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(54) **WELL TREATMENT METHODS AND SYSTEMS**

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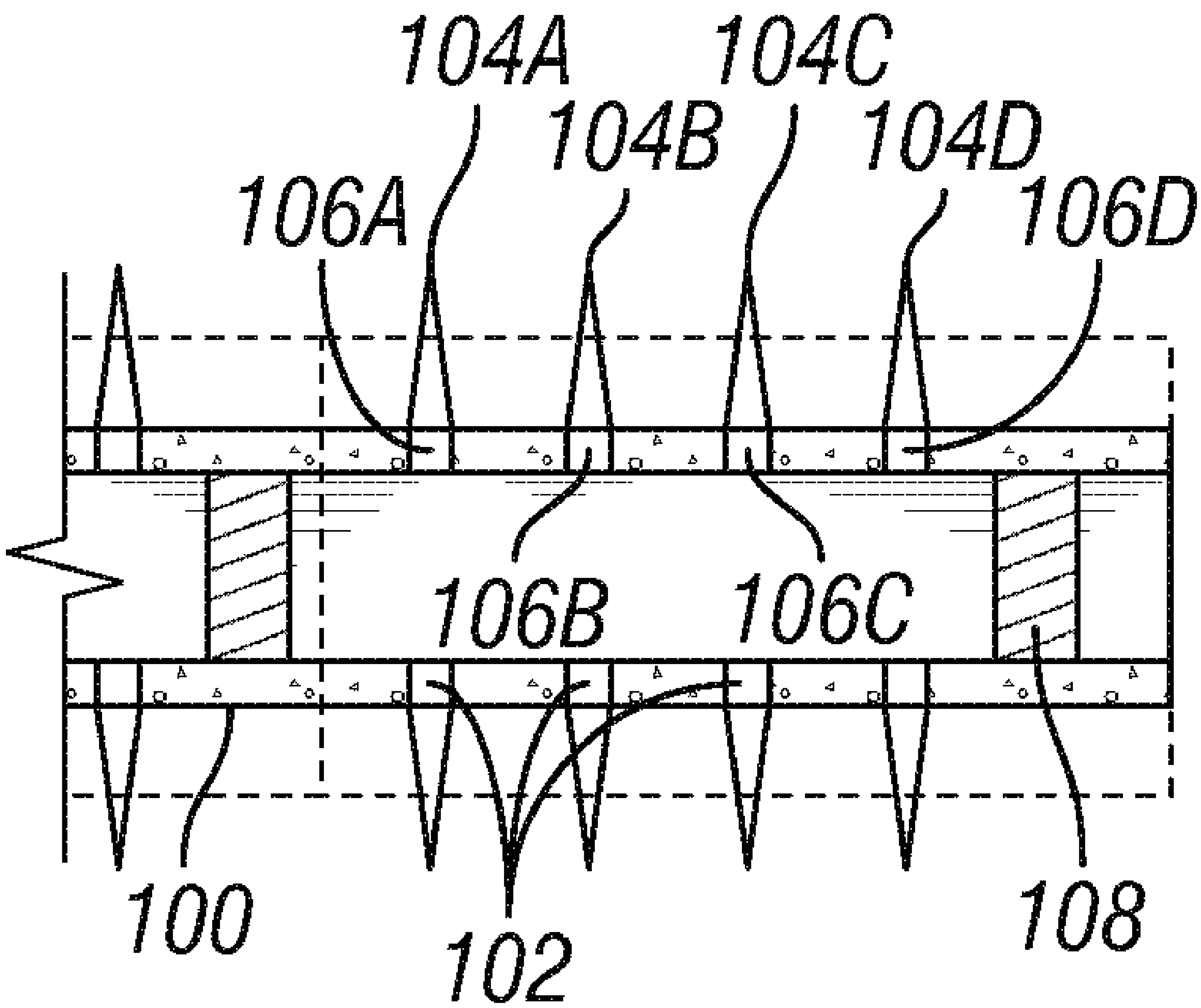
USPC **166/280.1**

(57) **ABSTRACT**

Methods, fluids, equipment and/or systems for treating a subterranean formation penetrated by a wellbore, which use less water, less energy, less equipment, have a smaller wellsite footprint, a reduced carbon dioxide emission, an improved distribution of proppant among a plurality of flow paths, an improved stimulation of reservoir fluid production, an improved risk management method, or the like, or any combination thereof, relative to comparable conventional treatment methods, fluids, equipment and/or systems such as, for example, hydraulic fracture treatments of subterranean formations using slickwater and/or high-viscosity treatment fluids.



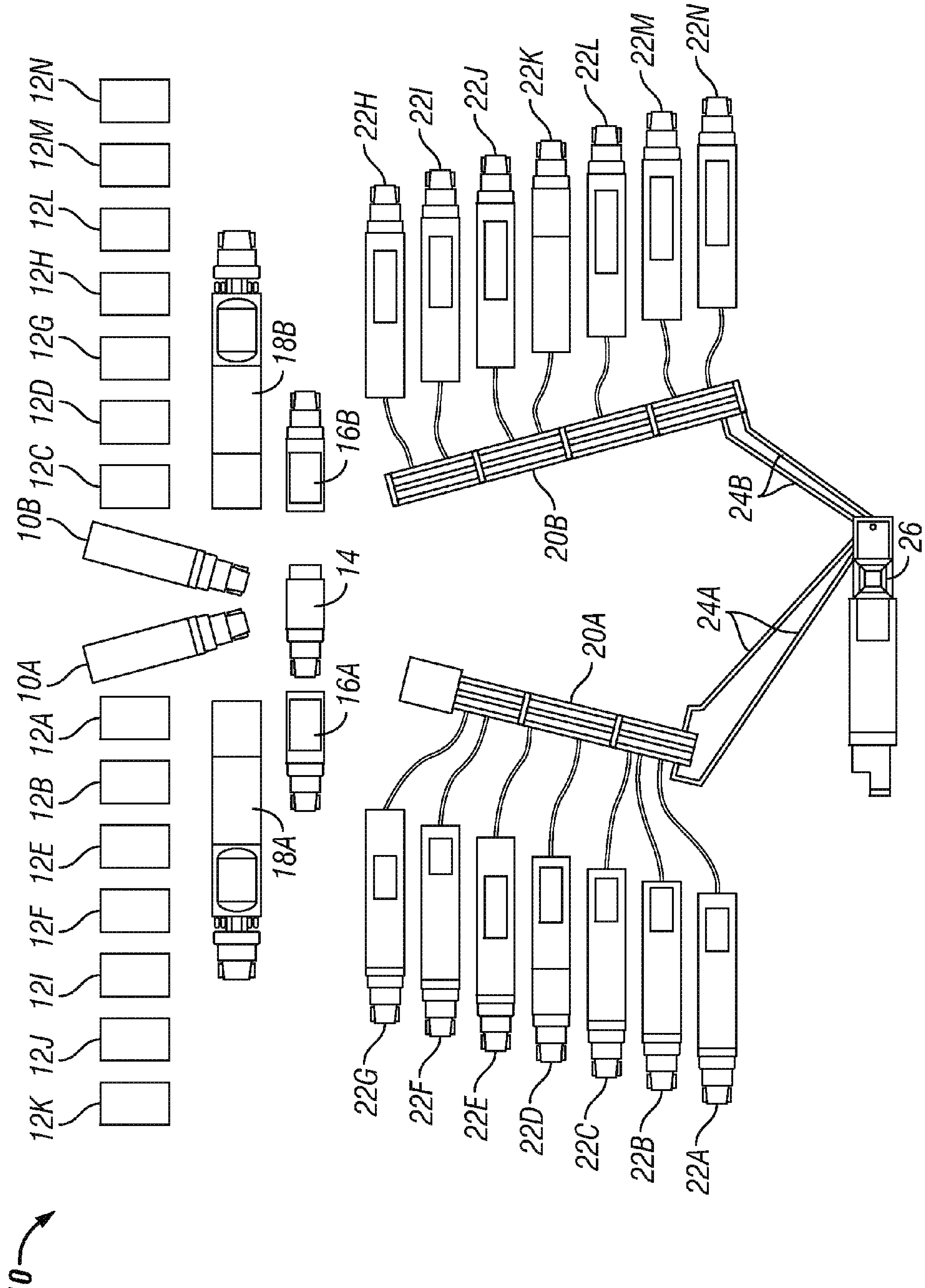


FIG. 1
(Prior Art)

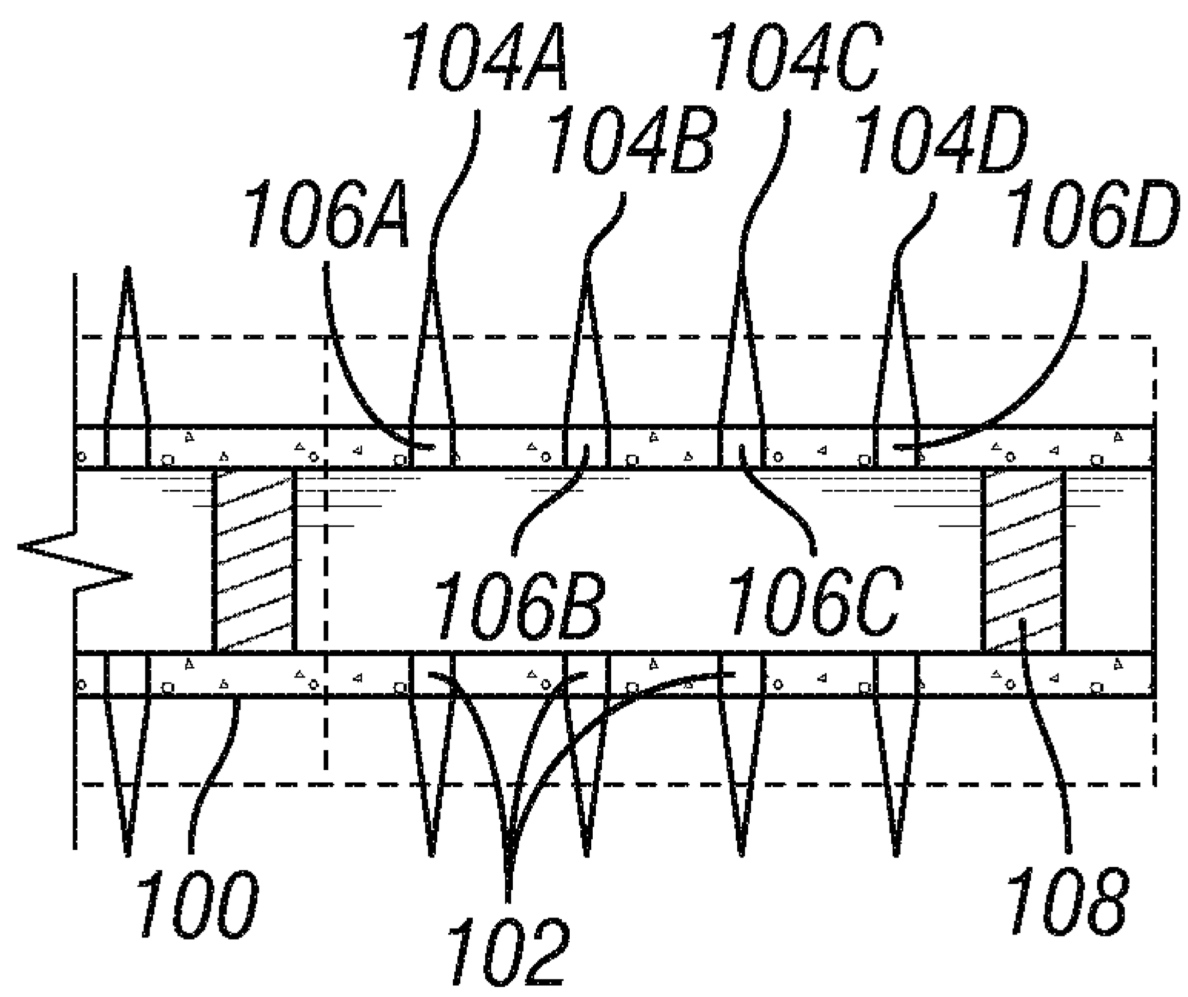

104A
104C
104B
104D
106A
106D
106B
106C
100
102
108

FIG. 2

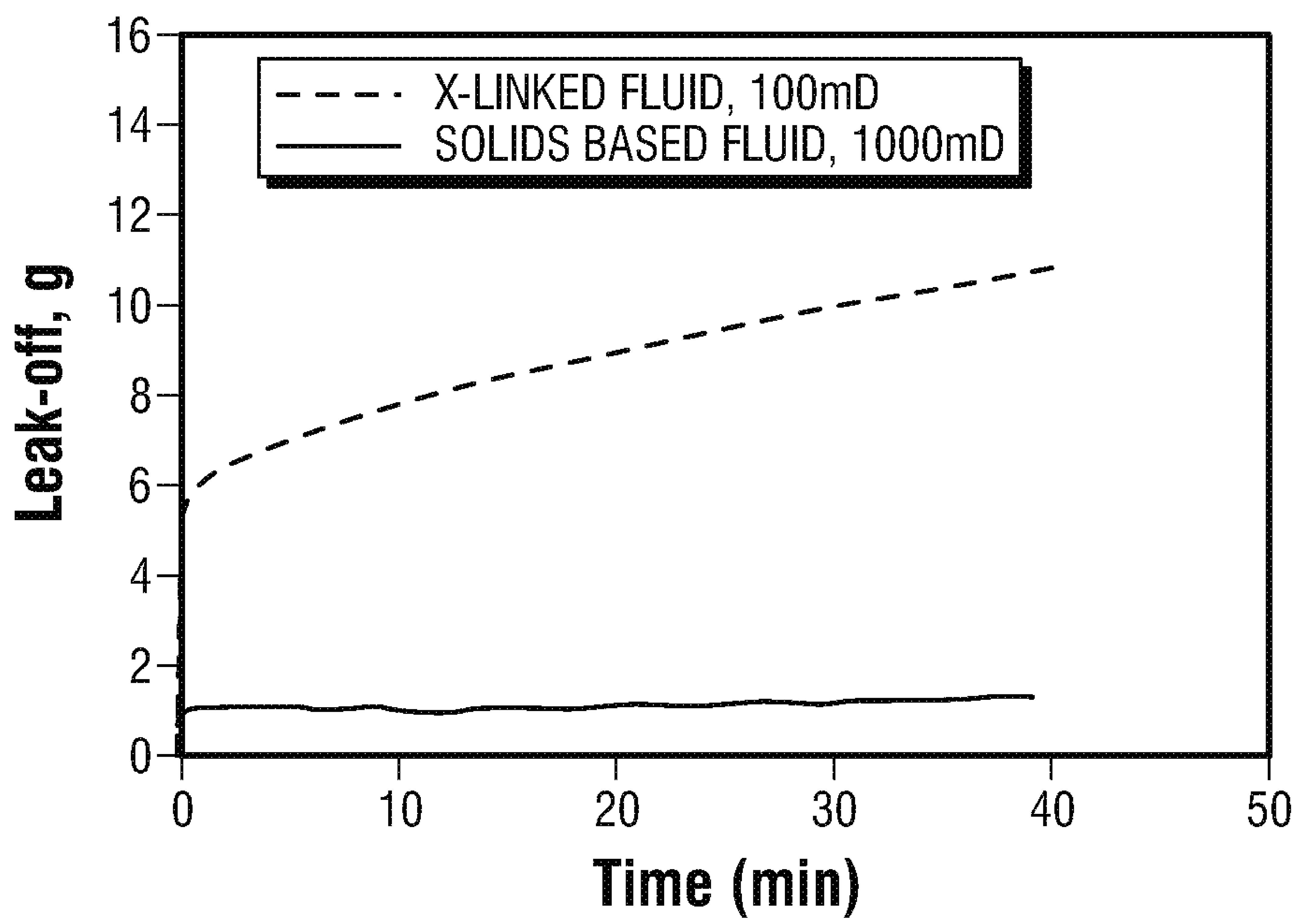

X-LINKED FLUID, 100mD
SOLIDS BASED FLUID, 1000mD
Leak-off, g
Time (min)
0
2
4
6
8
10
12
14
16
0
10
20
30
40
50

FIG. 3

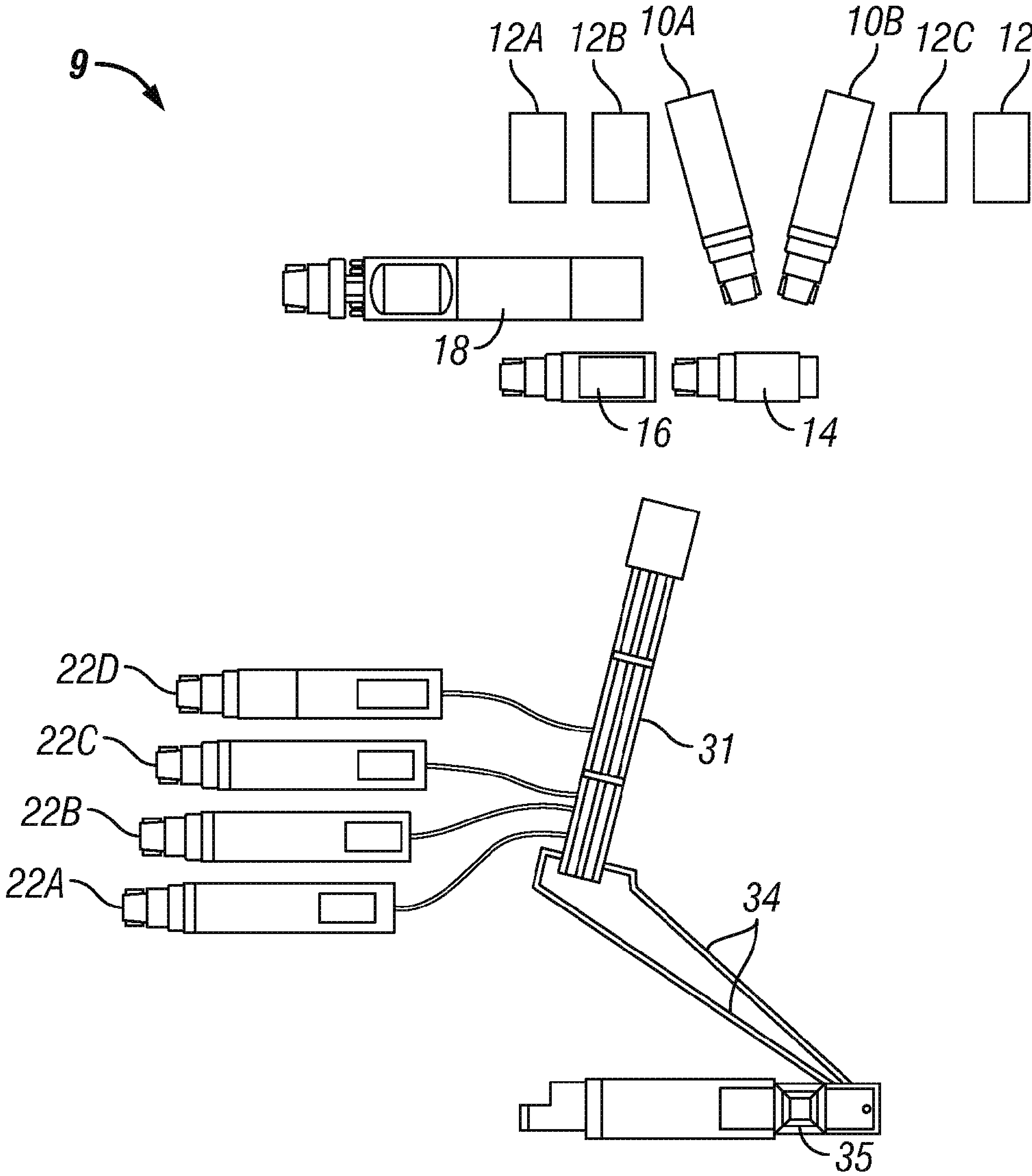


FIG. 4

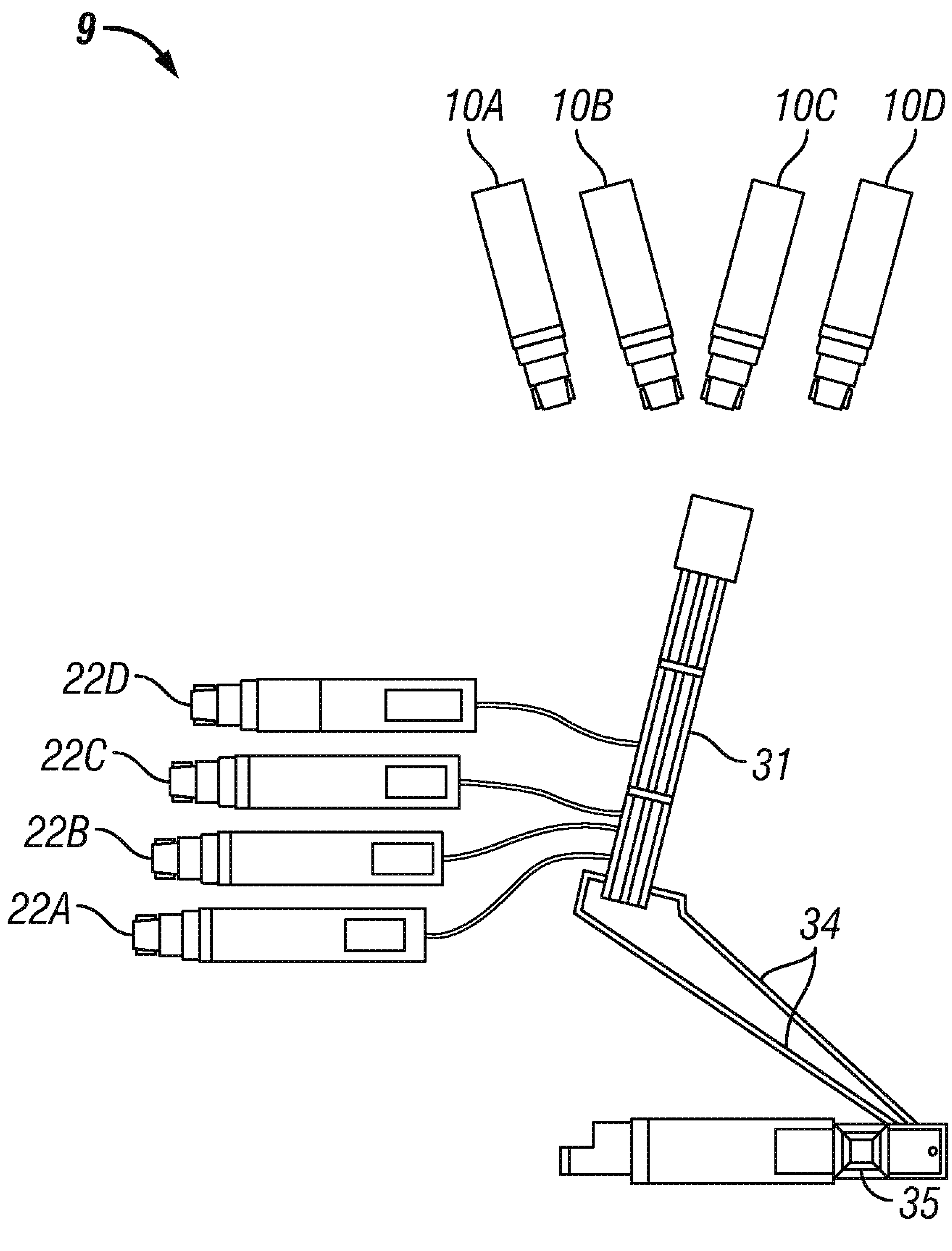


FIG. 5

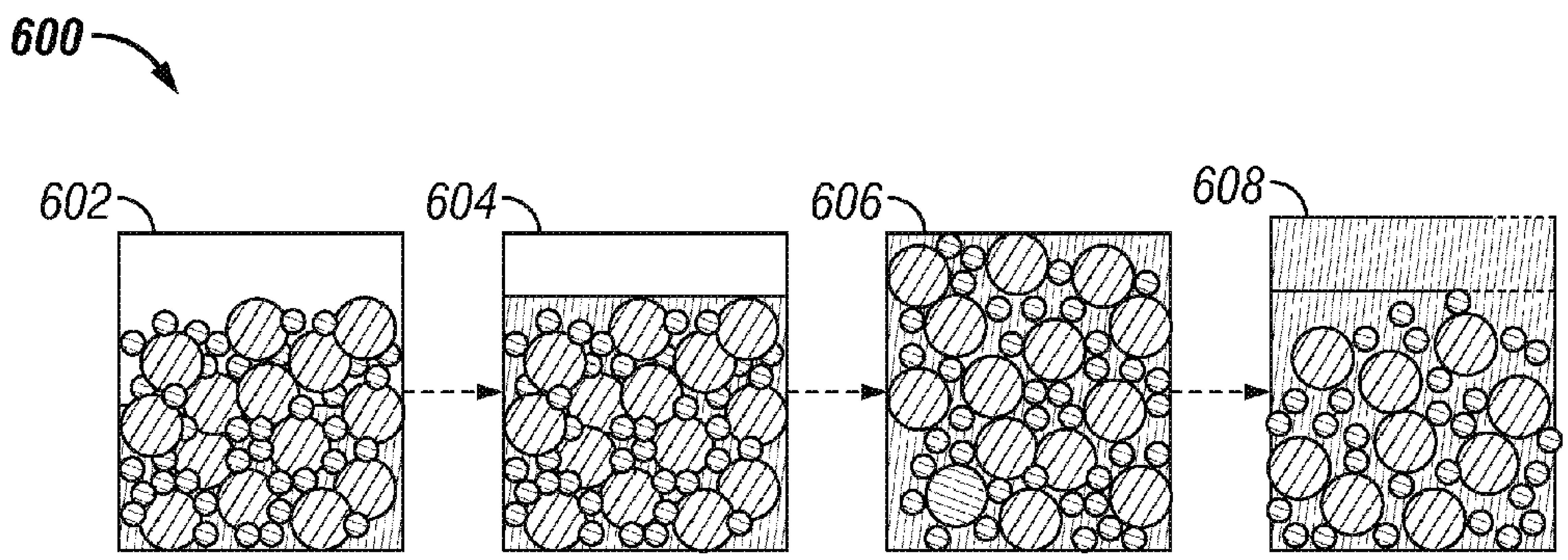

600
602
604
606
608

FIG. 6

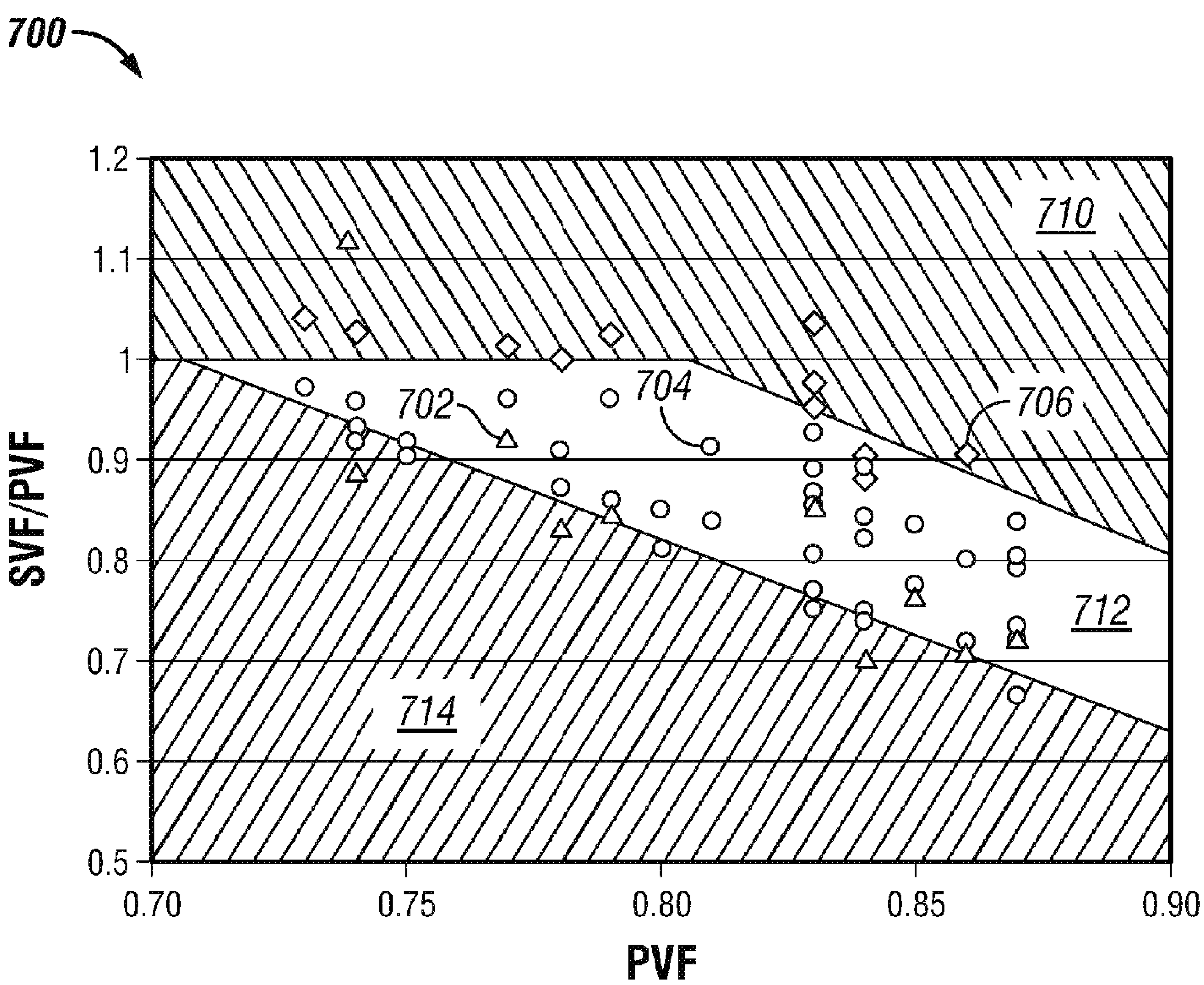

700
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
SVF/PVF
0.70
0.75
0.80
0.85
0.90
PVF
702
704
706
710
712
714

FIG. 7

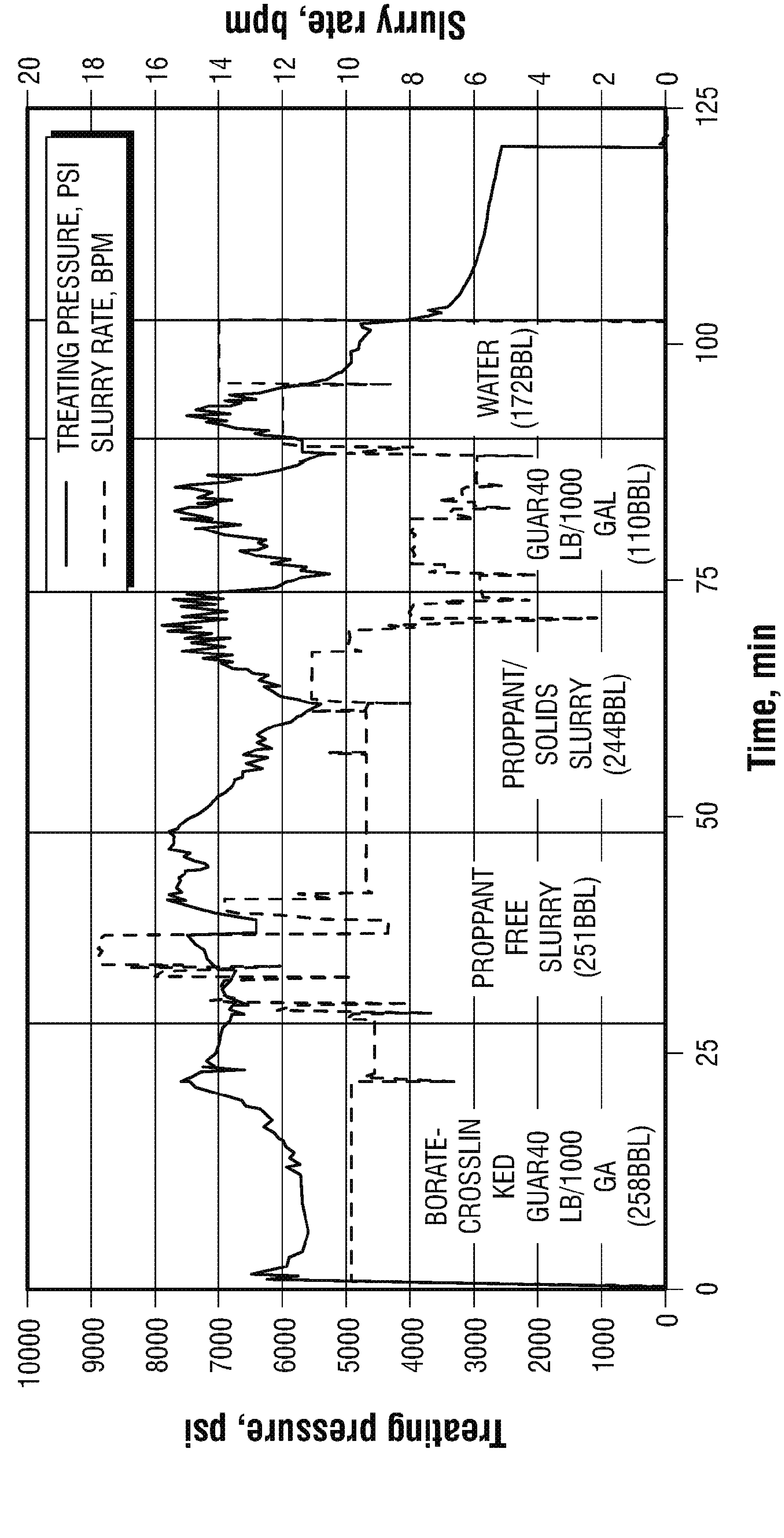

TREATING PRESSURE, PSI
SLURRY RATE, BPM
Slurry rate, bpm
Treating pressure, psi
Time, min
BORATE-CROSSLINKED GUAR40 LB/1000 GA (258BBL)
PROPPANT FREE SLURRY (251BBL)
PROPPANT/SOLIDS SLURRY (244BBL)
GUAR40 LB/1000 GAL (110BBL)
WATER (172BBL)
0
25
50
75
100
125
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
0
2
4
6
8
10
12
14
16
18
20

FIG. 8

WELL TREATMENT METHODS AND SYSTEMS

RELATED APPLICATION DATA

[0001] The current application claims the benefit of U.S. provisional application Ser. No. 61/697,072, filed on Sep. 5, 2012, titled "Well Treatment Methods And Systems", the entire content of which is incorporated herein by reference.

BACKGROUND

[0002] The statements in this section merely provide background information related to the present disclosure and may not constitute prior art.

[0003] Many hydraulic fracturing techniques, e.g., slickwater techniques, use an excessive amount of water, energy and on-site equipment to entrain and deliver proppant at high pumping rates into the subterranean formation fracture, leading to excessive water treatment costs, formation damage, undesirable fracture geometries in heterogeneous formations, high flowback fluid volumes, delayed production following treatment, waste disposal issues, public concerns about potential potable aquifer contamination, and other problems. Other techniques, e.g., viscosified proppant carrier fluids, require excessive amounts of viscosifiers that can damage the formation, e.g., as by impairing conductivity, or may be incompatible with downhole conditions such as pH, temperature, the presence of reactive chemicals, etc. In either case, high pump rates are frequently needed to maintain entrainment of the proppant and to maintain a sufficient downhole pressure for fracture initiation and propagation, i.e., fracture creation.

[0004] Typically, deliveries of liquids, proppant, and chemicals to the wellsite are accomplished before the fracturing job begins. Specialized storage equipment is normally used for handling the large quantities of materials, such as sand chiefs made by Besser. Similarly, specialized tanks such as water tanks and frac tanks are used for liquids. These tanks are typically the largest possible volume that can be transported without difficulty on the available roads within the limits of weight, length, width, height, etc. High pressure (e.g., 55 MPa (8 ksi)), high volume (e.g., 1.6 m^3/min (10 BPM)), high power (e.g., three 1.67 MW=5.0 MW total (3×2250 hp=6750 hp total)) fracturing pumps, and spare(s) because such pumps are prone to a high failure rate, are also used. The pumps are also the highest possible capacity at the required pressures that can be transported on the available roads using the available trucks, or that can be obtained within the limits of permissible vibration and noise. Once everything is ready, more specialized equipment is used to prepare gel, mix in proppant, dose with chemicals, and deliver the resulting fluid under positive pressure to the inlet piping of the fracturing pumps. All of these specialized well site vehicles and units are expensive, and lead to a very large footprint on location.

[0005] FIG. **1** illustrates a wellsite configuration **10** that is typically used in current land-based fracturing operations. The proppant is contained in sand trailers **10**A, **10**B. Water tanks **12**A, **12**B, **12**C, . . . **12**N are arranged along one side of the operation site. Hopper **14** receives sand from the sand trailers **10**A, **10**B and distributes it into the mixers **16**A, **16**B. Blenders **18**A, **18**B are provided to blend the carrier medium (such as brine, viscosified fluids, etc.) with the proppant and then the slurry is discharged to manifolds **20**A, **20**B. The final mixed and blended slurry, also called frac fluid, is then transferred to the pump trucks **22**A, **22**B, **22**C . . . **22**N, and routed at treatment pressure through treating lines **24**A, **24**B to wellhead **26**, and then pumped downhole.

[0006] It is also desired to reduce the emission of pollutants, including dust, greenhouse gases, such as nitrous oxide and carbon dioxide, and other gases such as carbon monoxide and hydrocarbons. Many types of oilfield equipment are operated by means of diesel engines, which typically produce a relatively large quantity of emissions from the combustion of diesel fuel.

[0007] Improvements in slurry treatments, methods, fluids and systems in general and in fracture treatments in particular, are desired.

SUMMARY

[0008] In some embodiments herein, methods and systems for treating a subterranean formation are disclosed. In some embodiments, the treatment methods or systems employ a stabilized treatment slurry (STS) wherein the solid phase, which may include proppant, is inhibited from gravitational settling in the fluid phase.

[0009] In some embodiments herein, treatment methods, fluids, equipment and/or systems in general or in fracturing in particular have, or provide, or are associated with, one or more of the following characteristics, namely: use of less water, improvement of energy efficiency, use of less energy, reduction of emissions of dust, NOx, CO, HC, and/or CO_2, use of less equipment (e.g., fewer trucks or pumps), use of a relatively lower pumping rate, use of a lower pressure drop through perforations, use of a lower friction pressure, use of a relatively lower pump discharge pressure, a smaller wellsite footprint, improvement of solids transport, improvement of distribution of solids among a plurality of transverse flow paths, improvement of stimulation of reservoir fluid production (in oil and gas well treatments), use of a slurry with a longer settling time, allowing pumping or flow of the fluid to be stopped and started or re-started without significant solids settling, allow adjustment of the treatment fluid density, allowing the use of a fluid with controllable bridging characteristics, use of a low-viscosity treatment fluid, use of a low viscosifier content, use of a yield stress fluid, or the like, or any combination thereof, relative to comparable conventional treatment methods, fluids, equipment and/or systems such as, for example, hydraulic fracture treatments of subterranean formations with slickwater and/or high-viscosity treatment fluids, in the case of hydraulic fracturing.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] 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.

[0011] FIG. **1** is a schematic representation of the equipment configuration of a conventional fracturing operation.

[0012] FIG. **2** shows a schematic of a horizontal well with perforation clusters according to some embodiments of the current application.

[0013] FIG. **3** shows the leakoff property of a low viscosity, high proppant treatment fluid (lower line) according to some embodiments of the current application compared to conventional crosslinked fluid (upper line).

[0014] FIG. 4 shows a schematic representation of the wellsite equipment configuration with onsite mixing according to some embodiments of the current application.

[0015] FIG. 5 shows a schematic representation of the wellsite equipment configuration with a pump-ready fluid according to some embodiments of the current application.

[0016] FIG. 6 shows a schematic slurry state progression chart for a treatment fluid according to some embodiments of the current application.

[0017] FIG. 7 illustrates fluid stability regions for a treatment fluid according to some embodiments of the current application.

[0018] FIG. 8 shows the treating pressure and slurry rate for a fracture operation according to some embodiments of the current application.

DETAILED DESCRIPTION OF SOME ILLUSTRATIVE EMBODIMENTS

[0019] 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.

[0020] 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.

[0021] 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.

[0022] In some embodiments herein, a method comprises: (a) injecting a treatment fluid containing proppant into (i) a subterranean formation or (ii) a subterranean formation penetrated by a wellbore; and (b) creating a fracture in the subterranean formation with the fluid. As used herein, "fracture creation" encompasses either or both the initiation of fractures and the propagation or growth thereof. The following conventions with respect to slurry terms are intended herein unless otherwise indicated explicitly or implicitly by context: "proppant" refers to a particle size mode or modes in the slurry having a weight average mean particle size greater than or equal to about 100 microns [105=140 mesh] (unless a different proppant size is indicated in the claim or a smaller proppant size is indicated in a claim depending therefrom); "subproppant" refers to particle size modes having a smaller size than the proppant modes (including colloidal and submicron particles); references to "proppant" exclude subproppant particles and vice versa; "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); "treatment fluid" or "fluid" (in context) refers to the entire treatment fluid, including any proppant, subproppant particles, liquid, gas etc.; "fluid phase" or "liquid phase" refer to the fluid or liquid that is present including any solutes, thickeners or colloidal particles only, exclusive of other solids; "whole fluid," "total fluid" and "base fluid" are used herein to refer to the fluid phase plus any subproppant particles, but exclusive of proppant particles; reference to "water" in the slurry refers only to water and excludes any particles, solutes, thickeners, colloidal particles, etc.; "solids-free" and similar terms exclude proppant and subproppant particles, except particulate thickeners such as colloids for the purposes of determining the viscosity of a "solids-free" fluid.

[0023] With reference to the embodiments of FIG. 2, a cased and cemented horizontal well **100** is configured to receive a treatment stage for simultaneously introducing treatment fluid through a plurality of perforations **102**, creating at least one fracture or a plurality of fractures, or multiple fractures **104**A, **104**B, **104**C, **104**D. The treatment stage in these embodiments is provided with four corresponding cluster sets **106**A, **106**B, **106**C, **106**D to form the respective fractures **104**A, **104**B, **104**C, **104**D. Four cluster sets are shown for purposes of illustration and example, but the invention is not limited to any particular number of cluster sets in the stage. Each cluster set **104**A, **104**B, **104**C, **104**D is provided with a plurality of radially arrayed perforations **102**. A fracture plug **108**, which may be mechanical, chemical or particulate-based (e.g., sand), may be provided to isolate the stage for treatment. The treatment stage may have the number and/or size of the perforations in the individual clusters and/or the number of clusters determined for the appropriate amount and rate of proppant to be delivered. The amount of proppant delivered to each fracture is generally determined by the relative number of perforations in the particular cluster associated with the respective fracture in question.

[0024] It should be understood that, although a substantial portion of the following detailed description is 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 from the disclosure of the current application as well. Similarly, it should be understood that, although a substantial portion of the following detailed description is provided in the context of a horizontal wellbore cased and cemented in the subterranean formation with clusters of perforations generated on the wellbore, the fracturing treatment methods, fluids and/or systems described herein are not necessarily limited to such application. Vertical or deviated wells, non-cased wells, non-completed wells, partially completed wells, open-hole wells, non-perforated completions, etc. can also utilize and benefit from the disclosure of the current application. Moreover, the fracturing treatment methods, fluids and/or systems described herein can be implemented through a single flow path into the formation, plural or multiple flow paths into fracture(s), and/or the like. All variations that can be readily perceived by people skilled in the art having the benefit of the current application should be considered as within the scope of the current application.

[0025] In certain embodiments herein, a method comprises combining proppant and a fluid phase at a volumetric ratio of the fluid phase (Vfluid) to the proppant (Vprop) equal to or less than 1.5 to form a treatment fluid; and injecting the treatment fluid into a subterranean formation to create a fracture in the subterranean formation. In embodiments, Vfluid/Vprop is equal to or less than 1. In embodiments, Vfluid/Vprop is equal to or less than 0.7. In embodiments, Vfluid/Vprop is equal to or less than 0.6. 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 0.2. In embodiments, the method further comprises stabilizing the treatment fluid. In embodiments, the treatment fluid comprises a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.) and a yield stress between 1 and 20 Pa (2.1-42 lb_f/ft^2). In embodiments, the treatment fluid comprises a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), a solids phase having a packed volume fraction (PVF) equal to or 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).

[0026] In certain embodiments herein, a method comprises: injecting a proppant-containing treatment fluid into a low mobility subterranean formation; creating a fracture in the subterranean formation containing a first volume (V**1**) of the proppant-containing treatment fluid; and allowing the fracture to close on the proppant to form a proppant-supported fracture having a second volume (V**2**) of packed proppant support, wherein a ratio of the second volume (V**2**) to the first volume (V**1**) is at least 0.5. In embodiments, the second volume (V**2**) to the first volume (V**1**) is at least 0.6. In embodiments, the second volume (V**2**) to the first volume (V**1**) is at least 0.7. In embodiments, the low mobility formation comprises a carbonate or siltstone formation. In embodiments, the low mobility formation comprises permeability less than 0.1 mD and further comprising producing hydrocarbon liquid from the formation. In embodiments, the low mobility formation comprises permeability less than 1000 nD and further comprising producing hydrocarbon gas from the formation. In embodiments, the method further comprises forming the proppant-supported fracture to extend away from a wellbore for a distance of at least 30 m (98 feet) into the subterranean formation, at least 50 m (164 feet) into the subterranean formation, at least 100 m (328 feet) into the subterranean formation, or at least 150 m (492 feet) into the subterranean formation. In embodiments, the method further comprises placing the packed proppant support in pillars and forming open channels in spaces between the pillars. In embodiments, the proppant-containing treatment fluid comprises a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.) and a yield stress between 1 and 20 Pa (2.1-42 lb_f/ft^2). In embodiments, the proppant-containing treatment fluid comprises 0.36 liters (L) (0.95 gal or 0.023 bbl) or more of proppant volume per liter of proppant-containing treatment fluid (equivalent to 8 lbs proppant added per gallon of base fluid ("ppa") where the proppant has a specific gravity of 2.6), a viscosity less than 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). In embodiments, the proppant-containing treatment fluid comprises 0.4 L or more of proppant volume per liter of proppant-containing treatment fluid (9 ppa where the proppant has a specific gravity of 2.6), or 0.45 L or more of proppant volume per liter of proppant-containing treatment fluid (10 ppa where the proppant has a specific gravity of 2.6).

[0027] In certain embodiments herein, a method comprises injecting a proppant-containing treatment fluid from a wellbore through a perforation at a sustained perforation velocity of less than 50 m/s (164 ft/s) for a continuous period of at least 5 minutes to create a fracture in a subterranean formation; and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore, at least 50 m (164 feet) away from the wellbore, at least 100 m (328 feet) away from the wellbore, or at least 150 m (492 feet) away from the wellbore. In embodiments, the sustained perforation velocity over the continuous period is less than 30 m/s. In embodiments, the method further comprises preparing the proppant-containing treatment fluid by combining at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid and stabilizing the proppant-containing treatment fluid.

[0028] In certain 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 whole fluid to form a proppant-containing treatment fluid; stabilizing the proppant-containing treatment fluid; injecting the proppant-containing treatment fluid into a subterranean formation; creating a fracture in the subterranean formation with the treatment fluid; stopping injection of the treatment fluid to interrupt the creation of the fracture thereby stranding the treatment fluid in the wellbore; and thereafter resuming injection of the treatment fluid to inject the stranded treatment fluid into the formation and continue the fracture creation.

[0029] In certain 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 whole fluid to form a proppant-containing treatment fluid; stabilizing the proppant-containing treatment fluid; injecting the proppant-containing treatment fluid into a subterranean formation; propagating a fracture in the subterranean formation with the treatment fluid; stopping injection of the treatment fluid to interrupt the propagation of the fracture thereby stranding the treatment fluid in the wellbore; and thereafter circulating 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.

[0030] In certain embodiments herein, a method comprises: injecting into a subterranean formation one or more treatment fluids comprising a volume of an aqueous phase (Vw) and a volume of proppant (Vprop) at an overall ratio of Vw/Vprop less than 2; creating and filling a fracture in the subterranean formation with at least one of the one or more treatment fluids comprising the volume of proppant distributed therein; allowing fracture closure on the proppant to form a proppant-supported fracture; transporting at least a fraction of the injected volume of the aqueous phase from the one or more treatment fluids into the subterranean formation; and producing a reservoir fluid comprising hydrocarbon (oil or gas) through the proppant-supported fracture free of any aqueous phase flowback or with an aqueous phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw) less than 5% over an initial production period of 5 days (FRR5). In embodiments, FRR5 is less than 1%. In embodiments, any water produced from the reservoir after a period of continuous hydrocarbon production of at least 10 days comprises less than 1% treatment fluid water and at least 99% produced water. As used herein, produced water refers to water produced from a wellbore that is not from the treatment fluid. In embodiments, the production comprises a proppant placement/aqueous phase flowback ratio (Vprop/Vflowback) of at least 100 over the initial 5 day production period (PFR5).

[0031] In certain embodiments herein, a method comprises: pumping a stabilized proppant-containing treatment fluid into a wellbore in fluid communication with a subterranean formation, wherein the stabilized proppant containing treatment fluid comprises at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa (170 s^{-1}, 25° C.), at a proppant pumping energy efficiency of at least 2 L of proppant pumped per MJ of pumping energy (1.4 gal/hp-h); injecting the stabilized proppant-containing treatment fluid from the wellbore into a subterranean formation to create a fracture; and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore, at least 50 m (164 feet) away from the wellbore, at least 100 m (328 feet) away from the wellbore, or at least 150 m (492 feet) away from the wellbore. In embodiments, the proppant pumping energy efficiency is at least 5 L/MJ (3.5 gal/hp-h).

[0032] In certain embodiments herein, a method is provided to improve proppant pumping energy efficiency in a fracturing procedure comprising pumping a proppant-containing treatment fluid at a surface treatment pressure (at the wellhead) into a wellbore in fluid communication with a subterranean formation, injecting the proppant-containing treatment fluid from the wellbore into a subterranean formation to create a fracture, placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture extending away from the wellbore and in fluid communication therewith. In embodiments, the improvement comprises: (a) preparing the proppant-containing treatment fluid to comprise at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.); (b) stabilizing the proppant-containing treatment fluid to form a stabilized treatment slurry (STS) meeting at least one of the following conditions: (1) the slurry has a Herschel-Buckley or Bingham plastic yield stress equal to or greater than 1 Pa; or (2) the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or 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 (3) the apparent dynamic viscosity (25° 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 +/−20% of the initial dynamic viscosity; or (4) 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 (5) 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; and (c) pumping the STS to the surface treatment pressure (pressure at the wellhead) for introduction into the wellbore.

[0033] In embodiments of the improvement, the proppant-supported fracture extends for a distance of at least 30 meters (98 feet) away from the wellbore, at least 50 m (164 feet) away from the wellbore, at least 100 m (328 feet) away from the wellbore, or at least 150 m (492 feet) away from the wellbore. In embodiments, the STS is pumped to surface treatment pressure with a proppant pumping energy efficiency of at least 2 L of proppant pumped per MJ of pumping energy (1.4 gal/hp-h). In 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° C., 170 s^{-1}) across column strata after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than +/−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 5% greater than 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.

[0034] In embodiments of the improvement, the STS is formed by at least one of: (1) decreasing the density difference between particles and liquid phase in the treatment fluid by introducing into the treatment fluid particles having a density less than 2.6 g/mL, carrier fluid having a density greater than 1.05 g/mL or a combination thereof; (2) increasing a yield stress of the treatment fluid to at least 1 Pa; (3) increasing apparent viscosity of the treatment fluid to at least 50 mPa-s (170 s^{-1}, 25° C.); (4) introducing a viscosifier selected from viscoelastic surfactants and hydratable gelling agents (optionally including crosslinked gelling agents) into the treatment fluid in an amount ranging from 0.01 up to 2.4 g/L of fluid phase; (5) introducing colloidal particles into the treatment fluid; (6) introducing sufficient particles into the treatment fluid to increase the SVF of the treatment fluid to at least 0.4; (7) introducing particles into the treatment fluid having an aspect ratio of at least 6, such as, for example, fiber, flakes, discs, rods, stars, etc; (8) introducing ciliated or coated proppant into the treatment fluid; and (9) combinations thereof.

[0035] In embodiments, the improvement further comprises maintaining a relatively low perforation pressure drop (relative to the pressure drop of the treating fluid passing through the perforation at a higher velocity) corresponding to a sustained velocity of the treatment fluid through the perforations below 50 m/s. In embodiments, the improvement further comprises lowering friction pressure drop in the wellbore by maintaining a sustained flow rate of treatment fluid in the wellbore below 1.6 m^3/min (10 BPM). In embodiments, the improvement further comprises increasing liquid head in the wellbore and reducing the treatment pressure by increasing the density of the treatment fluid to at least 2 g/mL. In embodiments, the STS comprises particles having a density greater than 2.8 g/mL, brine having a density greater than 1.2 g/mL, or a combination thereof.

[0036] In certain embodiments herein, a method comprises: (1) preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a stabilized proppant-containing treatment fluid comprising at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid, a packed volume fraction (PVF) greater than a slurry solids volume fraction (SVF), and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein a spurt loss (Vspurt) is less than 10 vol % of a fluid phase of the stabilized proppant-containing treatment fluid or less than 50 vol % of an excess fluid phase (Vspurt<0.50*(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); (2) injecting the stabilized proppant-containing treatment fluid into the subterranean formation according to the treatment plan to create a fracture, wherein the spurt loss is sufficiently low to maintain fluidity of the stabilized proppant-containing treatment fluid entering the fracture; and (3) placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

[0037] In embodiments, the sum of spurt volume (Vspurt) plus continuous fluid loss from the treatment fluid (Vw) during the treatment fluid injection is greater than the total volume of fluid phase (Vfluid), as calculated according to the equation [(Vw+Vspurt)>(Vtreatmentfluid*(1−SVF))], wherein $Vw=4*A*Cw*t_1^{-0.5}$ wherein Vtreatmentfluid is the volume of treatment fluid injected into the fracture, A is the exposed area of one fracture face, Cw is the loss coefficient, and t_1 is the duration of the treatment fluid injection. In embodiments, the method further comprises immediately producing hydrocarbons from the formation via the fracture wherein a fluid phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) is less than 1% over an initial production period of 5 days (FRR5).

[0038] In embodiments, the sum of spurt volume (Vspurt) plus continuous fluid loss from the treatment fluid (Vw) during the treatment fluid injection and a shut in period is greater than the total volume of fluid phase (Vfluid), as calculated according to the equation [(Vw+Vspurt)>(Vtreatmentfluid*(1−SVF))], wherein $Vw=4*A*Cw*(t_1+t_2)^{-0.5}$ wherein Vtreatmentfluid is the volume of treatment fluid injected into the fracture, A is the exposed area of one fracture face, Cw is the loss coefficient, t_1 is the duration of the treatment fluid injection and t_2 is the duration of the shut in period. In embodiments, the method further comprises producing hydrocarbons from the formation via the fracture after the shut in period, wherein a fluid phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) is less than 1% over an initial production period of 5 days (FRR5).

[0039] In certain embodiments herein, a method of managing risk in a fracturing operation comprises: (1) preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore with surface access at a wellsite location, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a stabilized proppant-containing treatment fluid comprising at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.); (2) installing at the wellsite a pumping system having a maximum available pumping power capacity matching the sum of a maximum pumping power required to implement the pumping schedule plus a reserve pumping power capacity available in case of a pumping deviation event requiring additional power, wherein the reserve pumping power capacity comprises less than 50% of the maximum available pumping power capacity; (3) activating the pumping system with the reserve pumping power capacity in ready standby mode; (4) supplying the one or more treatment fluids to the activated pumping system according to the treatment plan; (5) pumping the one or more treatment fluids into the wellbore according to the treatment plan; and (6) if there is an occurrence of a said pumping deviation event requiring additional pumping power, automatically recruiting pumping power capacity from the reserve pumping power capacity to continue the treatment plan.

[0040] In embodiments of the risk management method, the pumping system has a maximum pump discharge pressure for safe operation and wherein the pumping schedule comprises pumping the proppant-containing treatment fluid into the wellbore at a rate exceeding 1600 L/min (10 bpm) at a pump discharge pressure below the safe operation pressure, and the method further comprises: (a) pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture; (b) thereafter reducing the pumping rate of the proppant-containing treatment fluid to less than 1600 L/min to control the pump discharge pressure in response to a pumping deviation event comprising a pump discharge pressure approaching or exceeding the safe operation pressure; and (c) pumping a volume of the proppant-containing treatment fluid to complete the treatment plan according to a total volume of proppant-containing treatment fluid specified in the treatment plan.

[0041] In embodiments of the risk management method, a pumping deviation event comprises shutdown of the pumping system after pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture, thereby stranding the proppant-containing treatment fluid in the wellbore under static conditions, and the method further comprises thereafter restoring the pumping system to operational status; and resuming pumping of the stranded proppant-containing treatment fluid from the wellbore into the fracture to continue the treatment substantially according to a remainder of the treatment plan.

[0042] In embodiments of the risk management method, a pumping deviation event comprises shutdown of the pumping system after pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture, thereby stranding the proppant-containing treatment fluid in the wellbore under static conditions, and the method further comprises circulating the stranded proppant-containing treatment fluid out of the wellbore as an intact plug, optionally with a managed interface between the stranded treatment fluid and a displacing fluid.

[0043] In certain embodiments herein, a method comprises: injecting a multimodal proppant-containing treatment fluid from a wellbore through a perforation to create a fracture in a subterranean formation, wherein the treatment fluid comprises at least 0.36, at least 0.4 or at least 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein a ratio of a diameter of the perforation to a diameter of the proppant is less than 6; and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore, at least 50 m (164 feet) away from the wellbore, at least 100 m (328 feet) away from the wellbore, or at least 150 m (492 feet) away from the wellbore.

[0044] In certain embodiments, the proppant may be said to go where the fracture grows, i.e., the proppant is generally reliably placed where the fracture is created, without forming appreciable proppant-free zones within the fracture so that the entire fracture is propped open with proppant, e.g., not more than 5 volume percent or more than 2 volume percent or more than 1 volume percent of the propagated fracture prior to closure comprises proppant-free zones. As used herein a proppant-free zone in a propagated fracture is one having a volume equal to or greater than 10,000 proppant particle volumes in which the proppant concentration is less than 50 percent of the proppant concentration in the treatment fluid. In some embodiments, a method, comprises injecting a multimodal proppant-containing treatment fluid from a wellbore into a subterranean formation to initiate and propagate a fracture, wherein the treatment fluid comprises at least 0.36 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein the fracture is propagated with entry of the proppant-containing treatment fluid such that the propagated fracture is contiguously filled with proppant to form an interconnected fracture system containing less than 5 volume percent of any proppant-free zones; and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

[0045] 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.

[0046] As used herein, "slurry" refers to an optionally flowable 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 or low-shear (5.11 s^{-1}) viscosity less than 1000 Pa 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.

[0047] "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 R1B5F1 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, 5.11, 85.0, 170 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 $\gamma=170\ s^{-1}$, and the yield stress (τ_{10}) (if any) is determined as the y-intercept using a best fit of the Herschel-Buckley rheological model, $\tau=\tau_0+k(\gamma)^n$, 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 is equal to 1, the Herschel-Buckley fluid is known as a Bingham plastic. 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 y-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.

[0048] The following conventions with respect to slurry terms are intended herein unless otherwise indicated explicitly or implicitly by context.

[0049] "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" encompasses both liquids per se and supercritical fluids, including any solutes dissolved therein.

[0050] 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 in the absence of non-colloidal 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.

[0051] 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(s) 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 guars, xanthan and diutan, hydroxyethylcellulose, polyvinyl alcohol, other hydratable polymers, colloids, etc.), a cross-linked hydratable gel, a viscosified acid (e.g. gel-based), an emulsified acid (e.g. oil outer phase), an energized fluid (e.g., an N_2 or CO_2 based foam), a viscoelastic surfactant (VES) viscosified fluid, and an oil-based fluid including a gelled, foamed, or otherwise viscosified oil.

[0052] 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 disjointed 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.

[0053] In certain embodiments, the particle(s) 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.

[0054] 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 particle 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 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, US 2010/0300688, US 2012/0000641, US 2012/0138296, US 2012/0132421, US 2012/0111563, WO 2012/054456, US 2012/0305245, US 2012/0305254, US 2012/0132421, PCT/RU2011/000971 and U.S. Ser. No. 13/415,025, each of which are hereby incorporated herein by reference.

[0055] "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 about one-half of the weight average mean particle size of a smallest one of the proppant modes, e.g., a suspensive/stabilizing mode.

[0056] 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.

[0057] 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.

[0058] "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.

[0059] 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.

[0060] 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 (6'3"), 140 mm (4'7"), 84 mm (2'9") and 33 mm (1'1"), and rheologically evaluated for viscosity and yield stress as described above.

[0061] As used herein, a stabilized treatment slurry (STS) may meet at least one of the following conditions:

[0062] (1) the slurry has a low-shear viscosity equal to or greater than 1 Pa-s (5.11 s^{-1}, 25° C.);

[0063] (2) the slurry has a Herschel-Buckley (including Bingham plastic) yield stress (as determined in the manner described herein) equal to or greater than 1 Pa; or

[0064] (3) the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or

[0065] (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

[0066] (5) the apparent dynamic viscosity (25° 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 +/−20% of the initial dynamic viscosity; or

[0067] (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

[0068] (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.

[0069] In 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° C., 170 s^{-1}) across column strata after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than +/−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 5% greater than 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.

[0070] In some embodiments, the treatment slurry comprises at least one of the following stability indicia: (1) an SVF of at least 0.4 up to SVF=PVF; (2) a low-shear viscosity of at least 1 Pa-s (5.11 s^{-1}, 25° C.); (3) a yield stress (as determined herein) 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 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, (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.

[0071] 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.

[0072] 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.

[0073] 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, 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.

[0074] 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.

[0075] 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 one or more of the solids phase having a PVF greater than 0.7, and optionally 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.

[0076] In embodiments, the treatment slurry is formed (stabilized) 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° 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° 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 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.

[0077] 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. 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.

[0078] 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.

[0079] In embodiments, the stabilized slurry is formed by at least four of the slurry stabilization operations, such as, for example, increasing the SVF, increasing the low-shear viscosity, increasing the yield stress and increasing apparent viscosity, and optionally one or more of introducing the multimodal solids phase, introducing the solids phase having the PVF greater than 0.7, introducing the viscosifier, introducing colloidal particles, reducing the particle-fluid density delta, introducing particles into the treatment fluid having the aspect ratio of at least 6, introducing the ciliated or coated proppant or a combination thereof.

[0080] In embodiments, the stabilized slurry is formed by at least five of the slurry stabilization operations, such as, for example, increasing the SVF, increasing the low-shear viscosity, increasing the yield stress, increasing the apparent viscosity and introducing the multimodal solids phase, and optionally one or more of introducing the solids phase having the PVF greater than 0.7, introducing the viscosifier, introducing colloidal particles, reducing the particle-fluid density delta, introducing particles into the treatment fluid having the aspect ratio of at least 6, introducing the ciliated or coated proppant or a combination thereof.

[0081] 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.

[0082] In embodiments, yield stress fluids, and also 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 on the fluid beneath it must generally exceed the yield stress of the fluid to initiate fluid flow and thus settling onset. 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, 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.

[0083] 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 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 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 fluid phase viscosity ranges from any lower limit to any higher upper limit.

[0084] 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. 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.

[0085] 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 gellant and/or thickener.

[0086] 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 100 mPa-s, or at least about 150 mPa-s, or at least about 300 mPa-s, and an upper limit of apparent dynamic viscosity, determined at 170 s^{-1} and 25° C., of less than about 500 mPa-s, or 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 treatment fluid viscosity ranges from any lower limit to any higher upper limit.

[0087] 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:

$$PVF = \text{Particle volume}/(\text{Particle volume} + \text{Non-particle Volume}) = 1 - \phi$$

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

[0088] Here, the porosity, ϕ, 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.

[0089] 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_{50}) 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

$$\text{SVF}=\text{Particle volume}/(\text{Particle volume}+\text{Liquid volume})$$

[0090] 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 2.4 g/L, less than 1.2 g/L, less than 0.6 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 0.2 g/L or less than 0.1 g/L of viscosifier may be present in the STS.

[0091] 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 system embodiments, 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.

[0092] FIG. **6** 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).

[0093] The fourth fluid **608** shown in FIG. **6** 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.

[0094] FIG. **7** 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 slurriable 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 slurriable 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 slurriable 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 slurriable region **712**, and a settling region **714**.

[0095] FIG. **7** 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 or about 0.65 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 1−2.1*(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 1−2.1*(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 settling area **714** embodiments (where SVF/PVF is less than or equal to about 1−2.1*(PVF−0.72)) to also be useful as an STS or in applications where a non-settling, slurriable/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.

[0096] 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, US20080196896, 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.

[0097] 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.

[0098] 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.

[0099] 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.

[0100] 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.

[0101] 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 (gelled 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.

[0102] 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.

[0103] 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.

[0104] 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<0.50*(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).

[0105] 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^{-4} m/min$^{1/2}$(10^{-3} ft/min$^{1/2}$) or less, or about 3×10^{-5} m/min$^{1/2}$ (10^{-4} ft/min$^{1/2}$) or less. As used herein, Vspurt and the total leak-off 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.

[0106] The unique low to no fluid loss property allows the 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 leakoff 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.

[0107] 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 polyvinylidene 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, $CaCO_3$, SiO_2, bentonite etc.; particulates with different shapes such as glass fibers, flakes, films; and any combination thereof or the like. Fluid loss agents can if desired also include or be used in combination with acrylamido-methyl-propane 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.

[0108] The treatment fluid may additionally or alternatively include, without limitation, friction reducers, clay stabilizers, biocides, crosslinkers, 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.

[0109] 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.

[0110] The treatment fluid may be prepared on location, e.g., at the wellsite when and as needed using conventional treatment fluid blending equipment.

[0111] 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 **11**A, **11**B. Water tanks **12**A, **12**B, **12**C, **12**D are arranged along one side of the operation site. Hopper **14** receives sand from the sand trailers **10**A, **10**B and distributes it into the mixer truck **16**. Blender **18** is provided to blend the carrier medium (such as brine, viscosified fluids, etc.) with the proppant, i.e., "on the fly," and then the slurry is discharged to manifold **20**. The final mixed and blended slurry, also called frac fluid, is then transferred to the pump trucks **22**A, **22**B, **22**C, **22**D, and routed at treatment pressure through treating line **24** to rig **26**, 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.

[0112] 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 **10**A to **10**D and further elimination of the mixer **26**, hopper **14**, and/or blender **18**. In some embodiments the treatment fluid is prepared offsite 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 entireties. 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.

[0113] In certain embodiments herein, for example in gravel packing, 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 0.7. In embodiments, Vfluid/Vprop is equal to or less than 0.6. 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 0.35. 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 V_{fluid}/V_{prop} 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.

[0114] Nota bene, the STS may optionally comprise subproppant 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 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 embodiments (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 ppt 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.

[0115] 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 (13 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).

[0116] 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 subproppant 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), 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 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 0.54 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.

[0117] 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 enter the aquifers and other intervals. The low flowback leads to less delay in producing the stimulated formation, which can be placed into production with a shortened clean up stage or in some cases immediately without a separate flowback recovery operation.

[0118] In embodiments where the fracturing treatment fluid also has a low viscosity and a relatively high SVF, 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.

[0119] 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. As used herein a conductive fracture is one having a higher permeability than the formation matrix in which it is formed, and a high conductivity fracture is one having a dimensionless fracture conductivity for the reservoir fluid that is at least 10 times that of the adjacent formation matrix, i.e., FCD>10, where FCD=kfw/kFLf, FCD is the dimensionless fracture conductivity, w is the fracture width, kf is the fracture permeability, kF is the formation permeability and Lf is the fracture half-length (wellbore to tip).

[0120] 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_f/ft^2). 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).

[0121] According to some embodiments of the current application, treatment methods, fluids, equipment and/or systems for hydraulically fracturing a subterranean formation are disclosed which use substantially high concentration of proppant in the treatment fluid and/or a low water content, to more efficiently create fractures in the subterranean formation. In some embodiments herein, a method comprises injecting a proppant-containing treatment fluid into a low mobility subterranean formation, creating a fracture in the subterranean formation containing a first volume (V**1**) of proppant-containing treatment fluid, and fracture closure, i.e., allowing the fracture to close on the proppant and place the proppant in compression, to form a proppant-supported fracture having a second volume (V**2**) of packed proppant support, wherein a ratio of the second volume to the first volume (V**2**/V**1**) is at least 0.3. In some embodiments, the ratio of V**2**/V**1** is at least 0.4. In some embodiments, the ratio of V**2**/V**1** is at least 0.5. In some embodiments, the ratio of V**2**/V**1** is at least 0.6. In some embodiments, the ratio of V**2**/V**1** is at least 0.65. In some embodiments, the ratio of V**2**/V**1** is at least 0.7. In some embodiments, the ratio of V**2**/V**1** is at least 0.75.

[0122] In some embodiments the subterranean formation treated according to the embodiments wherein the ratio V**2**/V**1** is as specified, the subterranean formation may comprise a permeability less than 100 mD. In some embodiments, the subterranean formation comprises a permeability less than 10 mD. In some embodiments, the subterranean formation comprises a permeability less than 1 mD. In some embodiments, the subterranean formation comprises a permeability less than 100 μD. In some embodiments, the subterranean formation comprises a permeability less than 10 μD. In some embodiments, the subterranean formation comprises a permeability less than 1 μD, e.g., less than 300 nD or less than 100 nD. In some embodiments, the wellbore is substantially horizontal. A substantially horizontal well bore is generally plus or minus 15 degrees from horizontal. In some embodiments the subterranean formation treated according to the embodiments wherein the ratio V**2**/V**1** is as specified, the subterranean formation may be a low mobility formation. A low mobility formation as used herein has a low ratio of permeability to reservoir fluid viscosity, i.e., less than or equal to 0.5 mD/mPa-s. Permeability herein can be determined according to RP40, Recommeded Practices for Core Analysis. Viscosity of reservoir hydrocarbons herein can be determined at reservoir conditions (temperature and pressure) according to testing procedures known to the ordinarily skilled artisan, such as, for example, by Brookfield viscometer, capillary viscometer, and the like, or may be estimated using an appropriate predictive models, correlations or nomographs based on known properties or composition of the fluid. Low mobility oil-bearing formations may have a permeability down in the microdarcy range, e.g., less than 1 mD or less than 200 μD or less than 100 μD, whereas petroleum may have a viscosity at reservoir conditions in the range of 0.3 to 3 mPa-s. Low mobility gas-bearing formations may have a permeability down in the nanodarcy range, e.g., less than 1 microdarcy or less than 300 nD or less than 100 nD, whereas natural gas may have a viscosity at reservoir conditions in the range of 0.05 to 0.4 mPa-s. Alternatively or additionally, the subterranean formation may be any low permeability formation, such as, for example, a shale, carbonate or siltstone formation.

[0123] In some embodiments, the method comprises forming the proppant-supported fracture to extend away from a wellbore into the subterranean formation for a distance of at least 15 m (49 feet), or at least 30 m (98 feet), or at least 50 m (160 feet), or at least 75 m (250 feet), or at least 100 m (330 feet), or at least 125 m (410 feet), or at least 150 m (490 feet).

[0124] In some embodiments, the treatment method comprises placing the packed proppant support in pillars and forming open channels in spaces between the pillars. Various techniques are available for forming proppant clusters in the fracture as posts or islands that prevent complete fracture closure and rely on the formation of proppant-lean flow channels to impart conductivity for reservoir fluid or injection fluid to flow through the fracture between the wellbore and the formation. Examples of these techniques are disclosed in U.S. Pat. No. 6,776,235, U.S. application Ser. No. 13/073,458, and U.S. application Ser. No. 13/153,529, which are hereby incorporated herein by reference.

[0125] In some embodiments, the method comprises 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_f/ft^2). 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).

[0126] In embodiments, the proppant stage treatment fluid 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. 2.7; nota bene: ppg here refers to the ratio of proppant solids only to the entire treatment fluid volume including proppant and subproppant particles, whereas ppa generally refers to the ratio of proppant added to the base fluid), 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).

[0127] 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. 2.7; nota bene: ppg here refers to the ratio of proppant solids only to water only, excluding proppant and subproppant particles, whereas ppa generally refers to the ratio of proppant added to the base fluid including subproppant particles), 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), wherein the treatment optionally comprises one or more of a pre-pad stage, a pad stage, a front-end stage, a flush stage, and a post-flush stage, in addition to the proppant stage. Note that subproppant particles are not a factor in the determination of the proppant water ratio.

[0128] In some embodiments, the front-end stage is present and 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.

[0129] In some embodiments, the pad stage is present in advance of the front-end stage and 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 s^{-1} and 25° C.

[0130] In some embodiments, the flush stage is present and 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 flush stage comprises a first substage comprising viscosifier and a second substage 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).

[0131] In some embodiments, the proppant stage comprises a continuous single injection free of spacers.

[0132] In some embodiments, the method comprises combining proppant and a fluid phase at a volumetric ratio of the fluid phase to the proppant (V_{fluid}/V_{prop}) equal to or less than 1 to form a treatment fluid, and injecting the treatment fluid into a subterranean formation to create a fracture in the subterranean formation. Due to the high volume of proppant and other solids in the treatment fluid according to some embodiments, the volume of the fluid phase (V_{fluid}) in the proppant laden treatment fluid, i.e., excluding proppant, sub-proppant and any other solids in the treatment fluid, is relatively low compared with conventional fracturing fluids. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 3. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 2.5. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 2. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 1.5. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 1.25. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 1. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.75. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.7. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.6. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.5. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.4. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.35. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.3. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.25. In some embodiments, the ratio V_{fluid}/Vprop is equal to or less than 0.2. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.15. In some embodiments, the ratio V_{fluid}/V_{prop} is equal to or less than 0.1. In some embodiments, the ratio V_{fluid}/V_{prop} 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.

[0133] In some of the embodiments wherein the ratio is as specified, the method further comprises stabilizing the treatment fluid wherein the treatment fluid comprises: 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_f/ft^2); or 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). In further embodiments, the treatment fluid comprises a viscosity less than 100 mPa-s (170 s^{-1}, 25 C), or less than 10 mPa-s (170 s^{-1}, 25 C).

[0134] In some embodiments, a volumetric ratio of the proppant mode(s) to aqueous phase is greater than about 1.0. In some embodiments, a volumetric ratio of the proppant mode(s) to aqueous phase is greater than about 1.5. In some embodiments, a volumetric ratio of the proppant mode(s) to aqueous phase is greater than about 2.0. In some embodiments, a volumetric ratio of the proppant mode(s) to aqueous phase is greater than about 2.5. As used herein, the aqueous phase refers to the solids-free liquid in the absence of any solid particles regardless of size and in the absence of non-aqueous liquids.

[0135] In some embodiments the total proppant volume injected is at least 800 liters. In some embodiments, the total proppant volume injected is at least 1600 liters. In some embodiments, the total proppant volume injected is at least 3200 liters. In some embodiments, the total proppant volume injected is at least 8000 liters. In some embodiments, the total proppant volume injected is at least 80,000 liters. In some embodiments, the total proppant volume injected is at least 800,000 liters. The total proppant volume injected is typically not more than 16 million liters.

[0136] The methods and systems of the current application allow for fewer pumps to be used for fracture treatment because the injection rate, either overall or per restrictive flow area cross section or per perforation relative to slickwater, is reduced, or because the surface pressure requirements are reduced and/or the proppant loading is increased relative to high viscosity treatment fluid. In some embodiments, the concentrated proppant loading, as well as water displacement by the sub-proppant particles, allow less treatment fluid to be used and especially less water (or other fluid phase fluid) to be used, either overall or per volume of proppant placed or per volume of propped fracture created. This in turn can lead to a reduced footprint owing to fewer pumping trucks, less energy required, reduced CO_2 and other emissions, fewer water trucks, etc.

[0137] The rate of fluid and/or proppant through each perforation (or other flow restriction between the wellbore and the formation) depends on (1) the pressure difference between the fluid in the wellbore and in the formation at the perforation and (2) the perforation friction. The treatment pressure of a hydraulic fracture at surface is a sum of multiple pressures and stress as shown in Eq. 1.

$$P_S = \sigma_{min} + P_{net} P_{perf} - P_{hyd} + P_{friction} \quad \text{Eq. 1}$$

[0138] Where P_s is surface treating pressure (pump discharge), σ_{min} is the minimum stress of the formation, P_{net} is the net pressure required to initiate and propagate hydraulic pressure, P_{perf} is the pressure drop pumping through any perforations, P_{hyd} is the hydrostatic pressure created by the fluid and $P_{friction}$ is the pipe friction pressure drop while pumping.

[0139] In this equation, σ_{min} is a formation property, P_{hyd} is a property of the fluid, and both can be regarded as constants once a fluid and a formation are selected. The ideal operation is to maximize the surface treating pressure transformation to P_{net}. Both P_{perf} and $P_{friction}$ are pressure losses and increase with an increase of the pumping rate. So pumping slow according to embodiments can be beneficial in improving the energy efficiency in hydraulic fracture and reducing the surface pressure required of the pumps delivering the fracture fluid.

[0140] Therefore, compared with conventional hydraulic fracturing methods, a relatively small amount of pumping energy is needed to deliver a given volume of proppant to a fracture in a subterranean formation. In some embodiments, the ratio of the pumping energy to the proppant volume (V_{prop}) to be injected into the formation is equal to or less than 0.5 MJ/L (0.35 hp-h/gal). In some embodiments, the ratio of the pumping energy to the proppant volume (V_{prop}) to be injected into the formation is equal to or less than 0.2 MJ/L (0.14 hp-h/gal). In some embodiments, the ratio of the pumping energy to the proppant volume (V_{prop}) to be injected into the formation is equal to or less than 0.1 MJ/L. In some embodiments, the ratio of the pumping energy to the proppant volume (V_{prop}) to be injected into the formation is equal to or less than 0.05 MJ/L (0.07 hp-h/gal).

[0141] Also, compared with conventional hydraulic fracturing methods, a relatively small CO_2 emission from pump engines is resulted for delivering a given volume of proppant to a fracture in a subterranean formation. In some embodiments, the ratio of the CO_2 emission to the proppant volume (V_{prop}) where the pump engines use diesel fuel is equal to or less than 40 g/L, equal to or less than 15 g/L, equal to or less than 10 g/L, equal to or less than 5 g/L, or equal to or less than 1 g/L, and a proportional reduction in nitrogen oxides, carbon monoxide, sulfur compounds, fine particles (2.5 micron) and hydrocarbons, is also obtained due to reduced fuel combustion for pumping. In the case of natural gas as the fuel, the ratio of the CO_2 emission to the proppant volume (V_{prop}) is equal to or less than 32 g/L, equal to or less than 12 g/L, equal to or less than 8 g/L, equal to or less than 4 g/L, or equal to or less than 0.8 g/L, with a proportional reduction in concomitant air pollutants.

[0142] FIG. **4** shows a wellsite equipment configuration for a fracture treatment job according to some embodiments using the principles disclosed herein, for a fracture treatment job of similar in scope to that of FIG. **1**. In this configuration the number of pump trucks **22** is reduced to just four, three for active pumping and one as a spare, and the number of water trailers **12** is similarly reduced to just four. The water trailers **12**E-**12**N from FIG. **1** are not needed, as are the mixer truck **16**B, pump trucks **22**E to **22**N, blender **18**B, manifold **20**B and lines **24**B, and the overall footprint is considerably reduced.

[0143] 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 **10**A to **10**D and further elimination of the mixer **26**A, hopper **14**, and/or blender **18**B.

[0144] With reference again to FIG. **2**, a conventional multi-clusters/multi-perforations fracturing operation, proppant can be maldistributed, e.g., with less proppant going to the initial clusters/perforations and more to the end clusters/perforations. This is because proppant typically has a higher density and more momentum while the treatment fluid is viscoelastic, both of which tend to concentrate the proppant in the center of the wellbore, carrying the proppant past the initial perforation clusters and concentrating the proppant in the treatment fluid injected into the end cluster(s). According to some embodiments of the current application, the presently disclosed hydraulic fracture treatment methods or systems are capable of producing a generally uniform overall per-perforation proppant placement in the formation. As used herein, a "generally uniform overall per-perforation proppant placement" means that the total volume of proppant injected in any one perforation is within 50% of the quotient of the total volume of proppant injected in all the perforations of the stage divided by the number of perforations in the stage. In some embodiments, the total volume of proppant injected at each perforation or other restrictive flow passage in the stage is within +/−50% of the per perforation average, or within +/−40% of the per perforation average, or within +/−35% of the per perforation average, or within +/−30% of the per perforation average, or within +/−25% of the per perforation average, or within +/−20% of the per perforation average, or within +/−15% of the per perforation average, or within +/−10% of the per perforation average. Where the perforations have a variable size, the per-perforation average is normalized by the flow area of each perforation, e.g., a perforation in a ten-perforation stage having 10% of the total flow area through the perforations would count as 1.0 perforation whereas a perforation having 5% of the total flow area as 0.5 perforations, or having 20% as 2.0 perforations.

[0145] In some embodiments, the flow velocities of the treatment fluid flowing simultaneously into a plurality of perforations is within +/−50% of the average perforation velocity, or within +/−40% of the per perforation average velocity, or within +/−35% of the average perforation velocity, or within +/−30% of the average perforation velocity, or within +/−25% of the average perforation velocity, or within +/−20% of the average perforation velocity, or within +/−15% of the average perforation velocity, or within +/−10% of the average perforation velocity.

[0146] As used herein, a "generally uniform overall per-perforation (or per-restrictive flow passage) proppant injection" means that the total volume of proppant injected in any one perforation is within 50% of the quotient of the total volume of proppant injected in all the perforations of the stage divided by the number of perforations in the stage. In some embodiments, the total volume of proppant injected at each perforation or other restrictive flow passage in the stage is within +/−50% of the per perforation average, or within +/−40% of the per perforation average, or within +/−35% of the per perforation average, or within +/−30% of the per perforation average, or within +/−25% of the per perforation average, or within +/−20% of the per perforation average, or within +/−15% of the per perforation average, or within +/−10% of the per perforation average.

[0147] In some embodiments, a volumetric proppant loading in the fluid injected into each perforation in the stage is within +/−50%, 40%, 35%, 30%, 25%, 20% or 15%, of an overall volumetric proppant loading in the proppant stage treatment fluid injected into the wellbore. In some embodiments, a volumetric proppant loading in the fluid injected into each perforation cluster in the stage is within +/−50%, 40%, 35%, 30%, 25%, 20% or 15%, of an overall volumetric proppant loading in the proppant stage treatment fluid injected into the wellbore.

[0148] In some embodiments, where low perforation velocity is desired, for example to reduce pressure drop and thereby reduce surface pumping pressure, a method comprises injecting a proppant-containing treatment fluid from a wellbore through a perforation at a sustained perforation velocity of less than 200 m/s to create a proppant-supported fracture in a subterranean formation, and propagating the fracture into the subterranean formation for a distance of at least 30 meters (98 feet) away from the wellbore. In some embodiments the sustained perforation velocity in the injection and propagation is less than 100 m/s, less than 75 m/s, less than 50 m/s, less than 30 m/s or less than 25 m/s. By "sustained" or continuous is meant a period of time of at least 5 minutes or at least 10 minutes without interruption. In these embodiments, the method may further comprise preparing the proppant-containing treatment fluid by combining at least 0.36, at least 0.4, or at least 0.45 L of proppant per liter of base fluid and stabilizing the proppant-containing treatment fluid.

[0149] Sometimes it is 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 sub-optimally 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 treatment fluid and the 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.

[0150] 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, injecting the proppant-containing treatment fluid into a subterranean formation, creating a fracture in the subterranean formation with the treatment fluid, stopping injection of the treatment fluid to interrupt the propagation of the fracture thereby stranding the treatment fluid in the wellbore, and thereafter resuming injection of the treatment fluid to inject the stranded treatment fluid into the formation and continue the fracture creation.

[0151] Also due to the stability of the proppant suspension in the treatment fluid, the treatment fluid will retain its flow properties during the time the pumping is interrupted, and can be easily circulated out of the wellbore if it is decided not to complete the proppant placement in the fracture. 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, injecting the proppant-containing treatment fluid into a subterranean formation, propagating a fracture in the subterranean formation with the treatment fluid, stopping injection of the treatment fluid to interrupt the propagation of the fracture thereby stranding the treatment fluid in the wellbore, and thereafter circulating 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.

[0152] 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.

[0153] 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.

[0154] 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, imbibition 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.

[0155] 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. For example, as noted in embodiments above, the FRR5 (flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) in % over an initial production period of 5 days) is less than 5% or less than 1%, or the PFR5 (proppant placement/aqueous phase flowback ratio (Vprop/Vflowback) in % over the initial 5 day production period) is at least 100, or the water from the treatment fluid comprises less than 1% of water production after 10 days of hydrocarbon production.

[0156] 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.

[0157] For example, a fracture of width W formed in the formation will have opposing faces with an exposed surface area A at each face. The water (or other carrier fluid) wetting loss from the fracture fluid is known as the "spurt" loss and can be estimated from the equation:

$$Vspurt=2*A*Sp$$

wherein Vspurt is the volume of water loss and Sp is the spurt loss coefficient, and depends on the characteristics of the formation such as the saturation level (how dry the formation is) and the fracturing fluid. As used herein, Sp is 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) and a loss collection period of 60 minutes, or an equivalent testing procedure. In some embodiments, Sp can be within a range of from about 10 to about 50 ml/m^2, or from about 15 to about 40 ml/m^2, or from about 20 to about 35 ml/m^2, or from about 24 to about 32 ml/m^2. Vspurt represents the wetting water loss from the initial contact between the freshly exposed fracture faces and the fracturing fluid, and in some embodiments may be much less than the volume of water present in the fracturing fluid, e.g., less than 10% or less than 8% or less than 5% or less than 4% or less than 3% or less than 2% or less than 1.5% or less than 1% of the volume of water present in the fracturing fluid. In other embodiments, Vspurt is less than about 50% of the free water in the fracturing fluid, i.e., PVF−SVF, or less than about 30%, or less than about 25% or less than about 20% or less than about 15% of the free water, where the free water is calculated as the product of the volume of fracturing fluid introduced into the formation and the difference between the PVF and SVF of the fracturing fluid. The concept of "free water" assumes that when all the solids touch each other, i.e., when the water volume equals (1−PVF), the water loss mechanism changes from hydraulic pressure due to pumping during the injection operation and/or overburden during post-injection shut-in, to one of drainage and/or capillary action.

[0158] The total water present in the volume of the fracturing fluid introduced into the formation, of course, depends on the overall or average SVF of the fluid introduced into the fracture, whereas for small water losses the fracture volume, i.e., fracture width W times fracture surface area, can be taken as an estimate of the volume of fracturing fluid. In embodiments the fracture width may be within a range of from about 2.5 mm (0.1 in.) to about 12.5 mm (0.5 in.). For example, in the condition where Sp is relatively high and the width is relatively narrow, e.g., say Sp is 32 ml/m^2 and the fracture width is 2.5 mm, for a fracturing fluid with PVF of 0.78 and SVF of 0.6, the Vspurt would be about 6% of the total water and about 14% of the free water in the fracturing fluid, which should be sufficient to maintain fluidity of the fracturing fluid upon initial contact.

[0159] As the fracture operation proceeds and additional fracture is created, i.e., initiated and/or propagated, additional water is continuously lost into the formation according to the volume estimated from the equation:

$$Vw=2*2*A*Cw*t_1^{-0.5}$$

wherein Vw is the continuous water loss to the matrix, Cw is the loss coefficient and t_1 is the duration of the fluid treatment injection operation into the formation. As used herein, the loss coefficient Cw is 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 MPs (500 psi), 100 ml sample loading, and a loss collection period of 60 minutes, or an equivalent test. In some embodiments Cw may be within the range from about 0.06 to about 0.15 mm/min$^{-0.5}$ (0.0002 to 0.0005 ft/min$^{-0.5}$). In some embodiments the calculated value of Vw is such that the sum of the calculated values of Vspurt plus Vw is equal to or greater than the volume of free water, or much greater than the volume of free water, for example, (Vspurt+Vw)/(A*W)>(SVF−PVF), or (Vspurt+Vw)/(A*W)>2*(SVF−PVF), or (Vspurt+Vw)/(A*W)>5*(SVF−PVF), or (Vspurt+Vw)/(A*W)>10*(SVF−PVF), or (Vspurt+Vw)/(A*W)>20*(SVF−PVF), wherein the product of A times W is taken as the total volume of fracturing fluid injected into the formation during fracture initiation and propagation. In some other embodiments, the calculated value of Vw is such that the sum of Vspurt plus Vw is equal to or greater than the volume of total water in the treatment fluid injected into the fracture, or much greater than the total water in the treatment fluid injected into the fracture, for example, (Vspurt+Vw)/(A*W)>(1−SVF), or (Vspurt+Vw)/(A*W)>2*(1−SVF), or

(Vspurt+Vw)/(A*W)>5*(1−SVF), or (Vspurt+Vw)/(A*W) >10*(1−SVF), based on calculated values wherein the product of A times W is taken as the total volume of fracturing fluid injected into the formation during fracture initiation and propagation. In some of these embodiments, since the total water loss from the fracturing fluid into the formation equals or exceeds the free water and/or total water present in the fracturing fluid, i.e., water loss proceeds essentially to dehydration during the fracture operation, there is no water flowback even when the formation is produced immediately or without a specific shut-in period.

[0160] For the previous narrow fracture/high Sp example, where Sp is 32 ml/m^2, W is 2.5 mm, PVF is 0.78, SVF of 0.6, assuming Cw is high, e.g., 0.15 mm/min$^{-0.5}$ (0.0005 ft/min$^{-0.5}$), and the fracture creation operation lasts 3 hours, the calculated water loss into the formation exceeds the total water in the fracture treatment fluid by a factor of about 8, and the well can thus be placed immediately into production, i.e., without a specified shut-in period, without seeing water flowback. The same result also obtains in this example when Cw is relatively high, e.g., 0.06 mm/min$^{-0.5}$(0.0002 ft/min$^{-0.5}$), since Vw is calculated at approximately 2-3 times the total water present in the injected treatment fluid.

[0161] In some other embodiments where the free water in the injected treatment fluid during the fracture creation operation is less than the calculated sum of Vspurt plus Vw, i.e., (Vspurt+Vw)/(A*W)<(SVF−PVF) (without a shut-in period), the well can be shut in for a period of time sufficient to inhibit water flowback. In these embodiments, the continuous water loss into the formation, Vw, is calculated using the following equation:

$$Vw=2*2*A*Cw*(t_1-t_2)^{-0.5}$$

[0162] wherein t2 is a shut-in period following the injection stage(s) and all other variables are as previously defined. In some embodiments the calculated value of Vw (where t2>0) is such that the sum of the calculated values of Vspurt plus Vw is equal to or greater than the volume of free water, or much greater than the volume of free water, for example, (Vspurt+Vw)/(A*W)>(SVF−PVF), or (Vspurt+Vw)/(A*W)>2*(SVF−PVF), or (Vspurt+Vw)/(A*W)>5*(SVF−PVF), or (Vspurt+Vw)/(A*W)>10*(SVF−PVF), or (Vspurt+Vw)/(A*W)>20*(SVF−PVF), wherein the product of A times W is taken as the total volume of fracturing fluid injected into the formation during fracture initiation and propagation and t2>0. Similarly, in some other embodiments where the total water in the injected treatment fluid during the fracture creation operation is less than the calculated sum of Vspurt plus Vw, i.e., (Vspurt+Vw)/(A*W)<(1−SVF) (without a shut-in period, i.e., t2=0), the well can be shut in for a period of time sufficient to inhibit water flowback where t2 is such that the calculated value of the sum of Vspurt plus Vw is equal to or greater than the volume of total water in the treatment fluid injected into the fracture, or much greater than the total water in the treatment fluid injected into the fracture, for example, (Vspurt+Vw)/(A*W)>(1−SVF), or (Vspurt+Vw)/(A*W) >2*(1−SVF), or (Vspurt+Vw)/(A*W)>5*(1−SVF), or (Vspurt+Vw)/(A*W)>10*(1−SVF), based on calculated values wherein the product of A times W is taken as the total volume of fracturing fluid injected into the formation during fracture initiation and propagation and t2>0. For example, the required shut-in period to inhibit flow back can be calculated in advance of the job, and then implemented when the job is executed by employing a shut-in period equal to or greater than that planned. In some of these embodiments, since the total water loss from the fracturing fluid into the formation equals or exceeds the free water and/or total water present in the fracturing fluid, i.e., water loss proceeds essentially to dehydration during the fracture operation, there is no water flowback when the formation is produced following a shut-in period equal to or longer than that specified.

[0163] In some embodiments herein, a method comprises injecting into a subterranean formation one or more treatment fluids comprising a volume of an aqueous phase (Vw) and a volume of proppant (Vprop) at an overall ratio of Vw/Vprop less than 2, 1.5, 1, 0.75, 0.5. 0.25, 0.2, or 0.1, creating and filling a fracture in the subterranean formation with at least one of the one or more treatment fluids comprising the volume of proppant distributed therein, fracture closure on the proppant to form a proppant-supported fracture, adsorption of all or a fraction of the injected volume of the aqueous phase into the subterranean formation, producing a reservoir fluid comprising hydrocarbon gas through the proppant-supported fracture free of any aqueous phase flowback or with an aqueous phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw) less than 5% for an initial production period of 5 days (FRR5) and a flowback recovery ratio less than 10% for an initial production period of 90 days (FRR90).

[0164] In some embodiments, FRR5 is less than 1% and/or FRR90 is less than 2%. In some embodiments, any water produced from the reservoir after a period of continuous hydrocarbon production of at least 10 days comprises less than 1% injected water and at least 99% connate water. In some embodiments, the production comprises a proppant placement/aqueous phase flowback ratio (Vprop/Vflowback) of at least 100 over the initial 5 day production period (PFR5), or PFR5 is at least 200 or at least 300 or at least 400 or at least 500.

[0165] In certain embodiments herein, a method of managing risk in a fracturing operation comprises:

- **[0166]** 1. preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore with surface access at a wellsite location, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a proppant-containing treatment fluid comprising a viscosity between 0.1 and 300 mPa-s (170 s^{-1}, 25° C.);
- **[0167]** 2. optionally storing the treatment plan in a computer-readable medium;
- **[0168]** 3. optionally retrieving the treatment plan from the computer-readable medium and displaying the treatment plan at the wellsite location;
- **[0169]** 4. installing at the wellsite a pumping system having a maximum available pumping power capacity matching a maximum pumping power required to implement the pumping schedule plus a reserve pumping power capacity available in case of a pumping deviation event requiring additional pumping power, wherein the reserve pumping power capacity comprises less than 50% of the maximum available pumping power capacity;
- **[0170]** 5. combining and stabilizing proppant and a base fluid to form the proppant-containing treatment fluid;
- **[0171]** 6. activating the pumping system with the reserve pumping power capacity in ready standby mode;

[0172] 7. supplying the one or more treatment fluids to the activated pumping system according to the treatment plan;

[0173] 8. pumping the one or more treatment fluids into the wellbore according to the treatment plan; and

[0174] 9. if there is an occurrence of a said pumping deviation event requiring additional pumping power, automatically recruiting pumping power capacity from the reserve pumping power capacity to continue the treatment plan.

[0175] 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.

[0176] In embodiments of the risk management method, the pumping system has a maximum pump discharge pressure for safe operation and wherein the pumping schedule comprises pumping the proppant-containing treatment fluid into the wellbore at a rate exceeding 1600 L/min (10 bpm) at a pump discharge pressure below the safe operation pressure. In embodiments, the risk management method further comprises: pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture; thereafter reducing the pumping rate of the proppant-containing treatment fluid to less than 1600 L/min to control the pump discharge pressure in response to a pumping deviation event comprising a pump discharge pressure approaching or exceeding the safe operation pressure; and pumping a volume of the proppant-containing treatment fluid to complete the treatment plan according to a total volume of proppant-containing treatment fluid specified in the treatment plan.

[0177] In alternative or additional embodiments of the risk management method, wherein a pumping deviation event comprises shutdown of the pumping system after pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture, thereby stranding the proppant-containing treatment fluid in the wellbore under static conditions, the method further comprises thereafter restoring the pumping system to operational status and resuming pumping of the stranded proppant-containing treatment fluid from the wellbore into the fracture to continue the treatment substantially according to a remainder of the treatment plan. In a further embodiment of the risk management method, the method further comprises circulating the stranded proppant-containing treatment fluid out of the wellbore as an intact plug, optionally with a managed interface between the stranded treatment fluid and a displacing fluid.

[0178] In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 1.0 m^3/minute (6 bbl/min). In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 0.5 m^3/minute (3 bbl/min). In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 0.4 m^3/minute (2.4 bbl/min). In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 0.3 m^3/minute (1.8 bbl/min). In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 0.2 m^3/minute (1.2 bbl/min). In some embodiments, the overall proppant laden treatment fluid injection rate in the stage is equal to or less than an average of about 0.1 m^3/minute (0.6 bbl/min).

[0179] In some embodiments, the hydraulic fracture treatment comprises fracture propagation with injection of the proppant stage treatment fluid through the perforations at a velocity less than 135 m/s (2 BPM per perforation), or less than 100 m/s (1.5 BPM per perforation), or less than 80 m/s (1.2 BPM per perforation), or less than 65 m/s (1 BPM per perforation), or less than 50 m/s (0.8 BPM per perforation), or less than 40 m/s (0.6 BPM per perforation), or less than or equal to 25 m/s (0.4 BPM per perforation).

[0180] In some embodiments, the injection of the treatment fluid of the current application can be stopped all together (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.

[0181] In some embodiments, the proppant stage 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 proppant stage 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. The weight of the treatment fluid can provide additional hydrostatic head pressurization in the wellbore at the perforations or other fracture location, and also facilitates 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 2.6) 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.

[0182] 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.

[0183] Various jetting and jet cutting operations in embodiments are significantly improved by the non-settling and solids carrying abilities of the STS. Jet perforating and jet slotting are embodiments for the STS, wherein the proppant is replaced with an abrasive or erosive particle. Multi-zone fracturing systems using a locating sleeve/polished bore and jet cut opening are embodiments.

[0184] Drilling cuttings transport and cuttings stability during tripping are also improved in embodiments. The STS can act to either fracture the formation or bridge off cracks, depending on the exact mixture used. The STS can provide an extreme ability to limit fluid losses to the formation, a very significant advantage. Minimizing the amount of liquid will make oil based muds much more economically attractive.

[0185] The modification of producing formations using explosives and/or propellant devices in embodiments is improved by the ability of the STS to move after standing stationary and also by its density and stability.

[0186] Zonal isolations 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.

[0187] 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.

[0188] 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 delivered in embodiments by using degradable materials to convert a non-permeable pack into a permeable pack after a period of time.

[0189] 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. The ability of the STS to re-fluidize after long periods of immobilization facilitates this embodiment. 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 CemCRETE 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, and are commercially available from Schlumberger.

[0190] This STS in other embodiments finds application in pipeline cleaning to remove methane hydrates due to its carrying capacity and its ability to resume motion.

[0191] Accordingly, the present invention provides the following embodiments:

1 A method comprising: (a) injecting a treatment fluid containing proppant into (i) a subterranean formation or (ii) a subterranean penetrated by a wellbore; and (b) creating a fracture in the subterranean formation with the fluid.

2. A method, comprising: combining proppant and a fluid phase at a volumetric ratio of the fluid phase (Vfluid) to the proppant (Vprop) equal to or less than 1.5 to form a treatment fluid; and injecting the treatment fluid into a subterranean formation to create a fracture in the subterranean formation.

3 The method of embodiment 2, wherein Vfluid/Vprop is equal to or less than 1.

4. The method of embodiment 2, wherein Vfluid/Vprop is equal to or less than 0.4.

5. The method of embodiment 2, 3 or 4, further comprising stabilizing the treatment fluid.

6. The method of any one of embodiments 1 to 5 wherein the treatment fluid comprises a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.) and a yield stress between 1 and 20 Pa (2.1-42 lb_f/ft^2).

7. The method of any one of embodiments 1 to 6 wherein the treatment fluid comprises a viscosity less than 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).

8. A method, comprising: injecting a proppant-containing treatment fluid into a low mobility subterranean formation; creating a fracture in the subterranean formation containing a first volume (V**1**) of the proppant-containing treatment fluid; and allowing the fracture to close on the proppant to form a proppant-supported fracture having a second volume (V**2**) of packed proppant support, wherein a ratio of the second volume (V**2**) to the first volume (V**1**) is at least 0.5.

9. The method of embodiment 8, wherein the low mobility formation comprises a carbonate or siltstone formation.

10. The method of embodiments 8 or 9, wherein the low mobility formation comprises permeability less than 0.1 mD and further comprising producing hydrocarbon liquid from the formation.

11. The method of embodiments 8 or 9, wherein the low mobility formation comprises permeability less than 1000 nD and further comprising producing hydrocarbon gas from the formation.

12. The method of any one of embodiments 8 to 11 comprising forming the proppant-supported fracture to extend away from a wellbore for a distance of at least 30 m (98 feet) into the subterranean formation.

13. The method of any one of embodiments 8 to 12, further comprising placing the packed proppant support in pillars and forming open channels in spaces between the pillars.

14. The method of any one of embodiments 8 to 13 wherein the proppant-containing treatment fluid comprises a viscosity

less than 300 mPa-s (170 s^{-1}, 25° C.) and a yield stress between 1 and 20 Pa (2.1-42 lb_f/ft^2).

15. The method of any one of embodiments 8 to 14 wherein the proppant-containing treatment fluid comprises 0.36 L or more of proppant volume per liter of proppant-containing treatment fluid (8 ppa proppant where specific gravity is 2.6), a viscosity less than 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). The method of any one of embodiments 8 to 15 wherein the ratio V**2**/V**1** is at least 0.6.

16 The method of any one of embodiments 8 to 15 wherein the ratio V**2**/V**1** is at least 0.7.

17 The method of any one of embodiments 8 to 17 wherein the proppant-containing treatment fluid comprises 0.4 L or more of proppant volume per liter of proppant-containing treatment fluid (9 ppa proppant where specific gravity is 2.6).

19 The method of any one of embodiments 8 to 18 wherein the proppant-containing treatment fluid comprises 0.45 L or more of proppant volume per liter of proppant-containing treatment fluid (10 ppa proppant where specific gravity is 2.6).

20. A method, comprising: injecting a proppant-containing treatment fluid from a wellbore through a perforation at a sustained perforation velocity of less than 50 m/s for a continuous period of at least 5 minutes to create a fracture in a subterranean formation; and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

21. The method of embodiment 20, wherein the sustained perforation velocity over the continuous period is less than 30 m/s.

22. The method of embodiment 20, further comprising preparing the proppant-containing treatment fluid by combining at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid and stabilizing the proppant-containing treatment fluid.

23 The method of embodiments 20, 21 or 22, wherein the proppant-supported fracture extends for a distance of at least 50 meters (164 feet) away from the wellbore.

24 The method of embodiments 20, 21 or 22, wherein the proppant-supported fracture extends for a distance of at least 100 meters (328 feet) away from the wellbore.

25 The method of embodiments 20, 21 or 22, wherein the proppant-supported fracture extends for a distance of at least 150 meters (492 feet) away from the wellbore.

26. A method, comprising: combining at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid to form a proppant-containing treatment fluid; stabilizing the proppant-containing treatment fluid; injecting the proppant-containing treatment fluid into a subterranean formation; creating a fracture in the subterranean formation with the treatment fluid; stopping injection of the treatment fluid to interrupt the creation of the fracture thereby stranding the treatment fluid in the wellbore; and thereafter resuming injection of the treatment fluid to inject the stranded treatment fluid into the formation and continue the fracture creation.

27. A method, comprising: combining at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid to form a proppant-containing treatment fluid; stabilizing the proppant-containing treatment fluid; injecting the proppant-containing treatment fluid into a subterranean formation; propagating a fracture in the subterranean formation with the treatment fluid; stopping injection of the treatment fluid to interrupt the propagation of the fracture thereby stranding the treatment fluid in the wellbore; and thereafter circulating 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.

28. A method, comprising: injecting into a subterranean formation one or more treatment fluids comprising a volume of an aqueous phase (Vw) and a volume of proppant (Vprop) at an overall ratio of Vw/Vprop less than 2; creating and filling a fracture in the subterranean formation with at least one of the one or more treatment fluids comprising the volume of proppant distributed therein; allowing fracture closure on the proppant to form a proppant-supported fracture; transporting at least a fraction of the injected volume of the aqueous phase from the one or more treatment fluids into the subterranean formation (e.g., the matrix or a natural fracture or void); producing a reservoir fluid comprising hydrocarbon gas through the proppant-supported fracture free of any aqueous phase flowback or with an aqueous phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw) less than 5% over an initial production period of 5 days (FRR5).

29. The method of embodiment 28, wherein FRR5 is less than 1%.

30. The method of embodiment 28 or 29, wherein any water produced from the reservoir after a period of continuous hydrocarbon production of at least 10 days comprises less than 1% injected water and at least 99% connate water.

31. The method of embodiments 28, 29 or 30 wherein the production comprises a proppant placement/aqueous phase flowback ratio (Vprop/Vflowback) of at least 100 over the initial 5 day production period (PFR5).

32. A method, comprising: pumping a stabilized proppant-containing treatment fluid into a wellbore in fluid communication with a subterranean formation, wherein the stabilized proppant containing treatment fluid comprises at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa (170 s^{-1}, 25° C.), at a proppant pumping energy efficiency of at least 2 L of proppant pumped per MJ of pumping energy (1.4 gal/hp-h); injecting the stabilized proppant-containing treatment fluid from the wellbore into a subterranean formation to create a fracture, and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

33. The method of embodiment 32, wherein the proppant pumping energy efficiency is at least 5 L/MJ (3.5 gal/hp-h).

34 The method of embodiment 32 or 33, wherein the proppant-supported fracture extends for a distance of at least 50 meters (164 feet) away from the wellbore.

35 The method of embodiment 32 or 33, wherein the proppant-supported fracture extends for a distance of at least 100 meters (328 feet) away from the wellbore.

36 The method of embodiment 32 or 33, wherein the proppant-supported fracture extends for a distance of at least 150 meters (492 feet) away from the wellbore.

37. A method to improve proppant pumping energy efficiency in a fracturing procedure comprising pumping a proppant-containing treatment fluid at a surface treatment pressure into a wellbore in fluid communication with a subterranean formation, injecting the proppant-containing treatment fluid from the wellbore into a subterranean formation to create a fracture, placing the proppant into the fracture and closing the

fracture to form a proppant-supported fracture extending away from the wellbore and in fluid communication therewith, the improvement comprising: preparing the proppant-containing treatment fluid to comprise at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.); stabilizing the proppant-containing treatment fluid to form a stabilized treatment slurry (STS) meeting at least one of the following conditions:

[0192] a. the slurry has a low-shear viscosity equal to or greater than 1 Pa-s (5.11 $s^{-1,\ 25°}$ C.);

[0193] b. the slurry has a Herschel-Buckley (including Bingham plastic) yield stress (as determined in the manner described herein) equal to or greater than 1 Pa; or

[0194] c. the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or

[0195] d. 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

[0196] e. the apparent dynamic viscosity (25° 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 +/−20% of the initial dynamic viscosity; or

[0197] f. 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

[0198] g. 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; and

pumping the STS to the surface treatment pressure (at the wellhead) for introduction into the wellbore.

38. The method of embodiment 37, wherein the proppant-supported fracture extends for a distance of at least 30 meters (98 feet) away from the wellbore.

39 The method of embodiment 37, wherein the proppant-supported fracture extends for a distance of at least 50 meters (164 feet) away from the wellbore.

40 The method of embodiment 37, wherein the proppant-supported fracture extends for a distance of at least 100 meters (328 feet) away from the wellbore.

41 The method of embodiment 37, wherein the proppant-supported fracture extends for a distance of at least 150 meters (492 feet) away from the wellbore.

42. The method of any one of embodiments 37 to 41 wherein the STS is pumped to surface treatment pressure (at the wellhead) with a proppant pumping energy efficiency of at least 2 L of proppant pumped per MJ of pumping energy (1.4 gal/hp-h).

43. The method of any one of embodiments 37 to 42, wherein:

[0199] 1. 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;

[0200] 2. the apparent dynamic viscosity (25° C., 170 s^{-1}) across column strata after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than +/−20% of the initial dynamic viscosity;

[0201] 3. 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 5% greater than the initial SVF; and

[0202] 4. 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.

44. The method of any one of embodiments 37 to 43, wherein the STS is formed by at least one of: (1) decreasing the density difference between particles and liquid phase in the treatment fluid by introducing into the treatment fluid particles having a density less than 2.6 g/mL, carrier fluid having a density greater than 1.05 g/mL or a combination thereof; (2) increasing a yield stress of the treatment fluid to at least 1 Pa; (3) increasing apparent viscosity of the treatment fluid to at least 50 mPa-s (170 s^{-1}, 25° C.); (4) introducing a viscosifier selected from viscoelastic surfactants and hydratable gelling agents into the treatment fluid in an amount ranging from 0.01 up to 2.4 g/L of fluid phase; (5) introducing colloidal particles into the treatment fluid; (6) introducing sufficient particles into the treatment fluid to increase the SVF of the treatment fluid to at least 0.4; (7) introducing particles into the treatment fluid having an aspect ratio of at least 6; (8) introducing ciliated or coated proppant into the treatment fluid; and (9) combinations thereof.

45. The method of any one of embodiments 37 to 44, further comprising lowering a perforation pressure drop by maintaining a sustained velocity of the treatment fluid through the perforations below 50 m/s, i.e., maintaining a relatively low perforation pressure drop (relative to the pressure drop of the treating fluid passing through the perforation at a higher velocity) corresponding to a sustained velocity of the treatment fluid through the perforations below 50 m/s.

46. The method of any one of embodiments 37 to 45, further comprising lowering friction pressure drop in the wellbore by maintaining a sustained flow rate of treatment fluid in the wellbore below 1.6 m^3/min (10 BPM).

47. The method of any one of embodiments 37 to 46, further comprising increasing liquid head in the wellbore and reducing the treatment pressure by increasing the density of the treatment fluid to at least 2 g/mL.

48. The method of any one of embodiments 37 to 47, wherein the STS comprises particles having a density greater than 2.8 g/mL, brine having a density greater than 1.2 g/mL, or a combination thereof.

49. A method, comprising: preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a stabilized proppant-containing treatment fluid comprising at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid, a packed volume fraction (PVF) greater than a slurry solids volume fraction (SVF), and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein a spurt loss (Vspurt) is less than 10 vol % of a fluid phase of the stabilized proppant-containing treatment fluid or less than 50 vol % of an excess fluid phase (Vspurt<0.50*(PVF−SVF)); injecting the stabilized proppant-containing treatment fluid into the subterranean formation according to the treatment plan to create a fracture, wherein the spurt loss is sufficiently low to maintain fluidity of the stabilized proppant-containing treatment fluid entering the fracture; and placing the proppant into the fracture and closing the fracture to form

a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

50. The method of embodiment 49, wherein the sum of spurt volume (Vspurt) plus continuous fluid loss into the formation matrix (Vw) during the treatment fluid injection is greater than the total volume of fluid phase (Vfluid), as calculated according to the equation [(Vw+Vspurt)>(Vtreatmentfluid*(1−SVF))], wherein $Vw=4*A*Cw*t_1^{-0.5}$ wherein Vtreatmentfluid is the volume of treatment fluid injected into the fracture, A is the exposed area of one fracture face, Cw is the loss coefficient, and t_1 is the duration of the treatment fluid injection.

51. The method of embodiment 50, further comprising immediately producing hydrocarbons from the formation via the fracture wherein a fluid phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) is less than 1% over an initial production period of 5 days (FRR5).

52. The method of embodiment 49, wherein the sum of spurt volume (Vspurt) plus continuous fluid loss into the formation matrix (Vw) during the treatment fluid injection and a shut in period is greater than the total volume of fluid phase (Vfluid), as calculated according to the equation [(Vw+Vspurt)>(Vtreatmentfluid*(1−SVF))], wherein $Vw=4*A*Cw*(t_1+t_2)^{-0.5}$ wherein Vtreatmentfluid is the volume of treatment fluid injected into the fracture, A is the exposed area of one fracture face, Cw is the loss coefficient, t_1 is the duration of the treatment fluid injection and t_2 is the duration of the shut in period.

53. The method of embodiment 52, further comprising producing hydrocarbons from the formation via the fracture after the shut in period, wherein a fluid phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) is less than 1% over an initial production period of 5 days (FRR5).

54 The method of any one of embodiments 49 to 53, wherein the proppant-supported fracture extends for a distance of at least 50 meters (164 feet) away from the wellbore.

55 The method of any one of embodiments 49 to 53, wherein the proppant-supported fracture extends for a distance of at least 100 meters (328 feet) away from the wellbore.

56 The method of any one of embodiments 49 to 53, wherein the proppant-supported fracture extends for a distance of at least 150 meters (492 feet) away from the wellbore.

57. A method of managing risk in a fracturing operation, comprising:

[0203] preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore with surface access at a wellsite location, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a stabilized proppant-containing treatment fluid comprising at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.);

[0204] installing at the wellsite a pumping system having a maximum available pumping power capacity matching the sum of a maximum pumping power required to implement the pumping schedule plus a reserve pumping power capacity available in case of a pumping deviation event requiring additional power, wherein the reserve pumping power capacity comprises less than 50% of the maximum available pumping power capacity;

[0205] activating the pumping system with the reserve pumping power capacity in ready standby mode;

[0206] supplying the one or more treatment fluids to the activated pumping system according to the treatment plan; pumping the one or more treatment fluids into the wellbore according to the treatment plan; and

[0207] if there is an occurrence of a said pumping deviation event requiring additional pumping power, automatically recruiting pumping power capacity from the reserve pumping power capacity to continue the treatment plan.

58. The risk management method of embodiment 57, wherein the pumping system has a maximum pump discharge pressure for safe operation and wherein the pumping schedule comprises pumping the proppant-containing treatment fluid into the wellbore at a rate exceeding 1600 L/min (10 bpm) at a pump discharge pressure below the safe operation pressure, and further comprising:

[0208] pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture;

[0209] thereafter reducing the pumping rate of the proppant-containing treatment fluid to less than 1600 L/min to control the pump discharge pressure in response to a pumping deviation event comprising a pump discharge pressure approaching or exceeding the safe operation pressure; and

[0210] pumping a volume of the proppant-containing treatment fluid to complete the treatment plan according to a total volume of proppant-containing treatment fluid specified in the treatment plan.

59. The risk management method of embodiment 57, wherein a pumping deviation event comprises shutdown of the pumping system after pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture, thereby stranding the proppant-containing treatment fluid in the wellbore under static conditions, and further comprising:

[0211] thereafter restoring the pumping system to operational status; and

[0212] resuming pumping of the stranded proppant-containing treatment fluid from the wellbore into the fracture to continue the treatment substantially according to a remainder of the treatment plan.

60. The risk management method of embodiment 57, wherein a pumping deviation event comprises shutdown of the pumping system after pumping of the proppant-containing treatment fluid according to at least a portion of the pumping schedule to create a fracture, thereby stranding the proppant-containing treatment fluid in the wellbore under static conditions, and further comprising circulating the stranded proppant-containing treatment fluid out of the wellbore as an intact plug, optionally with a managed interface between the stranded treatment fluid and a displacing fluid.

61. A method, comprising: injecting a multimodal proppant-containing treatment fluid from a wellbore through a perforation to create a fracture in a subterranean formation, wherein the treatment fluid comprises at least 0.36, 0.4 or 0.45 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein a ratio of a diameter of the perforation to a diameter of the proppant is less than 6;

and placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore. In embodiments, the ratio of the perforation/proppant diameters is at least 2, at least 3, at least 4, or at least 5.

62. A method, comprising: injecting a multimodal proppant-containing treatment fluid from a wellbore into a subterranean formation to initiate and propagate a fracture, wherein the treatment fluid comprises at least 0.36 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein the fracture is propagated with entry of the proppant-containing treatment fluid such that the propagated fracture is contiguously filled with proppant to form an interconnected fracture system containing less than 5 volume percent of any proppant-free zones; and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

EXAMPLES

Example 1

Stabilized Treatment Slurry

[0213] An example of a stabilized treatment slurry (STS) is provided in Table 1 below.

TABLE 1

STS Composition.

Fluid components	Stabilized Proppant Free Slurry (g/L of STS)	Stabilized Proppant/ Solids Slurry (g/L of STS)
Crystalline silica 40/70 mesh	0	900-1100
Crystalline silica 100 mesh	0	125-225
Crystalline silica 400 mesh	600-800	100-250
Calcium Carbonate[1] 2 micron	300-400	175-275
Water	150-250	150-250
Latex[2]	300-500	100-300
Dispersant[3]	2-4	2-4
Antifoam[4]	3-5	1-3
Viscosifier[5]	6-10	6-10

[1]Calcium Carbonate = SAFECARB 2 from MI-SWACO
[2]Latex = Styrene-Butadiene copolymer dispersion
[3]Dispersant = Polynaphthalene sulfonate
[4]Antifoam = Silicone emulsion
[5]Viscosifier = AMPS/acrylamide copolymer solution

[0214] 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 MPs (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

Stabilized Treatment Slurry

[0215] 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 2

STS Composition

Components	Wt %	Vol %
40/70 proppant	49.7%	37.5%
100 mesh sand	8.9%	6.7%
30μ silica	8.9%	6.7%
2μ CaCO3	12.4%	9.2%
Liquid Latex	9.8%	19.3%
Water and additives	10.3%	20.6%

[0216] 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 siltstone 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.

[0217] As can be seen, to transport the same amount of proppant, the amount of water required is significantly reduced. To deliver 45,000 kg (100,000 lb) of proppant, a conventional slickwater treatment will require the use of 380 m^3 (100,000 gallons) of water assuming the average slickwater proppant concentration is 0.12 kg/L (1 ppa). On the contrary, to deliver the same amount of proppant using the STS formulation of these embodiments, less than 11.3 m^3 (3,000 gallons) of water are required, for a proppant stage placement v/v efficiency of 150 percent (volume of proppant placed is 1.5 times volume of water in proppant stage) versus 4.5 percent for the 1 ppa slickwater. The STS in this embodiment is using only 3% of the water that is required using the slickwater fracturing technique. Even considering any requirements of a pad, a flush and other non-STS fluid, the amount of water used by STS in this embodiment is still at least an order of magnitude less than the comparable slickwater technique, e.g., less than 10% of the water required for the slickwater technique. In embodiments, the proppant stage placement v/v water efficiency (volume of proppant/volume of water) is at least 10%, at least 20%, at least 30%, at least 40%, at least 50%, at least 60%, at least 70%, at least 80%, at least 90%, at least 100%, at least 110%, or at least 120%, and in additional or alternative embodiments the aqueous phase in the high-efficiency proppant stage has a viscosity less than 300 mPa-s.

Example 3

STS Slurry Stability Tests

[0218] A slurry sample was prepared with the formulation given in Table 3.

TABLE 3

STS Composition

Components	g/L Slurry
40/70 proppant	700-800
100 mesh sand	100-150
30µ silica	100-140
2µ CaCO3 (SafeCARB2)	150-200
0.036 wt % Diutan solution	0.4-0.6
Water and other additives	250-350

[0219] 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 RUSHTON 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 R1B5F1 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, 5.10, 85.0, 170 and 255 s^{-1}) recorded as the shear stress, and the yield stress (τ_0) determined as the y-intercept using the Herschel-Buckley rheological model.

[0220] 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 (6'3"), 140 mm (4'7"), 84 mm (2'9") and 33 mm (1'1") 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@15 Hz/10 d static"). The 15 Hz/1 mm amplitude condition was selected to correspond to surface transportation and/or storage conditions prior to the well treatment.

[0221] 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

Rheological properties, initial and 8 h@15 Hz/10 d Dynamic-static aged samples

	Shear Stress (Pa (lbf/100 ft2)) Shear Rate (s^{-1}):				Delta, @170 s^{-1}
	2.55	5.1	85	170	(%)
Initial slurry	17.9 (37.4)	21.3 (44.5)	84.5 (176.4)	135 (282.7)	(base line)
Aged slurry, 8 h@15 Hz/10 d static					
Top sample	15.4 (32.1)	19.3 (40.4)	76.8 (160.3)	123 (257.1)	−8.9
Upper middle sample	15.9 (33.3)	20.2 (42.2)	81.9 (171)	132 (276.1)	−2.3
Lower middle sample	14.8 (30.9)	19.3 (40.4)	79.3 (165.7)	130 (271.4)	−3.7
Bottom sample	18.6 (38.9)	22.7 (47.5)	89.6 (187.1)	146 (305.8)	+8.1

[0222] 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. **7**.

[0223] From the data seen in FIG. **7**, 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).

Example 5

Slot orifice Flow Data

[0224] 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, the slurry was loaded into a cell with bottom slot 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. 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

Results of different slurries flowing through different opening slots

Fluid	% slurry flowed through 1.8 mm (0.0708 in.) slot	% slurry flowed through 1.5 mm (0.0591 in.) slot
Slickwater with high ppa	20%*	0%
60% SVF STS	100%	50%
50% SVF STS	100%	100%

*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.).

[0225] 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.

Example 6

Field Experiment

[0226] In a field experiment, the STS of Table 2 above was stored at static condition for five days before performing the pumping treatment. The solids were perfectly suspended. The fluid was also pumped using three triplex pumps without any fluid-related problems in the job. This good suspension makes the proppant (solid) transport independent of flow rates.

[0227] Given these properties of STS, the field experiment confirmed that the fracturing operation could be performed at very low rate. As can be seen in FIG. **8**, the majority of the pump rate was around 1600 L/min (10 bbl/min or bpm). There were some periods of less than 960 L/min (6 bpm) and occasionally less than 640 L/min (4 bpm). This combination of low treating rate and high proppant concentration (>1.56 kg/L of carrier fluid, excluding the volume of proppant and other solids (13 lbs proppant added per gallon of fluid (ppa)) allows hydraulic fracture treatment to be achieved without screenout, using smaller or fewer pumps and slurry preparation equipment, while at the same time reducing the total water used.

Examples 1-10

Additional Formulations

[0228] Additional STS formulations were prepared as shown in Table 2. Example 7 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 8 was similar to Example 7 except that it contained proppant including 100 mesh sand. Example 9 was prepared with gelling agent instead of latex. Example 10 was similar to Example 9, but was prepared with dispersed oil particles instead of calcium carbonate. Examples 8-10 exemplify treatment fluids suitable for fracturing low mobility formations.

TABLE 6

STS Composition and Properties

STS	Size (μm)	Example 7 Wt %	Example 8 Wt %	Example 9 Wt %	Example 10 Wt %
Components					
40/70 proppant	210-400	—	50-55	50-55	50-55
100 mesh sand	150	—	8-12	8-12	8-12
Silica flour	28-33	40-45	6-12	6-12	6-12
CaCO3	2.5-3	20-25	8-12	8-12	—
Liquid Latex	0.18	20-25	8-12	—	—
Viscosifier	—	0.1-1	0.1-1	—	—
Anti-foam	—	0.05-0.5	0.05-0.5	—	—
Gelling agent	—	—	—	0.01-0.05	0.01-0.05
Dispersant	—	0.05-0.5	0.05-0.5	0.05-0.5	—
Breaker	—	—	—	0.01-0.1	0.01-0.1
Breaker aid	—	—	—	0.005-0.05	0.005-0.05
Oil	—	—	—	—	2-3
Surfactant	—	—	—	—	0.1-1
Water	—	8-12	8-12	18-22	18-22
Rheology					
Yield Point (Pa)		11.5	8.9	15.3	13.5
K (Pa-s^n)		5.41	3.09	1.42	2.39
n		0.876	0.738	0.856	0.725
Stability (static 72 h)		Stable	Stable	Stable	Stable

TABLE 6-continued

STS Composition and Properties					
STS	Size (μm)	Example 7 Wt %	Example 8 Wt %	Example 9 Wt %	Example 10 Wt %
Leakoff control					
Cw (ft/min$^{1/2}$)		0.0002	0.00015	0.003	0.0014
Filter cake (mm)		~1	<1	~5	~5
Clean up permeability (D)		ND	ND	0.004-0.024	1-1.2
Fluid Properties					
SVF (%)		40 (60*)	60 (70*)	60	54 (60*)
Specific gravity		1.68	2	2	1.88
PPA (whole fluid)		NA	14	14	13.6

Notes:
ND = not determined
NA = not applicable
*= including latex or oil

[0229] All of the fluids were stable, and had a yield point above 10 Pa and a viscosity less than 10 Pa-s. Rehological, leak-off control and other fluid properties are given in Table 6.

[0230] 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.

[0231] 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 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.

We claim:

1. A method, comprising:

injecting a proppant-containing treatment fluid into a low mobility subterranean formation;

creating a fracture in the subterranean formation containing a first volume (V**1**) of the proppant-containing treatment fluid; and

allowing the fracture to close on the proppant to form a proppant-supported fracture having a second volume (V**2**) of packed proppant support, wherein a ratio of the second volume (V**2**) to the first volume (V**1**) is at least 0.7.

2. The method of claim **1**, wherein the low mobility formation comprises a carbonate or siltstone formation.

3. The method of claim **1**, wherein the low mobility formation comprises permeability less than 0.1 mD and further comprising producing hydrocarbon liquid from the formation.

4. The method of claim **1**, wherein the low mobility formation comprises permeability less than 1000 nD and further comprising producing hydrocarbon gas from the formation.

5. The method of claim **1**, comprising forming the proppant-supported fracture to extend away from a wellbore for a distance of at least 30 m (98 feet) into the subterranean formation.

6. The method of claim **1**, further comprising placing the packed proppant support in pillars and forming open channels in spaces between the pillars.

7. The method of claim **1**, wherein the proppant-containing treatment fluid comprises a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.) and a yield stress between 1 and 20 Pa (2.1-42 lb_f/ft^2).

8. The method of claim **1**, wherein the proppant-containing treatment fluid comprises 0.36 L or more of proppant volume per liter of proppant-containing treatment fluid (8 ppa proppant), a viscosity less than 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).

9. The method of claim **1**, further comprising:

injecting the proppant-containing treatment fluid via a wellbore at a sustained perforation velocity of less than 50 m/s for a continuous period of at least 5 minutes to create a fracture in the subterranean formation; and

placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

10. The method of claim **1**, further comprising:

stopping injection of the treatment fluid to interrupt the creation of the fracture thereby stranding the treatment fluid in the wellbore; and

thereafter resuming injection of the treatment fluid to inject the stranded treatment fluid into the formation and continue the fracture creation.

11. A method to improve proppant pumping energy efficiency in a fracturing procedure comprising pumping a proppant-containing treatment fluid at a surface treatment pressure into a wellbore in fluid communication with a subterranean formation, injecting the proppant-containing treatment fluid from the wellbore into a subterranean formation to create a fracture, placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture extending away from the wellbore and in fluid communication therewith, the improvement comprising:

preparing the proppant-containing treatment fluid to comprise at least 0.36 L of proppant per liter of whole fluid and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.);

stabilizing the proppant-containing treatment fluid to form a stabilized treatment slurry (STS) meeting at least one of the following conditions:

a) the slurry has a low-shear viscosity equal to or greater than 1 Pa-s (5.11 s-1, 25° C.);

b) the slurry has a Herschel-Buckley (including Bingham plastic) yield stress (as determined in the manner described herein) equal to or greater than 1 Pa; or

c) the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or

d) 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

e) the apparent dynamic viscosity (25° 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 +/−20% of the initial dynamic viscosity; or

f) 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

g) 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.

pumping the STS to the surface treatment pressure for introduction into the wellbore.

12. The method of claim **11**, wherein the proppant-supported fracture extends for a distance of at least 30 meters (98 feet) away from the wellbore.

13. The method of claim **11**, wherein the STS is pumped to surface treatment pressure with a proppant pumping energy efficiency of at least 2 L of proppant pumped per MJ of pumping energy.

14. The method of claim **11**, wherein:

1. 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;
2. the apparent dynamic viscosity (25° C., 170 s^{-1}) across column strata after the 8 h@15 Hz/10 d-static dynamic settling test condition is no more than +/−20% of the initial dynamic viscosity;
3. 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 5% greater than the initial SVF; and
4. 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.

15. The method of claim **11**, wherein the STS is formed by at least one of: (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° 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° 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.

16. The method of claim **11**, further comprising maintaining a relatively low perforation pressure drop corresponding to a sustained velocity of the treatment fluid through the perforations below 50 m/s, relative to the pressure drop of the treating fluid passing through the perforation at a higher velocity.

17. The method of claim **11**, further comprising lowering friction pressure drop in the wellbore by maintaining a sustained flow rate of treatment fluid in the wellbore below 1.6 m^3/min (10 BPM).

18. A method, comprising:

preparing a treatment plan for fracturing a subterranean formation penetrated by a wellbore, wherein the treatment plan comprises a schedule for pumping into the wellbore one or more treatment fluids specified in the treatment plan including a stabilized proppant-containing treatment fluid comprising at least 0.36 L of proppant per liter of whole fluid, a packed volume fraction (PVF) greater than a slurry solids volume fraction (SVF), and a viscosity less than 300 mPa-s (170 s^{-1}, 25° C.), and wherein a spurt loss (Vspurt) is less than 10 vol % of a fluid phase of the stabilized proppant-containing treatment fluid or less than 50 vol % of an excess fluid phase (Vspurt<0.50*(PVF−SVF));

injecting the stabilized proppant-containing treatment fluid into the subterranean formation according to the treatment plan to create a fracture, wherein the spurt loss is sufficiently low to maintain fluidity of the stabilized proppant-containing treatment fluid entering the fracture; and

placing the proppant into the fracture and closing the fracture to form a proppant-supported fracture for a distance of at least 30 meters (98 feet) away from the wellbore.

19. The method of claim **18**, wherein the sum of spurt volume (Vspurt) plus continuous fluid loss into the formation matrix (Vw) during the treatment fluid injection is greater than the total volume of fluid phase (Vfluid), according to the equation [(Vw+Vspurt)>(Vtreatmentfluid*(1−SVF))], wherein $Vw=4*A*Cw*t_1^{-0.5}$ wherein Vtreatmentfluid is the volume of treatment fluid injected into the fracture, A is the exposed area of one fracture face, Cw is the loss coefficient, and t_1 is the duration of the treatment fluid injection.

20. The method of claim **19**, further comprising immediately producing hydrocarbons from the formation via the fracture wherein a fluid phase flowback recovery volume (Vflowback) at a flowback recovery ratio (Vflowback/Vw where Vw is the fluid phase volume of the treatment fluid) is less than 1% over an initial production period of 5 days (FRR5).

* * * * *