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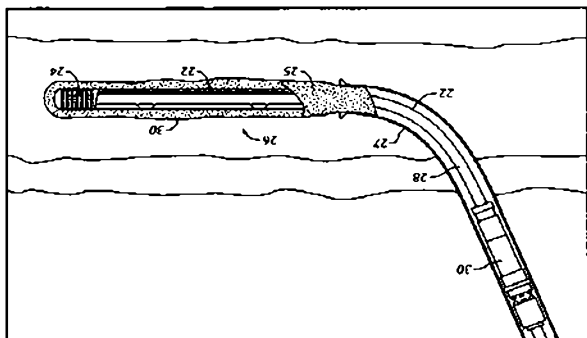
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Titre : Methods of using oleaginous fluids for completion operations.

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Abrégé :

In a method of gravel packing a wellbore in a subterranean formation, the wellbore having a cased section and an uncased section, the method may include pumping into the wellbore a gravel pack composition having gravel and a carrier fluid, where the carrier fluid includes an oleaginous fluid and an inorganic solid aggregator material.



Embodiments disclosed herein relate generally to wellbore fluids for operations. In particular, embodiments disclosed herein relate to oleaginous fluids in gravel packing.

Background

During the drilling of a wellbore, various fluids are typically used in the well for various 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 circulation, the drilling fluid may act to remove drill cuttings from the bottom of the wellbore, to suspend cuttings and weighting material when circulation is interrupted, to control subsurface pressures, to maintain the integrity of the wellbore until the well is cased and cemented, to isolate the fluids from the formation by providing a hydrostatic pressure to prevent the ingress of formation fluids into the wellbore, to lubricate the drill string and bit, and/or to maximize penetration rate.

In most rotary drilling procedures the drilling fluid takes the form of a "mud," which has solids suspended therein. The solids function to impart desired properties to the drilling fluid and also to increase the density thereof in order to maintain a suitable hydrostatic pressure at the bottom of the well. The drilling mud may be water-based or an oil-based mud.

Many wells, especially in oil fields in shale formations (having water sensitive formations), deep-water/subsea environments, are drilled with synthetic/oil-based muds. Because of the extremely high cost of intervention and high production requirements, wells require reliable completion techniques that prevent sand production and maintain productivity throughout the entire life of the well. One such technique is open hole gravel packing.

In unconsolidated formations, sand control measures are implemented to prevent formation sand. Common practice for controlling sand displacement includes placing a gravel pack to hold formation sand in place. The gravel pack is typically placed around a screen. The gravel pack filters the sand while still allowing formation

two techniques are significantly different. The alternate path technique allows for the placement of sand control screens in any bridges that may form in the annulus, caused by for example high leak-off rates, formation damage, or exceeding the fracturing pressure. It also allows for the placement of screens in areas of sloughing/shale-swelling or localized formation collapse on the sand control screen. Most of the recently discovered deep-water fields contain a high fraction of shale and are water-sensitive, although many have been gravel packed with water-based fluids. A very large fraction of them have been completed with viscous fluids using the alternate path technique. Viscoelastic surfactant (VES) solutions have been the most common carrier fluid in open hole gravel packing with the alternate path technique due to formation and gravel pack damage characteristics, their low drawdown requirements, their capability of incorporating filtercake cleanup chemicals into the carrier fluid, and their low friction pressures.

In wells drilled with synthetic or oil-based muds (often the case for high shale content and/or deep water wells), three main approaches have been used for gravel packing. The first approach involves displacement of the entire wellbore to water-based fluid prior to drilling the reservoir section, and subsequently running the sand control screens in the open hole, setting the packer and gravel packing with a water based fluid. However, as experienced by several operators, the problem with this approach is that exposure of reactive shales to water-based fluids for prolonged time periods can cause shale collapse or swelling which effectively reduces the wellbore diameter and makes it impossible to install sand control screens to the target depth (see SPE 89815, SPE 90751). The addition of dispersants into the carrier fluid during gravel packing which can have a significant impact on well productivity (Ali et al.--Petroleum Engineer International, March 1995). The success of this approach is therefore heavily dependent on the reactivity of the shale. One approach subsequently practiced involved installation of a pre-drilled liner in oil-based mud, then displacement of the entire wellbore to water based fluid, subsequent installation of the sand control screens to target depth and finally gravel packing with a water based fluid. This approach solved the problem of inability to install screens to target depth, since shale collapse would occur onto the pre-drilled liner.

A more recent approach that has been practiced heavily in two deepwater developments (see SPE 90758 and SPE 107297) and an oilfield in Azerbaijan (see SPE 98146) involved conditioning of the oil based mud by passing the mud through screens of a certain size (to prevent plugging of sand screens), then running screens in conditioned oil based mud, and subsequently displacing the wellbore based fluids and proceeding with gravel packing with a water based carrier fluid (see Nos. 6,883,608 and 7,373,978). This approach has been successfully used in over 75 wells to date by two major operators, in conjunction with the alternate path of screens.

Other developments include utilizing solids-free fluids (see SPE 17161-PA and SPE DF-HO-07), in efforts to overcome issues of wellbore destabilization. This approach in gravel packing fluids has been the widely accepted approach in the industry. Instead of incorporating solids to achieve desired fluid rheology and density, liquid incorporated liquid additives to maintain solids-free gravel pack fluids.

While the above-described methods may be adequate for installing sand screens and gravel packing in many wells formed in reactive shale-containing formations, there is a continuing need for improvements in the completion fluids used during such methods.

SUMMARY

In one aspect, embodiments disclosed herein relate to a method of gravel packing a wellbore in a subterranean formation, the wellbore comprising a cased section and an uncased section, where the method includes pumping into the wellbore a completion fluid composition comprising gravel and a carrier fluid, where the carrier fluid comprises an oleaginous fluid and an inorganic solid aggregator material.

In another aspect, embodiments disclosed herein relate to a method of completing a wellbore penetrating a subterranean formation, the wellbore comprising a cased section and an uncased section, where the method includes introducing a fluid into the uncased section of the wellbore, where the fluid comprises an oleaginous fluid and a solid material; running a liner, sand control screen assembly, swell packer and an inflow control device to a selected depth within the uncased section of the wellbore.

composition comprising gravel and a carrier fluid, where the carrier fluid comprises an oleaginous fluid and a weighting agent.

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

BRIEF DESCRIPTION OF DRAWINGS

FIGS. 1A-1D show cross-sectional views of a completion interval depicting various stages of a gravel packing operation.

FIG. 2 shows a schematic view of a completion interval depicting a gravel packing operation.

DETAILED DESCRIPTION

In one aspect, embodiments disclosed herein relate to methods of completion that use oleaginous fluids during the technique(s). More particularly, the disclosure is directed toward the use of oleaginous-based wellbore fluids in gravel packing and/or installing liners and/or sand control screens in a wellbore that may contain shale or clay or in which the use of an oleaginous-based fluid may otherwise be beneficial. As used herein, "oleaginous fluid," "oleaginous-based fluid," "oil-based fluid," and similar expressions may be used interchangeably and refer to a hydrocarbon-based fluid derived from crude oil or chemical synthesis. Illustrative oleaginous fluids include mineral oil, white oil, n-alkanes, synthetic oils, saturated polyalphaolefins, and unsaturated polyalphaolefins. As used herein, the expressions "reactive shale," "reactive shale material," and similar expressions may be used interchangeably and refer to those shale materials that may swell, crumble, particulate, flake, slough off or otherwise degrade when exposed to aqueous fluids, particularly fresh water. As used herein, "Oil to Water ratio," or similar expressions may be used, and refer to the oleaginous to water ratio of a fluid. As used herein, "high internal phase ratio (HIPRE) emulsion" or "high internal phase emulsions (HIPE)" may be used interchangeably and refer to an emulsion where the internal phase of the emulsified fluid is at least 50%. As used herein, "oil-in-water emulsion" is an emulsion where an oleaginous fluid serves as a continuous phase and a non-oleaginous fluid serves as a discontinuous phase, the non-oleaginous

formation rock present as cuttings or drilled solids that are removed from the wellbore. The drilling fluid is circulated back to the surface.

In the construction of the well, a casing may be positioned within a portion of the wellbore and cemented into place. The portion of the wellbore that is not lined with casing forms the uncased or open hole section where a sand control screen may be placed to facilitate gravel packing for controlling the migration and production of sand and to stabilize the formation of the open hole section.

Once the wellbore is drilled and the casing cemented into place, the well is completed by installing sand screens and gravel packing the open hole section. Produced fluids from the formation are allowed to flow through the gravel pack and sand screen and may be recovered through the wellbore. The open hole section may be in any orientation, including vertical and horizontal hole sections.

After the open hole and cased hole sections are displaced with the completion fluids, the drilling string may be removed from the wellbore and a sand control screen assembly may be run or lowered to a selected depth within the open hole section of the well bore. The sand screen assembly may be run or lowered into the wellbore on a tubular member or wash pipe, which is used for conducting fluids from the sand screen and the surface. Running the sand screen assembly to the selected depth may include positioning the sand screen in vertical or non-vertical (horizontal) orientation in the well. A packer may be positioned and set in the casing above the sand screen to isolate the interval being packed. A crossover service tool may also be provided with the sand screen assembly to selectively allow fluids to flow between the annulus formed by the casing and the screen assembly and the interior of the tubular member and wash pipe.

With the sand control screen assembly in place, a gravel pack slurry containing sand and gravel forming the gravel pack and a carrier fluid is introduced into the wellbore to facilitate the gravel packing of the open hole section of wellbore in the annulus surrounding the sand control screen. The gravel pack slurry is typically introduced into the tubular member and wash pipe and flows to the cross over tool into the annulus of the open hole section below the tool joint. The slurry then flows to the exterior of the sand control screen. As the gravel settles within the open hole section, it forms a gravel pack around the sand control screen.

advantages and limitations. However, either packing technique may use an fluid of the present disclosure.

Alpha-beta packing involves gravel packing with a low viscosity carrier fluid (could be a completion brine) by a high fluid velocity. Gravel is generally added to the concentrations and is transported by velocity. Completion brines are conventional as the carrier for such technique, as the technique relies on the carrier fluid having Newtonian (or near-Newtonian) fluid properties for the annulus to be filled in with this technique. While conventional oil-based fluids have historically not had desirable properties (ability to possess low viscosity with high density) for gravel packing, the oleaginous fluids of the present disclosure possess both low viscosity and high density.

Referring to FIGS. 1A-1D, a schematic of a horizontal open hole completion interval in a well that is generally designated 50 being filled by alpha-beta packing is shown in FIG. 1A, casing 52 is cemented within a portion of a well 54 proximate the heel end of the horizontal portion of well 54. A work string 56 extends through casing 52 into the open hole completion interval 58. A packer assembly 60 is positioned around work string 56 and casing 52 at a cross-over assembly 62. Work string 56 includes one or more sand control screen assemblies such as sand control screen assembly 64. Sand control screen assembly 64 includes a base pipe 70 that has a plurality of openings which allow the flow of fluids therethrough.

Gravel packing the interval is accomplished by delivering fluid slurry 84 down work string 56 into cross-over assembly 62. Fluid slurry 84 exits cross-over assembly 62 through cross-over ports 90 and is discharged into horizontal completion interval 58 as indicated by arrows 92. In the illustrated embodiment of alpha-beta packing, fluid slurry 84 travels within production interval 58 with portions of the gravel dropping out of the slurry and building up on the low side of wellbore 54 from the heel to the toe of well 54, as indicated by alpha wave front 94 of the alpha wave portion of the gravel packing. At the same time, portions of the carrier fluid pass through sand control screen assembly 64 and travel through annulus 96 between wash pipe assembly 76 and the interior of casing 52.

dominate this "alpha" wave, so gravel settles until reaching an equilibrium height. If the flow remains above the crucial velocity for particle transport, gravel will move along the horizontal section toward the toe. Once the alpha wave has reached the far end of the wellbore, the "beta" wave phase as indicated by beta wave front 118 begins to deposit gravel on the heel side of the wellbore, on top of the alpha wave deposition, progressing from the far end to the near (heel) end of the production interval. The beta wave requires a higher flow velocity to maintain turbulent flow and move gravel along the top of the wellbore. To achieve the properties for alpha-beta packing when using an oleaginous fluid or an oil-in-water invert emulsion, the OWR is in the range of 95:5 to 35:65. Further, the fluid is viscosified in such a manner that the fluid possesses Newtonian (or near-Newtonian) rheological properties.

As shown in FIG. 2, the gravel slurry 20 is diverted to flow through shunt tubes 22 outside of the screen assembly 24, which provide an alternative pathway for the gravel slurry. The gravel slurry exits from nozzles (not shown) on the shunt tubes 22 to form a gravel heel in a heel to toe manner. As the gravel settles within the open hole section 26, the carrier fluid passes through the screen 24 and into the inner tubular member 28. The carrier fluid is conducted to the crossover tool 30 and exits into the annulus between the casing 27 and the tubular member 28 above the packer 32. When an invert emulsion fluid is desired, the invert emulsions may be formed using HPR emulsions with viscosifiers (such as those disclosed herein) to form a viscosified fluid that may be used to gravel pack by the alternate path technique. In invert emulsions or in substantially all oil-containing fluids, the viscosifier may be selected by type and amount to result in non-Newtonian fluid properties.

Under either packing technique, the gravel particles may be ceramics, natural materials, or other particulate materials suitable for such purposes. The gravel particles are selected such that they will not pass through the screen openings. Typical particle sizes in mesh size may range from about 12 mesh (1.68 mm) to about 70 mesh (0.210 mm). A combination of different particle sizes may be used. Examples of typical particle size combinations for the gravel particles are from about 12/20 mesh (1.68 mm to 0.85 mm).

In addition to (or instead of) using the oleaginous fluid as a carrier fluid for gravel, in accordance with the present disclosure, the oleaginous fluid may also be used in the placement of sand control screens and/or liners, as well as other completion equipment.

The oleaginous-based fluids of the present disclosure may be used with almost any type of liner or and/or sand control screen assembly. These may include pre-formed screens, slotted, liners, wire-wrapped screens, prepacked screens, direct-wrapped sand screens, mesh screens, premium-type screens, etc. Premium-type screens typically include multiple multi-layers of mesh woven media along with a drainage layer. Premium-type screens do not have a well defined screen opening size. In contrast, wire wrap screens consist of a wire uniformly wrapped around a perforated base pipe. The wire wrap screens have a uniform screen opening defined as gauge opening. Further, as described above, a sand control screen assembly may also include those with alternate flow paths or screens. Moreover, screen assemblies may also include those that include diverted screens that diverting fluid returns through a shorter pathway, preventing pressure build up during the gravel packing process. Other completion equipment with which the oleaginous-based fluids may be used includes packer assemblies (including swell packer assemblies) that separate upper annuli from lower production equipment in a well, or inflow control devices (which limit the inflow of fluids into the production tubing). The particular type of completion equipment is of no limitation on the present disclosure; rather, the oleaginous based fluids may be used with any type of equipment while the equipment is being run in the hole during subsequent completion operations prior to the well being put into production. Depending on the arrangement, one or more of such completion equipment may be used in combination with each other.

In accordance with embodiments of the present disclosure, prior to installing sand control screens and/or gravel packing, the drilling fluid may optionally be first displaced from the open hole section to a displacement fluid, and a second fluid may optionally be used to displace the fluid in a cased hole section. Displacement of the drilling fluids from the open hole section may be carried out by introducing the displacement fluid into the

or clays that could otherwise be damaged if water-based fluids were used to circulate drilling fluids. The volume of first displacement fluid used may be sufficient to fill the open hole section plus the cased hole section up to the packer setting depth.

When a sufficient volume of the first displacement fluid is introduced into the wellbore, it displaces the drilling fluid from the open hole section of the wellbore. A second displacement fluid (optionally the same or different than the first) is used to displace at least a portion or all of the cased hole section of the wellbore. The volume of the second displacement fluid may be sufficient to displace the entire cased section above the packer setting depth. This may be carried out by raising the end of the tubular drill string so that it is positioned within the cased hole section above the open hole section so that the second displacement fluid is discharged from the end of the drill string into the cased hole section.

Sand control screens and/or liners, or other completion equipment such as swell packer assemblies (including swell packer assemblies) or inflow control devices (ICDs) to control the inflow of fluids into the production tubing) are then run to target depth, optionally in the presence of the invert emulsions of the present disclosure. The sand control screen may be a standalone sand screen or an expandable sand screen. When a sand control screen is installed, the well may be gravel packed with an oleaginous fluid, as disclosed herein. Further, one of ordinary skill in the art would appreciate that one or more of such completion equipment may be used in combination.

Carrier Fluid

Under either packing technique, and under all methods of the present disclosure, the carrier fluid may be an oleaginous fluid. In some embodiments of the present disclosure, the oleaginous fluid is substantially oil-based. In other embodiments of the present disclosure, the oleaginous fluid is an invert emulsion fluid, where the invert emulsion fluid comprises an oleaginous external phase, a non-oleaginous internal phase, and an emulsifier stabilizing the oleaginous external phase and the non-oleaginous internal phase.

Oil-Based Fluids

acids, specifically straight chain, branched and cyclical alkyl ethers or fatty acids thereof and similar compounds known to one of skill in the art; and mixtures thereof. In cases where the oleaginous fluid is substantially oil-based, a viscosifier may be included. The viscosifier will maintain low rheological properties, and prevent settling of the weight material during both packing techniques. Illustrative viscosifiers include organophilic clays, amine treated clays, organophilic polymers, polyamides, polyolefin amides, polycarboxylic acids, metal soaps (such as aluminum stearate), diamides, alkyl phosphate esters (alone or crosslinked with metal ions, for example), thickeners (silica, nanocellulose, etc). Examples of polymeric viscosifiers may include organophilic polyacrylamides, styrene-butadiene polymers, styrene-isoprene copolymers, polyisobutylene, polyisoprene, polybutadiene, etc. The amount of viscosifier in the fluid composition can vary upon the application. However, a concentration of about 0.1% by weight range is sufficient for most applications. The particular range selected may be based on the type of gravel packing mechanism to be used. Specifically, the type of viscosifier may affect the rheological properties of a fluid, *i.e.*, whether the fluid is Newtonian, non-Newtonian, or on the scale between strongly Newtonian and strongly non-Newtonian (near-Newtonian), which is relevant to whether the fluid is best used for beta gravel packing (Newtonian) or an alternative path packing (non-Newtonian). VERSAPAC[®] is an organic polymer distributed by M-I SWACO, Houston, Texas, and VG-PLUS[™] are organoclay materials distributed by M-I SWACO, Houston, Texas, and VERSA-HRP[™] is a polyamide resin material manufactured and distributed by M-I SWACO, that may be used in the fluids disclosed herein.

In some embodiments, the oleaginous based fluid may also have a sufficient Fanning friction factor, which may allow for longer intervals when packing with the beta packing technique through fluid hydraulics. A Fanning friction factor is a dimensionless number that relates to the shear stress at the wall and may be calculated as $f = 2\tau / \rho u^2$, where τ is the shear stress at the wall, f is the Fanning friction factor, ρ is the density of the fluid, and u is the fluid velocity. The shear stress at the wall may be calculated as $\tau = \Delta P D / 4L$, where ΔP is the pressure drop, D is the diameter

16.25 feet of tubing.

In some embodiments, a friction reducer may be incorporated into a substantial fluid to reduce the friction of the fluid and allow for longer intervals during gravity separation. Examples of such friction reducers that may be used in an oil-based fluid may include, for example, polyalphaolefins such as polyisobutylene, organophilic polyacrylamides, and various dispersants known in the art, including amidoamine surfactants, which may be provided alone or in an inert liquid carrier such as vegetable oil, alcohols, glycerol, or water. It is also noted that the friction reducer may be incorporated as an in-situ additive or may be used in conjunction with one or more other components.

Invert Emulsion Fluids

As discussed above, the methods of the present disclosure may use an invert emulsion fluids having an oleaginous-to-non-oleaginous ratio of 90:10 to 10:90.

Oil-in-water emulsions are typically stabilized by both electrostatic stabilization (charge double layer between the two phases) and steric stabilization (van der Waals forces), whereas invert emulsions (water-in-oil) are typically stabilized by steric stabilization. Because only one mechanism can be used to stabilize an invert emulsion, invert emulsions are generally more difficult to stabilize, particularly at higher internal phase concentrations, and often experience highly viscous fluids.

Invert emulsion fluids of the present disclosure may have OWR ranging from 65:35 to 10:90 depending on the completion technique and the conditions of the wellbore environment where the invert emulsion fluid is a HIPR emulsion with an OWR of less than 10:90. The invert emulsion fluid is stabilized by an emulsifying agent without significant increase in viscosity. Additionally, by virtue of the greater internal phase concentration, density may be provided to the fluid partly through the inherent weight of the aqueous or oleaginous phase, thus minimizing the need for external agents to increase the density of the fluid. As the internal non-oleaginous 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, HIPR invert emulsion fluids may possess

The invert emulsion fluid may also possess an internal non-oleaginous phase that is emulsified within the external oleaginous phase. Specifically, upon application of an electric field to an invert emulsion fluid, the emulsified non-oleaginous phase, which carries a net electrical charge, will migrate to one of the electrodes used to generate the electric field. The incorporation of emulsifiers in the invert emulsion fluid stabilizes the emulsion against the effects of the electric field 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 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 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 at which the current reaches 61 μ A. 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 the electrode gap in the probe. The higher the ES voltage measured for the fluid, the more stable 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 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 emulsions and droplets. For example, the non-oleaginous phase distributed in the oleaginous phase may have an average diameter in the range of 0.5 to 5 microns in one embodiment and a range of 1 to 3 microns in a more particular embodiment. The droplet size distribution is generally 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 of droplet size may be approximately one-third to one-fourth the size of emulsions formed using conventional emulsifiers. In a particular embodiment, the emulsions

ethers of fatty acids, mixtures thereof and similar compounds known to one of skill in the art and mixtures thereof. In a particular embodiment, the fluids may be formulated with a natural oil or a synthetic oil as the external phase. The oleaginous fluid in one embodiment includes at least 5% by volume of a material selected from the group including esters, acetals, dialkylcarbonates, hydrocarbons, and combinations thereof.

The concentration of the oleaginous fluid should be sufficient so that an invert emulsion forms. More specifically, the amount of oleaginous fluid is from about 70% to about 95% by volume, depending on the completion operation. In cases where the completion operation is alpha-beta gravel packing, then the oleaginous-to-non-oleaginous ratio is in the range of 65:35 to 35:65, and in the range of 45:55 to 55:45 in a more particular embodiment. In cases where the completion operation is alternate path technology, the oleaginous-to-non-oleaginous ratio is in the range of 30:70 to 10:90, and from 35:65 to 15:85 in a more particular embodiment.

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 fluid 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 various desired salts in fresh water. Such salts may include, but are not limited to, sodium, calcium, aluminum, magnesium, strontium, and lithium, salts of chlorides, bromides, carbonates, iodides, bromates, formates, nitrates, oxides, phosphates, sulfates, silicates, and fluorides. Salts that may be found in natural seawater or any other organic or inorganic dissolved salts. Additionally, the fluids that may be used in the drilling fluids disclosed herein may be natural or synthetic, with

forming an invert emulsion. The amount of non-oleaginous fluid is more than about 10% of the total volume, depending on the completion operation. In cases where the completion operation is alpha-beta gravel packing, then the oleaginous-to-non-oleaginous ratio is in the range of 65:35 to 35:65. Where the completion operation is alternate path technique, the oleaginous-to-non-oleaginous ratio is in the range of 30:70 to 10:90.

One example of an emulsifying agent that may stabilize the emulsion of non-oleaginous fluid within the oleaginous fluid is an emulsifier formed from C₁₅₋₄₀ polyamides with a molecular weight greater than 1200, and amines. Regarding the chemical composition of the emulsifier used in invert emulsion fluids of the present disclosure, the emulsifier may be used in an amount ranging from 1 to 10 lb per barrel.

The term "HLB" (Hydrophilic Lipophilic Balance) refers to the ratio of the hydrophilicity of the polar groups of the surface-active molecules to the hydrophobicity of the lipophilic groups of the same molecules. An HLB value may be calculated by considering the weight contributions of the respective hydrophilic and lipophilic portions and the ratio thereof (divided by 5). Generally, the Bancroft rule applies to the formation of emulsions: emulsifiers and emulsifying particles tend to promote dispersion of the phase in which they do not dissolve very well; for example, a compound that dissolves better in water than in oil tends to form oil-in-water emulsions (that is they promote the dispersion of oil droplets throughout a continuous phase of water). Emulsifiers are typically amphiphilic. That is, they possess both a hydrophilic portion and a hydrophobic portion. The nature and strength of the hydrophilic polar group compared with those of the lipophilic 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. To form an oil-in-water emulsion, an emulsifier (or a mixture of emulsifiers) having a low HLB may be used. Emulsifiers of the present disclosure have an HLB less than 3.

Emulsifiers used in invert emulsions may include C₁₅₋₄₀ polyolefins, polyamides with a molecular weight greater than 1200, and amines. The term "amine number" refers to the ratio of the mass of potassium hydroxide which consumes exactly as much

The fluids of the present disclosure may also include an inorganic solid material. Historically, gravel pack fluids have remained solids-free because of that a solid can cause to the formation. However, it has been surprisingly disclosed that the composition and sizing of the inorganic solid aggregation material will impact the performance of the oleaginous-based fluid and minimize damage to the formation. The inorganic solid aggregation material of the present disclosure may impact the wettability of the gravel pack, thereby resulting in a tighter packing. Furthermore, the solid aggregation materials of the present disclosure may also reduce top oil separation and in some cases eliminate top oil separation in the case of invert emulsion. Top oil separation measures the amount of oil that has separated from the invert emulsion. If some oil may separate, the emulsion has not been completely broken because a portion of the invert emulsion fluid remains. However, the rheological properties of the remaining invert emulsion fluid may be adversely impacted by top oil separation. Inorganic solid aggregation materials suitable for use in the fluids disclosed herein include calcium hydroxide, calcium oxide, calcium carbonate, silica, and combinations thereof. The quantity of the inorganic solid material depends on the composition of the oleaginous and non-oleaginous phases. The inorganic solid aggregation material may be present in an amount in the range of 0.1 to 10 pounds per barrel, and more preferably in the range of 0.4 to 5 pounds per barrel. As previously discussed, the sizing of the inorganic solid aggregation material will impact its suitability for use in the invert emulsion of the present disclosure. The sizing of the inorganic solid material will vary depending on the inorganic solid aggregation material used. The inorganic solid aggregation material may be sized to have a d_{50} less than 100 microns, and more preferably sized to have a d_{50} less than 10 microns.

Weighting Agents

The fluids of the present disclosure may also include weighting agents. Weighting agents are high density materials (other than the inherent weight provided by the internal aqueous phase). Suitable for use the fluids disclosed herein may include barium sulfate, calcium sulfate, galena, hematite, magnetite, iron oxides, illmenite, siderite, celestite, dolomite, and combinations thereof.

some embodiments may include weighting agents having a smaller particle size than API grade weighting agents, which may generally be referred to as submicron weighting agents. Such weighting agents may generally be in the micron range, including submicron particles in the nanosized range.

In some embodiments, the average particle size (d50) of the weighting agents may range from a lower limit of greater than 5 nm, 10 nm, 30 nm, 50 nm, 100 nm, 200 nm, 500 nm, 0.5 micron, 1 micron, 1.2 microns, 1.5 microns, 3 microns, 5 microns, or 7.5 microns to an upper limit of less than 500 nm, 700 nm, 1 micron, 3 microns, 5 microns, 10 microns, 15 microns, 20 microns, where the particles may range from any lower limit to any upper limit. In other embodiments, the d90 (the size at which 90% of the particles are smaller) of the weighting agents may range from a lower limit of greater than 20 nm, 100 nm, 200 nm, 500 nm, 700 nm, 1 micron, 1.2 microns, 1.5 microns, 2 microns, 5 microns, 10 microns, or 15 microns to an upper limit of less than 30 microns, 20 microns, 15 microns, 10 microns, 8 microns, 5 microns, 2.5 microns, 1 micron, 700 nm, 500 nm, where the particles may range from any lower limit to any upper limit. The above described particle ranges may be achieved by grinding the materials to the desired particle size or by precipitation of the material from a solution using an assembly approach. Precipitation of such materials is described in U.S. Patent No. 2010/009874, which is assigned to the present assignee and herein incorporated by reference. One of ordinary skill in the art would recognize that, depending on the precipitation 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 bimodal, or polymodal.

In one embodiment, a 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 percent by volume; particles having a diameter between 8 microns and 12 microns are 5 to 15 percent by volume; particles having a diameter greater than 12 microns are 5 to 15 percent by volume.

percent are in the range of 6 microns to 10 microns; and less than 90 percent range of 10 microns to 24 microns.

Coated weighting agents may be formed by grinding a solid particulate material with a polymeric dispersing agent so that the dispersing agent is absorbed to the surface of the resulting solid particles. The grinding may be carried out in the presence of an oleaginous base fluid or a non-oleaginous base fluid. Where the grinding is carried out in the presence of an oleaginous fluid, the polymeric dispersing agent is selected from the group consisting of acrylic acid, polybasic fatty acids, alkylbenzenesulfonic acids, alkane sulfonic acids, linear alpha olefin sulfonic acids, or the alkaline earth metal salts of any of the above acids, phospholipids, and a polyacrylate ester made from at least one of the following monomers: stearyl methacrylate, butylacrylate, and acrylic acid. Where the grinding is carried out in the presence of a non-oleaginous base fluid, the polymeric dispersing agent may be a water-soluble polymer that is a homopolymer or copolymer of monomers selected from the group consisting of acrylic acid, itaconic acid, maleic acid or anhydride, hydroxypropyl methacrylate, vinylsulfonic acid, acrylamido 2-propane sulfonic acid, acrylamide, styrene, methyl methacrylate, acrylonitrile, acrylate, acid, acrylic phosphate esters, methyl vinyl ether and vinyl acetate, where the monomers may also be neutralized to a salt.

Weighting agents may also be coated through a dry process, where the weighting agent is dry blended with a polymeric dispersing agent, as discussed in U.S. Serial No. 12/440706, which is assigned to the present assignee and is hereby incorporated by reference. The polymeric dispersing agent for the dry blending process may be selected from the group consisting of polyacrylate esters, oleic acid, polybasic fatty acids, alkylbenzenesulfonic acids, alkane sulfonic acids, linear alpha olefins sulfonic acid, alkaline earth metal salts of any of the above acids, phospholipids, and combinations thereof.

Weighting agents may also be formed by chemical precipitation, as discussed in U.S. Application Serial No. 12/440706, which is assigned to the present assignee and is hereby incorporated by reference. The precipitation occurs following the mixing of two or more chemical species in a solution. The chemical identity of those chemicals mixed is determined on the desired resulting compound to be used as a weighting agent. For example,

pounds per gallon (but up to 21 pounds per gallon or up to 19 pounds per gallon for particular embodiments). Additionally, it is also within the scope of the present invention that the fluid may also be weighted up using salts (such as in the non-oleaginous aqueous fluid) discussed below). One having ordinary skill in the art would recognize that selection of a particular material may depend largely on the density of the material. Typically, the lowest wellbore fluid viscosity at any particular density is obtained by using the highest density particles.

Other Additives

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

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

As discussed above, viscosifying agents that may be used in the fluids disclosed herein include organophilic clays, amine treated clays, oil soluble polymers, polyanionic polymers, polycarboxylic acids, and soaps, particularly during gravel packing by the alternate technique (viscous fluid packing). The amount of viscosifier used in the composition may vary upon the end use of the composition. However, normally about 0.1% to 60%

The fluids disclosed herein are especially useful in the drilling, completion and workover of subterranean oil and gas wells. In particular the fluids disclosed herein may be used 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. Conventional methods can be used to formulate the completion fluids disclosed herein in a manner analogous to those normally used to prepare conventional oil-based fluids. In cases where an invert emulsion is desired, a desired quantity of oleaginous fluid such as a base oil and a suitable amount of water are mixed together and the remaining components are added sequentially with stirring. An invert emulsion may also be formed by vigorously agitating, mixing together the oleaginous fluid and the non-oleaginous fluid.

EXAMPLE

The following examples were used to test the stability and rheological properties of an internal phase ratio invert emulsion, such as those described in the present disclosure.

Example 1

A 13.5 ppg invert emulsion fluid was formulated having the following components shown below in Table 1. Specifically, the components include ESCAID® 110, an internal olefin as the base oil; a 14.2 ppg calcium bromide brine; BioAdco emulsifier available from Shrieve Chemical Products (Spring, Texas); lime; a surfactant concentrate, a micronized weighting agent available from M-I SWACO (Houston, Texas); and a defoamer.

IO C16-C18	16.2% (vol)
CaBr ₂ brine	69.4% (vol)
BioAdd™ 778	3.5 ppb
Lime	0.87 ppb
WARP® concentrate	13.2% (vol)

The invert emulsion fluid shown in Table 1 was heat aged at the temperature below in Table 2 by hot rolling for 16 hours, and the rheological properties of mud formulations were determined using a Fann Model 35 Viscometer, available from Fann Instrument Company. The fluid was subjected to the pressures indicated in Table 2. η_p is plastic viscosity, YP is yield point, K' and n' are power law constants calculated using Hydragram/Mudware software. K' is the Fann 35 300 reading / $511^{n'}$ and n' is $\log_{10}(\text{Fann 35 600 reading} / \text{Fann 35 300 reading})$. The fluid exhibited the following properties:

Table 2

	Result with Fann 35 atmosphere		Result with Fann 70 w/ pressure	
	Room temp Dial vs. cP	150F Dial vs. cP	150F - 526psi Dial vs. cP	275F - 473psi Dial vs. cP
600	480 vs. 240	250 - 125	312 – 156	136 – 68
300	315 - 315	170 – 170	243 – 243	80 – 80
200	240 - 360	130 - 195	183 – 275	58 – 87
100	155 - 465	90 - 270	110 – 330	34 – 102
6	25 - 1250	17.5 - 875	17 – 850	5 – 250
3	15 - 1500	12.5 - 1250	11 - 1100	4 - 400
PV	165	80	69	56
YP	150	90	174	24
K' slot	0.06195	0.05665	0.04425	0.01346
n'	0.6526	0.5696	0.6532	0.6570

Upon addition of gravel (at mesh size 20/40) to the fluid shown in Table 1, c the gravel at both room temperature and 275°F for greater than 30 minutes, can be used for alternate path packing.

Components	
LVT 200	48.1% (vol)
Cs formate brine	50% (vol)
BioAdd™ 778	6 ppb

The fluid in Table 3 was also formulated with 1 ppb lime added thereto. Both fluids possessed the same Fann 35 dial readings (at 72°F): 600rpm=49, 300rpm=29, 200rpm=19, 100rpm=10, 6rpm=1, 3rpm=1. The fluid without lime resulted in a top oil separation of 33% after 1 day, and 38% after 2 days. In contrast, the fluid formulated with lime resulted in a reduced top oil separation of 26% after 1 day and 32% after 2 days. Further, upon addition of 20/40 gravel to the fluid, the fluid formulation without lime resulted in a very loose packing, whereas the lime addition resulted in a much tighter packing of the gravel.

A 13 ppg (Fluids A and B) and a 16 ppg fluid (Fluids C and D) were formulated with the same components as shown below in Table 4. Specifically, the components included an isomerized C₁₆ to C₁₈ alpha-olefin as the base oil; WARP® concentrate, a weighting agent available from M-I SWACO® (Houston, Texas), and VERSALOX® organic polymer available from M-I SWACO® (Houston, Texas).

bbl	0.515	0.515		0.755	0.755
IO 16/18, bbl	0.485	0.485		0.245	0.245
VERSAPAC, ppb	-	2		-	2

Fluids B and D shown in Table 4 were heat aged at 140°F by hot rolling for 16 hr. After aging, the rheological properties of the various mud formulations were determined using a Fann Model 35 Viscometer, available from Fann Instrument Company. The fluids were then subjected to the pressures indicated below. The fluids exhibited the following properties:

Table 5

	A	B		C	D	
	Initial	Initial	Aged	Initial	Initial	Aged
600 rpm	14	14	15	28	31	36
300 rpm	8	7	9	15	16	19
200 rpm	6	6	6	10	11	13
100 rpm	3	3	3	5	6	7
6 rpm	1	1	1	1	2	1
3 rpm	1	1	1	0	1	1
PV, cps	6	7	6	13	15	17
YP, lbs/100 ft ²	2	0	3	2	1	2
10 Second Gel	1	1	1	1	1	1
10 Minute Gel	1	1	1	1	1	1
Settling (Y/N)	Y	N	N	Y	N	N

Fig. 1. 12-14-15 (B and D) results from a Fann Model 35 Viscometer at 140°F.

Screen Type	Premium	Premium
Screen Size	230 microns	230 microns
1" Sand-bed size	12/20	12/20
Time, seconds	6	6
Volume passed through Screen, mL	200	200
1" Sand-bed size	30/50	30/50
Time, seconds	8	7
Volume passed through Screen, mL	200	200
1" Sand-bed size	50/70	50/70
Time, seconds	10	13
Volume passed through Screen, mL	200	200

Example 3

Several fluids were formulated to determine of effect of the fluid compos Fanning friction factor. The fluids were composed of one or more of LVT-20 based fluid containing a micronized weighting agent, and an invert emulsi which are considered with and without a friction reducer (NECADD

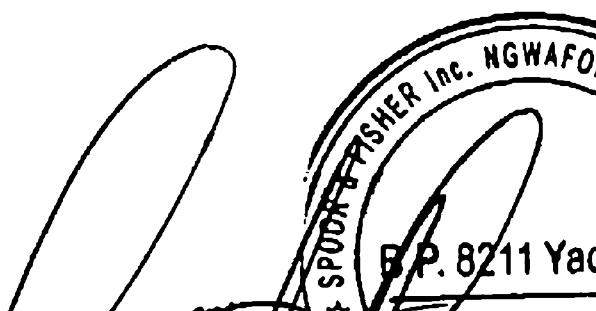
Table 7

Fluid	Fluid density (ρ), ppg	Flow rate (gpm)	Pressure drop (ΔP), psi	Wall shear stress, (τ_w), Pa	Fluid velocity (v), m/s
LVT-200 oil	6.8	5.1	77.9	209.96	6.82
LVT-200 oil with friction reducer; LVT200+100ppm NECADD 370	6.8	5.1	31.9	85.98	6.82
OB WARP	15.7	5	148	398.90	6.68
OB WARP with friction reducer; 4.8 gal OB WARP with 40 ml NECADD 370	15.7	5	88	237.18	6.68
Invert emulsion: LVT-11CaCl 50:50, 6ppb BioAdd 778	9.1	5.4	82.2	221.55	7.22
Invert emulsion with friction reducer; LVT-11CaCl 50:50, 6ppb BioAdd 778, 0.5v% HE150	9	5.3	88.3	237.99	7.08

As shown in Table 7, incorporation of a friction reducer results in a reduced friction factor for the substantially oil fluids (fluids 1-2) as well as for the fluids containing fluids (fluids 3-4) but showed no impact on the invert emulsion (fluid 5).

formation with brines, which can have a negative effect on the production of
Such fluids may be particularly desirable for use in open hole wells exposed
shales, by minimizing the potential contact of such reactive shales with water.

While the disclosure 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 disclosed herein. Accordingly, the scope of the invention should be limited by the attached claims.



a cased section and an uncased section, the method comprising:

pumping into the wellbore a gravel pack composition comprising gravel and a carrier fluid comprising:

an oleaginous fluid; and

an inorganic solid aggregator material.

The method of claim 1, further comprising:

packing the uncased section of the wellbore with gravel using alpha and beta v carrier fluid.

The method of claim 1, further comprising:

packing the uncased section of the wellbore with gravel using alternate path tech

The method of any of the above claims, wherein the inorganic solid aggregator has a d_{50} less than 100 microns.

The method of any of the above claims, wherein the inorganic solid aggregator is selected from the group consisting of calcium hydroxide, calcium oxide, calcium silica, and combinations thereof.

The method of any of claims 1-5, wherein the oleaginous fluid comprises an invert emulsion wherein the invert emulsion comprises:

an oleaginous external phase;

a non-oleaginous internal phase; and

an emulsifier stabilizing the oleaginous external phase and the non-oleaginous internal phase.

The method of claim 6, wherein the invert emulsion fluid has an oleaginous to non-oleaginous ratio in the range of 30:70 to 10:90.

The method of claim 6, wherein the invert emulsion fluid has an oleaginous to non-oleaginous ratio in the range of 65:35 to 35:65.

The method of claim 8, wherein the emulsifier is formed from C_{15-40} polyolefins,

pressure drop across a length of 16.25 feet of tubing.

The method of claim 1, wherein the oleaginous fluid further comprises a weighting agent having a d_{50} less than 10 microns.

The method of claim 14, wherein the weighting agent is selected from the group consisting of barium sulfate, calcium carbonate, dolomite, ilmenite, hematite, olivine, siderite, barite, sulfate, manganese oxide, and combinations thereof.

The method of claim 14, wherein the weighting agent is coated with a dispersant.

A method of completing a wellbore penetrating a subterranean formation, the wellbore comprising a cased section and an uncased section, the method comprising:

introducing an oleaginous fluid into the uncased section of the wellbore;

running a liner, sand control screen assembly, swell packer assembly, or inflatable device to a selected depth within the uncased section of the wellbore in which the invert emulsion fluid is located;

introducing a gravel pack slurry containing gravel and an oleaginous carrier fluid into the wellbore.

The method of claim 17, wherein introducing the oleaginous fluid into the uncased section of the wellbore displaces a drilling fluid from the uncased section of the wellbore.

The method of claim 17, wherein introducing the oleaginous fluid into the uncased section of the wellbore comprises drilling the wellbore through the subterranean formation with the oleaginous fluid.

The method of claim 17, wherein the oleaginous fluid further comprises an inorganic solid aggregator material having a d_{50} less than 100 microns.

The method of claim 20, wherein the inorganic solid aggregator material is selected from the group consisting of calcium hydroxide, calcium oxide, calcium carbonate, and combinations thereof.

The method of claim 17, wherein the oleaginous fluid is an invert emulsion,

with a molecular weight greater than 1200, and amines.

The method of claim 22, wherein the emulsifier has an amine number in the range of 10-50.

The method of claim 22, wherein the emulsifier has an HLB less than 3.

The method of claim 17, wherein the carrier fluid has a fanning friction factor of 0.01, calculated by pumping a fluid sample through a tubing having an inner diameter of 0.5 inches at a specified flow rate in the range of 5-5.5 gpm, and by measuring the pressure drop across a length of 16.25 feet of tubing.

The method of claim 17, wherein the fluid further comprises a weighting agent having a particle size less than 10 microns.

The method of claim 27, wherein the weighting agent is selected from the group consisting of barium sulfate, calcium carbonate, dolomite, ilmenite, hematite, olivine, siderite, barium sulfate, manganese oxide, and combinations thereof.

The method of claim 28, wherein the weighting agent is coated with a dispersant.

A method of gravel packing a wellbore in a subterranean formation, the wellbore comprising a cased section and an uncased section, the method comprising:

pumping into the wellbore a gravel pack composition comprising gravel and a carrier fluid comprising:

- an oleaginous fluid; and

- a weighting agent.

The method of claim 30, wherein the weighting agent has a d_{50} less than 10 microns.

The method of claim 30, wherein the weighting agent is selected from the group consisting of barium sulfate, calcium carbonate, dolomite, ilmenite, hematite, olivine, siderite, barium sulfate, manganese oxide, and combinations thereof.

The method of claim 30, wherein the weighting agent is coated with a dispersant.

The method of claim 30, wherein the carrier fluid has a fanning friction factor of 0.01, calculated by pumping a fluid sample through a tubing having an inner diameter of 0.5 inches at a specified flow rate in the range of 5-5.5 gpm, and by measuring the pressure drop across a length of 16.25 feet of tubing.

The method of claim 30, wherein the oleaginous fluid is an invert emulsion, invert emulsion comprises:

- an oleaginous external phase;

- a non-oleaginous internal phase; and

- an emulsifier stabilizing the oleaginous external phase and the non-oleaginous phase.

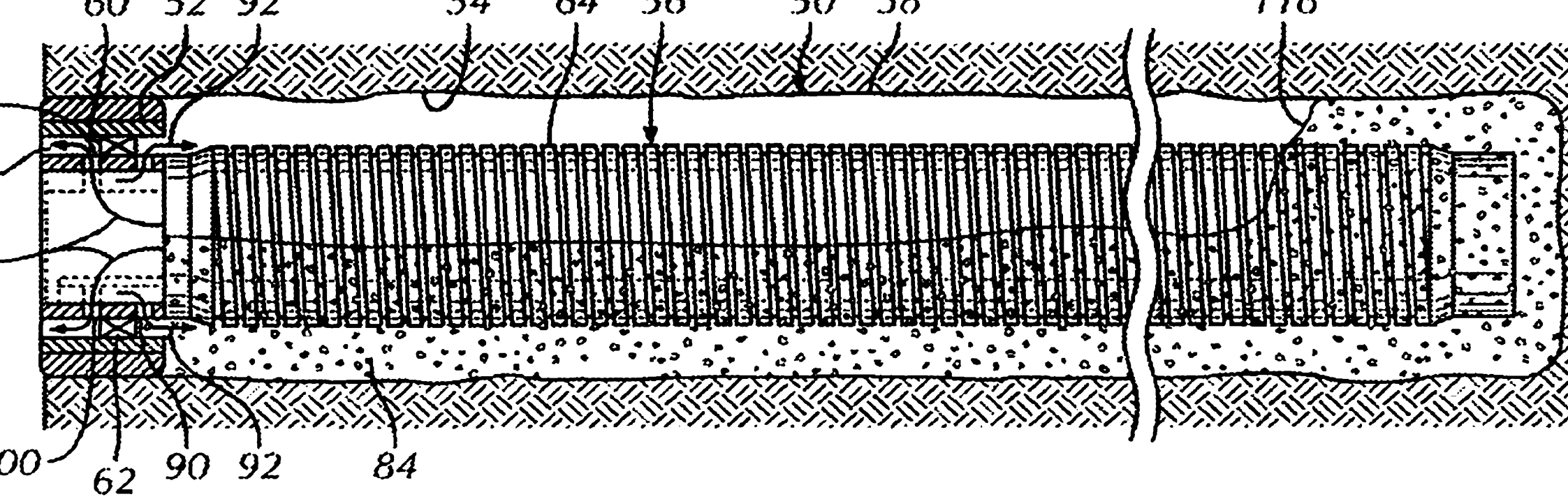


FIG. 1C

