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(54) WELLBORE FLUIDS FOR CEMENT DISPLACEMENT OPERATIONS

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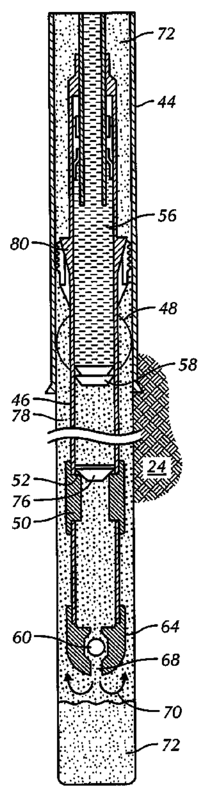
(57) **ABSTRACT**

A method of cementing a pipe into a wellbore filled with a drilling fluid that includes displacing the drilling fluid with the displacement fluid which includes a base fluid, a micronized weighting agent; suspending a pipe in the wellbore; and pumping cement into the wellbore to substantially fill the annulus formed between the outer surface of the pipe and the wellbore is disclosed.



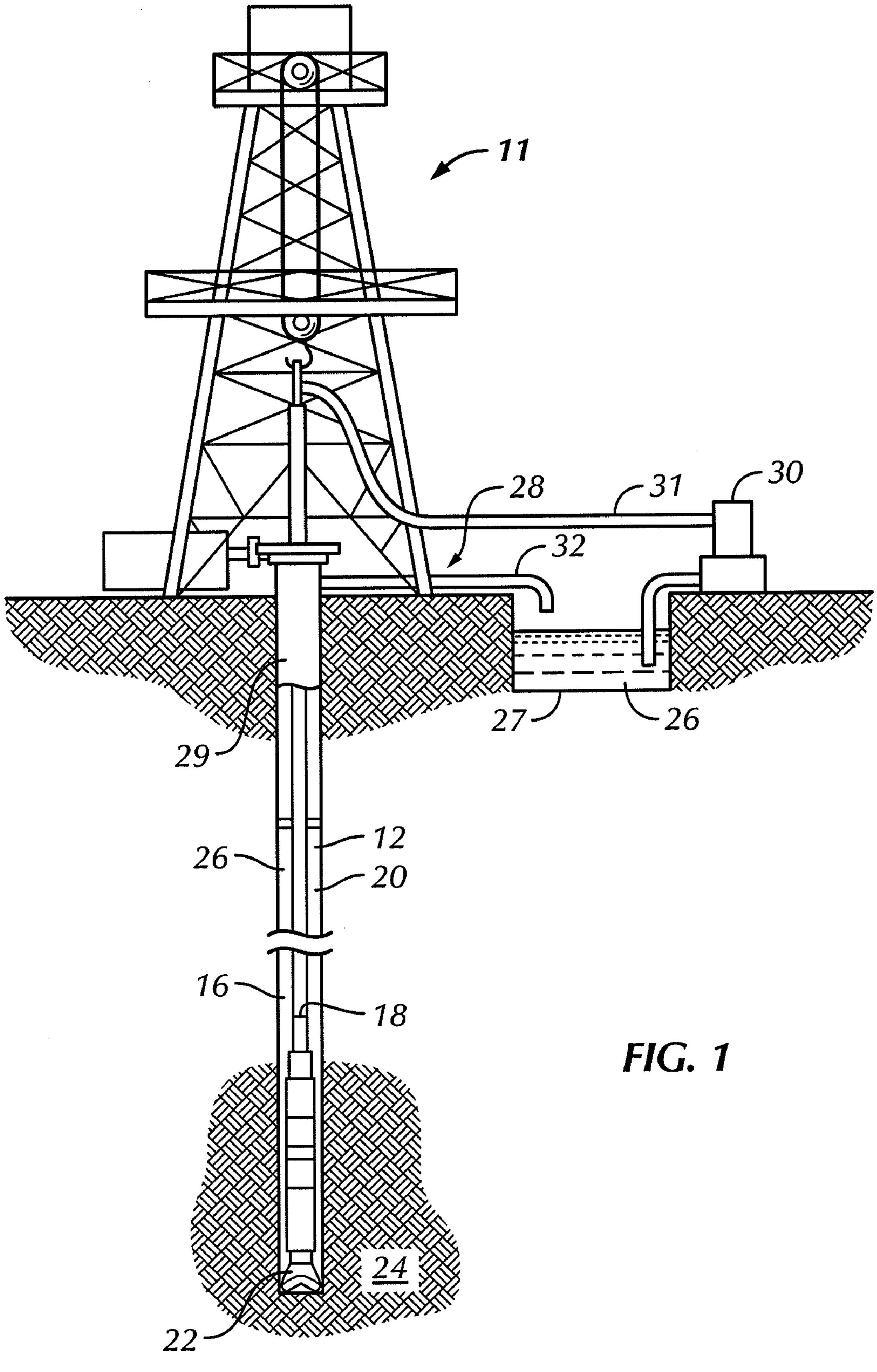


FIG. 1

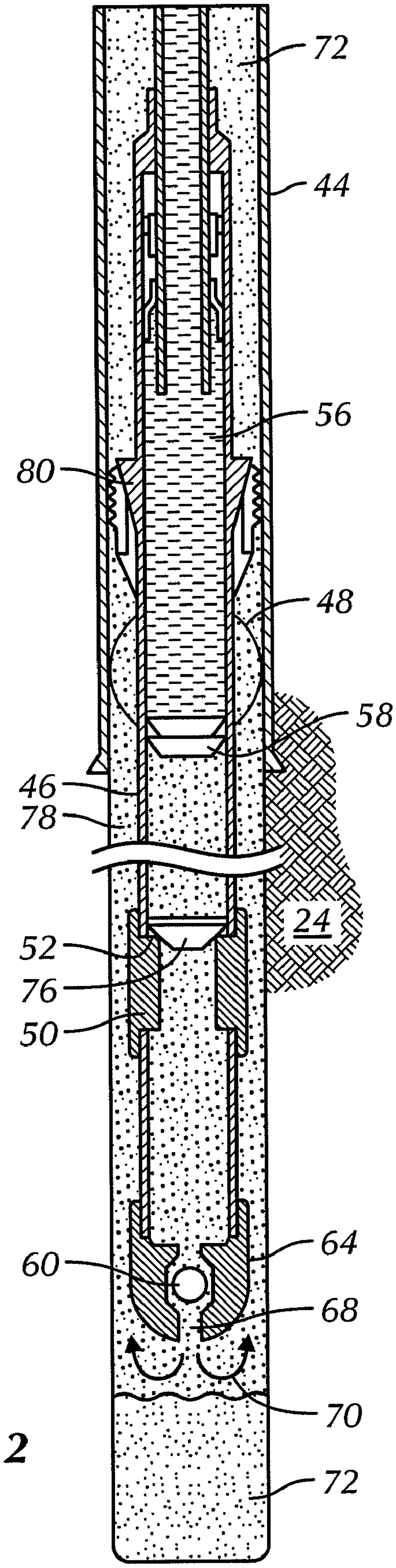


FIG. 2

WELLBORE FLUIDS FOR CEMENT DISPLACEMENT OPERATIONS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation-in-part of co-pending U.S. patent application Ser. Nos. 11/737,284 and 11/737,303, which are, respectively, a continuation application and a divisional application of U.S. patent application Ser. No. 10/610,499, which is a continuation-in-part of U.S. application Ser. No. 09/230,302, which is the U.S. national phase application under 35 U.S.C. § 371 of a PCT International Application No. PCT/EP97/003802, filed Jul. 16, 1997 which in turn claims priority under the Paris Convention to United Kingdom Patent Application No. 9615549.4 filed Jul. 24, 1996. This application is also a continuation-in-part application of co-pending U.S. patent application Ser. No. 11/617,576, which is a continuation application of U.S. patent application Ser. No. 11/145,054, now U.S. Pat. No. 7,176,165, which claims priority to U.S. Provisional Application Ser. No. 60/576,420. This application is also a continuation-in-part application of co-pending U.S. patent application Ser. No. 11/617,031, which is a continuation application of U.S. patent application Ser. No. 11/145,053, now U.S. Pat. No. 7,169,738, which claims priority to U.S. Provisional Application Ser. No. 60/576,420. This application is also a continuation-in-part application of U.S. patent application Ser. No. 11/741,199, which claims priority to U.S. Provisional Application Ser. No. 60/825,156. Each of the above listed priority documents is hereby incorporated by reference.

BACKGROUND OF INVENTION

[0002] 1. Field of the Invention

[0003] Embodiments disclosed here generally relate to wellbore fluids for use in cement displacement applications and methods of using such fluids.

[0004] 2. Background Art

[0005] In the drilling of oil and gas wells, a borehole is formed in the earth with a drill bit typically mounted at the end of a string of relatively small diameter tubing or drill string. Upon drilling a predetermined length successfully, the wellbore is typically prepared for its completions phase by isolating formations transversed by the wellbore with a casing string. Specifically, the bit and drill string are removed from the well, and a larger diameter string of casing or liner is inserted therein.

[0006] Generally, the annulus between the casing and the borehole wall or between the liner and casing is filled with a cement slurry which will permanently seal the annulus and provide structural support for the casing or liner. After the cement slurry is pumped into the annulus, it hardens to bond the casing to the borehole or liner to prevent fluids in one formation from migrating to another, and also prevents corrective formation fluids from damaging the casing. The cement slurry is formed at the well site prior to cementing, by mixing a dry cementious material such as fly ash with water to form a thin, watery mixture that is easy to pump. Once hardened in the annulus, cement is critical for not only supporting and protecting casing but also for sealing formation pressures hydraulically.

[0007] Additionally, cementing operations are used to provide zonal isolation, a means to prevent wellbore fluids from contaminating sensitive zones such as freshwater aquifers and production intervals. An important factor for successful cementing is adequate drilling fluid removal, or "mud displacement." To enhance mud removal, a primary technique used is to pump a displacement and/or spacer fluid with modified rheology ahead of the cement slurry to improve mud displacement.

[0008] Several factors are known to directly impact the success of a cement operation, including wellbore geometry, mud conditioning, casing movement via reciprocation and rotation, mud displacement, casing centralization, and optimizing the pump rate. Of these factors, the displacement of the drilling fluid is of critical relevance. In some cases, the rheology of the drilling fluid being displaced may be such that the pressures in the wellbore while pumping the cement slurry may exceed the fracture pressure of the formation. This undesirable event may result in significant fluid loss to the formation, and consequently a significant increase in cost due to increased wait time or remedial repair.

[0009] Generally, in any wellbore pumping operation including the pumping of drilling fluids, cementing fluids, and fracturing fluids where the formation fracture pressure is low, pump pressures and ECD may need to be reduced to prevent the formation from being fractured and inducing fluid losses. For cementing operations in particular, to prevent the formation from being fractured, the flow rate and pump pressure are reduced. By reducing the flow rate, the time required to complete the cement operation and to place the cement into the annulus is lengthened. Thus, a critical property of a cement slurry is the 'thickening time.' The thickening time is a relative indication of the hardening process of the cement slurry and is a measure of the time required for the cement slurry to become too viscous to be pumpable. It is thus essential that the time required to place and pump the cement slurry into the annulus is less than the thickening time of the cementing slurry. Being able to pump a cement slurry in the annulus, with flow rates as high as possible, preferably under turbulent flow conditions, in the shortest possible time, within the constraints of formation pore and fracture pressures is highly desirable.

[0010] While cementing efficiencies and zonal isolation may be realized with proper drilling fluid displacement, cementing generally requires for a much narrower hydraulic tolerance upon the borehole, thus restricting pump pressures and high flow rates. For example, the small annular spacing from which a drilling fluid is being displaced and into which the cement slurry is being pumped generally leads to increased frictional forces and pressures, which in turn may lead to an elevated equivalent circulation density (ECD). If the ECD of the drilling fluid exceeds the ability of the formation to resist fracture, fluid losses (also referred to as lost circulation events) typically result. Additionally, due to narrow fracture formation pressure, little room is left for conventional ECD reduction devices, and thus, ECD must be controlled by tailoring the rheological properties of the drilling fluid.

[0011] Generally, wellbore fluids may 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 typically maintained at a higher pressure than the pore pressure. While it is highly advantageous to maintain the wellbore pressures above the pore pressure, on the other hand, if the pressure exerted by the wellbore fluids exceeds the fracture resistance of the formation, a formation fracture and thus induced wellbore fluid losses may occur. Further, with a formation fracture, when the wellbore fluid in the annulus flows into the fracture, the loss of wellbore fluid may cause 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 typically defines an upper limit for allowable wellbore pressure in an open wellbore while the pore pressure defines a lower limit. Therefore, a major constraint on well design and selection of wellbore fluids is the balance between varying pore pressures and formation fracture pressures or fracture gradients though the depth of the well.

[0012] A particularly challenging situation arises in depleted reservoirs, in which high pressured formations are neighbored by or inter-bedded with normally or abnormally pressured zones. For example, high permeability pressure depleted sands may be neighbored by high pressured low permeability rocks, such as shale or high pressure sands. This can make the drilling and completion of certain depleted zones nearly impossible because the wellbore fluid weight required to support the shale exceeds the fracture resistance of the pressure depleted sands and silts.

[0013] Thus, there remains an increasing need for wellbore fluids having the rheological profiles that enable wells to be drilled, cemented, and completed more easily. Drilling fluids having tailored Theological properties ensure that cuttings are removed from the wellbore as efficiently and effectively as possible to avoid the formation of cuttings beds in the well which can cause the casing string to become stuck, among other issues. There is also the need from a hydraulics perspective (equivalent circulating density) to reduce the pressures required to circulate the fluid, this helps to avoid exposing the formation to excessive forces that can fracture the formation causing the fluid, and possibly the well, to be lost. In addition, an enhanced rheology profile is desired to prevent settlement or sag, i.e., solids falling out of suspension, of any weighting agents present in the fluid. If settlement or sag occurs, an uneven density profile within the circulating fluid system, and thus well control (gas/fluid influx) and wellbore stability problems (caving/fractures), may result.

[0014] To obtain the fluid characteristics required to meet these challenges, the fluid must be easy to pump so only a small amount of pressure is required to force it through restrictions in the circulating fluid system, such as bit nozzles, down-hole tools, or narrow wellbore annuli. In other words, the fluid must have the lowest possible viscosity under high shear conditions.

[0015] Wellbore fluids used during drilling operations, specifically, may if properly designed, also be used as displacement and/or as spacer fluids prior to pumping the cement slurry into the borehole. Thus, such fluids having this rheological compatibility may be used in both the drilling and completion of a wellbore. If a higher rheology fluid is used during drilling, a tailored wellbore fluid having low rheology properties of plastic viscosity, yield point, viscometer 6 rpm dial readings, and gel strengths may be displaced into the wellbore prior to cementing to reduce pump pressure and equivalent circulating density (ECD) while cementing. As known in the art, maintaining pump pressures and ECD below the fracture pressure of the formation prevents costly fluid losses to permeable formations. In addition, higher flow rates of the cement slurry and sufficiently better zonal coverage around the casing or liner are desired to avoid costly secondary and tertiary remedial operations. As will be further appreciated by those skilled in the art, proper cement displacement often results in more efficient clean up for a stronger cement bond and the rotation of casing or liner during the cement operation.

[0016] Being able to also formulate a wellbore fluid having a low rheology is important in cementing operations where a reduction in ECD and complete removal of residual wellbore fluids is required. High rheology properties can result in an increase in pressure at the bottom of the hole under pumping conditions. Increases in ECD, as mentioned above, can result in opening fractures in the formation, and serious losses of the wellbore fluid into the fractured formation. Further, the stability of the suspension is also important in order to maintain the hydrostatic head to avoid a blow out. The goal of low rheology fluids with low viscosity plus minimal sag of weighting material continues to be a challenge.

[0017] Another highly desirable feature of the drilling fluid, which is being displaced from the annulus by the spacers, pre-flushes, chemical washes that are pumped ahead of the cementing fluid, is the ability to remove residual drilling fluid from the wellbore and casing/liner to effect a good cement bond between the cement slurry and the casing/liner. If residual drilling fluid remains the casing and/or wellbore before the cement slurry is placed, a micro-annulus or channel may result, thereby favouring interzonal intercommunication and an incomplete bond between the cement and casing or wellbore that may, at some later date, require remedial treatment. Drilling fluids that are viscous, with high gel strengths are particularly problematic to the ultimate success of a cementing operation and in some cases, as mentioned above, it is necessary to reduce the rheology of the drilling fluid prior to the cementing operation. However, reducing the rheology of a drilling fluid may induce settlement of the drilling fluid weight material which may then be difficult to remove by the cementing fluid, cause channeling and ultimately an incomplete bond between the cementing fluid and casing.

[0018] Thus, one requirement of these wellbore fluid formulations is that the additives therein form a stable suspension and do not readily settle out. A second requirement is that the suspension exhibits a tailored viscosity and controlled ECD in order to facilitate pumping and to minimize the generation of high pressures, while also preventing settlement or sag. Finally, the wellbore fluid should also prevent fluid losses.

[0019] Accordingly, there exists a continuing need for wellbore fluids that control fluid ECD while simultaneously reducing wellbore pressures and minimizing both fluid loss and increases in pressure, and in particular, fluids that may be used in cement displacement operations.

SUMMARY OF INVENTION

[0020] In one aspect, the embodiments disclosed herein relate to a method of cementing a pipe into a wellbore filled with a drilling fluid that includes displacing the drilling fluid with the displacement fluid which includes a base fluid, a micronized weighting agent; suspending a pipe in the wellbore; and pumping cement into the wellbore to substantially fill the annulus formed between the outer surface of the pipe and the wellbore.

[0021] In another aspect, the embodiments disclosed herein relate to a method of drilling and cementing a wellbore that includes drilling the wellbore with a drilling fluid; displacing the drilling fluid with a displacement fluid comprising: a base fluid; and a micronized weighting agent; suspending a pipe in the well; and pumping cement into the well so as to fill the annulus formed between the outer surface of the pipe and the wellbore.

[0022] In yet another aspect, the embodiments disclosed herein relate to a method of drilling and cementing a wellbore that includes drilling the wellbore with a wellbore fluid comprising: a base fluid; and a micronized weighting agent; suspending a pipe in the well; and pumping cement into the well so as to fill the annulus formed between the outer surface of the pipe and the wellbore.

[0023] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0024] FIG. **1** shows a schematic of one embodiment of a drilling operation or system.

[0025] FIG. **2** shows a schematic of one embodiment of a cement displacement operation.

DETAILED DESCRIPTION

[0026] In one aspect, embodiments disclosed herein relate to the use of micronized weighting agents in wellbore fluids used in cement displacement operations. Such fluids may include micronized weighting agents mixed into a base fluid which may be any of a number of fluids including water, seawater, brine, mineral oil, diesel, and synthetic oils. Use of these fluids may provide for a fluid to be present in the annulus prior to the cementing operation that possesses a low rheology and low gel strength, which may improves the effectiveness/efficiency of cement spacers, washes and pre-flushes to remove residual drilling fluid prior to the cementing operation, and which in turn may improve the quality of the cement bond between casing and wellbore and overall quality of the cementing operation. Such fluids may also have improved rheology and ECD properties to simultaneously reduce wellbore pressures and minimize both fluid loss and increases in pressure in the wellbore during cement operations.

[0027] The wellbore fluids of the present disclosure may, as disclosed herein, be pumped prior to the cement displacement operation, in which a cement slurry is displaced into the annulus between a pipe and the walls of the borehole. In particular, the wellbore fluids may be referred to as a displacement fluid because they are used to displace the fluids used in drilling from the wellbore prior to cementing. Similarly, displacement fluids may also be used to displace fluid or a cement slurry out of the casing string and into the annulus to complete the cement displacement operation.

[0028] As used herein, the term pipe may include any "casing," "liner," "tubular," "casing string," "liner string," or "string" is known in art to be cemented in place in the wellbore, to provide structural integrity to the wellbore.

[0029] Referring to FIG. **1**, one embodiment of a typical drilling system is shown. As shown in FIG. **1**, a drilling rig **11** is disposed atop a borehole **12**. A drill bit **22** is located at the lower end of the drill string **18** and carves a borehole **12** through the earth formation **24**. Drilling mud **26** is pumped from a storage reservoir pit **27** near the wellhead **28**, down an axial passage (not shown) through the drill string **18**, out of apertures in the bit **22** and back to the surface through the annular region **16**, generally referred to as the annulus. Casing **29** is positioned in the borehole **12** above the drill bit **22** for maintaining the integrity of the upper portion of the borehole **12**.

[0030] Segments of casing **29** are placed in borehole **12**. Thus, after following drilling of a segment thereof, to place the casing **29**, the drill string **18** is pulled out of the borehole, a string of casing **29** (or liner) is run into the well at least down to the formation **24** which is believed to contain oil and/or gas hydrocarbons. Greater details of such placements are shown in FIG. **2**.

[0031] Referring to FIG. **2**, a close-up view of the placement and cementing of a liner **46** is shown. As shown in FIG. **2**, borehole **42** drilled into a subterranean formation **24** from an offshore or onshore rig has suspended therein a length of liner **46** to be cemented in place. The liner **46** is suspended by a hanger **80** positioned in the lower portion of the casing **44**. The casing **44** is shown in the upper portion of the wellbore and a further extension of the wellbore as defined by wellbore walls **42** is shown. The term "liner" as used herein relates generally to a well casing whose upper end does not extend all the way to the surface, but is hung down hole from a larger diameter casing string. Thus, one skilled in the art would appreciate that the techniques described with respect to a liner would be the same or similar for cementing a casing or other pipe. Thus, embodiments of the present disclosure relate to both placement of casing and liners or other pipes.

[0032] Referring back to FIG. **2**, centralizers **48** center the liner **46**. Disposed at the bottom of the liner **46** is a landing collar **50** having an annular shoulder **52**. Float shoes **64** or landing collars **50** are attached to the lower end of the liner **46** and include an upwardly closing check valve **60** to prevent reverse flow of cement slurry **68** once it has been pumped through the check valves **60** and into the annulus **78** that is formed between the outer diameter of the liner **46** and the walls of the borehole **42**. The purpose of the cementing operation is to fill the annulus **78** so that fluids in the formation **24** that have been penetrated by the borehole **42** can not migrate therethrough. After the cementing operation is completed, a portion of the liner **46** may be perforated to bring the well into production, or a smaller diameter borehole may be drilled below the borehole **42** and then lined and cemented to deepen the well.

[0033] Still referring to FIG. **2**, during the drilling of the borehole **42**, borehole **42** is filled with a weighted wellbore mud **72** or "mud" that has hydrostatic head which overbalances the formation fluid pressure to prevent a blowout. Mud **72** is circulated to remove cuttings produced by the rotary drilling process. During cementing, the mud **72** located in annulus **78** is displaced by a cement slurry **68** and removed from the well. To prevent contamination or mixing of the cement slurry **68** by or with the mud **72**, a spacer fluid (not shown) may be pumped prior to the cement slurry **68** to separate the mud **72** from the cement slurry **68**.

[0034] A cementing head (not shown) is mounted on the top joint of the casing **44** hanging in the mast or derrick. Just before the cement slurry **68** arrives at the head, a wiper plug **76** is positioned at the lower end of the cement slurry **68** to maintain separation of the cement slurry **68** from mud **72** present in the casing or liner. The outer edge of each plug **76** is sized to sealingly engage the inner walls of the liner **46** while sliding downward. The bottom plug **76** separates the cement slurry **68** from any mud **72** inside the casing **44** and prevents the mud **72** from contaminating the cement **68**. As cement slurry **68** is pumped into the well, the cement slurry **68** forwards the bottom plug **76** down the casing **44**.

[0035] After pumping the desired quantity of cement slurry **68**, a top plug **58** is placed on top of the cement slurry **68**. The top plug **58** separates the last of the cement slurry **68** to go into the casing **44** from displacement fluid **56** pumped on top of the cement slurry **68**. Displacement fluid **56**, which is usually salt water or a specially formulated drilling mud, moves or displaces, the cement slurry **68** from the casing **44** as the cement pump applies pressure to move the cement slurry **68**, the top plug **58**, and the displacement fluid **56** down the casing.

[0036] As the cement pump applies pressure, the bottom plug **76** continues to travel down the string of pipe until it stops or seats in the landing collar **50**. Continued pumping is then used to rupture a membrane on the bottom plug **76** and open a passage therein. Cement slurry **68** then proceeds through the bottom plug **76** and continues down the last few joints of casing **44**. The cement slurry **68** flows through an opening in the guide shoe **64** and up the annulus **78** between the casing **44** and the borehole **42**. Pumping continues until the cement slurry **68** fills the annulus **78**. As the last of the cement slurry **68** enters the casing **44** pumped therethrough, the top plug **58** is released from the cementing head. The top plug **58** is similar to the bottom plug **76** with the exception that it has no membrane or passage.

[0037] Most of the cement slurry **68** flows out of the casing **44** and into the annulus **78**. Eventually, the top plug **58** seats on, or bumps, the bottom plug **76** in the landing collar **50**. When it bumps, the pump pressure is no longer applied. Cement slurry **68** is only in the casing below the landing collar **50** and in the annulus **78**. Most of the casing **44** is full of displacement fluid **56**. Cement slurry **68** is then allowed to set, bonding the liner **46** to the borehole walls **42** and/or to an inner surface of a portion of an above casing string.

[0038] As shown in FIG. **2** and described above, cement slurry **68** displaces mud **72** from the annulus **78**; however, in accordance with the present disclosure, mud **72** being displaced by cement slurry **68** may be a fluid formulated with micronized barite (or other weighting agents). Such micronized barite fluid may be used to displace the fluid having drilled the interval, and thus it is this micronized barite fluid which is displaced during cementing.

[0039] According to various embodiments, the wellbore fluids of the present disclosure may be used in cement displacement operations, where a casing string is to be sealed and/or bonded in the annular space between the walls of the borehole and the outer diameter of the casing with a cementing bonding material. In one embodiment, the wellbore fluid may include a base fluid and a micronized weighting agent. However, such a fluid may not be the fluid used to drill the well. Rather, following drilling of a given interval, once placement of a casing or liner is desired, the drilling fluid may be displaced by a micronized barite fluid. The drill bit and drill string may be pulled from the well and a casing or liner string may be suspended therein.

[0040] A cement slurry may be pumped through the interior of the casing, optionally separated from the micronized barite displacement fluid with one or more spacer fluids or plugs, as known in the art of cementing. Following the cement slurry, a second displacement fluid (for example, the fluid with which the next interval will be drilled or a fluid similar to the first displacement fluid) may displace the cement slurry into the annulus between the casing or liner and borehole wall. Once the cement slurry has set in the annular space, drilling of the next interval may continue. Prior to production, the interior of the casing or liner may be cleaned and perforated, as known in the art of completing a wellbore.

[0041] As discussed above, in order to prevent the formation being fractured during pumping of any fluids including during cementing operations, the flow rate (and hence pump pressure) is reduced. By reducing the flow rate, the time taken to complete the cement operation and place the cement in the annulus is lengthened such that it is less than the thickening time property of the cementing fluid, and the cement sets prior to being pumped into the correct location (as the cementing fluid thickens it will become so viscous it is unpumpable). By using the micronized barite fluids of the present disclosure, greater pump rates for a given ECD ceiling may be achieved, thus allowing for better placement of the cement slurry to avoid premature thickening.

[0042] Being able to pump a cement slurry in the annulus, with flow rates as high as possible, preferably under turbulent flow conditions, in the shortest possible time, within the constraints of formation pore and fracture pressures is highly desirable. As a consequence of using the "low rheology" micronized barite fluids of the present disclosure, higher flow rates may be achieved, the time taken to place the cementing fluid in the annulus may be reduced, and the risk of the cementing fluid prematurely hardening is similarly reduced. Additionally, for a formation susceptible to fracture, lower ECDs may result for a given pump rate of the fluids of the present disclosure.

[0043] Further, it is specifically within the scope of the embodiments disclosed herein that the micronized barite fluids of the present disclosure may, as an alternative, be used as drilling fluids, and be displaced by a cement slurry, without the use of an additional displacement fluid. Furthermore, while FIG. **2** described one embodiment of cement displacement; one skilled in the art would appreciate that the embodiment shown in, FIG. **2** is just one example of a cementing displacement operation and that there may be variations and/or different types of equipment and specific techniques used which do not depart from the scope of the invention as disclosed herein.

[0044] Micronized Weighting Agent

[0045] Fluids used in embodiments disclosed herein may include micronized weighting agents. In some embodiments, the micronized weighting agents may be uncoated. In other embodiments, the micronized weighting agents may be coated with a dispersant. For example, fluids used in some embodiments disclosed herein may include dispersant coated micronized weighting agents. The coated weighting agents may be formed by either a dry coating process or a wet coating process. Weighting agents suitable for use in other embodiments disclosed herein may include those disclosed in U.S. Patent Application Publication Nos. 20040127366, 20050101493, 20060188651, U.S. Pat. Nos. 6,586,372 and 7,176,165, and U.S. Provisional Application Ser. No. 60/825,156, each of which is hereby incorporated by reference.

[0046] Micronized weighting agents used in some embodiments disclosed herein may include a variety of compounds well known to one of skill in the art. In a particular embodiment, the weighting agent may be selected from one or more of the materials including, for example, barium sulphate (barite), calcium carbonate (calcite), dolomite, ilmenite, hematite or other iron ores, olivine, siderite, manganese oxide, and strontium sulphate. One having ordinary skill in the art would recognize that selection of a particular material may depend largely on the density of the material as typically, the lowest wellbore fluid viscosity at any particular density is obtained by using the highest density particles. However, other considerations may influence the choice of product such as cost, local availability, the power required for grinding, and whether the residual solids or filter cake may be readily removed from the well.

[0047] In one embodiment, the micronized weighting agent may have a d_{90} ranging from 1 to 25 microns and a d_{50} ranging from 0.5 to 10 microns. In another embodiment, the micronized weighting agent includes particles having a d_{90} ranging from 2 to 8 microns and a d_{50} ranging from 0.5 to 5 microns. One of ordinary skill in the art would recognize that, depending on the sizing technique, the weighting agent may have a particle size distribution other than a monomodal distribution. That is, the weighting agent may have a particle size distribution that, in various embodiments, may be monomodal, which may or may not be Gaussian, bimodal, or polymodal.

[0048] It has been found that a predominance of particles that are too fine (i.e. below about 1 micron) results in the formation of a high rheology paste. Thus, it has been unexpectedly found that the weighting agent particles must be sufficiently small to avoid issues of sag, but not so small as to have an adverse impact on rheology. Thus weighting agent (barite) particles meeting the particle size distribution criteria disclosed herein may be used without adversely impacting the rheological properties of the wellbore fluids. In one embodiment, a micronized weighting agent is sized such that: particles having a diameter less than 1 microns are 0 to 15 percent by volume; particles having a diameter between 1 microns and 4 microns are 15 to 40 percent by volume; particles having a diameter between 4 microns and 8 microns are 15 to 30 by volume; particles having a diameter between 8 microns and 12 microns are 5 to 15 percent by volume; particles having a diameter between 12 microns and 16 microns are 3 to 7 percent by volume; particles having a diameter between 16 microns and 20 microns are 0 to 10 percent by volume; particles having a diameter greater than 20 microns are 0 to 5 percent by volume. In another embodiment, the micronized weighting agent is sized so that the cumulative volume distribution is: less than 10 percent or the particles are less than 1 microns; less than 25 percent are in the range of 1 microns to 3 microns; less than 50 percent are in the range of 2 microns to 6 microns; less than 75 percent are in the range of 6 microns to 10 microns; and less than 90 percent are in the range of 10 microns to 24 microns.

[0049] The use of micronized weighting agents has been disclosed in U.S. Patent Application Publication No. 20050277553 assigned to the assignee of the current application, and herein incorporated by reference. Particles having these size distributions may be obtained by several means. For example, sized particles, such as a suitable barite product having similar particle size distributions as disclosed herein, may be commercially purchased. A coarser ground suitable material may be obtained, and the material may be further ground by any known technique to the desired particle size. Such techniques include jet-milling, ball milling, high performance wet and dry milling techniques, or any other technique that is known in the art generally for milling powdered products. In one embodiment, appropriately sized particles of barite may be selectively removed from a product stream of a conventional barite grinding plant, which may include selectively removing the fines from a conventional API-grade barite grinding operation. Fines are often considered a by-product of the grinding process, and conventionally these materials are blended with courser materials to achieve API-grade barite. However, in accordance with the present disclosure, these by-product fines may be farther processed via an air classifier to achieve the particle size distributions disclosed herein. In yet another embodiment the micronized weighting agents may be formed by chemical precipitation. Such precipitated products may be used alone or in combination with mechanically milled products.

[0050] In some embodiments, the micronized weighting agents include solid colloidal particles having a deflocculating agent or dispersant coated or sprayed onto the surface of the particle. Further, one of ordinary skill would appreciate that the term "colloidal" refers to a suspension of the particles, and does not impart any specific size limitation. Rather, the size of the micronized weighting agents of the present disclosure may vary in range and are only limited by the claims of the present application. The micronized particle size generates high density suspensions or slurries that show a reduced tendency to sediment or sag, while the dispersant on the surface of the particle controls the inter-particle interactions resulting in lower Theological profiles. Thus, the combination of high density, fine particle size, and control of colloidal interactions by surface coating the particles with a dispersant reconciles the objectives of high density, lower viscosity and minimal sag.

[0051] In some embodiments, a dispersant may be coated onto the particulate weighting additive during the comminution (grinding) process. That is to say, coarse weighting additive is ground in the presence of a relatively high concentration of dispersant such that the newly formed surfaces of the fine particles are exposed to and thus coated by the dispersant. It is speculated that this allows the dispersant to find an acceptable conformation on the particle surface thus coating the surface. Alternatively, it is speculated that because a relatively higher concentration of dispersant is in the grinding fluid, as opposed to that in a drilling fluid, the dispersant is more likely to be absorbed (either physically or chemically) to the particle surface. As that term is used in herein, "coating of the surface" is intended to mean that a sufficient number of dispersant molecules are absorbed (physically or chemically) or otherwise closely associated with the surface of the particles so that the fine particles of material do not cause the rapid rise in viscosity observed in the prior art. By using such a definition, one of skill in the art should understand and appreciate that the dispersant molecules may not actually be fully covering the particle surface and that quantification of the number of molecules is very difficult. Therefore, by necessity, reliance is made on a results oriented definition. As a result of the process, one can control the colloidal interactions of the fine particles by coating the particle with dispersants prior to addition to the drilling fluid. By doing so, it is possible to systematically control the rheological properties of fluids containing in the additive as well as the tolerance to contaminants in the fluid in addition to enhancing the fluid loss (filtration) properties of the fluid.

[0052] In some embodiments, the weighting agents include dispersed solid colloidal particles with a weight average particle diameter (d_{50}) of less than 10 microns that are coated with a polymeric deflocculating agent or dispersing agent. In other embodiments, the weighting agents include dispersed solid colloidal particles with a weight average particle diameter (d_{50}) of less than 8 microns that are coated with a polymeric deflocculating agent or dispersing agent; less than 6 microns in other embodiments; less than 4 microns in other embodiments; and less than 2 microns in yet other embodiments. The fine particle size will generate suspensions or slurries that will show a reduced tendency to sediment or sag, and the polymeric dispersing agent on the surface of the particle may control the inter-particle interactions and thus will produce lower Theological profiles. It is the combination of fine particle size and control of colloidal interactions that reconciles the two objectives of lower viscosity and minimal sag. Additionally, the presence of the dispersant in the comminution process yields discrete particles which can form a more efficiently packed filter cake and so advantageously reduce filtration rates.

[0053] Coating of the micronized weighting agent with the dispersant may also be performed in a dry blending or spray drying process such that the process is substantially free of solvent. The process includes blending the weighting agent and a dispersant at a desired ratio to form a blended material. In one embodiment, the weighting agent may be un-sized initially and rely on the blending process to grind the particles into the desired size range as disclosed above. Alternatively, the process may begin with sized weighting agents. The blended material may then be fed to a heat exchange system, such as a thermal desorption system. The mixture may be forwarded through the heat exchanger using a mixer, such as a screw conveyor. Upon cooling, the polymer may remain associated with the weighting agent. The polymer/weighting agent mixture may then be separated into polymer coated weighting agent, unassociated polymer, and any agglomerates that may have formed. The unassociated polymer may optionally be recycled to the beginning of the process, if desired. In another embodiment, the dry blending process alone may serve to coat the weighting agent without heating.

[0054] Alternatively, a sized weighting agent may be coated by thermal adsorption as described above, in the absence of a dry blending process. In this embodiment, a process for making a coated substrate may include heating a sized weighting agent to a temperature sufficient to react monomeric dispersant onto the weighting agent to form a polymer coated sized weighting agent and recovering the polymer coated weighting agent. In another embodiment, one may use a catalyzed process to form the polymer in the presence of the sized weighting agent. In yet another embodiment, the polymer may be preformed and may be thermally adsorbed or spray dried onto the sized weighting agent.

[0055] In some embodiments, the micronized weighting agent may be formed of particles that are composed of a material of specific gravity of at least 2.3; at least 2.4 in other embodiments; at least 2.5 in other embodiments; at least 2.6 in other embodiments; and at least 2.68 in yet other embodiments. For example, a weighting agent formed of particles having a specific gravity of at least 2.68 may allow wellbore fluids to be formulated to meet most density requirements yet have a particulate volume fraction low enough for the fluid to be pumpable.

[0056] As mentioned above, embodiments of the micronized weighting agent may include a deflocculating agent or a dispersant. In one embodiment, the dispersant may be selected from carboxylic acids of molecular weight of at least 150 Daltons, such as oleic acid and polybasic fatty acids, alkylbenzene sulphonic acids, alkane sulphonic acids, linear alpha-olefin sulphonic acids, phospholipids such as lecithin, including salts thereof and including mixtures thereof. Synthetic polymers may also be used, such as HYPERMER OM-1 (Imperial Chemical Industries, PLC, London, United Kingdom) or polyacrylate esters, for example. Such polyacrylate esters may include polymers of stearyl methacrylate and/or butylacrylate. In another embodiment, the corresponding acids methacrylic acid and/or acrylic acid may be used. One skilled in the art would recognize that other acrylate or other unsaturated carboxylic acid monomers (or esters thereof) may be used to achieve substantially the same results as disclosed herein.

[0057] When a dispersant coated micronized weighting agent is to be used in water-based fluids, a water soluble polymer of molecular weight of at least 2000 Daltons may be used in a particular embodiment. Examples of such water soluble polymers may include a homopolymer or copolymer of any monomer selected from acrylic acid, itaconic acid, maleic acid or anhydride, hydroxypropyl acrylate vinylsulphonic acid, acrylamido 2-propane sulphonic acid, acrylamide, styrene sulphonic acid, acrylic phosphate esters, methyl vinyl ether and vinyl acetate or salts thereof.

[0058] The polymeric dispersant may have an average molecular weight from about 10,000 Daltons to about 300,000 Daltons in one embodiment, from about 17,000 Daltons to about 40,000 Daltons in another embodiment, and from about 200,000-300,000 Daltons in yet another embodiment. One of ordinary skill in the art would recognize that when the dispersant is added to the weighting agent during a grinding process, intermediate molecular weight polymers (10,000-300,000 Daltons) may be used.

[0059] Further, it is specifically within the scope of the embodiments disclosed herein that the polymeric dispersant be polymerized prior to or simultaneously with the wet or dry blending processes disclosed herein. Such polymerizations may involve, for example, thermal polymerization, catalyzed polymerization, initiated polymerization or combinations thereof.

[0060] Given the particulate nature of the micronized and dispersant coated micronized weighting agents disclosed herein, one of skill in the art should appreciate that additional components may be mixed with the weighting agent to modify various macroscopic properties. For example, anti-caking agents, lubricating agents, and agents used to mitigate moisture build-up may be included. Alternatively, solid materials that enhance lubricity or help control fluid loss may be added to the weighting agents and drilling fluid disclosed herein. In one illustrative example, finely powdered natural graphite, petroleum coke, graphitized carbon, or mixtures of these are added to enhance lubricity, rate of penetration, and fluid loss as well as other properties of the drilling fluid. Another illustrative embodiment utilizes finely ground polymer materials to impart various characteristics to the fluid. In instances where such materials are added, it is important to note that the volume of added material should not have a substantial adverse impact on the properties and performance of the wellbore fluids. In one illustrative embodiment, polymeric fluid loss materials comprising less than 5 percent by weight are added to enhance the properties of the wellbore fluid. Alternatively, less than 5 percent by weight of suitably sized graphite and petroleum coke are added to enhance the lubricity and fluid loss properties of the fluid. Finally, in another illustrative embodiment, less than 5 percent by weight of a conventional anti-caking agent is added to assist in the bulk storage of the weighting materials.

[0061] The particulate materials as described herein (i.e., the coated and/or uncoated micronized weighting agents) may be added to a wellbore fluid as a weighting agent in a dry form or concentrated as slurry in either an aqueous medium or as an organic liquid.

[0062] As is known, an organic liquid should have the necessary environmental characteristics required for additives to oil-based drilling fluids. With this in mind, the oleaginous fluid may have a kinematic viscosity of less than 10 centistokes (10 mm^2/s) at 40° C. and, for safety reasons, a flash point of greater than 60° C. Suitable oleaginous liquids are, for example, diesel oil, mineral or white oils, n-alkanes or synthetic oils such as alpha-olefin oils, ester oils, mixtures of these fluids, as well as other similar fluids known to one of skill in the art of drilling or other wellbore fluid formulation. In one embodiment the desired particle size distribution is achieved via wet milling of the courser materials in the desired carrier fluid.

[0063] Wellbore Fluid Formulations.

[0064] In accordance with one embodiment, the micronized weighting agent may be used in a wellbore fluid formulation. The wellbore fluid may be a water-based fluid, an invert emulsion, or an oil-based fluid.

[0065] Water-based wellbore fluids may have an aqueous fluid as the base fluid and a micronized weighting agent. The aqueous fluid may include at least one of fresh water, sea water, brine, mixtures of water and water-soluble organic compounds and mixtures thereof. For example, the aqueous fluid may be formulated with mixtures of desired salts in fresh water. Such salts may include, but are not limited to alkali metal chlorides, hydroxides, or carboxylates, for example. In various embodiments of the drilling fluid disclosed herein, the brine may include seawater, aqueous solutions wherein the salt concentration is less than that of sea water, or aqueous solutions wherein the salt concentration is greater than that of sea water. Salts that may be found in seawater include, but are not limited to, sodium, calcium, aluminum, magnesium, potassium, strontium, and lithium, salts of chlorides, bromides, carbonates, iodides, chlorates, bromates, formates, nitrates, oxides, phosphates, sulfates, silicates, and fluorides. Salts that may be incorporated in a 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.

[0066] The oil-based/invert emulsion wellbore fluids may include an oleaginous continuous phase, a non-oleaginous discontinuous phase, and a micronized weighting agent. One of ordinary skill in the art would appreciate that the micronized weighting agents described above may be modified in accordance with the desired application. For example, modifications may include the hydrophilic/hydrophobic nature of the dispersant.

[0067] The oleaginous fluid may be a liquid, more preferably a natural or synthetic oil, and more preferably the oleaginous fluid is 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; similar compounds known to one of skill in the art; and mixtures thereof. The concentration of the oleaginous fluid should be sufficient so that an invert emulsion forms and may be less than about 99% by volume of the invert emulsion. In one embodiment, the amount of oleaginous fluid is from about 30% to about 95% by volume and more preferably about 40% to about 90% by volume of the invert emulsion fluid. The oleaginous fluid, in one embodiment, may include at least 5% by volume of a material selected from the group including esters, ethers, acetals, dialkylearbonates, hydrocarbons, and combinations thereof.

[0068] The non-oleaginous fluid used in the formulation of the invert emulsion fluid disclosed herein is a liquid and may be an aqueous liquid. In one embodiment, the non-oleaginous liquid may be selected from the group including sea water, a brine containing organic and/or inorganic dissolved salts, liquids containing water-miscible organic compounds, and combinations thereof. The amount of the non-oleaginous fluid is typically less than the theoretical limit needed for forming an invert emulsion. Thus, in one embodiment, the amount of non-oleaginous fluid is less that about 70% by volume, and preferably from about 1% to about 70% by volume. In another embodiment, the non-oleaginous fluid is preferably from about 5% to about 60% by volume of the invert emulsion fluid. The fluid phase may include either an aqueous fluid or an oleaginous fluid, or mixtures thereof. In a particular embodiment, coated barite or other micronized weighting agents may be included in a wellbore fluid having an aqueous fluid that includes at least one of fresh water, sea water, brine, and combinations thereof.

[0069] Conventional methods may be used to prepare the wellbore fluids disclosed herein in a manner analogous to those normally used, to prepare conventional water- and oil-based fluids. In one embodiment, a desired quantity of water-based fluid and a suitable amount of one or more micronized weighting agents, as described above, are mixed together and the remaining components of the drilling fluid added sequentially with continuous mixing. In another embodiment, a desired quantity of oleaginous fluid such as a base oil, a non-oleaginous fluid, and a suitable amount of one or more micronized weighting agents are mixed together and the remaining components are added sequentially with continuous mixing. An invert emulsion may be formed by vigorously agitating, mixing, or shearing the oleaginous fluid and the non-oleaginous fluid.

[0070] Other additives that may be included in the wellbore fluids disclosed herein include, for example, wetting agents, organophilic clays, viscosifiers, fluid loss control agents, surfactants, dispersants, interfacial tension reducers, pH buffers, mutual solvents, thinners, thinning agents, and cleaning agents. The addition of such agents should be well known to one of ordinary skill in the art of formulating wellbore fluids and muds.

EXAMPLE

[0071] One field example where such an invert emulsion wellbore fluid was used for a cement displacement operation included a barite weighting agent with a d_{90} of <5 microns. Table 1 below shows the fluid formulations.

TABLE 1

	Drilling Fluid	Displacement Fluid
FLUID PROPERTIES		
Density, lb/gal	12.85	12.90
Oil/Water Ratio	76/24	75/25
Plastic Viscosity (cps)	46	27
Yield Point (lbs/100 ft^2)	21	2
6 rpm	11	1
10 sec/10 min Gel Strengths	13/21	2/4
FLUID FORMULATION		
Base Fluid (bbls)	0.56	0.56
$CaCl_2$ Brine	0.21	0.21
Primary Emulsifier (lb/bbl)	3.5	3.5
Secondary Emulsifier (lb/bbl)	4.0	4.0
Viscosifier (lb/bbl)	5.0	2.5
Lime	6.0	6.0
Fluid Loss Additive (lb/bbl)	6.0	6.0
API Grade Barite (lb/bbl)	275	0.0
Micronised weighting agent (lb/bbl)	0.0	275

[0072] A well was drilled and a liner string ran with an outside diameter was 5½" into a faulted, depleted reservoir with a narrow pore pressure window prior to a cement operation. Without displacing the existing oil base drilling fluid, an estimated ECD of 14.78 at 160 gal/min, which while close to the 14.81 lb/gal upper ECD limit, would be too slow to place the cement slurry, increasing the likelihood that cement slurry would begin to thicken before displacement into annulus was complete. Thus, the existing drilling fluid was displaced with a micronized barite fluid prior to pumping the cement slurry. The ECD of the micronized weighting agent fluid resulted in a displacement flow rate of 160 gal/min and a lower ECD of 14.1 allowing (use of and further below the ECD ceiling) a higher pump rate of 250 gal/min, which gives an ECD of 14.65 lb/gal, and no observable fluid losses to the formation. Thus, use of the micronized displacement fluid allowed for keeping the ECD at a manageable level without viscosity settling prior to completion of the cementing operation, and without any measurable losses of the wellbore displacement fluid to the formation.

[0073] Advantageously, embodiments of the present disclosure provide for one or more of the following: reduced risk of weighting agent sag or settlement; improved ability to formulate thin fluids for reduced pumping pressures; improved ECD control; improved cement job quality. In cement displacement, the reduction in annular space generally leads to increased ECD. The fluids of the present disclosure may possess Theological properties such that increases in viscosity (and thus ECD) may be minimized while also allowing for reduction in sag and particle settlement. Further, by controlling ECD, bottomhole pressures, and thus, wellbore stability, may be controlled. Additionally, the fluids of the present disclose may advantageously allow for lower frictional pressures with less risk of fluid losses where pressures are close to the fracture pressure, thus resulting in higher flow rates for turbulent flow placement, and less pumping time required for placing the cement slurry in the annulus, thereby reducing the risk of the cement slurry prematurely hardening during cementing operations.

[0074] While the invention has been described with respect to a limited number of embodiments, those skilled in the art, having benefit of this disclosure, will appreciate that other embodiments can be devised which do not depart from the scope of the invention as disclosed herein. Accordingly, the scope of the invention should be limited only by the attached claims.

What is claimed:

1. A method of cementing a pipe into a wellbore filled with a drilling fluid, comprising:

displacing the drilling fluid with the displacement fluid, comprising:

a base fluid; and

a micronized weighting agent;

suspending a pipe in the wellbore; and

pumping cement into the wellbore to substantially fill the annulus formed between the outer surface of the pipe and the wellbore.

2. The method of claim **1**, further comprising:

pumping a spacer fluid into the well prior to pumping the cement.

3. The method of claim **1**, further comprising:

pumping a second displacement fluid into the wellbore to displace the pumped cement into the annulus.

4. The method of claim **1**, wherein pumping the cement displaces the displacement fluid from the wellbore.

5. The method of claim **1**, further comprising:

introducing at least one plug into the pipe.

6. The method of claim **1**, wherein the micronized weighting agent is at least one selected from barite, calcium carbonate, dolomite, ilmenite, hematite, olivine, siderite, hausmannite, and strontium sulfate.

7. The method of claim **1**, wherein the micronized weighting agent is coated with a dispersant made by the method comprising dry blending a micronized weighting agent and a dispersant to form a micronized weighting agent coated with the dispersant.

8. The method of claim **1**, wherein the micronized weighting agent comprises colloidal particles having a coating thereon.

9. The method of claim **1**, wherein the micronized weighting agent has a particle size d_{90} of less than about 20 microns.

10. The method of claim **1**, wherein the micronized weighting agent has a particle size d_{90} of less than about 10 microns.

11. The method of claim **1**, wherein the micronized weighting agent has a particle size d_{90} of less than about 5 microns.

12. The method of claim **7**, wherein the coating comprises at least one selected from oleic acid, polybasic fatty acids, alkylbenzene sulfonic acids, alkane sulfonic acids, linear alpha-olefin sulfonic acids, alkaline earth metal salts thereof, polyacrylate esters, and phospholipids.

13. The method of claim **1**, wherein the base fluid is at least one of an oleaginous fluid and a non-oleaginous fluid.

14. A method of drilling and cementing a wellbore, comprising:

drilling the wellbore with a drilling fluid;

displacing the drilling fluid with a displacement fluid comprising:

a base fluid; and

a micronized weighting agent;

suspending a pipe in the well; and

pumping cement into the well so as to fill the annulus formed between the outer surface of the pipe and the wellbore.

15. The method of claim **14**, further comprising:

pumping a spacer fluid into the well prior to pumping the cement.

16. The method of claim **14**, further comprising:

pumping a second displacement fluid into the wellbore to displace the pumped cement into the annulus.

17. The method of claim **14**, wherein pumping the cement displaces the displacement fluid from the wellbore.

18. The method of claim **1**, further comprising:

introducing at least one plug into the pipe.

19. A method of drilling and cementing a wellbore, comprising:

drilling the wellbore with a wellbore fluid comprising:

a base fluid; and

a micronized weighting agent;

suspending a pipe in the well; and

pumping cement into the well so as to fill the annulus formed between the outer surface of the pipe and the wellbore.

20. The method of claim **19**, further comprising:

pumping a spacer fluid into the well prior to pumping the cement.

21. The method of claim **19**, further comprising:

pumping a displacement fluid into the wellbore to displace the pumped cement into the annulus.

22. The method of claim **19**, wherein pumping the cement displaces the drilling fluid from the wellbore.

23. The method of claim **19**, further comprising:

introducing at least one plug into the pipe.

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