such as sands or ceramic particles and combinations thereof. Such particles may range in size from 25 microns to 1500 microns. Selection of size may depend on the level of fluid loss, the fracture width, the formation type, *etc.*

[0067] Application of LCM-forming components adjacent a permeable formation may be accomplished by methods known in the art. For example, "thief zones" or permeable intervals will often be at or near the bottom of the wellbore and will begin to absorb drilling fluids when exposed during drilling operations. In such situations, a LCM treatment may be spotted adjacent the permeable formation by pumping a slug or pill of the treatment down and out of the drill pipe or drill bit as is known in the art. It may be, however, that the permeable formation is at a point farther up in the wellbore, which may result, for example, from failure of a previous seal. In such cases, the drill pipe may be raised as is known in the art so that the pill or slug of the LCM treatment may be deposited adjacent the permeable formation. The volume of the slug of LCM treatment that is spotted adjacent the permeable formation may range from less than that of the open hole to more than double that of the open hole.

[0068] In some instances, more than one sequence of the described fluid system treatments may be applied to produce sufficient LCM material to treat a given interval experiencing fluid loss. Such need may arise when a first treatment is insufficient to plug the fissures and thief zone or was placed incorrectly. Further, in some instances, the first round of treatment may have sufficiently plugged the first lost circulation zone, but a second (or more) lost circulation zone may also exist that warrants further treatment.

[0069] It is also within the scope of the present disclosure that one or more spacer pills may be used in conjunction with the pills of the present disclosure. A spacer is generally characterized as a thickened composition that functions primarily as a fluid piston in displacing fluids present in the wellbore and/or separating two fluids from each other.

[0070] Embodiments of the present disclosure may provide for a lost circulation fluid that may be useful in high and low fluid loss zones. Use of the fluid systems of the present disclosure may allow for the formation of a plug or seal of a permeable formation that has a high compressive strength, which allows for greater pressures to be used without risk of experiencing further losses to the sealed lost circulation zone.

[0071] While the disclosure has presented 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 disclosure as presented herein. Moreover, embodiments described herein may be practiced in the absence of any element that is not specifically disclosed herein. Accordingly, the scope of the disclosure should be limited only by the attached claims.

CLAIMS

What is claimed:

1. A method comprising:
   drilling at least a section of a wellbore using a first wellbore fluid comprising:
      a first base fluid, and
      a first LCM-forming component;
   injecting, upon experience of a fluid loss, a second wellbore fluid comprising:
      a second base fluid, and
      a second LCM-forming component; and
   reacting the first LCM-forming component with the second LCM-forming component to form an LCM that reduces the fluid loss.

2. The method of claim 1, wherein the first base fluid is an invert emulsion.

3. The method of claim 1, further comprising resuming drilling operations after the formed LCM reduces fluid loss.

4. The method of claim 1, wherein injecting the second wellbore fluid comprises injecting the second wellbore fluid through an opening present on a drill bit and/or drill string.

5. The method of claim 1, wherein forming an LCM is triggered by temperature, electromagnetic radiation, pH, or shear.

6. The method of claim 1, wherein the second LCM-forming component is encapsulated.

7. The method of claim 5, wherein the encapsulated second LCM-forming component remains encapsulated when exposed to shear forces below about 15,000 s^{-1}.

8. The method of claim 6, wherein the encapsulated second LCM-forming component is activated by subjecting the encapsulated second LCM-forming component to shear forces of at least 15,000 s^{-1}.

9. The method of claim 7, wherein the shear forces are generated by pumping the second wellbore fluid through an opening present on a drill bit and/or drill string.

10. The method of claim 5, wherein the encapsulated second LCM-forming component is activated by temperature, electromagnetic radiation, pH, or shear.

11. The method of claim 1, wherein the first LCM-forming component is one or more silicates, and the second LCM-forming component is at least one of an alcohol, polyol, amine, or polyamine.

12. The method of claim 1, wherein the first LCM-forming component is at least one of an alcohol, polyol, amine, or polyamine; and the second LCM-forming component is one or more silicates.

13. The method of claim 1, wherein the second wellbore fluid is pumped as a fluid loss pill.

14. The method of claim 1, wherein the formed LCM is an alcohol crosslinked silicate.

15. A fluid system comprising:
    a first component comprising a first base fluid and a first LCM-forming component; and
    a second component comprising a second base fluid and a second LCM-forming component, wherein the second LCM-forming component is capable of reacting with the first LCM-forming component to form a LCM.

16. The system of claim 15, wherein the second LCM-forming component is encapsulated.

17. The system of claim 16, wherein the encapsulated second LCM-forming component remains encapsulated when exposed to shear forces below about 15,000 s^{-1}.

18. The system of claim 15, wherein the first base fluid is an invert emulsion.

19. The system of claim 15, wherein the first LCM-forming component is at least one of alcohol, polyol, amine, or polyamine; and the second LCM-forming component is one or more silicates.

20. The system of claim 15, wherein the first LCM-forming component is one or more silicates; and the second LCM-forming component is at least one of an alcohol, polyol, amine, or polyamine.

21. A method comprising drilling at least a section of a wellbore with a wellbore fluid comprising:
a base fluid; and

an encapsulated LCM component, wherein the encapsulated LCM component is inactive when exposed to shear forces below about 10,000 s^{-1}.

22. The method of claim 21, wherein the encapsulated LCM component become at least partially active when exposed to shear forces greater than about 12,000 s^{-1}.

23. The method of claim 21, wherein the encapsulated LCM component becomes at least partially active when exposed to shear forces greater than about 15,000 s^{-1}.

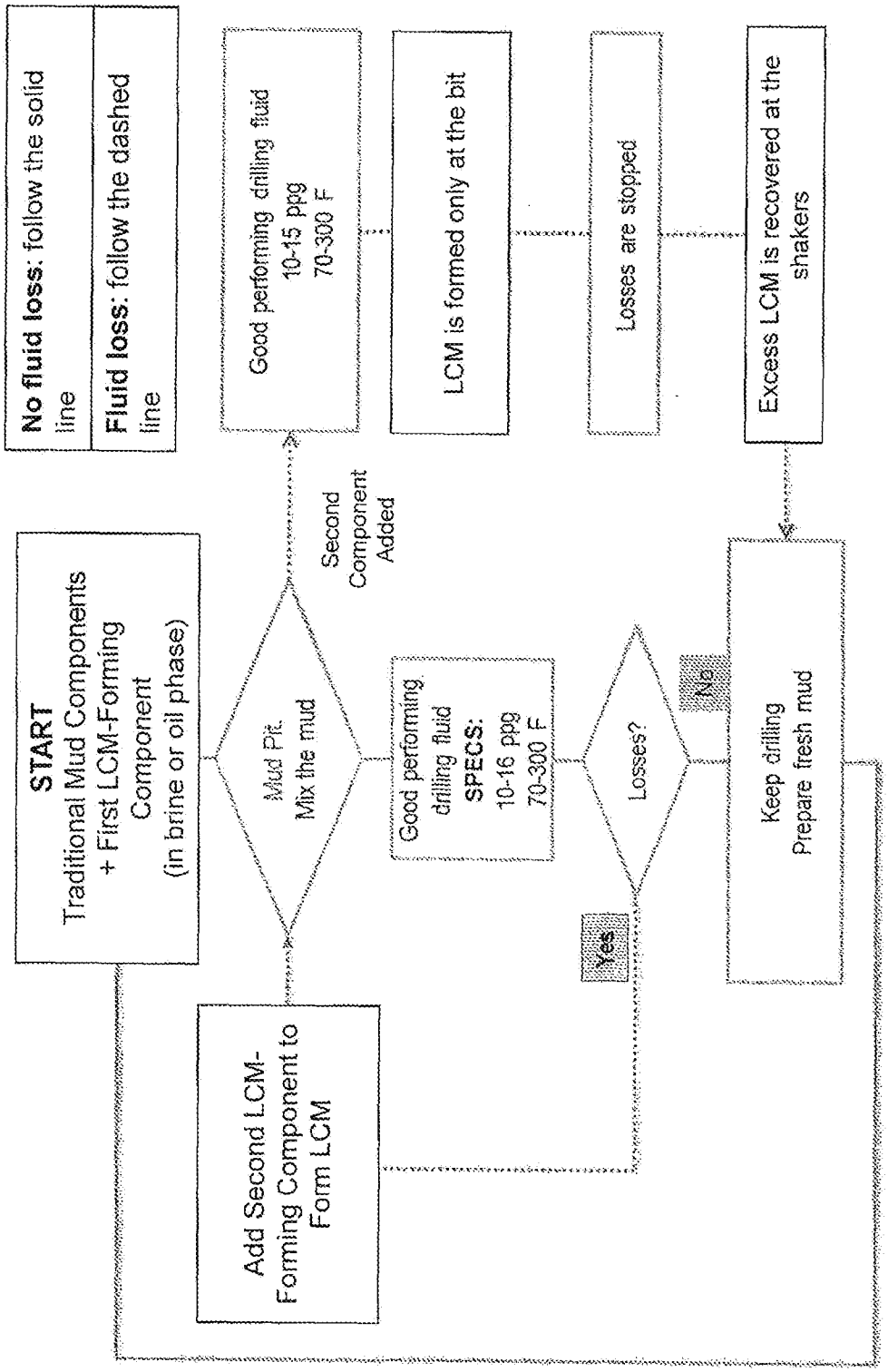

No fluid loss: follow the solid line
Fluid loss: follow the dashed line
START
Traditional Mud Components + First LCM-Forming Component (in brine or oil phase)
Mud Pit
Mix the mud
Second Component Added
Good performing drilling fluid
10-15 ppg
70-300 F
Good performing drilling fluid
SPECS:
10-16 ppg
70-300 F
LCM is formed only at the bit
Losses?
Yes
No
Losses are stopped
Excess LCM is recovered at the shakers
Keep drilling
Prepare fresh mud
Add Second LCM-Forming Component to Form LCM

FIG. 1

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/023253

A. CLASSIFICATION OF SUBJECT MATTER

C09K 8/487(2006.01)i, C09K 8/36(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)
C09K 8/487; E21B 43/00; C09K 7/02; C09K 8/08; E21B 33/13; E21B 43/16; C09K 8/00; C09K 8/36

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: alcohol, crosslinked, silicate, lost circulation material (LCM), drilling, crosslinking, ethylene glycol ethyl ether

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2013-0133888 A1 (M-I L.L.C.) 30 May 2013 See paragraphs [0012], [0032], [0036], [0055]-[0058], [0064] and [0065]; and claims 7 and 19.	1-5,13,15,18
Y		6-10,16,17
A		11,12,14,19-23
X	US 2011-0139454 A1 (SHINDGIKAR, NIKHIL et al.) 16 June 2011 See paragraphs [0015], [0028] and [0031]; and claims 14, 19 and 20.	21-23
Y		6-10,16,17
A	US 2006-0079408 A1 (VERRET, ROBIN J.) 13 April 2006 See paragraphs [0002] and [0016].	1-23
A	US 4473480 A (GREEN, PETER C. et al.) 25 September 1984 See claims 1-5.	1-23
A	US 2007-0034410 A1 (XIANG, TAO) 15 February 2007 See paragraph [0007]; and claims 1-4.	1-23

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

☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"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
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
22 June 2015 (22.06.2015)	**22 June 2015 (22.06.2015)**

Name and mailing address of the ISA/KR
International Application Division
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INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/023253

Box No. II Observations where certain claims were found unsearchable (Continuation of item 2 of first sheet)

This international search report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:

2. ☐ Claims Nos.:
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:

3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box No. III Observations where unity of invention is lacking (Continuation of item 3 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

Invention group I (Claims 1-20): A fluid system comprising (1) a first wellbore fluid comprising a first base fluid and a first LCM-forming component, and (2) a second wellbore fluid comprising a second base fluid and a second LCM-forming component, wherein the first LCM-forming component is capable of reacting with the second LCM-forming component to form an LCM, and a method involving the fluid system.

Invention group II (Claims 21-23): A method comprising drilling at least a section of a wellbore with a wellbore fluid comprising: a base fluid and an encapsulated LCM component, wherein the encapsulated LCM component is inactive when exposed to shear forces below about 10,000 s-1.

1. ☐ As all required addtional search fees were timely paid by the applicant, this international search report covers all searchable claims.

2. ☒ As all searchable claims could be searched without effort justifying an additional fees, this Authority did not invite payment of any additional fees.

3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:

4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest

☐ The additional search fees were accompanied by the applicant's protest and, where applicable, the payment of a protest fee.

☐ The additional search fees were accompanied by the applicant's protest but the applicable protest fee was not paid within the time limit specified in the invitation.

☐ No protest accompanied the payment of additional search fees.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.
PCT/US2015/023253

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
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		AU 2007-240294 B2	03/11/2011
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		US 7226895 B2	05/06/2007
		US 7507692 B2	24/03/2009