



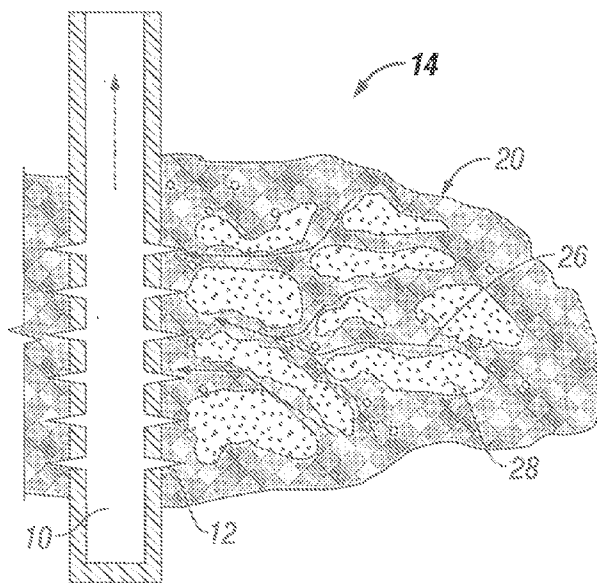
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[Continued on next page]

- (54) Title: PROPPANT PILLAR PLACEMENT IN A FRACTURE WITH HIGH SOLID CONTENT FLUID



(57) Abstract: A method of placing particulate blend into a fracture formed in a subterranean formation from a wellbore comprises injecting through the wellbore a first treatment fluid to initiate or propagate the fracture in the subterranean formation; wherein the first treatment fluid comprises a particulate blend slurry; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 micrometers and at least a second amount of particulates having a second average particle size between about three and twenty times smaller than the first average particle size; injecting through the wellbore a second treatment fluid having a viscosity different from the first treatment fluid; and forming with the particulate blend slurry a plurality of particulate-rich clusters spaced apart by particulate-free regions forming open channels.



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PROPPANT PILLAR PLACEMENT IN A FRACTURE WITH HIGH SOLID CONTENT FLUID

Field of the Invention

[0001] The invention relates to stimulation of wells penetrating subterranean formations, to fracture stimulation by injection of proppant into a fracture to form regions of low resistance to flow through the fracture for the production of hydrocarbons and by using a high solid content fluid.

Background

[0002] Various methods are known for fracturing a subterranean formation to enhance the production of fluids therefrom. In the typical application, a pressurized fracturing fluid hydraulically creates and propagates a fracture. The fracturing fluid carries proppant particulates into the extending fracture. When the fracturing fluid is removed, the fracture does not completely close from the loss of hydraulic pressure; instead, the fracture remains propped open by the packed proppant, allowing fluids to flow from the formation through the proppant pack to the production wellbore.

[0003] The success of the fracturing treatment may depend on the ability of fluids to flow from the formation through the proppant pack. In other words, the proppant pack or matrix must have a high permeability relative to the formation for fluid to flow with low resistance to the wellbore. Furthermore, the surface regions of the fracture should not be significantly damaged by the fracturing to retain fluid permeability for optimal flow from the formation into the fracture and the proppant pack.

[0004] The prior art has sought to increase the permeability of the proppant pack by increasing the porosity of the interstitial channels between adjacent proppant particles within the proppant matrix. For example, US7,255,169, US7,281,580, US7,571,767

incorporated herewith by reference discloses a method of forming a high porosity propped fracture with a slurry that includes a fracturing fluid, proppant particulates and a weighting agent. These prior art technologies seek to distribute the porosity and interstitial flow passages as uniformly as possible in the consolidated proppant matrix filling the fracture, and thus employ homogeneous proppant placement procedures to substantially uniformly distribute the proppant and non-proppant, porosity-inducing materials within the fracture. In another approach, proppant particulates and degradable material do not segregate before, during or after injection to help maintain uniformity within the proppant matrix. Fracturing fluids are thoroughly mixed to prevent any segregation of proppant and non-proppant particulates. In another approach, non-proppant materials have a size, shape and specific gravity similar to that of the proppant to maintain substantial uniformity within the mixture of particles in the fracturing fluid and within the resulting proppant pack. A tackifying compound coating on the particulates has also been used to enhance the homogenous distribution of proppant and non-proppant particulates as they are blended and pumped downhole into a fracture.

[0005] A recent approach to improving hydraulic fracture conductivity has been to try to construct proppant clusters in the fracture, as opposed to constructing a continuous proppant pack. US6,776,235 incorporated herewith by reference discloses a method for hydraulically fracturing a subterranean formation involving alternating stages of proppant-containing hydraulic fracturing fluids contrasting in their proppant-settling rates to form proppant clusters as posts that prevent fracture closing. This method alternates the stages of proppant-laden and proppant-free fracturing fluids to create proppant clusters, or islands, in the fracture and channels between them for formation fluids to flow. The amount of proppant deposited in the fracture during each stage is modulated by varying the fluid transport characteristics (such as viscosity and elasticity), the proppant densities, diameters, and concentrations and the fracturing fluid injection rate. However, the positioning of the proppant-containing fluid is difficult to control. For example, the proppant-containing fluid can have a higher density than the proppant-free fluid and can thus override the proppant-free fluid. This override can result in non-uniform distribution of proppant clusters, which in turn can lead to excessive fracture closure where

there is not enough proppant and constricted flow channels where there is too much proppant.

[0006] It is an object of the present invention to provide an improved method of propping a fracture, or a part of a fracture.

Summary

[0007] According to some embodiments, the method comprises injecting through the wellbore a first treatment fluid to initiate or propagate a fracture in the subterranean formation; wherein the first treatment fluid comprises a particulate blend slurry; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 micrometers and at least a second amount of particulates having a second average particle size between about three and twenty times smaller than the first average particle size; injecting through the wellbore a second treatment fluid having a viscosity different from the first treatment fluid; and forming with the particulate blend slurry a plurality of particulate-rich clusters spaced apart by particulate-free regions forming open channels.

Brief Description of the Drawings

[0008] Figure 1 schematically illustrates in section placement of proppant and removable channelant in a hydraulic fracture operation according to one embodiment.

[0009] Figure 2 schematically illustrates in section the arrangement of the wellbore, perforations and the proppant pillars in the fracture according to a second embodiment.

[00010] Figure 3 shows a schematic diagram of the fluid displacement set up.

[00011] Figures 4A to 4H shows an illustration of the various patterns developed by interaction of a first treatment fluid and the second treatment fluid.

[00012] Figure 5 shows a schematic diagram of the injection test setup.

[00013] Figure 6 shows a schematic diagram of the sandstones cores used in the injection tests.

[00014] Figure 7 illustrates a graph showing the pressure response and ISCO pump volume during an injection test of high solid content fluid.

[00015] Figure 8 illustrates a graph showing the pressure response of high solid content fluid injection for continuous pumping.

Detailed Description

[00016] At the outset, it should be noted that in the development of any such actual embodiment, numerous implementation—specific decisions must be made to achieve the developer's specific goals, such as compliance with system related and business related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time consuming but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure.

[00017] The description and examples are presented solely for the purpose of illustrating the preferred embodiments and should not be construed as a limitation to the scope. While the compositions are described herein as comprising certain materials, it should be understood that the composition could optionally comprise two or more chemically different materials. In addition, the composition can also comprise some components other than the ones already cited. In the summary and this detailed description, each numerical value should be read once as modified by the term "about" (unless already expressly so modified), and then read again as not so modified unless otherwise indicated in context. Also, in the summary and this detailed description, it should be understood that a concentration range listed or described as being useful, suitable, or the like, is intended that any and every concentration within the range, including the end points, is to be considered as having been stated. For example, "a range of from 1 to 10" is to be read as indicating each and every possible number along the

continuum between about 1 and about 10. Thus, even if specific data points within the range, or even no data points within the range, are explicitly identified or refer to only a few specific, it is to be understood that inventors appreciate and understand that any and all data points within the range are to be considered to have been specified, and that inventors possession of the entire range and all points within the range.

[00018] In hydraulic and acid fracturing, a first, viscous fluid called a “pad” is typically injected into the formation to initiate and propagate the fracture. This is followed by a second fluid that contains a proppant to keep the fracture open after the pumping pressure is released. In “acid” fracturing, the second fluid contains an acid or other chemical such as a chelating agent that can dissolve part of the rock, causing irregular etching of the fracture face and removal of some of the mineral matter, resulting in the fracture not completely closing when the pumping is stopped. Occasionally, hydraulic fracturing is done without a highly viscosified fluid (i.e., slick water) to minimize the damage caused by polymers or the cost of other viscosifiers.

[00019] Fracturing fluids according to the present method can include proppant and optionally a removable proppant-spacing material, which can function to form open channels around the proppant pillars. These extramatrix channel-forming materials, including proppant-spacing particles, are referred to herein as “channelant.”

[00020] As used herein, the term “open channels” refers to interconnected passageways formed in the proppant-fracture structure. Open channels are distinct from interstitial passages between individual proppant particles in the proppant matrix in that the channels fully extend between opposing fracture faces or that there is a gap of proppant not touching both fracture faces, free of obstruction by proppant or other flow-impeding structures, and exist outside the proppant matrix, laterally bounded by the proppant pillars. Such open channels generally have a hydraulic radius, and hence a hydraulic conductivity, that is at least an order of magnitude larger than that of interstitial flow passages through the proppant matrix.

[00021] The open channels can be formed by placing the proppant and optional channelant in the fracture in such a way that the pillar-forming proppant islands are ultimately segregated from the channel-forming removable material. The segregation can

occur or begin in the preparation, mixing or pumping of the treatment fluid, in the injection of the treatment fluid in the fracture, in or after the proppant placement, packing or settling in the fracture, by a distinct post-injection step of chemical and/or mechanical manipulation or treatment of the proppant/channelant following initial placement in the fracture, or by aggregating and consolidating the proppant during the channelant removal.

[00022] In the case channelant is used, the terms “segregation,” “segregating” and the like refer to any heterogeneous proppant/channelant distribution between proppant-rich pillar-forming islands or regions and proppant-lean channelant regions. It may not be necessary to keep the proppant-rich regions entirely free of channelant because the presence of channelant, especially in relatively minor amounts, may not exceed any level that prevents the formation or consolidation of the proppant into pillars of sufficient strength to prevent the fracture from closing. In an embodiment, the channelant can function in the proppant or proppant regions to consolidate or reinforce the proppant islands and/or to strengthen the proppant pillars. Conversely, the channelant regions can contain proppant particles, especially relatively minor amounts, which remain unconsolidated or do not otherwise prevent removal of the channelant to form the open channels and which do not result in obstruction or excessive clogging of the open channels by the proppant.

[00023] A simplified first embodiment of the method is illustrated with reference to Figure 1. A wellbore 10 can be completed with perforations 12 in formation 14. A pad substantially free of particles can optionally be injected through the wellbore 10 to initiate and propagate a fracture 20. A first treatment fluid made of high solid content slurry is injected through the wellbore 10 to initiate and/or propagate a fracture 20. The first treatment fluid optionally comprises a viscosifying agent. In one further embodiment, segregated proppant particles are injected through the wellbore 10 into the fracture 20 in the first treatment fluid alternating stage of a proppant-rich phase made of high solid content slurry or proppant laden phase and a proppant-free phase optionally comprising a gas (or a supercritical fluid) and a viscosifying agent. Thereafter, a second treatment fluid is injected through the wellbore 10. The second treatment fluid has a viscosity different from the first treatment fluid. Injection of the second treatment fluid will create fingering in the first injected treatment fluid creating proppant-rich islands or clusters 28 forming

pillars spaced apart by proppant-free regions or channels 26. The fracture 20 can be allowed to close, and the proppant blend islands 28 compressed to form pillars to support the fracture 20 and prevent the opposing fracture faces from contacting each other. Due to the viscosity properties difference of the second treatment fluid the alternating stages pick up the proppant and form localized clusters (similar to the wedges) and redistribute them farther up and out into the fracture. The second treatment fluid can be alternated many times to achieve varied distribution of the clusters in the fracture. This phenomenon will create small pillars in the fracture that will help keep more of the fracture open and create higher overall conductivity and effective fracture half-length.

[00024] A simplified second embodiment of the method is illustrated with reference to Figure 2. A wellbore 10 can be completed with perforations 12 in formation 14. A pad substantially free of particles can optionally be injected through the wellbore 10 to initiate and propagate a fracture 20. A first treatment fluid made of high solid content slurry is injected through the wellbore 10 to initiate and/or propagate a fracture 20. The first treatment fluid optionally comprises a viscosifying agent. Segregated proppant particles 16 and channelant particles 18 are injected in the first treatment fluid made of high solid content slurry through the wellbore 10 into the fracture 20, where they can be heterogeneously placed in respective proppant-rich islands or clusters 22 forming pillars spaced apart by channelant-rich regions 24. Thereafter, a second treatment fluid is injected through the wellbore 10. The second treatment fluid has a viscosity different from the first treatment fluid. Injection of the second treatment fluid will create fingering in the first injected treatment fluid creating proppant-rich islands or clusters 28 forming pillars spaced apart by proppant-free regions 26 and channelant-rich regions 24. The fracture 20 can be allowed to close, and the proppant blend islands 22 compressed to form pillars to support the fracture 20 and prevent the opposing fracture faces from contacting each other. The channelant can be packed in the proppant-lean regions 24 and can help restrict the islands 22 from creeping or spreading laterally due to compression by the weight of the formation, thereby facilitating a greater height or open dimension of the resulting propped fracture and a greater hydraulic conductivity.

[00025] During the next operative step, the channelant can be removed in various embodiments by flushing, dissolving, softening, melting, breaking, or degrading the

channelant, wholly or partially, via a suitable activation mechanism, such as, but not limited to, temperature, time, pH, salinity, solvent introduction, catalyst introduction, hydrolysis, and the like, or any combination thereof. The activation mechanism can be triggered by ambient conditions in the formation, by the invasion of formation fluids, exposure to water, passage of time, by the presence of incipient or delayed reactants in or mixed with the channelant particles, by the post-injection introduction of an activating fluid, or the like, or any combination of these triggers. Then, the formation fluid can be allowed to invade the fracture 20 to displace any channelant, channelant solution, channelant degradation products, and any unconsolidated proppant or other particles, from the proppant-lean regions. For example, the channelant can simply be unconsolidated so that it can be removed hydraulically, or can include unconsolidated particles that can be removed hydraulically, e.g. by flushing the fracture with formation fluid and/or an injected flushing or back-flushing fluid. A network of interconnected open channels can thus be formed around the pillars to provide the fracture 20 with high conductivity for fluid flow. Fluids can now be produced from the formation 14, into the fracture 20, through the open channels and perforations 12, and into the wellbore 10.

[00026] The channelant can be removed mechanically, for example by using fluid to push channelant out of the formation. In such instances, the channelant can remain in a solid state from the time of injection through removal from the fracture. Some suitable materials that can resist degradation and crushing include glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, and high-density plastics that are oil-resistant and exhibit a crystallinity of greater than about 10%. Some other suitable high density plastic materials include nylons, acrylics, styrenes, polyesters, polyethylenes, oil-resistant thermoset resins and combinations thereof.

[00027] Alternatively, the channelant can be softened, dissolved, reacted or otherwise made to degrade. Materials suitable for dissolvable channelant include for example, and without limitation, polyvinyl alcohol (PVOH) fibers, salt, wax, calcium carbonate, and the like and combinations thereof. An oil-degradable channelant can be selected, so that it will be degraded by produced fluids. Alternatively, a channelant can be selected which is degraded by agents purposefully placed in the formation by injection,

wherein mixing the channelant with the agent induces a delayed reaction degradation of the channelant.

[00028] In some fracturing operations, a solid acid-precursor can be used as the degradable channelant. Suitable acid-generating dissolvable channelants can include for example, and without limitation, PLA, PGA, carboxylic acid, lactide, glycolide, copolymers of PLA or PGA, and the like and combinations thereof. Provided that the formation rock is carbonate, dolomite, sandstone, or otherwise acid reactive, then the hydrolyzed product of the channelant, a reactive liquid acid, can etch the formation at surfaces exposed between the proppant pillars. This etching can enlarge the open channels and thus further enhance the conductivity between the pillars. Other uses of the generated acid fluid can include aiding in the breaking of residual gel, facilitating consolidation of proppant clusters, curing or softening resin coatings and increasing proppant permeability.

[00029] In some embodiments, the channelant may be formed of, or contain, a fluoride source capable of generating hydrofluoric acid upon release of fluorine and adequate protonation. Some nonlimiting examples of fluoride sources which are effective for generating hydrofluoric acid include fluoboric acid, ammonium fluoride, ammonium fluoride, and the like, or any mixtures thereof.

[00030] During hydraulic fracturing, high pressure pumps on the surface inject the fracturing fluid into a wellbore adjacent to the face or pay zone of a geologic formation. In an optional first stage, also referred to as the “pad stage” involves injecting a treatment fluid into the wellbore at a sufficiently high flow rate and pressure sufficient to literally break or fracture a portion of surrounding strata at the sand face. The pad stage is pumped until the fracture has sufficient dimensions to accommodate the subsequent slurry pumped in the proppant stage. The volume of the pad can be designed by those knowledgeable in the art of fracture design, for example, as described in *Reservoir Stimulation*, 3rd Ed., M. J. Economides, K. G. Nolte, Editors, John Wiley and Sons, New York, 2000, incorporated herewith by reference.

[00031] According to one embodiment, the pad comprises a gaseous component or a supercritical fluid to form a foam or energized fluid. For example, a gas such as air, nitrogen or carbon dioxide, a supercritical fluid as supercritical carbon dioxide can be used

to provide an energized fluid or foam. Among other benefits, the dispersion of the gas into the fluid in the form of bubbles or droplets increases the viscosity of such fluid and impacts positively its performance, particularly its ability to effectively induce hydraulic fracturing of the formation, and also its capacity to carry solids (“proppants”) that are placed within the fractures to create pathways through which oil or gas can be further produced. The presence of the gas also enhances the flowback of the first fluid from the interstices of the formation and of the proppant pack into the wellbore, due to the expansion of such gas once the pressure is reduced at the wellhead at the end of the fracturing operation.

[00032] The foamed or energized fluid may contain “foamers”, most commonly surfactant or blends of surfactants that facilitate the dispersion of the gas into the fluid in the form of small bubbles or droplets, and confer stability to the dispersion by retarding the coalescence or recombination of such bubbles or droplets. Foamed and energized fluids are generally described by their foam quality, i.e. the ratio of gas volume to the foam volume. If the foam quality is between 52% and 95%, the fluid is conventionally called foam, and below 52%, an energized fluid. However, as used herein the term "energized fluid" is defined as any stable mixture of gas and liquid, notwithstanding the foam quality value.

[00033] In one embodiment, optionally after the fracture is induced, proppant can be injected with the first treatment fluid into the fracture as a slurry or suspension of particles in the fracturing fluid during what is referred to herein as the “proppant stage.” The first treatment fluid will be injected at a sufficiently high flow rate and pressure sufficient to literally break or fracture a portion of surrounding strata at the sand face or to propagate the fracture if a pad was used. The pad stage is followed with a sequence of proppant-laden and optionally proppant-free stages to enhance the creation of the network of the open channels inside the fracture. The fluid used in the proppant-laden and proppant-free stages can be of the same nature and be crosslinked to facilitate the proppant transport. It can also be of the different nature: crosslinked in proppant-laden stages and linear, crosslinked or energized/foamed in proppant-free stages. The proppant-free stage can be of the same type as pad i.e. foamed or energized fluid. According to one embodiment, the stages of proppant-rich phase and proppant-free phase are separated by injection of a fiber spacer. This fibers can include, for example, glass, ceramics, carbon and carbon-based compounds,

metals and metallic alloys, and the like and combinations thereof. Also the fibers can include, for example, polylactic acid, polyglycolic acid, polyethylterephthalate (PET), polyol, and the like and combinations thereof.

[00034] The proppant-rich phase made of high solid content slurry or proppant laden phase stage includes a slurry with a particulate blend made of proppant; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 μm and at least a second amount of particulates having a second average particle size between about three to twenty times smaller than the first average particle size. In one embodiment, the slurry comprises particulate materials with defined particles size distribution. On example of realization is disclosed in U.S. patent 7,784,541, herewith incorporated by reference in its entirety. In certain embodiments, the selection of the size for the first amount of particulates is dependent upon the characteristics of the propped fracture, for example the closure stress of the fracture, the desired conductivity, the size of fines or sand that may migrate from the formation, and other considerations understood in the art.

[00035] The selection of the size of the second amount of particulates is dependent upon maximizing or optimizing a packed volume fraction (PVF) of the mixture of the first amount of particulates and the second amount of particulates. The packed volume fraction or packing volume fraction (PVF) is the fraction of solid content volume to the total volume content. A second average particle size of between about seven to ten times smaller than the first amount of particulates contributes to maximizing the PVF of the mixture, but a size between about three to twenty times smaller, and in certain embodiments between about three to fifteen times smaller, and in certain embodiments between about three to ten times smaller will provide a sufficient PVF for most slurry. Further, the selection of the size of the second amount of particulates is dependent upon the composition and commercial availability of particulates of the type comprising the second amount of particulates. In certain embodiments, the particulates combine to have a PVF above 0.70, 0.74 or 0.75 or above 0.80. In certain further embodiments the particulates may have a much higher PVF approaching 0.95.

[00036] The slurry may further include a third amount of particulates having a third average particle size that is smaller than the second average particle size. In certain further embodiments, the slurry may have a fourth or a fifth amount of particles. Also in some embodiments, the same chemistry can be used for the third, fourth, or fifth average particle size. Also in some embodiments, different chemistry can be used for the same third average particle size: e.g. in the third average particle size, half of the amount is a certain type of proppant and the other half is another type of proppant. For the purposes of enhancing the PVF of the slurry, more than three or four particles sizes will not typically be required. However, additional particles may be added for other reasons, such as the chemical composition of the additional particles, the ease of manufacturing certain materials into the same particles versus into separate particles, the commercial availability of particles having certain properties, and other reasons understood in the art.

[00037] Thereafter, the second treatment fluid is injected downhole. The second treatment fluid has a viscosity that is different from the first treatment fluid. According to one embodiment, the second treatment fluid has a viscosity that is lower than the first treatment fluid. The viscosity can be between about two to about twenty times lower than the first treatment fluid, or between about two to about ten times lower than the first treatment fluid. According to a second embodiment, the second treatment fluid has a viscosity that is greater than the first treatment fluid. The viscosity can be between about two to about twenty times greater than the first treatment fluid, or between about two to about ten times greater than the first treatment fluid.

[00038] The first treatment fluid has a very high solid content (a solid volume fraction (SVF) of about 60%) and good solid suspension ability. The first treatment fluid has tunable viscosity based on the fluid formulation. During hydraulic fracturing treatment, the first treatment fluid can carry solid to basically wherever the fluid goes. This ensures a complete coverage of the fracture created. The first treatment fluid also has good fluid loss control ability and the first treatment fluid stays mobile for extended period. In this period, when the first treatment fluid is already placed in the fracture, it is still possible to move the first treatment fluid with another second treatment fluid. If the second treatment fluid used to push the first treatment fluid has different viscosity than the first treatment fluid, it will finger through the first treatment fluid and create a pathway for the new fluid.

Interaction of the first treatment fluid and the second treatment fluid will create proppant-rich islands or clusters forming pillars spaced apart by proppant-free regions or channels.

[00039] The second treatment fluid may comprise a gaseous component or a supercritical fluid to form a foam or energized fluid. For example, a gas such as air, nitrogen or carbon dioxide, a supercritical fluid as supercritical carbon dioxide can be used to provide an energized fluid or foam. The foamed or energized fluid may contain "foamers", most commonly surfactant or blends of surfactants that facilitate the dispersion of the gas into the second treatment fluid in the form of small bubbles or droplets, and confer stability to the dispersion by retarding the coalescence or recombination of such bubbles or droplets. Foamed and energized fluids are generally described by their foam quality, i.e. the ratio of gas volume to the foam volume. If the foam quality is between 52% and 95%, the fluid is conventionally called foam, and below 52%, an energized fluid. However, as used herein the term "energized fluid" is defined as any stable mixture of gas and liquid, notwithstanding the foam quality value.

[00040] According to some embodiments the second treatment fluid may be a stable foamed fluid as described in U.S. Pat. No. 7,494,957 and 7,569,522, all incorporated by reference in their entirety herewith. The gas component of the second treatment fluid may be produced from any suitable gas that forms an energized fluid when introduced into the aqueous medium. See, for example, U.S. Pat. No. 3,937,283 (Blauer et al.) hereinafter incorporated by reference. The gas component may comprise a gas selected from the group consisting of nitrogen, air, carbon dioxide and any mixtures thereof. The gas component may comprise carbon dioxide, in any quality readily available. The gas component assists in the fracturing operation and the well clean-up process. The second fluid may contain from about 10% to about 90% volume gas component based upon total second fluid volume percent, from about 30% to about 80% volume gas component based upon total second fluid volume percent, and from about 40% to about 70% volume gas component based upon total second fluid volume percent.

[00041] The second treatment fluid may comprise further a viscosifying agent or a friction reducer agent. The second treatment fluid comprises a carrier fluid, which as discussed may be a gaseous component or a supercritical fluid, or any other conventional

carrier fluid in the art. Water-based fracturing fluids are common, with natural or synthetic water-soluble polymers optionally added to increase fluid viscosity, and can be with the first treatment fluid and subsequent with the second treatment fluid made of proppant and/or channelant. These polymers include, but are not limited to, guar gums; high-molecular-weight polysaccharides composed of mannose and galactose sugars; or guar derivatives, such as hydroxypropyl guar, carboxymethyl guar, carboxymethylhydroxypropyl guar, and the like. Cross-linking agents based on boron, titanium, zirconium or aluminum complexes are typically used to increase the effective molecular weight of the polymer for use in high-temperature wells. To a small extent, cellulose derivatives, such as hydroxyethylcellulose or hydroxypropylcellulose and carboxymethylhydroxyethylcellulose, are used with or without cross-linkers. Two biopolymers – xanthan and scleroglucan – provide excellent proppant suspension, but are more expensive than guar derivatives and so are used less frequently. Polyacrylamide and polyacrylate polymers and copolymers are typically used for high-temperature applications or as friction reducers at low concentrations for all temperatures ranges. Polymer-free, water-base fracturing fluids can also be obtained using viscoelastic surfactants. Usually, these fluids are prepared by mixing in appropriate amounts of suitable surfactants, such as anionic, cationic, nonionic, amphoteric, and zwitterionic. The viscosity of viscoelastic surfactant fluids are attributed to the three-dimensional structure formed by the fluid's components. When the surfactant concentration in a viscoelastic fluid significantly exceeds a critical concentration, and in most cases in the presence of an electrolyte, surfactant molecules aggregate into species, such as worm-like or rod-like micelles, which can interact to form a network exhibiting viscous and elastic behavior.

[00042] According to further embodiment, the slurry of the first treatment fluid may contain a binding agent such as resins and cement that can be activated downhole to bind all the individual components in the slurry to form a strong pillar. The advantages with this type of pillar is that it is much stronger than a proppant slug made of individual proppant particles as the slurry with maximized PVF contains greater than 50% solids in each pillar and has a high packing density and in that, the binding agent prevents the pillar from disintegrating during production whereas in conventional proppant pillars the proppant particles are subject to movement during production which can disintegrate the pack. The

binding agent may be resins (epoxy, furan, phenolic etc.), cement, sticky fibers, polymers that exhibit sticky properties at high temperature and all additives giving the same properties already disclosed in the present description.

[00043] If the first treatment fluid is injected with two alternative stages of proppant-laden and proppant-free stages, the durations of the proppant-laden and proppant-free stages, as well as the concentration of proppant are selected based on the geomechanical properties of the formation and desired fracture geometry. The volumes of the particle-laden and particle-free stages may be the same or different and may vary from 1bbl to 30bbl. As a result, the proppant does not completely fill the fracture. Rather, spaced proppant clusters form as pillars. The volumes of proppant and carrier sub-stages as pumped can be different. That is, the volume of the carrier substages can be larger or smaller than the volume of the proppant and/or any mixed substages. Furthermore, the volumes and order of injection of these substages can change over the duration of the proppant stage. That is, proppant substages pumped early in the treatment can be of a smaller volume than a proppant substage pumped later in the treatment. The relative volume of the substages can be selected by the engineer based on how much of the surface area of the fracture it is desired to be supported by the clusters of proppant, and how much of the fracture area is desired as open channels through which formation fluids are free to flow.

[00044] Suitable proppants can include sand, gravel, glass beads, ceramics, bauxites, glass, and the like or combinations thereof. Also other proppants like, plastic beads such as styrene divinylbenzene, and particulate metals may be used. Proppant used in this application may not necessarily require the same permeability properties as typically required in conventional treatments because the overall fracture permeability will at least partially develop from formation of channels. Other proppants may be materials such as drill cuttings that are circulated out of the well. Also, naturally occurring particulate materials may be used as proppants, including, but are not necessarily limited to: ground or crushed shells of nuts such as walnut, coconut, pecan, almond, ivory nut, brazil nut, etc.; ground or crushed seed shells (including fruit pits) of seeds of fruits such as plum, olive, peach, cherry, apricot, etc.; ground or crushed seed shells of other plants such as maize (e.g., corn cobs or corn kernels), etc.; processed wood materials such as those derived from

woods such as oak, hickory, walnut, poplar, mahogany, etc., including such woods that have been processed by grinding, chipping, or other form of particalization, processing, etc, some nonlimiting examples of which are proppants made of walnut hulls impregnated and encapsulated with resins. Further information on some of the above-noted compositions thereof may be found in Encyclopedia of Chemical Technology, Edited by Raymond E. Kirk and Donald F. Othmer, Third Edition, John Wiley & Sons, Volume 16, pages 248-273 (entitled "Nuts"), Copyright 1981, which is incorporated herein by reference. Resin coated (various resin and plastic coatings) or encapsulated proppants having a base of any of the previously listed propping materials such as sand, ceramics, bauxite, nut shells, etc. may be used in accordance with the invention. Essentially, the proppant can be any material that will hold open the propped portion of the fracture.

[00045] The selection of proppant can balance the factors of proppant long-term strength, proppant distribution characteristics, proppant PVF in the slurry and proppant cost. The proppant can have the ability to flow deeply into the hydraulic fracture and form spaced pillars that resist crushing upon being subjected to the fracture closure stress. Relatively inexpensive, low-strength materials, such as sand, can be used for hydraulic fracturing of formations with small internal stresses. Materials of greater cost, such as ceramics, bauxites and others, can be used in formations with higher internal stresses. Further, the chemical interaction between produced fluids and proppants, which can significantly change the characteristics of the proppant, can be considered.

[00046] In further embodiments, reinforcing and/or consolidating material can be introduced into the fracture fluid to increase the strength of the proppant clusters formed and prevent their collapse during fracture closure. Typically the reinforcement material can be added to the proppant substage and/or the mixed substage. For example, the reinforcement material can be a fiber that serves to reinforce the proppant clusters, but can be removed as or with the channelant from the proppant-lean regions. The concentrations of both proppant and the reinforcing materials can vary in time throughout the proppant stage, and from substage to substage. That is, the concentration of proppant reinforcing material can be different at two subsequent substages. It can also be suitable in some applications of the present method to introduce the reinforcing material in a continuous or semi-continuous fashion throughout the proppant stage, during a plurality of adjacent

carrier, channelant, mixed and proppant substages. In any case, introduction of the reinforcing material need not be limited only to the proppant substage. Particularly, different implementations may be when the concentration of the reinforcing material does not vary during the entire proppant stage; monotonically increases during the proppant stage; or monotonically decreases during the proppant stage.

[00047] Curable or partially curable, resin-coated proppant can be used as reinforcing and consolidating material to form proppant clusters. The selection process of the appropriate resin-coated proppant for a particular bottom hole static temperature (BHST), and the particular fracturing fluid are well known to experienced workers. In addition, organic and/or inorganic fibers can reinforce the proppant cluster. These materials can be used in combination with resin-coated proppants or separately. These fibers can have an inherently adhesive surface, can be chemically or physically modified to have an adhesive coating, or can have an adhesive coating resulting from a layer of non-adhesive substance dissolvable in the fracture by a fluid simultaneously or subsequently passed through the fracture. Fibers made of adhesive material can be used as reinforcing material, coated by a non-adhesive substance that dissolves in the fracturing fluid or another fluid as it is passed through the fracture at the subterranean temperatures. Metallic particles are another embodiment for reinforcing material and can be produced using aluminum, steel optionally containing special additives that inhibit corrosion, and other metals and alloys, and the like. The metallic particles can be shaped to resemble a sphere and measure 0.1 – 4 mm, for example. In one embodiment, metallic particles can have an elongated shape with a length longer than 2 mm and a diameter of 10 to 200 microns. In another embodiment, plates of organic or inorganic substances, ceramics, metals or metal-based alloys can be used as reinforcing material in the proppant. These plates can be disk or rectangle-shaped and of a length and width such that for all materials the ratio between any two of the three dimensions is greater than 5 to 1.

[00048] Alternatively, a high permeability and/or high porosity proppant pack can be suitably employed without detriment. In one embodiment, the permeability of the proppant can provide some limited fracture conductivity in the event the channels are not properly formed or do not fully interconnect. Additionally, under some formation conditions it can be advantageous when using the present method to perform a final tail-in

stage of the fracturing treatment involving continuous proppant introduction into the fracturing fluid, with the proppant at this stage consisting essentially of uniform particle size to obtain a zone of continuous-porosity proppant adjacent to the wellbore. If employed, the tail-in stage of the fracturing treatment resembles a conventional fracturing treatment, where a continuous bed of well-sorted conventional proppant is placed in the fracture relatively near to the wellbore. The tail-in stage can involve introduction of both an agent that increases the proppant transport capability of the treatment fluid and/or an agent that acts as a reinforcing material. The tail-in stage is distinguished from the second stage by the continuous placement of a well-sorted proppant, that is, a proppant with an essentially uniform particle size. The proppant strength is sufficient to prevent its cracking (crumbling) when subjected to stresses that occur at fracture closure. The role of the proppant at this tail stage is to prevent fracture closure and, therefore, to provide good fracture conductivity in proximity to the wellbore.

[00049] In a second embodiment, after the fracture is induced, proppant and additional channelant can be injected with the first treatment fluid into the fracture as a slurry or suspension of particles in the fracturing fluid during what is referred to herein as the “proppant stage.” In the proppant stage, proppant and optional channelant can be injected in one or more segregated substages alternated between a “proppant substage” and a “channelant substage,” and/or as a mixture of channelant and proppant in one or more substages referred to herein as a “mixed substage.” Further, the proppant, channelant and/or mixed substages can be separated by one or more optional “carrier substages”, which are substantially free of proppant and channelant and can also be substantially free of other particles. The fluid used in the proppant-laden and proppant-free stages can be of the same nature and be crosslinked to facilitate the proppant transport. It can also be of the different nature: crosslinked in proppant-laden stages and linear, crosslinked or energized/foamed in proppant-free stages. The proppant-free stage can be of the same type as the first treatment fluid i.e. foamed or energized fluid.

[00050] The choice of channelant can depend on the mode of channelant segregation and placement in the fracture, as well as the mode of channelant removal and channel formation. In its simplest form, the channelant can be a solid particulate that can be maintained in its solid form during injection and fracture closure, and readily dissolved or

degraded for removal. Materials that can be used can be organic, inorganic, glass, ceramic, nylon, carbon, metallic, and so on. Suitable materials can include water- or hydrocarbon-soluble solids such as, for example, salt, calcium carbonate, wax, or the like. Polymers can be used in another embodiment, including polymers such as , polylactic acid (PLA), polyglycolic acid (PGA), polyol, polyethylene terephthalate (PET), polysaccharide, wax, salt, calcium carbonate, benzoic acid, naphthalene based materials, magnesium oxide, sodium bicarbonate, soluble resins, sodium chloride, calcium chloride, ammonium sulfate, and the like, and so on, or any combinations thereof. As used herein, “polymers” includes both homopolymers and copolymers of the indicated monomer with one or more comonomers, including graft, block and random copolymers. The polymers can be linear, branched, star, crosslinked, derivitized, and so on, as desired. The channelant can be selected to have a size and shape similar or dissimilar to the size and shape of the proppant particles as needed to facilitate segregation from the proppant. Also, channelant can be taken into account for the PVF maximization. And the channelant can be embodied as a third amount of particulates having a third average particle size that is smaller than the second average particle size, or even as the fourth or fifth amount of particles as disclosed above. Channelant particle shapes can include, for example, spheres, rods, platelets, ribbons, and the like and combinations thereof. In some applications, bundles of fibers, or fibrous or deformable materials, can be used. These fibers can additionally or alternatively form a three-dimensional network, reinforcing the proppant and limiting its flowback.

[00051] The channelant can also be a gas, for example CO₂ (supercritical or gas), N₂ or other gaseous material. The material can exist by itself or as foam or emulsion etc.

[00052] For example, the separation of injected proppant blend and channelant as introduced and placed in the fracture can be induced by differences (or similarities) in size, density or shape of the two materials. The specific gravities and the volume concentrations of proppant blend and channelant can be tailored to minimize mixing and homogenization during placement. Properly sizing the channelant or adding various weighting agents to the channelant-rich fluid can facilitate segregation at the appropriate time and location.

[00053] Either the proppant or the proppant-spacing particles can also be made to be “sticky”, so particles of similar material adhere to one another, helping ensure

heterogeneity between the two dissimilar materials. Proppant particles can be selected that adhere to other proppant particles as discussed above and to be repelled by or repel the channelant particles. Alternatively, or additionally, channelant particles can be selected that are self-adherent and non-adherent to the proppant. The channelant can, for example, include a self-adherent coating. Another technique to encourage separation of the two materials is selecting proppant and channelant with inherent hydroaffinity differences, or creating surface hydroaffinity differences by treating either the proppant or the channelant with hydrophobic or hydrophilic coatings.

[00054] The presence of the channelant in the fracturing fluid in the proppant stage, e.g. in a mixed substage or in a segregated channelant substage, can have the benefit of increasing the proppant transport capability. In other words, the channelant can reduce the settling rate of proppant in the fracture treatment fluid. The channelant can in an embodiment be a material with elongated particles having a length that much exceeds a diameter. This material can affect the rheological properties and suppress convection in the fluid, which can result in a decrease of the proppant settling rate in the fracture fluid and maintain segregation of the proppant from proppant lean regions. The channelant can be capable of decomposing in the water-based fracturing fluid or in the downhole fluid, such as fibers made on the basis of polylactic acid (PLA), polyglycolic acid (PGA), polyvinyl alcohol (PVOH), and others. The fibers can be made of or coated by a material that becomes adhesive at subterranean formation temperatures. They can be made of adhesive material coated by a non-adhesive substance that dissolves in the fracturing fluid or another fluid as it is passed through the fracture. The fibers used in one embodiment can be up to 2 mm long with a diameter of 10 – 200 microns, in accordance with the main condition that the ratio between any two of the three dimensions be greater than 5 to 1. In another embodiment, the fibers can have a length greater than 1 mm, such as, for example, 1 – 30 mm, 2 – 25 mm or 3 – 18 mm, e.g. about 6 mm; and they can have a diameter of 5 – 100 microns and/or a denier of about 0.1-20, preferably about 0.15-6. These fibers are desired to facilitate proppant carrying capability of the treatment fluid with reduced levels of fluid viscosifying polymers or surfactants. Fiber cross-sections need not be circular and fibers need not be straight. If fibrillated fibers are used, the diameters of the individual fibrils can be much smaller than the aforementioned fiber diameters.

[00055] The concentration of the channelant in the first treatment fluid can conveniently be such that the channelant compressed between the proppant islands by fracture closure has a packed volume to fill the spaces between the packed proppant islands with similar stress in both the proppant and channelant. In other words, the channelant fill serves to hold the proppant islands in place and inhibit lateral expansion that would otherwise reduce the ultimate height of the proppant pillar. The weight concentration of the fibrous channelant material in the fracturing fluid can be from 0.1 to 10 percent in one embodiment. The concentration of the solid channelant material in the treatment fluid in another embodiment is typically from about 0.6 g/L (about 5 ppt) to about 9.6 g/L (about 80 ppt).

[00056] In some embodiments, a first type of fiber additive can provide reinforcement and consolidation of the proppant. This fiber type can include, for example, glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, and the like and combinations thereof, as a material that is packed in the proppant to strengthen the proppant pillars. And in other applications, a second type of fiber can be used that inhibits settling of the proppant in the treatment fluid. The second fiber type can include, for example, polylactic acid, polyglycolic acid, polyethylterephthalate (PET), polyol, and the like and combinations thereof, as a material that inhibits settling or dispersion of the proppant in the treatment fluid and serves as a primary removable fill material in the spaces between the pillars. Yet other applications include a mixture of the first and second fiber types, the first fiber type providing reinforcement and consolidation of the proppant and the second fiber type inhibiting settling of the proppant in the treatment fluid.

[00057] The fibers can be hydrophilic or hydrophobic in nature. Hydrophilic fibers are preferred in one embodiment. Fibers can be any fibrous material, such as, but not necessarily limited to, natural organic fibers, comminuted plant materials, synthetic polymer fibers (by non-limiting example polyester, polyaramide, polyamide, novoloid or a novoloid-type polymer), fibrillated synthetic organic fibers, ceramic fibers, inorganic fibers, metal fibers, metal filaments, carbon fibers, glass fibers, ceramic fibers, natural polymer fibers, and any mixtures thereof. Particularly useful fibers are polyester fibers coated to be highly hydrophilic, such as, but not limited to, DACRON® polyethylene terephthalate (PET) Fibers available from Invista Corp. Wichita, Kans., USA, 67220.

Other examples of useful fibers include, but are not limited to, polylactic acid polyester fibers, polyglycolic acid polyester fibers, polyvinyl alcohol fibers, and the like.

[00058] In an embodiment, the solid channelant material is selected from substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, and mixtures of such materials. Preferred examples are polyglycolic acid or PGA, and polylactic acid or PLA. These materials function as solid-acid precursors, and upon dissolution in the fracture, can form acid species which can have secondary functions in the fracture.

[00059] If desired, a pH control agent can be used in the second treatment fluid, especially where a solid acid precursor is present and one or more of the other treatment fluids is pH-sensitive. The pH control agent can be selected from amines and alkaline earth, ammonium and alkali metal salts of sesquicarbonates, carbonates, oxalates, hydroxides, oxides, bicarbonates, and organic carboxylates, for example sodium sesquicarbonate, triethanolamine, or tetraethylenepentamine.

[00060] For example, the channelant can function as an acid breaker for a viscosifying agent, where the channelant is selected from a solid that contains an acid and that hydrolyzes to release an acid, a solid that hydrolyzes to release an acid, and mixtures of such materials. The solid can be present in particles sufficiently small that they at least partially enter pores of the formation, and/or sufficiently large that they remain in the fracture in the spaces between the proppant pillars. The treatment fluid can also contain a pH control agent present in an amount sufficient to neutralize any acid present in the solid material before the injection and to neutralize any acid generated by the solid material during the injection, so that the acid breaker is not available to break the fluid during the injection. When the injection is stopped, the solid is allowed to release acid in excess of the amount that can be neutralized by any pH control agent, thereby breaking the viscous fluid. Optionally, the viscosifying agent in this embodiment is a viscoelastic surfactant system. Optionally, the solid material is of a size that forms an internal filter cake in the

pores of the formation. Optionally, the solid material is of a size that does not block the flow of fluid in the pores of the formation. The solid material is selected from substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, and mixtures of such materials. One example is polyglycolic acid. The pH control agent is selected from amines and alkaline earth, ammonium and alkali metal salts of sesquicarbonates, carbonates, oxalates, hydroxides, oxides, bicarbonates, and organic carboxylates, for example sodium sesquicarbonate, triethanolamine, or tetraethylenepentamine.

[00061] Suitable solid acids for use in viscoelastic surfactant (VES) fluid systems include substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, a copolymer of polylactic acid and polyglycolic acid, a copolymer of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, a copolymer of lactic acid with other hydroxy-, carboxylic acid or hydroxycarboxylic acid-containing moieties, or mixtures of the preceding. Other materials suitable for use in VES fluid systems are all those polymers of hydroxyacetic acid (glycolic acid) with itself or other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties described in U.S. Patent Nos. 4,848,467; 4,957,165; and 4,986,355, all three hereby incorporated by reference. Suitable solid acids are also described in U. S. Patent Application Publication Nos. 2003/002195 and 2004/0152601, both of which are hereby incorporated by reference and are assigned to the assignee of the present application.

[00062] Excellent solid acid components for VES systems are solid cyclic dimers, or solid polymers, of certain organic acids, that hydrolyze under known and controllable conditions of temperature, time and pH to form organic acids. One example, a suitable solid acid is the solid cyclic dimer of lactic acid known as "lactide", which has a melting point of 95 to 125 °C depending upon the optical activity. Another is a polymer of lactic acid, sometimes called a polylactic acid or "PLA", or a polylactate, or a polylactide. Another example is the solid cyclic dimer of glycolic acid known as "glycolide", which has a melting point of about 86 °C. Yet another example is a polymer of glycolic acid

(hydroxyacetic acid), also known as polyglycolic acid (“PGA”), or polyglycolide. Another example is a copolymer of lactic acid and glycolic acid. These polymers and copolymers are polyesters. The as-received materials can contain some free acid and some solvent, typically water.

[00063] Natureworks L.L.C., Minnetonka, MN, USA, produces the solid cyclic lactic acid dimer called “lactide” and from it produces lactic acid polymers, or polylactates, with varying molecular weights and degrees of crystallinity, under the generic trade name NATUREWORKS™ PLA. The PLA’s currently available from Cargill Dow have molecular weights of up to about 100,000, although any polylactide (made by any process by any manufacturer) and any molecular weight material of any degree of crystallinity can be used in the embodiments of the Invention. The PLA polymers are solids at room temperature and are hydrolyzed by water to form lactic acid. Those available from Cargill Dow typically have crystalline melt temperatures of from about 120 to about 170 °C, but others are obtainable. Poly(d,l-lactide) is available from Bio-Invigor, Beijing and Taiwan, with molecular weights of up to 500,000. Bio-Invigor also supplies polyglycolic acid (also known as polyglycolide) and various copolymers of lactic acid and glycolic acid, often called “polyglactin” or poly(lactide-co-glycolide). The rates of the hydrolysis reactions of all these materials are governed, among other factors, by the molecular weight, the crystallinity (the ratio of crystalline to amorphous material), the physical form (size and shape of the solid), and in the case of polylactide, the amounts of the two optical isomers. (The naturally occurring l-lactide forms partially crystalline polymers; synthetic dl-lactide forms amorphous polymers.) Amorphous regions are more susceptible to hydrolysis than crystalline regions. Lower molecular weight, less crystallinity and greater surface-to-mass ratio all result in faster hydrolysis. Hydrolysis is accelerated by increasing the temperature, by adding acid or base, or by adding a material that reacts with the hydrolysis product(s).

[00064] Homopolymers of PGA and PLA can be more crystalline; copolymers tend to be amorphous unless they are block copolymers. The extent of the crystallinity can be controlled by the manufacturing method for homopolymers and by the manufacturing method and the ratio and distribution of lactide and glycolide for the copolymers. Polyglycolide can be made in a porous form. Some of the polymers dissolve very slowly

in water before they hydrolyze; it is to be understood that the terms hydrolyze or hydrolysis, etc., are intended to include dissolution.

[00065] The solid acids can be coated to slow the hydrolysis. Suitable coatings include polycaprolate (a copolymer of glycolide and epsilon-caprolactone), and calcium stearate, both of which are hydrophobic. Polycaprolate itself slowly hydrolyzes. Generating a hydrophobic layer on the surface of the solid acids by any means can facilitate segregation from hydrophilic proppant and can delay the hydrolysis for injection and fracture. Note that coating here can refer to encapsulation or simply to changing the surface by chemical reaction or by forming or adding a thin film of another material. Another suitable method of delaying the hydrolysis of the solid acid, and the release of acid, is to suspend the solid acid, optionally with a hydrophobic coating, in an oil or in the oil phase of an emulsion. The hydrolysis and acid release do not occur until water contacts the solid acid.

[00066] The VES self-destructs *in situ*, that is, in the location where it is placed. That location can be part of a suspension in a treatment fluid in the wellbore, in perforations, in a gravel pack, or in a fracture; or as a component of a filter cake on the walls of a wellbore or of a fracture; or in the pores of a formation itself. The VES can be used in formations of any lithology but are used most commonly in carbonates or sandstones. A particular advantage of these materials is that the solid acid precursors and the generated acids are non-toxic and are biodegradable. The solid acids are often used as self-dissolving sutures in medical practice, for example.

[00067] A polyol is a polyhydric alcohol, i.e., one containing three or more hydroxyl groups. One embodiment of a polyol useful as a channelant is a polymeric polyol solubilizable upon heating, desalination or a combination thereof, and which consists essentially of hydroxyl-substituted carbon atoms, in a polymer chain, spaced from adjacent hydroxyl-substituted carbon atoms by at least one carbon atom in the polymer chain. In other words, the useful polyols are preferably essentially free of adjacent hydroxyl substituents. In one embodiment, the polyol has a weight average molecular weight greater than 5000 up to 500,000 or more, and from 10,000 to 200,000 in another embodiment. The polyol can if desired be hydrophobically modified to further inhibit or

delay solubilization, e.g. by including hydrocarbyl substituents such as alkyl, aryl, alkaryl or aralkyl moieties and/or side chains having from 2 to 30 carbon atoms. The polyol can also be modified to include carboxylic acid, thiol, paraffin, silane, sulfuric acid, acetoacetylate, polyethylene oxide, or quaternary amine or other cationic monomers. Such modifications have several affects on the properties of the polyol; affects on solubility, sensitivity to salinity, pH, and crosslinking functionalities (e.g. hydroxyl groups and silanol groups which are chelates that can crosslink with common crosslinkers) are of most interest to the present invention. All of said modifications are commercially available products.

[00068] In one embodiment, the polyol is a substituted or unsubstituted polyvinyl alcohol that can be prepared by at least partial hydrolysis of a precursor polyvinyl compound having ester substituents, such as, for example, polyvinyl acetate, polyvinyl propanoate, polyvinyl butanoate, polyvinyl pentanoate, polyvinyl hexanoate, polyvinyl 2-methyl butanoate, polyvinyl 3-ethylpentanoate, polyvinyl 3-ethylhexanoate, and the like, and combinations thereof. When the polyol comprises polyvinyl alcohol prepared by at least partial hydrolysis of polyvinyl acetate, the polyol is not generally soluble in salt water, as discussed in more detail below, and further, the polyol is commercially available in the form of partially crystalline fibers that have a relatively sharp trigger temperature below which the fibers are not soluble in water and above which they readily dissolve.

[00069] According to a further embodiment, the first treatment fluid comprises a viscosifier material and the second treatment fluid comprises a trigger, wherein the viscosifier material is inactive in a first state and is able to decrease viscosity when in a second state activated by the trigger.

[00070] According to a further embodiment, the first treatment fluid comprises a viscosifier material and the second treatment fluid comprises a trigger, wherein the viscosifier material is inactive in a first state and is able to increase viscosity when in a second state activated by the trigger. In another embodiment, the first treatment fluid comprises the trigger and the second treatment fluid comprises the viscosifier material. The result will be stabilization by viscosifying fluid obtained from combination of the viscosifier material and trigger around channels. Viscosity may be increased because of

reaction between chemical components of the first treatment fluid and displacing second treatment fluid.

[00071] In one embodiment, it can be done by cross-linking reaction when polymer is included in the first treatment fluid and cross-linker is included in the composition of the displacing second treatment fluid. A crosslinked polymer is generally formed by reacting or contacting proper proportions of the crosslinkable polymer with the crosslinking agent. The composition may comprise at least the crosslinkable polymer or monomers capable of polymerizing to form a crosslinkable polymer (e.g. acrylamide, vinyl acetate, acrylic acid, vinyl alcohol, methacrylamide, sodium AMPS, ethylene oxide, propylene oxide, and vinyl pyrrolidone).

[00072] Typically, the crosslinkable polymer is water soluble. Common classes of water soluble crosslinkable polymers include polyvinyl polymers, polymethacrylamides, cellulose ethers, polysaccharides, lignosulfonates, ammonium salts thereof, alkali metal salts thereof, as well as alkaline earth salts of lignosulfonates. Specific examples of typical water soluble polymers are acrylic acid-acrylamide copolymers, acrylic acid-methacrylamide copolymers, polyacrylamides, partially hydrolyzed polyacrylamides, partially hydrolyzed polymethacrylamides, polyvinyl alcohol, polyvinyl pyrrolidone, polyalkyleneoxides, carboxycelluloses, carboxyalkylhydroxyethyl celluloses, hydroxyethylcellulose, galactomannans (e.g., guar gum), substituted galactomannans (e.g., hydroxypropyl guar), heteropolysaccharides obtained by the fermentation of starch-derived sugar (e.g., xanthan gum), and ammonium and alkali metal salts thereof. Other water soluble crosslinkable polymers include hydroxypropyl guar, partially hydrolyzed polyacrylamides, xanthan gum, polyvinyl alcohol, and the ammonium and alkali metal salts thereof.

[00073] The crosslinkable polymers are typically synthetic polymers for long term stability but could include biological polymers.

[00074] The crosslinkable polymer is available in several forms such as a water solution or broth, a gel log solution, a dried powder, and a hydrocarbon emulsion or dispersion. As is well known to those skilled in the art, different types of equipment are employed to handle these different forms of crosslinkable polymers.

[00075] With respect to the crosslinking agents, these agents are organic and inorganic compounds well known to those skilled in the art. Exemplary organic crosslinking agents include, but are not limited to, aldehydes, dialdehydes, phenols, substituted phenols, and ethers. Phenol, phenyl acetate, resorcinol, glutaraldehyde, catechol, hydroquinone, gallic acid, pyrogallol, phloroglucinol, formaldehyde, and divinylether are some of the more typical organic crosslinking agents. The organic crosslinker can also take the form of a polymer such as polyalkyleneimines such as polyethyleneimine or polyalkylenepolyamines such as polyethylenepolyamines and polypropylenepolyamines as disclosed in Patents numbers U.S. 4,773,481 and 6,192,986 incorporated by reference herewith. Typical inorganic crosslinking agents are polyvalent metals, chelated polyvalent metals, and compounds capable of yielding polyvalent metals. Some of the more common inorganic crosslinking agents include chromium salts, aluminates, gallates, dichromates, titanium chelates, aluminum citrate, chromium citrate, chromium acetate, and chromium propionate.

[00076] In another embodiment, it can be done by increasing viscosity caused by changing pH at the fluid interface. The first treatment fluid comprises both (a) the crosslinking agent and (b) either (i) the crosslinkable polymer or (ii) the polymerizable monomers capable of forming a crosslinkable polymer. And the second treatment fluid comprises pH agent which will cause the reaction. One of the example of such system is a solution of guar polymer and borate cross-linker at pH about 7. Cross-linking may be activated by increasing pH of the system, e.g. by adding NaOH.

[00077] Still, in another embodiment, viscoelastic surfactant may be used for increasing viscosity at the fluid interface. Specific example of this situation is when VDA/HCl is used as a displacing fluid for carbonate containing high solid content fluid. Reaction between HCl and carbonate viscosifies VDA solution.

[00078] To facilitate a better understanding, the following example of embodiments is given. In no way should the following example be read to limit, or define, the scope.

Examples

[00079] A series of experiments were conducted to demonstrate method of treatment according to the invention.

[00080] To visualize the fluid displacement and movement, an experiment setup illustrated in Figure 3 is used. A gap is created between two transparent plexiglass plates 8 separated by spacer 9. About 15 mL of high solid content fluid sample 1 is first injected with a syringe 4 through a 1/8" opening in the middle of the top plate (as show in Figure 4A). The second sample representing the second treatment fluid of about 15 mL is then injected through the hole again. The second treatment fluid will either displace the first one evenly or finger through the high solid content fluid. The resulting displaced fluid patterns are pictured and showed in Figures 4B to 4H. To help visualize the fluid interfaces, the high solid content fluid sample was dyed with a bright pink water-soluble colors (not shown on the pictures).

[00081] Figure 4A shows the first treatment fluid injected. Figures 4B to 4H show patterns of the first treatment fluid having high solid content fluid being displaced by the second treatment fluid. Figure 4A shows the first treatment fluid before displacement. Figure 4B shows first treatment fluid being displaced with water. Figure 4C shows first treatment fluid being displaced with 0.24% by weight of linear guar. Figure 4D shows first treatment fluid being displaced with 0.48% by weight of linear guar. Figure 4E shows first treatment fluid being displaced with crosslinked 0.24% by weight of guar. Figure 4F shows first treatment fluid being displaced by another high solid content fluid (having smaller particle sizes) with similar viscosity. Figure 4G shows first treatment fluid being displaced with another high solid content fluid (having smaller particle sizes) with 1/4 viscosity than first treatment fluid. Figure 4H shows first treatment fluid being displaced with another high solid content fluid (having smaller particle sizes) with 1/10 viscosity than first treatment fluid.

[00082] It is not surprising to see that the channeling of second treatment fluid through the first treatment fluid made of high solid content fluid is a function of the second fluid viscosity, or viscosity contrast between the second fluid and high solid content fluid. It is important to notice that the interfaces of these fingering appears to be different. If the

high solid content fluid is being pushed by water or WF fluids, the interfaces between the high solid content fluid and the water fluids appears to be segregated. If the original high solid content fluid is being pushed by another high solid content fluid of lower viscosity (regardless of particle size, though the example showed with smaller particle formulation), the interfaces do not appear to have segregation. This is an important factor to design the over flush fluid. If segregation is severe, local screen out can happen and the high solid content fluid placed may not be movable and over flush will not happen. However, if no segregation happens, the channel created will not be sustained and will be closed in a short time. Figures 4B and 4H demonstrated that we can create such channels and have ways to tune the flowability and channel stability 40.

[00083] An high solid content fluid injection test is used to prove the feasibility of high solid content fluid injectivity after placement. Figure 5 shows a schematic drawing of the conductivity test. The goal is to inject high solid content fluid between two sandstone cores an upper core portion 14 and a bottom core portion 18 placed under confinement through an upper piston 12 and a bottom piston 20 inside a conductivity cell 16. To pump the fluid into the conductivity cell, an accumulator driven by an ISCO pump is used. Confining stress is adjusted by the conductivity press. Although we made an effort to keep the confining stress constant, the press is operating in the low end of its range and the variation of the stress during the test was not enough to trigger the adjustment of the press. This is why we are seeing pressure responses to the injection pressure (see result plots in Figures 7 and 8). Figure 6 is the schematic drawing of the cores placed inside the conductivity cell 16. The upper core is cut at the entrance 26, allowing the fluid 24 to enter. Once the fluid is pumped into the system, it pushed the upper core up allowing the fluid to flow between the top 14 and bottom 18 cores, eventually flow out from the exit 28. The bottom piston surface (where the sandstone core sits) has channels and holes made to collect fluid into the piston. Then fluid collected flows outside through side ports 22. The fluid collected could be the excess of water coming from the core, and/or the filtrate coming from the fluid leakoff through the core. In our experiments, the side ports 22 remained opened to let the fluid leak off through the sand stone cores.

[00084] The results of two tests with different high solid concentration formulations are shown in Figure 7 and 8. In the first test (Figure 7), the confining stress is around 1000

psi. The ISCO volume is recorded in this test. As can be seen in the plot, the injection pressure increases quickly after about 1 min injection. It reached a peak where the flow was initiated into the conductivity cell. The fluid flowed for about 30 seconds (at time 380 seconds) and exit from the other end of the conductivity cell. Once the fluid start to exit the cell, the injection pressure drops. It can be seen in the plot that around 400 seconds, the injection pressure is lower than that of the confining stress and continues to decrease. The pump was shut down at around 430 second. During the test, since the cell is completely filled by the high solid content fluid, in order to keep the gap open, the injection pressure should be higher than or at least equal to the confining stress. The lower injection pressure than confining stress seen in the experiment is an indication that the cores is propped open by some solid particles and the high solid content fluid can just be moved through the gap.

[00085] To confirm this phenomenon, we rerun the test using a different formulation and at a different confining stress (200 psi). The pumping was also performed for longer time in order to confirm that the later injection pressure is lower than the confining stress. The results are shown in Figure 8. It should be note that the sharp pressure increase at the end of the test is due to that the accumulator used to hold the high solid content fluid run out of fluid and the floating piston is pushing against the accumulator end cap. From Figure 8 it can be seen that the injection pressure spikes twice at the early part of the injection then level down to a value way below that of the confining stress until fluid is run out. These two experiments proves that the high solid content fluid can be pushed away once placed. It also indicates that certain pillars can be formed in the high solid content fluid pack, which will support the closure stress, while other parts of the high solid content fluid can be flowed through. Although experiments with other fluids have not been performed, it is believed that similar behavior for high solid content fluid holds. The channeling materials can be formulated with degradable material and finally be removed from the fracture to give good conductivity.

[00086] The foregoing disclosure and description of the invention is illustrative and explanatory thereof and it can be readily appreciated by those skilled in the art that various changes in the size, shape and materials, as well as in the details of the illustrated construction or combinations of the elements described herein can be made without departing from the spirit of the invention.

Claims

What is claimed is:

1. A method of placing particulate blend into a fracture formed in a subterranean formation from a wellbore, the method comprising:
 - injecting through the wellbore a first treatment fluid to initiate or propagate the fracture in the subterranean formation; wherein the first treatment fluid comprises a particulate blend slurry; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 micrometers and at least a second amount of particulates having a second average particle size between about three and twenty times smaller than the first average particle size;
 - injecting through the wellbore a second treatment fluid having a viscosity different from the first treatment fluid; and
 - forming with the particulate blend slurry a plurality of particulate-rich clusters spaced apart by particulate-free regions forming open channels.
2. The method of claim 1, wherein the particulate blend slurry is made of proppant and forming with the particulate blend slurry a plurality of proppant-rich clusters spaced apart by proppant-free regions forming open channels.
3. The method of claim 1, wherein the second treatment fluid is substantially free of macroscopic particles.
4. The method of claim 1, wherein injection of the first treatment fluid is done by alternating stages of proppant-rich phase made of the particulate blend high solid content slurry and a proppant-free phase.

5. The method of claim 4, wherein the stages of proppant-rich phase made of the particulate blend high solid content slurry and a proppant-free phase are separated by injection of a fiber spacer.
6. The method of claim 2, wherein the first treatment fluid comprises further a channelant, and the second treatment fluid forms a plurality of proppant clusters forming pillars spaced apart by the channelant.
7. The method of claim 6, further comprising removing the channelant to form further open channels around the pillars for fluid flow from the subterranean formation through the fracture toward the wellbore.
8. The method of claim 1, wherein the first treatment fluid comprises a first carrier fluid comprising a viscosifying agent or a friction reducer and water.
9. The method of claim 1, wherein the first treatment fluid comprises a viscosifier material or a trigger and the second treatment fluid comprises respectively the trigger or the viscosifier material, wherein the viscosifier material is inactive in a first state and is able to decrease viscosity when in a second state activated by the trigger.
10. The method of claim 1, wherein the first treatment fluid comprises a viscosifier material or a trigger and the second treatment fluid comprises respectively the trigger or the viscosifier material, wherein the viscosifier material is inactive in a first state and is able to increase viscosity when in a second state activated by the trigger.
11. The method of claim 10, wherein the viscosifier material is a crosslinkable polymer; and wherein the trigger is a crosslinker for the crosslinkable polymer.

12. The method of claim 10, wherein the viscosifier material is a crosslinkable polymer and a crosslinker; and wherein the trigger is a pH agent.
13. The method of claim 10, wherein the viscosifier material is a viscoelastic surfactant and acid; and wherein the trigger is a pH agent neutralizing the acid.
14. The method of claim 1, wherein the second treatment fluid comprises a second carrier fluid comprising a viscosifying agent or a friction reducer and water.
15. The method of claim 1, wherein the second treatment fluid comprises a gas.
16. The method of claim 15, wherein said gas component comprises a gas selected from the group consisting of carbon dioxide, supercritical carbon dioxide, nitrogen, air and any mixtures thereof.
17. The method of claim 15, wherein said gas component comprises from about 10% to about 90% of total first fluid volume percent, preferably from about 30% to about 80% of total first fluid volume percent, and more preferably from about 40% to about 70% of total first fluid volume percent.
18. The method of claim 1, wherein the particulate blend comprises a degradable material.
19. The method of claim 1, wherein the particulate blend comprises a binding agent.
20. The method of claim 19, wherein the binding agent is selected from the group consisting of resin, cement, sticky fiber, polymer that exhibit sticky properties at high temperature and any mixtures thereof.
21. The method of claim 1, wherein the particulate blend comprises fiber.
22. The method of claim 21, wherein the fibers are selected from the group consisting of glass, ceramics, carbon and carbon-based compounds, metals and metallic

alloys, polylactic acid, polyglycolic acid, polyethylene terephthalate, polyol and combinations thereof.

23. The method of claim 1, wherein the second treatment fluid has a viscosity in the range of two to ten times lower than the first treatment fluid.
24. The method of claim 1, wherein the second treatment fluid has a viscosity in the range of two to ten times greater than the first treatment fluid.
25. The method of claim 1, further comprising producing fluids from the subterranean formation through the open channels and the wellbore.
26. A method of placing a proppant pack into a fracture formed in a subterranean formation, the method comprising:

injecting through the wellbore a first treatment fluid to initiate or propagate the fracture in the subterranean formation; wherein the first treatment fluid comprises a particulate blend slurry made of proppant ; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 micrometers and at least a second amount of particulates having a second average particle size between about three and twenty times smaller than the first average particle size;

injecting through the wellbore a second treatment fluid having a viscosity different from the first treatment fluid; and

forming with the particulate blend slurry a plurality of proppant-rich clusters spaced apart by proppant-free regions forming open channels.

27. The method of claim 26, wherein the first treatment fluid comprises a viscosifier material or a trigger and the second treatment fluid comprises respectively the

trigger or the viscosifier material, wherein the viscosifier material is inactive in a first state and is able to decrease viscosity when in a second state activated by the trigger.

28. The method of claim 26, wherein the first treatment fluid comprises a viscosifier material or a trigger and the second treatment fluid comprises respectively the trigger or the viscosifier material, wherein the viscosifier material is inactive in a first state and is able to increase viscosity when in a second state activated by the trigger.
29. The method of claim 28, wherein the viscosifier material is a crosslinkable polymer; and wherein the trigger is a crosslinker for the crosslinkable polymer.
30. The method of claim 28, wherein the viscosifier material is a crosslinkable polymer and a crosslinker; and wherein the trigger is a pH agent.
31. The method of claim 28, wherein the viscosifier material is a viscoelastic surfactant and acid; and wherein the trigger is a pH agent neutralizing the acid.
32. A method of placing a proppant pack into a fracture formed in a subterranean formation, the method comprising:

injecting through the wellbore a first treatment fluid to initiate or propagate the fracture in the subterranean formation; wherein the first treatment fluid comprises a particulate blend slurry made of proppant ; the particulate blend comprising at least a first amount of particulates having a first average particle size between about 100 and 5000 micrometers and at least a second amount of particulates having a second average particle size between about three and twenty times

smaller than the first average particle size; such that a packed volume fraction of the particulate blend exceeds 0.74;

injecting through the wellbore a second treatment fluid substantially free of macroscopic particles and having a viscosity different from the first treatment fluid; and

forming with the particulate blend slurry a plurality of proppant-rich clusters spaced apart by proppant-free regions forming open channels.

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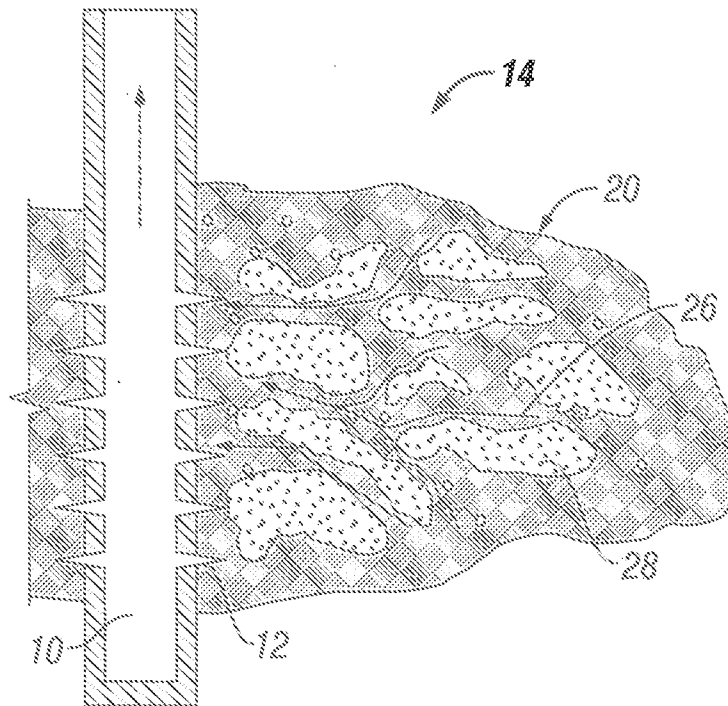


FIG. 1

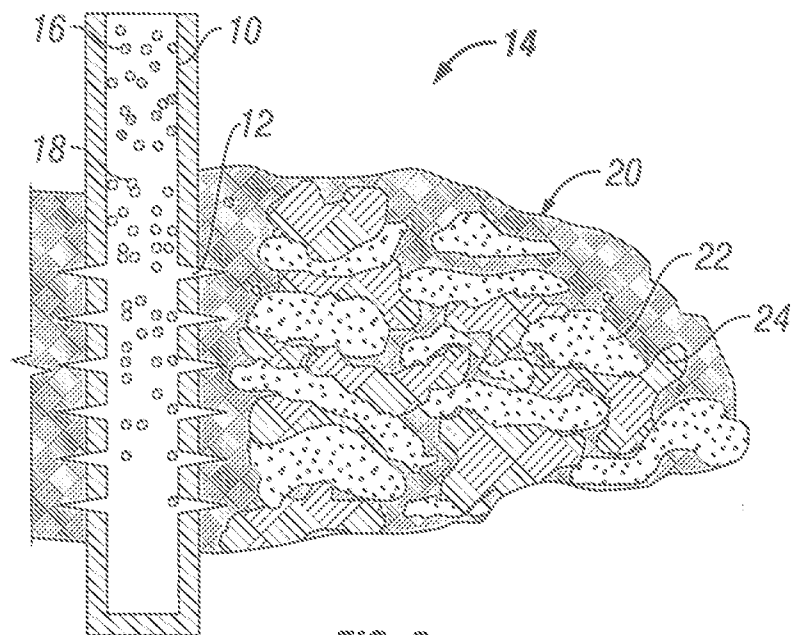


FIG. 2

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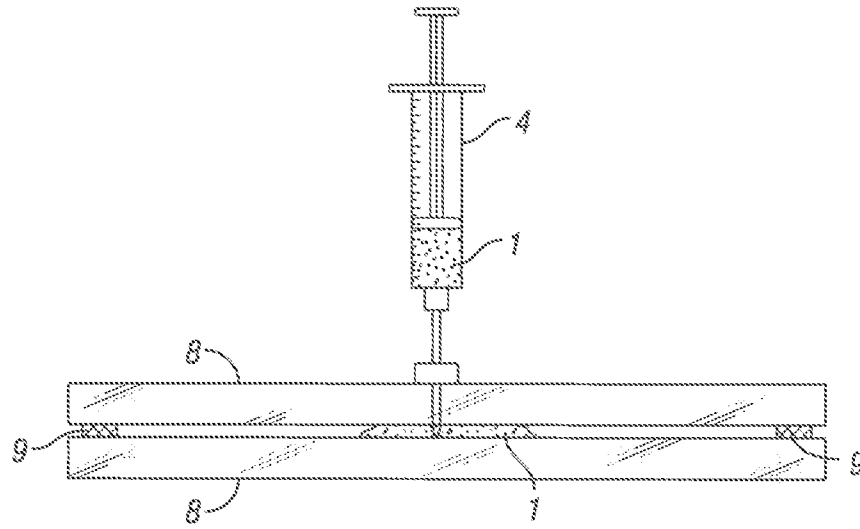


FIG. 3

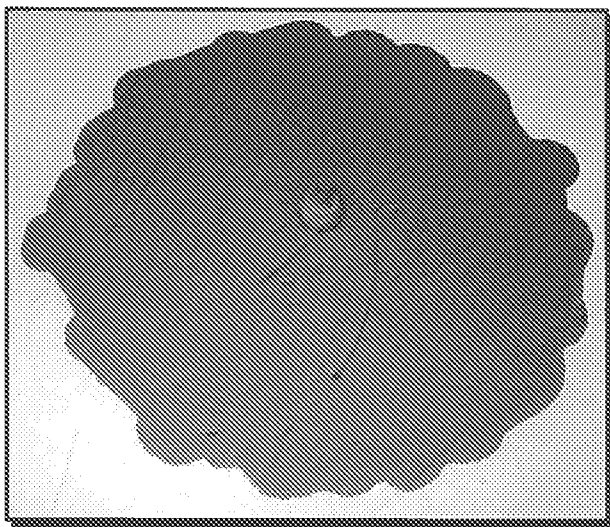


FIG. 4A

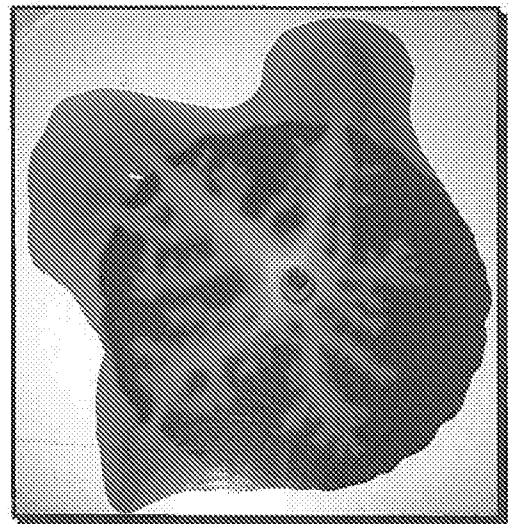


FIG. 4B

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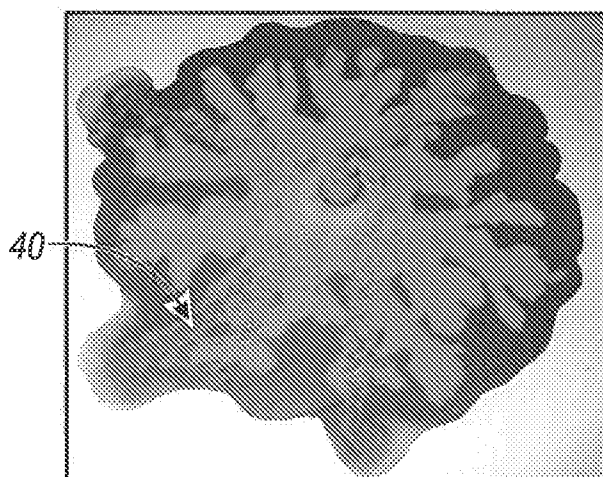


FIG. 4C

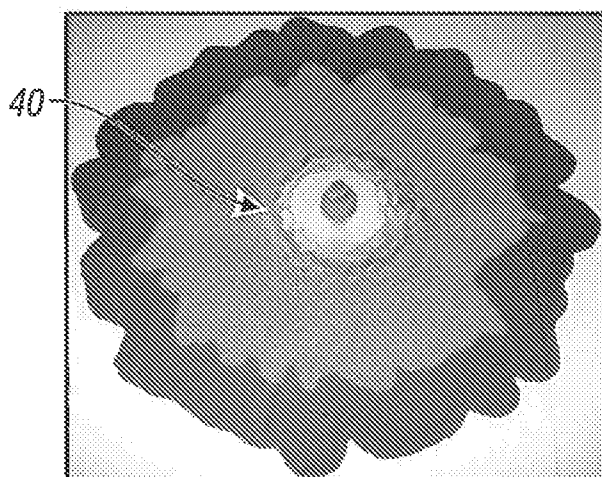


FIG. 4D

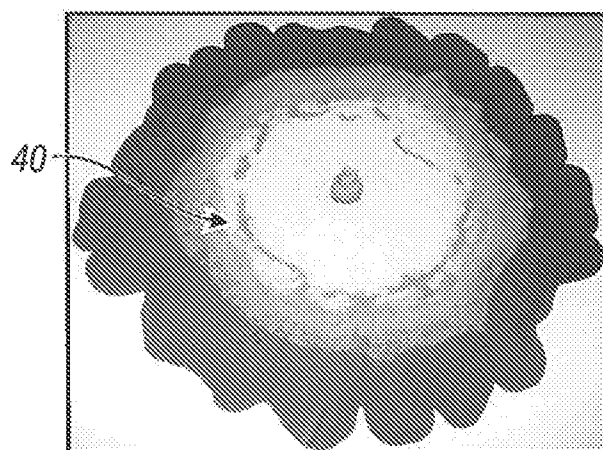


FIG. 4E

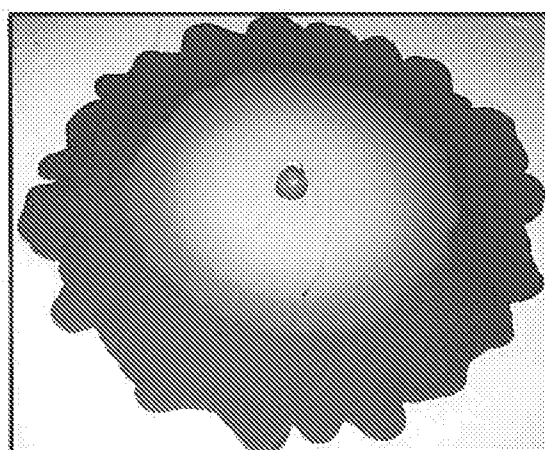


FIG. 4F

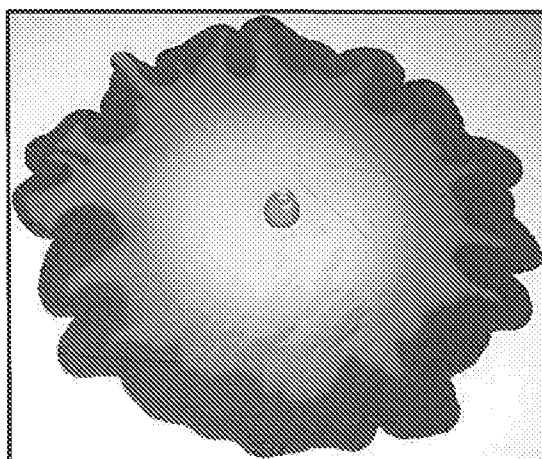


FIG. 4G

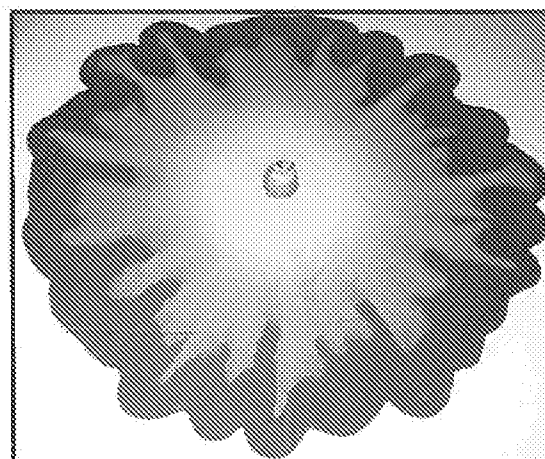


FIG. 4H

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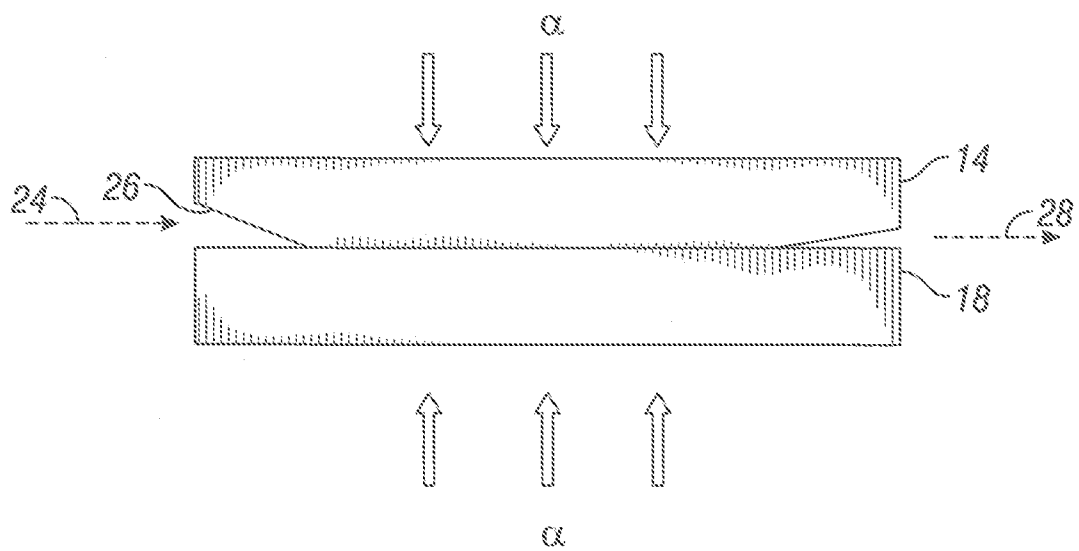
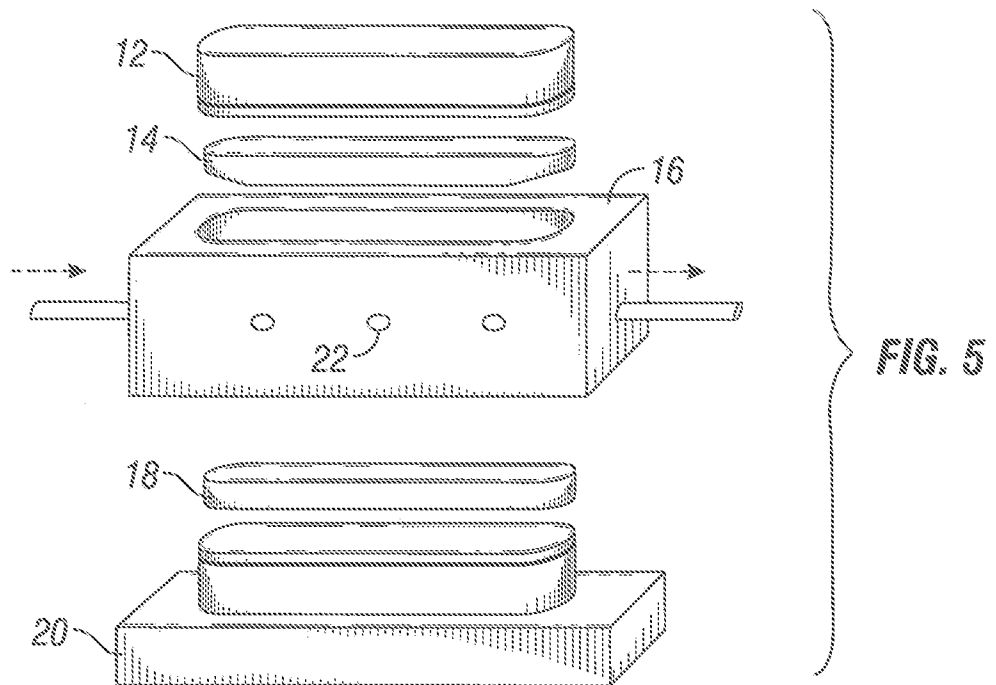


FIG. 6

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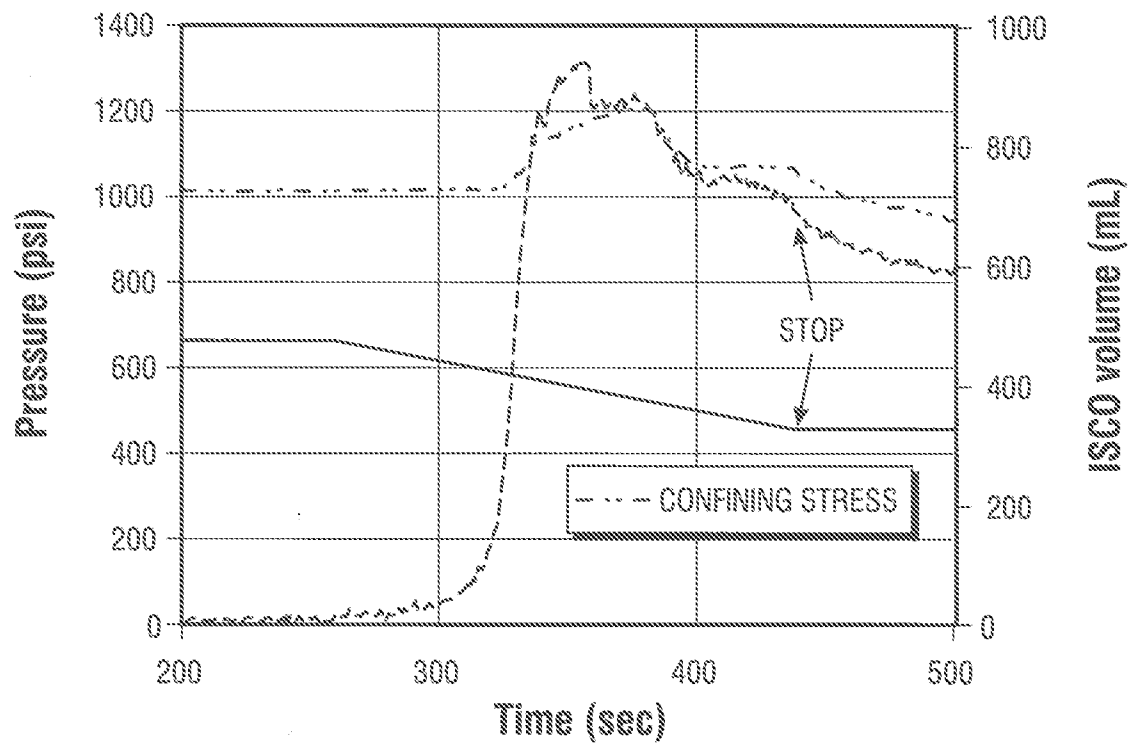


FIG. 7

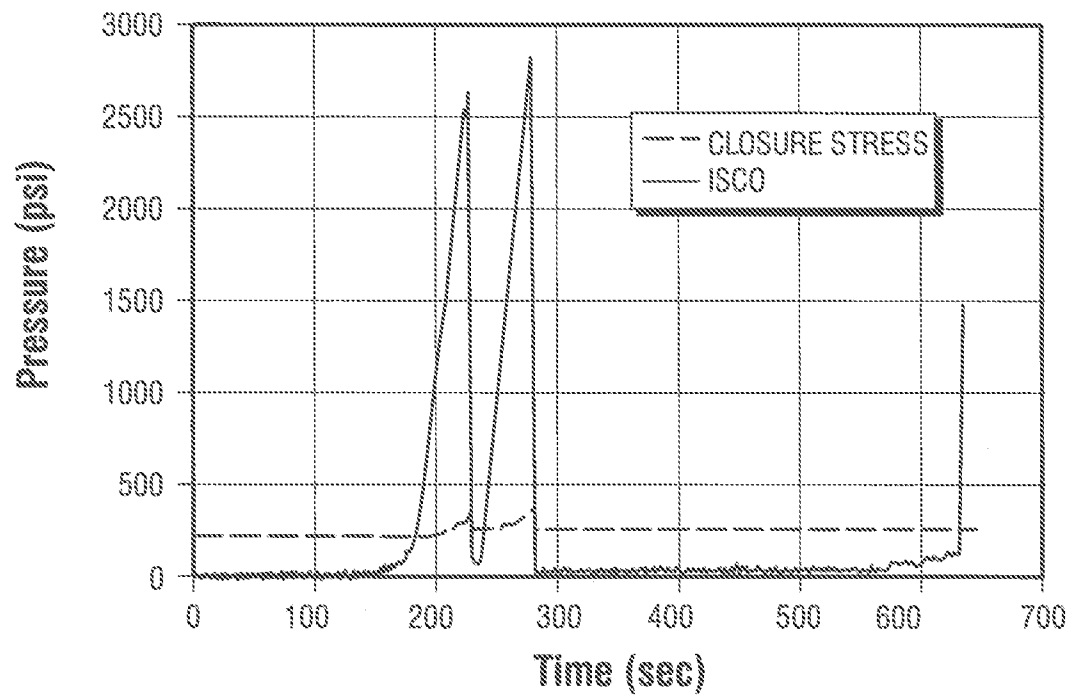


FIG. 8