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(54) Title: HYDRAULIC FRACTURING WITH PROPPANT PULSING THROUGH CLUSTERED ABRASIVE PERFORATIONS

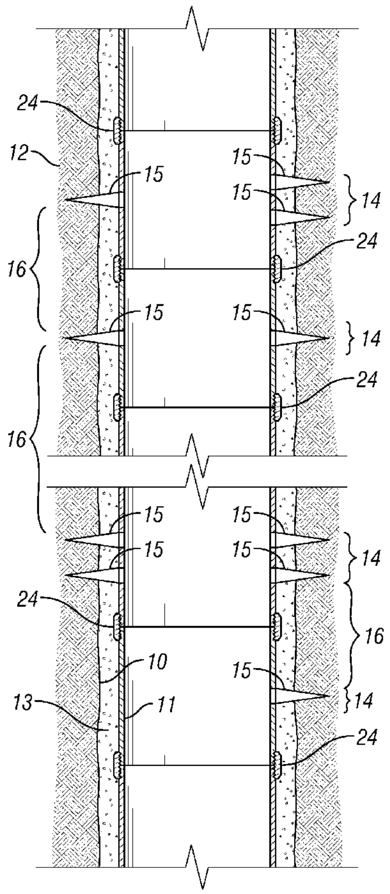

FIG. 1

(57) Abstract: Well completion techniques are disclosed that combine the creation of perforation clusters created using abrasive-jet perforation techniques with hydraulic fracturing techniques that include proppant pulsing through the clustered abrasive jet perforations. Both the abrasive-jet perforation and hydraulic fracturing with proppant pulsing may be carried out through coiled tubing.

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HYDRAULIC FRACTURING WITH PROPPANT PULSING THROUGH CLUSTERED ABRASIVE PERFORATIONS

Background

[0001] Hydrocarbons (oil, natural gas, etc.) are obtained from a subterranean geological formation by drilling a well that penetrates the hydrocarbon-bearing formation. This provides a partial flow path for the hydrocarbon to reach the surface. In order for the hydrocarbon to be "produced," that is, travel from the formation to the wellbore and ultimately to the surface, there must be a sufficiently unimpeded flow path.

[0002] Hydraulic fracturing is a primary tool for improving well productivity by placing or extending highly conductive fractures from the wellbore into the reservoir. During the first stage, hydraulic fracturing fluid is injected through wellbore into a subterranean formation at high rates and pressures. The fracturing fluid injection rate exceeds the filtration rate into the formation producing increasing hydraulic pressure at the sand face. When the pressure exceeds a critical value, the formation strata or rock cracks and fractures. The formation fracture is more permeable than the formation porosity.

[0003] During the next stage, proppant is deposited in the fracture to prevent it from closing after injection stops. The resulting propped fracture enables improved flow of the recoverable fluid, i.e., oil, gas or water. Many other proppants may be used such as sand, gravel, glass beads, walnut shells, ceramic particles, sintered bauxites and other materials including bearings of spherical, cylindrical or irregular shapes.

[0004] Hydraulic fracturing fluids are aqueous solutions containing a thickener, such as a soluble polysaccharide, to provide sufficient viscosity to transport the proppant. Typical thickeners are polymers, such as guar (phytogeneous polysaccharide), and guar derivatives (hydropropyl guar, carboxymethylhydropropyl guar). Other polymers can be used also as thickeners. Water with guar represents a linear gel with a viscosity that increases with polymer concentration. Cross-linking agents are used which provide engagement between polymer chains to form sufficiently strong couplings that increase the gel viscosity and create visco-elasticity. Common crosslinking agents for guar include boron-, titanium-, zirconium-, and aluminum-laden chemical compounds.

[0005] Fibers can be used to enhance the ability of the fracturing fluids to transport proppant and to mitigate proppant settling within the hydraulic fracture. For operations in which proppant is pumped in slugs or pulses, fibers can also be used to mitigate the dispersion of the proppant slugs as they travel throughout the well completion and into the fracture.

[0006] Proppant flow back control agents can also be used during the latter stages of the hydraulic fracturing treatment to limit the flow back of proppant placed into the formation. For instance, the proppant may be coated with a curable resin activated under down hole conditions. Different materials, such as bundles of fibers, or fibrous or deformable materials, also have been used to retain proppants in the fracture. Presumably, fibers form a three-dimensional network in the proppant pack that limits its flow back.

[0007] The success of a hydraulic fracturing treatment depends upon hydraulic fracture conductivity and fracture length. Fracture conductivity is the product of proppant permeability and fracture width; units are typically expressed as millidarcyfeet. Fracture conductivity is affected by a number of known parameters. Proppant particle size distribution is one key parameter that influences fracture permeability. The concentration of proppant between the fracture faces is another (expressed in pounds of proppant per square foot of fracture surface) and influences the fracture width. One may consider high-strength proppants, fluids with excellent proppant transport characteristics (ability to minimize gravity-driven settling within the fracture itself), high-proppant concentrations, or big proppants as means to improve fracture conductivity. Weak materials, poor proppant transport, and narrow fractures all lead to poor well productivity. Relatively inexpensive materials of little strength, such as sand, are used for hydraulic fracturing of formations with small internal stresses. Materials of greater cost, such as ceramics, bauxites and others, are used in formations with small to moderate closure stresses. Materials of greater cost, such as ceramics, bauxites and others, are used in formations with higher closure stresses.

[0008] The proppant pack must create a conduit having a higher hydraulic conductivity than the surrounding formation rock. The proppant pack within the fracture is often modeled as a permeable porous structure, and the flow of formation fluids through this layer is generally described using the well-known Darcy's law (1) or Forscheimer's equation (2):

[0009] (1) $\partial P/\partial x=-(\mu u/k)$;

[0010] (2) $\partial P\partial x=-[(\mu u/k)+\beta\rho u^2]$,

[0011] where

[0012] P is a fluid pressure in the fracture;

[0013] x is a distance along the fracture from the wellbore;

[0014] μ is a viscosity of the formation fluid;

[0015] u is a flow (filtration) speed of the formation fluid;

[0016] k is a permeability of the proppant pack;

[0017] β is a coefficient referred to as beta-factor that describes non-linear corrections to the Darcy's filtration law; and

[0018] ρ is a density of the formation fluid.

[0019] The result of multiplying fracture permeability by fracture width is referred to as "hydraulic conductivity". The most important aspect of fracture design is optimization of the hydraulic conductivity for a particular formation's conditions.

[0020] A fracture optimization process will strike a balance among the proppant strength, hydraulic fracture conductivity, proppant distribution, cost of materials, and the cost of executing a hydraulic fracturing treatment in a specific reservoir. The case of large proppant particle sizes illustrates compromises made during an optimization process. A significant hydraulic fracture conductivity increase is possible using large diameter proppants. However, at a given internal formation stress, large diameter proppants crush to a greater extent when subjected to high fracture closure stresses, leading to a decrease in the effective hydraulic conductivity of the proppant pack. Further, the larger the proppant particles, the more they are subjected to bridging and trapping in the fracture near the injection point.

[0021] Patent US 6,776,235, “Hydraulic Fracturing Method”, which is hereby incorporated by reference discloses a method and means for optimizing fracture conductivity. The well productivity is increased by sequentially injecting into the wellbore alternate stages of fracturing fluids having a contrast in their ability to transport propping agents to improve proppant placement, or having a contrast in the amount of transported propping agents. The propped fractures obtained following this process have a pattern characterized by a series of bundles of proppant spread along the fracture. In another words, the bundles form "pillars" that keep the fracture opens along its length but provide a lot of channels for the formation fluids to circulate.

[0022] Hydro-abrasive methods for surface treatment and cutting are often used for cutting perforation holes or slots in casing and formation instead of using explosive cumulative charges or milling cutters.

[0023] Devices for cutting slots in a formation with a hydro-abrasive jet may include a perforator hung on tubing inside of a well with a hydro-abrasive jet generator located on ground surface. The perforator may include two opposite side oriented nozzles directed to wall of the well. A hydro-abrasive slurry may be prepared in a hydro-abrasive jet generator and pumped through tubing and down hole to perforator. Other abrasive perforating devices are known in the art.

<u>Summary of the Disclosure</u>

[0024] 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 this summary intended to be used as an aid in limiting the scope of the claimed subject matter.

[0025] For purposes of this disclosure, the terms perforation and station are interchangeable and the term perforation will be used. On the other hand, a cluster may include one or more perforations. If the cluster includes a plurality of perforations, the perforations are grouped relatively close together and typically, are formed simultaneously using an abrasive jet perforations tool with a plurality of nozzles. A plurality of clusters would refer to individual clusters (i.e., one or more perforations) separated by an unperforated interval.

[0026] In one aspect, a method for perforating and fracturing of a subterranean formation with a wellbore lined with casing extending through at least part of the formation. The disclosed method may include forming at least one cluster of perforation(s) through the casing and into the formation with hydro-abrasive jets. The disclosed method may further include injecting a proppant-free fracturing fluid into the wellbore through the cluster. The disclosed method may also include combining the proppant-free fracturing fluid with a proppant to form a first proppant-laden slurry and alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the cluster of perforations. The method may also include repeating the combining of the proppant-free fracturing fluid with the proppant to provide additional (i.e., second, third, fourth, etc.) proppant-laden slurries of varying proppant concentrations, alternatingly and repeatedly injecting each additional proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the cluster of perforations. The method may also include forming additional cluster(s) through the casing and into the formation with hydro-abrasive jets, wherein the additional cluster(s) are spaced apart from the other cluster(s) by a non-perforated interval. The disclosed method may also include treating all clusters simultaneously with the proppant-free fracturing fluid followed by the proppant-laden slurries as discussed above.

Brief Description of the Drawings

[0027] FIG. 1 illustrates a plurality of discreet perforation clusters separated by non-perforated intervals that may be formed by abrasive-jet perforating.

[0028] FIG. 2 illustrates an annular fracturing and abrasive-jet perforating tool.

[0029] FIG. 3 graphically illustrates a fracturing pumping schedule in accordance with this disclosure.

[0030] FIG. 4 is a photograph of a cavern or perforation made by an abrasive-jet technique.

[0031] FIG. 5 is a flow diagram illustrating a perforation and pumping schedule in accordance with this disclosure.

Detailed Description

[0032] This disclosure is directed to the combination of improved abrasive-jet perforation techniques which enables the creation of discreet clusters of perforations separated by nonperforated intervals followed by improved hydraulic fracturing techniques which include proppant pulsing. Anywhere from one to 100 or more clusters may be treated together and each cluster may include from one to 20 or more perforations. Each cluster may be up to 5 m or more in length and the nonperforated intervals may range from about 10 cm to about 5 m or more in length. The abrasive-jet perforating may optionally be performed through coiled tubing and the subsequent fracturing techniques may optionally be performed through an annulus created by the coiled tubing and the casing. Of course, other techniques may be employed as will be apparent to those skilled in the art.

[0033] Abrasive-jet perforation may have advantages over cumulative perforation in the respect that abrasive-jet perforating can allow for a selective approach to perforating cluster location and a nonperforated interval between perforation clusters. Abrasive-jet perforation may also allow for significantly reduced amount of perforations inside the casing, but may still provide risk-free proppant admittance due to the large surface area of the caverns created inside the cement and the formation by abrasive-jet perforation techniques. Further, such caverns may connect the wellbore with the fracture.

[0034] In an embodiment, an abrasive perforating scheme may include clusters of perforations of up to 5 meters long and also may include non-perforated intervals between the clusters that can from about 10 cm to 5 m or more in length. The number of clusters for the fracturing treatment can vary from 1 to 100, or any suitable number, depending upon such factors as formation thickness, wellbore deviation and fracture design parameters. The number perforations in each cluster may vary from 1 to 20 or more, or any suitable number, depending upon such factors as formation characteristics and fracturing treatment design specifics. In one instance, each cluster may include from 1 to 6 perforations or caverns created in azimuthally different directions by fluid jet flow through nozzles of the perforator. An illustration of such a perforation scheme is shown in FIG 1 and an illustration of an abrasive-jet perforating device is shown in FIG. 2

[0035] FIG. 1 shows a sectional view of a wellbore 10 that is been lined with casing 11 with the annular space disposed between the casing and the formation 12 being filled with cement 13. FIG. 1 illustrates a plurality of perforation clusters 14 that, in the embodiment illustrated in FIG. 1, each include from one to four perforations 15 that form caverns that extend through the cement 13 and into the formation 12. The clusters 14 may be separated from one another by nonperforated intervals 16. While each cluster 14 may be treated separately using the improved hydraulic fracturing techniques disclosed below, each cluster 14 may also be treated simultaneously using the disclosed hydraulic fracturing techniques.

[0036] An abrasive-jet perforating tool 19 for forming the clusters 14 shown in FIG. 1 is illustrated in FIG. 2. The tool 19 includes a collar locator/centralizer 20, a connector 22, and a sand jetting sub 23. The collar locator/centralizer 20 is connected beneath connector 22, which may be used to attach the tool 19 to coiled tubing (not shown) or another tool string (not shown). The collar locator 20 is used to determine when the tool 19 is within a particular zone of interest in the well based on collars 24 located in the well casing 11 (FIG. 1). Although the embodiment of FIG. 2 includes a collar locator/centralizer 20, this device may be one of a various number of down hole devices used to determine the location of a down hole assembly within a wellbore 10. The disconnect tool 22 may releasably connect the tool 19 to the bottom end of a coiled tubing, tool string, drill pipe, wire line, etc. A reverse check valve with a bull nose 25 is disposed at a distal end of the tool 19.

[0037] Once the tool 19 has been located within the new zone of interest and the sand jetting sub 23 is positioned at the proper location, an abrasive laden fluid may be pumped at a high pressure through the jetting ports 27 on the exterior of the sand jetting sub 23. For example, 20/40 Ottowa sand may be pumped through the sand jetting sub 23 to create perforations 15 through the casing 11 at the desired locations as shown in FIG. 1. Using 20/40 Ottowa sand pumped through the sand jetting sub 23 may perforate the casing 11 and cement 13 at the zone of interest in as little as twenty minutes. The tool 19 may also be used to perforate tubing as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. The configuration of the jetting ports 27 of the sand jetting sub 23 may be varied to change the number and locations of perforations created by the sand jetting sub 23. The configuration of the individual jetting ports 27 may also be changed to modify the cutting power of the sand jetting sub 23.

[0038] After the casing 11 (or tubing) has been perforated as shown in FIG. 1, the tool 19 may be withdrawn from the wellbore 10 or, if the tool 19 is disposed at an end of a coiled tubing (not shown), the tool may be moved away from the perforations

15 to provide a sufficient annular flow path to allow stimulation of the perforations 15.

[0039] Fracturing fluid is pumped down the casing 11 at a high pressure in an attempt to generate fractures through the perforations 15 in the zones of interest.

[0040] In a hydraulic fracturing method for a subterranean formation, a first stage referred to as the "pad stage" involves injecting a fracturing fluid into a wellbore at a sufficiently high flow rate that it creates a hydraulic fracture in the formation. The pad stage is pumped until the fracture is of sufficient dimensions to accommodate the subsequent slurries pumped in the proppant stages. The volume of the pad can be designed by those knowledgeable in the art of fracture design.

[0041] Water-based fracturing fluids are common with natural or synthetic water-soluble polymers added to increase fluid viscosity and are used throughout the pad and subsequent propped 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 hydropropyl guar, carboxymethyl guar, and carboxymethylhydropropyl guar. Cross-linking agents based on boron, titanium, zirconium or aluminum complexes are typically used to increase the polymer's effective molecular weight making it better suited for use in high-temperature wells.

[0042] To a small extent, cellulose derivatives, such as hydroxyethylcellulose or hydroxypropylcellulose and carboxymethylhydroxyethylcellulose, are used with or without cross-linkers. Two biopolymers--xanthan and scleroglucan--prove excellent proppant-suspension ability, but are more expensive than guar derivatives and so are used less frequently. Polyacrylamide and polyacrylate polymers and copolymers are used typically for high-temperature applications or as friction reducers at low concentrations for all temperatures ranges.

[0043] Polymer-free, water-base fracturing fluids can be obtained using viscoelastic surfactants. Usually, these fluids are prepared by mixing in appropriate amounts of suitable surfactants, such as anionic, cationic, nonionic 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.

[0044] After the "pad stage", several stages, referred to as "propping stages", are injected into formation. A propping stage involves the periodical introduction into the fracturing fluid in the form of solid particles or granules to form a suspension. The propped stage is divided into two periodically repeated sub-stages, the "carrier sub-stage" involves injection of the fracturing fluid without proppant; and the "propping sub-stage" involves addition of proppant into the fracturing fluid. As a result of the periodic slugging of slurry containing granular propping materials, the proppant doesn't completely fill the fracture. Rather, spaced proppant clusters form as posts with channels between them through with formation fluids pass. The volumes of propping and carrier sub-stages as pumped may be different. That is the volume of the carrier sub-stages may be larger or smaller than the volume of the propping sub-stages. Furthermore the volumes of these sub-stages may change over time. That is, a propping sub-stages pumped early in the treatment may be of a smaller volume than a propping sub-stage pumped latter in the treatment. The relative volume of the sub-stages is selected by the engineer based on how much of the surface area of the fracture he desires to be supported by the clusters of proppant, and how much of the fracture area is open channels through which formation fluids are free to flow. As non limiting example, the volume of carrier sub-stage or propping sub-stage can be zero.

[0045] A sample pumping schedule for a propped stage is shown in Table 1 below. Table 1:

Stage	Pump Rate m^3/min	Fluid volume m^3	Prop Conc. kgPA	Prop mass kg	Slurry volume m^3	Pump time min	Dirty pulse sec	Clean pulse sec	Cycles
PAD	3.18	79.5	0	0	79.5	25	0	1500	0
1 PPA	3.18	3.9	120	228	3.9	1.2	12.4	12.4	2
2 PPA	3.18	7.4	240	854	7.6	2.4	12	12.0	6
3 PPA	3.18	6.1	359	1033	6.4	2.0	12	12.0	5
4 PPA	3.18	10.7	479	2401	11.4	3.6	12	12.0	9
5 PPA	3.18	11.8	589	3233	12.7	4.0	12	12.0	10
6 PPA	3.18	11.6	719	3766	12.7	4.0	12	12.0	10
7 PPA	3.18	18.3	839	6829	20.4	6.4	12	12.0	16
TAIL-IN	3.18	0.8	839	711	1.1	0.3	20	0	0
FLUSH	3.18	6.2	0	0	6.2	1.9	0	116.5	0

Another pumping schedule is illustrated graphically in FIG. 3. In Table 1 and FIG. 3, “dirty pulse’ refers to “propping sub-stage” and “clean pulse” refers to “carrier sub-stage”. Referring to FIG. 3, the first stage, known as the pad stage is shown at 31. A plurality of proppant stages are shown at 32-37 wherein, each proppant stage 32, 33, 34, 35, 36 represents the injection of a proppant-laden fracturing fluid having increasing concentrations of proppant. Within each stage, 32, 33, 34, 35, 36, pulses of “clean” fracturing fluid is followed by pulses of “dirty” or proppant-laden fracturing fluid (or slurry). The Δt for each pulse may vary widely from the example of 12 seconds given in Table 1. For example, the clean and dirty pulse times may range from about 5 seconds to a minute or longer, also pulse times in the range of from about 5 seconds to about 30 seconds may be preferred. The final tail-in stage is shown at 37 and has zero volume of clean pulse.

[0046] Some concepts in support of such an abrasive perforation scheme to promote channel creation inside fracture after treatment with proppant pulsing technique include the following: (1) The near-wellbore area is the most critical zone for proppant admittance (high tangential stresses). The disclosed technique may allow for reliable proppant admittance and reduction of risk for proppant bridging. This can be achieved even with a lower number of holes inside the casing than the number of holes that would be needed with a cumulative perforation technique. The reduced number of holes inside casing would be achieved by the geometry of the abrasive cavern – which has larger contact area with the fracture relative to the contact area generated from a channel developed with the cumulative perforation technique. An abrasive cavern is created without excessive temperatures or pressures and without damaging the surface around it. (2) Due to better proppant admittance, it is possible to decrease total number of perforation holes without increasing risk of proppant bridging (one perforation hole per cluster in some cases) to increase diverting pressure resulting in enhancement of injection profile (all clusters admit slurry). Better division of a proppant pulse into smaller structures is achieved by clusters at the wellbore, before slurry enters the fracture. (3) Decreasing number of perforations within a given perforation interval can be beneficial in completions where several fractures are to be initiated during fracturing fluid injection. An example is initiation of several transverse fractures in a horizontal wellbore where one fracture is to be initiated through each perforation cluster. The more perforations are created within a cluster, the less predictable the number of initiated fractures is. If the number of perforations within a cluster is not enough for adequate proppant admittance (e.g. cumulative perforations), then no fracture may be created at a given cluster. If the number of perforations is too large, then more than one fracture can be created within one cluster. Accurate estimation of number of fractures created is necessary for proper design of fracturing job. For example number of created fractures can affect choice of duration for “propping sub-stage” and “carrier sub-stage”. Hence, using of abrasive perforations with small number of holes within a cluster can result in more reliable design of the fracturing treatment. (4) Clusters can be tailored in their separation one from another to ensure optimal channel creation. Clusters sizes, distances between clusters, hole density, variations of hole density inside specific cluster, hole sizes, variations of hole sizes inside of specific cluster can be readily customized to fit changes of geomechanical properties of formation if abrasive perforation is used. One of characteristics of a perforation gun is shot density. Inverse value to shot density is shot spacing or distance between shots. If conventional perforation guns are used than cluster height and distance between clusters should be multiple to shot spacing. Abrasive perforation does not have such limitations. Hole size and perforation channel geometry in cumulative perforation depends on thickness of casing, charge type and rock properties. For cumulative perforation, parameters such as hole size and channel geometry are limited by gun and charge specifications. In case of abrasive perforation, slurry rate and duration of cutting can be chosen during treatment to customize hole size and cavern geometry

[0047] Reinforcing and/or consolidating material may be introduced into the fracture fluid during the propped stage to increase the strength of the proppant clusters formed and prevent their collapse during fracture closure. Typically the reinforcement material is added to the propping sub-stage, but this may not necessarily be always the case. The concentrations of both propping and the reinforcing materials can vary in time throughout the propping stage, and from sub-stage to sub-stage. That is, the concentration of reinforcing material may be different at two subsequent sub-stages. It may also be suitable in some applications of the present method to introduce the reinforcing material in a continuous fashion throughout the propped stage, both during the carrier and propping sub-stages. In other words, introduction of the reinforcing material isn't limited only to the propping sub-stage. Particularly, different implementations may be preferable when the reinforcing material's concentration doesn't vary during the entire propped stage; monotonically increases during the propped stage; or monotonically decreases during the propped stage.

[0048] Curable or partially curable, resin-coated proppant may be used as reinforcing and consolidating material to form proppant clusters. The selection process of the appropriate resin-coated proppant for a particular bottom hole static temperature (BHST), and the particular fracturing fluid are well known to experienced workers. In addition, organic and/or inorganic fibers can reinforce the proppant cluster. These materials can be used in combination with resin-coated proppants or separately. These fibers could be modified to have an adhesive coating alone; or an adhesive coating coated by a layer of non-adhesive substance dissolvable in the fracturing fluid as it passes through the fracture. Fibers made of adhesive material may be used as reinforcing material, coated by a non-adhesive substance that dissolves in the fracturing fluid as it passes through the fracture at the subterranean temperatures. Metallic particles are another preference for reinforcing material and may be produced using aluminum, steel containing special additives that reduce corrosion, and other metals and alloys. The metallic particles may be shaped to resemble a sphere and measure 0.1-4 mm. Preferably, metallic particles are used of an elongated shape with a length longer than 0.5 mm and a diameter of 10 to 200 microns. Additionally, plates of organic or inorganic substances, ceramics, metals or metal-based alloys may be used as reinforcing material. These plates may be disk or rectangle-shaped and of a length and width such that for all materials the ratio between biggest and smallest dimensions is greater than 5 to 1.

[0049] Both the carrier and propping sub-stages may include introduction of an agent into the fracturing fluid to increase the proppant transport capability. In other words, reducing the settling rate of proppant in the fracture fluid. The agent may be a material with elongated particles whose length much exceeds their diameter. This material affects the rheological properties and suppresses convection in the fluid, which results in a decrease of the proppant settling rate in the fracture fluid. Materials that may be used include fibers that are organic, inorganic, glass, ceramic, nylon, carbon and metallic. The proppant transport agents may be capable of decomposing in the water-based fracturing fluid or in the down hole fluid, such as fibers made on the basis of polylactic acid, polyglycolic acid, polyvinyl alcohol, and others. The fibers may be coated by or made of a material that becomes adhesive at subterranean formation temperatures. They may be made of adhesive material coated by a non-adhesive substance that dissolves in the fracturing fluid as its passes through the fracture. The fibers used can be longer than 0.5 mm with a diameter of 10-200 microns, in accordance with the main condition that the ratio between biggest and smallest dimensions is greater than 5 to 1. The weight concentration of the fibrous material in the fracturing fluid is from 0.1 to 10%. The proppant should be chosen with consideration to increasing the proppant clusters strength. In an embodiment, the fibers may be made of polylactic acid, polyglycolic acid or copolymers comprising lactic acid and/or glycolic acid. In another embodiment, the fibers are added at a concentration of 0.5 to 20 kg per m3 of fracturing fluid.

[0050] A proppant cluster should maintain a reasonable residual thickness at the full fracture closure stress. This method provides an increase in fluid inflow through open channels formed between the proppant clusters. In this situation, a permeability value of the proppant, as such, isn't decisive for increasing the well's productivity using this method. Thus, a proppant cluster may be created successfully using sand whose particles are too weak for use in standard hydraulic fracturing in the present formation. Sand costs substantially less than ceramic proppant. Additionally, destruction of sand particles during application of the fracture closure load might improve 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 increasing the proppant compactness degree. Sand pumped into the fracture to create proppant clusters doesn't need good granulometric properties, that is, the narrow diameter distribution of particles. For example, 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 about 100 tons of a proppant more expensive than sand would be necessary to obtain a similar value of hydraulic conductivity in the created fracture implementing the prior (conventional) method of hydraulic fracturing.

[0051] It may be preferable to use sand with an adhesive coating alone, or an adhesive coating coated by a layer of non-adhesive substance dissolvable in the fracturing fluid as it passes through the fracture. A non-adhesive substance guarantees that particles of the adhesive proppant won't form agglomerates prior to entering the fracture, and allows for control of a time moment (a place) in the fracture when (where) a proppant particle gains its adhesive properties. The adhesive coating is cured at the formation temperature, and sand particles conglutinate between each other. Bonding particles within the clusters reduces the proppant cluster erosion rate as formation fluids flow past the cluster, and minimizes proppant cluster destruction by erosion.

[0052] In some cases, the propping stage may be followed by a proppant stage, referred to as the "tail-in stage" in FIG. 3, which involves a continuous introduction of an amount of proppant. If employed, the tail-in stage of the fracturing treatment resembles a conventional fracturing treatment, where a continuous bed of proppant is placed in the fracture relatively near to the wellbore. The tail-in stage may involve introduction of both an agent that increases the fluid's proppant transport capability 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 size of particles. The proppant strength is sufficient to prevent its cracking (crumbling) when subjected to stresses that occur at fracture closure. The role of the proppant at this stage is to prevent fracture closure and, therefore, to provide good fracture conductivity in proximity to the wellbore.

[0053] The disclosed hydraulic fracturing methods introduce one or more agents into the treatment fluid to promote the formation of proppant clusters in the fracture during pumping, while continuously pumping propping agents. When the agent reacts it causes the local formation of a proppant cluster. Typically the agent is selected or designed such that its action or function is delayed until it is placed within the fracture. Delaying chemical and or physical reaction is a process commonly used in hydraulic fracturing as well as many other industrial processes. One process that can be used is the simple temperature activation of the agent as the fracturing fluid heats up as it enters the higher temperature formation deep in the earth. For example, ammonium persulfate homolysis is relatively slow at surface temperatures of 20°C, but relatively rapid at formation temperatures of 100°C. A second process is a slow dissolution of a reactive agent, or of a binder. For example, the dissolution ratio of polyvinyl alcohol in water is dependent on its molecular weight. Encapsulation of a reactive species is a common process employed in hydraulic fracturing. The reactive material or agent is protected for a time from the fracturing fluid by a relatively non-reactive capsule. The encapsulated material subsequently releases the reactive agent, either slowly or quickly by many different methods. The encapsulation can be designed to release its contents by dissolution, mechanical erosion, crushing swelling and rupturing, or simply by slow diffusion.

[0054] The first stage of the fracturing treatment, the "pad stage" (FIG. 3) is pumped as usual. Unlike the previous embodiment where proppants were pumped discontinuously, the proppant (propping agents) are pumped continuously. The concentration of the proppant may increase, stay constant, or decrease during the propped stage. Normally proppant concentrations start low, and are ramped up to higher concentrations near the end of the treatment. The key to this embodiment is that an agent causes the nucleation or formation of proppant clusters is discontinuously or periodically introduced into the fracturing fluid during the propped stage. The agent is designed to work in only a small region or zone within the fracture. Propping materials within this zone are influenced in such a way that they form cluster, bridge out and become immobile. In addition proppants that are pumped subsequent to the cluster formation may accumulate on the cluster and make it grow in size.

[0055] One way to generate clusters of proppant is to locally reduce the ability of the fluid to transport solid phase particles. In this case, the agent could be a high concentration of oxidative "breakers", such as ammonium persulfate, that--when reacting with the fracturing fluid at different places in the fracture--lead to drastic and significant decreases in the fracturing fluid's local viscosity. When fluid viscosity drops below a critical value, the fracturing fluid is unable to transfer the proppant particles and the particles stop, settle, and form proppant clusters. The addition of fibers greatly enhances proppant cluster formation. Encapsulated breakers with a long release time can be used at the beginning of the propped stage, and encapsulated breakers with short release times can be used at the end of the propped stage.

[0056] Reinforcing materials such as fibers can greatly increase the tendency of proppants to locally jam between the fracture walls and form a cluster. Therefore, in this embodiment fibers and or other reinforcing materials as discussed above may be added to the fracturing fluid during the propped stage either continuously into or discontinuously (at the same time as the breaker).

[0057] Requirements for proppant properties used in the first embodiment apply in the second one as well. It's possible to use a proppant without a narrow diameter distribution of particles, that is, a poorly-sorted proppant with a relatively small strength value per particle. For instance, there may be sand particles with coatings similar to that described in the first embodiment of the method. The above-mentioned third stage may also take place.

[0058] Chemical species that competitively bind the crosslinking agents could be another type of agent used to locally reduce fluid viscosity. The local release of chelants, (that react with zirconate crosslinkers), sorbitol or polyvinylalcohol (that react with borate crosslinkers) or other species that deactivate the cross linker can cause the polymer gel to de-crosslink and significantly reduce the fracturing fluid viscosity. Since many crosslinking reactions are pH dependent, the localized release of an acid or base can also reduce fluid viscosity. For example, one may manipulate the fracturing fluid pH through the introduction of an encapsulated acid and/or particles of substances, for instance polylactic acid or polyglycolic acid in which release or generation of the acid occurs at a controlled rate. Changing the fracturing fluid pH reduces the cross linker affinity to form stable bonds with the polymer and the fluid viscosity decreases for certain specific polymer cross linker combinations.

[0059] For said purposes, an encapsulated absorbent or competitive chelating agent of the polymer chain cross-linker may be used also, which allows for controlled release. Cross-linked gel chemicals, such as sodium gluconate or sorbitol, may be used for a borate. For metal crosslinkers, such as titanates or zirconates, chemicals including but not limited to EDTA, NTA, phosphates, polyvinyl acetates may be used. Selection of the specific chemical to attack the cross linker in question are well known to skilled workers. Such absorbents may be, for instance, phosphates or polyvinyl acetates.

[0060] The agent that provides proppant cluster formation by decreasing the fracturing fluid's local viscosity may also represent chemical substances that react with the fracturing fluid to provide a significant amount of local heat extraction, resulting in heating the fracturing fluid and thereby decreasing its local viscosity. Examples of such substances include explosives or encapsulated reactive metals such as sodium, that release the substance in various places in the fracture to provide proppant cluster formation throughout the length of the fracture.

[0061] Proppant clusters and channels between the clusters may be formed by reducing proppant mobility in the fracture. This method includes the pad and propping stages described above, but differs in that the agents that produce cluster formations decrease mobility of proppant particles.

[0062] Specifically, the additives may be fiber bundles that slowly expand and shed individual fibers due to mechanical agitation. The increased excluded volume of the bundle and the localized increase in fiber concentration can initiate jams and create of proppant clusters.

[0063] The additives may be also cut wires made of an alloy possessing "shape memory" properties. For example Copper-Aluminum-Nickel (CuAlNi) shape memory alloys function over the temperature range of many oil and gas-bearing formations. These materials may be bent to shape small balls (springs) and retain their shape at surface temperature. When heated to reservoir temperature, the material with "shape memory" undergoes phase transition accompanied by recovery of its original memorized straight-line shape. Phase transition temperature variation is possible by varying the alloy composition. It may be preferable to introduce a material whose phase transition temperature varies from portion to portion. At the beginning of the propped stage, for instance, it may be reasonable to introduce materials with the highest phase transition temperature, for example, slightly less than the formation temperature; and at the end of the second stage in may be reasonable to introduce a material having the lowest phase transition temperature, for example, slightly more than the surface fluid temperature. Balls of the material with "shape memory" are usually similar in size to proppant particles.

[0064] When the metal balls are subjected to an elevated temperature in the fracture, they recover their original shape, that is, they straighten. As noted above, local increase of their contents effectively promotes formation of proppant clusters in the fracture. The ability to vary the shape recovery temperature gradually by varying the alloy composition allows formation of wires and thereby immovable clusters of proppant distributed uniformly throughout the length of the fracture.

[0065] The use of super-absorbing material to form local jams in the flowing fracturing fluid may also be employed. Super-absorbents such as cross-linked polyacrylamide polyacrylate copolymers can adsorb an amount of water 100 to 300 times their weight in water. A wide variety of super-absorbents are available. Selection of a particular one may be determined by such factors as formation temperature, salt content of the water used to prepare the fracturing fluid, and others.

[0066] A super-absorbent may be used that is protected by a shell or emulsion that is dissolved or dispersed at its passes through the fracture or upon elevation of the fracturing fluid temperature, or a combination of these conditions. By varying shell thickness, it is possible to control the time span between introduction of a portion of the super-absorbent into the fracturing fluid and its release from the shell. When the shell dissolves or is dispersed, an absorbing particle begins its growth by absorbing water from its surroundings. Increasing the mass and size of particles decelerates their movement through the fracture and ultimately results in local jams, capture of proppant particles, and formation of proppant clusters.

[0067] Additives may also be used to decrease proppant mobility in the fracture may be granules, fibers, or plates whose surface becomes "adhesive" at formation temperatures. Additional coating of particles with adhesive surfaces with a layer of a non-adhesive substance dissolvable in the fracturing fluid may be preferable; by varying the substance thickness, the time span can be varied whose lapse gives rise to formation of proppant clusters due to their surface adhesive properties. Another technique for controlling time span employs coatings that gain adhesive properties at different temperatures. It may be preferable to introduce particles with a maximum thickness of protective coating (thus with a maximum temperature of demonstrating "adhesive" properties) at the beginning of the second stage. And be preferable to introduce respectively particles with a minimum thickness of a protective coating (thus with a minimum temperature of demonstrating "adhesive" properties) at the end of the second stage. When such particles enter the fracture, they collide (bump) and conglutinate forming agglomerates of proppant particles. When the agglomerates size become comparable with the characteristic width of the fracture, they wedge between the fracture faces causing local proppant jams and formation of proppant clusters.

[0068] Using reinforcing materials with the fracturing fluid may also be employed, thus increasing the strength of the formed proppant clusters; and introducing agents that increase the fluid's proppant transport ability by decreasing the proppant settling rate through the fracturing fluid. All these requirements for proppant selection, particularly for use of a proppant that is relatively moderately strong, a (possibly) wide distribution of particle sizes, the proppant coated preliminarily with a binder layer curable under formation conditions, remain applicable.

[0069] The formation of proppant clusters and channels between them by sequentially pumping two fluids with contrasting viscosities into the wellbore may be employed. This method involves a pad stage as discussed above, and the propping stage involves continuous introduction of proppant into a given fluid. Similar to the previous embodiments, the propping stage may involve introducing reinforcing materials into the fracturing fluid, these materials increasing the strength of the formed proppant clusters; and introducing an agent that increases the fluid's proppant transport ability by decreasing the proppants settling rate. All requirements for proppant selection, particularly the use of a proppant with a relatively moderate strength, a wide size distribution of particles, and preliminarily coated with a binder layer curable under formation conditions, are still applicable.

[0070] Then the injection of proppant-containing fracturing fluid together with other materials is terminated, and a fluid of very low viscosity is injected into the created fracture. Owing to the difference between their viscosities, injection of the lower-viscosity fluid after injection of the more viscous fluid results in penetrating the lower-viscosity fluid into the more viscous fluid in the form of "intrusions". This forms channels in the proppant that fills the fracture dividing the proppant into discrete clusters.

[0071] As discussed above, a fourth "tail-in" stage may involve a continuous introduction of a proppant with essentially uniform particle size, a reinforcing material, and/or a material with elongated particles that increase the proppant transport ability of the fracturing fluid into the fluid.

[0072] All methods for hydraulic fracturing described above and with different mechanisms to form proppant clusters provide very high hydraulic fracture conductivity. This occurs through the formation of strong proppant clusters well spaced throughout the fracture's length and height. The clusters are stable enough to prevent the fracture from closing; and the inter-cluster channels have a sufficiently large cross-section for formation fluids to flow.

Industrial Applicability

[0073] FIG. 5 is a flow diagram illustrating another disclosed combination of abrasive jet perforating and improved hydraulic fracturing techniques. Part 41 signifies the placement of the disclosed perforating tool 19 into the wellbore 10. The tool 19 is located within the zone of interest in part 42. An initial perforation cluster 14 is created within abrasive jet at part 43. In part 44, the tool 19 is relocated to a new zone of interest. In part 45, a new cluster 14 is perforated. In part 46, fracturing fluid without proppant is pumped down the casing 11. This is referred to above as the pad stage, which is also illustrated FIG. 3. Then, in part 47, proppant-laden slurry is pumped down the casing 11 and parts 46 and 47 are repeated sequentially for a given proppant concentration in part 48 as illustrated in FIG. 3. Then, another proppant-laden slurry is pumped down the casing 11 in part 49 followed by pumping clean fracturing fluid in part 50. Parts 49-50 may then be repeated in part 51 and the pattern set forth in FIG. 3 may be followed.

[0074] Although only a few example embodiments have been described in detail above, though skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from the spirit and scope of this disclosure. Features shown in individual embodiments referred to above may be used together in combinations other than those which have been shown and described specifically. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

Claims

What is claimed is:

1. A method for perforating and fracturing of a subterranean formation with a wellbore lined with casing extending through at least part of the formation, the method comprising:

forming a first cluster of at least one perforation through the casing and into the formation with hydro-abrasive jets;

injecting a proppant-free fracturing fluid into the wellbore through the first cluster;

combining the proppant-free fracturing fluid with a proppant to form a first proppant-laden slurry and alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the first cluster.

2. The method of claim 1 further including:

combining one of the proppant-free fracturing fluid with additional proppant to provide one or more additional proppant-laden slurries of varying concentrations of proppant and for each additional proppant-laden slurry, alternatingly and repeatedly injecting each additional proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the at least one cluster.

3. The method of claim 1 wherein the one or more additional proppant-laden slurries have a different concentration of proppant than the first proppant-laden slurry.

4. The method of claim 1 further including:

forming a second cluster of at least one perforation through the casing and into the formation with hydro-abrasive jets, wherein the second cluster is spaced apart from the first cluster by a nonperforated interval;

injecting the proppant-free fracturing fluid into the wellbore through the first and second clusters simultaneously;

alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through first and second clusters simultaneously.

5. The method of claim 1, wherein the non-perforated interval has a length ranging from about 10 cm to about 5 m.

6. The method of claim 1 wherein the first and second clusters each include from about 1 to about 10 perforations.

7. The method of claim 1 further including:

forming from 1 to about 100 additional clusters;

injecting the proppant-free fracturing fluid into the wellbore through all of the clusters simultaneously;

alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through all of the clusters simultaneously.

8. The method of claim 1, wherein the injecting of each of the first proppant-laden slurry followed by the injecting of the proppant-free fracturing fluid is carried out over a series of substantially uniform pulses.

9. The method of claim 1, wherein the fracturing fluid also includes fibers.

10. The method of claim 3, wherein the fracturing fluid also comprises fibers.

11. The method of claim 6, wherein the fracturing fluid also comprises fibers.

12. The method of claim 1 wherein the forming of the first cluster and the is performed through coiled tubing and the alternatingly and repeatedly injecting of the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through first cluster is performed through an annulus between the coiled tubing and the casing.

13. A method for perforating and fracturing of a subterranean formation with a wellbore lined with casing extending through at least part of the formation, the method comprising:

(a) forming a first cluster through the casing and into the formation with hydro-abrasive jets;

(b) injecting a proppant-free fracturing fluid into the wellbore through the first cluster of perforations;

(c) combining the proppant-free fracturing fluid with a proppant to form a first proppant-laden slurry;

(d) injecting the first proppant-laden slurry through the first cluster;

(e) repeating parts (b) and (d) in an alternating fashion.

14. The method of claim 13 further including:

(a)(1) forming a second cluster through the casing and into the formation with hydro-abrasive jets, with a nonperforated interval being disposed between the first and second clusters;

(b)(1) injecting the proppant-free fracturing fluid into the wellbore and through the first and second clusters simultaneously; and

(d)(1) injecting the first proppant-laden slurry through the first and second clusters simultaneously (e)(1) repeating parts (b)(1) and (d)(1) in an alternating fashion.

15. The method of claim 14 wherein the non-perforated interval has a length ranging from about 10 cm to about 5 m.

16. The method of claim 13 further including:

forming from 1 to about 100 additional clusters;

injecting the proppant-free fracturing fluid into the wellbore through all of the clusters simultaneously;

alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through all of the clusters simultaneously.

17. The method of claim 13 wherein the forming of the first cluster is performed through coiled tubing and the injecting of the first proppant-laden slurry and proppant-free fracturing fluid are carried out through an annulus between the casing and the coiled tubing.

18. The method of claim 13 wherein the forming of the first and second clusters is performed through coiled tubing and the injecting of the first proppant-laden slurry and proppant-free fracturing fluid are carried out through an annulus between the casing and the coiled tubing.

19. A method for perforating and fracturing of a subterranean formation with a wellbore lined with casing extending through at least part of the formation, the method comprising:

forming from 2 to about 100 clusters of perforations with abrasive-jets with nonperforated intervals disposed between each cluster;

injecting a proppant-free fracturing fluid into the wellbore through the clusters;

combining the proppant-free fracturing fluid with a proppant to form a first proppant-laden slurry and alternatingly and repeatedly injecting the first proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the clusters;

combining one of the proppant-free fracturing fluid or the first proppant-laden slurry with additional proppant to provide additional proppant-laden slurries of varying concentrations of proppant and for each additional proppant-laden slurry, alternatingly and repeatedly injecting each additional proppant-laden slurry followed by injecting the proppant-free fracturing fluid into the wellbore and through the first and second clusters.

20. The method of claim 19, wherein the non-perforated interval has a length ranging from about 10 cm to about 5 m, and

wherein clusters each include from about 1 to about 10 perforations.

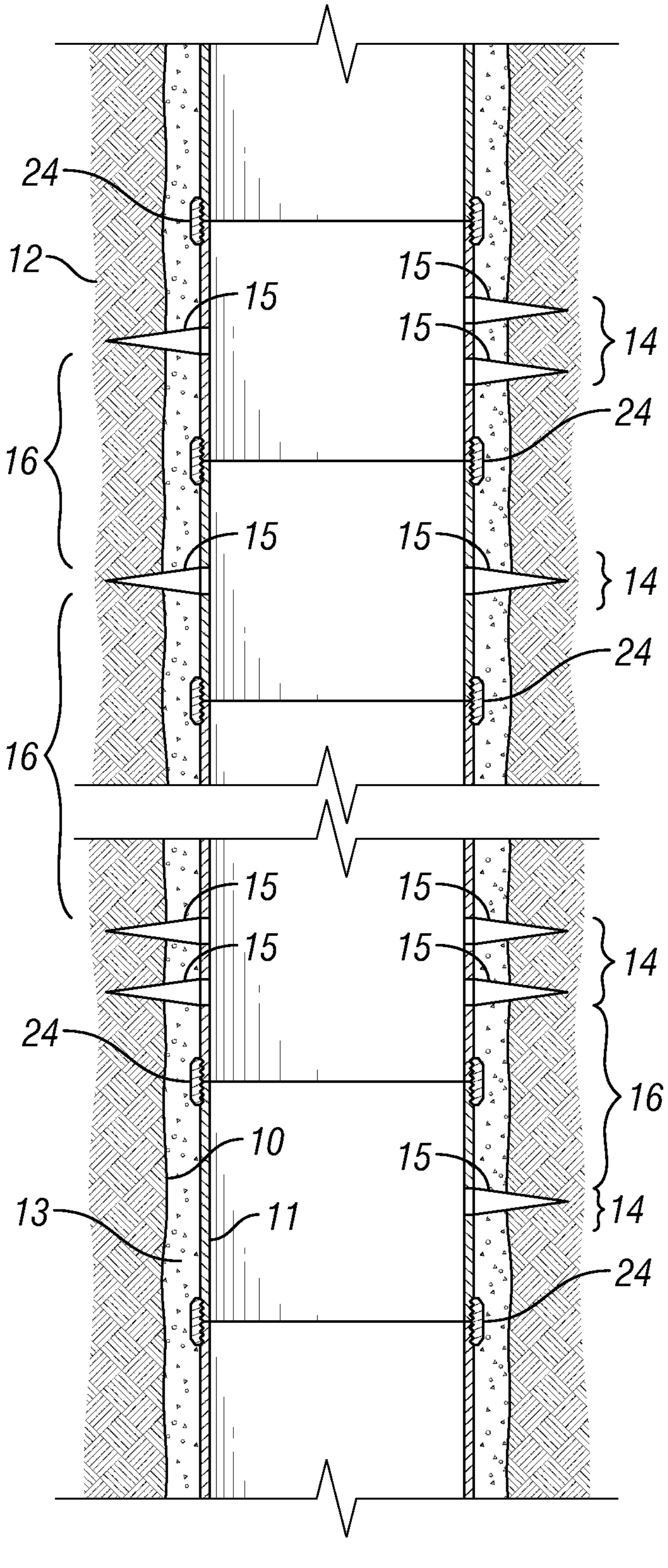
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FIG. 1

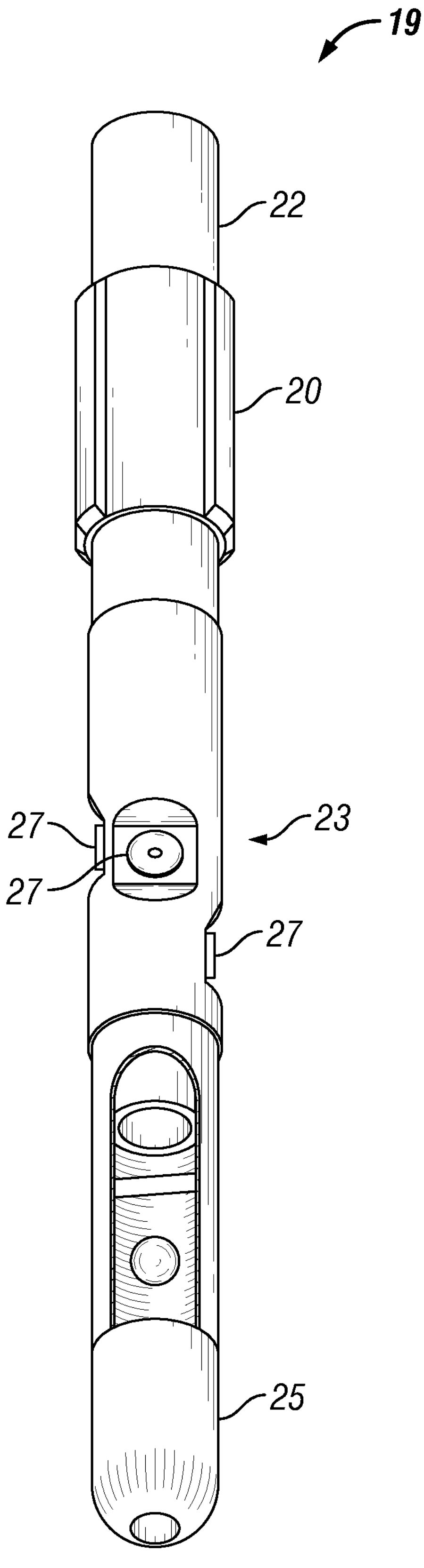
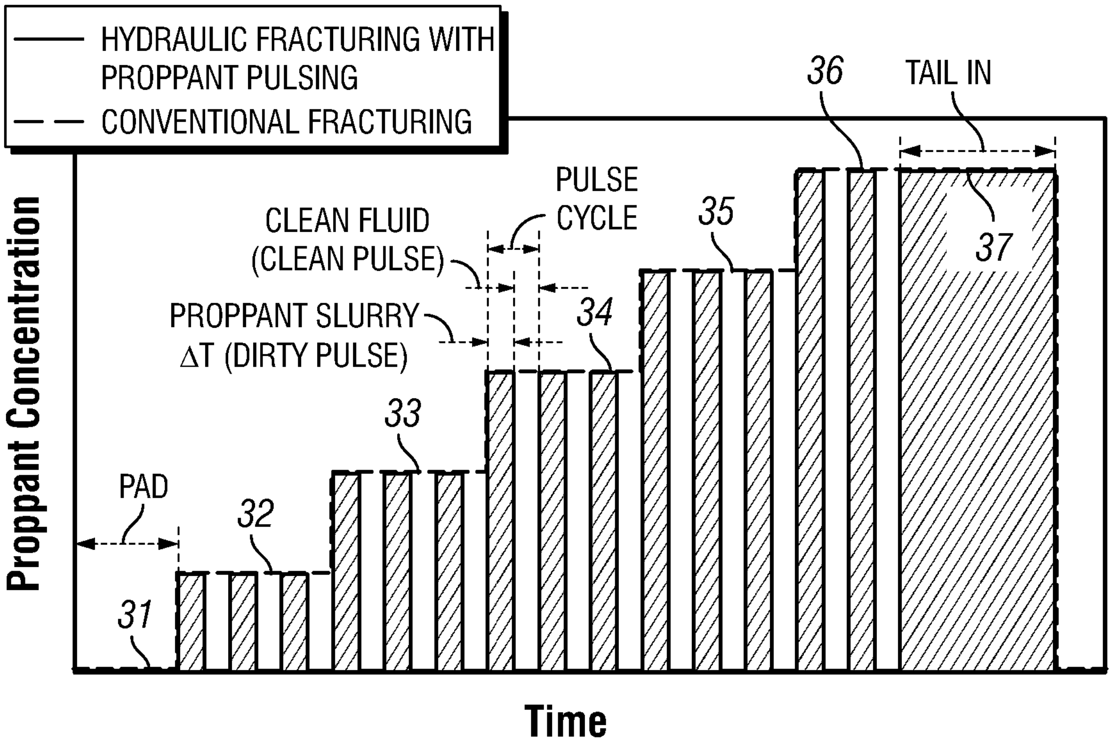


FIG. 2


HYDRAULIC FRACTURING WITH PROPPANT PULSING
CONVENTIONAL FRACTURING
Proppant Concentration
Time
PAD
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34
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36
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TAIL IN
PULSE CYCLE
CLEAN FLUID (CLEAN PULSE)
PROPPANT SLURRY ΔT (DIRTY PULSE)

FIG. 3

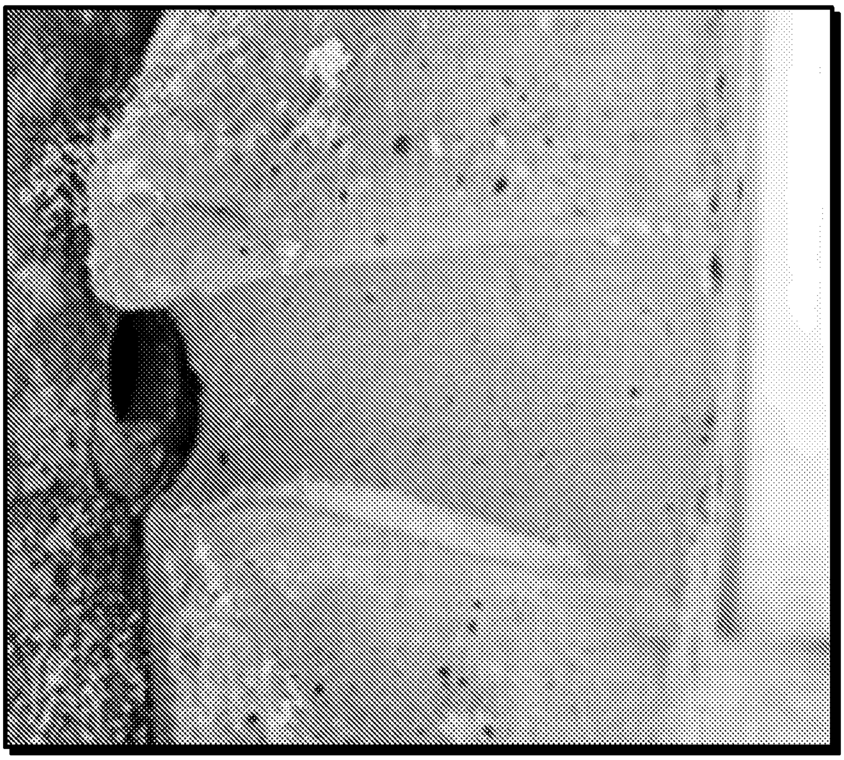
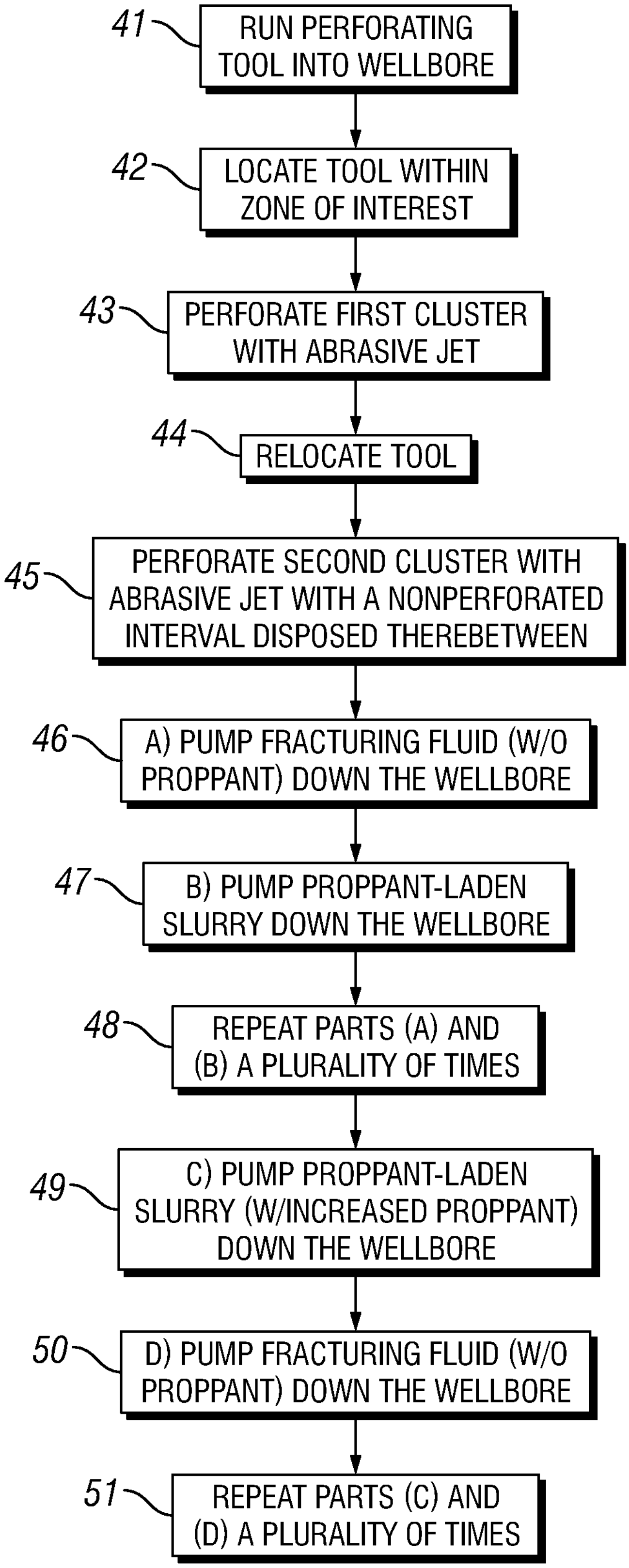


FIG. 4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RUN PERFORATING TOOL INTO WELLBORE
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LOCATE TOOL WITHIN ZONE OF INTEREST
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PERFORATE FIRST CLUSTER WITH ABRASIVE JET
44
RELOCATE TOOL
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PERFORATE SECOND CLUSTER WITH ABRASIVE JET WITH A NONPERFORATED INTERVAL DISPOSED THEREBETWEEN
46
A) PUMP FRACTURING FLUID (W/O PROPPANT) DOWN THE WELLBORE
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B) PUMP PROPPANT-LADEN SLURRY DOWN THE WELLBORE
48
REPEAT PARTS (A) AND (B) A PLURALITY OF TIMES
49
C) PUMP PROPPANT-LADEN SLURRY (W/INCREASED PROPPANT) DOWN THE WELLBORE
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D) PUMP FRACTURING FLUID (W/O PROPPANT) DOWN THE WELLBORE
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REPEAT PARTS (C) AND (D) A PLURALITY OF TIMES

FIG. 5