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(54) Method for reducing aqueous content of oil-based fluids

(57) A method for reducing the aqueous content of oil-based drilling fluid includes contacting an invert emulsion wellbore fluid with a water absorbing polymer, interacting the water absorbing polymer with the wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs at least a portion of the aqueous fluid form the wellbore fluid; and separating the water absorbing polymer containing the absorbed water from the wellbore fluid.

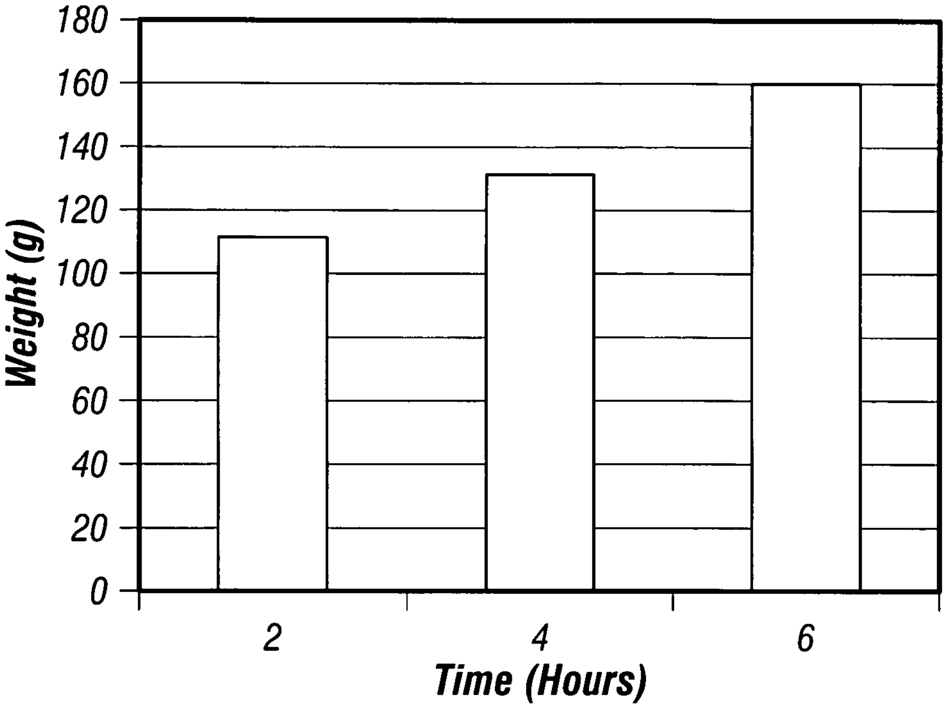

FIG. 1

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Description

FIELD OF INVENTION

[0001] The invention relates generally to wellbore fluids, and more specifically to the removal of the aqueous content from the oil-based wellbore fluids.

BACKGROUND OF INVENTION

[0002] When drilling or completing wells in earth formations, various fluids typically are used in the well for a variety of reasons. Common uses for well fluids include: lubrication and cooling of drill bit cutting surfaces while drilling generally or drilling-in (i.e., drilling in a targeted petroliferous formation), transportation of "cuttings" (pieces of formation dislodged by the cutting action of the teeth on a drill bit) to the surface, controlling formation fluid pressure to prevent blowouts, maintaining well stability, suspending solids in the well, minimizing fluid loss into and stabilizing the formation through which the well is being drilled, fracturing the formation in the vicinity of the well, displacing the fluid within the well with another fluid, cleaning the well, testing the well, fluid used for emplacing a packer, abandoning the well or preparing the well for abandonment, and otherwise treating the well or the formation.

[0003] Drilling fluids or muds typically include a base fluid (water, diesel or mineral oil, or a synthetic compound), weighting agents (most frequently barium sulfate or barite is used), emulsifiers and emulsifier systems, fluid loss additives, viscosity regulators and the like, for stabilizing the system as a whole and for establishing the desired performance properties.

[0004] Oil-based drilling fluids are generally used in the form of invert emulsion muds. Invert emulsion fluids are employed in drilling processes for the development of oil or gas sources, as well as, in geothermal drilling, water drilling, geoscientific drilling, and mine drilling. Specifically, the invert emulsion fluids are conventionally utilized for such purposes as providing stability to the drilled hole, forming a thin filter cake, lubricating the drilling bore and the downhole area and assembly, and penetrating salt beds without sloughing or enlargement of the drilled hole.

[0005] An invert emulsion mud consists of three phases: an oleaginous phase, an aqueous phase, and a finely divided particle phase. The discontinuous aqueous phase is dispersed in an external or continuous oleaginous phase with the aid of one or more emulsifiers. The oleaginous phase may be a mineral or synthetic oil, diesel or crude oil, while the aqueous phase is usually calcium chloride, sodium chloride or other brine.

[0006] The dispersed aqueous phase has several functions. The aqueous phase replaces part of the oleaginous phase, thereby building volume and reducing the total fluid cost. Further, the aqueous phase contributes to fluid density through its higher specific gravity. The highly dispersed state of the aqueous phase contributes to rheology and to fluid loss control. The dispersed aqueous phase also helps improve the inhibition of water-reactive shales by creating a favorable salinity balance.

[0007] The volume ratio of the oleaginous phase to the aqueous phase is referred to as the oil/water ratio (OWR). The OWR is commonly quoted as proportions out of a total of one hundred units, e.g. 90/10, 75/25, etc. Occasionally, through contamination at surface or influx of formation waters downhole, the water cut of an oil-based fluid increases, thereby decreasing the OWR. Such a decrease in the OWR can have an adverse effect on the rheology, density, and emulsion stability of the fluid. There are also occasions where an existing fluid, designed originally to have a higher water content, may have to be used in a drilling operation that requires a lower water portion. In both such cases, the water cut of the fluid has to be reduced in order to bring back the fluid properties within specification. In other words, the OWR has to be increased.

[0008] Previous attempts in the prior art to increase OWR has included dilution with the oleaginous phase, i.e. adding more oil to the oil-based drilling fluid. However, as more oil is added to the drilling fluid, the amount of fluid additives, such as rheology and fluid loss additives and weight material, necessarily increases in order to maintain the various desirable fluid properties. Consequently, not only does dilution of the oleaginous phase increase the overall volume of the drilling fluid, but it also increases costs, inventory, and waste.

[0009] Previous attempts in the prior art have also used a desiccant to remove small portions of water from a drilling fluid. This has been useful in applications requiring the drilling fluid remain in a water-free state. While these attempts have been successful at removing small quantities of water, these attempts have not addressed the need to remove large amounts of water from the drilling fluid during drilling, or adjusting an existing fluid to meet the requirements for a particular application. Further, these attempts do not address the need of removing aqueous content from an invert emulsion oil-based drilling fluid.

[0010] Accordingly, there exists a need for means to economically increase the OWR while reducing the amount of contaminant water present in the fluid without altering the fluid's desired properties. Further, there exists a need to remove large amounts of non-emulsified water from an oil-based drilling fluid. Further yet, there exists a need to remove the emulsified aqueous content from an invert emulsion oil-based drilling fluid.

SUMMARY OF INVENTION

[0011] In one aspect, the present invention relates to a method for removing the aqueous content from a wellbore fluid. The method may include the steps of contacting a wellbore fluid with a water absorbing polymer, where the wellbore fluid includes an invert emulsion, allowing the water absorbing polymer to interact with the wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs at least a portion of the aqueous content, and separating the water absorbing polymer containing the absorbed water from the wellbore fluid.

[0012] In another aspect, the present invention relates to a method for removing the non-emulsified aqueous content from an invert emulsion wellbore fluid in situ. The method may include the steps of determining a design limit of the oil-to-water ratio for the wellbore fluid, feeding the wellbore fluid to the borehole, monitoring the oil-to-water ratio of the wellbore fluid, adding a water absorbing polymer when the oil-to-water ratio decreases below the design limit, allowing the water absorbing polymer to interact with the wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs sufficient aqueous content to return the oil-to-water ratio above the design limit, and separating the water absorbing polymer containing the absorbed water from the wellbore fluid.

[0013] In another aspect, the present invention relates to a method for removing the emulsified aqueous content from a wellbore fluid. The method may include the steps of determining a desired oil-to-water ratio for the existing invert emulsion wellbore fluid, adding a sufficient amount of water absorbing polymer to the existing wellbore fluid to adjust the existing oil-to-water ratio to the desired oil-to-water ratio, allowing the water absorbing polymer to interact with the existing wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs sufficient aqueous content to adjust the existing wellbore fluid to the desired oil-to-water ratio, thereby yielding an adjusted wellbore fluid, and separating the water absorbing polymer containing the absorbed aqueous content from the adjusted wellbore fluid.

[0014] Other aspects and advantages of the claimed subject matter will be apparent from the following description and the appended claims.

Brief Description of the Drawings

[0015] FIG. 1 shows a graphical representation of the absorption of fresh water over a period of time.

[0016] FIG. 2 shows a graphical representation of the absorption of sea water over a period of time.

[0017] FIG. 3 shows a graphical representation of the effect of temperature on sea water absorption over a period of time.

[0018] FIG. 4 shows a graphical representation of the absorption of sea water in an oil environment over a period of time.

[0019] FIG. 5 shows a graphical representation of the absorption of sea water in an oil environment containing an invert emulsifier over a period of time.

[0020] FIG. 6 shows a graphical representation of the absorption of sea water in an oil environment containing an invert emulsifier and barite over a period of time.

[0021] FIG. 7 shows a graphical representation of the absorption of emulsified fresh water over a period of time.

[0022] FIG. 8 shows a graphical representation of the absorption of emulsified brine over a period of time.

[0023] FIG. 9 shows a graphical representation of the absorption of non-emulsified brine, setting the percent concentration (w/w) against the water activity.

[0024] FIG. 10 shows a flow chart for removing aqueous content from an invert emulsion drilling fluid using a water absorbing polymer.

[0025] FIG. 11 shows a flow chart for removing the non-emulsified aqueous content from an invert emulsion drilling fluid when the fluid is in process.

[0026] FIG. 12 shows a flow chart for removing emulsified aqueous content from an invert emulsion drilling fluid using a water absorbing polymer.

Detailed Description

[0027] In one aspect, embodiments of the invention are generally directed to a method for removing aqueous content from an oil based drilling fluid, thereby increasing the OWR. As described above, during the use of a wellbore fluid, water often contaminates the wellbore fluid so as to increase the total volume of the wellbore fluid and alter the OWR, as well as the concentration of salts or other wellbore additives from their initial, desired concentration. According to the embodiments of the present invention, excess aqueous content may be removed from a wellbore fluid by contacting the wellbore fluid with a water absorbing polymer. Wellbore fluids that may be used with a water absorbing polymer in accordance with the present invention may include any invert emulsion fluids having excess water that have been collected form a wellbore, such as drilling fluids, completion fluids, workover fluids, and drill-in fluids.

[0028] A method 100 of removing at least a portion of the aqueous content from a wellbore fluid is depicted in Fig. 10. The wellbore fluid comprises an invert emulsion oil-based drilling fluid. As stated above, an invert emulsion consists of three phases: an oleaginous phase, an aqueous phase, and a finely divided particle phase. In the invert emulsion oil-based drilling fluid, the discontinuous aqueous phase is dispersed in an external or continuous oleaginous phase with the aid of one or more emulsifiers.

[0029] The oleaginous continuous phase is preferably selected from at least one of the following: mineral oil, synthetic oil, diesel, crude oil, and mixtures thereof. The aqueous discontinuous phase is preferably selected from at least one of the following: fresh water, sea water, brine, mixture of water and water soluble organic compounds, and mixtures thereof. As used herein, brine refers to various salts and salt mixtures dissolved in an aqueous solution. A brine of the present invention may include monovalent or/and divalent salts of inorganic or organic acids. Preferably, a brine of the present invention includes calcium, sodium or potassium chloride; calcium, sodium or potassium bromide, potassium or cesium formate dissolved in an aqueous solution.

[0030] Method 100 comprises a contacting step 110, where a water absorbing polymer is contacted with the wellbore fluid. The water absorbing polymer is preferably a water absorbing crystalline polymer capable of absorbing at least 10 times its own weight in fresh water. Particularly, the water absorbing polymer may include acrylamide based polymers and copolymers, starch derivatives, and combinations thereof, as well as other water absorbing polymers known in the art.

[0031] The absorbance capacity of the water absorbing polymers may be explained by the matix-like structure of dry water absorbing polymer particle. The dry polymer may contain charged species within the matrix, such that the ionization of the polymer will cause the matrix network to open and create cavities that may absorb water by capillary action. Water absorbed into the polymer may be retained by hydrogen bonds that form between the charged species and the water. The actual mechanism for water absorbance and retention may vary based on the structure of a particular water absorbing polymer. For example, polyacrylamide, in the dry powdered state, contains a coiled backbone, lined with amide groups. When exposed to an aqueous solution, the amide groups dissociate into negatively charged amide ions, which may repel one another along the polymer chain. The repelling amide ions thereby widen the polymer coils and allow water to move into contact with inner amide groups, further continuing the widening or welling of the polymer. Water is retained within the polymer due to hydrogen bonding between the water and the amide ions on the polymer. Because of the crosslinking that exists in these water absorbing polymers, the water absorbing polymers remain insoluble in an aqueous solution.

[0032] Method 100 further comprises an interacting step 120, where the water absorbing polymer is allowed to contact the wellbore fluid for a period of time. The period of time should be sufficient so that the water absorbing polymer absorbs at least a portion of the aqueous fluid from the invert emulsion. The amount of time will vary depending on the application, and can be easily ascertained through representative testing. However, equilibrium has been obtained between 1 and three hours, depending on salinity as well as the state of emulsification.

[0033] Method 100 further comprises a separating step 130, where the water absorbing polymer containing the absorbed water from the wellbore fluid is separated from the wellbore fluid. This can be achieved through various filtration techniques, including passing the invert emulsion wellbore fluid containing the water absorbing polymer over appropriate sized shaker screens to remove the swollen water absorbing polymer. Alternatively, centrifuges or hydrocylcones, which work on the basis of size and density differences, may also be used to effectuate separation of the water absorbing polymer from the wellbore fluid.

[0034] In another aspect, embodiments of the invention are generally directed to a method for adjusting the OWR of the invert emulsion wellbore fluid. This may become necessary to remove excess downhole influx of water, or adjust the OWR of an existing wellbore fluid so it may meet the specifications of a particular application.

[0035] A method 200 for removing the non-emulsified aqueous content during the drilling process is depicted in Fig. 11. It may become necessary to remove excess aqueous content throughout the drilling process if, for example, there is an influx of water into the wellbore or there is surface contamination of the wellbore fluid. If the water portion of the invert emulsion wellbore fluid increases, the water absorbing polymer can be added to absorb at least a portion of the aqueous content, thereby increasing the OWR. The water absorbing polymer will absorb the influx water first, and then absorb the discontinuous aqueous phase of the wellbore fluid.

[0036] Method 200 comprises a determining step 210, where the design limit of the OWR for the invert emulsion wellbore fluid is determined. The design limit is the minimum OWR the wellbore fluid will tolerate without adversely effecting the rheology, density, and emulsion stability of the wellbore fluid. Accordingly, the design limit will vary depending upon the particular application.

[0037] Method 200 further comprises a feeding step 220, where an invert emulsion wellbore fluid is fed to the borehole. The wellbore fluid is generally fed to a borehole via nozzles in a drill bit, or other methods already known in the art.

[0038] Method 200 further comprises a monitoring step 230, where the OWR of the wellbore fluid is monitored. Determination of the OWR can be done by distilling the liquid part of the drilling fluid in a device called retort, or other means known in the art. The ideal OWR will vary depending upon the particular application, as will the design limit of the wellbore fluid. If the determined OWR falls below the design limit OWR, removal of the excess aqueous content becomes necessary.

[0039] Method 200 further comprises a contacting step 240, where the invert emulsion drilling fluid is contacted with a water absorbing polymer through introducing the water absorbing polymer to the circulating drilling fluid in the wellbore. The water absorbing polymer can be added directly to the active pit, or the water absorbing polymer may be added in the flow line carrying the invert emulsion wellbore fluid.

[0040] Method 200 further comprises an interacting step 250, where the water absorbing polymer interacts with the invert emulsion drilling fluid for a sufficient period of time so that the water absorbing polymer absorbs sufficient aqueous content to return the OWR above the design limit. In one embodiment, sub-millimetric polymer granules are added to the wellbore fluid and allowed to continuously circulate within the wellbore. As the polymer granules circulate with the wellbore fluid, at least a portion of the aqueous content of the wellbore fluid will be absorbed by the polymer granules. As the polymer granules absorb the aqueous content, the polymer granules will begin to expand.

[0041] The size of the water absorbing polymer is important, as it affects the rate of absorption. The smaller the size of the water absorbing polymer granules, the larger the surface area of the particles, yielding a higher absorption rate. However, the granules should not be so small that they negatively impact the rheology of the drilling fluid. The rheology of the drilling fluid may become negatively impacted if the particle size of the polymer granules become comparable to that of the drilling fluid solid constituents, i.e. the weight material and the fluid loss additive. Additionally, the granules should not be so small in size that they will pass through the shaker screens before they have swollen. Consequently, the particle size of the polymer granules is at least 300 micron.

[0042] Method 200 further comprises a separating step 260, where the water absorbing polymer containing the absorbed aqueous content is separated from the invert emulsion drilling fluid. After the water absorbing polymer has been allowed to contact the invert emulsion drilling fluid long enough for at least a portion of the aqueous content to be absorbed by the water absorbing polymer, the water absorbing polymer may removed from the invert emulsion drilling fluid. This may be done by passing the fluid through suitable sized shaker screens. Filtration of the aqueous content-bearing water absorbing polymer can be achieved after the water absorbing polymer has swelled enough to be caught by the shaker screens. However, if the water absorbing polymer has not swollen sufficiently, the water absorbing polymer will pass through the shaker screen and continue to circulate through the wellbore. This allows for continual aqueous content removal until all the water absorbing polymer swells enough to be removed by the shaker screens.

[0043] A method 300 for removing a portion of the emulsified aqueous content of an existing invert emulsion wellbore fluid is depicted in Fig. 12. The existing OWR of an existing invert emulsion wellbore fluid can be determined by retort, as stated above. In certain circumstances, the existing OWR of an invert emulsion wellbore fluid may need to be increased so that the invert emulsion wellbore fluid meets specifications of a particular application. Consequently, it would be necessary to remove part of the discontinuous aqueous phase of the invert emulsion wellbore fluid.

[0044] Method 300 comprises a determination step 310, where the desired OWR is determined. The desired OWR will vary depending upon a given application. Factors considered when determining the desired OWR include the fluid density, rheology, fluid loss properties and costs.

[0045] Method 300 further comprises an addition step 320, where a sufficient amount of the water absorbing polymer is added to the existing wellbore fluid to adjust the existing OWR to a desired OWR. In one embodiment, the existing wellbore fluid is held in storage, and polymer granules are added to the existing wellbore fluid. As previously stated, the size of the polymer granules affects the rate of absorption. Because the existing wellbore fluid is held in storage, and is not actively involved in drilling a wellbore, the amount of time it takes to adjust the OWR to the desired OWR is not as critical. Consequently, larger polymer granules are preferred. While larger granules may be used, they should not be so large as to be prematurely filtered during separating step 340. Therefore, polymer granules between 0.3 and 1.0 millimeter are most preferred

[0046] Method 300 further comprises an interacting step 330, where the invert emulsion wellbore fluid interacts with the water absorbing polymer for a sufficient period of time for the water absorbing polymer to absorb sufficient aqueous content to adjust the existing OWR to the desired OWR. In one embodiment, the invert emulsion wellbore fluid is moderately agitated for the duration of the time period. The agitation should be of an adequate level to distribute the polymer granules uniformly throughout the drilling fluid, i.e. prevent separation due to density difference.

[0047] Method 300 further comprises a separating step 340, where the water absorbing polymer containing the absorbed aqueous content is separated from the invert emulsion wellbore fluid. Once the desired OWR is reached, separation may be done by passing the invert emulsion wellbore fluid through suitable sized shaker screens.

[0048] **<u>EXAMPLES</u>**

[0049] The following examples demonstrate the capability of water-swelling polymers to remove water or salt solution from an aqueous and non-aqueous liquid environment. Granules of an acrylamide copolymer (POLYSWELL®, M-I SWACO) were used in all the examples given below. The granules were roughly cubic in shape, with approximate size 2-4 mm. These were ground in a small laboratory grinder to a d_{90} of about 400 micron. Unless otherwise stated, all the tests were carried out in ambient temperature (20-25 °C).

[0050] Examples 1-3 are general demonstrations of water absorption capacity of the polymer. Examples 4-6 generally show the high capacity of the polymer for removing non-emulsified water from a non-aqueous environment such as an oil-based fluid. This is analogous to surface contamination or down hole influx of water. Examples 7-9 generally illustrate the ability of the polymer, dispersed in an oil phase, to extract water from an emulsified aqueous phase. This is analogous to treating an existing oil-based fluid in order to increase its OWR.

[0051] **<u>Example 1:</u>**

[0052] One gram of the polymer was added to a 250 mL beaker containing fresh water and stirred gently. The polymer granules were removed by sieving and weighed at intervals, then returned to the beaker. Fig. 1 shows the weight gain of the polymer against time of interaction between the polymer and the fresh water. The results show that the polymer absorbs more than one hundred (100) times its own weight of fresh water in two hours.

[0053] **<u>Example 2:</u>**

[0054] One gram of the polymer was added to a 250 mL beaker containing sea water and stirred gently. The polymer granules were removed by sieving and weighed at intervals, then returned to the beaker. Fig. 2 shows the weight gain of the polymer against time of interaction between the polymer and the sea water. The results show that the polymer absorbs more than ten (10) times its own weight of sea water in two hours.

[0055] **Example 3:**

[0056] Fig. 3 shows the effect of a thirty (30) degree rise in temperature on sea water absorption. The higher temperature does not have a negative effect on water absorption capacity of the polymer.

[0057] **Example 4:**

[0058] One gram of polymer was dispersed in a 100 mL beaker of a mineral oil (EDC 95/11, Total). The mixture was gently stirred for two hours to allow the polymer surfaces to become fully oil-wet. A 50 mL volume of sea water was then added to the oil phase as the stirring continued. The polymer granules were weighed at intervals. Fig. 4 charts the weight of the absorbed sea water against time. Comparison with Fig. 2 shows that the presence of the oil does not inhibit absorption of sea water by the polymer.

[0059] **Example 5:**

[0060] Two and a half (2.5) grams of an invert emulsifier (VERSACLEAN FL®, M-I SWACO) was dissolved in 100 mL of mineral oil. One gram of polymer was added to the oil. Stirring continued for two hours to allow the polymer surfaces to become fully oil-wet. A 50 mL volume of sea water was then added to the oil phase with gentle stirring. The polymer granules were weighed at intervals. Fig. 5 shows the weight of the absorbed sea water against time. Comparison with Figs. 2-5 shows that the presence of the oil and emulsifier does not inhibit absorption of sea water by the polymer. It should be noted that high-shear mixing, which is required for forming a stable emulsion, was not applied in this test. (i.e. the mixture was stirred gently at all times)

[0061] **Example 6:**

[0062] Two and a half (2.5) grams of emulsifier was dissolved in 100 mL of mineral oil. One hundred eighteen (118) grams of barite was added to the oil and the mixture was sheared for thirty (30) minutes. One gram of the polymer was added to the oil-barite suspension and stirring continued for two hours. A 50 mL volume of sea water was then added to the suspension with gentle stirring. The polymer granules were removed at intervals by sieving and shaking to ensure that most of the oily suspension was removed from the swollen particles before weighing. Fig. 6 shows the weight of absorbed sea water against time. Comparison with Figs. 4 and 5 shows that the presence of barite particles reduces water absorption by the polymer. This may be due to coverage of polymer granules with fine particles of barite. Nevertheless, the polymer is capable of absorbing seven times its own weight of sea water in three (3) hours.

[0063] The following examples show the water absorption capability of the polymer when the water is present in an emulsified state, which is the case with invert emulsion fluids.

[0064] **Example 7:**

[0065] Two and a half (2.5) grams of emulsifier was dissolved in 100 mL of mineral oil. A 30.7 mL volume of fresh water was added to the oil and the mixture was subjected to high shear for thirty (30) minutes using a Hamilton Beach mixer. One gram of polymer was then added to the emulsion and the mixture was stirred gently. The polymer granules were removed at interval and weighed. Fig. 7 shows the weight of absorbed fresh water against time. The polymer readily absorbs fresh water, up to fourteen (14) times its own weight, even when the water is in an emulsified state.

[0066] **Example 8:**

[0067] A 22% (w/w) calcium chloride brine was made by dissolving 10.9 grams of calcium chloride (oilfield grade, 83.5% purity) in 30.7 mL of fresh water (equivalent to a water phase salinity of 173,887 mg/L of chloride ions, a common oilfield unit). Two and a half (2.5) grams of emulsifier was dissolved in 100 mL of mineral oil. The 30.7 mL volume of 22% (w/w) calcium chloride brine was added to the oil and the mixture was subjected to high shear for thirty (30) minutes using a Hamilton Beach mixer. One gram of polymer was then added to the emulsion and the mixture was stirred gently. The polymer granules were removed at interval and weighed. Fig. 8 shows the weight of absorbed brine against time. This is the worst case scenario for water absorption as both salinity and emulsification reduce absorption of water by the polymer. Nevertheless, the polymer is capable of absorbing more than three times its own weight of brine from a concentrated emulsified brine phase.

[0068] **Example 9:**

[0069] A test was conducted to determine whether it was water or brine that was absorbed by the polymer. Three hundred (300) grams of a 22% (w/w) solution of calcium chloride was prepared as described in Example 8. The water activity of this solution was measured by a Novasina Water Activity Meter (Model ms1-aw) to be 0.796 at 22.5 °C. Fifteen (15) grams of the polymer was added to the brine and mixed by gentle stirring. After eight hours, the polymer granules were removed by sieving, and subsequently weighed. A weight gain of 77.9 gram was registered. The water activity of the remaining brine was measured to be more or less unchanged, 0.790 at 24.0 °C.

[0070] Fig. 9 shows the percent concentration (w/w) against water activity. If the weight gain of the polymer was due to absorption of pure water, rather than brine solution, then the salt concentration of the remaining brine would have increased to 29.9%, equivalent to a water activity of about 0.64, as shown in Fig. 9. As mentioned above, the measured water activity of the remaining brine was 0.79. Therefore, it is concluded that the polymer absorbs the salt solution rather than pure water.

[0071] While the claimed subject matter 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.

Claims

1. A method for removing aqueous fluid from a wellbore fluid, comprising:

contacting the wellbore fluid with a water absorbing polymer, the wellbore fluid comprising:

an invert emulsion;

interacting the water absorbing polymer with the wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs at least a portion of the aqueous fluid from the wellbore fluid; and
separating the water absorbing polymer containing the absorbed aqueous fluid from the wellbore fluid.

2. The method of claim 1, wherein the invert emulsion is comprised of an oleaginous continuous phase and an aqueous discontinuous phase.

3. The method of claim 2, wherein the oleaginous continuous phase is selected from at least one of mineral oil, synthetic oil, diesel, crude oil, and mixtures thereof.

4. The method of claim 2 or 3, wherein the aqueous discontinuous phase is selected from at least one of fresh water, sea water, brine, mixture of water and water soluble organic compounds, and mixtures thereof.

5. The method of any one of the previous claims, wherein the water absorbing polymer is a water absorbing crystalline polymer capable of absorbing at least ten times its own weight in fresh water.

6. The method of claim 5, wherein the water absorbing polymer is selected from at least one of acrylamide based polymers and copolymers, starch derivatives, and combinations thereof.

7. The method of any one of the previous claims, wherein the sufficient period of time is one to three hours.

8. The method of any one of the previous claims, wherein the separating step further comprises passing the wellbore fluid over a shaker screen.

9. A method for removing non-emulsified aqueous content from a wellbore fluid in situ, comprising:

determining a design limit of the oil-to-water ratio for the wellbore fluid;
feeding the wellbore fluid to the borehole, the wellbore fluid comprising:

an invert emulsion;

monitoring the oil-to-water ratio of the wellbore fluid;
adding a water absorbing polymer when the oil/water ratio decreases below the design limit;
allowing the water absorbing polymer to interact with the wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs sufficient aqueous content to return the oil/water ratio above the design limit; and
separating the water absorbing polymer containing the absorbed water from the wellbore fluid.

10. The method of claim 9, where the oil-to-water ratio of the wellbore fluid is intermittently monitored.

11. The method of claim 9, where the oil-to-water ratio of the wellbore fluid is continually monitored.

12. The method of any one of claims 9 to 11, where the water absorbing polymer is added directly to an active bore hole pit.

13. The method of claim any one of claims 9 to 11, where the water absorbing polymer is added through a flow line carrying the wellbore fluid.

14. The method of any one of claims 9 to 13, where the water absorbing polymer is selected from at least one of acrylamide based polymers and copolymers, starch derivatives, and combinations thereof.

15. The method of any one of claims 9 to 14, where the water absorbing polymer is sub-millimetric polymer granules.

16. The method of claim any one of claims 9 to 15, where the separating step further comprises passing the wellbore fluid over a shaker screen.

17. A method for removing emulsified aqueous content from an existing invert emulsion wellbore fluid, where the existing invert emulsion wellbore fluid comprises an existing oil-to-water ratio, comprising:

determining a desired oil-to-water ratio for the existing invert emulsion wellbore fluid;
adding a sufficient amount of water absorbing polymer to the existing wellbore fluid to adjust

the existing oil-to-water ratio to the desired oil-to-water ratio;
allowing the water absorbing polymer to interact with the existing wellbore fluid for a sufficient period of time so that the water absorbing polymer absorbs sufficient aqueous content to adjust the existing wellbore fluid to the desired oil-to-water ratio, thereby yielding an adjusted wellbore fluid; and
separating the water absorbing polymer containing the absorbed aqueous content from the adjusted wellbore fluid.

18. The method of claim 17, where the water absorbing polymer is selected from at least one of acrylamide based polymers and copolymers, starch derivatives, and combinations thereof.

19. The method of claim 17 or 18, where the water absorbing polymer is 0.3 - 1.0 millimeter polymer granules.

20. The method of any one of claims 17 to 19, where the separating step further comprises passing the wellbore fluid over a shaker screen.

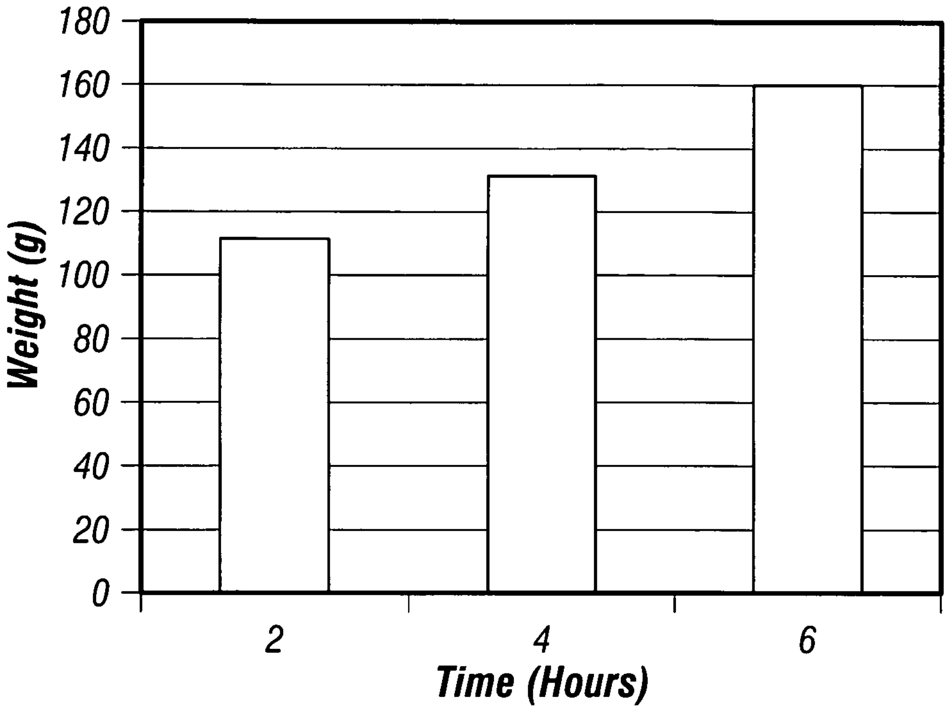
180
160
140
120
100
80
60
40
20
0
Weight (g)
2
4
6
Time (Hours)

FIG. 1

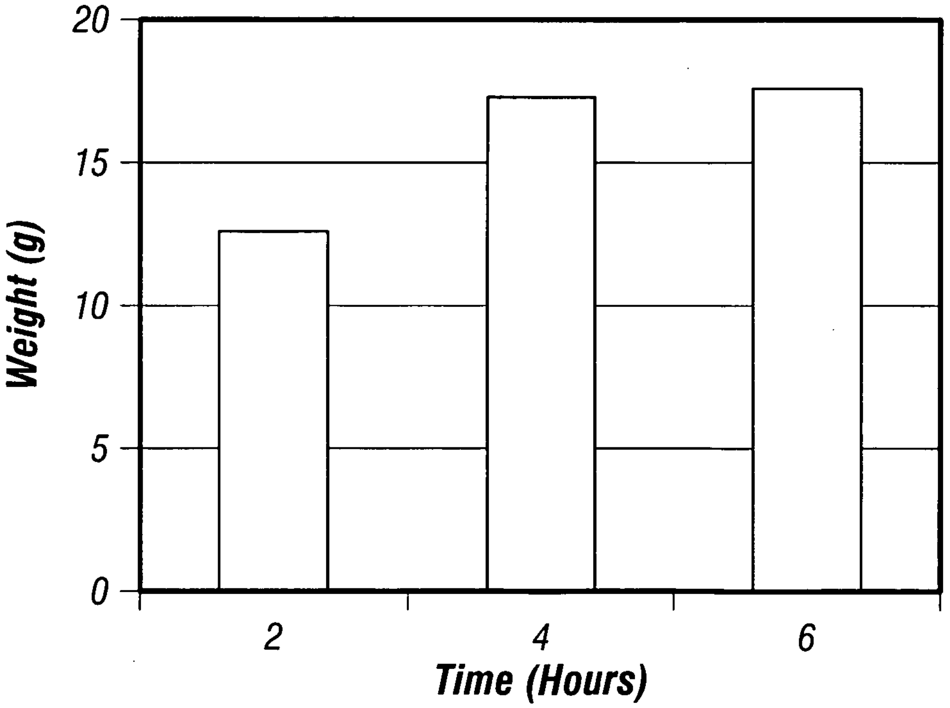
20
15
10
5
0
Weight (g)
2
4
6
Time (Hours)

FIG. 2

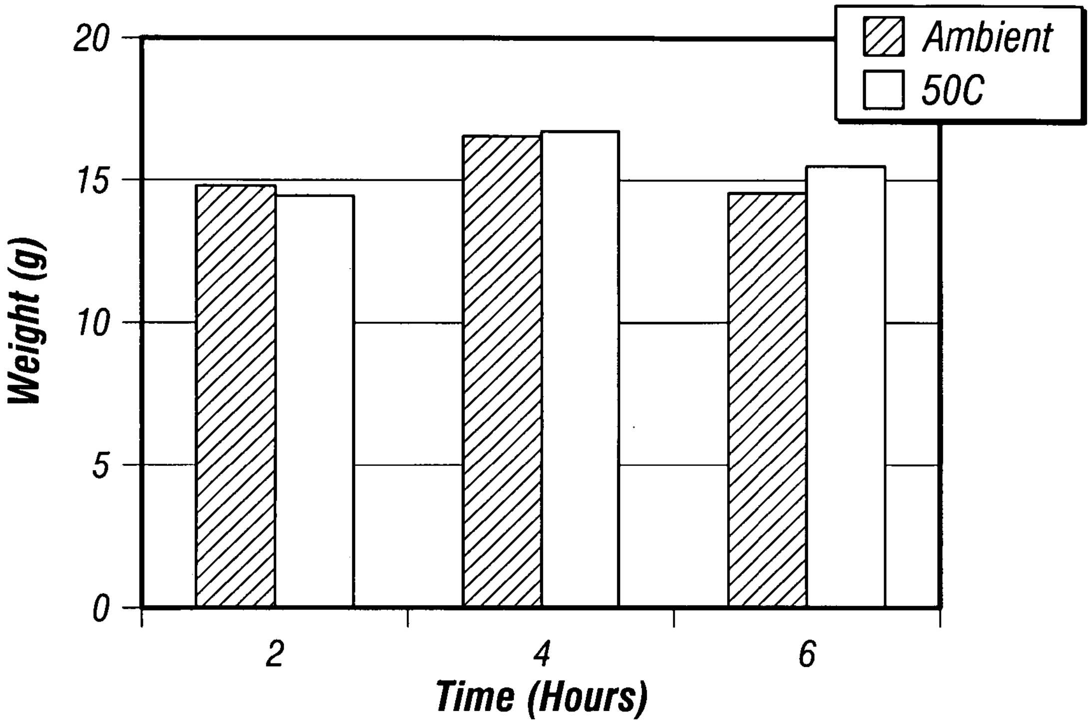
Ambient
50C
20
15
10
5
0
Weight (g)
2
4
6
Time (Hours)

FIG. 3

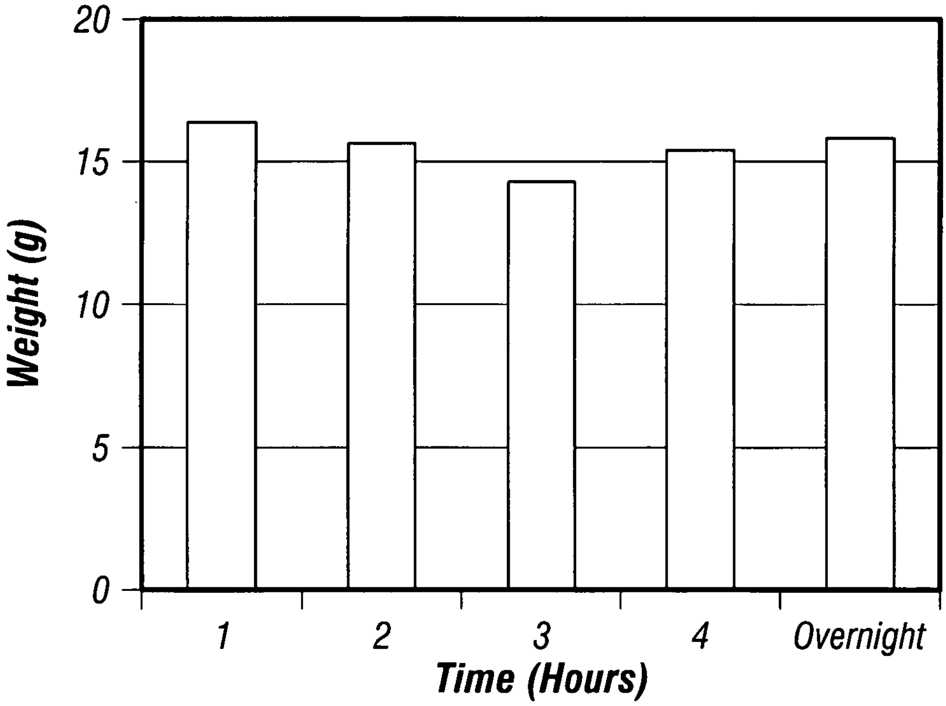
20
15
10
5
0
Weight (g)
1
2
3
4
Overnight
Time (Hours)

FIG. 4

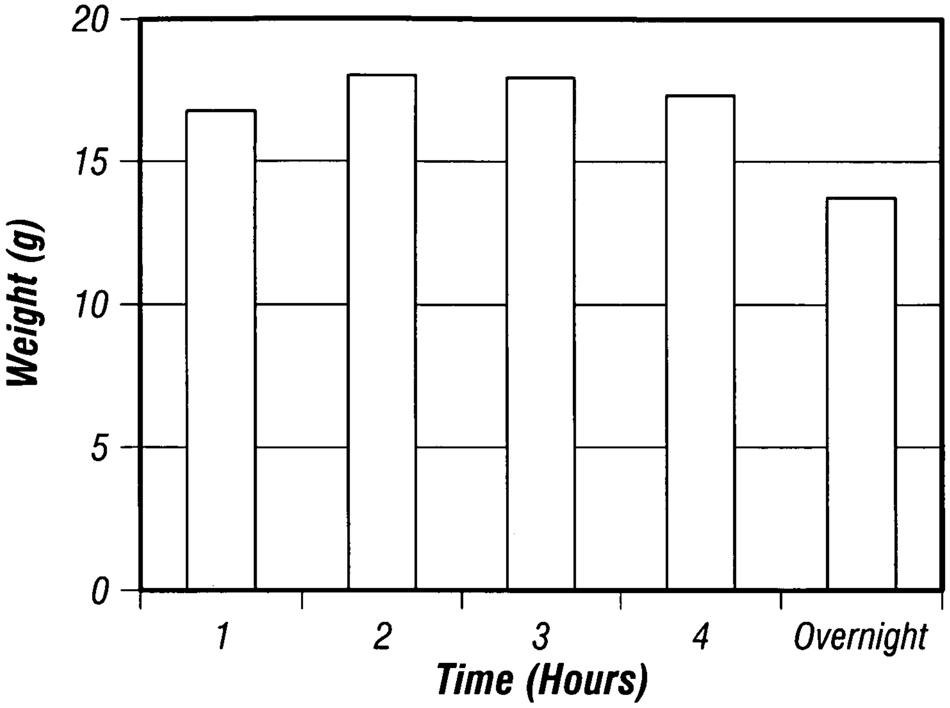
20
15
10
5
0
Weight (g)
1
2
3
4
Overnight
Time (Hours)

FIG. 5

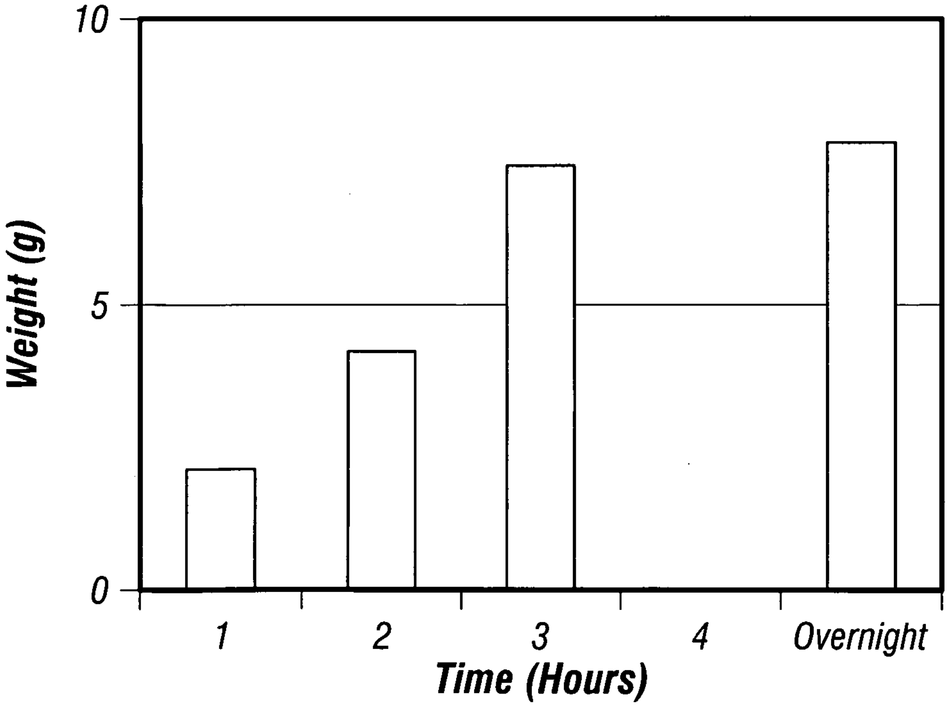
10
5
0
Weight (g)
1
2
3
4
Overnight
Time (Hours)

FIG. 6

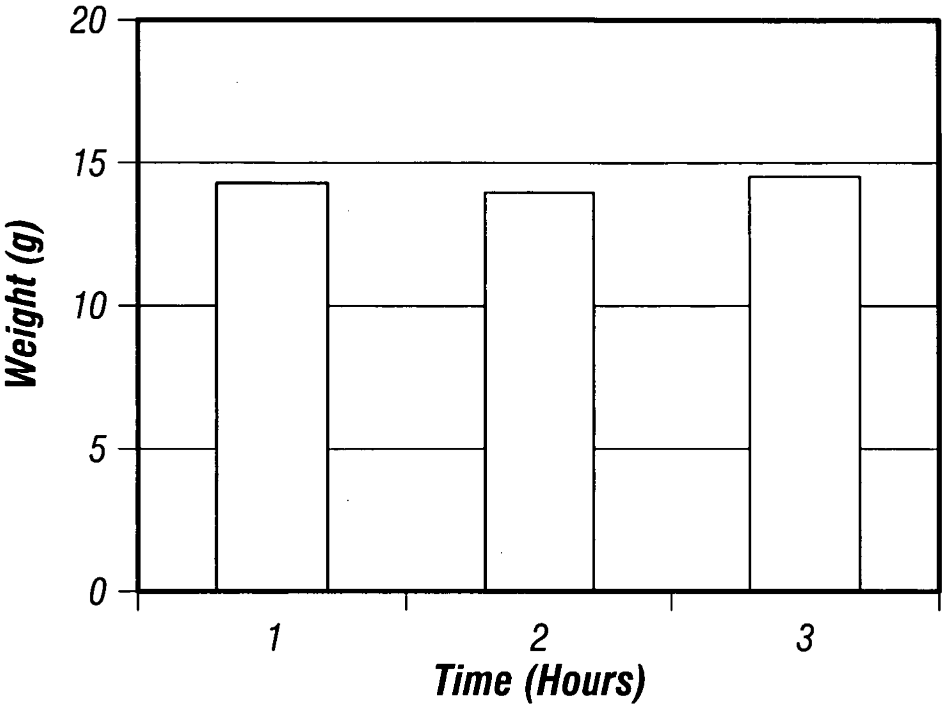
20
15
10
5
0
Weight (g)
1
2
3
Time (Hours)

FIG. 7

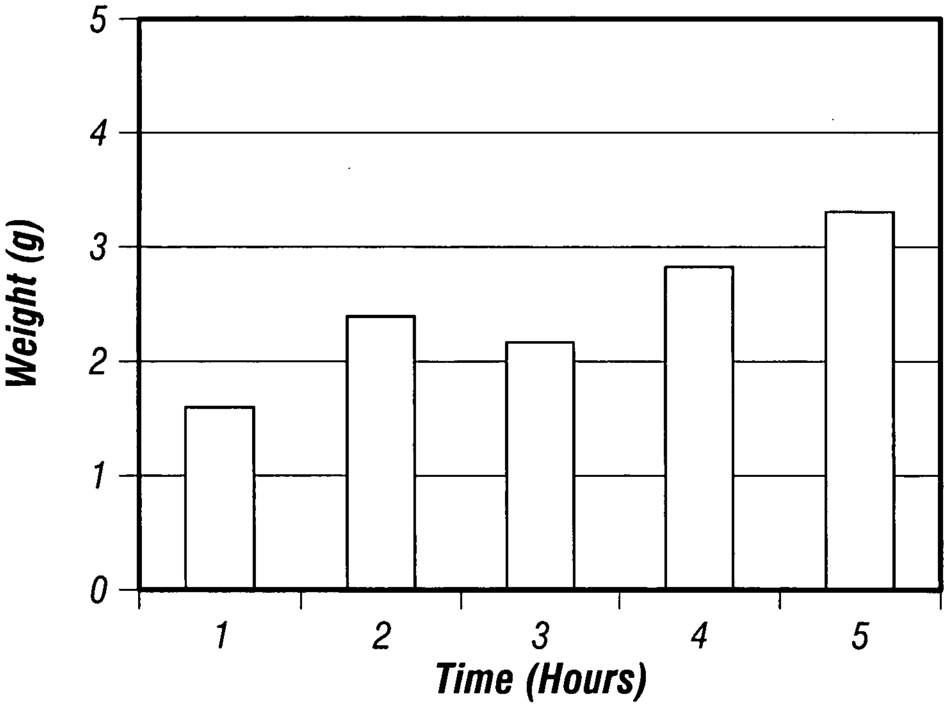
5
4
3
2
1
0
Weight (g)
1
2
3
4
5
Time (Hours)

FIG. 8

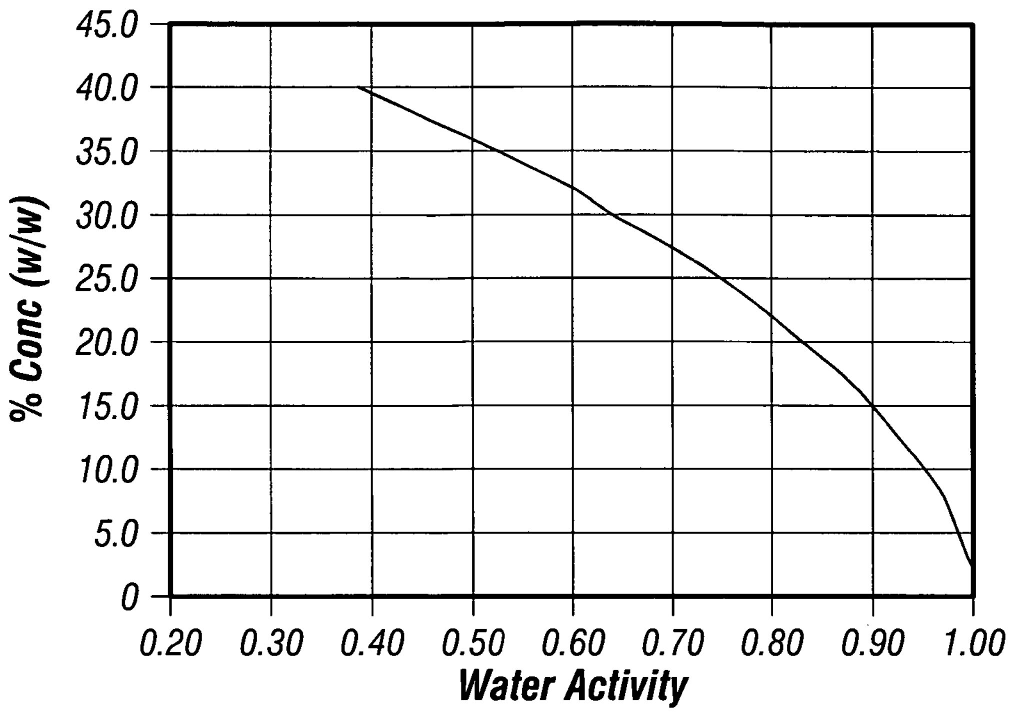
% Conc (w/w)
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
Water Activity

FIG. 9

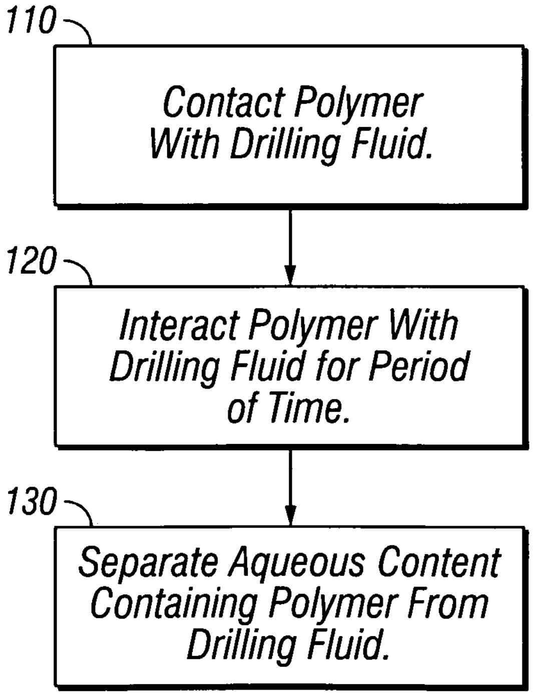
110
Contact Polymer With Drilling Fluid.
120
Interact Polymer With Drilling Fluid for Period of Time.
130
Separate Aqueous Content Containing Polymer From Drilling Fluid.

FIG. 10

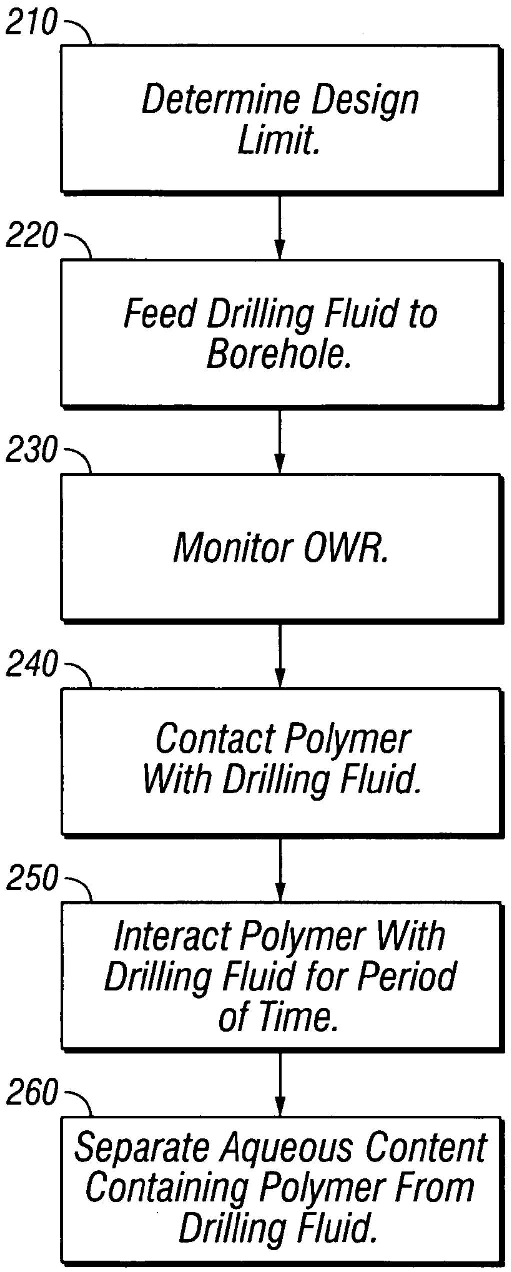
210
Determine Design Limit.
220
Feed Drilling Fluid to Borehole.
230
Monitor OWR.
240
Contact Polymer With Drilling Fluid.
250
Interact Polymer With Drilling Fluid for Period of Time.
260
Separate Aqueous Content Containing Polymer From Drilling Fluid.

FIG. 11

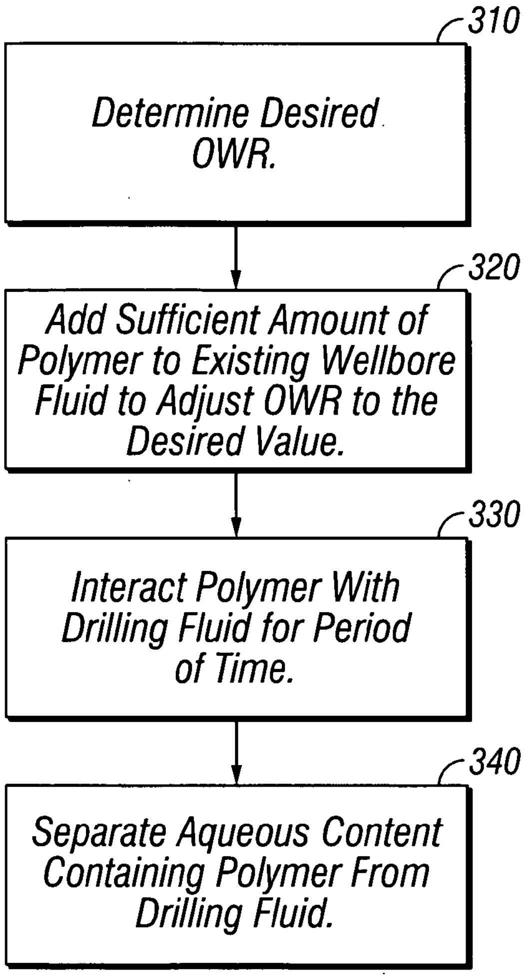
310
Determine Desired OWR.
320
Add Sufficient Amount of Polymer to Existing Wellbore Fluid to Adjust OWR to the Desired Value.
330
Interact Polymer With Drilling Fluid for Period of Time.
340
Separate Aqueous Content Containing Polymer From Drilling Fluid.

FIG. 12