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[Continued on next page]

(54) Title: HETEROGENEOUS PROPPANT PLACEMENT IN A FRACTURE WITH REMOVABLE EXTRAMETRICAL MATERIAL FILL

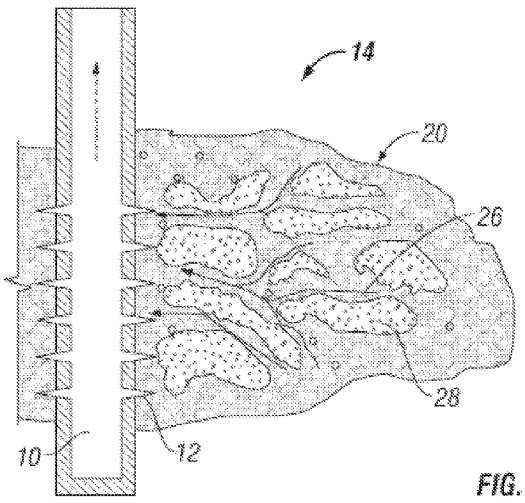

FIG. 2

(57) Abstract: A method of heterogeneous proppant placement in a subterranean fracture is disclosed. The method comprises injecting well treatment fluid including proppant (16) and proppant-spacing filler material (18) through a wellbore (10) into the fracture (20), heterogeneously placing the proppant in the fracture in a plurality of proppant clusters or islands (22) spaced apart by the material (24), and removing the filler material (24) to form open channels (26) around the pillars (28). The filler material can be dissolvable particles, initially acting as a consolidator during placement of the proppant in the fracture, and later dissolving to leave flow channels between the proppant pillars. The well treatment fluid can include extrametrical materials to provide reinforcement and consolidation of the proppant and, additionally or alternatively, to inhibit settling of the proppant in the treatment fluid.

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HETEROGENEOUS PROPPANT PLACEMENT IN A FRACTURE WITH REMOVABLE EXTRAMETRICAL MATERIAL FILL

BACKGROUND

[0001] The statements in this section merely provide background information related to the present disclosure and may not constitute prior art.

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

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

[0004] Some methods have sought to increase the permeability of the proppant pack by increasing the porosity of the interstitial channels between adjacent proppant particles within the proppant matrix. For example, United States Patent Application Publication Number 200600408944A1 (van Batenburg, et al.) discloses a method of forming a high porosity propped fracture with a slurry that includes a fracturing fluid, proppant particulates and a weighting agent. These technologies seek to distribute the porosity and interstitial flow passages as uniformly as possible in the consolidated proppant matrix filling the fracture, and thus employ homogeneous proppant placement procedures to substantially uniformly distribute the proppant and non-proppant, porosity-inducing materials within the fracture.

[0005] In other methods, as in United States Patent Application Publication Number 20060048943A1 (Parker, et al.), proppant particulates and degradable material are not segregated before, during or after injection in order to help maintain uniformity within the proppant matrix. Fracturing fluids are thoroughly mixed to prevent any segregation of proppant and non-proppant particulates. In another approach, non-proppant materials have a size, shape and specific gravity similar to that of the proppant to maintain substantial uniformity within the mixture of particles in the fracturing fluid and within the resulting proppant pack. A tackifying compound coating on the particulates has also been used to enhance the homogenous distribution of proppant and non-proppant particulates as they are blended and pumped downhole into a fracture.

[0006] A recent approach to improving hydraulic fracture conductivity has been to try to construct proppant clusters in the fracture, as opposed to constructing a continuous proppant pack. United States Patent Number 6,776,235 (England) discloses a method for hydraulically fracturing a subterranean formation involving alternating stages of proppant-containing hydraulic fracturing fluids contrasting in their proppant-settling rates to form proppant clusters as posts that prevent fracture closing. This method alternates the stages of proppant-laden and proppant-free fracturing fluids to create proppant clusters, or islands, in the fracture and channels between them for formation fluids to flow. The amount of proppant deposited in the fracture during each stage is modulated by varying the fluid transport characteristics (such as viscosity and elasticity), the proppant densities, diameters, and concentrations and the fracturing fluid injection rate. However, the positioning of the proppant-containing fluid is difficult to control. For example, the proppant-containing fluid can have a higher density than the proppant-free fluid and can thus underride the proppant-free fluid. This underride can result in non-uniform distribution of proppant clusters, which in turn can lead to excessive fracture closure where there is not enough proppant and constricted flow channels where there is too much proppant.

SUMMARY

[0007] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to

identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0008] According to some embodiments, a fracturing treatment includes the injection of both proppant and a removable material that can act as fill to physically separate the proppant clusters at appropriate distances during placement in the fracture, but can subsequently be removed to form channels. The proppant and removable material are disposed within a fracture in such a way that the removable material is segregated from the proppant to act as a temporary filler material compressed in the fracture in spaces between clusters or islands of proppant which form pillars to hold open the fracture. Then, the fill material is removed to form open channels for unimpeded fluid flow through the fracture in the spaces left around the proppant pillars. Applicant refers herein to the removable extrametrical material, or channel-forming fill material as "channelant." In alternative embodiments the extrametrical material may not necessarily serve as a channelant.

[0009] In one aspect, embodiments are related to methods of heterogeneous proppant placement in a subterranean fracture accomplished by injecting well treatment fluid through a wellbore into a fracture in a subterranean formation. The treatment fluid can include proppant and proppant-spacing extrametrical material. The proppant can be placed in the fracture in a plurality of proppant clusters forming pillars spaced apart by the extrametrical material. Then, the extrametrical material can be removed to form open channels around the pillars for fluid flow from the formation through the fracture toward the wellbore.

[00010] In another aspect, embodiments are related to methods of treating a subterranean formation penetrated by a wellbore, wherein a fracture is formed within the formation by injecting a fluid into the wellbore at a pressure equal to or greater than the fracture initiation pressure of the formation, followed by injecting one or more stages each of a proppant laded well treatment fluid and extrametrical material laden fluid. These fluids are injected separately and/or simultaneously. The extrametrical material may then be removed to form open channels around pillars of proppant for fluid flow from the formation through the fracture toward the wellbore. Removal of the extrametrical material may be influenced by such factors as invasion of formation fluids, by exposure to water, by passage of time, by the presence of incipient or delayed reactants in or mixed with the

extrametrical material particles, by the post-injection introduction of an activating fluid, and the like, or any combination of thereof.

[00011] In an embodiment, the extrametrical material can include solid particles that can be consolidated between the proppant islands or pillars. In an embodiment, the proppant and extrametrical material particles can be segregated during injection of the well treatment fluid. In another embodiment, the extrametrical material particles can be maintained in a solid state within the fracture.

[00012] The injection can include injecting a proppant-lean carrier stage to initiate the fracture; and thereafter injecting into the fracture proppant and extrametrical material.

[00013] In an embodiment, the injection can further include injecting a tail-in stage to form a permeable proppant pack in the fracture between the open channels and the wellbore.

[00014] In an embodiment, the treatment fluid can have mixed phases including a proppant-rich phase and an extrametrical material-rich phase. In embodiments, the proppant-rich phase can be discontinuous. Alternatively or additionally, the extrametrical material-rich phase can be continuous. In another embodiment, the treatment fluid can alternate volumes of proppant-rich fluid separated by volumes containing the extrametrical material.

[00015] The treatment fluid can alternatively or additionally include a mixture of proppant and extrametrical material during the injection, and the method can include the step of segregating the proppant and extrametrical material for the fracture placement. In an embodiment, the segregation can be facilitated by density differences between the proppant and extrametrical material. Alternatively or additionally, the segregation can be facilitated by differences between the proppant and extrametrical material.

[00016] Extrametrical material in one embodiment can include a solid acid-precursor to generate acid in the fracture. The generated acid can be used for gel breaking in the fracturing fluid. In another embodiment, the generated acid can etch surfaces of the formation to enlarge the channels. Alternatively or additionally, the generated acid can facilitate consolidation of the proppant clusters.

[00017] The proppant can be sand, nut hulls, ceramics, bauxites, glass, and the like and combinations thereof. In one embodiment, the proppant includes ceramic particles having a narrow particle size distribution and sand having a broad particle size distribution. Resin coated proppants (various resin and plastic coatings) having a base of any of the previously listed propping materials such as sand, ceramics, bauxite, nut shells, etc. may be used in accordance with the embodiment. Also other proppants like, plastic beads such as styrene divinylbenzene, and particulate metals may be used. Proppant used in this application may not necessarily require the same permeability properties as typically required in conventional treatments because the overall fracture permeability will at least partially develop from formation of channels. Other proppants may be materials such as drill cuttings that are circulated out of the well and/or other ground minerals, as shales, mica, and the like, or even ground waste of any kind, such as slag, scoria, sinter, ash, ground plastic, crushed glass, ground metal etc., and of which if properly consolidated, waste pillars can provide sufficient strength, particularly at low closure stress, as well as any combinations of any of the previous mentioned material types. In an embodiment, the proppant can be in the form of spheres, rods, platelets, irregular shapes and the like and combinations thereof. Many other organic materials could be resin coated and possible applied such as wood chips or various seeds, and the like. Essentially, the proppant can be any material that will hold open the propped portion of the fracture.

[00018] The extrametrical material can be any material degradable or dissolvable after placement within the fracture. The extrametrical material can be, for example, polylactic acid (PLA), polyglycolic acid (PGA), polyol, polyethylene terephthalate (PET), nylon 6, nylon 6,6, polyester, polyamide, polyolefin, polysaccharide, wax, salt, calcium carbonate, benzoic acid, naphthalene based materials, magnesium oxide, sodium bicarbonate, soluble resins, sodium chloride, calcium chloride, ammonium sulfate, and the like, or a combination thereof. The extrametrical material can have a size and shape matching the size and shape of the proppant to promote segregation. In an embodiment, the channelant can be in the form of spheres, fibers, rods, platelets, ribbons, and the like and combinations thereof.

[00019] In some embodiments the extrametrical materials can be, for example, glass, ceramics, carbon including carbon-based compounds, metal including metallic

alloys, or the like, or a combination thereof, or a polymeric material such as PLA, PGA, PET, polyol, polyamide, polyimide, or the like, or a combination thereof. In an embodiment, the extrametrical materials can form of an extrametrical material-based network. In an embodiment, the extrametrical materials can provide reinforcement and consolidation of the proppant. In another embodiment, the extrametrical materials can inhibit differential settling of proppant in the treatment fluid.

[00020] In yet another embodiment, the treatment fluid can include a mixture of first and second extrametrical material types, the first extrametrical material type providing reinforcement and consolidation of proppant, and the second extrametrical material type inhibiting settling of the proppant in the treatment fluid. The first extrametrical material type can be one of glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, or the like or a combination thereof, and the second extrametrical material type can be PLA, PGA, PET, polyol, polyamide, polyimide, or the like, or a combination thereof.

[00021] Alternatively or additionally, the proppant can be self-adherent and/or non-adherent to the extrametrical material. The proppant can have a self-adherent coating, for example. Similarly, the extrametrical material of another embodiment can be self-adherent and/or non-adherent to the proppant. The extrametrical material can have a self-adherent coating, for example.

[00022] In another embodiment, the proppant can have hydrophobic surfaces and the extrametrical material can have hydrophilic surfaces. Alternatively, the proppant can have hydrophilic surfaces and the extrametrical material hydrophobic surfaces.

[00023] In yet another aspect, method embodiments include injecting a plurality of stages of a well treatment fluid through a wellbore into a fracture in a subterranean formation, the stages of the fluid containing at least one of a proppant and an extrametrical material. The extrametrical material comprises at least one of a solid acid-precursor to generate acid in the fracture, and a solid base-precursor to generate a base in the fracture (in either case, a suitable acid or base is a material which alters the pH of an aqueous median, in either a decreasing or increasing direction, respectively). The proppant is placed in the fracture in a plurality of proppant clusters to form pillars. The extrametrical material then dissolves in the fracture, which may further enable fluid flow from the

formation through the fracture toward the wellbore (the term 'dissolve' in the present application means any suitable process, either chemical or mechanical, by which the extrametrical material voids the fracture space occupied).

[00024] In yet other embodiments, methods involve injecting a plurality of stages of a well treatment fluid through a wellbore into a fracture in a subterranean formation, where the stages of the fluid containing at least one of a proppant and a extrametrical material, and placing the proppant in the fracture in a plurality of proppant clusters to form pillars. The extrametrical material subsequently dissolves. The zone contacted by the treatment fluid in the formation comprises fine grained sedimentary rock formed by consolidation of clay and silt sized particles into thin, relatively impermeable layers.

[00025] A further aspect involves methods where a plurality of stages of a well treatment fluid are injected through a deviated wellbore into a fracture in a subterranean formation, and the stages of the fluid contain at least one of a proppant and an extrametrical material. The proppant is placed in the fracture in a plurality of proppant slugs; and the placed extrametrical material is allowed to dissolve. The treatment fluid stages are alternate volumes of proppant-rich fluid separated by volumes of extrametrical material-rich fluid.

[00026] In some embodiments, the pulsing fracturing treatment schedule is combined with homogeneous stage at the end of the treatment. Such approach may provide a substantial increase in the fracture conductivity achieved by loading a heterogeneous proppant pack (combination of proppant pillars) into the fracture.

[00027] Some embodiments are methods of reservoir stimulation with increased fracture conductivity, achieved by heterogeneous proppant placement in a hydraulic fracture. The method provides a treatment pumping schedule with parameters, optimized based on reservoir geomechanical properties. Design optimization can be performed either prior to the treatment or in real time. Different embodiments of design optimization are disclosed.

[00028] Any of the methods also include the step of producing fluids such as hydrocarbons, or any other suitable fluids, from the formation through the open channels and the wellbore.

[00029] Some other embodiments include the use of a foamed fluid, utilizing a suitable gas, such as, but not limited to air, nitrogen, carbon dioxide, and the like, or any mixtures thereof. Any suitable ration of gas phase to liquid phase may be utilized. In one case, the embodiment is a method including injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation; injecting a second treatment fluid comprising proppant and an extrametrical material through a wellbore and into a fracture in a subterranean formation, wherein the introducing is achieved with varied and pulsed proppant concentration in a pumping schedule, the pumping schedule being optimized based on fluid and formation properties, and/or wherein the introducing is achieved by varying pumping rate during pulses; and forming a plurality of proppant clusters comprising proppant and the extrametrical material in the fracture; where the extrametrical material consolidates the proppant into clusters, and wherein the extrametrical material is degradable.

[00030] In another aspect, the method includes injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation; injecting a second treatment fluid comprising proppant and an extrametrical material through a wellbore and into a fracture in a subterranean formation wherein the injecting is achieved with varied and pulsed proppant concentration in a pumping schedule, the pumping schedule being optimized based on fluid and formation properties, and/or wherein the introducing is achieved by varying pumping rate during pulses; and, placing the proppant in the fracture in a plurality of proppant clusters; where the extrametrical material reinforces the proppant clusters, and wherein the extrametrical material is a removable material.

[00031] Yet another method includes injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation; injecting a second treatment fluid comprising proppant and fiber through a wellbore and into a fracture in a subterranean formation; and forming a plurality of proppant clusters comprising proppant and fiber in the fracture; where the fiber consolidates the proppant into clusters, and wherein the fiber degrades.

[00032] Another embodiment includes a method involving injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation; injecting a second treatment fluid comprising proppant and fiber through a wellbore and into a fracture in a subterranean formation; and placing the proppant in the fracture in a plurality of proppant clusters; where the fiber reinforces the proppant clusters, and where the fiber is a removable material.

[00033] Also, another method involves constructing a system in a subterranean formation penetrated by a wellbore, where the construction includes:

i. injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

ii. injecting a second treatment fluid comprising proppant and fiber through a wellbore and into the fracture, wherein the fiber is a degradable material;

iii. placing the proppant in the fracture in a plurality of proppant clusters;

then producing formation fluids from the formation, through the system constructed.

[00034] Yet another method involves constructing a system in a subterranean formation penetrated by a wellbore, where the construction includes:

i. injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

ii. injecting a second treatment fluid comprising proppant and fiber through a wellbore and into the fracture, wherein the fiber is a removable material;

iii. placing the proppant in the fracture in a plurality of proppant clusters;

then producing formation fluids from the formation, through the system of a).

[00035] Other or alternative features will become apparent from the following description, from the drawings, and from the claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[00036] Certain embodiments will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements. It should be understood, however, that the accompanying drawings illustrate only the various implementations described herein and are not meant to limit the scope of various technologies described herein. The drawings are as follows:

FIG. 1 **schematically illustrates in section placement of proppant and removable extrametrical material in a hydraulic fracture operation according to an embodiment of the disclosure;**

FIG. 2 **schematically** illustrates in section the arrangement of the wellbore, perforations and the proppant pillars in the fracture following removal of the extrametrical material from the fracture of FIG. 1;

FIG. 3 schematically illustrates a side sectional view of a fracture filled with segregated proppant and degradable solid acid-precursor as extrametrical material in a carbonate formation according to an embodiment of the disclosure;

FIG. 4 schematically illustrates a side sectional view of the fracture of FIG. 3 following hydrolysis of the solid acid-precursor and etching at the faces of the fracture in the vicinity of the acid formed thereby;

FIG. 5 schematically illustrates an example of pulsation schedule according to one embodiment where time is on the x-axis and proppant concentration on the y-axis;

FIG. 6 schematically illustrates fractures filled with system of pillars so that there are open channels remain between pillars;

FIG. 7 illustrates how channel conductivity may depend upon propped fracture area for different ratio L/L_0;

FIG. 8 describes the results of numerical simulation for proppant transport in a horizontal transverse fracture (with black areas representing proppant) in which notations: 1 – wellbore, 2 – boundaries of the hydraulic fracture (transverse, located between stress barriers with confined height growth), 3 – proppant pulses transported radial in the central

part of the fracture, 4 – proppant pulses transported horizontally in the wings of the fracture; and

FIG. 9 describes the schematic model representing proppant transport in a horizontal well in which notations: 1 – wellbore, 2 – boundaries of the hydraulic fracture (transverse, located between stress barriers with confined height growth), 3 – proppant pulses transported radial in the central part of the fracture, 4 – proppant pulses transported horizontally in the wings of the fracture, 5 – proppant pack close to the near-wellbore area, 6 – area of potential pinching, if the proppant pack notated by 5 is placed incorrectly.

Detailed Description

[00037] At the outset, it should be noted that in the development of any such actual embodiment, numerous implementation—specific decisions must be made to achieve the developer's specific goals, such as compliance with system related and business related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time consuming but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure.

[00038] The description and examples are presented solely for the purpose of illustrating some of the various embodiments of the disclosure and should not be construed as a limitation to the scope and applicability of the disclosure. While the compositions of the present disclosure are described herein as comprising certain materials, it should be understood that the composition could optionally comprise two or more chemically different materials. In addition, the composition can also comprise some components other than the ones already cited. In the summary of the disclosure and this detailed description, each numerical value should be read once as modified by the term "about" (unless already expressly so modified), and then read again as not so modified unless otherwise indicated in context. Also, in the summary of the disclosure and this detailed description, it should be understood that a concentration range listed or described as being useful, suitable, or the like, is intended that any and every concentration within the range, including the end points, is to be considered as having been stated. For example, “a range of from 1 to 10” is

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

[00039] Some embodiments utilize fluids containing a gas phase and liquid phase. As used herein, the term “liquid phase” is meant to include all components of the fluid except the gas phase. The term "gas" is used herein to describe any fluid in a gaseous state or in a supercritical state, wherein the gaseous state refers to any state for which the temperature of the fluid is below its critical temperature and the pressure of the fluid is below its vapor pressure, and the supercritical state refers to any state for which the temperature of the fluid is above its critical temperature. When referred to in conjunction with a gas component, the terms "energized fluid", “foam” and “fluid” may be interchangeably used to describe any stable mixture of gas phase and liquid phase. Fluids described herein may also refer to liquids not containing a gas component, in accordance with the context of use. Foamed and energized fracturing fluids often contain “foamers”, most commonly surfactant or blends of surfactants that facilitate the dispersion of the gas into the base fluid in the form of small bubbles or droplets, and confer stability to the dispersion by retarding the coalescence or recombination of such bubbles or droplets. Foamed and energized fracturing fluids are generally described by their foam quality, i.e. the ratio of gas volume to the foam volume. If the foam quality is between about 52% and 95%, the fluid is conventionally called foam, and below about 52%, an energized fluid. However, as used herein the term "energized fluid" is defined as any stable mixture of gas and liquid, notwithstanding the foam quality value.

[00040] Fracturing fluids according to an example of the present method can include proppant and a removable proppant-spacing material, which can function to form open channels around the proppant pillars. In some embodiments, these extrametrical channel-forming materials, including proppant-spacing particles, are referred to herein as “channelant.” In other embodiments, the extrametrical material may not necessarily serve

as a channelant, but may be at least partially, or even totally removable under formation conditions, while in some cases the extrametrical material may not be removable.

[00041] As used herein, the term "open channels" refers to interconnected passageways formed in the proppant-fracture structure. Open channels are distinct from interstitial passages between individual proppant particles in the proppant matrix in that the channels fully extend between opposing fracture faces, free of obstruction by proppant or other flow-impeding structures, and exist outside the proppant matrix, in some cases laterally bounded by the proppant pillars. Such open channels generally have a hydraulic radius, and hence a hydraulic conductivity, which is at least an order of magnitude larger than that of interstitial flow passages through the proppant matrix.

[00042] The open channels can be formed by placing the proppant and extrametrical material in the fracture in such a way that the pillar-forming proppant islands are ultimately segregated from the channel-forming removable material. The segregation can occur or begin in the preparation, mixing or pumping of the treatment fluid, in the injection of the treatment fluid in the fracture, in or after the proppant placement, packing or settling in the fracture, by a distinct post-injection step of chemical and/or mechanical manipulation or treatment of the proppant/extrametrical material following initial placement in the fracture, or by aggregating and consolidating the proppant during the extrametrical material removal.

[00043] As used herein, the terms "segregation," "segregating" and the like refer to any heterogeneous proppant/extrametrical material distribution between proppant-rich pillar-forming islands or regions and proppant-lean extrametrical material regions. It may not be necessary to keep the proppant-rich regions entirely free of extrametrical material because the presence of extrametrical material, especially in relatively minor amounts, may not exceed any level that prevents the formation or consolidation of the proppant into pillars of sufficient strength to prevent the fracture from closing. In an embodiment, the extrametrical material can function in the proppant or proppant regions to consolidate or reinforce the proppant islands and/or to strengthen the proppant pillars. Conversely, the extrametrical material regions can contain proppant particles, especially relatively minor amounts, which remain unconsolidated or do not otherwise prevent removal of the

extrametrical material to form the open channels and which do not result in obstruction or excessive clogging of the open channels by the proppant.

[00044] A simplified embodiment of the method is illustrated with reference to FIGS. 1-2, in which the extrametrical material particles can be generally insoluble in the injection fluid and soluble in the formation fluid. In FIG. 1, a wellbore 10 can be completed with perforations 12 in formation 14. The wellbore is shown as a vertical wellbore for the purposes of illustration only. The wellbore can be deviated at any angle relative a vertical wellbore, or any combination of both vertical and deviated sections. Segregated proppant particles 16 and extrametrical material particles 18 can be injected in a fracturing fluid through the wellbore 10 into a fracture 20, where they can be heterogeneously placed in respective proppant-rich islands 22 spaced apart by extrametrical material-rich regions 24. The fracture 20 can be allowed to close, and the proppant islands 22 compressed to form pillars to support the fracture 20 and prevent the opposing fracture faces from contacting each other. Simultaneously, the extrametrical material can be packed in the proppant-lean regions 24 and can help restrict the islands 22 from creeping or spreading laterally due to compression by the weight of the formation, thereby facilitating a greater height or open dimension of the resulting propped fracture and a greater hydraulic conductivity.

[00045] During another operative step, the extrametrical material can be removed in various embodiments by flushing, dissolving, softening, melting, breaking, or degrading the extrametrical material, wholly or partially, via a suitable activation mechanism, such as, but not limited to, temperature, time, pH, salinity, solvent introduction, catalyst introduction, hydrolysis, and the like, or any combination thereof. The activation mechanism can be triggered by ambient conditions in the formation, by the invasion of formation fluids, exposure to water, passage of time, by the presence of incipient or delayed reactants in or mixed with the extrametrical material particles, by the post-injection introduction of an activating fluid, or the like, or any combination of these triggers.

[00046] Then, with reference to FIG. 2, the formation fluid can be allowed to invade the fracture 20 to displace any extrametrical material, extrametrical material solution, extrametrical material degradation products, and any unconsolidated proppant or other

particles, from the proppant-lean regions. In one embodiment, the extrametrical material can simply be unconsolidated so that it can be removed hydraulically, or can include unconsolidated particles that can be removed hydraulically, e.g. by flushing the fracture with formation fluid and/or an injected flushing or back-flushing fluid. A network of interconnected open channels 26 can thus be formed around the pillars 28 to provide the fracture 20 with high conductivity for fluid flow. Fluids can now be produced from the formation 14, into the fracture 20, through the open channels 26 and perforations 12, and into the wellbore 10.

[00047] The extrametrical material can, in some cases, be removed mechanically, for example by using fluid to push extrametrical material out of the formation. In such instances, the extrametrical material can remain in a solid state from the time of injection through removal from the fracture. Some suitable materials that can resist degradation and crushing include glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, naturally occurring and synthetic minerals, and high-density plastics that are oil-resistant and exhibit a crystallinity of greater than about 10%. Some other suitable high density plastic materials include nylons, acrylics, styrenes, polyesters, polyethylenes, oil-resistant thermoset resins, and combinations thereof.

[00048] Alternatively, the extrametrical material can be softened, dissolved, reacted or otherwise made to degrade. Materials suitable for dissolvable extrametrical material include for example, and without limitation, polyvinyl alcohol (PVOH) extrametrical materials, salt, wax, calcium carbonate, and the like and combinations thereof. An oil-degradable extrametrical material can be selected, so that it will be degraded by produced fluids. Alternatively, an extrametrical material can be selected which is degraded by agents purposefully placed in the formation by injection, wherein mixing the extrametrical material with the agent induces a delayed reaction degradation of the extrametrical material.

[00049] In some embodiments of fracturing operations, a solid acid-precursor can be used as the degradable extrametrical material. Suitable acid-generating dissolvable extrametrical materials can include for example, and without limitation, PLA, PGA, carboxylic acid, lactide, glycolide, copolymers of PLA or PGA, and the like and combinations thereof. Provided that the formation rock is carbonate, dolomite, sandstone,

or otherwise acid reactive, then the hydrolyzed product of the extrametrical material, a reactive liquid acid, can etch the formation at surfaces exposed between the proppant pillars. This etching can enlarge the open channels and thus further enhance the conductivity between the pillars. Other uses of the generated acid fluid can include aiding in the breaking of residual gel, facilitating consolidation of proppant clusters, curing or softening resin coatings and increasing proppant permeability.

[00050] In other embodiments of the disclosure, the extrametrical material may be formed of, or contain, a fluoride source capable of generating hydrofluoric acid upon release of fluorine and adequate protonation. Some nonlimiting examples of fluoride sources which are effective for generating hydrofluoric acid include but are not limited to fluoboric acid, ammonium fluoride, sodium fluoride, and the like, or any mixtures thereof.

[00051] FIGS. 3 - 4 illustrate the acid etching process for greater fracture conductivity. In reference to FIG. 3, proppant islands 30 are heterogeneously placed in fracture 32 with a degradable solid acid-precursor in the extrametrical material-rich regions 34. In reference to FIG. 4, delayed hydrolysis of the acid-precursor extrametrical material at formation conditions forms an acid that cuts into the face of the carbonate formation, resulting in localized etching 36 to enlarge the channels 38. The proppant pillars 30 remain intact to prop open the fracture.

[00052] The approach of heterogeneous proppant placement (HPP) is embodied in some aspects of embodiments of this disclosure. Heterogeneous proppant packs, hereinafter referred as proppant pillars, may prevent fracture closure and provide highly conductive channels around pillars serving as flow path for hydrocarbons. The HPP can result in a number of benefits when compared to conventional stimulation treatments, such as but not limited to increased fracture conductivity, improved fracture clean up, longer effective fracture length, reduced consumption of proppant and others.

[00053] The method of HPP according to some embodiments relies on pulsation of proppant concentration during fracturing treatment, which results in HPP. Parameters of the treatment schedule may include for example, duration of proppant slurry and clean fluid pulses, proppant concentration, and carrier fluid design. Optimization of the above and other design parameters, at least in part based on the geomechanical properties of a

treated reservoir, can significantly enhance fracture conductivity and effective length, eventually leading to hydrocarbon production increases.

[00054] In some embodiments, the treatment schedule utilizes a proppant pulsing schedule as shown in FIG. 5. The first stage is a proppant free stage, called PAD, which aims to initiate a fracture and helps to define its geometry. After that a number of proppant stages may be pumped with increasing proppant concentration. All or some proppant stages may be pumped in cycles, with every cycle comprising a clean fluid pulse and a proppant slurry pulse of the same or different duration. The proppant concentration in the proppant slurry pulses is kept similar or the same for every stage. In the last proppant stage, or otherwise known as a 'Tail-In', the schedule is pumped without pulses and serves as a coupling between the channeled fracture and a wellbore.

[00055] In some methods, pulse duration and proppant concentration may be varied and optimized. Pumping rate may be used a tool, as having the same pulse duration can provide different pulse volumes and correspondingly different spacing between pillars. In some cases, optimization of various pulse/slug volumes and/or durations and/or change pumping rates during pulses can be conducted.

[00056] Conductivity of a channeled fracture may depend upon the pillar width, the distance between the pillars, the stress exerted by pillars, geomechanical properties of formation and other factors. The pillar width may depend upon the concentration of proppant in proppant pulses and the hydraulic fracture width. Distance between pillars may be related to clean fluid pulse duration. The stress on pillars can be related to minimum in-situ stress in formation and percent fracture wall area covered by pillars.

[00057] Some embodiments refer to methods of optimization of the treatment pumping schedule, in particular on duration of stages, proppant concentration in pulses and clean fluid/proppant slurry pulse duration, which can provide optimally achievable fracture conductivity. The inverse approach allows to further define the schedule parameters so to provide predetermined fracture geometry and conductivity with less proppant and/or fracturing fluid.

[00058] For example, during the treatment a portion of the fracturing fluid may leak off into the formation. This may result in a fluid efficiency decrease and may also reduce the distance between proppant pillars in the fracture with an increase of the proppant

concentration. In addition, the friction properties of the fracturing fluid (effective viscosity) may have an impact on the hydraulic fracture width. Based on simulations of the leak off and friction properties of the fluid, the proppant concentration in the slurry pulses, as well as the durations of the proppant slurry and the clean fluid pulses can be calculated and the fracture conductivity can be further optimized. The schedule parameters can be further changed during the treatment, to optimally distribute the pillars along the fracture length. One possible implementation is shown as follows:

A fracture filled with a system of pillars so that there are open channels remaining between pillars (see Fig 6). The distance between pillar edges L is smaller than L_0 – the distance at which the channels begin to close. The ratio of the pillar area to the area of the pointed square (FIG. 6) S_{pillar} /S_{cell} determines ratio of area of propped fracture face to total fracture area. This ratio is related to $T_{prop}/(T_{prop} + T_{clean})$ where T_{prop} – time of dirty pulse and T_{clean} – time of clean pulse. The conductivity K of the channels between pillars depends on S_{pillar} /S_{cell} and L/L_0. For certain parameters the conductivity reaches theoretical maximum K_{max}. FIG. 7 illustrates how channel conductivity may depend upon propped fracture area for different ratio L/L_0.

[00059] In another example, as the fracturing fluid flows in a wellbore and in a fracture, the proppant slurry slugs may be affected by dispersion due to mixing with clean fluid at the interfaces between the two, which can result in increasing proppant slug volume and reduced proppant concentration in the slug. The degree of slug dispersion at entrance into formation (perforation clusters), depending on proppant concentration in the slugs and the slug volume on surface can be optimized to provide the required pulse parameters. The degree of slug dispersion can be determined from surface and downhole measurements of pressure, fluid density and/or other parameters, known to those skilled in the art.

[00060] In still another example, early proppant stages in hydraulic fracturing treatments are designed with low proppant concentrations to avoid screen-out. These stages are intended to place the proppant close to the tip of the fracture, where hydraulic width is small. In the case of HPP achieved by pulsations, channels in the tip area may have higher likelihood of closure, significantly affecting the fracture conductivity and the effective

fracture length. To reduce the risk of losing conductivity in the tip, the pulses of proppant slurry with different proppant concentrations may be pumped. The closed channels in this case may then remain propped, providing the conductivity of a homogeneous proppant pack. It is also possible to pump proppant continuously without pulses in the beginning of the treatment in order to prop the tip area and then switch to the optimized pulsed pumping schedule.

[00061] In a further example, highly deviated or essentially horizontal wells with multistage completions may facilitate initiations of multiple fractures during a single treatment. The fracturing fluid and proppant slurry may be distributed between open fractures in some ratios. The number of opened fractures (perforation clusters, accepting fluid) can be determined by methods, known from the art. This number can be an important parameter for the pulsing schedule design. Depending on the number of fractures, the clean fluid pulse duration can be tuned so as to provide an optimal average distance between pillars in all fractures. Since the number of fractures can change during the treatment (screen-out in some of fractures and/or new fracture opening) the pulsing schedule can be adjusted in the real time.

[00062] In a still further example, the practice of hydraulic fracturing involves pumping stages with gradually increasing proppant concentrations. This is done to reduce the risk of premature screen-out, as higher proppant concentration increases fracture conductivity but can also lead to proppant bridging in the fracture. On the other hand pumping of only a portion of proppant slurry pulses with higher concentration in particular stage can increase fracture conductivity without a considerable increase of the prossibility of screen out. A non-limiting example is during the 3 PPA stage pumping of every third slurry pulse with 4 PPA proppant concentration. In this case, proppant inside the fracture will have a higher concentratration, thus thicker pillars will be surrounded by thinner ones. This approach may allow a further increase of fracture conductivity and effective length with reduced risk of premature screen-out. Furthermore, some of pulses can be designed with lower concentrations, e.g. at the same 3 PPA stage, as in the previous example, every second pulse can be designed at 2 PPA. The frequency of lower proppant concentration slurry pulses and the value of proppant concentration can be designed to provide open

channels inside the fracture. In this case the fracture may have enough conductivity for high hydrocarbons production but with using less proppant.

[00063] Some other embodiments are methods of creating of a heterogeneous proppant pack in a hydraulic fracture for the case of horizontal well applications and therefore a creation of a network of the conductive open channels available for fluid flow. Hydraulic fractures covered by such a heterogeneous proppant pack may have an essentially higher conductivity than conventional (uniformly propped) fractures and therefore may increase the oil and gas production rate.

[00064] In such embodiments, the method for forming of a heterogeneous proppant pack (HPP) in the fracture is based on the alternate injection into the fracture of a fracturing fluid and a fracturing fluid loaded with proppant. With such a technique it may be important to optimally design the duration of the alternating stages, and furthermore, introduce the homogeneous pack nearer to the wellbore to prevent fracture pinching. HPP in horizontal applications hence comprises the following stages:

1) The first stage is an injection of a fracturing fluid and formation/propagation of a fracture. The fluid injected at this stage (pad stage) typically has no propping agent or low concentration of small size proppant as a loss prevention agent, or proppant slugs to clean up and erode the perforations, or proppant to engage parts of the fracture close to the tip.

2) The second stage comprises a repetitive addition of given volumes of the proppant to the fracturing fluid. The given volume of the proppant, mixed with the fracturing fluid (at given proppant concentration) is called a proppant pulse (or sub-stage). The volume or duration of a proppant pulse is an important parameter and it has essential influence on desired final properties of the fracture. In order to achieve an essential conductivity increase, in some cases the timing of a single slug pumping (on surface) can be less than 60 sec at the usual pumping rates, and corresponding volume may be less than 80 bbl. Durations between injected proppant pulses may may be controlling parameters, and, in some examples, are less than 60 sec or in terms of volume, do not exceed 80 bbl. The number of the proppant pulses injected in the second stage may be high enough, and may also depend on the size of the

fracturing treatment and designed geometry of the fracture. At the same time, to achieve the desired fracture conductivity, the number of the proppant pulses injected in the second stage may typically exceed 1, 2, 3, or even 4 pulses.

3) The third stage (tail-in stage) is the injection of a given volume of the fracturing fluid with proppant into the fracture. The proppant injected in this stage forms the stable proppant pack close to the wellbore to prevent formation walls to close in the near-wellbore zone. The duration of this stage is a controlling parameter, which depends upon the mechanical formation properties and parameters of the treatment. A very short "tail-in" stage may result in a pinching between the wellbore and the nearest proppant pulse, pumped in stage 2 (see FIG. 9, notation #6). At the same time, the HPP located close to the wellbore may compromise the production, as the conductivity of this area can be significantly lower than the conductivity of the channeled part. Hence, the duration of this stage is limited from the upper end by the production requirement. Summarizing, the pumping time of the third stage should typically exceed 6 sec (or in terms of volume it should exceed 3 bbl). At the same time it may be beneficial not to exceed the total pumping time or the injected volume of stage two (a standard duration pulse).

[00065] Methods described hereinabove may be also applicable to simultaneous stimulation of multiple fractures that may occur in the cases of open-hole completion and cased-hole with multiple perforation clusters. The volumes of the stages specified above are specified per one fracture. Hence, the on-surface pumping schedule may optimally be modified, and stage volumes be multiplied by expected number of fractures generated by the given treatment.

[00066] During hydraulic fracturing, high pressure pumps on the surface inject the fracturing fluid into a wellbore adjacent to the face or pay zone of a geologic formation. The first stage, also referred to as the "pad stage" (referred to above) involves injecting a fracturing fluid into a borehole at a sufficiently high flow rate and pressure sufficient to literally break or fracture a portion of surrounding strata at the sand face. The pad stage is pumped until the fracture has sufficient dimensions to accommodate the subsequent slurry pumped in the proppant stage. The volume of the pad can be designed by those

knowledgeable in the art of fracture design, for example, as described in Reservoir Stimulation, 3rd Ed., M. J. Economides, K. G. Nolte, Editors, John Wiley and Sons, New York, 2000.

[00067] Water-based fracturing fluids are common, with natural or synthetic water-soluble polymers optionally added to increase fluid viscosity, and can be used throughout the pad and subsequent proppant and/or extrametrical material stages. These polymers include, but are not limited to, guar gums; high-molecular-weight polysaccharides composed of mannose and galactose sugars; or guar derivatives, such as hydroxypropyl guar, carboxymethyl guar, carboxymethylhydroxypropyl guar, and the like. Cross-linking agents based on boron, titanium, zirconium or aluminum complexes are typically used to increase the effective molecular weight of the polymer for use in high-temperature wells.

[00068] To a small extent, cellulose derivatives, such as hydroxyethylcellulose or hydroxypropylcellulose and carboxymethylhydroxyethylcellulose, may be used with or without cross-linkers. Two biopolymers – xanthan and scleroglucan – provide excellent proppant suspension, but are more expensive than guar derivatives and so are used less frequently. Polyacrylamide and polyacrylate polymers and copolymers are typically used for high-temperature applications or as friction reducers at low concentrations for all temperatures ranges.

[00069] Water-based fracturing fluids can also be obtained using viscoelastic surfactants. Usually, these fluids are prepared by mixing in appropriate amounts of suitable surfactants, such as anionic, cationic, nonionic, amphoteric, and zwiterionic. The viscosity of viscoelastic surfactant fluids are attributed to the three-dimensional structure formed by the fluid's components. When the surfactant concentration in a viscoelastic fluid significantly exceeds a critical concentration, and in most cases in the presence of an electrolyte, surfactant molecules aggregate into species, such as worm-like or rod-like micelles, which can interact to form a network exhibiting viscous and elastic behavior. Also, polymer-free clay-based fluids, for example those based on Laponite® (synthetic clay viscosifier) may be useful as well.

[00070] After the fracture is induced, proppant and extrametrical material can be injected into the fracture as a slurry or suspension of particles in the fracturing fluid during what is referred to herein as a "proppant stage." In the proppant stage, proppant and

extrametrical material can be injected in one or more segregated substages alternating between a "proppant substage" and a "extrametrical material substage," and/or as a mixture of extrametrical material and proppant in one or more substages referred to herein as a "mixed substage." Further, the proppant, extrametrical material and/or mixed substages can be separated by one or more optional "carrier substages", which are substantially free of proppant and extrametrical material and can also be substantially free of other particles.

[00071] Some embodiments of this disclosure may benefit processes that are related to hydraulic fracturing. Examples of these embodiments include enhanced oil recovery, treatments for waste disposal wells for injecting a storing carbon dioxide, waste water or other liquid waste, and treatments for wells for environmental remediation i.e. to inject water to modify the direction or speed of groundwater flow or injection of a chemical to clean a polluted aquifer. Some embodiments may benefit from using seawater or production water with solids.

[00072] As a result, the proppant does not completely fill the fracture. Rather, spaced proppant clusters are formed as pillars, with proppant-spacing extrametrical material initially filling the channels between them. Upon subsequent removal of the extrametrical material, formation fluids are able to pass through the channels. The volumes of proppant, extrametrical material and carrier sub-stages as pumped can be different. That is, the volume of the extrametrical material and any carrier substages can be larger or smaller than the volume of the proppant and/or any mixed substages. Furthermore, the volumes and order of injection of these substages can change over the duration of the proppant stage. That is, proppant substages pumped early in the treatment can be of a smaller volume than a proppant substage pumped later in the treatment. The relative volume of the substages can be selected by an engineer or operator based upon how much of the surface area of the fracture is desired to be supported by the clusters of proppant, and how much of the fracture area is desired as open channels through which formation fluids are free to flow.

[00073] Suitable proppants can include sand, gravel, glass beads, ceramics, bauxites, mica, glass, and the like or combinations thereof. Also other proppants like, plastic beads such as styrene divinylbenzene, and particulate metals may be used. Proppant used in this

embodiments of this disclosure may not necessarily require the same permeability properties as typically required in conventional treatments because the overall fracture permeability will at least partially develop from the formation of channels. Other proppants may be materials such as drill cuttings that are circulated out of the well. Also, naturally occurring particulate materials may be used as proppants, including, but not necessarily limited to: ground or crushed shells of nuts such as walnut, coconut, pecan, almond, ivory nut, brazil nut, etc.; ground or crushed seed shells (including fruit pits) of seeds of fruits such as plum, olive, peach, cherry, apricot, etc.; ground or crushed seed shells of other plants such as maize (e.g., corn cobs or corn kernels), etc.; processed wood materials such as those derived from woods such as oak, hickory, walnut, poplar, mahogany, etc., including such woods that have been processed by grinding, chipping, or other form of particalization, processing, etc, some nonlimiting examples of which are proppants made of walnut hulls impregnated and encapsulated with resins. Further information on some of the above-noted compositions thereof may be found in Encyclopedia of Chemical Technology, Edited by Raymond E. Kirk and Donald F. Othmer, Third Edition, John Wiley & Sons, Volume 16, pages 248-273 (entitled "Nuts"), Copyright 1981. Resin coated (various resin and plastic coatings) or encapsulated proppants having a base of any of the previously listed propping materials such as sand, ceramics, bauxite, nut shells, etc. may be used in accordance with embodiments of this disclosure. Essentially, a proppant can be any material that will function to hold open the propped portion of the fracture.

[00074] The selection of proppant can balance the factors, for example, of proppant long-term strength, proppant distribution characteristics and proppant cost. The proppant can have the ability to flow deeply into the hydraulic fracture and form spaced pillars that resist crushing upon being subjected to the fracture closure stress. Relatively inexpensive, low-strength materials, such as sand, among others, can be used for hydraulic fracturing of formations with small internal stresses. Materials of greater cost, such as ceramics, bauxites and others, can be used in formations with higher internal stresses. Further, the chemical interaction between produced fluids and proppants, which can significantly change the characteristics of the proppant, can be considered as selection criteria.

[00075] Because an embodiment does not need to rely on the porosity or permeability of the packed proppant matrix to impart flow conductivity to the fracture, the availability for selection of a wide range of proppant materials can benefit a range of applications and cost restrictions. For example, a proppant can have a variety of sizes or range of mixed, variable diameters or other properties that yield a high-density, high-strength pillar, which can form a proppant matrix that has high or low porosity and high or low permeability. Proppant porosity and permeability are not as critical in an embodiment of this disclosure because fluid production is not required to flow through the proppant matrix. Another option for section is an adhesive or reinforcing material that would plug a conventional proppant pack. The adhesive or reinforcing material can be employed in the interstitial spaces of the proppant matrix herein, such as, for example, a settable or crosslinkable polymer which can be set or crosslinked in the proppant.

[00076] Accordingly for example, a proppant pillar of suitable strength can be successfully created using sand with particles considered too weak for use in conventional hydraulic fracturing. The relative costs of sand are substantially less than ceramic proppant. Additionally, destruction of sand particles during application of the fracture closure load can improve the strength behavior of the same cluster consisting of proppant granules. This can occur because the cracking/destruction of proppant particles decreases the cluster porosity thereby compacting the proppant. Sand pumped into the fracture to create proppant clusters does not need good granulometric properties, that is, the narrow particle size or diameter distribution required for a permeable proppant pack in conventional fracturing. For example, in one embodiment, it is possible to use 50 tons of sand, wherein 10 to 15 tons have a diameter of particles from 0.002 to 0.1 mm, 15 to 30 tons have a diameter of particles from 0.2 to 0.6 mm, and 10 to 15 tons have a diameter of particles from 0.005 to 0.05 mm. It should be noted that conventional hydraulic fracturing would require about 100 tons of a proppant more expensive than sand to obtain a similar value of hydraulic conductivity for fluid passage through the continuous-porosity proppant matrix in the propped fracture.

[00077] For the purposes of this disclosure, one embodiment of the proppant can use sand with an adhesive coating alone, or an adhesive coating coated with a layer of non-adhesive substance dissolvable while in the fracture as a fracture treatment fluid or another

fluid is passed through the fracture. A non-adhesive substance inhibits the formation of proppant agglomerates prior to entering the fracture, and allows for controlling the moment of time in the fracture when a proppant particle gains its adhesive properties. The moment of time corresponds to the location of the proppant within the fracture. The adhesive coating can be cured at the formation temperature, and sand particles conglutinate between each other. Bonding particles within the pillars can inhibit erosion of the proppant pillar as formation fluids flow past, thereby minimizing subsequent proppant island destruction by erosion.

[00078] In one embodiment, reinforcing and/or consolidating material can be introduced into the fracture fluid to increase the strength of the formed proppant clusters and preventing their collapse during fracture closure. Typically the reinforcement material can be added to the proppant substage and/or the mixed substage, but could also be introduced additionally or alternatively in the extrametrical material substage and/or the carrier substage, or in other ways. For example, the reinforcement material can be an extrametrical material that serves to reinforce the proppant clusters, but can be removed as or with the extrametrical material from the proppant-lean regions. The concentrations of both proppant and the reinforcing materials can vary in time throughout the proppant stage, and from substage to substage. That is, the concentration of proppant reinforcing material can be different at two subsequent substages. It can also be suitable in some applications of an embodiment of a method to introduce the reinforcing material in a continuous or semi-continuous fashion throughout the proppant stage, during a plurality of adjacent carrier, extrametrical material, mixed and proppant substages. For example, the reinforcing material deposited in the extrametrical material regions in the fracture can be removed with the extrametrical material as described below. In any case, introduction of the reinforcing material need not be limited only to the proppant substage. Particularly, different implementations can be considered where the concentration of the reinforcing material does not vary during the entire proppant stage; monotonically increases during the proppant stage; or monotonically decreases during the proppant stage.

[00079] Curable or partially curable, resin-coated proppant can be used as reinforcing and consolidating material to form proppant clusters. The selection process of an appropriate resin-coated proppant for a particular bottom hole static temperature

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

[00080] On the other hand, a high permeability and/or high porosity proppant pack can be suitably employed in some situations. In one embodiment, the permeability of the proppant can provide some limited fracture conductivity in the event the channels are not properly formed or do not fully interconnect. Additionally, under some formation conditions it can be advantageous when using some embodiments of the present method to perform a final tail-in stage of the fracturing treatment involving continuous proppant introduction into the fracturing fluid, with the proppant at this stage consisting essentially of uniform particle size to obtain a zone of continuous-porosity proppant adjacent to the wellbore. If employed, the tail-in stage of the fracturing treatment resembles a conventional fracturing treatment, where a continuous bed of well-sorted conventional proppant is placed in the fracture proximate to the wellbore. The tail-in stage can involve introduction of both an agent that increases the proppant transport capability of the treatment fluid and/or an agent that acts as a reinforcing material. The tail-in stage is

distinguished from the second stage by the continuous placement of a well-sorted proppant, that is, a proppant with an essentially uniform particle size, or even a rod-shaped proppant. The proppant strength should be sufficient to prevent its cracking (crumbling) when subjected to stresses that occur at fracture closure. The role of the proppant at this tail stage is to prevent fracture closure and, therefore, to provide good fracture conductivity relatively close to the wellbore.

[00081] The proppants useful in some embodiments of the present method should also be capable of being segregated into proppant-rich islands for heterogeneous placement in the fracture spaced away from adjacent proppant islands. Properties such as density, size, shape, magnetic characteristics, and surface characteristics, for example, hydroaffinity and reactivity, and chemical or mechanical interaction with the extrametrical material, and the like, can all influence the segregability of the proppant. Therefore, these characteristics may be considered as selection criteria to facilitate segregation from the extrametrical material-rich regions depending on a variety of conditions, such as the manner in which segregation is effected, downhole conditions, the extrametrical material, the treatment fluid, etc.

[00082] In an embodiment, the proppant can have a self-adherent surface, for example, by using a proppant that has a natural attraction for or a tendency to agglomerate with or adhere to other proppant particles, and/or by coating or chemically modifying the surface of the proppant for self-adhesion, e.g. by coating the proppant with an adhesive or tackifier, or grafting an adhesive or tackifying compound to the proppant. In some cases, the self-adherent proppant is non-adherent to the extrametrical material and other surfaces such as the surface piping, pumps and wellbore tubing, among others. In one version of the self-adherent proppant, the proppant is loosely held together in cohesive slugs or globules of a gel or a lightly crosslinked, flowable polymer for which the proppant has a differential affinity, e.g. the proppant can be grafted to the gel-forming polymer.

[00083] In other embodiments, the proppant can be hydrophilic, for example, by using a proppant that is normally hydrophilic, such as most sand, for example, and/or by treating the proppant particles with ionic or polar modifiers such as a strong acid, weak acid, strong base, weak base, or reacting the surface of the proppant to associate an ionic or polar moiety with an affinity to aqueous liquids. In this manner, the proppant can be

differentially attracted to other hydrophilic species in the treatment fluid, e.g. other proppant particles or an immiscible fluid phase in the treatment fluid, such as an aqueous phase, especially where the extrametrical material is hydrophobic and/or introduced via an immiscible hydrophobic fluid phase in the treatment fluid.

[00084] In still other embodiments, the proppant can be rendered hydrophobic, for example, by using proppant that is normally hydrophobic, such as wax, for example, and/or by treating the proppant particles with oil, wax or other hydrocarbon, or reacting the surface of the proppant to associate a hydrocarbyl moiety with a low affinity to aqueous liquids. In this manner, the proppant can be differentially attracted to other hydrophobic species in the treatment fluid, e.g. other proppant particles or an immiscible fluid phase in the treatment fluid, such as oil or other non-aqueous phase, especially where the extrametrical material is hydrophilic and/or introduced via an immiscible hydrophilic fluid phase in the treatment fluid.

[00085] In further embodiments the proppant can be present in a treatment fluid that is injected into the fracture in the form of an immiscible fluid packet or globule dispersed in a more or less continuous phase of a second fluid carrying the extrametrical material. The immiscible fluid proppant packets can each contain a sufficient quantity of proppant to form a suitably sized island, singly from isolated packet placement or in combination with one or more additional proppant packets where cumulative packet placement can occur. Because the open channels to be formed must interconnect between the wellbore and the remote exposed surfaces in the fracture, it can be convenient to provide the extrametrical material in a continuous phase in the treatment fluid in which the proppant packets are in a dispersed or discontinuous phase. In one version, the proppant packets can be provided with a thin encapsulating skin or deformable bladder to retain or group the proppant and configured to remain flowable during injection, and the bladder can be optionally ruptured or chemically or thermally removed during placement in the fracture and/or during closure of the fracture.

[00086] The choice of extrametrical material can depend on the mode of extrametrical material segregation and placement in the fracture, as well as the mode of extrametrical material removal and channel formation. In its simplest form, the extrametrical material can be a solid particulate that can be maintained in its solid form

during injection and fracture closure, and readily dissolved or degraded for removal. Materials that can be used can be organic, inorganic, glass, ceramic, nylon, carbon, metallic, and so on. Suitable materials can include water- or hydrocarbon-soluble solids such as, for example, salt, calcium carbonate, wax, or the like. Polymers can be used in another embodiment, including polymers such as polylactic acid (PLA), polyglycolic acid (PGA), polyol, polyethylene terephthalate (PET), polysaccharide, wax, salt, calcium carbonate, benzoic acid, naphthalene based materials, magnesium oxide, sodium bicarbonate, soluble resins, sodium chloride, calcium chloride, ammonium sulfate, and the like, and so on, or any combinations thereof. As used herein, "polymers" includes both homopolymers and copolymers of the indicated monomer with one or more comonomers, including graft, block and random copolymers. The polymers can be linear, branched, star, crosslinked, derivitized, and so on, as desired. The extrametrical material can be selected to have a size and shape similar or dissimilar to the size and shape of the proppant particles as needed to facilitate segregation from the proppant. Extrametrical material particle shapes can include, for example, fibers, spheres, rods, platelets, ribbons, and the like and combinations thereof. In some applications, bundles of fibers, or fibrous or deformable materials, can be used. These fibers can additionally or alternatively form a three-dimensional network, reinforcing the proppant and limiting its flowback.

[00087] For example, the separation of injected proppant and extrametrical material as introduced and placed in the fracture can be induced by differences (or similarities) in size, density or shape of the two materials. The specific gravities and the volume concentrations of proppant and extrametrical material can be tailored to minimize mixing and homogenization during placement. Properly sizing the extrametrical material or adding various weighting agents to the extrametrical material-rich fluid can facilitate segregation at the appropriate time and location.

[00088] Either the proppant or the proppant-spacing particles can also be made to be "sticky", so particles of similar material adhere to one another, helping ensure heterogeneity between the two dissimilar materials. Proppant particles can be selected that adhere to other proppant particles as discussed above and are repelled by or repel the extrametrical material particles. Alternatively, or additionally, extrametrical material particles can be selected that are self-adherent and non-adherent to the proppant. The

extrametrical material can, for example, include a self-adherent coating. Another technique to encourage separation of the two materials is selecting proppant and extrametrical material with inherent hydroaffinity differences, or creating surface hydroaffinity differences by treating either the proppant or the extrametrical material with hydrophobic or hydrophilic coatings.

[00089] The presence of the extrametrical material in the fracturing fluid in the proppant stage, e.g. in a mixed substage or in a segregated extrametrical material substage, can have the benefit of increasing the proppant transport capability. In other words, the extrametrical material can reduce the settling rate of proppant in the fracture treatment fluid. The extrametrical material in an embodiment may be a material with elongated particles having a length that much exceeds a diameter. This material can affect the rheological properties and suppress convection in the fluid, which can result in a decrease of the proppant settling rate in the fracture fluid and maintain segregation of the proppant from proppant lean regions. The extrametrical material can be capable of decomposing in the water-based fracturing fluid or in the downhole fluid, such as fibers made on the basis of polylactic acid (PLA), polyglycolic acid (PGA), polyvinyl alcohol (PVOH), and others.

[00090] The fibers can be made of or coated by a material that becomes adhesive at subterranean formation temperatures. They can be made of adhesive material coated by a non-adhesive substance that dissolves in the fracturing fluid or another fluid as it is passed through the fracture. The fibers used in one embodiment can be up to 2 mm long with a diameter of 10 – 200 microns, in accordance with a guideline that the ratio between any two of the three dimensions be greater than 5 to 1. In another embodiment, the fibers can have a length greater than 1 mm, such as, for example, 1 – 30 mm, **2 – 25 mm or 3 – 18 mm, or in some cases about 6 mm; and they can have a diameter of 5 – 100 microns and/or a denier of about 0.1-20, or in some cases about 0.15-6. These fibers are desired to facilitate proppant carrying capability of the treatment fluid with reduced levels of fluid viscosifying polymers or surfactants.** Fiber cross-sections need not be circular and fibers need not be straight. If fibrillated fibers are used, the diameters of the individual fibrils can be much smaller than the aforementioned fiber diameters.

[00091] The concentration of the extrametrical material in the treatment fluid can conveniently be such that the extrametrical material compressed between the proppant

islands by fracture closure has a packed volume to fill the spaces between the packed proppant islands at a stress similar to the proppant. In other words, the extrametrical material fill serves to hold the proppant islands in place and inhibit lateral expansion that would otherwise reduce the ultimate height of the proppant pillar. The weight concentration of the fibrous extrametrical material in the fracturing fluid can be from 0.1 to 10 percent in some applications. The concentration of the solid extrametrical material in the treatment fluid may be from about 0.6 g/L (about 5 ppt) to about 9.6 g/L (about 80 ppt).

[00092] In an embodiment, a first type of fiber additive can provide reinforcement and consolidation of the proppant. This fiber type can include, for example, glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, and the like and combinations thereof, as a material that is packed in the proppant to strengthen the proppant pillars. In other applications, a second type of fiber can be used that inhibits settling of the proppant in the treatment fluid. The second fiber type can include, for example, polylactic acid, polyglycolic acid, polyethylene terephthalate (PET), polyol, nylon, and the like and combinations thereof, as a material that inhibits settling or dispersion of the proppant in the treatment fluid and serves as a primary removable fill material in the spaces between the pillars. Yet still other applications may include a mixture of the first and second fiber types, the first fiber type providing reinforcement and consolidation of the proppant and the second fiber type inhibiting settling of the proppant in the treatment fluid.

[00093] The fibers can be hydrophilic or hydrophobic in nature. Hydrophilic fibers may be considered for a number of applications. Fibers can be any fibrous material, such as, but not necessarily limited to, natural organic fibers, comminuted plant materials, synthetic polymer fibers (by non-limiting example polyester, polyaramide, polyamide, novoloid or a novoloid-type polymer), fibrillated synthetic organic fibers, ceramic fibers, inorganic fibers, metal fibers, metal filaments, carbon fibers, glass fibers, ceramic fibers, natural polymer fibers, and any mixtures thereof. Particularly useful fibers are polyester fibers coated to be highly hydrophilic, such as, but not limited to, DACRON® polyethylene terephthalate (PET) Fibers available from Invista Corp. Wichita, Kans., USA, 67220. Other examples of useful fibers include, but are not limited to, polylactic acid polyester fibers, polyglycolic acid polyester fibers, polyvinyl alcohol fibers, and the like.

[00094] In some embodiments, the solid extrametrical material is selected from substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, and mixtures of such materials. Some examples are polyglycolic acid or PGA, and polylactic acid or PLA. These materials may function as solid-acid precursors, and upon dissolution in the fracture, can form acid species that can perform secondary functions in the fracture.

[00095] If desired, a pH control agent can be used in the treatment fluid, especially where a solid acid precursor is present and one or more of the other treatment fluids is pH-sensitive. The pH control agent can be selected from amines and alkaline earth, ammonium and alkali metal salts of sesquicarbonates, carbonates, oxalates, hydroxides, oxides, bicarbonates, and organic carboxylates, for example sodium sesquicarbonate, triethanolamine, or tetraethylenepentamine.

[00096] For example, the extrametrical material can function as an acid breaker for a viscosifying agent, where the extrametrical material is selected from a solid that contains an acid and that hydrolyzes to release an acid, a solid that hydrolyzes to release an acid, or mixtures of such materials. The solid can be present in particles sufficiently small that they at least partially enter the pores of the formation, and/or sufficiently large that they remain in the fracture in the spaces between the proppant pillars. The treatment fluid can also contain a pH control agent present in an amount sufficient to neutralize any acid present in the solid material before the injection and to neutralize any acid generated by the solid material during the injection, so that the acid breaker is not available to break the fluid during the injection. When the injection is stopped, the solid may be allowed to release acid in excess of the amount that can be neutralized by any pH control agent, thereby breaking the viscous fluid.

[00097] Optionally, the viscosifying agent in some embodiments may be a viscoelastic surfactant system. Also optionally, the solid material may be of a size that forms an internal filter cake in the pores of the formation. Still further optionally, the solid material may be of a size that does not block the flow of fluid in the pores of the formation.

The solid material is selected from substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, and mixtures of such materials. An example used in some embodiments is polyglycolic acid. The pH control agent is selected from amines and alkaline earth, ammonium and alkali metal salts of sesquicarbonates, carbonates, oxalates, hydroxides, oxides, bicarbonates, and organic carboxylates, for example sodium sesquicarbonate, triethanolamine, or tetraethylenepentamine.

[00098] Suitable solid acids for use in viscoelastic surfactant (VES) fluid systems include substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, a copolymer of polylactic acid and polyglycolic acid, a copolymer of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, a copolymer of lactic acid with other hydroxy-, carboxylic acid or hydroxycarboxylic acid-containing moieties, or mixtures of the preceding. Other materials suitable for use in VES fluid systems are all those polymers of hydroxyacetic acid (glycolic acid) with itself or other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties described in U.S. Patent Nos. 4,848,467; 4,957,165; and 4,986,355.

[00099] In some applications, suitable solid acid components for VES systems are solid cyclic dimers, or solid polymers, of certain organic acids, that hydrolyze under known and controllable conditions of temperature, time and pH to form organic acids. One example, a suitable solid acid is the solid cyclic dimer of lactic acid known as "lactide", which has a melting point of 95 to 125 °C depending upon the optical activity. Another is a polymer of lactic acid, sometimes called a polylactic acid or "PLA", or a polylactate, or a polylactide. Another example is the solid cyclic dimer of glycolic acid known as "glycolide", which has a melting point of about 86 °C. Yet another example is a polymer of glycolic acid (hydroxyacetic acid), also known as polyglycolic acid ("PGA"), or polyglycolide. Another example is a copolymer of lactic acid and glycolic acid. These polymers and copolymers are polyesters. The as-received materials can contain some free acid and some solvent, typically water.

[000100] Natureworks L.L.C., Minnetonka, MN, USA, produces a solid cyclic lactic acid dimer called "lactide" and from it produces lactic acid polymers, or polylactates, with varying molecular weights and degrees of crystallinity, under the generic trade name NATUREWORKS™ PLA. The PLA's currently available from Cargill Dow have molecular weights of up to about 100,000, although any polylactide (made by any process by any manufacturer) and any molecular weight material of any degree of crystallinity can be used in the embodiments of this disclosure. The PLA polymers are solids at room temperature and are hydrolyzed by water to form lactic acid. Those available from Cargill Dow typically have crystalline melt temperatures of from about 120 to about 170 °C, but others are obtainable.

[000101] Poly(d,l-lactide) is available from Bio-Invigor, Beijing and Taiwan, with molecular weights of up to 500,000. Bio-Invigor also supplies polyglycolic acid (also known as polyglycolide) and various copolymers of lactic acid and glycolic acid, often called "polyglactin" or poly(lactide-co-glycolide). The rates of the hydrolysis reactions of all of these materials are governed, among other factors, by the molecular weight, the crystallinity (the ratio of crystalline to amorphous material), the physical form (size and shape of the solid), and in the case of polylactide, the amounts of the two optical isomers. (The naturally occurring l-lactide forms partially crystalline polymers; synthetic dl-lactide forms amorphous polymers.) Amorphous regions are more susceptible to hydrolysis than crystalline regions. Lower molecular weight, less crystallinity and greater surface-to-mass ratio can result in faster hydrolysis. Hydrolysis can also be accelerated by increasing the temperature, by adding acid or base, or by adding a material that reacts with the hydrolysis product(s).

[000102] Homopolymers of PGA and PLA can be more crystalline; copolymers tend to be amorphous unless they are block copolymers. The extent of the crystallinity can be controlled by the manufacturing method for homopolymers and by the manufacturing method and the ratio and distribution of lactide and glycolide for the copolymers. Polyglycolide can be made in a porous form. Some of the polymers dissolve very slowly in water before they hydrolyze; it is to be understood that the terms hydrolyze or hydrolysis, etc., are intended to include dissolution.

[000103] The solid acids can be coated to slow the hydrolysis. Suitable coatings include polycaprolate (a copolymer of glycolide and epsilon-caprolactone), and calcium stearate, both of which are hydrophobic. Polycaprolate itself slowly hydrolyzes. Generating a hydrophobic layer on the surface of the solid acids by any means can facilitate segregation from hydrophilic proppant and can delay the hydrolysis for injection and fracture. Note that coating here can refer to encapsulation or simply to changing the surface by chemical reaction or by forming or adding a thin film of another material. Another suitable method of delaying the hydrolysis of the solid acid, and the release of acid, is to suspend the solid acid, optionally with a hydrophobic coating, in oil or in the oil phase of an emulsion. The hydrolysis and acid release do not occur until water contacts the solid acid.

[000104] The VES self-destructs *in situ*, that is, in the location where it is placed. That location can be part of a suspension in a treatment fluid in the wellbore, in perforations, in a gravel pack, or in a fracture; or as a component of a filter cake on the walls of a wellbore or of a fracture; or in the pores of a formation itself. The VES can be used in formations of any lithology but are used most commonly in carbonates or sandstones.

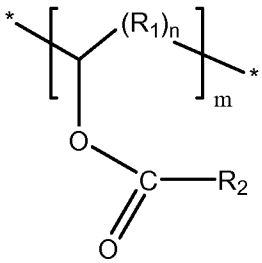
[000105] A particular advantage of these materials is that the solid acid precursors and the generated acids are non-toxic and are biodegradable. The solid acids are often used as self-dissolving sutures in medical practice, for example.

[000106] A polyol is a polyhydric alcohol, i.e., one containing three or more hydroxyl groups. One embodiment of a polyol useful as a extrametrical material is a polymeric polyol solubilizable upon heating, desalination or a combination thereof, and which consists essentially of hydroxyl-substituted carbon atoms, in a polymer chain, spaced from adjacent hydroxyl-substituted carbon atoms by at least one carbon atom in the polymer chain. In other words, the useful polyols are essentially free of adjacent hydroxyl substituents. In one embodiment, the polyol has a weight average molecular weight greater than 5000 up to 500,000 or more, and from 10,000 to 200,000 in some applictions. The polyol can be hydrophobically modified if desired to further inhibit or delay solubilization, e.g. by including hydrocarbyl substituents such as alkyl, aryl, alkaryl or aralkyl moieties and/or side chains having from 2 to 30 carbon atoms. The polyol can also

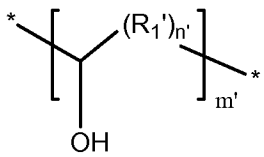
be modified to include carboxylic acid, thiol, paraffin, silane, sulfuric acid, acetoacetylate, polyethylene oxide, or quaternary amine or other cationic monomers. Such modifications have several affects on the properties of the polyol; affects on solubility, sensitivity to salinity, pH, and crosslinking functionalities (e.g. hydroxyl groups and silanol groups which are chelates that can crosslink with common crosslinkers) are of most interest to the present disclosure. All of said modifications are commercially available products.

[000107] In one embodiment, the polyol is a substituted or unsubstituted polyvinyl alcohol that can be prepared by at least partial hydrolysis of a precursor polyvinyl compound having ester substituents, such as, for example, polyvinyl acetate, polyvinyl propanoate, polyvinyl butanoate, polyvinyl pentanoate, polyvinyl hexanoate, polyvinyl 2-methyl butanoate, polyvinyl 3-ethylpentanoate, polyvinyl 3-ethylhexanoate, and the like, and combinations thereof. When the polyol comprises polyvinyl alcohol prepared by at least partial hydrolysis of polyvinyl acetate, the polyol is not generally soluble in salt water, as discussed in more detail below, and further, the polyol is commercially available in the form of partially crystalline fibers that have a relatively sharp trigger temperature below which the fibers are not soluble in water and above which they readily dissolve, also as discussed in more detail below.

[000108] Suitable repeating units in the polyols can have the following formulae:



1



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[000109] Polymers can contain units 1 and 2 in varying proportions, where R1 and R1' can be the same or different, but in some cases the same. In the structures, R_1 or R_1' is an alkyl chain that can be saturated or unsaturated, linear or branched, containing 1 to 5 carbon atoms, where n and n' = 1 to 5, and where n and n' can be equal or different, but in some cases equal. R_2 is an alkyl chain that can be saturated or unsaturated, aliphatic or aromatic, linear or branched, from 0 carbons (i.e. hydrogen) to 12 carbons. In the formulae

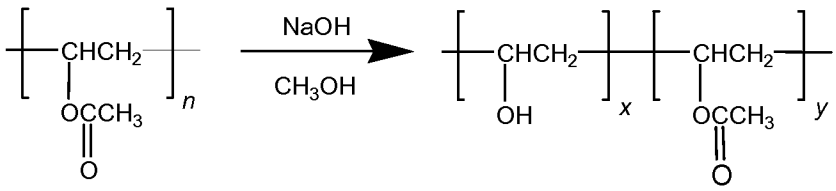
above, m = 0 to 5,000 and m' = 100 to 10,000. The units 1 and 2 can be alternating, random or block in configuration.

[000110] From the above general description, polymers can be defined by changing parameters. For example, polyvinyl alcohol 99.99% hydrolysis with MW of ~5000 would be: m = 0, R1' = CH_2, n' = 1, m' =100. Polyvinyl alcohol with 90% hydrolysis and MW of ~ 5000 and derived from polyvinyl acetate would be: m = ~10, n = n' = 1, R1 = R1' = CH_2, R2 = CH_3, m' = ~ 90.

[000111] For the purpose of illustration only, embodiments of this disclosure are described hereafter with reference to polyvinyl alcohol (PVOH) as one example of a suitable polyol extrametrical material. Those skilled in the art will appreciate that embodiments of the present disclosure are not limited to PVOH and is equally applicable to polyols that meet the above-stated criteria of having alterable solubility modes in the context of well treatment fluids and heterogeneous proppant placement methodology described herein.

[000112] A benefit of PVOH is that it is non-toxic and is biodegradable. For example, PVOH is commonly found in the medical industry and fiber forms are commonly used in clothing or fabrics that are intended to dissolve when washed in warm or hot water.

[000113] PVOH is a solid material that is manufactured in many forms, such as, for example, fibers, sheets, granules, beads, powder, and the like. PVOH is a synthetic polymer that is water soluble and generally unaffected by petroleum hydrocarbons. The polymer comprises a carbon chain backbone with hydroxyl and acetate groups. According to Kirk et al., *Encyclopedia of Chemical Technology, 3rd Edition, Vol. 23,* John Wiley and Sons, pp. 848 – 865 (1983), PVOH can be produced by the hydrolysis of polyvinyl acetate in methanol catalyzed by a base according to the following equation:



[000114] PVOH can generally exist in three different aggregation states, which may be controlled by solution conditions. In its solid state, PVOH is semi-crystalline. The degree of crystallinity varies from one mode of manufacture to another and with the degree

of hydrolysis and grade of the PVOH. In aqueous solution, PVOH can lose crystallinity and swell to form an amorphous structure, which is flexible and malleable, but not yet solubilized. Depending on solution conditions, PVOH can solubilize completely and exist as polymer stands in solution.

[000115] Embodiments of the present disclosure can use PVOH in an insoluble form to place the PVOH extrametrical material downhole in the fracture. By changing the salinity and/or temperature conditions adjacent the PVOH deposited in the fracture, the PVOH can be solubilized to remove the PVOH deposits and/or to activate the PVOH for use as a breaker or other downhole function. In addition to the channel-filling material, any PVOH filter cake can thus also be removed. The PVOH can also be employed as a fiber for fiber assisted transport of the proppant, for example. Solubilized PVOH can also function as a delayed breaker for crosslinked polymer or viscoelastic surfactant (VES fluid systems), for example.

[000116] Embodiments of disclosed methods can exploit the controllability of the solubility of PVOH and similar polyols in aqueous media by the fluid salt content. In a brine of sufficiently high salt concentration, PVOH is insoluble but will become a sticky, flexible material that readily bonds to itself and to solid surfaces, allowing it to function as a channel filler material. By dropping the brine concentration below a critical salt level, however, the self-adherent PVOH solids can become soluble and rapidly dissolve into solution.

[000117] Dissolution of PVOH is controlled by the degree of hydrolysis of the PVOH, molecular weight, crystallinity, particle size, and the like. The degree of hydrolysis is defined as the mole percent of hydroxyl groups on the polymer chain in relation to the non-hydrolyzed acetate groups. For example, PVOH with a degree of hydrolysis of 88 would have 88 mole percent hydroxyl groups and 12 mole percent acetate groups along the polymer backbone. The hydroxyl and/or acetate groups can be distributed randomly or in blocks.

[000118] Most PVOH grades dissolve at around 80°C (176°F). A degree of hydrolysis of about 88% is optimum for solubility in some cases, i.e. the solubility of the PVOH decreases when the degree of hydrolysis is more or less than about 88%. As the degree of hydrolysis increases above 88%, solubility decreases due to a tighter alignment

of the hydroxyl moieties which is thought to result from a form of hydrogen bonding. Below 88% hydrolysis, solubility decreases due to the increased number of acetate groups; polyvinyl acetate is generally insoluble in water. Other factors affecting PVOH solubility can include polymer concentration and salt concentration; the amount of unsolubilized PVOH, e.g. amorphous PVOH, can increase with increased concentrations of salt or polymer. The crystallinity of the PVOH can also be used to control the temperature at which the PVOH will dissolve. For example, PVOH's that are partially crystalline to varying extents can be soluble in water at temperatures ranging from 20°C to 90°C. As part of the dissolution process PVOH goes through a "glue like" or amorphous state. The solubility and the glue state of PVOH polymer can also be controlled through salt concentration. For example, a PVOH fiber that completely dissolves in 2 wt% KCl brine at 80°C (176°F), may not completely dissolve below 93°C (200°F) in 6% KCl brine, may only deform and clump at 93°C (200°F) in 10% KCl brine, and may not be affected at all at 93°C (200°F) in 12% KCl brine.

[000119] The conditions and rate of dissolution of PVOH, having a particular chemical and physical make-up, including crystallinity, degree of hydrolysis, molecular weight and distribution, a coating if present, at a particular temperature and in contact with a fluid or fluids of a particular salinity, is readily determined by a simple experiment: exposing the PVOH to the fluid or fluids under treatment conditions and monitoring the solubilization.

[000120] The PVOH can be manufactured and used in various solid shapes, including, but not limited to fibers, powders, granules, and the like. The system comprising a well treatment fluid and PVOH (and any other additives) can be batch-mixed or mixed on-the-fly using otherwise conventional treatment fluid mixing equipment and mixing techniques.

[000121] If the PVOH is in crystalline fiber form that is used primarily below its trigger temperature for placement and does not swell or become amorphous until just before downhole solubilization, then most commonly, straight fibers are used; however, curved, crimped, spiral-shaped and other three dimensional fiber geometries are useful. Also, the fibers can be bundled together, or hoed on one or both ends. In one embodiment, the fiber length is at least about 2 millimeters, and the fiber diameter ranges from about 3

to about 200 microns. There appears to be no upper limit on the length of the fibers employed from the standpoint of utility. Handling, mixing, and pumping equipment dictate the practical upper limit for the length of fibers. Suitable PVOH fibers in one embodiment have a length of about 2 – 25 mm, in other embodiments about 3 – 18 mm, and in still other embodiments about 6 mm; they have a denier of about 0.1-20, in some cases about 0.15-6 Such fibers are optimized for particle transport.

[000122] If the PVOH is amorphous or changes from crystalline to amorphous form in the well treatment fluid, the particular physical form is less critical since the PVOH will form a gluelike phase that will disperse as small particles in the treatment fluid. If the PVOH is also to be used as a fluid loss additive, the particle size of the PVOH particles is chosen based primarily on the desired fluid loss properties (*e.g.* spurt and wall building coefficient). Typical particle sizes for beads or powders range from submicron, for example about 0.2 microns, to about 200 microns, for example from about 10 to about 50 microns, but the actual size depends especially upon the formation properties and on other factors known to those of ordinary skill in the art. Amorphous or partially crystalline PVOH fibers in these size ranges are also suitable.

[000123] If the PVOH is to be used also as a breaker, the particles can be of a broad size range, for example from nanoparticles (for breaking a VES within a matrix) to the size of proppants for breaking carrier fluid. The PVOH and its properties, such as molecular weight and crystallinity, are chosen based primarily on the desired rates of dissolution in the carrier fluid to be used at the temperature and salinity at which it will be used. These choices can also be influenced by the desired time before the delayed break, which could depend upon the size of the job, whether the job is hydraulic fracturing or gravel packing, and other factors known to those of ordinary skill in the art, including the concentrations and natures of the VES or crosslinked polymer and any other additives, and the temperature.

[000124] Moreover, there can be changes to the parameters during a treatment which are taken into account in the choice of a particular PVOH solid, including its chemistry and crystallinity, its size and shape, and its concentration, among other factors, depending upon the way it will be used as a extrametrical material or otherwise. All of these parameters can be affected by the nature of the job, for example, whether or not fluid loss control is

needed, the temperature, the nature of the formation, and the time desired before a break occurs and/or the time desired by which a break has occurred. For example, fluid loss control may not be needed when gravel packing in a low permeability formation and the choices can be made on the basis of breaking properties. Suitable choices can be made with the aid of simple experiments like those described above, or in the examples below, optionally with the aid of simulation software.

[000125] When PVOH fibers, for example, are employed they can have a temperature-triggered solubility in water, for example, above 90°C. The trigger temperature should be above the injection temperature, but below the formation temperature. In this manner the PVOH fibers are injected with the treatment fluid as a solid, but become solubilized downhole, after spacing the proppant islands apart for fracture closure, as the temperature increases above the trigger temperature. Solubilization can be delayed by employing PVOH fibers with a trigger temperature just below the formation temperature and/or continued injection of low temperature fluids to maintain the fibers below the trigger temperature until dissolution is desired. Where the solubility of the fibers is controlled by maintaining a sub-trigger temperature, aqueous fluids with low salinity can be employed. Also, the solubilization of the fibers can be controlled or delayed further by using high-salinity fluid so that if the trigger temperature is exceeded, solubilization does not occur until the salinity is reduced. Care should be taken to avoid impairing fluid flow (when fluid flow is a requirement) at a condition where the fibers are not entirely soluble but have become "sticky" so as to clump and block interstitial spaces.

[000126] The PVOH fibers can also be used in a proppant stage employing fiber assisted transport to improve proppant and other particle transport while reducing the amount of other fluid viscosifiers required. The at least partially crystalline PVOH fibers can be made to dissolve after the treatment so that no permanent fiber residue is left in the wellbore or fracture. PVOH fibers having temperature triggers at pre-selected temperatures are available commercially under the trade designation KURALON K-II (Kuraray America, Incorporated), for example. These PVOH fibers completely dissolve in water when brought to a defined trigger temperature, but are virtually insoluble at lower temperature for a broad range of pH and chemical conditions. These PVOH fibers are made to have defined temperature trigger points for aqueous dissolution at desired

temperatures between 20°C and 90°C, in 10°C increments. When the PVOH fiber does dissolve into an aqueous treatment or reservoir fluid, it releases polyvinyl alcohol in solution. This can effectively break VES fluids. The dissolved fiber can also break some crosslinked guar based or other polymer-viscosified fluids since the addition of dissolved polyvinyl alcohol effectively acts to take borate, titanate, zirconate and similar ions away from the guar based molecules, thereby reducing the viscosity of the crosslinked polymer to that of the linear gel.

[000127] Fibers and other particle forms of PVOH are also available in non-crystalline or semicrystalline/amorphous form. When an amorphous PVOH is employed, dissolution of the PVOH can be controlled by salinity alone. The well treatment fluid in which the PVOH particles are introduced should have a high salinity to avoid premature dissolution. When it is desired to dissolve the PVOH solids, salinity conditions are reduced by introducing a subsequent treatment fluid of low salinity, e.g. fresh water or 2% KCl, or where the formation water has a low salinity, allowing the connate water to flow to the environment of the PVOH solids.

[000128] The PVOH solids can optionally be coated to slow the dissolution. Suitable coatings include polycaprolate (a copolymer of glycolide and epsilon-caprolactone), and calcium stearate, both of which are hydrophobic. Polycaprolate itself slowly hydrolyzes. Generating a hydrophobic layer on the surface of the PVOH solids by any means delays the dissolution. Note that coating here can refer to encapsulation or simply to changing the surface by chemical reaction or by forming or adding a thin film of another material. Another suitable method of delaying the dissolution of the PVOH solids is to suspend the solid, optionally with a hydrophobic coating, in oil or in the oil phase of an emulsion. The dissolution does not occur until low salinity water contacts the solid PVOH above any solubility trigger temperature.

[000129] In another embodiment of the disclosure, the application relates to a subterranean formation penetrated by a wellbore and a fracture within the formation. Within the fracture (i.e. spaces formed between formation faces) is a plurality of proppant clusters spaced apart by a plurality of extrametrical material clusters. The plurality of extrametrical material clusters is removable, by any suitable technique, to form open

channels around the plurality of proppant clusters to enable fluid flow from the formation through the fracture toward the wellbore.

[000130] In yet another aspect, method embodiments include injecting a plurality of stages of a well treatment fluid through a wellbore into a fracture in a subterranean formation, the stages of the fluid containing at least one of a proppant and an extrametrical material. The channelant comprises at least one of a solid acid-precursor to generate acid in the fracture, and a solid base-precursor to generate a base in the fracture (in either case, a suitable acid or base is a material which alters the pH of an aqueous median, in either a decreasing or increasing direction, respectively). The proppant is placed in the fracture in a plurality of proppant clusters to form pillars. The channelant then dissolves in the fracture, which may further enable fluid flow from the formation through the fracture toward the wellbore (the term 'dissolve' in the present application means any suitable process, either chemical or mechanical, by which the extrametrical material voids the fracture space occupied).

[000131] Some embodiments may benefit from the presence of degradable, high energy materials in fiber or emulsion form. Degradable, high energy (explosive or deflagrable) polymer or organic compound may be delivered to the fracture in fiber or emulsion form and initiated to degrade optionally with an explosion, thus leaving the proppant pack clear of fiber. Further, the formation is additionally stimulated. Methane dry gas wells may benefit from such embodiments because of their low permeability (in the range of 10 nD to 5 mD) and their longer fiber degradation time requirements due to lower water or oil flow rates. In some embodiments, the material contains both reducer and oxidizer in the same molecule and does not need active media participation in decomposition. Polymers or low molecular weight products or mixtures thereof may be used. Oxidizing groups within a molecule include nitro, azido, and/or peroxide groups. Materials for fibers include nitrocellulose, nitrostarch, nitro polyvinyl alcohol, nitropolystyrene, nitroindene, nitroethylene, nitro polyurethane, dinitropropyl acrylate, polyvinyl azide, glycidyl azide polymer, and their derivatives and mixtures thereof. Materials for emulsions include nitrocellulose at a different content of nitro groups, nitro polyvinyl alcohol, nitropolystyrene, nitroindene nitroethylene, nitro polyurethane,

dinitropropyl acrylate, polyvinyl azide, glycidyl azide polymer, 2,4,6-trinitrotoluene and other nitrobenzene derivative, hexanitrostilbene, and derivatives and mixtures thereof.

[000132] High energy containing material processes may benefit from compounds that have both hydrocarbon fragment as a reducer and nitro (or other nitrogen-loaded) fragment as an oxidizer and initiation cause decomposition (no chemical triggers required) ideally with CO2, N2, and H2O as final products. Fast degradable compounds may be used as solid gas precursor which provides slow or fast gas ceasing. This results in decreased hydrostatic pressure and improved production. As a practical matter, explosive and deflagrable fiber may be safely delivered to the location in wet or slurry form in water or gel. Three exemplary ways may be selected for this degradation.

1. Thermal slow decomposition of the material in bulk, with no decomposition wave propagation. The high temperatures in downhole conditions may be used to drive this decomposition. An advantage of this is the quick fiber disappearance and gas release. Decomposition may take about 10 days at 100°C, and the activation energy may be about 27 Kcal/mol.

2. Fast deflagration with wave propagation below the speed of sound. The fast deflagration may start after thermal or some other type of initiation. An advantage is faster fiber degradation, product gas release, heating up of the formation near the fracture, and control of the triggering process.

3. Explosion. Explosion may start after thermal or other (chemical, pressure, irradiation, acoustic wave, etc.) initiation. Explosion degrades fibers and induces fracture stimulation. An advantage is fast fiber degradation, additional formation stimulation, and controlled triggering.

[000133] Some embodiments that rely upon high energy fibers may benefit from using a high energy material emulsion to encapsulate other downhole chemicals such as breakers, aids, etc. Hydrophobic ingredients can be admixed to the hydrophobic phase of emulsion that remains stable at the surface. Thus, fast release of encapsulated reagents may be achieved.

[000134] High energy material emulsions may include 90 to 10 percent water, 90 to 10 percent degradable high energy material, and optionally organic solvent to dissolve the

degradable material, emulsifier, stabilizer, solid additives, encapsulated materials, and breaker aids. In downhole conditions, the emulsion is triggered for high energy material (internal phase) precipitation from the emulsion. Triggering may happen under action of downhole temperature, chemical destabilizing of emulsion droplets, extended surface, solids, electric discharge, ultra sound, other method, or a combination thereof.

[000135] The foregoing disclosure and description of the embodiments is illustrative and explanatory thereof. It can be readily appreciated by those skilled in the art that various changes in the size, shape and materials, as well as in the details of the illustrated construction or combinations of the elements described herein can be made. None of the description in the present application should be read as implying that any particular element, step, or function is an essential element which must be included in the claim scope.

Claims

1. A method, comprising:

injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and an extrametrical material through the wellbore and into the fracture, wherein introducing is achieved with varied and pulsed proppant concentrations in a pumping schedule, and

forming a plurality of proppant clusters comprising proppant and the extrametrical material in the fracture;

wherein the extrametrical material consolidates the proppant into clusters, and wherein the extrametrical material is degradable.

2. The method of claim 1, wherein the pumping schedule is based on fluid and formation properties.

3. The method of claim 1, wherein the pumping schedule is achieved by varying pumping rate during pulses.

4. The method of claim 1, wherein the pumping schedule is based on fluid and formation properties and is achieved by varying pumping rate during pulses.

5. The method of claim 1, further comprising degrading the extrametrical material after proppant placement in the fracture.

6. The method of claim 5, wherein the extrametrical material degradation provides fluid flow paths coupling the formation to the wellbore via the fracture.

7. The method of claim 1, wherein the extrametrical material comprises at least one of:

a solid acid-precursor to generate acid; or

a solid base-precursor to generate a base.

8. The method of claim 1, wherein the extrametrical material generates acid in the fracture.

9. The method of claim 1, wherein the method is repeated at another fracture in the wellbore.

10. The method of claim 1, wherein the proppant clusters are placed in transverse or longitudinal fractures along a wellbore deviated at an angle relative to a vertical wellbore.

11. The method of claim 1, wherein a zone contacted by the first and second treatment fluids in the formation comprises fine grained sedimentary rock formed by consolidation of clay and silt sized particles into thin, relatively impermeable layers.

12. The method of claim 1, further comprising injecting a fluid comprising extrametrical materials in a higher concentration than the second well treatment fluid into the fracture.

13. The method of claim 1, wherein the extrametrical material is a channelant.

14. The method of claim 1, wherein the extrametrical material is not a channelant during the introducing and the forming.

15. A method, comprising:

injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and an extrametrical material through the wellbore and into the fracture wherein the injecting is achieved with varied and pulsed proppant concentration in a pumping schedule;

placing the proppant in the fracture in a plurality of proppant clusters,

wherein the extrametrical material reinforces the proppant clusters, and wherein the extrametrical material is a removable material.

16. The method of claim 15, further comprising degrading the extrametrical material after the placing of the proppant.

17. The method of claim 16, wherein the degradation of the extrametrical material is by degraded by softening, dissolving, melting, or reacting.

18. The method of claim 15, wherein the extrametrical material comprises a solid acid-precursor to generate acid in the fracture.

19. The method of claim 15, wherein the extrametrical material comprises a solid base-precursor to generate a base in the fracture.

20. The method of claim 19, wherein the extrametrical material comprises a solid acid-precursor to generate acid in the fracture.

21. The method of claim 15, wherein the method is repeated at another fracture in the wellbore.

22. The method of claim 15, wherein the proppant clusters are in transverse or longitudinal fractures along a wellbore deviated at an angle relative a vertical wellbore.

23. The method of claim 15, wherein a zone contacted by the first and second treatment fluids in the formation comprises fine grained sedimentary rock.

24. The method of claim 15, further comprising injecting a third treatment fluid comprising extrametrical materials in a higher concentration than the second well treatment fluid into the fracture.

25. The method of claim 15, wherein the extrametrical material is a channelant.

26. The method of claim 15, wherein the extrametrical material separates the proppant clusters.

27. A method, comprising:

constructing a system in a subterranean formation penetrated by a wellbore, comprising:

injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and fiber through the wellbore and into the fracture, wherein the fiber is a degradable material;

placing the proppant in the fracture in a plurality of proppant clusters;

degrading the fiber; and

producing formation fluids from the formation.

28. The method of claim 27, wherein the fiber consolidates the proppant clusters.

29. The method of claim 27, further comprising injecting a fluid comprising the fiber in a higher concentration than the second well treatment fluid into the fracture.

30. The method of claim 27, wherein the fiber is a channelant.

31. The method of claim 27, wherein the fiber is not a channelant during the injecting of the second treatment fluid.

32. The method of claim 1 wherein the pumping schedule is modified during injecting due to processing data from surface or bottomhole gauges.

33. A method comprising:

injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and fiber through the wellbore and into the fracture; and

forming a plurality of proppant clusters comprising proppant and fiber in the fracture;

wherein the fiber consolidates the proppant into clusters, and wherein the fiber is degradable.

34. A method comprising:

injecting a first treatment fluid comprising a gas through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and fiber through the wellbore and into the fracture forming a plurality of proppant clusters; and

wherein the fiber reinforces the proppant clusters, and wherein the fiber is a removable material.

35. A method, comprising:

constructing a system in a subterranean formation penetrated by a wellbore, comprising:

injecting a first treatment fluid comprising a gas and substantially free of macroscopic particles through a wellbore at a pressure sufficient to initiate a fracture in a subterranean formation;

injecting a second treatment fluid comprising proppant and fiber through the wellbore and into the fracture, wherein the fiber is a removable material;

placing the proppant in the fracture in a plurality of proppant clusters; and

producing formation fluids from the formation.

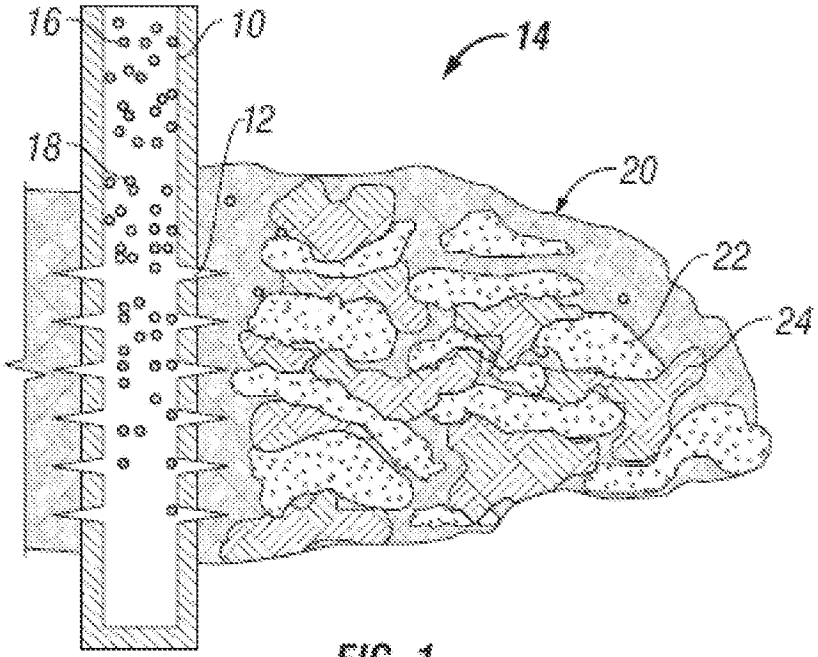


FIG. 1

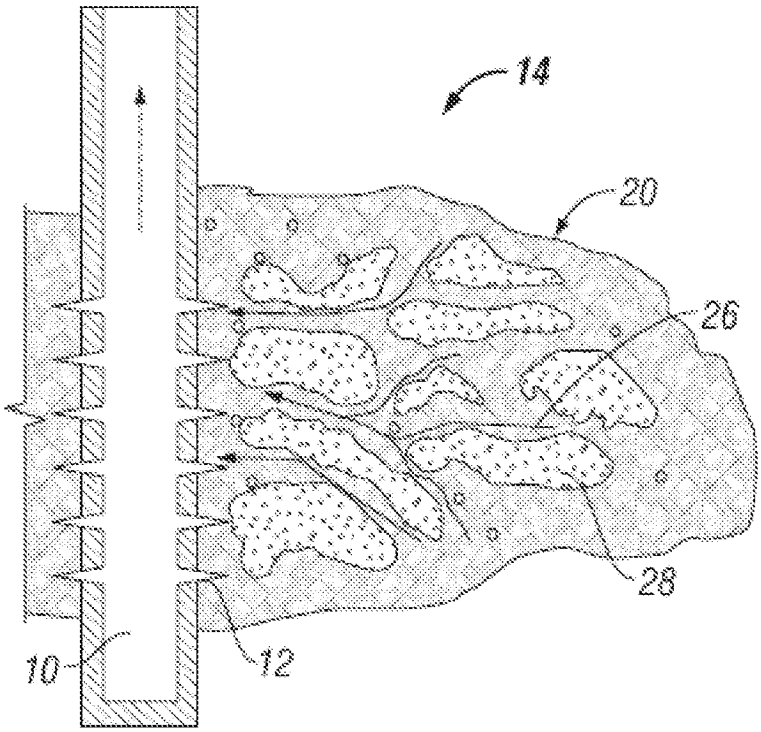


FIG. 2

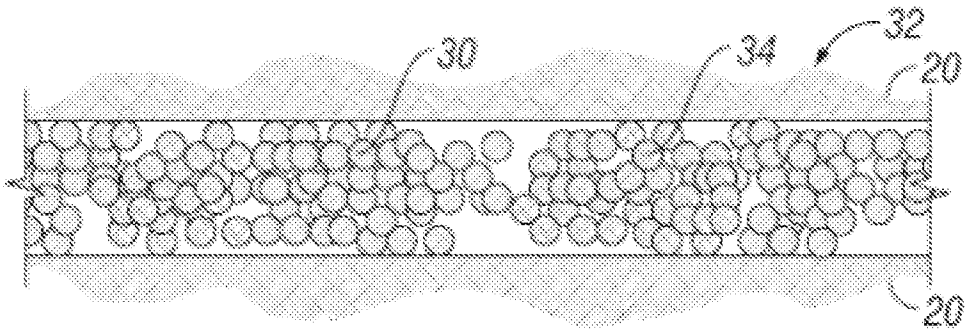


FIG. 3

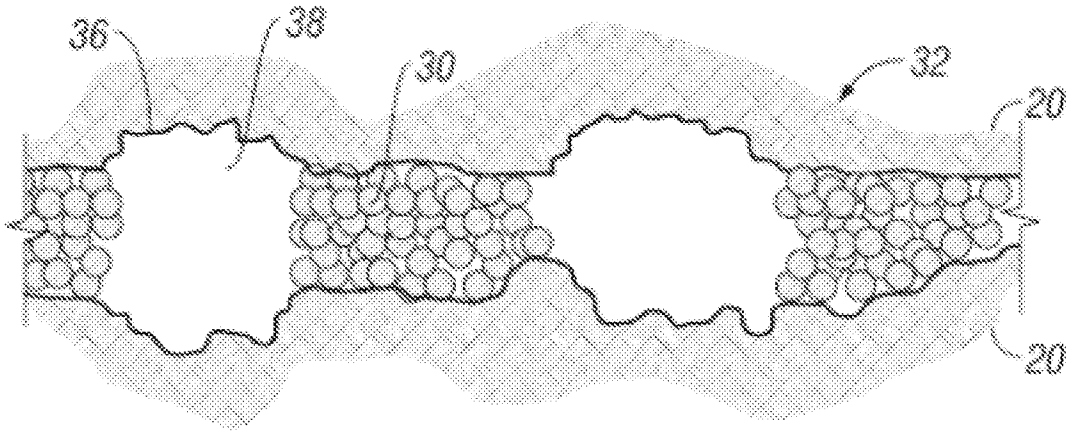


FIG. 4

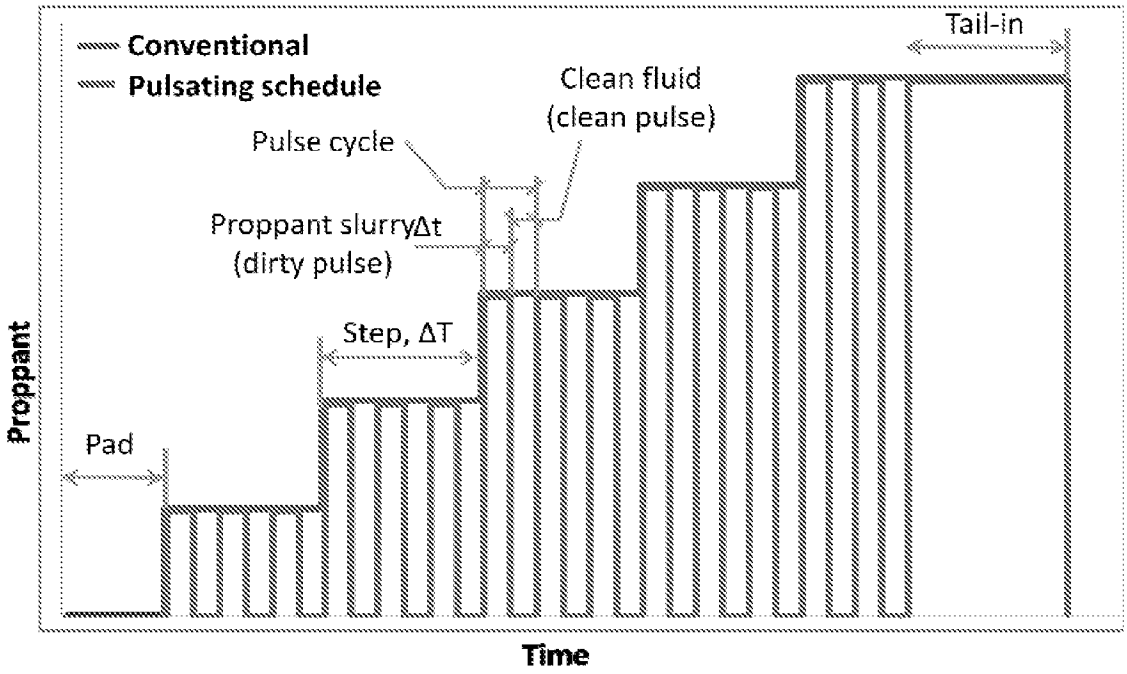

Conventional
Pulsating schedule
Tail-in
Clean fluid
(clean pulse)
Pulse cycle
Proppant slurryΔt
(dirty pulse)
Step, ΔT
Proppant
Pad
Time

FIG. 5

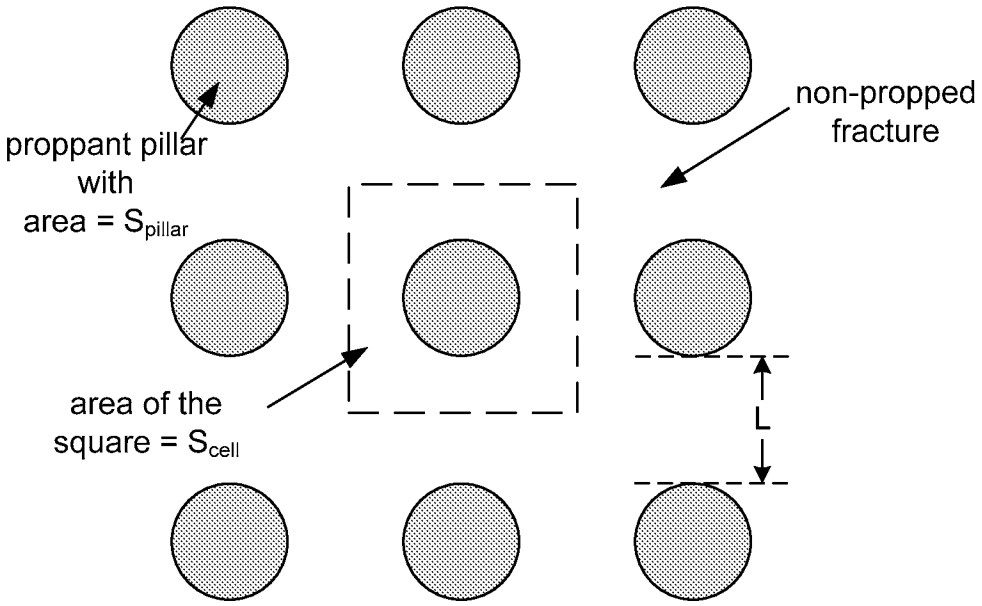

non-propped
fracture
proppant pillar
with
area = S_{pillar}
area of the
square = S_{cell}
L

FIG. 6

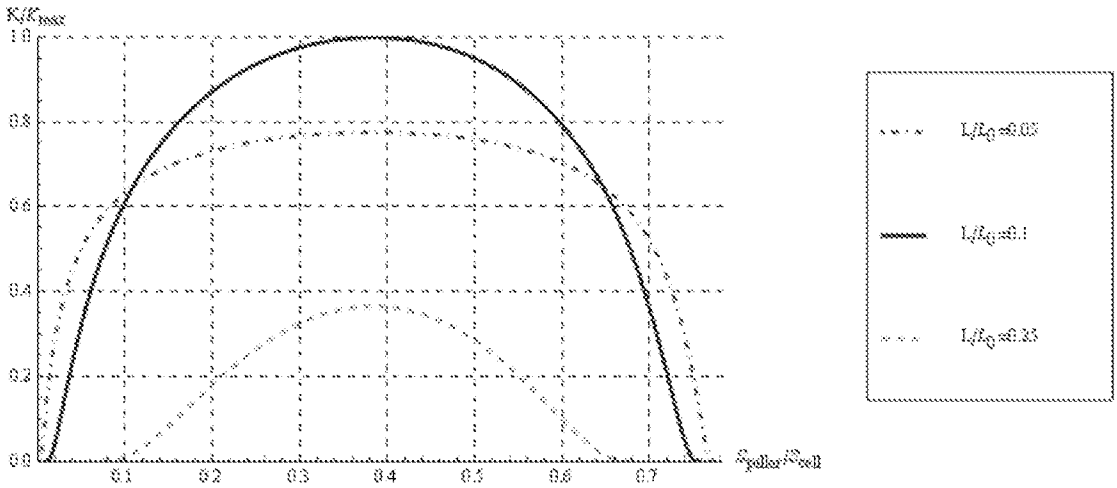


FIG. 7

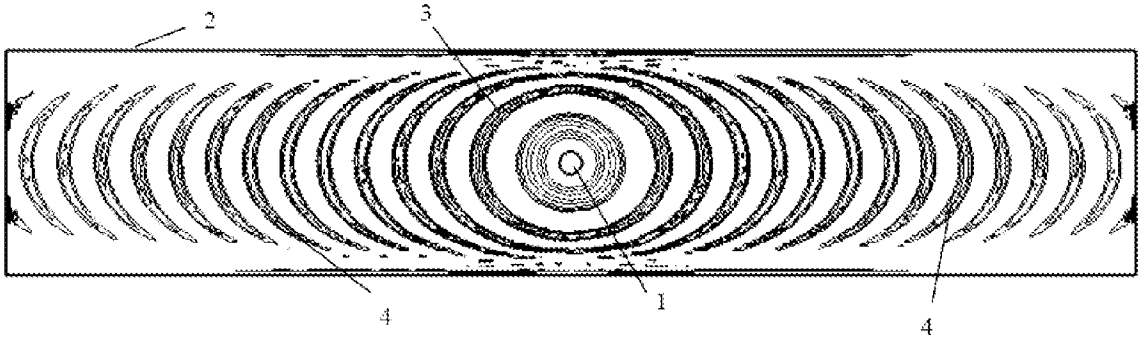


FIG. 8

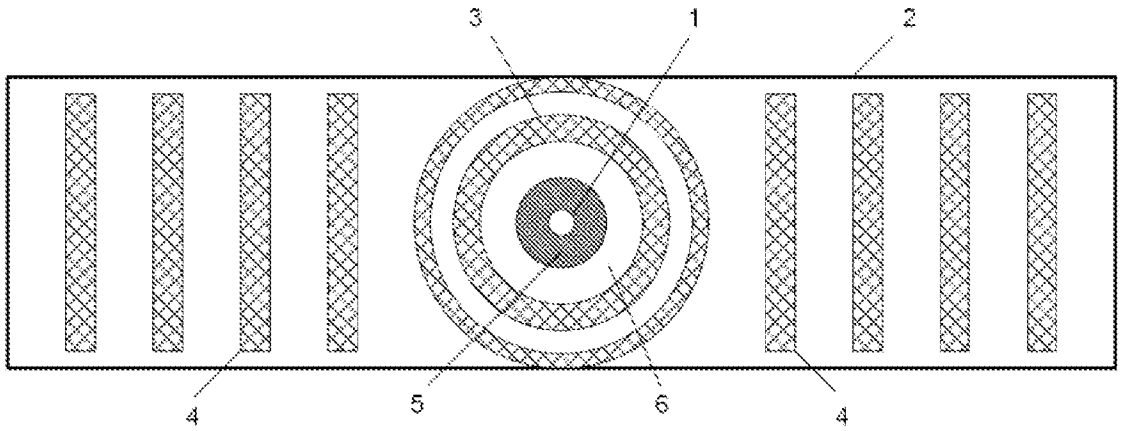


FIG. 9

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 12/46847

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - E21B 43/26 (2012.01)
USPC - 166/308.1
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC(8): E21B 43/26 (2012.01)
USPC: 166/308.1

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
additional USPC: 166/308.1, 166/305.1, 166/308.2, 166/308.3, 166/308.4, 166/308.5, 166/308.6, 166/268, 166/270.1, 166/400, 166/271

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
PubWEST(PGPB,USPT,USOC,EPAB,JPAB); Google Patents, Google, Google Scholar, PAIR
Search terms used: proppant, extrametrical, channelant, fiber, degradable, clusters, biodegradable, injecting, macroscopic, wellbore, pressure, fluid, second first treatment, concentrations, schedule, filling, filler, material, acid, dissolvable, transverse, vertical,

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X --- Y	US 2011/0083849 A1 (MEDVEDEV et al.) 14 April 2011 (14.04.2011) Fig 1; para [0019-0021]; para [0026-0027]; para [0032-0033]; para [0044]	1-9, 13-21, 25-28, 30, 31, 33-35 --- 10-12, 22-24, 29, 32
Y	US 2011/0061869 A1 (ABASS et al.) 17 March 2011 (17.03.2011) para [0027-0028]	10, 22
Y	US 2011/0033238 A1 (RIESE) 10 February 2011 (10.02.2011) para [0032-0036]; para [0062-0065]	11, 23
Y	US 2009/0281006 A1 (WALTERS et al.) 12 November 2009 (12.11.2009) para [0177-0178]	12, 24 and 29
Y	US 2009/0294122 A1 (HANSEN et al.) 3 December 2009 (03.12.2009) para [0059]; para [0081-0085]	32
Y	US 6,776,235 A1 (ENGLAND) 17 August 2004 (17.08.2004) col 1, ln 48-67; col 6, ln 10-56	32

☒ Further documents are listed in the continuation of Box C. ☐

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
20 September 2012 (20.09.2012)	05 OCT 2012
Name and mailing address of the ISA/US Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-3201	Authorized officer: Lee W. Young PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 12/46847

C (Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2009/0286700 A1 (LESKO et al.) 19 November 2009 (19.11.2009) entire document	1
Y	US 20110114313 A1 (LESKO et al.) 19 May 2011 (19.05.2011) para [0026]; para [0049-0051]	1
T	US 2011/0240293 A1 (LESKO et al.) 6 October 2011 (06.10.2011) entire document	1-33
T	US 2012/0118572 A1 (HUTCHINS) 17 May 2012 (17.05.2012) para [0059-0062]; para [0073]	1
A	US 7,178,596 B2 (BLAUCH) 20 February 2007 (20.02.2007) col 8, ln 1-12; col 10, ln 1-12	1
A	US 2006/0157243 A1 (NGUYEN) 20 July 2006 (20.07.2006) para [0014]; para [0051-0054; para [0062]	1