Proppant pillar placement in a fracture with a stabilized slurry treatment fluid. A method of placing a proppant pack by injecting a well treatment fluid comprising proppant and a stabilized slurry, and a slurry destabilizing system to consolidate solids from the slurry, and placing the proppant in the fracture in a plurality of proppant clusters forming pillars spaced apart by fluid flow channels from the formation through the fracture toward the wellbore. Also, a system for implementing the method, and the propped fracture system obtained as a result of placing the proppant pack into the fracture according to the method.
FIG. 3
STABILIZED FLUIDS IN WELL TREATMENT

RELATED APPLICATION DATA

BACKGROUND

The statements in this section merely provide background information related to the present disclosure and may not constitute prior art.

This application relates to stimulation of wells penetrating subterranean formations, and more specifically 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.

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.

The success of the fracturing treatment may depend on the ability of fluids to flow from the formation through the proppant pack. 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 a homogenous proppant matrix, as in, for example, U.S. Pat. No. 7,255,169, U.S. Pat. No. 7,281,580 and U.S. Pat. No. 7,571,767, incorporated herein by reference.

Another approach to improving fracture conductivity has been to try heterogeneous proppant placement techniques to construct proppant clusters, as opposed to constructing a continuous proppant pack. U.S. Pat. No. 6,776,235 incorporated herein by reference discloses a method for fracturing a subterranean formation involving alternating stages of proppant containing fracturing fluids contrasting in their proppant-settling rates to form proppant clusters as posts that prevent fracture closing, e.g., alternating 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 can be difficult to control.


Improvements in well treatment slurries and slurry treatments, systems, equipment, methods, and the like in general and for propping a fracture in particular, are desired.

SUMMARY

In some embodiments herein, stabilized treatment slurries, proppants and destabilizing systems are used in methods or systems to place consolidated proppant pillars in a fracture spaced apart by fluid flow channels, which may be open channels or relatively permeable channels filled with permeable proppant packs relative to the pillars, for the flow of reservoir fluid(s) from the formation through the fracture toward the wellbore.

According to some embodiments, methods of placing proppant packs into a fracture formed in a subterranean formation comprises: injecting well treatment fluids, at least a portion of the well treatment fluids comprises a proppant-containing stage, at least a portion of the well treatment fluids comprises a stabilized slurry stage and the proppant-containing and stabilized slurry portions may be the same or different; injecting a destabilizing system to destabilize the slurry and form regions of consolidated proppant from the destabilized slurry stage; and placing a plurality of clusters forming pillars from the consolidated proppant regions spaced apart by fluid flow channels from the formation through the fracture toward the wellbore.

According to some embodiments, a propped fracture system is obtained as a result of placing the proppant pack into the fracture according to the methods described herein.

A system for fracturing a subterranean formation comprises a supply module to inject a well treatment fluid which comprises proppants and stabilized treatment slurries through a wellbore into a fracture in a subterranean formation, and a destabilizing system in communication with the supply module for injection into the fracture with the well treatment fluid to form regions of consolidated proppant from the destabilized slurry stage fluid and form pillars spaced apart by fluid flow channels from the formation through the fracture toward the wellbore.

In some embodiments herein, the treatments, treatment fluids, systems, equipment, methods, and the like employ a stabilized treatment slurry (STS) having a solid phase, which may include proppant, is at least temporarily inhibited from gravitational settling in the fluid phase. In some embodiments, the STS may have an at least temporarily controlled rheology, such as, for example, viscosity, leakoff or yield strength, or other physical property, such as, for example, specific gravity, solids volume fraction (SVF), or the like. In some embodiments, the solids phase of the STS may have an at least temporarily controlled property, such as, for example, particle size distribution (including modality (ies)), packed volume fraction (PVF), density(ies), aspect ratio(s), sphericity(ies), roundness(es) (or angularity(ies)), strength(s), permeability(ies), solubility(ies), reactivity(ies), etc.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other features and advantages will be better understood by reference to the following detailed description when considered in conjunction with the accompanying drawings.

FIG. 1 shows a schematic slurry state progression chart for a treatment fluid according to some embodiments of the current application.
FIG. 2 illustrates fluid stability regions for a treatment fluid according to some embodiments of the current application. FIG. 3 shows the leakoff property of a low viscosity, stabilized treatment slurry (STS) (lower line) according to some embodiments of the current application compared to a conventional crosslinked fluid (upper line). FIG. 4 shows a schematic representation of the wellsite equipment configuration with onsite mixing of an STS according to some embodiments of the current application. FIG. 5 shows a schematic representation of the wellsite equipment configuration with a pump-ready STS according to some embodiments of the current application. FIG. 6 schematically illustrates in section placement of stabilized proppant slurry and slurry destabilizer in a hydraulic fracture operation according to embodiments disclosed. FIG. 7 schematically illustrates in section the arrangement of the wellbore, perforations and the proppant pillars in the fracture following slurry destabilization in the fracture of FIG. 1. FIG. 8 schematically illustrates a side sectional view of a fracture filled with segregated, consolidated proppant and permeable proppant regions according to embodiments disclosed. FIG. 9 schematically illustrates a side sectional view of a fracture filled with segregated, consolidated proppant and proppant-free regions according to embodiments disclosed. FIG. 10 schematically illustrates a plan view of a portion of a fracture filled with peripherally-consolidated proppant pillars and proppant-free channels according to embodiments disclosed. FIG. 11 schematically illustrates an alternatingly pulsed proppant/slurry/slurry crosslinker fracture treatment system according to embodiments disclosed. FIG. 12 schematically illustrates a plan view of a portion of a fracture filled with a proppant/stabilized slurry and a liquid removal agent.

DETAILED DESCRIPTION OF SOME ILLUSTRATIVE EMBODIMENTS

For the purposes of promoting an understanding of the principles of the disclosure, reference will now be made to some illustrative embodiments of the current application. Like reference numerals used herein refer to like parts in the various drawings. Reference numerals without suffixed letters refer to the part(s) in general; reference numerals with suffixed letters refer to a specific one of the parts.

As used herein, “embodiments” refers to non-limiting examples of the application disclosed herein, whether claimed or not, which may be employed or present alone or in any combination or permutation with one or more other embodiments. Each embodiment disclosed herein should be regarded both as an added feature to be used with one or more other embodiments, as well as an alternative to be used separately or in lieu of one or more other embodiments. It should be understood that no limitation of the scope of the claimed subject matter is thereby intended, any alterations and further modifications in the illustrated embodiments, and any further applications of the principles of the application as illustrated therein as would normally occur to one skilled in the art to which the disclosure relates are contemplated herein.

Moreover, the schematic illustrations and descriptions provided herein are understood to be examples only, and components and operations may be combined or divided, and added or removed, as well as re-ordered in whole or part, unless stated explicitly to the contrary herein. Certain operations illustrated may be implemented by a computer executing a computer program product on a computer readable medium, where the computer program product comprises instructions causing the computer to execute one or more of the operations, or to issue commands to other devices to execute one or more of the operations.

In embodiments, a method of placing a proppant pack into a fracture formed in a subterranean formation comprises injecting a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage, wherein at least a portion of the well treatment fluid comprises a stabilized slurry stage and wherein the proppant-containing and stabilized slurry portions may be the same or different; injecting a destabilizing system into the fracture with the well treatment fluid to destabilize the stabilized slurry stage and form regions of consolidated proppant from the destabilized slurry stage; and placing a plurality of proppant clusters forming pillars from the consolidated proppant regions spaced apart by fluid flow channels from the formation through the fracture toward the wellbore.

In embodiments, the stabilized slurry may comprise a liquid phase, and the slurry destabilizing system may comprise a liquid-removing agent to remove fluid from the slurry, thereby forming regions of increased solids volume fraction (SVF). In embodiments, the liquid phase may comprise water, which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase, and additionally or alternatively, the liquid-removal agent may comprise a hydratable compound, a superabsorbent polymer or the like.

In embodiments, the method may further comprise sequentially injecting a first stage of the treatment fluid into the formation followed by a second stage of the treatment fluid, e.g., as an overflush, wherein the first and second stages have stage a different viscosities, or wherein the first and second stages have different specific gravities, or both, wherein the stabilized slurry comprises the proppant in the first stage, and wherein the destabilizing system comprises a crosslinkable material in the first stage, and a crosslinking agent in at least one of the first and second stages to crosslink the crosslinkable material in the pillars. In some embodiments, the first stage has a higher viscosity relative to the second stage to initiate viscous fingering. In additional or alternate embodiments, the second stage may have a density matching that of the first stage to mitigate any gravity effects; or may have a density different from the first stage to facilitate gravity-mediated fingering. A “matching” density or specific gravity as used herein is one where the difference in specific gravity or density between two fluids is less than 1 g/mL, and in some embodiments the density differences may be less than 0.9 g/mL, or less than 0.8 g/L, or less than 0.7 g/L, or less than 0.6 g/L, or less than 0.5 g/L, or less than 0.4 g/L, or less than 0.3 g/L, or less than 0.2 g/L, or less than 0.1 g/L, or less than 0.05 g/L.

In embodiments, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal. In embodiments, one of the first and second stages comprises a
pH control material to provide an alkaline pH and the other one of the first and second stages comprises the source of borate or polyvalent metal. In embodiments, the first stage may comprise the polysaccharide and the pH control agent and the second stage may comprise the source of borate or polyvalent metal. In embodiments, the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent. In embodiments, the first stage may comprise subproppant particles, have an SVF of 0.4 or more, 0.5 or more, 0.6 or more, e.g., 0.56-0.61, and comprise solids comprising a packed volume fraction (PVF) of 0.7 or more, and the second stage may be free of solids or have an SVF less than 0.5, or less than 0.4, or less than 0.3, or less than 0.2, or less than 0.1 or less than 0.05.

[0034] In embodiments, the method may comprise alternatingly injecting a plurality of pulsed first and second slugs of the well treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry which may be the same or different, and wherein the slurry destabilizing system comprises a reagent selectively present in one of the first and second slugs to selectively form the pillars from consolidated proppant packs and the channels from relatively permeable propellant packs. In embodiments, the first and second slugs may comprise a crosslinkable material and the reagent may be or include a solid particulated crosslinking agent. In embodiments, as mentioned above, the stabilized slurry may comprise a liquid phase, the reagent may be or include a liquid-removal agent to remove fluid from at least one of the slurries, the liquid phase may comprise water, which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase, and the reagent may be or include a hydratable material, superabsorbent polymer or the like.

[0035] In embodiments, the method may comprise stabilizing the well treatment fluid to form the stabilized slurry, wherein the stabilized slurry meets at least one of the following conditions:

[0036] (1) the slurry has a low-shear viscosity of at least 1 Pa-s (5.11 s$^{-1}$, 25$^\circ$C); or

[0037] (2) the slurry has a Herschel-Buckley (including Bingham plastic) yield stress (as determined in the manner described below) equal to or greater than 1 Pa; or

[0038] (3) the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or

[0039] (4) the depth of any free fluid at the end of a 72-hour static settling test condition or an 8 h @ 15 Hz/10 d-static dynamic settling test condition (4 hours vibration followed by 20 hours static followed by 4 hours vibration followed finally by 10 days of static conditions) is no more than 2% of total depth; or

[0040] (5) the apparent dynamic viscosity (25$^\circ$C, 170 s$^{-1}$) across column strata after the 72-hour static settling test condition or the 8 h @ 15 Hz/10 d-static dynamic settling test condition is no more than $\pm$-20% of the initial dynamic viscosity; or

[0041] (6) the slurry solids volume fraction (SVF) across the column strata below any free water layer after the 72-hour static settling test condition or the 8 h @ 15 Hz/10 d-static dynamic settling test condition is no more than 5% greater than the initial SVF; or

[0042] (7) the density across the column strata below any free water layer after the 72-hour static settling test condition or the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than 1% of the initial density.

[0043] In some embodiments, the slurry has a low-shear viscosity of at least 1 Pa-s (5.11 s$^{-1}$, 25$^\circ$C).

[0044] In some embodiments, the depth of any free fluid at the end of the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than 2% of total depth, the apparent dynamic viscosity (25$^\circ$C, 170 s$^{-1}$) across column strata after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than $\pm$-20% of the initial dynamic viscosity, the slurry solids volume fraction (SVF) across the column strata below any free water layer after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than $\pm$-5% of the initial SVF, and the density across the column strata below any free water layer after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than 1% of the initial density.

[0045] In embodiments, the stabilized slurry is formed by at least one of the following slurry stabilization operations: (1) introducing sufficient particles into the slurry or treatment fluid to increase the SVF of the treatment fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry or treatment fluid to at least 1 Pa-s (5.11 s$^{-1}$, 25$^\circ$C); (3) increasing a yield stress of the slurry or treatment fluid to at least 1 Pa; (4) increasing apparent viscosity of the slurry or treatment fluid to at least 50 mPa-s (170 s$^{-1}$, 25$^\circ$C); (5) introducing a multimodal solids phase into the slurry or treatment fluid; (6) introducing a solids phase having a PVF greater than 0.7 into the slurry or treatment fluid; (7) introducing into the slurry or treatment fluid a viscosifier selected from viscoelastic surfactants, e.g., in an amount ranging from 0.01 up to 7.2 g/L (60 ppt), and hydratable gelling agents, e.g., in an amount ranging from 0.01 up to 4.8 g/L (40 ppt) based on the volume of fluid phase; (8) introducing colloidal particles into the slurry or treatment fluid; (9) reducing a particle-fluid density delta to less than 1.6 g/mL (e.g., introducing particles having a specific gravity less than 2.65 g/mL, carrier fluid having a density greater than 1.05 g/mL or a combination thereof); (10) introducing particles into the slurry or treatment fluid having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into slurry or treatment fluid; and (12) combinations thereof. The techniques to stabilize particle settling in various embodiments herein may use any one, or a combination of any two or three, or all of these approaches, i.e., a manipulation of particle/fluid density, carrier fluid viscosity, solids fraction, yield stress, and/or may use another approach. The slurry stabilization operations may be separate or concurrent, e.g., introducing a single viscosifier may also increase low-shear viscosity, yield stress, apparent viscosity, etc., or alternatively or additionally with respect to a viscosifier, separate agents may be added to increase low-shear viscosity, yield stress and/or apparent viscosity.

[0046] In embodiments, the stabilized slurry is formed by at least two of the slurry stabilization operations, such as, for example, increasing the SVF and increasing the low-shear viscosity of the treatment fluid, and optionally one or more of increasing the yield stress, increasing the apparent viscosity, introducing the multimodal solids phase, introducing the solids phase having the PVF greater than 0.7, introducing the viscosifier, introducing the colloidal particles, reducing the particle-fluid density delta, introducing the particles having the aspect ratio of at least 6, introducing the ciliated or coated proppant or a combination thereof.

[0047] In embodiments, the stabilized slurry is formed by at least three of the slurry stabilization operations, such as, for
example, increasing the SVF, increasing the low-shear viscosity and introducing the multimodal solids phase, and optionally one or more of increasing the yield stress, increasing the apparent viscosity, introducing the solids phase having the PVF greater than 0.7, introducing the viscosifier, introducing the colloidal particles, reducing the particle-fluid density delta, introducing the particles having the aspect ratio of at least 6, introducing the ciliated or coated proppant or a combination thereof.

In embodiments, the stabilized slurry is formed by introducing the second stage fluid, and wherein the destabilizing system comprises the crosslinkable material in the pillars. As mentioned above, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal; one of the first and second stages may comprise a pH control material to provide an alkaline pH and the other one of the first and second stages may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the pH control agent; and/or the second stage may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent; and/or the first stage may comprise substituted polypropylene or an aliphatic hydrocarbon.

In embodiments, the system may comprise a pump system, such as, for example, tanks, pumps and/or valves as appropriate, to alternately inject a plurality of pulsed first and second slugs of the treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry, wherein the slurry destabilizing system comprises a reagent selectively present in at least one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs. In embodiments, the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent. As mentioned above, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal; one of the first and second stages may comprise a pH control material to provide an alkaline pH and the other one of the first and second stages may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the pH control agent; and/or the second stage may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent; and/or the first stage may comprise substituted polypropylene or an aliphatic hydrocarbon.

In embodiments, the system may comprise a pump system, such as, for example, tanks, pumps and/or valves as appropriate, to alternately inject a plurality of pulsed first and second slugs of the treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry, wherein the slurry destabilizing system comprises a reagent selectively present in at least one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs. In embodiments, the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent. As mentioned above, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal; one of the first and second stages may comprise a pH control material to provide an alkaline pH and the other one of the first and second stages may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the pH control agent; and/or the second stage may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent; and/or the first stage may comprise substituted polypropylene or an aliphatic hydrocarbon.

In embodiments, the system may comprise a pump system, such as, for example, tanks, pumps and/or valves as appropriate, to alternately inject a plurality of pulsed first and second slugs of the treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry, wherein the slurry destabilizing system comprises a reagent selectively present in at least one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs. In embodiments, the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent. As mentioned above, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal; one of the first and second stages may comprise a pH control material to provide an alkaline pH and the other one of the first and second stages may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the pH control agent; and/or the second stage may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent; and/or the first stage may comprise substituted polypropylene or an aliphatic hydrocarbon.

In embodiments, the system may comprise a pump system, such as, for example, tanks, pumps and/or valves as appropriate, to alternately inject a plurality of pulsed first and second slugs of the treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry, wherein the slurry destabilizing system comprises a reagent selectively present in at least one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs. In embodiments, the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent. As mentioned above, the crosslinkable material may be or include a polysaccharide, and the crosslinking agent may be or include a source of borate or a polyvalent metal; one of the first and second stages may comprise a pH control material to provide an alkaline pH and the other one of the first and second stages may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the pH control agent; and/or the second stage may comprise the source of borate or polyvalent metal; the first stage may comprise the polysaccharide and the source of borate or polyvalent metal and the second stage may comprise the pH control agent; and/or the first stage may comprise substituted polypropylene or an aliphatic hydrocarbon.
ppt), and hydratable gelling agents in an amount ranging from 0.01 up to 4.8 g/L (40 ppt) based on the volume of fluid phase; (8) colloidal particles; (9) a particle-fluid density delta less than 1.6 g/ml., (e.g., particles having a specific gravity less than 2.65 g/ml., carrier fluid having a density greater than 1.05 g/ml. or a combination thereof); (10) particles having an aspect ratio of at least 6; (11) ciliated or coated proppant; and (12) combinations thereof.

[0056] In some embodiments, the stabilized slurry comprises at least two of the stability indicia, such as for example, the SVF of at least 0.4 and the low-shear viscosity of at least 1 Pa-s (5.11 s–1, 25°C); and optionally one or more of the yield stress of at least 1 Pa, the apparent viscosity of at least 50 mPa-s (170 s–1, 25°C), the multimodal solids phase, the solids phase having a PVF greater than 0.7, the viscosifier, the colloidal particles, the particle-fluid density delta less than 1.6 g/ml., the particles having an aspect ratio of at least 6, the ciliated or coated proppant, or a combination thereof.

[0057] In some embodiments, the stabilized slurry comprises at least three of the stability indicia, such as for example, the SVF of at least 0.4, the low-shear viscosity of at least 1 Pa-s (5.11 s–1, 25°C) and the yield stress of at least 1 Pa; and optionally one or more of the apparent viscosity of at least 50 mPa-s (170 s–1, 25°C), the multimodal solids phase, the solids phase having a PVF greater than 0.7, the viscosifier, the colloidal particles, the particle-fluid density delta less than 1.6 g/ml., the particles having an aspect ratio of at least 6, the ciliated or coated proppant, or a combination thereof.

[0058] In some embodiments, the stabilized slurry comprises at least four of the stability indicia, such as for example, the SVF of at least 0.4, the low-shear viscosity of at least 1 Pa-s (5.11 s–1, 25°C), the yield stress of at least 1 Pa and the apparent viscosity of at least 50 mPa-s (170 s–1, 25°C); and optionally one or more of the multimodal solids phase, the solids phase having a PVF greater than 0.7, the viscosifier, the colloidal particles, the particle-fluid density delta less than 1.6 g/ml., the particles having an aspect ratio of at least 6, the ciliated or coated proppant, or a combination thereof.

[0059] In some embodiments, the stabilized slurry comprises at least five of the stability indicia, such as for example, the SVF of at least 0.4, the low-shear viscosity of at least 1 Pa-s (5.11 s–1, 25°C), the yield stress of at least 1 Pa, the apparent viscosity of at least 50 mPa-s (170 s–1, 25°C) and the multimodal solids phase, and optionally one or more of the solids phase having a PVF greater than 0.7, the viscosifier, colloidal particles, the particle-fluid density delta less than 1.6 g/ml., the particles having an aspect ratio of at least 6, the ciliated or coated proppant, or a combination thereof.

[0060] In some embodiments, the stabilized slurry comprises at least six of the stability indicia, such as for example, the SVF of at least 0.4, the low-shear viscosity of at least 1 Pa-s (5.11 s–1, 25°C), the yield stress of at least 1 Pa, the apparent viscosity of at least 50 mPa-s (170 s–1, 25°C), the multimodal solids phase and the solids phase having a PVF greater than 0.7, and optionally one or more of the viscosifier, colloidal particles, the particle-fluid density delta less than 1.6 g/ml., the particles having an aspect ratio of at least 6, the ciliated or coated proppant, or a combination thereof.

[0061] As used herein, the terms “treatment fluid” or “wellbore treatment fluid” are inclusive of “fracturing fluid” or “treatment slurry” and should be understood broadly. These may be or include a liquid, a solid, a gas, and combinations thereof, as will be appreciated by those skilled in the art. A treatment fluid may take the form of a solution, an emulsion, slurry, or any other form as will be appreciated by those skilled in the art. It should be understood that, although a substantial portion of the following detailed description may be provided in the context of oilfield hydraulic fracturing operations, other oilfield operations such as cementing, gravel packing, etc., or even non-oilfield well treatment operations, can utilize and benefit as well from the disclosure of the present treatment slurry.

[0062] As used herein, “slurry” refers to an optionally flowshear mixture of particles dispersed in a fluid carrier. The terms “flowable” or “pumpable” or “mixable” are used interchangeably herein and refer to a fluid or slurry that has either a yield stress less than 1000 Pa or low-shear viscosity less than 1000 Pa-s, and a dynamic apparent viscosity of less than 10 Pa-s (10,000 cP) at a shear rate 170 s–1, where yield stress, low-shear viscosity and dynamic apparent viscosity are measured at a temperature of 25°C, unless another temperature is specified explicitly or in context of use.

[0063] “Viscosity” as used herein unless otherwise indicated refers to the apparent dynamic viscosity of a fluid at a temperature of 25°C and shear rate of 170 s–1. “Low-shear viscosity” as used herein unless otherwise indicated refers to the apparent dynamic viscosity of a fluid at a temperature of 25°C and shear rate of 5.11 s–1. Yield stress and viscosity of the treatment fluid are evaluated at 25°C in a Fann 35 rheometer with an R15SF1 spindle, or an equivalent rheometer/spindle arrangement, with shear rate ramped up to 255 s–1 (300 rpm) and back down to 0, an average of the two readings at 2.55, 5.15, 8.5 and 255 s–1 (3, 6, 100, 200 and 300 rpm) recorded as the respective shear stress, the apparent dynamic viscosity is determined as the ratio of shear stress to shear rate (τ/γ) at γ=170 s–1, and the yield stress (τγ) (if any) is determined as the γ-intercept using a best fit of the Herschel-Buckley rheological model, γ = τγ/k + kγγ′, where τ is the shear stress, k is a constant, γ is the shear rate and n is the power law exponent. Where the power law exponent n is equal to 1, the Herschel-Buckley fluid is known as a Bingham fluid. Yield stress as used herein is synonymous with yield point and refers to the stress required to initiate flow in a Bingham plastic or Herschel-Buckley fluid system calculated as the γ-intercept in the manner described herein. A “yield stress fluid” refers to a Herschel-Buckley fluid system, including Bingham plastics or another fluid system in which an applied non-zero stress as calculated in the manner described herein is required to initiate fluid flow.

[0064] The following conventions with respect to slurry terms are intended herein unless otherwise indicated explicitly or implicitly by context. “Treatment fluid” or “fluid” (in context) refers to the entire treatment fluid, including any proppant, subproppant particles, liquid, gas etc. “Whole fluid,” “total fluid” and “base fluid” are used herein to refer to the fluid phase plus any subproppant particles dispersed therein, but exclusive of proppant particles. “Carrier,” “fluid phase” or “liquid phase” refer to the fluid or liquid that is present, which may comprise a continuous phase and optionally one or more discontinuous fluid phases dispersed in the continuous phase, including any solutes, thickeners or colloidal particles only, exclusive of other solid phase particles; reference to “water” in the slurry refers only to water and excludes any particles, solutes, thickeners, colloidal particles, etc.; reference to “aqueous phase” refers to a carrier phase comprised predominantly of water, which may be a continuous or dispersed phase. As used herein the terms “liquid” or
“liquid phase” encompass both liquids perse and supercritical fluids, including any solutes dissolved therein.

[0065] The measurement or determination of the viscosity of the liquid phase (as opposed to the treatment fluid or base fluid) may be based on a direct measurement of the solids-free liquid, or a calculation or correlation based on a measurement (s) of the characteristics or properties of the liquid containing the solids, or a measurement of the solids-containing liquid using a technique where the determination of viscosity is not affected by the presence of the solids. As used herein, solids-free for the purposes of determining the viscosity of the liquid phase means the absence of non-coagulant particles larger than 1 micron such that the particles do not affect the viscosity determination, but in the presence of any submicron or colloidal particles that may be present to thicken and/or form a gel with the liquid, i.e., in the presence of ultrafine particles that can function as a thickening agent. In some embodiments, a “low viscosity liquid phase” means a viscosity less than about 300 mPa s measured without any solids greater than 1 micron at 170 s⁻¹ and 25°C.

[0066] In some embodiments, the treatment fluid may include a continuous fluid phase, also referred to as an external phase, and a discontinuous phase(s), also referred to as an internal phase(s), which may be a fluid (liquid or gas) in the case of an emulsion, foam or energized fluid, or which may be a solid in the case of a slurry. The continuous fluid phase may be any matter that is substantially continuous under a given condition. Examples of the continuous fluid phase include, but are not limited to, water, hydrocarbon, gas, liquefied gas, etc., which may include solutes, e.g. the fluid phase may be a brine, and/or may include a brine or other solution(s). In some embodiments, the fluid phase may optionally include a viscosifying and/or yield point agent and/or a portion of the total amount of viscosifying and/or yield point agent present. Some non-limiting examples of the fluid phase(s) include hydratable gels (e.g., gels containing polysaccharides such as guar(s), hydroxypropyl guar, carboxymethyl guar, carboxymethylhydroxypropyl guar, and the like), xanthan, diutan, hydroxyethylcellulose, polyvinyl alcohol, other hydratable polymers, colloids, etc), a cross-linked hydratable gel, a viscosify acid (e.g., gel-based), an emulsified acid (e.g., oil outer phase), an energized fluid (e.g., an N₂ or CO₂ based foam), a viscoelastic surfactant (VES) viscoelastic fluid, and an oil-based fluid including a gelled, foamed, or otherwise viscoelastic oil.

[0067] The discontinuous phase if present in the treatment fluid may be any particles (including fluid droplets) that are suspended or otherwise dispersed in the continuous phase in a discontinuous manner. In this respect, the discontinuous phase can also be referred to, collectively, as “particle” or “particulate” which may be used interchangeably. As used herein, the term “particle” should be construed broadly. For example, in some embodiments, the particle(s) of the current application are solid such as proppant, sands, ceramics, crystals, salts, etc.; however, in some other embodiments, the particle(s) can be liquid, gas, foam, emulsified droplets, etc. Moreover, in some embodiments, the particle(s) of the current application are substantially stable and do not change shape or form over an extended period of time, temperature, or pressure; in some other embodiments, the particle(s) of the current application are degradable, dissolvable, deformable, meltable, sublimeable, or otherwise capable of being changed in shape, state, or structure.

[0068] In certain embodiments, the particle(s), which may be proppant or subproppant, is substantially round and spherical. In some certain embodiments, the particle(s) is not substantially spherical and/or round, e.g., it can have varying degrees of sphericity and roundness, according to the API RP-60 sphericity and roundness index. For example, the particle(s) may have an aspect ratio, defined as the ratio of the longest dimension of the particle to the shortest dimension of the particle, of more than 2, 3, 4, 5 or 6. Examples of such non-spherical particles include, but are not limited to, fibers, flakes, discs, rods, stars, etc. All such variations should be considered within the scope of the current application.

[0069] The particles in the slurry in various embodiments may be multimodal. As used herein multimodal refers to a plurality of particle sizes or modes which each has a distinct size or particle size distribution, e.g., proppant and fines. As used herein, the terms distinct particle sizes, distinct particle size distribution, or multi-modes or multimodal mean that each of the plurality of particles has a unique volume-averaged particle size distribution (PSD) mode. That is, statistically, the particle size distributions of different particles appear as distinct peaks (or “modes”) in a continuous probability distribution function. For example, a mixture of two particles having normal distribution of particle sizes with similar variability is considered a bimodal mixture if their respective means differ by more than the sum of their respective standard deviations, and/or if their respective means differ by a statistically significant amount. In certain embodiments, the particles contain a bimodal mixture of two or more particles; in certain other embodiments, the particles contain a trimodal mixture of three particles; in certain additional embodiments, the particles contain a tetramodal mixture of four particles; in certain further embodiments, the particles contain a pentamodal mixture of five particles, and so on. Representative references disclosing multimodal particle mixtures include U.S. Pat. No. 5,518,996, U.S. Pat. No. 7,784,541, U.S. Pat. No. 7,789,146, U.S. Pat. No. 8,008,234, U.S. Pat. No. 8,119,574, U.S. Pat. No. 8,210,249, U.S. Pat. No. 2010/0306688, US 2012/000641, US 2012/0138296, US 2012/0132421, US 2012/0111563, WO 2012/054456, US 2012/050254, US 2012/0305254, US 2012/032421, PCT/ RU/2011/000971 and U.S. Ser. No. 13/415,025, each of which are hereby incorporated herein by reference.

[0070] “Solids” and “solids volume” refer to all solids present in the slurry, including proppant and subproppant particles, including particulate thickeners such as colloids and submicron particles. “Solids-free” and similar terms generally exclude proppant and subproppant particles, except particulate thickeners such as colloids for the purposes of determining the viscosity of a “solids-free” fluid. “Proppant” refers to particulates that are used in well work-overs and treatments, such as hydraulic fracturing operations, to hold fractures open following the treatment, of a particle size mode or modes in the slurry having a weight average mean particle size greater than or equal to about 100 microns, e.g., 140 mesh particles correspond to a size of 105 microns, unless a different proppant size is indicated in the claim or a smaller proppant size is indicated in a claim depending therefrom. “Gravel” refers to particles used in gravel packing, and the term is synonymous with proppant as used herein. “Subproppant” or “subproppant” refers to particles or particle size or mode (including colloidal and submicron particles) having a smaller size than the proppant mode(s); references to “proppant” exclude subproppant particles and vice versa. In some
embodiments, the sub-proppant mode or modes each have a weight average mean particle size less than or equal to one-half of the weight average mean particle size of a smallest one of the proppant modes, e.g., a suspensive/stabilizing mode.

[0071] The proppant, when present, can be naturally occurring materials, such as sand grains. The proppant, when present, can also be man-made or specially engineered, such as coated (including resin-coated) sand, modulus of various nuts, high-strength ceramic materials like sintered bauxite, etc. In some embodiments, the proppant of the current application, when present, has a density greater than 2.45 g/ml., e.g., 2.5-2.8 g/ml., such as sand, ceramic, sintered bauxite or resin coated proppant. In some embodiments, the proppant of the current application, when present, has a density less than or equal to 2.45 g/ml., such as less than about 1.60 g/ml., less than about 1.50 g/ml., less than about 1.40 g/ml., less than about 1.30 g/ml., less than about 1.20 g/ml., less than 1.10 g/ml., or less than 1.00 g/ml., such as light/ultralight proppant from various manufacturers, e.g., hollow proppant.

[0072] In some embodiments, the treatment fluid comprises an apparent specific gravity greater than 1.3, greater than 1.4, greater than 1.5, greater than 1.6, greater than 1.7, greater than 1.8, greater than 1.9, greater than 2, greater than 2.1, greater than 2.2, greater than 2.3, greater than 2.4, greater than 2.5, greater than 2.6, greater than 2.7, greater than 2.8, greater than 2.9, or greater than 3. The treatment fluid density can be selected by selecting the specific gravity and amount of the dispersed solids and/or adding a weighting solute to the aqueous phase, such as, for example, a compatible organic or mineral salt. In some embodiments, the aqueous or other liquid phase may have a specific gravity greater than 1, greater than 1.05, greater than 1.1, greater than 1.2, greater than 1.3, greater than 1.4, greater than 1.5, greater than 1.6, greater than 1.7, greater than 1.8, greater than 1.9, greater than 2, greater than 2.1, greater than 2.2, greater than 2.3, greater than 2.4, greater than 2.5, greater than 2.6, greater than 2.7, greater than 2.8, greater than 2.9, or greater than 3, etc. In some embodiments, the aqueous or other liquid phase may have a specific gravity less than 1. In embodiments, the weight of the treatment fluid can provide additional hydrostatic head pressurization in the wellbore at the perforations or other fracture location, and can also facilitate stability by lessening the density differences between the larger solids and the whole remaining fluid. In other embodiments, a low density proppant may be used in the treatment, for example, lightweight proppant (apparent specific gravity less than 2.65) having a density less than or equal to 2.5 g/ml., such as less than about 2 g/ml., less than about 1.8 g/ml., less than about 1.6 g/ml., less than about 1.4 g/ml., less than about 1.2 g/ml., less than 1.1 g/ml., or less than 1 g/ml. In other embodiments, the proppant or other particles in the slurry may have a specific gravity greater than 2.6, greater than 2.7, greater than 2.8, greater than 2.9, greater than 3, etc.

[0073] “Stable” or “stabilized” or similar terms refer to a stabilized treatment slurry (STS) wherein gravitational settling of the particles is inhibited such that no or minimal free liquid is formed, and/or there is no or minimal rheological variation among strata at different depths in the STS, and/or the slurry may generally be regarded as stable over the duration of expected STS storage and use conditions, e.g., an STS that passes a stability test or an equivalent thereof. In certain embodiments, stability can be evaluated following different settling conditions, such as for example static under gravity alone, or dynamic under a vibratory influence, or dynamic-static conditions employing at least one dynamic settling condition followed and/or preceded by at least one static settling condition.

[0074] The static settling test conditions can include gravity settling for a specified period, e.g., 24 hours, 48 hours, 72 hours, or the like, which are generally referred to with the respective shorthand notation “24 h-static”, “48 h-static” or “72 h-static”. Dynamic settling test conditions generally indicate the vibratory frequency and duration, e.g., 4 h@15 Hz (4 hours at 15 Hz), 8 h@5 Hz (8 hours at 5 Hz), or the like. Dynamic settling test conditions are at a vibratory amplitude of 1 mm vertical displacement unless otherwise indicated. Dynamic-static settling test conditions will indicate the settling history preceding analysis including the total duration of vibration and the final period of static conditions, e.g., 4 h@15 Hz/20 h-static refers to 4 hours vibration followed by 20 hours static, or 8 h@15 Hz/10 d-static refers to 8 hours total vibration, e.g., 4 hours vibration followed by 20 hours static followed by 4 hours vibration, followed by 10 days of static conditions. In the absence of a contrary indication, the designation “8 h@15 Hz/10 d-static” refers to the test conditions of 4 hours vibration, followed by 20 hours static followed by 4 hours vibration, followed by 10 days of static conditions. In the absence of specified settling conditions, the settling condition is 72 hours static. The stability settling and test conditions are at 25° C. unless otherwise specified.

[0075] In certain embodiments, one stability test is referred to herein as the “8 h@15 Hz/10 d-static STS stability test”, wherein a slurry sample is evaluated in a rheometer at the beginning of the test and compared against different strata of a slurry sample placed and sealed in a 152 mm (6 in.) diameter vertical gravitational settling column filled to a depth of 2.13 m (7 ft), vibrated at 15 Hz with a 1 mm amplitude (vertical displacement) two 4-hour periods the first and second settling days, and thereafter maintained in a static condition for 10 days (12 days total settling time). The 15 Hz/1 mm amplitude condition in this test is selected to correspond to surface transportation and/or storage conditions prior to the well treatment. At the end of the settling period the depth of any free water at the top of the column is measured, and samples obtained, in order from the top sampling port down to the bottom, through 25.4-mm sampling ports located on the settling column at 190 mm (7.5"), 140 mm (5.5"), 94 mm (3.7") and 33 mm (1.3"), and rheologically evaluated for viscosity and yield stress as described above.

[0076] As mentioned above, various slurry stabilizing operations may be employed to obtain one or more of the slurry stabilization indicia. For example, decreasing the density difference between the particle and the carrier fluid may be done in embodiments by employing porous particles, including particles with an internal porosity, i.e., hollow particles. However, the porosity may also have a direct influence on the mechanical properties of the particle, e.g., the elastic modulus, which may also decrease significantly with an increase in porosity. In certain embodiments employing particle porosity, care should be taken so that the crush strength of the particles exceeds the maximum expected stress for the particle, e.g., in the embodiments of proppants placed in a fracture the overburden stress of the subterranean formation in which it is to be used should not exceed the crush strength of the proppants.

[0077] In embodiments, yield stress fluids and/or fluids having a high low-shear viscosity are used to retard the
motion of the carrier fluid and thus retard particle settling. The gravitational stress exerted by the particle at rest or descending slowly on the fluid beneath it must generally exceed the yield stress of the fluid to initiate fluid flow and thus settling onset, or just after settling onset it must exceed the low-shear resistance to flow. For a single particle of density 2.7 g/mL and diameter of 600 μm settling in a yield stress fluid phase of 1 g/mL, the critical fluid yield stress, i.e., the minimum yield stress to prevent settling onset, is in this example is 1 Pa. The critical fluid yield stress might be higher for larger particles, including particles with size enhancement due to particle clustering, aggregation or the like.

[0078] Increasing carrier fluid viscosity in a Newtonian fluid also proportionally increases the resistance of the carrier fluid motion. In some embodiments, the fluid carrier has a lower limit of low-shear viscosity, determined at 5.11 s⁻¹ and 25°C, of at least about 1 Pa-s, or at least about 5 Pa-s, or at least about 10 Pa-s, or at least about 25 Pa-s, or at least about 50 Pa-s, or at least about 75 Pa-s, or at least about 100 Pa-s, or at least about 150 Pa-s. In some embodiments, the fluid carrier has a lower limit of apparent dynamic viscosity, determined at 170 s⁻¹ and 25°C, of at least about 0.1 mPa-s, or at least about 1 mPa-s, or at least about 10 mPa-s, or at least about 25 mPa-s, or at least about 50 mPa-s, or at least about 75 mPa-s, or at least about 100 mPa-s, or at least about 150 mPa-s. A disadvantage of increasing the viscosity is that as the viscosity increases, the friction pressure for pumping the slurry generally increases as well. In some embodiments, the fluid carrier has an upper limit of low-shear viscosity, determined at 5.11 s⁻¹ and 25°C, of less than about 300 Pa-s, or less than about 150 Pa-s, or less than about 100 Pa-s, or less than about 75 Pa-s, or less than about 50 Pa-s, or less than about 25 Pa-s, or less than about 10 Pa-s. In some embodiments, the fluid carrier has an upper limit of apparent dynamic viscosity, determined at 170 s⁻¹ and 25°C, of less than about 300 mPa-s, or less than about 150 mPa-s, or less than about 100 mPa-s, or less than about 75 mPa-s, or less than about 50 mPa-s, or less than about 25 mPa-s, or less than about 10 mPa-s. In embodiments, the low-shear and/or apparent dynamic fluid phase viscosity ranges from any respective lower limit to any respective higher upper limit.

[0079] In some embodiments, an agent may both viscosify and impart yield stress characteristics, and in further embodiments may also function as a friction reducer to reduce friction pressure losses in pumping the treatment fluid. In embodiments, the liquid phase is essentially free of viscosifier or comprises a viscosifier in an amount ranging from 0.01 up to 2.4 g/L (0.08-20 lb/1000 gals) of the fluid phase. The viscosifier can be a viscoelastic surfactant (VES) or a hydratable gelling agent such as a polysaccharide, which may be crosslinked. In embodiments, the liquid phase comprises a hydratable gelling agent in an amount ranging from 0.01 up to 4.8 g/L (0.08-40 lb/1000 gals) of the fluid phase, or a VES in an amount ranging from 0.01 up to 7.2 g/L (0.08-60 lb/1000 gals) of the fluid phase. When using viscosifiers and/or yield stress fluids, it may be useful to consider the need for and if necessary implement a clean-up procedure, i.e., removal or inactivation of the viscosifier and/or yield stress fluid during or following the treatment procedure, since fluids with viscosifiers and/or yield stresses may present clean up difficulties in some situations or if not used correctly. In certain embodiments, clean up can be effected using a breaker(s). In some embodiments, the slurry is stabilized for storage and/or pumping or other use at the surface conditions, and clean-up is achieved downhole at a later time and at a higher temperature, e.g., for some formations, the temperature difference between surface and downhole can be significant and useful for triggering degradation of the viscosifier, the particles, a yield stress agent or characteristic, and/or a breaker. Thus in some embodiments, breakers that are either temperature sensitive or time sensitive, either through delayed action breakers or delay in mixing the breaker into the slurry, can be useful.

[0080] In certain embodiments, the fluid may be stabilized by introducing colloidal particles into the treatment fluid, such as, for example, colloidal silica, which may function as a gelant and/or thickener.

[0081] In addition or as an alternative to increasing the viscosity of the carrier fluid (with or without density manipulation), increasing the volume fraction of the particles in the treatment fluid can also hinder movement of the carrier fluid. Where the particles are not deformable, the particles interfere with the flow of the fluid around the settling particle to cause hindered settling. The addition of a large volume fraction of particles can be complicated, however, by increasing fluid viscosity and pumping pressure, and increasing the risk of loss of fluidity of the slurry in the event of carrier fluid losses. In some embodiments, the treatment fluid has a lower limit of apparent dynamic viscosity, determined at 170 s⁻¹ and 25°C, of at least about 1 mPa-s, or at least about 10 mPa-s, or at least about 25 mPa-s, or at least about 50 mPa-s, or at least about 75 mPa-s, or at least about 150 mPa-s. A disadvantage of increasing the viscosity is that as the viscosity increases, the friction pressure for pumping the slurry generally increases as well. In some embodiments, the fluid carrier has an upper limit of low-shear viscosity, determined at 5.11 s⁻¹ and 25°C, of less than about 300 Pa-s, or less than about 150 Pa-s, or less than about 100 Pa-s, or less than about 75 Pa-s, or less than about 50 Pa-s, or less than about 25 Pa-s, or less than about 10 Pa-s. In some embodiments, the fluid carrier has an upper limit of apparent dynamic viscosity, determined at 170 s⁻¹ and 25°C, of less than about 300 mPa-s, or less than about 150 mPa-s, or less than about 100 mPa-s, or less than about 75 mPa-s, or less than about 50 mPa-s, or less than about 25 mPa-s, or less than about 10 mPa-s. In embodiments, the low-shear and/or apparent dynamic fluid phase viscosity ranges from any respective lower limit to any respective higher upper limit.

[0082] In embodiments, the treatment fluid may be stabilized by introducing sufficient particles into the treatment fluid to increase the SVF of the treatment fluid, e.g., to at least 0.5. In a powder or particulated medium, the packed volume fraction (PVF) is defined as the volume of space occupied by the particles (the absolute volume) divided by the bulk volume, i.e., the total volume of the particles plus the void space between them:

$$\text{PVF} = \frac{\text{Particle volume}}{\text{Particle volume} + \text{Non-particle Volume}}$$

For the purposes of calculating PVF and SVF herein, the particle volume includes the volume of any colloidal and/or submicron particles.

[0083] Here, the porosity, \( \phi \), is the void fraction of the powder pack. Unless otherwise specified the PVF of a particulated medium is determined in the absence of overburden or other compressive force that would deform the packed solids. The packing of particles (in the absence of overburden) is a purely geometrical phenomenon. Therefore, the PVF depends only on the size and the shape of particles. The most ordered arrangement of monodisperse spheres (spheres with exactly the same size in a compact hexagonal packing) has a PVF of 0.74. However, such highly ordered arrangements of particles rarely occur in industrial operations. Rather, a somewhat random packing of particles is prevalent in oilfield treatment. Unless otherwise specified, particle packing in the current application means random packing of the particles. A random packing of the same spheres has a PVF of 0.64. In other words, the randomly packed particles
occupy 64% of the bulk volume, and the void space occupies 36% of the bulk volume. A higher PVF can be achieved by preparing blends of particles that have more than one particle size and/or a range(s) of particle sizes. The smaller particles can fit in the void spaces between the larger ones.

[0084] The PVF in embodiments can therefore be increased by using a multimodal particle mixture, for example, coarse, medium, and fine particles in specific volume ratios, where the fine particles can fit in the void spaces between the medium-size particles, and the medium size particles can fit in the void space between the coarse particles. For some embodiments of two consecutive size classes or modes, the ratio between the mean particle diameters \(d_{\text{m}}\) of each mode may be between 7 and 10. In such cases, the PVF can increase up to 0.95 in some embodiments. By blending coarse particles (such as proppant) with other particles selected to increase the PVF, only a minimum amount of fluid phase (such as water) is needed to render the treatment fluid pumpable. Such concentrated suspensions (i.e., slurry) tend to behave as a porous solid and may shrink under the force of gravity. This is a hindered settling phenomenon as discussed above and, as mentioned, the extent of solids-like behavior generally increases with the slurry solid volume fraction (SVF), which is given as:

\[
\text{SVF} = \frac{\text{Particle volume (Particle volume + Liquid volume)}}
\]

[0085] It follows that proppant or other large particle mode settling in multimodal embodiments can if desired be minimized independently of the viscosity of the continuous phase. Therefore, in some embodiments little or no viscosifier and/or yield stress agent, e.g., a gelling agent, is required to inhibit settling and achieve particle transport, such as, for example, less than 0.75 g/L, less than 0.2 g/L, less than 0.06 g/L, less than 0.3 g/L, less than 0.15 g/L, less than 0.08 g/L, less than 0.04 g/L, less than 0.02 g/L or less than 0.1 g/L of viscosifier may be present in the STS.

[0086] It is helpful for an understanding of the current application to consider the amounts of particles present in the slurries of various embodiments of the treatment fluid. The minimum amount of fluid phase necessary to make a homogeneous slurry blend is the amount required to just fill all the void space in the PVF with the continuous phase, i.e., when SVF = PVF. However, this blend may not be flowable since all the solids and liquid may be locked in place with no room for slipping and mobility. In flowable systems, the SVF may be lower than PVF, e.g., SVF/PVF = 0.99. In this condition, in a stabilized treatment slurry, essentially all the voids are filled with excess liquid to increase the spacing between particles so that the particles can roll or flow past each other. In some embodiments, the higher the PVF, the lower the SVF/PVF ratio should be to obtain a flowable slurry.

[0087] FIG. 1 shows a slurry state progression chart for a system 600 having a particle mix with added fluid phase. The first fluid 602 does not have enough liquid added to fill the pore spaces of the particles, or in other words the SVF/PVF is greater than 1.0. The first fluid 602 is not flowable. The second fluid 604 has just enough fluid phase to fill the pore spaces of the particles, or in other words the SVF/PVF is equal to 1.0. Testing determines whether the second fluid 604 is flowable and/or pumpable, but a fluid with an SVF/PVF of 1.0 is generally not flowable or barely flowable due to an excessive apparent viscosity and/or yield stress. The third fluid 606 has slightly more fluid phase than is required to fill the pore spaces of the particles, or in other words the SVF/PVF is just less than 1.0. A range of SVF/PVF values less than 1.0 will generally be flowable and/or pumpable or mixable, and if it does not contain too much fluid phase (and/or contains an added viscosifier) the third fluid 606 is stable. The values of the range of SVF/PVF values that are pumpable, flowable, mixable, and/or stable are dependent upon, without limitation, the specific particle mixture, fluid phase viscosity, the PVF of the particles, and the density of the particles. Simple laboratory testing of the sort ordinarily performed for fluids before fracturing treatments can readily determine the stability (e.g., the STS stability test as described herein) and flowability (e.g., apparent dynamic viscosity at 170 s\(^{-1}\) and 25° C. of less than about 10,000 mPa-s).

[0088] The fourth fluid 608 shown in FIG. 1 has more fluid phase than the third fluid 606, to the point where the fourth fluid 608 is flowable but is not stabilized and settles, forming a layer of free fluid phase at the top (or bottom, depending upon the densities of the particles in the fourth fluid 608). The amount of free fluid phase and the settling time over which the free fluid phase develops before the fluid is considered unstable are parameters that depend upon the specific circumstances of a treatment, as noted above. For example, if the settling time over which the free liquid develops is greater than a planned treatment time, then in one example the fluid would be considered stable. Other factors, without limitation, that may affect whether a particular fluid remains stable include the amount of time for settling and flow regimes (e.g., laminar, turbulent, Reynolds number ranges, etc.) of the fluid flowing in a flow passage of interest or in an agitated vessel, e.g., the amount of time and flow regimes of the fluid flowing in the wellbore, fracture, etc., and/or the amount of fluid leakoff occurring in the wellbore, fracture, etc. A fluid that is stable for one fracturing treatment may be unstable for a second fracturing treatment. The determination that a fluid is stable at particular conditions may be an iterative determination based upon initial estimates and subsequent modeling results. In some embodiments, the stabilized treatment fluid passes the STS test described herein.

[0089] FIG. 2 shows a data set 700 of various essentially Newtonian fluids without any added viscosifiers and without any yield stress, which were tested for the progression of slurry state on a plot of SVF/PVF as a function of PVF. The fluid phase in the experiments was water and the solids had specific gravity 2.6 g/ml. Data points 702 indicated with a triangle were values that had free water in the slurry, data points 704 indicated with a circle were slurries fluids that were mixable without excessive free water, and data points 706 indicated with a diamond were not easily mixable liquid-solid mixtures. The data set 700 includes fluids prepared having a number of discrete PVF values, with liquid added until the mixture transitions from not mixable to a slurrible fluid, and then further progresses to a fluid having excess settling. At an example for a solids mixture with a PVF value near PVF = 0.83, it was observed that around an SVF/PVF value of 0.95 the fluid transitions from an unmixable mixture to a slurrible fluid. At around an SVF/PVF of 0.7, the fluid transitions from a stable slurry to an unstable fluid having excessive settling. It can be seen from the data set 700 that the compositions can be defined approximately into a non-mixable region 710, a slurrible region 712, and a settling region 714.

[0090] FIG. 2 shows the useful range of SVF and PVF for slurries in embodiments without gelling agents. In some embodiments, the SVF is less than the PVF, or the ratio
SVF/PVF is within the range from about 0.6 to about 0.95 or about 0.98. Where the liquid phase has a viscosity less than 10 mPa-s or where the treatment fluid is water essentially free of thickeners, in some embodiments PVF is greater than 0.72 and a ratio of SVF/PVF is greater than about 1-2.14* (PVF−0.72) for stability (non-settling). Where the PVF is greater than 0.81, in some embodiments a ratio of SVF/PVF may be less than 1-2.14* (PVF−0.81) for mixability (flowability). Adding thickening or suspending agents, or solids that perform this function such as calcium carbonate or colloids, i.e., to increase viscosity and/or impart a yield stress, in some embodiments allows fluids otherwise in the setting area 714 embodiments where (SVF/PVF is less than or equal to about 1-2.14* (PVF−0.72)) to also be useful as an STS or in applications where a non-settling, slurrable/mixable slurry is beneficial, e.g., where the treatment fluid has a viscosity greater than 10 mPa-s, greater than 25 mPa-s, greater than 50 mPa-s, greater than 75 mPa-s, greater than 100 mPa-s, greater than 150 mPa-s, or greater than 300 mPa-s; and/or a yield stress greater than 0.1 Pa, greater than 0.5 Pa, greater than 1 Pa, greater than 10 Pa or greater than 20 Pa.

[0091] Introducing high-aspect ratio particles into the treatment fluid, e.g., particles having an aspect ratio of at least 6, represents additional or alternative embodiments for stabilizing the treatment fluid. Examples of such non-spherical particles include, but are not limited to, fibers, flakes, discs, rods, stars, etc., as described in, for example, U.S. Pat. No. 7,275,596, US 2008/0196896, which are hereby incorporated herein by reference. In certain embodiments, introducing ciliated or coated proppant into the treatment fluid may stabilize or help stabilize the treatment fluid.

[0092] Proppant or other particles coated with a hydrophilic polymer can make the particles behave like larger particles and/or more tacky particles in an aqueous medium. The hydrophilic coating on a molecular scale may resemble ciliates, i.e., proppant particles to which hairlike projections have been attached to or formed on the surfaces thereof. Herein, hydrophilically coated proppant particles are referred to as “ciliated or coated proppant.” Hydrophilically coated proppants and methods of producing them are described, for example, in WO 2011-050046, U.S. Pat. No. 5,905,468, U.S. Pat. No. 8,227,026 and U.S. Pat. No. 8,234,072, which are hereby incorporated herein by reference.

[0093] In some additional or alternative embodiment, the STS system may have the benefit that the smaller particles in the voids of the larger particles act as slip additives like mini-ball bearings, allowing the particles to roll past each other without any requirement for relatively large spaces between particles. This property can be demonstrated in some embodiments by the flow of the STS through a relatively small slot orifice with respect to the maximum diameter of the largest particle mode of the STS, e.g., a slot orifice less than 6 times the largest particle diameter, without bridging at the slot, i.e., the slurry flowed out of the slot has an SVF that is at least 90% of the SVF of the STS supplied to the slot. In contrast, the slickwater technique requires a ratio of perforation diameter to proppant diameter of at least 6, and additional enlargement for added safety to avoid screen out usually dictates a ratio of at least 8 or 10 and does not allow high proppant loadings.

[0094] In embodiments, the flowability of the STS through narrow flow passages such as perforations and fractures is similarly facilitated, allowing a smaller ratio of perforation diameter and/or fracture height to proppant size that still provides transport of the proppant through the perforation and/or to the tip of the fracture, i.e., improved flowability of the proppant in the fracture, e.g., in relatively narrow fracture widths, and improved penetration of the proppant-filled fracture extending away from the wellbore into the formation. These embodiments provide a relatively longer proppant-filled fracture prior to screenout relative to slickwater or high viscosity fluid treatments.

[0095] As used herein, the “minimum slot flow test ratio” refers to a test wherein an approximately 100 ml slurry specimen is loaded into a fluid loss cell with a bottom slot opened to allow the test slurry to come out, with the fluid pushed by a piston using water or another hydraulic fluid supplied with an ISCO pump or equivalent at a rate of 20 ml/min, wherein a slot at the bottom of the cell can be adjusted to different openings at a ratio of slot width to largest particle mode diameter less than 6, and wherein the maximum slot flow test ratio is taken as the lowest ratio observed at which 50 vol % or more of the slurry specimen flows through the slot before bridging and a pressure increase to the maximum gauge pressure occurs. In some embodiments, the STS has a minimum slot flow test ratio less than 6, or less than 5, or less than 4, or less than 3, or a range of 2 to 6, or a range of 3 to 5.

[0096] Because of the relatively low water content (high SVF) of some embodiments of the STS, fluid loss from the STS may be a concern where flowability is important and SVF should at least be held lower than PVF, or considerably lower than PVF in some other embodiments. In conventional hydraulic fracturing treatments, there are two main reasons that a high volume of fluid and high amount of pumping energy have to be used, namely proppant transport and fluid loss. To carry the proppant to a distant location in a fracture, the treatment fluid has to be sufficiently turbulent (slickwater) or viscous (gel fluid). Even so, only a low concentration of proppant is typically included in the treatment fluid to avoid settling and/or screen out. Moreover, when a fluid is pumped into a formation to initiate or propagate a fracture, the fluid pressure will be higher than the formation pressure, and the liquid in the treatment fluid is constantly leaking off into the formation. This is especially the case for slickwater operations. The fracture creation is a balance between the fluid loss and new volume created. As used herein, “fracture creation” encompasses either or both the initiation of fractures and the propagation or growth thereof. If the liquid injection rate is lower than the fluid loss rate, the fracture cannot be grown and becomes packed off. Therefore, traditional hydraulic fracturing operations are not efficient in creating fractures in the formation.

[0097] In some embodiments of the STS herein where the SVF is high, even a small loss of carrier fluid may result in a loss of flowability of the treatment fluid, and in some embodiments it is therefore undertaken to guard against excessive fluid loss from the treatment fluid, at least until the fluid and/or proppant reaches its ultimate destination. In embodiments, the STS may have an excellent tendency to retain fluid and thereby maintain flowability, i.e., it has a low leakoff rate into a porous or permeable surface with which it may be in contact. According to some embodiments of the current application, the treatment fluid is formulated to have very good leakoff control characteristics, i.e., fluid retention to maintain flowability. The good leak control can be achieved by including a leakoff control system in the treatment fluid of the current application, which may comprise one or more of high
viscosity, low viscosity, a fluid loss control agent, selective construction of a multi-modal particle system in a multimodal fluid (MMF) or in a stabilized multimodal fluid (SMMF), or the like, or any combination thereof.

As discussed in the examples below and as shown in FIG. 3, the leakoff of embodiments of a treatment fluid of the current application was an order of magnitude less than that of a conventional crosslinked fluid. It should be noted that the leakoff characteristic of a treatment fluid is dependent on the permeability of the formation to be treated. Therefore, a treatment fluid that forms a low permeability filter cake with good leakoff characteristic for one formation may or may not be a treatment fluid with good leakoff for another formation. Conversely, certain embodiments of the treatment fluids of the current application form low permeability filter cakes that have substantially superior leakoff characteristics such that they are not dependent on the substrate permeability provided the substrate permeability is higher than a certain minimum, e.g., at least 1 mD. 

In certain embodiments herein, the STS comprises a packed volume fraction (PVF) greater than a slurry solids volume fraction (SVF), and has a spurt loss value (Vspurt) less than 10 vol % of a fluid phase of the stabilized treatment fluid or less than 50 vol % of an excess fluid phase (Vspurt=0.5*(PVF−SVF)), where the “excess fluid phase” is taken as the amount of fluid in excess of the amount present at the condition SVF=PVF, i.e., excess fluid phase=PVF−SVF).

In some embodiments the treatment fluid comprises an STS also having a very low leakoff rate. For example, the total leakoff coefficient may be about 3×10⁻⁹ m/min⁻¹/² (10⁻⁴ ft/min⁻¹/²) or less, or about 3×10⁻⁹ m/min⁻¹/² (10⁻⁴ ft/min⁻¹/²) or less. As herein, Vspurt and the total leakoff coefficient Cw are determined by following the static fluid loss test and procedures set forth in Section 8-8.1, “Fluid loss under static conditions,” in Reservoir Stimulation, 3rd Edition, Schlumberger, John Wiley & Sons, Ltd., pp. 8-23 to 8-24, 2000, in a filter-press cell using ceramic disks (FANN filter disks, part number 210538) saturated with 2% KCl solution and covered with filter paper and test conditions of ambient temperature (25°C), a differential pressure of 3.45 MPa (500 psi), 100 mL sample loading, and a loss collection period of 60 minutes, or an equivalent testing procedure. In some embodiments of the current application, the treatment fluid has a fluid loss value of less than 10 g in 30 min when tested on a core sample with 1000 mD porosity. In some embodiments of the current application, the treatment fluid has a fluid loss value of less than 8 g in 30 min when tested on a core sample with 1000 mD porosity. In some embodiments of the current application, the treatment fluid has a fluid loss value of less than 6 g in 30 min when tested on a core sample with 1000 mD porosity. In some embodiments of the current application, the treatment fluid has a fluid loss value of less than 2 g in 30 min when tested on a core sample with 1000 mD porosity.

The unique low to no fluid loss property allows the stabilized treatment fluid to be pumped at a low rate or pumping stopped (static) with a low risk of screen out. In embodiments, the low fluid loss characteristic may be obtained by including a leak-off control agent, such as, for example, particulated loss control agents (in some embodiments less than 1 micron or 0.05-0.5 microns), graded PSD or multimodal particles, polymers, latex, fiber, etc. As used herein, the terms leak-off control agent, fluid loss control agent and similar refer to additives that inhibit fluid loss from the slurry into a permeable formation.

As representative leakoff control agents, which may be used alone or in a multimodal fluid, there may be mentioned latex dispersions, water soluble polymers, submicron particulates, particulates with an aspect ratio higher than 1, or higher than 6, combinations thereof and the like, such as, for example, crosslinked polyvinyl alcohol microgel. The fluid loss agent can be, for example, a latex dispersion of polyvinyl chloride, polyvinyl acetate, polystyrene-co-butadiene; a water soluble polymer such as hydroxyethylcellulose (HEC), guar, copolymers of polyacrylamide and their derivatives; particulate fluid loss control agents in the size range of 30 nm to 1 micron, such as γ-alumina, colloidal silica, CaCO₃, SiO₂, bentonite etc.; particulates with different shapes such as glass fibers, flakes, films; and any combination thereof or the like. Fluid loss agents can be added or can be used in combination with acrylamido-methyl-propyl sulfonate polymer (AMPS). In embodiments, the leak-off control agent comprises a reactive solid, e.g., a hydrolysable material such as PGA, PLA or the like; or it can include a soluble or solubilizable material such as a wax, an oil-soluble resin, or another material soluble in hydrocarbons, or calcium carbonate or another material soluble at low pH; and so on. In embodiments, the leak-off control agent comprises a reactive solid selected from ground quartz, oil soluble resin, degradable rock salt, clay, zeolite or the like. In other embodiments, the leak-off control agent comprises one or more of magnesium hydroxide, magnesium carbonate, magnesium calcium carbonate, calcium carbonate, aluminum hydroxide, calcium oxalate, calcium phosphate, aluminum metaphosphate, sodium zinc potassium polyphosphate glass, and sodium calcium magnesium polyphosphate glass, or the like.

The treatment fluid may additionally or alternatively include, without limitation, friction reducers, clay stabilizers, biocides, crosslinkers, gas generating agents, breakers, corrosion inhibitors, and/or proppant flowback control additives. The treatment fluid may further include a product formed from degradation, hydrolysis, hydration, chemical reaction, or other process that occur during preparation or operation.

In certain embodiments herein, the STS may be prepared by combining the particles, such as proppant if present and subproppant, the carrier liquid and any additives to form a proppant-containing treatment fluid; and stabilizing the proppant-containing treatment fluid. The combination and stabilization may occur in any order or concurrently in single or multiple stages in a batch, semi-batch or continuous operation. For example, in some embodiments, the base fluid may be prepared from the subproppant particles, the carrier liquid and other additives, and then the base fluid combined with the proppant.

The treatment fluid may be prepared on location, e.g., at the wellsite when and as needed using conventional treatment fluid blending equipment. FIG. 4 shows a wellsite equipment configuration 10 for a fracture treatment job according to some embodiments using the principles disclosed herein, for a land-based fracturing operation. The proppant is contained in sand trailers 10A, 10B. Water tanks 12A, 12B, 12C, 12D are arranged along one side of the operation site. Hopper 14 receives sand from the sand trailers 10A, 10B and distributes it into the mixer truck 16. Blender 18 is provided to blend the carrier medium (such as brine, viscosity fluids, etc.) with the proppant, i.e., "on the fly," and then the slurry is discharged to manifold 31. The final mixed and blended slurry, also called frac fluid, is then transferred to
the pump trucks 22A, 22B, 22C, 22D, and routed at treatment pressure through treating line 34 to rig 35, and then pumped downhole. This configuration eliminates the additional mixer truck(s), pump trucks, blender(s), manifold(s) and line(s) normally required for slickwater fracturing operations, and the overall footprint is considerably reduced.

[0106] FIG. 5 shows further embodiments of the wellsite equipment configuration with the additional feature of delivery of pump-ready treatment fluid delivered to the wellsite in trailers 10A to 10D and further elimination of the mixer, hopper 14, and/or blender 18. In some embodiments the treatment fluid is prepared offshore and pre-mixed with proppant and other additives, or with some or all of the additives except proppant, such as in a system described in co-pending co-assigned patent applications with application Ser. No. 13/415,025, filed on Mar. 8, 2012, and application Ser. No. 13/487,002, filed on Jun. 1, 2012, the entire contents of which are incorporated herein by reference in their entirety. As used herein, the term “pump-ready” should be understood broadly. In certain embodiments, a pump-ready treatment fluid means the treatment fluid is fully prepared and can be pumped downhole without being further processed. In some other embodiments, the pump-ready treatment fluid means the fluid is substantially ready to be pumped downhole except that a further dilution may be needed before pumping or one or more minor additives need to be added before the fluid is pumped downhole. In such an event, the pump-ready treatment fluid may also be called a pump-ready treatment fluid precursor. In some further embodiments, the pump-ready treatment fluid may be a fluid that is substantially ready to be pumped downhole except that certain incidental procedures are applied to the treatment fluid before pumping, such as low-speed agitation, heating or cooling under exceptionally cold or hot climate, etc.

[0107] In certain embodiments herein, for example in low water fracturing and frac-and-pack operations, the STS comprises proppant and a fluid phase at a volumetric ratio of the fluid phase (Vfluid) to the proppant (Vprop) equal to or less than 3. In embodiments, Vfluid/Vprop is equal to or less than 2.5. In embodiments, Vfluid/Vprop is equal to or less than 2. In embodiments, Vfluid/Vprop is equal to or less than 1.5. In embodiments, Vfluid/Vprop is equal to or less than 1.25. In embodiments, Vfluid/Vprop is equal to or less than 1. In embodiments, Vfluid/Vprop is equal to or less than 0.75. In embodiments, Vfluid/Vprop is equal to or less than 0.5. In embodiments, Vfluid/Vprop is equal to or less than 0.4. In embodiments, Vfluid/Vprop is equal to or less than 0.3. In embodiments, Vfluid/Vprop is equal to or less than 0.25. In embodiments, Vfluid/Vprop is equal to or less than 0.2. In embodiments, Vfluid/Vprop is equal to or less than 0.1. In embodiments, Vfluid/Vprop may be sufficiently high such that the STS is flowable. In some embodiments, the ratio Vfluid/Vprop is equal to or greater than 0.05, equal to or greater than 0.1, equal to or greater than 0.15, equal to or greater than 0.2, equal to or greater than 0.25, equal to or greater than 0.3, equal to or greater than 0.35, equal to or greater than 0.4, equal to or greater than 0.5, or equal to or greater than 0.6, or within a range from any lower limit to any higher upper limit mentioned above.

[0108] Nota bene, the STS may optionally comprise sub-proppant particles in the whole fluid which are not reflected in the Vfluid/Vprop ratio, which is merely a ratio of the liquid phase (sans solids) volume to the proppant volume. This ratio is useful, in the context of the STS where the liquid phase is aqueous, as the ratio of water to proppant, i.e., Vwater/Vprop. In contrast, the “ppa” designation refers to pounds proppant added per gallon of base fluid (liquid plus subproppant particles), which can be converted to an equivalent volume of proppant added per volume of base fluid if the specific gravity of the proppant is known, e.g., 2.65 in the case of quartz sand. In embodiments, in which case 1 ppa=0.12 kg/L=45 ml/L; whereas “ppg” (pounds of proppant per gallon of treatment fluid) and “ppt” (pounds of additive per thousand gallons of treatment fluid) are based on the volume of the treatment fluid (liquid plus proppant and subproppant particles), which for quartz sand embeddings (specific gravity=2.65) also convert to 1 ppg=1000 ppt=0.12 kg/L=45 ml/L. The ppa, ppg and ppt nomenclature and their metric or SI equivalents are useful for considering the weight ratios of proppant or other additive(s) to base fluid (water or other fluid and subproppant) and/or to treatment fluid (water or other fluid plus proppant plus subproppant). The ppg nomenclature is generally used in embodiments reference to the concentration by weight of low concentration additives other than proppant, e.g., 1 ppt=0.12 g/L.

[0109] In embodiments, the proppant-containing treatment fluid comprises 0.27 L or more of proppant volume per liter of treatment fluid (corresponding to 720 g/L (6 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.36 L or more of proppant volume per liter of treatment fluid (corresponding to 960 g/L (8 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.4 L or more of proppant volume per liter of treatment fluid (corresponding to 1.08 kg/L (9 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.44 L or more of proppant volume per liter of treatment fluid (corresponding to 1.2 kg/L (10 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.53 L or more of proppant volume per liter of treatment fluid (corresponding to 1.44 kg/L (12 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.58 L or more of proppant volume per liter of treatment fluid (corresponding to 1.56 kg/L (15 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.62 L or more of proppant volume per liter of treatment fluid (corresponding to 1.68 kg/L (14 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.67 L or more of proppant volume per liter of treatment fluid (corresponding to 1.8 kg/L (15 ppg) in embodiments where the proppant has a specific gravity of 2.65), or 0.71 L or more of proppant volume per liter of treatment fluid (corresponding to 1.92 kg/L (16 ppg) in embodiments where the proppant has a specific gravity of 2.65).

[0110] As used herein, in some embodiments, “high proppant loading” means, on a mass basis, more than 1.0 kg proppant added per liter of whole fluid including any sub-proppant particles (8 ppa), or on a volumetric basis, more than 0.36 L proppant added per liter of whole fluid including any sub-proppant particles, or a combination thereof. In some embodiments, the treatment fluid comprises more than 1.1 kg proppant added per liter of whole fluid including any sub-proppant particles (9 ppa), or more than 1.2 kg proppant added per liter of whole fluid including any sub-proppant particles (10 ppa), or more than 1.44 kg proppant added per liter of whole fluid including any sub-proppant particles (12 ppa).
ppa), or more than 1.68 kg proppant added per liter of whole fluid including any sub-proppant particles (14 ppa), or more than 1.92 kg proppant added per liter of whole fluid including any sub-proppant particles (16 ppa), or more than 2.4 kg proppant added per liter of fluid including any sub-proppant particles (20 ppa), or more than 2.9 kg proppant added per liter of whole fluid including any sub-proppant particles (24 ppa).

In some embodiments, the treatment fluid comprises more than 0.45 L proppant added per liter of whole fluid including any sub-proppant particles, or more than 0.63 L proppant added per liter of whole fluid including any sub-proppant particles, or more than 0.72 L proppant added per liter of whole fluid including any sub-proppant particles, or more than 0.9 L proppant added per liter of whole fluid including any sub-proppant particles.

[0111] In some embodiments, the water content in the fracture treatment fluid formulation is low, e.g., less than 30% by volume of the treatment fluid, the low water content enables low overall water volume to be used, relative to a slickwater fracture job for example, to place a similar amount of proppant or other solids, with low to essentially zero fluid infiltration into the formation matrix and/or with low to zero flowback after the treatment, and less chance for fluid to migrate away from the hydrocarbon reservoir into adjacent intervals. The low flowback leads to less delay in producing the stimulated formation, which can be placed into production with a shortened cleanup stage or in some cases immediately without a separate flowback recovery operation.

[0112] In embodiments where the fracturing treatment fluid also has a low viscosity and a relatively high STV, e.g., 40, 50, 60 or 70% or more, the fluid can in some surprising embodiments be very flowable (low viscosity) and can be pumped using standard well treatment equipment. With a high volumetric ratio of proppant to water, e.g., greater than about 1.0, these embodiments represent a breakthrough in water efficiency in fracture treatments. Embodiments of a low water content in the treatment fluid certainly results in correspondingly low fluid volumes to infiltrate the formation, and importantly, no or minimal flowback during fracture cleanup and when placed in production. In the solid pack, as well as on formation surfaces and in the formation matrix, water can be retained due to a capillary and/or surface wetting effect. In embodiments, the solids pack obtained from an STS with multimodal solids can retain a larger proportion of water than conventional proppant packs, further reducing the amount of water flowback. In some embodiments, the water retention capability of the fracture-formation system can match or exceed the amount of water injected into the formation, and there may thus be no or very little water flowback when the well is placed in production.

[0113] In some specific embodiments, the proppant laden treatment fluid comprises an excess of a low viscosity continuous fluid phase, e.g., a liquid phase, and a multimodal particle phase, e.g. solids phase, comprising high proppant loading with one or more proppant modes for fracture conductivity and at least one sub-proppant mode to facilitate proppant injection. As used herein an excess of the continuous fluid phase implies that the fluid volume fraction in a slurry (1-SVF) exceeds the void volume fraction (1-PVF) of the solids in the slurry, i.e., SVF>PVF. Solids in the slurry in embodiments may comprise both proppant and one or more sub-proppant particle modes. In embodiments, the continuous fluid phase is a liquid phase.

[0114] In some embodiments, the STS is prepared by combining the proppant and a fluid phase having a viscosity less than 300 mPa-s (170 s⁻¹, 25 °C) to form the proppant-containing treatment fluid, and stabilizing the proppant-containing treatment fluid. Stabilizing the treatment fluid is described above. In some embodiments, the proppant-containing treatment fluid is prepared to comprise a viscosity between 0.1 and 300 mPa-s (170 s⁻¹, 25 °C) and a yield stress between 1 and 20 Pa (2.1-42 lb/ft²). In some embodiments, the proppant-containing treatment fluid comprises 0.36 L or more of proppant volume per liter of proppant-containing treatment fluid (8 ppa proppant equivalent where the proppant has a specific gravity of 2.6), a viscosity between 0.1 and 300 mPa-s (170 s⁻¹, 25 °C), a solids phase having a packed volume fraction (PVF) greater than 0.72, a slurry solids volume fraction (SVF) less than the PVF and a ratio of SVF/PVF greater than about 1–2.1/(PVF-0.72).

[0115] In some embodiments, e.g., for delivery of a fracturing stage, the STS comprises a volumetric proppant/treatment fluid ratio (including proppant and sub-proppant solids) in a main stage of at least 0.27 L/L (6 ppg at sp. gr. 2.65), or at least 0.36 L/L (8 ppg), or at least 0.44 L/L (10 ppg), or at least 0.53 L/L (12 ppg), or at least 0.58 L/L (13 ppg), or at least 0.62 L/L (14 ppg), or at least 0.67 L/L (15 ppg), or at least 0.71 L/L (16 ppg).

[0116] In some embodiments, the hydraulic fracture treatment may comprise an overall volumetric proppant/water ratio of at least 0.13 L/L (3 ppg at sp. gr. 2.65), or at least 0.18 L/L (4 ppg), or at least 0.22 L/L (5 ppg), or at least 0.26 L/L (6 ppg), or at least 0.38 L/L (8 ppg), or at least 0.44 L/L (10 ppg), or at least 0.53 L/L (12 ppg), or at least 0.58 L/L (13 ppg). Note that subproppant particles are not a factor in the determination of the proppant-water ratio.

[0117] As used herein, a “destabilized” STS refers to a previously stable or stabilized treatment slurry which has been modified so that it is no longer a stable slurry as defined above, or includes discontinuous regions of consolidated slurry solids that are no longer stable or no longer flowable within a network of flow channels, wherein the flow channels comprise free fluid, flowable slurry, a permeable solids matrix relative to the discontinuous regions of consolidated slurry solids, or a combination. As used herein, the term “destabilizing system” refers to one or a combination chemical and/or physical agent(s) that render the STS destabilized, and in some embodiments refers to such an agent or combination of agents that precipitates the solids from the slurry into consolidated, immobilized proppant pillars. In embodiments, the destabilizing system may be present in whole or in part in a stabilized treatment slurry, which may or may not be the same STS containing proppant, or in another treatment fluid such as a non-stabilized slurry or a solution, injected in one or more before, concurrently with or after one or more stages of the stabilized slurry to be destabilized.

[0118] As used herein, the term “channels” refers to interconnected conductive passageways formed between the proppant pillars in the proppant-fracture structure. “Open channels” present in some embodiments are distinct from “permeable channels,” which refer to channels containing proppant pack comprising a network of interstitial passages between individual proppant particles in a proppant matrix, in that the open channels fully extend between opposing 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
in embodiments may have a hydraulic conductivity, that is at least an order of magnitude larger than that of interstitial flow passages through the proppant matrix. In some embodiments, the pillars may also be conductive, including as or nearly as conductive as the channels between the pillars. “Pillars” as used herein refer to either or both consolidated and/or less conductive immobilized proppant regions within a proppant pack having permeable, and consolidated or immobilized proppant regions spaced apart by open channels.

The open channels in embodiments may be formed by displacing the STS and/or proppant in the fracture with a solids-free or low-solids treatment fluid and a destablizing system in such a way that the pillar-forming proppant islands are ultimately formed by destabilization, e.g., uneven proppant settling, and distributed in a spaced-apart configuration within the fracture. The permeable channels in embodiments may be formed by placing one or more treatment fluids comprising an STS and proppant with a destabilizing system in such a way that the proppant within the pillar-forming proppant regions is consolidated, the pillars being formed by destabilization and distributed in a spaced-apart configuration within the fracture. The destabilization can occur or begin in the preparation, mixing or pumping of the treatment fluid(s), in the injection of the treatment fluid(s) in the fracture, in or after the proppant placement, packing or settling in the fracture. In embodiments, the destabilization of the STS leads to heterogeneous proppant distribution between proppant-rich pillar-forming islands or regions and conductive channels, which may be open channels or permeable, proppant-filled channels as mentioned above. In embodiments, the destabilizing system can function in the proppant or proppant regions to consolidate or reinforce the proppant islands and/or to strengthen the proppant pillars. Conversely, the conductive regions can contain proppant particles, especially relatively minor amounts, which remain unconsolidated or do not otherwise result in obstruction or excessive flow resistance of the channels by the proppant.

A simplified version of some embodiments of the method is illustrated with reference to FIGS. 6-7, in which a wellbore 110 can be completed with perforations 112 in formation 114. Proppant particles 116 and destabilizing system particles 118, either or both of which can be formulated in one or more STS fluids, can be injected through the wellbore 110 into a fracture 120, where they can be heterogeneously placed in respective proppant-rich islands 122 in contact with regions 124 comprising one or more destabilizing system components. The fracture 120 can be allowed to close, and the proppant islands 122 compressed to form pillars to support the fracture 120 and prevent the opposing fracture faces from contacting each other. Simultaneously, in embodiments the regions 124 can be open or proppant-packed. In embodiments, the destabilizing system can facilitate consolidation and in some further embodiments, strengthening of the regions 122. With reference to FIG. 7, a network of interconnected conductive channels 126 can thus be formed around the pillars 128 to provide the fracture 120 with high conductivity for fluid flow. Fluids can now be produced from the formation 114, into the fracture 120, through the channels 126 and perforations 112, and into the wellbore 110.

If desired, in some embodiments, solids in the channels 126, or a portion of solids from the channels 126 (and/or pillars 128 where improved conductivity of the pillars is also desired), may be removed mechanically, for example by using fluid to push solids out of the fracture. In such instances, the solids can remain in a solid state from the time of injection through removal from the fracture. Alternatively or additionally in some embodiments, the solids can be softened, dissolved, reacted or otherwise made to degrade. Materials suitable for dissolution include for example, and without limitation, polyvinyl alcohol (PVOH) fibers, salt, wax, calcium carbonate, and the like and combinations thereof. Oil-degradable solids can be selected, so that they will be degraded by produced fluids in some embodiments. Alternatively or additionally in embodiments, a solid can be included which is degraded by agents purposefully placed in the formation by injection, wherein mixing the solid with the agent induces a delayed reaction degradation of the solid.

In some fracturing operations of the present disclosure, a solid acid-precursor can be used as a degradable material in the treatment fluid. Suitable acid-generating materials 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, a reactive liquid acid, can etch the formation at exposed surfaces. This etching can enlarge the channels and/or remove smaller particles or gel from the interstices between proppant particles and thus further enhance the conductivity of the propped fracture. 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.

In some embodiments of the disclosure, the solids in the treatment fluid 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 fluoroboric acid, ammonium fluoride, ammonium fluoride, and the like, or any mixtures thereof.

FIGS. 8-9 illustrate the acid etching process for greater fracture conductivity. In reference to FIG. 8, proppant islands 130 are heterogeneously placed in fracture 132 with a degradable solid acid-precursor in the regions 134. In reference to FIG. 9, delayed hydrolysis of the acid-precursor at formation conditions forms an acid that cuts into the face of the carbonate formation, resulting in localized etching 136 to enlarge the channels 138. The proppant pillars 130 remain intact to prop open the fracture.

In embodiments, the destabilizing system may be or include a liquid-removing agent such as, for example, a compound that reacts with or absorbs water, such as a hydratable compound or mixture of compounds that react with water to form a hydrate, e.g., a hydraulic cement or an inorganic cement component, such as, for example, Portland cement, pozzolan-lime cement, slag-lime cement, supersulfated cement, calcium aluminate cement, calcium sulfoaluminate cement, fly ash, blast furnace slag, lime-silica blends, lime-pozzolan blends, zeolites, cement kiln dust, geopolymers, Sorel cements, chemically bonded phosphate ceramics, and the like; or a superabsorbent polymer (SAP) such as crosslinked or uncrosslinked polymers or copolymers of acrylonitrile, acrylic acid, acrylate esters, acrylamide, vinyl alcohol, ethylene/maleic anhydride, carboxymethylcellulose, alkylene oxide, and the like. As used herein, a hydratable compound is a compound which forms an inorganic salt with
water bound to a metal center or incorporated in a crystal structure. As used herein, hydraulic cement refers to any cement that reacts with water to set. As used herein, an SAP is one that is capable of absorbing at least ten times its weight of water, and representative, non-limiting examples include polyacrylamide copolymers, sodium polyacrylates, ethylene maleic anhydride copolymers, cross-linked carboxymethyl-cellulose, polyvinyl alcohol copolymers, cross-linked polyethylene oxides, and starch grafted copolymers of polyacrylonitrile, to name a few.

[0126] The liquid-removing agents in some embodiments may be selected to delay the liquid removal until after or just after or mostly after the agent has been placed in the fracture or other location where destabilization of the STS is desired. For example in some embodiments the liquid-removing agent may be encapsulated, e.g., in a resin, or coated, e.g., with a hydrophobic material such as oil, for placement and activated by crushing, eroding, dissolving or permeating the encapsulating or coating material; and in additional or alternative embodiments the liquid removal rate may be controlled by selecting the appropriate liquid-removal agent and/or liquid phase media or other encapsulant, coating, or chemical or physical trigger.

[0127] The liquid-removing agents in some embodiments may destabilize the STS by reducing the liquid content and thereby inducing rheological changes due to the altered SVF. For example, in some embodiments alternating slugs of the STS may be formulated with a hydratable compound such as hydraulic cement and/or inorganic cement particles to cause local dehydration within the STS placed in the fracture and create inhomogeneous fluid placement of dispersed, high-SVF regions relative to the STS supplied to the fracture, leading to formation of pillars comprised of hydrated cement and other STS solids, which may be concrete-reinforced proppant pills in embodiments where the hydratable compound hardens, e.g., where a hydraulic cement cures to a strong concrete. The cement-formulated STS slugs in various embodiments may be alternated with essentially cement-free slugs of a similar or different STS or of an essentially solids-free fluid or low-solids slurry. In some embodiments where the cement-free slugs comprise STS, channels formed between the pillars may fill with a packed solids matrix that is more conductive than the cement-containing pillars, or in other embodiments the cement-containing pillars may if necessary be chemically modified, e.g., by acid washing or solvent treatment, to improve the conductivity of the cement-containing pillars, even to the point where if desired the conductivity of the cement-containing regions may be similar to or exceed the conductivity of the non-cement-containing regions.

[0128] In a further example, in some embodiments the STS may be formulated to contain SAP particles which upon placement in the fracture or other location may absorb water through hydrogen bonding with water molecules in the immediately surrounding areas, dehydrating the STS and creating local inhomogeneity and destabilization within the placed fluid resulting in conductive channels around the water-swollen SAP materials. The water-swollen SAP material may also in some embodiments infiltrate the interstices between other STS particles adjacent to the SAP particle. In some embodiments the individual SAP particles are initially within an order of magnitude of the volume of the largest individual STS particles, e.g., from 0.1 to 10 times the volume of any proppant particles, but after saturation with water may ultimately swell to a volume more than ten times the initial volume, e.g., to from 30 to 60 times the initial volume or than the largest STS particle, e.g., from 3 to 600 times the volume of a proppant particle, or from 5 to 300 times the volume of a proppant particle, or from 10 to 300 times the volume of a proppant particle. As used herein, the initial volume of an SAP particle is determined as it enters the wellbore, since SAP may be partially pre-swollen during surface preparation of the treatment fluid such as an STS containing it; for example, in some embodiments the SAP may be prepared in an STS containing 0.9 wt % saline as the carrier fluid wherein the SAP has an absorbency of only 50 times its weight, and the SAP may be contacted downhole with fresh water in which it may absorb 500 times its weight.

[0129] In embodiments, the swollen volume of the SAP particles is less than 90% of the void volume of the proppant pack (<90% (1-PVF)), or less than 80% of the void volume of the proppant pack (<80% (1-PVF)), or less than 70% of the void volume of the proppant pack (<70% (1-PVF)), or less than 60% of the void volume of the proppant pack (<60% (1-PVF)), or less than 50% of the void volume of the proppant pack (<50% (1-PVF)), or less than 40% of the void volume of the proppant pack (<40% (1-PVF)), or less than 30% of the void volume of the proppant pack (<30% (1-PVF)), or less than 20% of the void volume of the proppant pack (<20% (1-PVF)). In some embodiments, the swollen volume of the SAP particles is more than 10% of the void volume of the proppant pack (>10% (1-PVF)), or more than 20% of the void volume of the proppant pack (>20% (1-PVF)), or more than 30% of the void volume of the proppant pack (>30% (1-PVF)), or more than 40% of the void volume of the proppant pack (>40% (1-PVF)), or more than 50% of the void volume of the proppant pack (>50% (1-PVF)), or more than 60% of the void volume of the proppant pack (>60% (1-PVF)), or more than 70% of the void volume of the proppant pack (>70% (1-PVF)), or more than 80% of the void volume of the proppant pack (>80% (1-PVF)).

[0130] In some embodiments, the destabilizing system comprises a crosslinking agent to crosslink a crosslinkable material in the pillars. For example, the crosslinked material may destabilize the STS, binding and consolidating the proppant and/or other solids in the STS to form the pillars, where regions of non-crosslinked STS or other treatment fluid remain between the pillars to form conductive, i.e., open or permeable, flow channels between the crosslinked regions. In some embodiments the crosslinking agent and/or a triggering agent on the one hand, and the crosslinkable material on the other, may be in alternate treatment fluid stages, e.g., with different viscosities so that one stage of low viscosity entering the fracture as an overflush will finger into another stage previously placed in the fracture, and with crosslinking occurring at the interface between the two fluid stages. In these embodiments, the crosslinking occurs at least at a perimeter of the dispersed crosslinkable material-containing regions, consolidating the proppant-containing regions into immobilized pillars. In embodiments, the crosslinked material reinforces at least an outer wall of the pillar perimeters.

[0131] In embodiments, the crosslinkable material may be a suitable monomer or polymer that is compatible in the treatment fluid, i.e., it forms a stable treatment slurry or does not prematurely destabilize an STS before it can be placed in the fracture. Where polysaccharides such as guar gum are used as the crosslinkable material in some embodiments, the crosslinking agent may be a source of borate or a polyvalent
cation such as a metal, and the triggering agent may be a pH control agent to modify the pH to one conducive to crosslinking. e.g., an alkaline pH (pH>7) may be required to initiate crosslinking. 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. 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 hydroxide, sodium sesquicarbonate, triethanolamine, or tetraethylenepentamine. The crosslinkable material, the crosslinking agent and any triggering agent may independently be particulated solids in the slurry, dissolved in a carrier fluid component, or a miscible or immiscible fluid in the slurry. The composition of the STS containing the crosslinkable material, but without the crosslinking agent and/or the triggering agent, in some embodiments is designed such that it can be or made relatively more conductive than the pillars, e.g., through dilution with fluid or other means of viscosity reduction to promote placement or settling within the channels as opposed to the pillars.

In embodiments, depending on the desired morphology of the pillar-channel system to be formed, the relative sizes (volumes) of the alternated stages can be varied, e.g., from a single STS stage followed by a single destabilizing stage, to several alternated stages, to a train of relatively small-volume alternated stages.

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. The first stage, also referred to as the “pad stage” or the “front-end stage,” involves injecting a fracturing fluid into a borehole at a sufficiently high flow rate and pressure sufficient to literally break or fracture a portion of surrounding strata at the wellbore 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, Chapter 10, Fracture Treatment Design, by Jack Elbel and Larry Brit, pp. 10-1 to 10-49, 2000.

In some embodiments, e.g., the front-end stage is an STS wherein the slurry comprises a stabilized solids mixture comprising a particulated leakoff control system (which may include solid and/or liquid particles, e.g., submicron particles, colloids, micelles, PLA dispersions, latex systems, etc.) and a solids volume fraction (SVF) of at least 0.4. In some embodiments, e.g., a pad stage STS, the slurry comprises viscosifier in an amount to provide a viscosity in the pad stage of greater than 300 mPa-s, determined on a whole fluid basis at 170 °C. and 25% C.

In some embodiments, e.g., in a flush stage STS, the slurry comprises a proppant-free slurry comprising a stabilized solids mixture comprising a particulated leakoff control system (which may include solid and/or liquid particles, e.g., submicron particles, colloids, micelles, PLA dispersions, latex systems, etc.) and a solids volume fraction (SVF) of at least 0.4. In other embodiments, the proppant-containing fracturing stage may be used with a flush stage comprising a first stage comprising viscosifier and a second stage comprising slickwater. The viscosifier may be selected from viscoelastic surfactant systems, hydratable gelling agents (optionally including crosslinked gelling agents), and the like. In other embodiments, the flush stage comprises an overflush equal to or less than 3200 L (20.42-gal bbls), equal to or less than 2400 L (15 bbls), or equal to or less than 1900 L (12 bbls).

In some embodiments, the proppant stage comprises a continuous single injection of the STS free of spacers.

In some embodiments the STS comprises a total proppant volume injected into the wellbore or to be injected into the wellbore of at least 800 liters. In some embodiments, the total proppant volume is at least 1600 liters. In some embodiments, the total proppant volume is at least 3200 liters. In some embodiments, the total proppant volume is at least 8000 liters. In some embodiments, the total proppant volume is at least 80,000 liters. In some embodiments, the total proppant volume is at least 800,000 liters. The total proppant volume injected into the wellbore or to be injected into the wellbore is typically not more than 16 million liters.

Sometimes it may be desirable to stop pumping a treatment fluid during a hydraulic fracturing operation, such as for example, when an emergency shutdown is required. For example, there may be a complete failure of surface equipment, there may be a near wellbore screenout, or there may be a natural disaster due to weather, fire, earthquake, etc. However, with unstabilized fracturing fluids such as slickwater, the proppant suspension will be inadequate at zero pumping rate, and proppant may screen out in the wellbore and/or fail to get placed in the fracture. With slickwater it is usually impossible to resume the fracturing operation without first cleaning the settled proppant out of the wellbore, often using coiled tubing or a workover rig. There is some inefficiency in fluidizing proppant out of the wellbore with coiled tubing, and a significant amount of a specialized clean out fluid will be used to entrain the proppant and lift it to surface. After the clean out, a decision will need to be made whether to repeat the treatment or just leave that portion of the wellbore suboptimally treated. In contrast, in embodiments herein, the treatment fluid is stabilized and the operator can decide to resume and/or complete the fracture operation, or to circulate the STS (and any proppant) out of the well bore. By stabilizing the treatment fluid to practically eliminate particle settling, the treatment fluid possesses the characteristics of excellent proppant conveyance and transport even when static.

Due to the stability of the treatment fluid in some embodiments herein, the proppant will remain suspended and the fluid will retain its fracturing properties during the time the pumping is interrupted. In some embodiments herein, a method comprises combining at least 0.36, at least 0.4, or at least 0.45 L of proppant per liter of base fluid to form a proppant-containing treatment fluid, stabilizing the proppant-containing treatment fluid, pumping the STS, e.g., injecting the proppant-containing treatment fluid into a subterranean formation and/or creating a fracture in the subterranean formation with the treatment fluid, stopping pumping of the STS thereby stranding the treatment fluid in the wellbore, and thereafter resuming pumping of the treatment fluid, e.g., to inject the stranded treatment fluid into the formation and continue the fracture creation, and/or to circulate the stranded treatment fluid out of the wellbore as an intact plug with a managed interface between the stranded treatment fluid and a displacing fluid. Circulating the treatment fluid out of the wellbore can be achieved optionally using coiled tubing or a workover rig, if desired, but in embodiments the treatment
fluid will itself suspend and convey all the proppant out of the wellbore with high efficiency. In some embodiments, the method may include managing the interface between the treatment fluid and any displacing fluid, such as, for example, matching density and viscosity between the treatment and displacing fluids, using a wiper plug or pig, using a gelled pill or fiber pill or the like, to prevent density and viscous instabilities.

In some embodiments, the treatment provides production-related features resulting from a low water content in the treatment fluid, such as, for example, less infiltration into the formation and/or less water flowback. Formation damage occurs whenever the native reservoir conditions are disturbed. A significant source of formation damage during hydraulic fracturing occurs when the fracturing fluids contact and infiltrate the formation. Measures can be taken to reduce the potential for formation damage, including adding salts to improve the stability of fines and clays in the formation, addition of scale inhibitors to limit the precipitation of mineral scales caused by mixing of incompatible brines, addition of surfactants to minimize capillary blocking of the tight pores and so forth. There are some types of formation damage for which additives are not yet available to solve. For example, some formations will be mechanically weakened upon coming in contact with water, referred to herein as water-sensitive formations. Thus, it is desirable to significantly reduce the amount of water that can infiltrate the formation during a well completion operation.

Very low water slurries and water free slurries according to certain embodiments disclosed herein offer a pathway to significantly reduce water infiltration and the collateral formation damage that may occur. Low water STS minimizes water infiltration relative to slick water fracture treatments by two mechanisms. First, the water content in the STS can be less than about 40% of slickwater per volume of respective treatment fluid, and the STS can provide in some embodiments more than a 90% reduction in the amount of water used per volume or weight of proppant placed in the formation. Second, the solids pack in the STS in embodiments including subproppant particles retains more water than conventional proppant packs so that less water is released from the STS into the formation.

After fracturing, water flowback plagues the prior art fracturing operations. Load water recovery typically characterizes the initial phase of well start up following a completion operation. In the case of horizontal wells with massive hydraulic fractures in unconventional reservoirs, 15 to 30% of the injected hydraulic fracturing fluid is recovered during this start up phase. At some point, the load water recovery rate becomes very low and the produced gas rate high enough for the well to be directed to a gas pipeline to market. We refer to this period of time during load water recovery as the fracture clean up phase. It is normal for a well to clean up for several days before being connected to a gas sales pipeline. The flowback water must be treated and/or disposed of, and delays pipeline production. A low water content slurry according to embodiments herein can significantly reduce the volume and/or duration, or even eliminate this fracture clean up phase. Fracturing fluids normally are lost into the formation by various mechanisms including filtration into the matrix, inhibition into the matrix, wetting the freshly exposed new fracture face, loss into natural fractures. A low water content slurry will become dry with only a small loss of its water into the formation by these mechanisms, leaving in some embodiments no or very little free water to be required (or able) to flow back during the fracture clean up stage. The advantages of zero or reduced flowback include reduced operational cost to manage flowback fluid volumes, reduced water treatment cost, reduced time to put well to gas sales, reduction of problematic waste that will develop by injected waters solubilizing metals, naturally occurring radioactive materials, etc.

There have also been concerns expressed by the general public that hydraulic fracturing fluid may find some pathway into a potable aquifer and contaminate it. Although proper well engineering and completion design, and fracture treatment execution will prevent any such contamination from occurring, if it were to happen by an unforeseen accident, a slickwater system will have enough water and mobility in an aquifer to migrate similar to a salt water plume. A low water STS in embodiments may have a 90% reduction in available water per mass of proppant such that any contact with an aquifer, should it occur, will have much less impact than slickwater treatment.

Subterranean formations are heterogeneous, with layers of high, medium, and low permeability strata interlaced. A hydraulic fracture that grows to the extent that it encounters a high permeability zone will suddenly experience a high leakoff area that will attract a disproportionately large fraction of the injected fluid significantly changing the geometry of the created hydraulic fracture possibly in an undesirable manner. A hydraulic fracturing fluid that would automatically plug a high leakoff zone is useful in that it would make the fracture execution phase more reliable and probably ensure the fracture geometry more closely resembles the designed geometry (and thus production will be closer to that expected). One feature of embodiments of an STS is that it will dehydrate and become an immobile mass (plug) upon losing more than 25% of the water it is formulated with. As an STS in embodiments only contains up to 50% water by volume, then it will only require a loss of a total of 12.5% of the STS treatment fluid volume in the high fluid loss affected area to become an immobile plug and prevent subsequent fluid loss from that area; or in other embodiments only contains up to 40% water by volume, requiring a loss of a total of 10% of the STS treatment fluid volume to become immobile. A slick water system would need to lose around 90% or 95% of its total volume to dehydrate the proppant into an immobile mass.

Sometimes, during a hydraulic fracture treatment, the surface treating pressure will approach the maximum pressure limit for safe operation. The maximum pressure limit may be due to the safe pressure limitation of the wellhead, the surface treating lines, the casing, or some combination of these items. One common response to reaching an upper pressure limit is to reduce the pumping rate. However, with ordinary fracturing fluids, the proppant suspension will be inadequate at low pumping rates, and proppant may fail to get placed in the fracture. The stabilized fluids in some embodiments of this disclosure, which can be highly stabilized and practically eliminate particle settling, possess the characteristic of excellent proppant conveyance and transport even when static. Thus, some risk of treatment failure is mitigated since a fracture treatment can be pumped to completion in some embodiments herein, even at very low pump rates should injection rate reduction be necessary to stay below the maximum safe operating pressure during a fracture treatment with the stabilized treatment fluid.
In some embodiments, the injection of the treatment fluid of the current application can be stopped altogether (i.e. at an injection rate of 0 bbl/min). Due to the excellent stability of the treatment fluid, very little or no proppant settling occurs during the period of 0 bbl/min injection. Well intervention, treatment monitoring, equipment adjustment, etc. can be carried out by the operator during this period of time. The pumping can be resumed thereafter. Accordingly, in some embodiments of the current application, there is provided a method comprising injecting a proppant laden treatment fluid into a subterranean formation penetrated by a wellbore, initiating or propagating a fracture in the subterranean formation with the treatment fluid, stopping injecting the treatment fluid for a period of time, restarting injecting the treatment fluid to continue the initiating or propagating of the fracture in the subterranean formation.

In some embodiments, the treatment and system may achieve the ability to fracture using a carbon dioxide proppant stage treatment fluid. Carbon dioxide is normally too light and too thin (low viscosity) to carry proppant in a slurry useful in fracturing operations. However, in an STS fluid, carbon dioxide may be useful in the liquid phase, especially where the proppant stage treatment fluid also comprises a particulated fluid loss control agent. In embodiments, the liquid phase comprises at least 10 wt % carbon dioxide, at least 50 wt % carbon dioxide, at least 60 wt % carbon dioxide, at least 70 wt % carbon dioxide, at least 80 wt % carbon dioxide, at least 90 wt % carbon dioxide, or at least 95 wt % carbon dioxide. The carbon dioxide-containing liquid phase may alternatively or additionally be present in any pre-pad stage, pad stage, front-end stage, flush stage, post-flush stage, or any combination thereof.

Zonal isolation operations in embodiments are improved by specific STS formulations optimized for leakoff control and/or bridging abilities. Relatively small quantities of the STS radically improve the sealing ability of mechanical and inflatable packers by filling and bridging off gaps. Permanent isolation of zones is achieved in some embodiments by bullheading low permeability versions of the STS into water producing formations or other formations desired to be isolated. Isolation in some embodiments is improved by using a setting formulation of the STS, but non-setting formulations can provide very effective permanent isolation. Temporary isolation may be achieved in embodiments by using deformable materials to convert a non-permeable pack into a permeable pack after a period of time.

The pressure containing ability and ease of placement/removal of sand plugs in embodiments are significantly improved using appropriate STS formulations selected for high bridging capacity. Such formulations will allow much larger gaps between the sand packer tool and the well bore for the same pressure capability. Another major advantage is the reversibility of dehydration in some embodiments; a solid sand pack may be readily re-fluidized and circulated out, unlike conventional sand plugs.

In other embodiments, plug and abandon work may be improved using CRETE cementing formulations in the STS and also by placing bridging/leakoff controlling STS formulations below and/or above cement plugs to provide a seal repairing material. CRETE cementing formulations are disclosed in U.S. Pat. No. 6,626,991, GB 2,277,927, U.S. Pat. No. 6,874,578, WO 2009/046980, Schlumberger CEMENT CRETE Brochure (2003), and Schlumberger Cementing Services and Products—Materials, pp. 39-76 (2012), available at http://www.slb.com/-/media/Files/cementing/catalogs/05_cementing_materials.pdf which are hereby incorporated herein by reference. The ability of the STS to re-fluidize after long periods of immobilization facilitates this embodiment.

Accordingly, the present disclosure provides the following Embodiments:

A. A method of placing a proppant pack into a fracture formed in a subterranean formation, the method comprising: injecting a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage, wherein at least a portion of the well treatment fluid comprises a stabilized slurry stage and wherein the proppant-containing and stabilized slurry portions may be the same or different; injecting a destabilizing system into the fracture with the well treatment fluid to destabilize the slurry stage and form regions of consolidated proppant from the destabilized slurry stage; and placing a plurality of proppant clusters forming pillars from the consolidated proppant regions spaced apart by fluid flow channels (which may be open or relatively permeable) from the formation through the fracture toward the wellbore.

B. The method of Embodiment A wherein the stabilized slurry comprises a liquid phase (which may optionally be aqueous and/or hydrophobic), and wherein the slurry destabilizing system comprises a liquid-removing agent to remove fluid from the slurry (e.g., and thereby increase the solids volume fraction (SVF) of the slurry).

C. The method of Embodiment B wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the liquid-removal agent comprises a hydratable compound (e.g., a hydrophilic cement or an inorganic cement component, such as, for example, Portland cement, pozzolan-lime cement, slag-lime cement, supersulfated cement, calcium aluminate cement, calcium sulfoaluminate cement, fly ash, blast furnace slag, lime-silica blends, lime-pozzolan blends, zeolites, cement kiln dust, geopolymers, Sorel cements, chemically bonded phosphate ceramics).

D. The method of Embodiment B or Embodiment C wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the liquid-removal agent comprises a superabsorbent polymer.

E. The method of any one of Embodiments A to D, further comprising: sequentially injecting a first stage of the treatment fluid into the formation followed by a second stage of the treatment fluid (e.g., as an overflush), wherein the first and second stages have different viscosities, different specific gravities, or both, to initiate viscous fingering; wherein the stabilized slurry comprises the proppant in the first stage; wherein the destabilizing system comprises a crosslinkable material in the first stage, and a crosslinking agent in at least one of the first and second stages to crosslink the crosslinkable material in the pillars.

F. The method of Embodiment E wherein the specific gravity of the first stage is matched with the specific gravity of the second stage to mitigate gravity effects (or where the difference in density between two fluids is less than 0.9 g/mL, or less than 0.8 g/L, or less than 0.7 g/L, or less than 0.6 g/L, or less than 0.5 g/L, or less than 0.4 g/L, or less than 0.3 g/L, or less than 0.2 g/L, or less than 0.1 g/L, or less than 0.05 g/L).

G. The method of Embodiment E or Embodiment F wherein the crosslinkable material comprises a
polysaccharide, and wherein the crosslinking agent comprises a source of borate or a polyvalent metal.

[0159] H. The method of Embodiment G wherein one of the first and second stages comprises a pH control material to provide an alkaline pH and the other one of the first and second stages comprises the source of borate or polyvalent metal.

[0160] I. The method of Embodiment H wherein the first stage comprises the polysaccharide and the pH control agent and the second stage comprises the source of borate or polyvalent metal.

[0161] J. The method of Embodiment H wherein the first stage comprises the polysaccharide and the source of borate or polyvalent metal and the second stage comprises the pH control agent.

[0162] K. The method of Embodiment H wherein the first stage comprises subpraparant particles, has a slurry solids volume fraction (SVF) of 0.6 or more and solids comprising a packed volume fraction (PVF) of 0.7 or more; and wherein the second stage is free of solids or has an SVF less than 0.05.

[0163] L. The method of Embodiment A, further comprising: alternatingly injecting a plurality of pulsed first and second slugs of the well treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry which may be the same or different; wherein the slurry destabilizing system comprises a reagent selectively present in one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs.

[0164] M. The method of Embodiment I wherein the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent.

[0165] N. The method of Embodiment L or Embodiment M wherein the stabilized slurries comprise a liquid phase, and wherein the reagent comprises a solid liquid removal agent to remove fluid from at least one of the slurries.

[0166] O. The method of Embodiment N wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the reagent comprises a hydratable compound (e.g., a hydraulic cement or an inorganic cement component, such as, for example, Portland cement, pozzolan-lime cement, slag-lime cement, supersulfated cement, calcium aluminate cement, calcium sulfoaluminate cement, fly ash, blast furnace slag, lime-silica blends, lime- pozzolan blends, zeolites, cement kiln dust, geopolymers, Sorel cements, chemically bonded phosphate ceramics).

[0167] P. The method of Embodiment N wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the reagent comprises a superabsorbent polymer.

[0168] Q. The method of any one of Embodiments A to P, further comprising stabilizing the well treatment fluid to form the stabilized slurry.

[0169] R. The method of Embodiment Q wherein the stabilized slurry is formed by at least one of the slurry stabilization operations selected from: (1) introducing sufficient particles into the slurry to increase a solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25°C); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) increasing apparent viscosity of the slurry to at least 50 mPas (170 s⁻¹, 25°C); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscosifier selected from viscoelastic surfactants and hydratable gelling agents; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

[0170] S. The method of Embodiment Q wherein the stabilized slurry is formed by at least two of the slurry stabilization operations selected from: (1) introducing sufficient particles into the slurry to increase a solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25°C); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) increasing apparent viscosity of the slurry to at least 50 mPas (170 s⁻¹, 25°C); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscosifier selected from viscoelastic surfactants and hydratable gelling agents; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

[0171] T. The method of Embodiment Q wherein the stabilized slurry is formed by at least three of the slurry stabilization operations selected from: (1) introducing sufficient particles into the slurry to increase a solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25°C); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) increasing apparent viscosity of the slurry to at least 50 mPas (170 s⁻¹, 25°C); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscosifier selected from viscoelastic surfactants and hydratable gelling agents; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

[0172] U. The method of Embodiment Q wherein the stabilized slurry is formed by at least four of the slurry stabilization operations selected from: (1) introducing sufficient particles into the slurry to increase a solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25°C); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) increasing apparent viscosity of the slurry to at least 50 mPas (170 s⁻¹, 25°C); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscosifier selected from viscoelastic surfactants and hydratable gelling agents; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less
than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

[0173] V. The method of Embodiment Q wherein the stabilized slurry is formed by at least five of the slurry stabilization operations selected from: (1) introducing sufficient particles into the slurry to increase a solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25° C.); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) introducing apparent viscosity of the slurry to at least 50 mPa·s (170 s⁻¹, 25° C.); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscoelastic fluid containing a viscoelastic surfactant; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

[0174] W. The method of any one of Embodiments R to V comprising introducing sufficient particles into the slurry to increase the SVF to at least 0.4 (or 0.5 or more, or 0.6 or more, or 0.56 to 0.61).

[0175] X. The method of any one of Embodiments R to W comprising increasing the low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25° C.).

[0176] Y. The method of any one of Embodiments R to X comprising increasing the yield stress of the treatment fluid to at least 1 Pa (or to from 1 to 20 Pa).

[0177] Z. The method of any one of Embodiments A to Y wherein the stabilized slurry comprises solids comprising 60-75 volume percent proppant larger than 100 mesh, 5-20 volume percent 100 mesh sand, 5-20 volume percent silica flour, and 8-30 volume percent of 1-10 micron particles, based on the total volume of solids in the stabilized slurry, and from 1.2 to 4.8 g/L (10-40 ppt) of a hydrolyzable gel.

[0178] AA. A propped fracture system obtained as a result of placing the proppant pack into the fracture according to the method of any one of the Embodiments A to Z.

[0179] BB. A system for fracturing a subterranean formation comprising: a supply module to inject a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage fluid, wherein at least a portion of the well treatment fluid comprises a stabilized stage fluid and wherein the proppant-containing and stabilized slurry portions may be the same or different fluids; and a destabilizing system in communication with the supply module for injection into the fracture with the well treatment fluid to destabilize the slurry stage fluid, form regions of consolidated proppant from the destabilized stage fluid and form pillars spaced apart by fluid flow channels (which may be open or permeable) from the formation through the fracture toward the wellbore.

[0180] CC. The system of Embodiment BB wherein the stabilized slurry comprises a liquid phase (which may optionally be aqueous and/or hydrophobic), and wherein the slurry destabilizing system comprises a liquid-removing agent to remove fluid from the stabilized slurry (e.g., and thereby increase the solids volume fraction (SVF) of the slurry).

[0181] DD. The system of Embodiment CC wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the liquid-removal agent comprises a hydratable component (e.g., a hydratable cement or an inorganic cement component, such as, for example, Portland cement, pozolan-lime cement, slag-lime cement, supersulfated cement, calcium aluminate cement, calcium sulfaluminum cement, fly ash, blast furnace slag, lime-silica blends, lime-pozzolan blends, zeolites, cement kiln dust, geopolymers, Sorel cements, chemically bonded phosphate ceramics).

[0182] EE. The system of Embodiment CC or Embodiment DD wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the liquid-removal agent comprises a superabsorbent polymer.

[0183] FF. The system of any one of Embodiments BB to EE, further comprising: a pump system to sequentially inject a first stage of the treatment fluid into the formation followed by a second stage of the treatment fluid (e.g., as an overflush), wherein the first and second stages have different viscosities, different specific gravities, or both, to initiate viscous fingering; wherein the stabilized slurry comprises the proppant in the first stage; wherein the destabilization system comprises a crosslinkable material in the first stage, and a crosslinking agent in at least one of the first and second stages to crosslink the crosslinkable material in the pillars.

[0184] GG. The system of Embodiment FF wherein the specific gravity of the first stage is matched with the specific gravity of the second stage to mitigate gravity effects (or where the difference in density between two fluids is less than 0.9 g/mL, or less than 0.8 g/mL, or less than 0.7 g/mL, or less than 0.6 g/mL, or less than 0.5 g/mL, or less than 0.4 g/mL, or less than 0.3 g/mL, or less than 0.2 g/mL, or less than 0.1 g/mL, or less than 0.05 g/mL).

[0185] HH. The system of Embodiment GG wherein the crosslinkable material comprises a polysaccharide, and wherein the crosslinking agent comprises a source of borate or a polyvalent metal.

[0186] II. The system of Embodiment HH wherein one of the first and second stages comprises a pH control material to provide an alkaline pH and the other one of the first and second stages comprises the source of borate or polyvalent metal.

[0187] JJ. The system of Embodiment II wherein the first stage comprises the polysaccharide and the pH control agent and the second stage fluid comprises the source of borate or polyvalent metal.

[0188] KK. The system of Embodiment II wherein the first stage comprises the polysaccharide and the source of borate or polyvalent metal and the second stage comprises the pH control agent.

[0189] LL. The system of Embodiment II wherein the stabilized slurry comprises the proppant and subpropellant particles, has a solids volume fraction (SVF) of 0.6 or more and solids comprising a packed volume fraction (PVF) of 0.7 or more; and wherein the second stage is free of solids or has an SVF less than 0.05.

[0190] MM. The system of Embodiment BB, further comprising: a pump system to alternatingly inject a plurality of pulsed first and second slugs of the treatment
fluid, wherein the first and second slugs each comprise a said stabilized slurry; wherein the slurry destabilizing system comprises a reagent selectively present in one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs.

[0191] NN. The system of Embodiment MM wherein the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent.

[0192] OO. The system of Embodiment MM or Embodiment NN wherein the stabilized slurries comprise a liquid phase, and wherein the reagent comprises a solid liquid-removal agent to remove fluid from the stabilized slurry.

[0193] PP. The system of Embodiment NN wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the reagent comprises a hydratable compound (e.g., a hydraulic cement or an inorganic cement component, such as, for example, Portland cement, pozzolan-lime cement, slag-lime cement, supersulfated cement, calcium aluminate cement, calcium sulfoaluminate cement, fly ash, blast furnace slag, lime-silica blends, lime-kiln dust, geopolymers, Sorel cements, chemically bonded phosphate cements).

[0194] QQ. The system of Embodiment NN wherein the liquid phase comprises water (which may optionally be in a continuous or dispersed aqueous phase in an emulsion with a hydrophobic phase) and the reagent comprises a superabsorbent polymer.

[0195] RR. The system of any one of Embodiments BB to QQ wherein the stabilized slurry comprises at least one of the stability indicia selected from: (1) a solids volume fraction (SVF) of at least 0.4; (2) a low-shear viscosity of at least 1 Pa-s (5.11 s⁻¹, 25° C.); (3) a yield stress of at least 1 Pa; (4) an apparent viscosity of at least 50 mPa-s (170 s⁻¹, 25° C.); (5) a multimodal solids phase; (6) a solids phase having a packed volume fraction (PVF) greater than 0.7; (7) a viscosifier selected from viscoelastic surfactants, in an amount ranging from 0.01 up to 7.2 g/L (60 ppt), and hydratable gelling agents in an amount ranging from 0.01 up to 4.8 g/L (40 ppt), based on the volume of fluid phase; (8) colloidal particles; (9) a particle-fluid density delta less than 1.6 g/mL; (10) particles having an aspect ratio of at least 6; (11) ciliated or coated proppant; and (12) combinations thereof.

[0196] SS. The system of Embodiment RR wherein the SVF is at least 0.4 (or 0.5 or more, or 0.6 or more, or 0.56 to 0.61).

[0197] TT. The system of any one of Embodiments RR to SS wherein the low-shear viscosity of the slurry is at least 1 Pa (or to from 1 to 20 Pa).

[0198] UU. The system of any one of Embodiments RR to TT wherein the yield stress is at least 1 Pa (or to from 1 to 20 Pa).

[0199] VV. The system of any one of Embodiments RR to UU wherein the apparent viscosity is at least 50 mPa-s (170 s⁻¹, 25° C.).

[0200] WW. The system of any one of Embodiments RR to VV comprising the multimodal solids phase.

[0201] XX. The system of any one of Embodiments RR to WW, comprising the packed volume fraction (PVF) greater than 0.7.

[0202] YY. The system of any one of Embodiments RR to XX, comprising the viscoelastic surfactant in an amount ranging from 0.01 up to 7.2 g/L (60 ppt) based on the volume of fluid phase.

[0203] ZZ. The system of any one of Embodiments RR to YY comprising the hydratable gelling agent in an amount ranging from 0.01 up to 4.8 g/L (40 ppt) based on the volume of fluid phase.

EXEMPLARY EXAMPLES

Example 1

[0204] Stabilized Treatment Slurry. An example of a stabilized treatment slurry (STS) is provided in Table 1 below.

<table>
<thead>
<tr>
<th>Fluid components</th>
<th>Stabilized Proppant Free Slurry (g/L of STS)</th>
<th>Stabilized Proppant/Solids Slurry (g/L of STS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crystalline silica</td>
<td>0</td>
<td>900-1100</td>
</tr>
<tr>
<td>40/70 mesh</td>
<td>0</td>
<td>125-225</td>
</tr>
<tr>
<td>Water</td>
<td>150-250</td>
<td>100-250</td>
</tr>
<tr>
<td>Latex</td>
<td>300-500</td>
<td>175-275</td>
</tr>
<tr>
<td>Dispersant</td>
<td>2-4</td>
<td>1-3</td>
</tr>
<tr>
<td>Anti-foam</td>
<td>6-10</td>
<td>6-10</td>
</tr>
</tbody>
</table>

1Calcium Carbonate = SAFECARB 2 from Mill-SWACO
2Latex = Styrene-Butadiene copolymer dispersion
3Dispersant = Polymethylsiline sulfonate
4Antifoam = Silicone emulsion
5Viscosifier = AMPS/acylamide copolymer solution

[0205] Excellent particle (proppant) suspension capability and very low fluid loss were observed. The fluid leakoff coefficient was determined by following the static fluid loss test and procedures set forth in Section 8-8.1, "Fluid loss under static conditions," in Reservoir Stimulation, 3rd Edition, Schlumberger, John Wiley & Sons, Ltd., pp. 8-23 to 8-24, 2000, in a filter-press cell using ceramic disks (FANN filter disks, part number 210538) saturated with 2% KCl solution and covered with filter paper, and test conditions of ambient temperature (25° C.), a differential pressure of 3.45 MPa (500 psi), 100 ml sample loading, and a loss collection period of 60 minutes, or an equivalent test. The results are shown in FIG. 3. The total leakoff coefficient of STS was determined to be very low from the test. The STS fluid loss did not appear to be a function of differential pressure. This unique low to no fluid loss property, and excellent stability
(low rate of solids settling), allows the STS to be pumped at a low rate without concern of screen out.

Example 2

[0206] Stabilized Treatment Slurry. Another example of an STS is provided in Table 2 below, which has an SVF of 60%. The fluid is very flowable and has been pumped into a subterranean formation with available field equipment. Typical slickwater operation has an SVF up to about 8% only. In contrast, the fluid in the current example delivers proppant at a much higher efficiency. It should be noted that not all of the solids in these embodiments are conventional proppant, and the 40/70 mesh proppant and 100 mesh sand are conventionally referred to as proppant. In this regard, the SVF of the conventional proppant in the total fluid is 44.2%, and the volumetric ratio of proppant to fluid phase is quite high, 44.2/39.9=1.11. This represents a breakthrough in water efficiency for proppant placement.

<table>
<thead>
<tr>
<th>Components</th>
<th>Wt %</th>
<th>Vol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>40/70 proppant</td>
<td>49.7%</td>
<td>37.5%</td>
</tr>
<tr>
<td>100 mesh sand</td>
<td>8.9%</td>
<td>6.7%</td>
</tr>
<tr>
<td>3q silica</td>
<td>8.9%</td>
<td>6.7%</td>
</tr>
<tr>
<td>2q CaCO3</td>
<td>12.4%</td>
<td>9.2%</td>
</tr>
<tr>
<td>Liquid Latex</td>
<td>9.8%</td>
<td>19.3%</td>
</tr>
<tr>
<td>Water and additives</td>
<td>10.3%</td>
<td>20.6%</td>
</tr>
</tbody>
</table>

Table 2

[0207] A low total water content in the STS results from both high proppant loading in the STS and the conversely relatively low amount of free water required for the slurry to be flowable/ pumpable. Low water volume injection embodiments certainly result in correspondingly low fluid volumes to flow back. It can also be seen from the STS example in Table 2, the PVF of that formulation is 69%. This means that only 31% of the volume is fluid-filled voids. In a solid pack, a certain amount of water is retained due to capillary and/or surface wetting effects. The amount of retained water in this embodiment is higher than that of a conventional proppant pack, further reducing the amount of water flow back (in addition to inhibiting water infiltration into the matrix). Considering the statistical amount of water flowed back from a shale, carbonate or silstone formation after a conventional fracturing treatment, in embodiments of the STS fracturing treatment the flow back is less than 30% or less than 20% or less than 10% of the water injected in the STS stage and/or the total water injected (including any pre-pad, pad, front-end, proppant, flush, and post-flush stage(s)), and there is a good chance that there may even be zero flow back.

Example 3

[0209] STS Slurry Stability Tests. A slurry sample was prepared with the formulation given in Table 3.

<table>
<thead>
<tr>
<th>Components</th>
<th>g/L Slurry</th>
</tr>
</thead>
<tbody>
<tr>
<td>40/70 proppant</td>
<td>700-800</td>
</tr>
<tr>
<td>100 mesh sand</td>
<td>100-150</td>
</tr>
<tr>
<td>3q silica</td>
<td>100-140</td>
</tr>
<tr>
<td>2q CaCO3 (SafeCARB2)</td>
<td>150-200</td>
</tr>
<tr>
<td>0.036 wt% Diutan solution</td>
<td>0.4-0.6</td>
</tr>
<tr>
<td>Water and other additives</td>
<td>250-350</td>
</tr>
</tbody>
</table>

Table 3

[0210] The slurry was prepared by mixing the water, diutan and other additives, and SafeCARB particles in two 37.9-L (10 gallon) batches, one in an eductor and one in a RUSHITION turbine, the two batches were combined in a mortar mixer and mixed for one minute. Then the sand was added and mixed one minute, silica added and mixed with all components for one minute. A sample of the freshly prepared slurry was evaluated in a Fann 35 rheometer at 25°C, with an R135F1 configuration at the beginning of the test with speed ramped up to 300 rpm and back down to 0, an average of the two readings at 3, 6, 100, 200 and 300 rpm (2.55, 5.11, 85.0, 170 and 255 s⁻¹) recorded as the shear stress, and the yield stress (τₒ) determined as the y-intercept using the Herschel-Buckley rheological model.

[0211] The slurry was then placed and sealed with plastic in a 152 mm (6 in.) diameter vertical gravitational settling column filled with the slurry to a depth of 2.13 m (7 ft). The column was provided with 25.4-mm (1 in.) sampling ports located on the settling column at 190 mm (63"), 140 mm (47"), 84 mm (29") and 33 mm (11") connected to clamped tubing. The settling column was mounted with a shaker on a platform isolated with four airbag supports. The shaker was a BUTTKICKER brand low frequency audio transducer. The column was vibrated at 15 Hz with a 1 mm amplitude (vertical displacement) for two 4-hour periods the first and second settling days, and thereafter maintained in a static condition for 10 days (12 days total settling time, hereinafter "8 h(a) 15 Hz/10 d static"). The 15 Hz/1 mm amplitude condition was
[0212] At the end of the settling period the depth of any free water at the top of the column was measured, and samples were obtained, in order from the top sampling port down to the bottom. The post-settling period samples were similarly evaluated in the rheometer under the same configuration and conditions as the initial slurry, and the Herschel-Buckley yield stress calculated. The results are presented in Table 4.

### TABLE 4

<table>
<thead>
<tr>
<th>Shear Stress (Pa (lbf/100 ft²))</th>
<th>Delta, @</th>
<th>Shear Rate (s⁻¹)</th>
<th>Slurry Rutting (0.87):</th>
<th>Viscosity (cP) (Base line)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial slurry</td>
<td>2.55</td>
<td>2.13</td>
<td>85</td>
<td>170</td>
</tr>
<tr>
<td>(37.4)</td>
<td>(44.5)</td>
<td>(176.4)</td>
<td>(282.7)</td>
<td></td>
</tr>
<tr>
<td>Aged slurry, 8 h @ 15 Hz/10 d static</td>
<td>15.4</td>
<td>19.3</td>
<td>76.8</td>
<td>123</td>
</tr>
<tr>
<td>Top sample</td>
<td>(32.1)</td>
<td>(40.4)</td>
<td>(160.3)</td>
<td>(257.1)</td>
</tr>
<tr>
<td>Upper middle sample</td>
<td>15.9</td>
<td>20.2</td>
<td>81.9</td>
<td>132</td>
</tr>
<tr>
<td>(33.3)</td>
<td>(42.2)</td>
<td>(171)</td>
<td>(276.1)</td>
<td></td>
</tr>
<tr>
<td>Lower middle sample</td>
<td>14.8</td>
<td>19.3</td>
<td>79.3</td>
<td>130</td>
</tr>
<tr>
<td>(30.9)</td>
<td>(40.4)</td>
<td>(165.7)</td>
<td>(271.4)</td>
<td></td>
</tr>
<tr>
<td>Bottom sample</td>
<td>18.6</td>
<td>22.7</td>
<td>89.6</td>
<td>146</td>
</tr>
<tr>
<td>(38.9)</td>
<td>(47.5)</td>
<td>(187.1)</td>
<td>(305.8)</td>
<td></td>
</tr>
</tbody>
</table>

[0213] Since the slurry showed no or low free water depth after aging, the apparent viscosities (taken as the shear rate) of the aged samples were all within 9% of the initial slurry, the slurry was considered stable. Since none of the samples had an apparent viscosity (calculated as shear rate shear stress) greater than 300 mPa.s, the slurry was considered readily flowable. The carrier fluid was deionized water. Slurries were prepared by mixing the solids mixture and the carrier fluid. The slurry samples were screened for mixability and the depth of any free water formed before and after allowing the slurry to settle for 72 hours at static conditions. Samples which could not be mixed using the procedure described were considered as not mixable. The samples in which more than 5% free water formed were considered to be excessively settling slurries. The results were plotted in the diagram seen in FIG. 2.

[0214] From the data seen in FIG. 2, stable, mixable slurries were generally obtained where PVF is about 0.71 or more, the ratio of SVF/PVF is greater than 2.1* (PVF=0.71), and, where PVF is greater than about 0.81, SVF/PVF is less than 1–2.1* (PVF=0.81). These STS systems were obtained with a low carrier fluid viscosity without any yield stress. By increasing the viscosity of the carrier fluid and/or using a yield stress fluid, an STS may be obtained in some embodiments with a lower PVF and/or a with an SVF/PVF ratio less than 1–2.1* (PVF=0.71).

[0215] Example 5

[0215] Slot Orifice Flow Data. The multimodal STS system has an additional benefit in these embodiments in that the smaller particles in the voids of the larger particles act as slip additives like mini-ball bearings, allowing the particles to roll past each other without any requirement for relatively large spaces between particles. This property was demonstrated by the flow of the Table 2 STS formulation of these embodiments through a small slot orifice. In this experiment, approximately 100 mL of the slurry was loaded into a fluid loss cell and the bottom slot was opened to allow fluid and solid to come out, and the fluid was pushed by a piston using water as a hydraulic fluid supplied with an ISCO pump at a rate of 20 mL/min. The slot at the bottom of the cell was adjusted to different openings, 1.8 mm (0.0708 in.) and 1.5 mm (0.0591 in.). A few results of different slurries flowing through the slots are shown in Table 5.

### TABLE 5

<table>
<thead>
<tr>
<th>Fluid</th>
<th>% slurry flowed through 1.8 mm (0.0708 in.) slot</th>
<th>% slurry flowed through 1.5 mm (0.0591 in.) slot</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slickwater with high ppb</td>
<td>20%*</td>
<td>0%</td>
</tr>
<tr>
<td>60% SVF STS</td>
<td>100%</td>
<td>50%</td>
</tr>
<tr>
<td>50% SVF STS</td>
<td>100%</td>
<td>100%</td>
</tr>
</tbody>
</table>

*The slurry flowed out of the cell has less solid than what was left inside the cell, biggest particle in the formulation is 267 microns (0.0105 in.).

[0216] It can be seen from the results that the passage of the STS through the slot in this embodiment was facilitated, which validates the flowability observation. With the larger slot the ratio of slot width to largest proppant diameter was about 6.7; but just 5.6 in the case of the smaller slot. The slickwater technique requires a ratio of perforation diameter to proppant diameter of at least 6, and additional enlargement for added safety to avoid screen out usually dictates a ratio of at least 8 or 10 and does not allow high proppant loadings. In embodiments, the flowability of the STS through narrow flow passages (ratio of diameter of proppant to diameter or width of flow passage less than 6, e.g., less than 5, less than 4 or less than 3 or a range of 2 to 6 or 3 to 5) such as perforations and fractures is similarly facilitated, allowing a smaller ratio of perforation size to proppant size as well as a narrower fracture that still provides transport of the proppant to the tip, i.e., improved flowability of the proppant in the fracture and improved penetration of the proppant-filled fracture extending away from the wellbore into the formation. These embodiments provide a relatively longer proppant-filled fracture prior to screenout relative to slickwater or high-viscosity fluid treatments.
Examples 6-9

[0217] Additional Formulations. Additional STS formulations were prepared as shown in Table 2. Example 6 was prepared without proppant and exemplifies a high-solids stabilized slurry without proppant that can be used as a treatment fluid, e.g., as a spacer fluid, pad or managed interface fluid to precede or follow a proppant-containing treatment fluid. Example 7 was similar to Example 6 except that it contained proppant including 100 mesh sand. Example 8 was prepared with gelling agent instead of latex. Example 9 was similar to Example 8, but was prepared with dispersed oil particles instead of calcium carbonate. Examples 7-9 exemplify treatment fluids suitable for fracturing low mobility formations.

Additional Formulations

Additional STS formulations were prepared as shown in Table 2. Example 6 was prepared without proppant and exemplifies a high-solids stabilized slurry without proppant that can be used as a treatment fluid, e.g., as a spacer fluid, pad or managed interface fluid to precede or follow a proppant-containing treatment fluid. Example 7 was similar to Example 6 except that it contained proppant including 100 mesh sand. Example 8 was prepared with gelling agent instead of latex. Example 9 was similar to Example 8, but was prepared with dispersed oil particles instead of calcium carbonate. Examples 7-9 exemplify treatment fluids suitable for fracturing low mobility formations.

TABLE 6

<table>
<thead>
<tr>
<th>STS Components</th>
<th>Example 6</th>
<th>Example 7</th>
<th>Example 8</th>
<th>Example 9</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size (μm)</td>
<td>Example 6</td>
<td>Example 7</td>
<td>Example 8</td>
<td>Example 9</td>
</tr>
<tr>
<td>40/70 proppant</td>
<td>210-400</td>
<td>50-55</td>
<td>50-55</td>
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<td>100 mesh sand</td>
<td>150</td>
<td>8-12</td>
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<tr>
<td>Silica flour</td>
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<td>40-45</td>
<td>6-12</td>
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<tr>
<td>CaCO₃</td>
<td>2.5-3</td>
<td>20-25</td>
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<tr>
<td>Liquid Latex</td>
<td>0.18</td>
<td>20-25</td>
<td>8-12</td>
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<tr>
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<td>0.1-1</td>
<td>—</td>
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<tr>
<td>Anti-foam</td>
<td>—</td>
<td>0.05-0.5</td>
<td>0.05-0.5</td>
<td>—</td>
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<tr>
<td>Gelling agent</td>
<td>—</td>
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<tr>
<td>Dispersant</td>
<td>—</td>
<td>0.05-0.5</td>
<td>0.05-0.5</td>
<td>—</td>
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<tr>
<td>Breaker</td>
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<td>—</td>
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<tr>
<td>Breaker aid</td>
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<td>—</td>
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</tr>
<tr>
<td>Oil</td>
<td>—</td>
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<tr>
<td>Surfactant</td>
<td>—</td>
<td>—</td>
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<td>Water</td>
<td>8-12</td>
<td>8-12</td>
<td>18-22</td>
<td>18-22</td>
</tr>
</tbody>
</table>

Yield Point (Pa)
11.5
K (Pa.s⁻¹)
5.41
n
0.876
Stability (static 72 h)
Stable
Leakoff control
Stable
Cw (ft/min¹/²)
0.0002
Filter cake (μm)
<1
Clean up permeability (D)
ND
ND
ND
ND
0.004-0.024
1-1.2
Fluid Properties
SVE (%)
40 (60*)
60 (70*)
60
54 (60*)
Specific gravity
1.68
2
2
1.88
PAA (whole fluid)
NA
14
14
13.6
Notes:
ND = not determined
NA = not applicable
* = including latex or oil

[0218] All of the fluids were stable, and had a yield point above 10 Pa and a viscosity less than 10 Pa.s. Rheological, leak-off control and other fluid properties are given in Table 6.

Example 10

[0219] Crosslinked Pills. An STS was prepared from a mix of solids including 40/70 mesh proppant at 65 percent by volume of the total solids (% BVOB), 100 mesh silica sand at 11%BVOB, silica flour at 10% BVOB and 2-micron calcium carbonate at 14% BVOB. The carrier fluid was water viscosified with guar at 2.4 g/L (20 ppt) and containing NaOH to provide an alkaline pH conducive to crosslinking. An overflush fluid was prepared from borate crosslinker in water without viscosifier. The STS was pumped into a flow visualization cell consisting of a pair of opposing glass panes separated apart by 3 mm to simulate a fracture opening. Then the overflush fluid was pumped into the cell. The resulting pattern of proppant placement was observed visually and a representative depiction is illustrated in FIG. 10. As shown, the overflush fluid created relatively wide conductive channels due to viscous fingering phenomena attributed to the lower viscosity of the overflush fluid compared with the STS fluid, but also strengthened the periphery of the islands or pillars through crosslinking of the guar to encapsulate the pillar.

Example 11

[0220] Crosslinked Pills from Alkaline Overflush Fluid. This example is similar to Example 10 except the crosslinker is incorporated in the STS formulation without caustic and the overflush fluid comprises aqueous NaOH without crosslinker, i.e., the crosslinker and the NaOH are switched between the STS and overflush as compared with Example 10. The end result is essentially the same as in Example 10 where the overflush fluid not only creates wide conductive channels due to viscous fingering but also strengthens the periphery of the islands or pillars through crosslinking of the guar. The pillar is again encapsulated by the crosslinked gel.
Example 12

[0221] Crosslinked Pillars from Pulsed STS Fluids. In this example, a solid particulate crosslinker comprising CaOH, boric acid and sodium tetraborate pentahydrate is added to the STS fluid of Example 10 comprising guar and NaOH. As shown in FIG. 11, the crosslinker-STS fluid is pulsed to form slugs 1010 in the flowline 1012 in a train with alternating slugs 1014 formed from the same or a different STS fluid but without the crosslinker. When the train of fluids is pumped into the flow visualization cell 1016, the fluids form elongated, swirl-shaped regions 1018, 1020 corresponding to the respective slugs 1010, 1014. The presence of the crosslinker in the slugs 1010/regions 1018 does not crosslink the guar immediately because of the delayed release of the crosslinker from the solid particulate relative to the liquid/solution crosslinker as in Examples 10-11. Hence during pumping the train of fluids remains ungelled; however, once the train of fluid is placed in a fracture the regions 1018 develop localized gelling due to the release of the crosslinker in the STS with time, increased temperature, etc., and there are also STS regions 1020 that are not gelled STS. The non-gelled STS regions 1020 are considered to be more conductive channels compared with the gelled STS regions 1018. Furthermore, the proppant in the gelled regions 1018 does not sediment in the crosslinked gel, whereas the proppant in the non-gelled areas 1020 in embodiments sediments with time to enhance the conductivity of the non-gelled channels 1020. The STS fluid formulation in embodiments is adjusted to promote sedimentation through dilution or by incorporating a destabilization agent thus making it more conductive compared with the gelled regions 1018. The solid crosslinker is used in this example to delay the crosslinking and additionally it may be encapsulated with different material to control the rate of release that is temperature, pressure or chemistry dependent.

Example 13

[0222] Crosslinked Pillars from Hydraulic Cement Treatment. This example is similar to Example 12 except that the slugs 1010 are freshly prepared (uncured) hydraulic cement slurry or a slurry such as an STS containing hydraulic cement particulates, and the slugs 1014 comprise an STS. The pulsed cement creates local dehydration within the STS fluid(s) placed inside the fracture, thus creating inhomogeneous fluid placement and strengthening of pillars 1018 comprised of cured, hydrated cement and STS fluid in its vicinity. The cement containing areas 1018 in the fracture are less conductive relative to areas 1020 without cement, or the cement-STS slug 1010 may be chemically formulated such that both of the areas 1018, 1020 are highly conductive relative to the formation of the fracture.

Example 14

[0223] Crosslinked Pillars from SAP Treatment. In this example an STS with a solids mix similar to that of Example 11 was formulated with polyacrylamide superabsorbent polymer (SAP) particles capable of absorbing 500 times their weight of water (from 30-60 times initial volume). The STS includes means to delay swelling of the SAP until after placement in the fracture, and the rate of dehydration is controlled by selecting the SAP, valence cations in the aqueous carrier, encapsulant polymer, and/or chemical or physical trigger(s) to initiate the aqueous fluid absorption. The SAP-STS was pumped into the flow visualization cell 1030 to simulate a fracture opening and the SAP allowed to swell in a simulated shut-in, dehydrating localized regions of the STS. The resulting pattern of proppant placement was observed visually and a representative depiction is illustrated in FIG. 12. As shown, the SAP-proppant agglomerants formed relatively small pillars 1032 within a network of conductive channels 1034 corresponding to SAP-free regions.

[0224] While the disclosure has provided specific and detailed descriptions to various embodiments, the same is to be considered as illustrative and not restrictive in character. Only certain example embodiments have been shown and described. Those skilled in the art will appreciate that many modifications are possible in the example embodiments without materially departing from the disclosure. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

[0225] In reading the claims, it is intended that when words such as “a,” “an,” “at least one,” or “at least one portion” are used there is no intention to limit the claim to only one item unless specifically stated to the contrary in the claim. When the language “at least a portion” and/or “a portion” is used the claim item can include a portion and/or the entire item unless specifically stated to the contrary. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures. For example, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures. It is the express intention of the applicant not to invoke 35 U.S.C. §112, paragraph 6 for any limitations of any of the claims herein, except for those in which the claim expressly uses the words “means for” together with an associated function.

What is claimed is:

1. A method of placing a proppant pack into a fracture formed in a subterranean formation, the method comprising:
   - injecting a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage, wherein at least a portion of the well treatment fluid comprises a stabilized slurry stage and wherein the proppant-containing and stabilized slurry portions may be the same or different;
   - injecting a destabilizing system into the fracture with the well treatment fluid to destabilize the slurry stage and form regions of consolidated proppant from the destabilized slurry stage; and
   - placing a plurality of proppant clusters forming pillars from the consolidated proppant regions spaced by fluid flow channels from the formation through the fracture toward the wellbore.
2. The method of claim 1 wherein the stabilized slurry comprises a liquid phase, and wherein the slurry destabilizing system comprises a liquid-removing agent to remove fluid from the slurry.

3. The method of claim 2 wherein the liquid phase comprises water and the liquid-removing agent comprises a hydratable compound.

4. The method of claim 2 wherein the liquid phase comprises water and the liquid-removing agent comprises a superabsorbent polymer.

5. The method of claim 1, further comprising: sequentially injecting a first stage of the treatment fluid into the formation followed by a second stage of the treatment fluid, wherein the first and second stages have different viscosities, different specific gravities, or both, to initiate viscous fingering; wherein the stabilized slurry comprises the proppant in the first stage; wherein the destabilizing system comprises a crosslinkable material in the first stage, and a crosslinking agent in at least one of the first and second stages to crosslink the crosslinkable material in the pillars.

6. The method of claim 5 wherein the specific gravity of the first stage is matched with the specific gravity of the second stage to mitigate gravity effects.

7. The method of claim 5 wherein the crosslinkable material comprises a polysaccharide, and wherein the crosslinking agent comprises a source of borate or a polyvalent metal.

8. The method of claim 7 wherein one of the first and second stages comprises a pH control material to provide an alkaline pH and the other one of the first and second stages comprises the source of borate or polyvalent metal.

9. The method of claim 8 wherein the first stage comprises subproppant particles and has a slurry solids volume fraction (SVF) of 0.4 or more; and wherein the second stage is free of solids or has an SVF less than 0.4.

10. The method of claim 1, further comprising: alternatingly injecting a plurality of pulsed first and second slugs of the well treatment fluid, wherein the first and second slugs each comprise a said stabilized slurry which may be the same or different; wherein the slurry destabilizing system comprises a reagent selectively present in one of the first and second slugs to respectively form the pillars from consolidated proppant packs and the channels from relatively permeable proppant packs.

11. The method of claim 10 wherein the first and second slugs comprise a crosslinkable material and wherein the reagent comprises a solid particulated crosslinking agent.

12. The method of claim 10 wherein water and the reagent comprises a hydratable compound to remove water from at least one of the slurries.

13. The method of claim 10 wherein the stabilized slurries comprise water and the reagent comprises a superabsorbent polymer to remove water from at least one of the slurries.

14. The method of claim 1, wherein the stabilized slurry is formed by at least one of: (1) introducing sufficient particles into the slurry to increase the solids volume fraction (SVF) of the slurry fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry to at least 1 Pa·s (5.11 s⁻¹, 25° C); (3) increasing a yield stress of the slurry to at least 1 Pa; (4) increasing apparent viscosity of the slurry to at least 50 mPa·s (170 s⁻¹, 25° C); (5) introducing a multimodal solids phase into the slurry; (6) introducing a solids phase having a packed volume fraction (PVF) greater than 0.7 into the slurry; (7) introducing into the slurry a viscosifier selected from viscoelastic surfactants and hydratable gelling agents; (8) introducing colloidal particles into the slurry; (9) reducing a particle-fluid density delta in the slurry to less than 1.6 g/mL; (10) introducing particles into the slurry having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into the slurry; and (12) combinations thereof.

15. A propped fracture system obtained as a result of placing a propping pack into a fracture according to a method comprising: injecting a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage, wherein at least a portion of the well treatment fluid comprises a stabilized slurry stage and wherein the proppant-containing and stabilized slurry portions may be the same or different; injecting a destabilizing system into the fracture with the well treatment fluid to destabilize the slurry stage and form regions of consolidated proppant from the destabilized slurry stage; and placing a plurality of proppant clusters forming pillars from the consolidated proppant regions spaced apart by fluid flow channels from the formation through the fracture toward the wellbore.

16. A system for fracturing a subterranean formation, comprising: a supply module to inject a well treatment fluid through a wellbore into a fracture in a subterranean formation, wherein at least a portion of the well treatment fluid comprises a proppant-containing stage fluid, wherein at least a portion of the well treatment fluid comprises a stabilized slurry stage fluid and wherein the proppant-containing and stabilized slurry portions may be the same or different fluids; and a destabilizing system in communication with the supply module for injection into the fracture with the well treatment fluid to destabilize the slurry stage fluid, form regions of consolidated proppant from the destabilized slurry stage fluid and form pillars spaced apart by fluid flow channels from the formation through the fracture toward the wellbore.

17. The system of claim 16 wherein the stabilized slurry comprises a liquid phase, and wherein the slurry destabilizing system comprises a liquid-removing agent to remove fluid from the stabilized slurry.

18. The system of claim 16, further comprising: a pump system to sequentially inject a first stage of the treatment fluid into the formation followed by a second stage of the treatment fluid, wherein the first stage treatment fluid has a higher viscosity relative to the second
stage treatment fluid, or wherein the first and second stages have different specific gravities, to initiate visco-
cous fingering;
wherein the stabilized slurry comprises the proppant in the
first stage fluid;
wherein the destabilizing system comprises a crosslink-
able material in the first stage fluid, and a crosslinking
agent in at least one of the first and second stage fluids to
crosslink the crosslinkable material in the pillars.
19. The system of claim 18 wherein the crosslinkable mate-
rial comprises a polysaccharide, and wherein the crosslinking
agent comprises a source of borate or a polyvalent metal.
20. The system of claim 19 wherein one of the first and
second stage fluids comprises a pH control material to pro-
vide an alkaline pH and the other one of the first and second
stage fluids comprises the source of borate or polyvalent
metal.
21. The system of claim 20 wherein the stabilized slurry
comprises the proppant and subproppant particles, has a sol-
ids volume fraction (SVF) of 0.6 or more and solids comprising
a packed volume fraction (PVF) of 0.7 or more; and
wherein the second stage fluid is free of solids or has an SVF
less than 0.05.
22. The system of claim 16, further comprising:
apump system to alternately inject a plurality of pulsed
first and second slugs of the treatment fluid, wherein the
first and second slugs each comprise a said stabilized
slurry;
wherein the slurry destabilizing system comprises a pri-
mary reagent selectively present in one of the first and
second slugs to respectively form the pillars from con-
solidated proppant packs and the channels from rela-
tively permeable proppant packs.
23. The system of claim 22 wherein the first and second
slugs comprise a crosslinkable material and wherein the
reagent comprises a solid particulated crosslinking agent.
24. The system of claim 23 wherein the stabilized slurrys
comprise a liquid phase, and wherein the reagent comprises a
solid liquid-removal agent to remove fluid from the stabilized
slurry.
25. The system of claim 16, wherein the stabilized slurry
comprises at least one of the stability indicia selected from:
(1) a solids volume fraction (SVF) of at least 0.4; (2) a
low-shear viscosity of at least 1 Pa·s (5.11 s⁻¹, 25° C.); (3) a
yield stress of at least 1 Pa; (4) an apparent viscosity of at least
50 mPa·s (170 s⁻¹, 25° C.); (5) a multimodal solids phase; (6)
a solids phase having a packed volume fraction (PVF) greater
than 0.7; (7) a viscosifier selected from viscoelastic surfac-
tants, in an amount ranging from 0.01 up to 7.2 g/L (60 ppt),
and hydratable gelling agents in an amount ranging from 0.01
up to 4.8 g/L (40 ppt) based, on the volume of fluid phase; (8)
colloidal particles; (9) a particle-fluid density delta less than
1.6 g/mL; (10) particles having an aspect ratio of at least 6;
(11) ciliated or coated proppant; and (12) combinations thereof.