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(54) **Title**: INVERT DRILLING FLUIDS

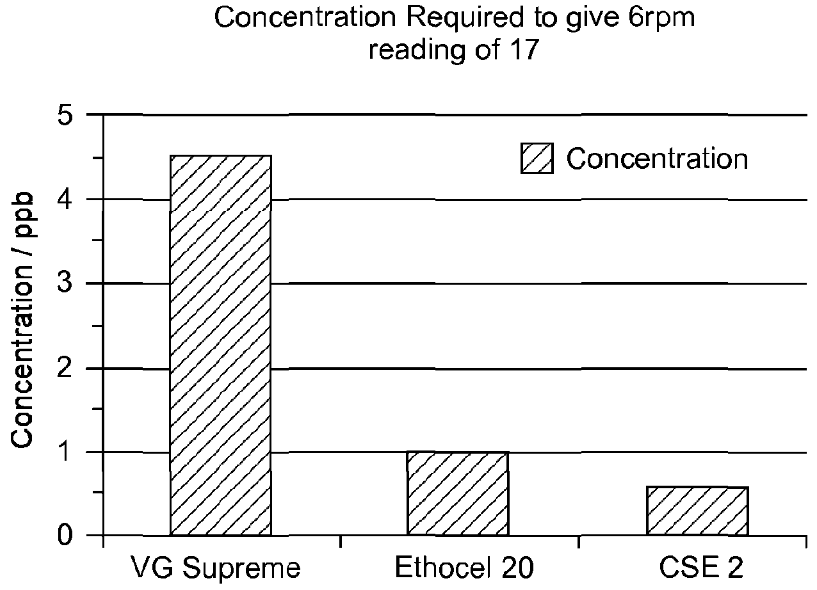

Fig. 4

(57) **Abstract**: There is described an invert emulsion wellbore fluid that includes: an oleaginous external phase; a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50 by volume; an emulsifier; and a rheological additive comprising a sulphonated polymer formed from 100 to 10,000 monomers. There is also described a method of drilling a subterranean hole using the invert emulsion drilling fluid.

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INVERT DRILLING FLUIDS

BACKGROUND OF INVENTION

Field of the Invention

Embodiments disclosed herein relate generally to invert emulsion wellbore fluids. In particular, embodiments disclosed herein relate to invert emulsion wellbore fluids having a high internal phase concentration.

Background Art

During the drilling of a wellbore, various fluids are typically used in the well for a variety of functions. The fluids may be circulated through a drill pipe and drill bit into the wellbore, and then may subsequently flow upward through 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.

In certain rotary drilling procedures the drilling fluid takes the form of a "mud," *i.e.,* a liquid having solids suspended therein. The solids function to impart desired rheological properties to the drilling fluid and also to increase the density thereof in order to provide a suitable hydrostatic pressure at the bottom of the well. The drilling mud may be either a water-based or an oil-based mud. Alternatively the drilling fluid may be a completion fluid (especially a solids free completion fluid) or a so-called pill.

Many types of fluids have been used in wellbores particularly in connection with the drilling of oil and gas wells. The selection of an oil-based wellbore fluid involves a careful balance of the required fluid characteristics and the environmental impact of such fluids in a particular application. The primary benefits of selecting an oil-based drilling fluid include: superior hole stability, especially in shale formations; formation of a thinner filter cake than the filter cake achieved with a water based mud; excellent lubrication of the drilling string and downhole tools; penetration of salt beds without sloughing or enlargement of the hole as well. An especially beneficial property of oil-based muds is their lubrication qualities. These lubrication properties permit the drilling of wells having a significant vertical deviation, as is typical of off-shore or deep water drilling operations or when a horizontal well is desired. In such highly deviated holes, torque and drag on the drill string are a significant problem because the drill pipe lies against the low side of the hole, and the risk of pipe sticking is high when water based muds are used. In contrast oil based muds provide a thin, slick filter cake which helps to prevent pipe sticking and thus the use of the oil-based mud can be justified.

Oil-based drilling fluids are generally used in the form of invert emulsion muds. The components of the invert emulsion fluids include an oleaginous liquid such as hydrocarbon oil which serves as a continuous phase, a non-oleaginous liquid such as water or brine solution which serves as a discontinuous phase, and an emulsifying agent. The oil/water (or oil:water) ratio of invert emulsion fluids is traditionally within the range of 65:45 to 95:5. The emulsifying agent serves to lower the interfacial tension of the liquids so that the non-oleaginous liquid may form a stable dispersion of fine droplets in the oleaginous liquid. A full description of such invert emulsions may be found in *Composition and Properties of Drilling and Completion Fluids,* 5th Edition, H. C. H. Darley, George R. Gray, Gulf Publishing Company, 1988, pp. 328- 332.

Additionally, such invert emulsion muds generally contain one or more weighting agents, surfactants, viscosifiers, fluid loss control agents or bridging agents. The drawback to use of invert emulsion fluids is their cost (due to the oil content) and environmental concerns associated with waste and disposal (greater oil percentage may be correlated to more oil retention on drilled cuttings). However, as the oil to water ratio decreases (increased internal water phase), the viscosity of the fluid often increases beyond a workable range. Additionally, it also becomes more difficult to stabilize an invert emulsion (water-in-oil) as the water content increases.

SUMMARY OF INVENTION

In one aspect, the invention provides an invert emulsion wellbore fluid that includes:

an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50;

an emulsifier;

a rheological additive comprising a sulphonated polymer formed from 100 to 10,000 monomers.

The terms 'monomer' and 'repeat unit' are used interchangeably herein and have the same meaning. The polymer may be formed from at least one monomer by a polymerisation reaction. Such polymerisation reactions are known in the art. Thus, the sulphonated polymer described herein is obtainable by the polymerisation of from 100 to 10,000 monomers.

The polymer may be formed from 500 to 10,000 monomers (repeat units), and typically in the range of from 1,000 to 10,000 monomers (repeat units).

The sulphonated polymer may be formed from at least one monomer that is sulphonated.

The sulphonated polymer may be a copolymer formed from at least one polymer which is sulphonated and at least one monomer that is not sulphonated.

The sulphonated polymer may be formed from a base polymer and subsequently sulphonated. The sulphonation may be achieved by processes known in the art. The base polymer may be formed from ethylene propylene diene monomer (EPDM) units.

The sulphonated polymer comprises a sulphonate functional group, such as $-SO_3X$ where X is hydrogen or a cation, particularly a monovalent cation such as one or more of the group comprising Li^+, Na^+ and K^+. The sulphonate functional group may also be a chlorosulphonate group.

The rheological additive is used to control the rheological profile of the wellbore fluid. Although the emulsifier may affect the rheology of the wellbore fluid, it is the additive that is used to control the rheology. The rheological additive may specifically be used to control the low shear rate viscosity of the wellbore fluid.

The rheological additive may be in one or both of the oleaginous and non-oleaginous phase. Typically the rheological additive is present at an interface between the oleaginous or non-oleaginous phase.

Unlike a surfactant, the rheological additive affects the low shear rate viscosity of the wellbore fluid. The rheological additive may have (i) an oil soluble backbone (for instance the polymer backbone), (ii) functionality (an ionic component) responsible for the interaction between and/or within portions of the rheological additive (for instance the sulphonate group) and (iii) bulk (molecular weight) provided by the length of the chain of the backbone. The balance of (i), (ii) and (iii) may provide the necessary control of the rheological profile of the wellbore fluid. Surfactants do not have the right balance of these components.

The term oleaginous is used herein to refer to all oil and oil dispersible and soluble additives. The term non-oleaginous is used herein to refer to all water and water dispersible and soluble additives.

All ratios detailed herein relate to volume ratio. When calculating oleaginous/ non-oleaginous rations such as oil water ratios, the oleaginous phase, typically the oil phase includes all oil-based components of the emulsion whilst the non-oleaginous phase, typically the water phase includes only water.

For certain embodiments, the sulphonated polymer is an elastomeric based polymer. Preferably the polymer has a number average molecular weight of more than 20,000. Elastomeric based polymers typically have a molecular weight of from 20,000 to 500,000.

A fluid as described herein with a ratio of the oleaginous external phase and non oleaginous internal-phase being less than 50:50 by volume (that is less than 50 parts by volume of the oleaginous external phase to 50 parts by volume of the non-oleaginous internal phase) is referred to as a High Internal Phase Ratio (HIPR) fluid or alternatively may also be referred to as high internal phase emulsions (HIPE).

The inventors of the present disclosure have found that whilst improved properties are apparent from the use of HIPR fluids that the viscosity at low shear rate, normally tested at 6rpm on a FANN 35 viscometer, is too low when compared to the viscosity at high shear rate (the difference between the 600rpm and 300rpm reading on a FANN 35 viscometer and referred to as the plastic viscosity). This can lead to poor hole cleaning and/or sag of a weighting agent added to the fluid in use. Thus the inventors have recognised that a rheological additive which can modify or control the viscosity at the low shear rate while having low impact on the high shear rate viscosity would be beneficial.

The inventors of the present disclosure have appreciated that the inclusion of a rheological modifier comprising a sulphonated polymer can increase the viscosity at the low shear rate and/or reduce the viscosity at the high shear rate/plastic viscosity.

The sulphonated polymer may be a chlorosulphonated polymer. The sulphonated polymer may be prepared such that it is a chlorosulphonated polymer.

The sulphonated polymer may be an α-olefin copolymer. The α-olefin may provide the necessary reactivity for the production of the sulphonated polymer from its constituent monomer parts.

The chlorosulphonated polymer may be formed from a base polymer and subsequently sulphonated or may be formed from one or more monomers, at least one of which is chlorosulphonated. It may be formed from monomer units of ethylene and α-olefin, that is $-(CH_2-CH_2)_n-$ and $-(R^5CH-CH_2)_m-$ wherein R^5 is hydrogen or an alkyl radical having from 1 to 18 carbon atoms. The resulting base polymer may be subsequently chlorosulphonated. Alternatively, at least a portion of one or both of the ethylene and α-olefin may be substituted with a chlorosulphonate group.

Preferably the sulphonated polymer is formed from monomers which are derived from, and typically may be, ethylene and an α-olefin that contains from 3 to 20 carbon atoms, optionally 4 to 8 carbon atoms.

Certain embodiments include a chlorosulphonated α-olefin copolymer which is formed from monomers which are derived from, and typically may be, ethylene and an α-olefin that contains from 3 to 20 carbon atoms, optionally 4 to 8 carbon atoms.

The sulphonated polymer typically contains from 0.2wt% to 5wt% sulphur and can be reacted with water to yield a sulphonic acid or reacted and neutralised with a base to yield an alkali sulphonated copolymer.

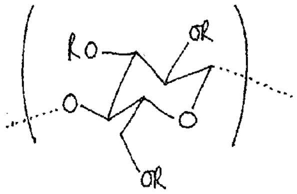
In another aspect, the invention provides an invert emulsion wellbore fluid that includes:

an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50 by volume;

an emulsifier; and

a rheological additive comprising an organosoluble cellulose represented by the following formula:



wherein R is independently H or an alkyl radical having a carbon backbone of from 1 to 10 carbon atoms.

The organosoluble cellulose may be obtained from Dow Chemical Company (www.dow.com) as part of their Ethocel range. Ethocel 4 and Ethocel 20 having viscosity ranges of 3 – 5.5 and 18 – 22cP respectively are preferred.

The organosoluble cellulose may be soluble in at least one organic solvent. The organosoluble cellulose may have a viscosity of from 0.1 to 120cP at 25°C in the organic solvent.

The organosoluble cellulose may have a viscosity of 0.1 to 250cP. The viscosity of the organosoluble cellulose may be from 1 to 120, optionally 3 – 22cP. The viscosity is measured under the conditions noted in the Ethocel product range (www.Dow.com) that is in 5% solutions measured at 25°C in an Ubbleohde type viscometer. For medium organosoluble cellulose products, the solvent is 60% toluene and 40% ethanol. For all other organosoluble cellulose products the solvent is 80% toluene and 20% ethanol.

Preferably the organosoluble cellulose has repeating anhydroglucose units. The anhydroglucose unit may be in the form of a ring. Each anhydroglucose ring may have three –OH (hydroxyl) sites, which are optionally alkoxylated to from –OR groups wherein R is an alkyl group with between 1 and 10, normally between 1 and 5 carbon atoms in a chain. In certain embodiments the –OH sites are ethoxylated to form -OC_2H_5 groups.

The wellbore fluid may be a variety of wellbore fluids including completion fluids with or without any solids, pills, and fluids containing heavy weight brine.

The non-oleaginous internal phase may comprise a plurality of droplets. The droplets can be dispersed in the oleaginous external phase. Optionally an average diameter of the droplets comprising the non-oleaginous internal phase ranges from 0.5 to 5 micrometers, typically from 1 to 3 micrometers.

Optionally the invert emulsion wellbore fluid has a viscometer reading of less than 200cP measured at 600 rpm, typically a viscometer reading of less than 40cP at 6 and 3 rpm.

The polymer may be a derivative of cellulose. The cellulose may be a polysaccharide of glucose (monomer) units. Derivatisation of the cellulose may involve conversion of hydroxyl groups on the repeating glucose units to ethyl ether groups.

The polymer may be a depolymerised derivative of cellulose or alkyl derivatives thereof.

In yet another aspect, embodiments disclosed herein relate to a method of drilling a subterranean hole with an invert emulsion drilling fluid that may include mixing an oleaginous fluid, a non-oleaginous fluid, and a rheological additive to form an invert emulsion wellbore fluid and drilling the subterranean hole using said invert emulsion wellbore fluid as the drilling fluid. The invert emulsion may include an oleaginous external phase; a non oleaginous internal phase, wherein a ratio of the oleaginous external phase and non oleaginous internal phase is less than 50:50; and a rheological additive stabilising the oleaginous external phase and the non-oleaginous internal phase, wherein the rheological additive is at least one of a sulphonated polymer and an organosoluble cellulose.

According to another aspect of the disclosure there may be provided an invert emulsion wellbore fluid that includes:

an emulsifier;

an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50; and wherein the non-oleaginous phase comprises a brine having a specific gravity of above 1.4.

The specific gravity of the brine may be above 1.55.

Normally such an aspect is provided for emulsions according to earlier aspects of the invention. The non-oleaginous internal phase of this aspect may be used in the other aspects of the invention described above.

In particular the fluid may further comprise a rheological additive comprising one of a sulphonated polymer and an organosoluble cellulose.

Optionally the fluid may possess a high shear viscosity of less than 200cP at 600 rpm, and a low shear viscosity of less than 40cP at 6 and 3 rpm, and less than 20cP at 6 and 3 rpm in particular embodiments (all of which are measured using a Fann 35 Viscometer from Fann Instrument Company (Houston, Texas) at 120°F (48.9°C)).

In another aspect, the invention provides an invert emulsion wellbore fluid that includes:

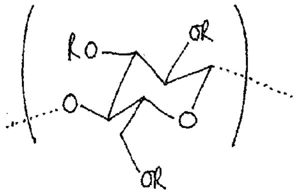
an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50 by volume;

an emulsifier;

a first rheological additive comprising a sulphonated polymer formed from 100 to 10,000 monomers; and

a second rheological additive comprising an organosoluble cellulose represented by the following formula:



wherein R is independently H or an alkyl radical having a carbon backbone of from 1 to 10 carbon atoms.

The invert emulsion wellbore fluid of this aspect may be used in the other aspects of the invention described above.

Other aspects and advantages of the disclosure will be apparent from the following description and the appended claims.

DETAILED DESCRIPTION

The oil / water ratio in invert emulsion fluids conventionally used in the field is in the range of 65/45 to 95/5. Several factors have conventionally dictated such ranges, including: the concentration of solids in the mud to provide the desired mud weight (solids laden muds must have a high oil/water (O/W) ratio to keep the solids oil wet and dispersed) and the high viscosities often experienced upon increase of the internal aqueous phase (due to the greater concentration of the dispersed internal phase). The instability of the emulsions may be explained by examining the principles of colloid chemistry. The stability of a colloidal dispersion (emulsion for a liquid: liquid dispersion) is determined by the behaviour of the surface of the particle via its surface charge and short-range attractive van der Waals forces. Electrostatic repulsion prevents dispersed particles from combining into their most thermodynamically stable state of aggregation, in macroscopic form, thus rendering the dispersions metastable. Emulsions are metastable systems for which phase separation of the oil and water phases represents the most stable thermodynamic state due to the addition of a surfactant to reduce the interfacial energy between oil and water.

Oil-in-water emulsions are typically stabilised by both electrostatic stabilisation (electric double layer between the two phases) and steric stabilisation (van der Waals repulsive forces), whereas invert emulsions (water-in-oil) are typically stabilised by only steric stabilisation. Because only one mechanism can be used to stabilise an invert emulsion, invert emulsions are generally more difficult to stabilise, particularly at higher levels of the internal phase, and are often highly viscous fluids.

Thus, embodiments of the present disclosure relate to invert emulsion fluids having a high internal phase concentration (< 50:50 oleaginous/non-oleaginous, typically O/W), which are stabilised by an emulsifying agent preferably without significant increases in viscosity. Additional by virtue of the greater internal phase concentration, weight may be provided to the fluid partly through the inherent weight of the aqueous or other internal phase, thus minimising the total solid content.

The non-oleaginous phase is typically a brine. It may be a relatively dense brine. The specific gravity of the non-oleaginous phase may be above 1.4, optionally above 1.55. The invert emulsion fluid may contain no solid component. Furthermore, the invert emulsion may not contain barite.

Thus the invention may independently provide an invert emulsion wellbore fluid that includes:

- an emulsifier;
- an oleaginous external phase;
- a non-oleaginous internal phase,

wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50;
and wherein the non-oleaginous phase comprises a brine having a specific gravity of above 1.4, optionally above 1.55.

Normally such an aspect is provided for emulsions according to earlier aspects of the invention.

As discussed above, as the internal aqueous phase of a given fluid system increases, the viscosity and rheological profile of the fluid also increases due to the greater concentration of the dispersed internal phase. However, the invert emulsion fluids of the present disclosure may possess rheological profiles more similar to fluids having a lower internal phase concentration, *i.e.,* >50:50 oleaginous/non-oleaginous, typically O/W. In particular, in accordance with embodiments of the present disclosure, the fluids may possess a high shear viscosity of less than 200cP at 600 rpm, and a low shear viscosity of less than 40cP at 6 and 3 rpm, and less than 20cP at 6 and 3 rpm in particular embodiments (all of which are measured using a Fann 35 Viscometer from Fann Instrument Company (Houston, Texas) at 120°F (48.9°C)).

The fluid may also possess an internal non-oleaginous phase, typically aqueous phase, that is stably emulsed within the external oleaginous phase. Specifically, upon application of an electric field to an invert emulsion fluid, the emulsified non-oleaginous phase, which possesses charge, will migrate to one of the electrodes used to generate the electric field. The incorporation of emulsifiers in the invert emulsion fluid stabilises the emulsion and results in a slowing of the migration rate and/or increased voltage for breakage of the emulsion. Thus, an electrical stability

(ES) test, specified by the American Petroleum Institute at API Recommended Practice 13B-2, Third Edition (February 1998), is often used to determine the stability of the emulsion. ES is determined by applying a voltage-ramped, sinusoidal electrical signal across a probe (consisting of a pair of parallel flat-plate electrodes) immersed in the mud. The resulting current remains low until a threshold voltage is reached, whereupon the current rises very rapidly. This threshold voltage is referred to as the ES ("the API ES") of the mud and is defined as the voltage in peak volts-measured when the current reaches 61 μA. The test is performed by inserting the ES probe into a cup of 120°F (48.9°C) mud applying an increasing voltage (from 0 to 2000 volts) across an electrode gap in the probe. The higher the ES voltage measured for the fluid, the stronger or harder to break would be the emulsion created with the fluid, and the more stable the emulsion is. Thus, the present disclosure relates to invert emulsion fluids having a high internal phase ratio but that also have an electrical stability of at least 50 v and at least 100 v or 150 v in more particular embodiments.

Further, the present disclosure also relates to fluids having a high internal phase ratio wherein the emulsion droplet size is smaller as compared to conventional emulsion droplets. For example, the non-oleaginous phase distributed in the oleaginous phase may comprise droplets having an average diameter in the range of 0.5 to 5 microns in one embodiment, and in the range of 1 to 3 microns in a more particular embodiment. The droplet size distribution may generally be such that at least 90% of the diameters are within 20% or especially 10% of the average diameter. In other embodiments, there may be a multimodal distribution. This droplet size may be approximately one quarter less than the size of droplets in conventional emulsions droplets formed using conventional emulsifiers. In a particular embodiment, the emulsion droplets may be smaller than the solid weighting agents used in the fluids.

The emulsifier may be any suitable emulsifier. In preferred embodiments, the emulsifier is an alkoxylated ether acid emulsifier which stabilises the oleaginous external phase and the non-oleaginous internal phase, wherein the alkoxylated ether acid is represented by the following formula:

$R^4O[CH_2CHR^1O]_n[CH_2]_m\text{-COOH}$

where R^4 is a C_6-C_{24} alkyl or alkenyl radical or $-C(O)R^3$ (where R^3 is a C_{10}-C_{22} alkyl or alkenyl radical);
R^1 is H or a C_1-C_4 alkyl radical;
n has a value of from 1 to 20; and
m has a value of from 0 to 4.

The C_6-C_{24} alkyl or alkenyl radical of group R may be branched or unbranched (straight-chain).

Such compounds 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 be 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 hydrophilic-lipophilic balance (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.

Emulsifiers are typically amphiphilic. That is, they possess both a hydrophilic portion and a hydrophobic portion. The chemistry and strength of the hydrophilic polar group compared with those of the lipophilic nonpolar group determine whether the emulsion forms as an oil-in-water or water-in-oil emulsion. In particular, emulsifiers may be evaluated based on their HLB value. Generally, to form a water in-oil emulsion, an emulsifier (or a mixture of emulsifiers) having a low HLB, such as between 3 and 8, may be desirable. In a particular embodiment, the HLB value of the emulsifier may range from 4 to 6.

In particular embodiments, the emulsifier may be used in an amount ranging from 1 to 15 pounds per barrel (lbm/bbl or ppb), that is from 2.85 to 42.80 kg/m^3, and from 2 to 10 pounds per barrel (lbm/bbl or ppb), that is from 5.70 to 28.50 kg/m^3 in other particular embodiments.

In addition to the emulsifying agent that stabilises the oleaginous continuous phase and non-oleaginous discontinuous phase, the wellbore fluids may also include, for example, weighting agents.

Weighting agents or density materials (other than the inherent weight provided by the internal aqueous phase) suitable for use in the fluids disclosed herein may include barite, galena, hematite, magnetite, iron oxides, illmenite, siderite, celestite, dolomite, calcite, and the like. The quantity of such material added, if any, depends upon the desired density of the final composition. Typically, weighting material may be added to provide a fluid density of up to about 24 pounds per gallon (lbm/gal or ppg), that is a specific gravity of 2.87 (but up to 21 pounds per gallon (lbm/gal or ppg), that is a specific gravity of 2.50 or up to 19 pounds per gallon (lbm/gal or ppg), that is a specific gravity of 2.27 in other particular embodiments). Additionally, it is also within the scope of the present disclosure that the fluid may also be weighted using salts (such as in the non-oleaginous fluid (often aqueous fluid) discussed below). The 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.

The oleaginous fluid may be a liquid and more preferably is 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, mixtures thereof and similar compounds; and mixtures thereof. In a particular embodiment, the fluids may be formulated using diesel oil or a synthetic oil as the external phase. The concentration of the oleaginous fluid should be sufficient so that an invert emulsion forms and may be less than about 50% by volume of the invert emulsion. In one embodiment the amount of oleaginous fluid is from about 50% to about 20% by volume and more preferably about 40% to about 20% by volume of the invert emulsion fluid. The oleaginous fluid in one embodiment may include at least 5% by volume of a material selected from the group including esters, ethers, acetals, dialkylcarbonates, hydrocarbons and combinations thereof.

The non-oleaginous fluid used in the formulation of the invert emulsion fluid disclosed herein is a liquid and preferably is an aqueous liquid. More preferably, 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. 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, aluminium, magnesium, potassium, strontium, and lithium, salts of chlorides, bromides, carbonates, iodides, chlorates, bromates, formates, nitrates, oxides, phosphates, sulphates, silicates, and fluorides. Salts that may be incorporated in a given brine include any one or more of those present in natural seawater or any other organic or inorganic dissolved salts. Additionally, brines that may be used in the 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.

In one embodiment the amount of non-oleaginous fluid is more than about 50% by volume and preferably from about 50% to about 80% by volume of the invert emulsion fluid. In another embodiment, the non-oleaginous fluid is preferably from about 60% to about 80% by volume of the invert emulsion fluid.

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.

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.

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 sulphates and sulphonates, 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 minimised so as to not adversely affect the reversibility of the invert emulsion disclosed herein. FAZEWET™, VERSA COAT™, SUREWET ™, VERSA WET™, 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).

Organophilic clays, normally amine treated clays, may be added in addition to the viscosifiers described 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 about 6% by weight range 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. 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.

Conventional suspending agents, as well as those described herein, may be used in the fluids disclosed herein and 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.

Additionally, lime or other alkaline materials are typically added to conventional invert emulsion drilling fluids and muds to maintain a reserve alkalinity. The fluids disclosed herein are especially useful in the drilling, completion and working over of subterranean oil and gas wells. In particular the fluids disclosed herein may find use in formulating drilling muds and completion fluids that allow for the easy and quick removal of the filter cake. Such muds and fluids are especially useful in the drilling of horizontal wells into hydrocarbon bearing formations. In various embodiments, methods of drilling a subterranean hole with an invert emulsion drilling fluid may comprise mixing an oleaginous fluid, a non-oleaginous fluid, a viscosifier, such as those described above, and in the ratios described above, to form an invert emulsion; and drilling the subterranean hole using this invert emulsion as the drilling fluid. The fluid may be pumped down to the bottom of the well through a drill pipe, where the fluid emerges through ports in the drilling bit, for example. In one embodiment, the fluid may be used in conjunction with any drilling operation, which may include, for example, vertical drilling, extended reach drilling, and directional drilling. Oil-based drilling muds may be prepared with a large variety of formulations. Specific formulations may depend on the state of drilling a well at a particular time, for example, depending on the depth and/or the composition of the formation.

Embodiments of the disclosure will now be described, by way of example only, with reference to the accompanying figures in which:

Figure 1 is a concentration profile showing the main rheology parameters for ETHOCEL 300;

Figure 2 is a concentration profile showing the main rheology parameters for a chlorosulphonated polymer;

Figure 3 is a table showing the results of ageing fluids comprising rheological additives according to the present disclosure;

Figure 4 shows the amount of rheological additive required to gain a viscosity at low shear rate for a known rheological additive and rheological additives according to the presently disclosure; and

Figure 5 shows the plastic viscosity gained for the fluid based on the amount of rheological modifier required to reach the low shear viscosity set out in figure 4.

A series of experiments were carried out using a mud formulation made up on a Hamilton Beech mixer over an hour with the following order of addition:

1. Mosspar H oil (continuous phase)
2. Emulsifier, oil wetting agent, for example EMI-2184 (available from M-I L.L.C.) / Surewet
3. Conventional Organophilic rheology modifier (viscosifier gellant): VG Supreme
4. Ecotrol RD (fluid loss additive)
5. Lime (alkalinity source)
6. Fresh Water and (25wt%)CaCl2(s) (discontinuous phase)
7. API Barite (weighting agent)

Muds were tested initially for FANN 35 rheology and ESV and retested for rheology, ESV and HTHP after ageing by hot rolling at 250°F (121.1°C) for 16 hours.

A number of OBM viscosifiers were screened in an optimised 45:55 HIPR formulation mud containing a minimal level of 1.0 ppb (pound per barrel) organoclay viscosifier. A bulk volume of base mud was prepared on the Silverson mixer over one hour at 6000 rpm and the viscosifier added and mixed for a further 20 minutes on the Hamilton Beech mixer. Muds were tested initially for FANN 35 rheology and ESV, and retested after ageing for 16 hours at 250°F (121.1°C) for rheology, ESV and HTHP fluid loss.

<u>Ethocel</u>

Table 1 shows the performance, after ageing of various organosoluble celluloses (ETHOCEL obtained from Dow Chemical Company) added to a drilling fluid composition comprising an OWR of 45:55, an emulsifier and 3.0 ppb of the rheological additive.

They are compared, after ageing, to a benchmark which does not comprise any of the rheological additive. As can be seen from Table 1, ETHOCEL 4 and ETHOCEL 20 gave a significant increase in the low shear (6 rpm) parameter as well as plastic viscosity.

The ratio of 6 rpm/PV shows the balance of the fluid and a high ratio is better. The ratio for Ethocel 4 and Ethocel 20 is particularly good.

Table 1

	Plastic Viscosity(PV) cP	Yield Point (YP) (lb/100ft^2)_	6 rpm reading	6rpm/ PV
Benchmark	52	21	6	0.12
Ethocel 4	71	47	42	0.59
Ethocel 20	62	30	22	0.35
Ethocel 300	57	22	12	0.21

Table 2 shows the equivalent data for chloro-sulphonated elastomer (CSE) products. The CSE products were elastomers having a range of sulphonation and neutralisation. These products were tested initially at 0.5 ppb concentration of the rheological additive. All the CSE versions gave increases in plastic viscosity, yield point and 6 rpm reading over the benchmark. Two versions gave the largest improvement in 6 rpm reading and 6 rpm/PV ratio.

Table 2

	Plastic Viscosity(PV) cP	Yield Point (YP) (lb/100ft^2)	6 rpm reading	6rpm/PV
Benchmark	52	21	6	0.11
CSE 1	66	33	19	0.29
CSE 2	60	33	17	0.28
CSE 3	69	39	13	0.19
CSE 4	73	36	11	0.15
CSE 5	74	33	11	0.15
CSE 6	79	40	11	0.14

Figures 1 and 2 give concentration profiles showing the main rheology parameters for ETHOCEL 300 and CSE 1, respectively. The former (cellulosic) product gave a relatively linear profile throughout the 0 - 3.0 ppb range, whereas the sulphonated polymer gave a flat response up until 0.2 ppb after which the rheology was found to increase. A similar trend was observed for the CSE 6 polymer. For these cases, at least, the sulphonated polymer looks likely to be more sensitive to concentration than the cellulosic product and so appeared generally more effective based on the weight of additive.

ETHOCEL 4, 20 and CSE 2, were retested in the same benchmark formulation as for the earlier experiments but with the organophilic clay rheology modifier component removed. Initial tests were at the concentration used in the initial tests i.e. 3.0 and 0.5 ppb, respectively, but additional tests were run at varying concentration in order to match the 6 rpm for each product at the same mud specification level. A comparison set of data for fluids at 1-5 ppb with the organophilic clay rheology modifier (VG Supreme) was included for comparison. The table shown in Figure 3 shows the data.

Figure 4 shows the concentration of each additive required to achieve a 6rpm reading of 17 and, in figure 5, its relative plastic viscosity. As can be seen, the amount of ETHOCEL 20 and CSE 2 required to achieve this low shear rate level is much less than the VG supreme. At these levels, their corresponding plastic viscosity is reduced. Thus for ETHOCEL 20 and CSE 2, these results show that a greatly improved 6rpm/PV ratio was observed with a plastic viscosity of only half that for a organophilic clay (VG supreme). This makes these products particularly useful in formulations with less than 50:50 oil in water, that is High Internal Phase Rheology (HIPR).

Thus the results herein show emulsions with an improved rheology over US 2008/0248975 because they were found to give surprisingly low overall rheology in the HIPR system but allowed the low shear rate viscosity (LSRV) to be controlled to specification without excessive build up of plastic viscosity. Given the disclosure in US 2008/0248975, one would expect the low shear viscosity to be off-scale and not prove practicable.

Improvements and modifications may be made without departing from the scope of the disclosure.

CLAIMS

1. An invert emulsion wellbore fluid that includes:

an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50 by volume;

an emulsifier; and

a rheological additive comprising a sulphonated polymer formed from 100 to 10,000 monomers.

2. A fluid as claimed in claim 1, wherein the sulphonated polymer is a chlorosulphonated polymer.

3. A fluid as claimed in any preceding claim, wherein the sulphonated polymer is an α-olefin copolymer.

4. A fluid as claimed in any preceding claim, wherein the sulphonated polymer is formed from ethylene and an α-olefin that contains from 3 to 20 carbon atoms.

5. A fluid as claimed in any preceding claim, wherein the sulphonated polymer is a chlorosulphonated α-olefin copolymer which is formed from ethylene and an α-olefin that contains from 3 to 20 carbon atoms.

6. A fluid as claimed in any preceding claim, wherein the non-oleaginous internal phase comprises a plurality of droplets, said droplets having an average diameter in the range of from 0.5 to 5 micrometers.

7. A fluid as claimed in claim 6, wherein the average diameter of the droplets is in the range of from 1 to 3 micrometers.

8. A fluid as claimed in any preceding claim, wherein the ratio of the oleaginous external phase to non-oleaginous internal phase is in the range of from more than 20:80 to less than 50:50 by volume.

9. A fluid as claimed in any preceding claim, wherein the non-oleaginous internal phase comprises brine with a specific gravity greater than 1.4.

10. A fluid as claimed in any preceding claim, wherein the emulsifier is an alkoxylated ether acid.

11. A fluid as claimed in claim 10, wherein the emulsifier is an alkoxylated ether acid represented by the following formula:

$R^4O[CH_2CHR^1O]_n[CH_2]_m\text{-}COOH$

wherein R^4 is a C_6-C_{24} alkyl or alkenyl radical or $-C(O)R^3$ (where R^3 is a C_{10}-C_{22} alkyl or alkenyl radical);
R^1 is H or a C_1-C_4 alkyl radical;
n has a value of from 1 to 20; and
m has a value of from 0 to 4.

12. A fluid as claimed in claim 11, wherein when R^1 is H, n has a value of from 1 to 10.

13. A fluid as claimed in claim 11 or 12, wherein n has a value of from 2 to 5.

14. A fluid as claimed in any one of claims 11 to 13, wherein when R^1 is $-CH_3$, n has a value of from 1 to 20.

15. A fluid as claimed in any preceding claim, wherein the fluid has a high shear viscosity of less than 200cP at 600 rpm and a low shear viscosity of less than 40cP at 6 and 3 rpm.

16. A fluid as claimed in any preceding claim, wherein the fluid has a high shear viscosity of less than 200cP at 600 rpm and a low shear viscosity of less than 20cP at 6 and 3 rpm.

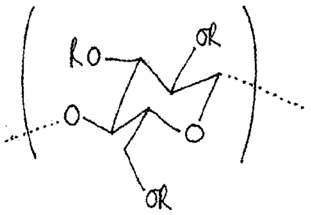
17. An invert emulsion wellbore fluid that includes:

an oleaginous external phase;

a non-oleaginous internal phase, wherein a ratio of the oleaginous external phase and non-oleaginous internal phase is less than 50:50 by volume;

an emulsifier; and

a rheological additive comprising an organosoluble cellulose represented by the following formula:



wherein R is independently H or an alkyl radical having a carbon backbone of from 1 to 10 carbon atoms.

18. A fluid as claimed in claim 17, wherein R is the alkyl radical CH_2CH_3.

19. A fluid as claimed in claim 17 and claim 18, wherein the organosoluble cellulose has a viscosity of from 0.1 to 250 cP measured at 25 °C.

20. A fluid as claimed in claim 17 and claim 18, wherein the viscosity of the organosoluble cellulose is from 1 to 120 cP measured at 25 °C.

21. A fluid as claimed in claim 17 and claim 18, wherein the viscosity of the organosoluble cellulose is from 3 to 22 cP measured at 25 °C.

22. A method of drilling a subterranean hole with an invert emulsion drilling fluid, drilling the subterranean hole using the invert emulsion wellbore fluid as claimed in any preceding claim.

23. A method as claimed in claim 22, wherein the method further includes the step of mixing an oleaginous fluid, a non-oleaginous fluid, an emulsifier and a rheological additive to form the invert emulsion wellbore fluid.

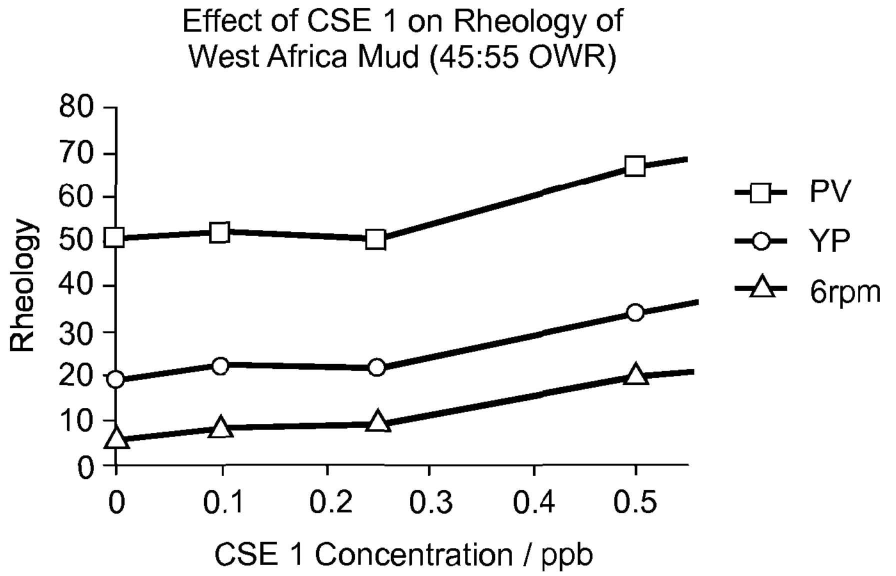

Effect of CSE 1 on Rheology of
West Africa Mud (45:55 OWR)
Rheology
80
70
60
50
40
30
20
10
0
0
0.1
0.2
0.3
0.4
0.5
CSE 1 Concentration / ppb
PV
YP
6rpm

Fig. 1

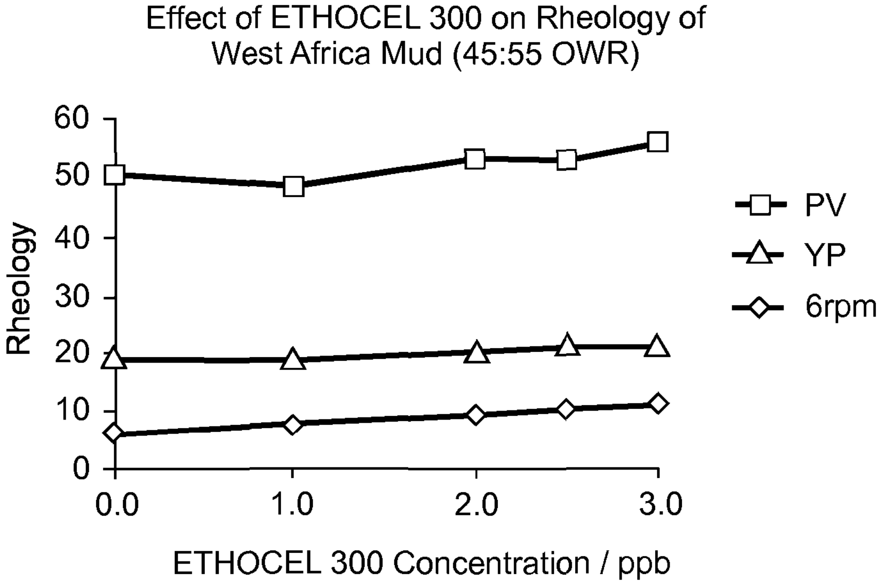

Effect of ETHOCEL 300 on Rheology of
West Africa Mud (45:55 OWR)
Rheology
60
50
40
30
20
10
0
0.0
1.0
2.0
3.0
ETHOCEL 300 Concentration / ppb
PV
YP
6rpm

Fig. 2

PRODUCTS	Units	Benchmark		XRP038		Ethocel4		Ethocel20		Ethocel20		Ethocel20		VG Supreme		VG Supreme		VG Supreme		VG Supreme	
Mosspar H	g	97.0		97.0		97.0		97.0		97.0		97.0		97.0		97.0		97.0		97.0	
EMI-2184	g	7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0	
Surewet	g	2.0		2.0		2.0		2.0		2.0		2.0		2.0		2.0		2.0		2.0	
ECOTROL RD	g	0.5		0.5		0.5		0.5		0.5		0.5		0.5		0.5		0.5		0.5	
LIME	g	7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0		7.0	
FRESHWATER	g	157.2g		157.2g		157.2g		157.2g		157.2g		157.2g		157.2g		157.2g		157.2g		157.2g	
$CaCl_2$(s) 95%	g	56.2		56.2		56.2		56.2		56.2		56.2		56.2		56.2		56.2		56.2	
APIBARITE	g	175.3		175.3		175.3		175.3		175.3		175.3		175.3		175.3		175.3		175.3	
Ethocel4	g	-		-		3.0		-		-		-		-		-		-		-	
Ethocel20	g	-		-		-		1.0		2.0		3.0		-		-		-		-	
CSE2	g	-		0.5		-		-		-		-		-		-		-		-	
VG Supreme	g	-		-		-		-		-		-		1.0		2.0		3.0		5.0	
AGEING		BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F	BHR	250°F
Rheology Temp °F		120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
600		110	122	124	147	138	190	108	130	126	137	127	184	135	128	182	151	198	170	>300	295
300		61	69	70	87	84	130	60	76	70	87	71	112	77	73	106	88	111	101	213	182
200		44	50	41	65	65	108	43	57	50	70	51	86	55	51	78	63	85	74	165	138
100		26	30	32	42	47	83	26	38	29	48	31	58	33	30	47	37	51	45	108	86
6		5	6	8	17	30	65	7	17	7	27	10	33	6	6	10	7	9	9	25	20
3		3	4	6	15	28	64	5	16	5	25	8	31	5	4	8	6	7	7	19	15
10"Gel		4	5	7	18	33	71	7	17	6	27	9	36	6	5	8	7	8	7	18	15
10"Gel		5	5	11	19	35	57	8	18	7	29	10	37	6	6	9	7	9	8	22	17
PV		49	53	54	60	54	60	48	54	56	50	56	72	6	55	76	63	87	69	#####	113
YP		12	16	16	27	30	70	12	22	14	37	15	40	71	18	30	25	24	32	#####	69
HTHP Fluid Loss		2.0		0.5		0.3		0.6		0.4		0.4		0.2		0.6		0.8		0.1	
Water in Filtrate																					
ES (V)		187	324	177	289	176	303	248	322	228	353	222	290	298	507	269	500	187	340	355	120

Fig. 3

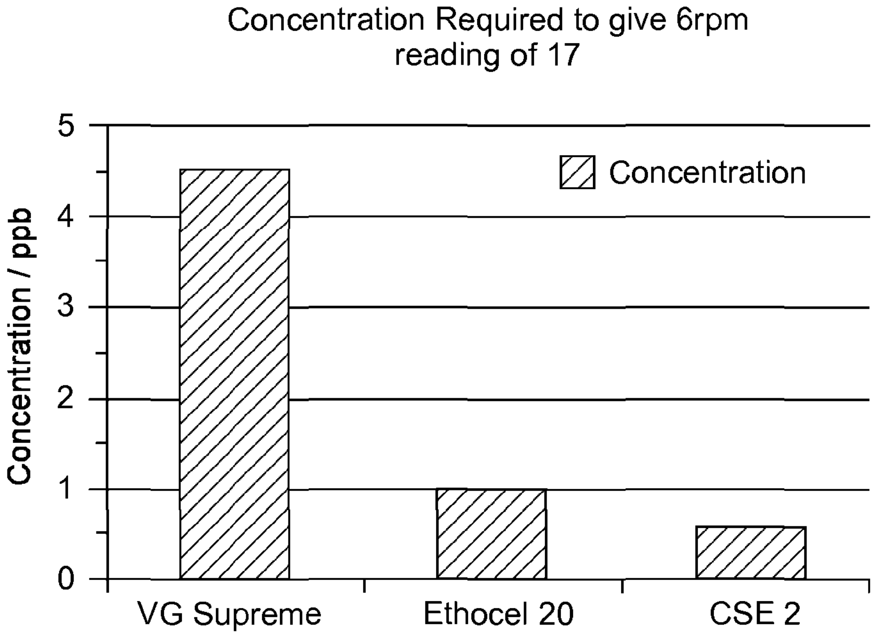

Concentration Required to give 6rpm reading of 17
Concentration / ppb
5
4
3
2
1
0
▨ Concentration
VG Supreme
Ethocel 20
CSE 2

Fig. 4

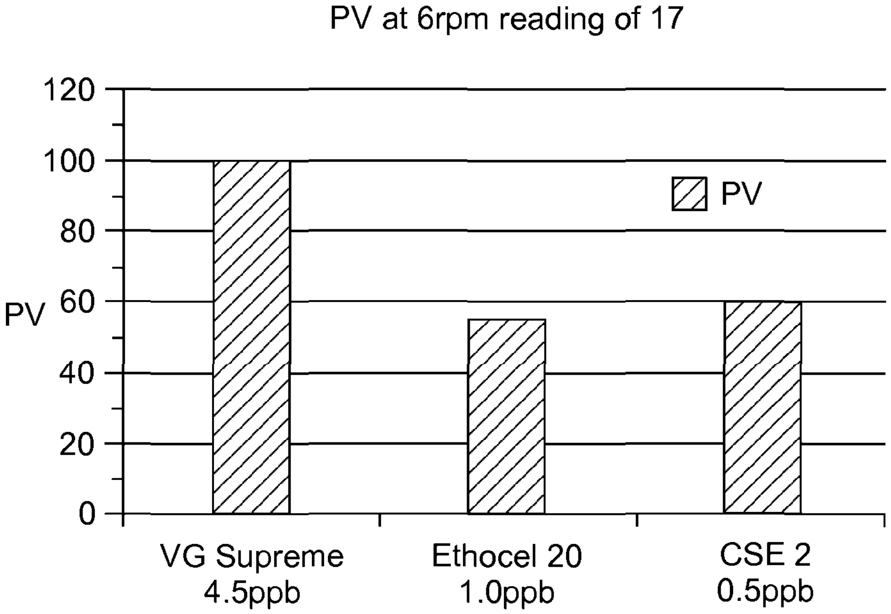

PV at 6rpm reading of 17
PV
120
100
80
60
40
20
0
▨ PV
VG Supreme 4.5ppb
Ethocel 20 1.0ppb
CSE 2 0.5ppb

Fig. 5