SYSTEM AND METHOD FOR COMPLEX FRACTURE GENERATION

Applicant: Schlumberger Technology Corporation, (US)

Inventors: Yiyan Chen, Sugar Land, TX (US);
Anthony Loiseau, Sugar Land, TX (US);
Harisharan Ramakrishnan, Oklahoma City, OK (US)

Assignee: Schlumberger Technology Corporation, Sugar Land, TX (US)

Appl. No.: 13/833,190
Filed: Mar. 15, 2013

Publication Classification

Int. Cl.
E21B 43/26 (2006.01)

ABSTRACT

A system includes a first fluid comprising a viscosified fluid composed to generate an initial fracture geometry, a first spacer fluid, a second fluid being a high solids content fluid (HSCF) having a fine particle formulation, a third fluid being an HSCF having a coarse particle formulation, a second spacer fluid, a conventional proppant slurry fluid, and a flush fluid. The system includes a positive displacement pump fluidly coupled to a wellbore, the wellbore intersecting a formation of interest, and a controller that executes functions to perform complex fracture generation in the formation of interest. The controller provides pump commands to deliver a number of stage groupings to the formation of interest, each stage grouping including the first fluid, the first spacer fluid, the second fluid, the third fluid, and the second spacer fluid.
## Example Treatment Schedule

<table>
<thead>
<tr>
<th>Stage</th>
<th>Group</th>
<th>Fluid Name</th>
<th>Fluid Volume</th>
<th>Pump Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>Clean Gel</td>
<td>500 BBL</td>
<td>20-50 BPM</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>Fine HSCF</td>
<td>800 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>Coarse HSCF</td>
<td>500 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>Clean Gel</td>
<td>300 BBL</td>
<td>10-20 BPM</td>
</tr>
<tr>
<td>7</td>
<td>2</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>8</td>
<td>2</td>
<td>Fine HSCF</td>
<td>800 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>9</td>
<td>2</td>
<td>Coarse HSCF</td>
<td>500 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>10</td>
<td>2</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>11</td>
<td>3</td>
<td>Clean Gel</td>
<td>300 BBL</td>
<td>10-20 BPM</td>
</tr>
<tr>
<td>12</td>
<td>3</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>13</td>
<td>3</td>
<td>Fine HSCF</td>
<td>800 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>14</td>
<td>3</td>
<td>Coarse HSCF</td>
<td>500 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>15</td>
<td>3</td>
<td>Spacer</td>
<td>50 BBL</td>
<td>20 BPM</td>
</tr>
<tr>
<td>16</td>
<td>3</td>
<td>8 PPA Slurry</td>
<td>500 BBL</td>
<td>10-20 BPM</td>
</tr>
<tr>
<td>17</td>
<td>3</td>
<td>Flush</td>
<td>300 BBL</td>
<td>10-20 BPM</td>
</tr>
</tbody>
</table>

Assuming a 300 BBL wellbore volume.

---

**FIG. 4**

![Graph showing flow rate vs. friction pressure for different fluids and tubing sizes.]

- **504**: Conventional fracturing slurry in 1/4" tubing.
- **506**: HSCF in 1/4" tubing.
- **502**: HSCF in 3/8" tubing.

**FIG. 5**

![Graph showing a range of flow rates and corresponding friction pressures for different fluid types.](image)
SYSTEM AND METHOD FOR COMPLEX FRACTURE GENERATION

RELATED APPLICATION DATA

[0001] None.

BACKGROUND

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

[0003] The technical field generally, but not exclusively, relates to generating complex fractures in a hydrocarbon bearing formation, and more particularly but not exclusively relates to generating complex fractures in a low permeability formation, and/or in a shale formation. Presently known techniques for fracturing in very low permeability applications suffer from several challenging aspects. Low permeability formations are benefited from fracturing techniques that provide for high fracturing surface area. One such technique includes a slick water fracturing treatment, which includes fracturing with a moderate to low viscosity uncrosslinked fluid. A slick water treatment does not provide for good proppant transport, especially away from the wellbore into the formation. Accordingly, the fracture network is limited in the deliverability of fluid to the wellbore, both initially and after a period of time producing. Additionally, slick water treatments have very low fluid efficiency and high fluid leakoff into the formation. Further, slick water treatments are limited to fracturing according to the formation properties—including formation anisotropy and natural fractures defining the primary fracture direction and mechanism.

SUMMARY

[0004] Embodiments relate to methods for generating complex fractures in formations of interest. Further embodiments include unique systems and methods for treating formations with a fine formulation high solids content fluid (HSCF) and a coarse formulation HSCF. This summary is provided to introduce a selection of concepts that are further described below in the illustrative embodiments. 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. Further embodiments, forms, objects, features, advantages, aspects, and benefits shall become apparent from the following description and drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005] FIG. 1 is a schematic diagram of a system for complex fracture generation.

[0006] FIG. 2 is a schematic diagram of an example post-treatment fracture network.

[0007] FIG. 3 is a depiction of experimental data resulting from an example treatment.

[0008] FIG. 4 is a depiction of an example pump schedule.

[0009] FIG. 5 is a depiction of experimental data for friction pressures with an HSCF and a conventional fracturing fluid.

[0010] FIG. 6 is a schematic diagram of another example post-treatment fracture network.

[0011] FIG. 7 is an illustrative diagram of a fracture at a first fracture treatment operating condition.

[0012] FIG. 8 is an illustrative diagram of a fracture at a second fracture treatment operating condition.

[0013] FIG. 9 is an illustrative diagram of a fracture at a third fracture treatment operating condition.

[0014] FIG. 10 is an illustrative diagram of a fracture at a fourth fracture treatment operating condition.

[0015] FIG. 11 is an illustrative diagram of a fracture at a fifth fracture treatment operating condition.

[0016] FIG. 12 is an illustrative diagram of a fracture at a sixth fracture treatment operating condition.

DETAILED DESCRIPTION OF SOME ILLUSTRATIVE EMBODIMENTS

[0017] For the purposes of promoting an understanding of the principles of the disclosure, reference will now be made to the embodiments illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the claimed subject matter is thereby intended, any alterations and further modifications in the illustrated embodiments, and any further applications of the principles of the application as illustrated therein as would normally occur to one skilled in the art to which the disclosure relates are contemplated herein.

[0018] 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. In addition, the composition used/disclosed herein can also comprise some components other than those cited. In the summary and this detailed description, each numerical value should be read once as modified by the term “about” (unless already expressly so modified), and then read again as not so modified unless otherwise indicated in context. Also, in the summary and this detailed description, it should be understood that a concentration range listed or described as being useful, suitable, or the like, is intended that any and every concentration within the range, including the end points, is to be considered as having been stated. For example, “a range of from 1 to 10” is to be read as indicating each and every possible number along the continuum between about 1 and about 10. Thus, even if specific data points within the range, or even no data points within the range, are explicitly identified or refer to only a few specific, it is to be understood that the Applicant appreciates and understands that any and all data points within the range are to be considered as having been specified, and that the Applicant possessed knowledge of the entire range and all points within the range.

[0019] The term viscousified fluid as used herein should be understood broadly. A viscousified fluid is any fluid having sufficient viscosity to generate fractures in the formation of the designed geometry. A viscousified fluid may be an emulsified fluid, an energized fluid, a polymer-laden fluid, and/or a crosslinked gel fluid. One of skill in the art, having the benefit of the disclosures herein and general knowledge of a formation of interest, such as the fracture gradient, minimum and maximum horizontal stresses, Young’s modulus and Poisson’s ratio, formation mineralogy, etc., can readily determine the fluid viscosity indicated to generate a desired frac-
ture geometry, and a fluid formulation that generates that fluid viscosity. The indicated fluid viscosity is determinable through fracture modeling, experience in the formation or a related formation, through iterative testing, and/or through any other method. The indicated viscosity may vary with the fracturing stage, either with a higher viscosity indicated for earlier stages or with a lower viscosity indicated for earlier stages. The type of viscosified fluid may likewise vary with the fracturing stage, and/or during a particular fracturing stage. The viscosified fluid may further include breakers, fibers, or other fluid additives. Additionally or alternatively, the viscosified fluid may be a fluid suitable for a PAD stage of a fracturing treatment.

[0020] The term spacer fluid as used herein should be understood broadly. A spacer fluid provides operational distance between two fluids—for example distance in geometry, time, or functionality, such that two fluids do not have undesirable interactions. A spacer fluid includes sufficient volume and/or viscosity to provide the desired separation characteristics. In certain embodiments, a spacer fluid includes a polymer and/or a crosslinked polymer. Additional or alternative embodiments of a spacer fluid include an energized fluid or an emulsified fluid. In some embodiments, a spacer fluid does not include any particles, and/or any insoluble particles. In some embodiments, a spacer fluid has the same composition, or a similar composition, to one of the two fluids being separated, and the spacer fluid is an additional amount of fluid included to provide the spacing.

[0021] The term high solids content fluid (HSCF) as used herein should be understood broadly. An HSCF fluid includes at least two particle size modalities, such that a packed volume fraction (PVF) of the fluid is greater than with a single particle size modality. A particle size modality is a single particle size, which may be a distribution of sizes, such as an average size and a statistical distribution, a defined range of sizes, or any other particle size description. The difference in sizes between the particle size modalities may be any amount that provides an increased PVF, including a next smaller size being no greater than 45% of a next larger size, and/or a size ratio between a next smaller size to a next larger size being in the range 3:10, 2.5:15, and/or 2:25. In some embodiments, an HSCF includes three or more particle size modalities. An ideal spherical distribution of particles provides for a PVF of around 0.64, and in some embodiments, an HSCF includes a PVF of greater than 0.65. An HSCF utilizing three or more particle sizes can have a very high PVF, exceeding 0.8, 0.9, or greater. An HSCF having three or four particle sizes, for example in a range of 1:3 to 1:10 between adjacent size modalities, can be provided to exceed a 0.98 PVF.

[0022] The solid volume fraction (SVF) of the HSCF may be a different value than the PVF. An amount of liquid phase just filling the interstitial spaces between particles would provide a SVF equal to the PVF. However, for an HSCF to be a pumpable fluid, a greater amount of liquid is provided. The excess liquid provided can be any amount that provides pumpability and still leaves the HSCF with the desired properties such as friction pressures, settling rates, etc. Table A following includes a number of fluid formulations. The fluid formulations A through E, without limiting to any other formulation, are example HSCF formulations for some embodiments.

[0023] A fluid formulation consistent with fluid B from Table A was developed and allowed to settle in a graduated cylinder. The rheology of the fluid was stable over a 4 days period, and no significant settling of the fluid was observed throughout the 4 days period. The results of the formulation B fluid are consistent with the expected results from various HSCF formulations.

<table>
<thead>
<tr>
<th>TABLE A</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fluid formulations A through F</strong></td>
</tr>
<tr>
<td><strong>Formulation</strong></td>
</tr>
<tr>
<td><strong>Materials</strong></td>
</tr>
<tr>
<td>Sand</td>
</tr>
<tr>
<td>Sand</td>
</tr>
<tr>
<td>Silica flour</td>
</tr>
<tr>
<td>CaCO₃</td>
</tr>
<tr>
<td>Latex</td>
</tr>
<tr>
<td>Oil</td>
</tr>
<tr>
<td>Water</td>
</tr>
<tr>
<td>Emulsifier</td>
</tr>
<tr>
<td>Dispersant</td>
</tr>
<tr>
<td>Viscosifier</td>
</tr>
<tr>
<td>Anti-foam</td>
</tr>
<tr>
<td>Gelling Agent</td>
</tr>
</tbody>
</table>

[0024] The composition of particles in an HSCF may be any particles known in the art. In some embodiments, an example of largest particle type is a proppant, including sand, ceramic, bauxite, resin coated sand, or any other proppant type. Other particle types may be a similar material to the proppant (e.g. silica flour), or example to support fracture width conservation, but may additionally or alternatively include other materials such as calcium carbonate, latex, fibers, a degradable material, an encapsulated material, a dispersing fluid phase (e.g. emulsion droplets within a continuous phase), a material that melts (e.g. paraffin) and/or otherwise disperses under formation conditions (e.g. at time and/or temperature). In some embodiments, the largest particle size is not a proppant material, or is not sized as large as typical proppant materials. A degradable material can be any material that dissolves, reacts, or otherwise changes from a solid particle shape in response to, without limitation, formation fluids, time and temperature, exposure to treatment fluids, exposure to evolving constituents of a treatment fluid (a breaker, a released chemical, and encapsulated material, etc.), and/or exposure to fracture closure pressure.

[0025] The term fine particle formulation as used herein should be understood broadly. A fine particle formulation includes an HSCF fluid having two or more particle size modalities, where a largest particle size modality is lower than a typical proppant sized particle. An example includes a fine particle formulation that includes a largest particle modality smaller than 20/40 proppant sizes, smaller than 40/70 proppant sizes, smaller than 100 mesh sand, smaller than 150 microns, smaller than 100 microns, and/or between 5 and 100 microns. Additionally or alternatively, a fine particle formulation may be sized relative to a corresponding coarse particle formulation present in the same system, and may include a largest particle size in the fine particle formulation that is between 1/1000 and 1/5000 of the largest particle size in the corresponding coarse particle formulation.

[0026] The term coarse particle formulation as used herein should be understood broadly. A coarse particle formulation includes an HSCF fluid having two or more particle size modalities, where a largest particle size modality at least equal to a proppant sized particle. An example includes a
coarse particle formulation that includes a largest particle modality in the 100 mesh sand size range, in the 40/70 propant size range, in the 20/40 propant size range, in the 16/30 propant size range, and/or greater than these sizes. In certain embodiments, a largest particle size modality includes particle sizes greater than 100 microns, and/or between 150 and 1,500 microns.

The term proppant slurry fluid as used herein should be understood broadly. A proppant slurry fluid includes a fluid having a proppant amount as a significant constituent, wherein significance includes an amount sufficient to provide some fracture conductivity to the fractured formation after the closure of the formation with the proppant slurry fluid positioned therein. Example and non-limiting proppant slurry fluids include a fluid having at least 2 pounds proppant added (PPA) per gallon of liquid phase fluid, at least 4 PPA, at least 6 PPA, at least 8 PPA, or any other amount of proppant. The amount of proppant in the proppant slurry fluid depends upon the formation permeability, the closure pressure and the type of proppant, the desired final conductivity of the fracture, the generated fracture width and the proppant concentration that can be positioned therein, and other considerations understood to one of skill in the art having the benefit of the disclosures herein. In certain embodiments, a proppant slurry fluid includes at least 6 PPA, or at least 8 PPA. A conventional proppant slurry fluid is a proppant slurry fluid that includes a mono-modal proppant distribution. A conventional proppant slurry fluid may include other particles, such as fluid leakoff control, flowback control (e.g., fibers), breakers or encapsulated breakers, and the like. However, a conventional proppant slurry fluid does not include additional particles beyond the proppant amount that are included in a size and/or amount that would create a fluid composition that is an HISC fluid. The mono-modal proppant distribution is a single proppant particle size, or a single distribution range of particle sizes, such as 20/40 or 40/70 mesh size particles.

Returning to FIG. 1, an example system 100 includes a formation of interest 102 and an overburden 104. A wellbore 106 intersects the formation of interest 102. In the example system 100, the wellbore 106 is horizontal through the formation of interest 102, although vertical, deviated, and/or highly deviated wellbores are contemplated herein. The wellbore 106 may be a cased, a liner, or a cemented in place casing, or open hole completion. A tubing string 130 is positioned therein, and in the example system 100 the tubing string 130 is utilized to position the treatment in the wellbore 106. Additionally or alternatively, inflatable packers (not shown) or other fluid isolation mechanisms may be utilized, and the tubing string 130 may be a coiled tubing unit (not shown), and/or may not be present and the fracturing treatment may be performed through casing or a casing-tubing annulus.

The system includes a first fluid 112 which is a viscosified fluid that generates an initial fracture geometry, a first spacer fluid 114 that maintains separation between the first fluid 112 and a second fluid 116, where the second fluid 116 is a high solids content fluid (HISC) having a fine particle formulation. The system 100 further includes a third fluid 118 which is an HISC having a coarse particle formulation, and a second spacer 114 fluid that maintains separation between the third fluid and either the first fluid (e.g., of a subsequent stage) and a conventional proppant slurry fluid 112. In the example system 100, the spacers 114 are both provided as the same fluid, although the spacers 114 may be provided as separate fluids. In the example system 100, the first fluid 112 and the conventional proppant slurry fluid 112 are provided as the same liquid phase fluid, with a sand delivery device 126—for example a sand truck or a silo—providing proppant to a blender 124 for mixing into the conventional proppant slurry fluid. The system further includes a flush fluid 120, which may be just water, water with a clay stabilizer (e.g., calcium chloride), water with a polymer added (e.g. to reduce pumping friction), or any other fluid known in the art.

In the example system 100, various fluids are presented from separate fluid vessels 112, 114, 116, 118, 120, although one or more fluids may have the same base liquid phase and be thereby delivered from the same vessel. Additives provided at the blender 124, or from an additives pump (not shown), and/or provided as added particles, may create the separate fluids at a position downstream of the vessels. Additionally or alternatively, any or all of the fluids batch mixed or may be created in whole or part in real time during the treatment from one or more base materials or precursors. The batch mixing or fluid creation in real time may be performed at the well site or at a remote location, and fluids may be delivered to the well site as base materials, precursors, or fully pump ready fluids. Delivery to the well site may be by transport vehicle (e.g. trucks or rail cars), or through fluid lines coupling a fluid preparation facility (not shown) to the wellsite. The fluid creation may also be performed in a remote location that would deliver the fluid to a storage facility or a delivery facility that would be closer from the well site. This would enable a faster reaction time when fluid is required for operations and the fluid may be even delivered directly to the well site for example through pipelines.

The system 100 includes a low pressure line 110 that provides pressurized fluid to various pumps 128 on an inlet side. The pumps 128 are positive displacement pumps of sufficient pressurizing and flow rate capacity to perform the designed fracture treatment. The number of pumps present may be any number, including a single pump, and may be provided with additional pumps to provide any desired excess capacity in the event of a pump failure or an unexpected pressure level during the treatment.

The system 100 includes a high pressure line 108 fluidly coupling the pumps 128 to the wellbore 106. The system 100 includes a controller 122 which is structured to functionally execute operations for providing complex fractures in the formation of interest 102. The controller 122 is depicted as a single device, for example on a centralized control vehicle, however the controller 122 may be a single device or a distributed number of devices. The controller 122 includes connections to any sensors or actuators in the system 100 to allow the controller to perform designed operations, for example but not limited to pressure sensors, pump sensors (pressure, flowrate) and actuators (torque, speed, gear, etc.), and blende sensors and actuators (additive pump rates, proppant addition gate position, fluid density, etc.). The illustrated and described sensors and actuators are non-limiting examples, and a given system may omit any described sensor or actuator, and/or include additional sensors and actuators. One or more operations of the controller 122 may be performed in hardware or software, and may be performed in whole or part by an operator responding to a schedule, a sensor, or a computer in communication with an output device.

The example system 100 includes the controller 122 providing pumping commands to deliver a number of stage
groupings to the formation of interest, each stage grouping including, in order, the first fluid, the first spacer fluid, the second fluid, the third fluid, and the second spacer fluid. The positive displacement pump is responsive to the pumping commands. Referencing FIG. 4, an example treatment schedule is depicted for an example system 100 and controller 122. The treatment schedule 400 includes three stage groupings, each having a first fluid (“Clean gel”), a first spacer fluid, a second fluid (“fine HSFC”), a third fluid (“Coarse HSFC”), and a second spacer fluid stage. The third stage grouping can be seen to additionally include a conventional proppant slurry fluid (“8 ppa slurry”) and a flush stage. The pumping rates and volumes depicted in FIG. 4 are non-limiting examples. The pumping rates and fluid volumes are determinable from ordinary considerations, including without limitation fracture geometry generation, fluid loss management, treatment pressures and pressure limitations of any equipment in the system 100.

[0034] An HSFC exhibits several behaviors that can be utilized to enhance a fracture treatment by one of skill in the art having the benefit of the disclosures herein. An HSFC exhibits a bridging behavior in response to a very small loss of fluid and/or a small change in fracture environment such as width of the fracture. The bridged fluid portion (e.g. a “plug” of particles) is short and has a low permeability. The fluid upstream of the plug is flowable and therefore transmits pressure through to the plug, causing intermittent width generation and/or fluidization of the plug and/or by-pass of the plug, assisting with the bridging/de-bridging nature of the HSFC and the plug. The bridged fluid causes a large pressure increase in the local environment of the bridge. Further, an HSFC can de-bridge rapidly in response to a small amount of fluid re-entering the HSFC, and/or in response to a small change in the fracture environment such as the fracture width. Accordingly, an HSFC progression into a fracture can stop and restart, unlike behavior typically observed with an ordinary fracture fluid. Additionally, the large pressure generated with an HSFC can cause a fracture to exceed the maximum horizontal in-situ stress, opening fractures in alternate directions (typically perpendicular) from the primary fracture. Without being limited to a particular theory, it is expected that after a fracture proceeds against the maximum horizontal in-situ stress, the fracture will likely re-orient against the minimum horizontal in-situ stress.

[0035] Referencing FIG. 5, experimental data 500 was taken from various fracturing fluids in small tubes in a laboratory environment. The curve 502 depicts the frictional pressure drop exhibited by a conventional fracturing fluid (cross-linked gel) in a 1/4" tubing. The curve 506 depicts the frictional pressure drop exhibited by an HSFC in a similar tubing through a range of pumping rates, and the curve 504 depicts the frictional pressure drop exhibited by the HSFC in a 3/8" tubing through a similar range of pumping rates. It can be seen in FIG. 5 that the HSFC exhibits an order of magnitude greater friction in the same sized tubing, and even with significantly greater tubing flow area (3/8" tubing has over double the flow area of 1/4" tubing) the HSFC exhibits about 3× the friction of conventional fracturing fluid.

[0036] While the high frictional pressure of the HSFC has some implications for performing the fracture treatment, the frictional pressure in the tubulars while performing the treatment can be managed. The HSFC is a higher density fluid than conventional fracturing treatments, providing for greater hydrostatic head which otherwise reduces the overall treating pressure required. Additionally, a larger tubular for performing the fracturing treatment can be utilized where required. FIG. 5 illustrates that the HSFC exhibits very high frictional increases in highly restricted flow, but has a more normal increase rate (although at a higher frictional baseline) in a less restricted flow such as the 3/8" tubing. However, the high frictional pressure of the HSFC provides significant localized net pressure assistance. The high frictional pressure in the restricted space of the generated fracture allow the HSFC to produce back pressure within the fracture, increasing the localized net pressure and providing for an enhanced opportunity to exceed the maximum in-situ horizontal stress and create complex fractures.

[0037] Referencing FIG. 3, experimental data 300 was taken from a field test utilizing a staged HSFC pumping schedule. The pumping rate curve 304 shows that the pumping rate for the treatment was held almost constant. The pressure curve 302 clearly depicts both a small time scale and large time scale oscillation in the pressure, consistent with the bridging and debridging nature of the HSFC. Bridging and debridging concept has been disclosed in co-pending U.S. application Ser. No. 13/327,965, incorporated herein by reference in its entirety. Additionally, the formation pressures hold in two regimes that are significantly separated (about 7800 psi early, and 6500 psi late), consistent with a significant shift in the pressure experienced within the formation throughout the treatment. Additionally, several different breakdown pressures are observed in the early formation treatment (approximately 7650, 7200, 7500, and 7800 psi treating pressure). In many formations, net pressure fluctuations of a few hundred psi are sufficient to overcome the difference between the minimum and the maximum in-situ horizontal stresses, inducing fractures in alternate directions and a complex fracture geometry.

[0038] Referencing FIG. 2, a fracture profile 200 post-treatment is depicted schematically. The wellbore 202 in FIG. 2 progresses from the right side of the figure, and the fractures 204 represent the primary fracture in the direction perpendicular to the minimum in-situ horizontal stress. The fractures 206 represent secondary fractures in the direction perpendicular to the maximum in-situ horizontal stress, as induced by large net pressure events from the bridging and high friction pressures of the HSFC. The fractures 208 represent tertiary fractures in the same stress direction as the primary fractures 204, generated when the localized pressure in a secondary fracture 206 drops and the fracture turns back to the direction perpendicular to the minimum in-situ horizontal stress.

[0039] An example system includes each HSFC fluid being a fluid having a number of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65. In certain further embodiments, the coarse particle formulation and/or the fine particle formulation each include a PVF exceeding 0.75, 0.80, 0.85, 0.90, 0.93, and/or 0.96. Despite the largest size of a particle size modality, the PVF of a fluid is determined by the size ratios of the particle size modalities therein, as well as the characteristics of the particles such as particle uniformity, shape, etc. Accordingly, the PVF for each of the fine particle formulation and coarse particle formulation are selectable independent of the largest particle size modality in each fluid.

[0040] An example system includes the fine particle formulation having a largest particle size modality with an average size between 0.5 microns and 100 microns, and/or the coarse
particle formulation having a largest particle size modality with an average size between 150 microns and 1,500 microns. An example controller provides the pump commands such that the second fluid is pumped in a volume ratio to the first fluid of second fluid: first fluid between 1 and 5 inclusive, and/or such that the third fluid is pumped in a volume ratio to the second fluid of third fluid: second fluid between 1 and \(\frac{1}{3}\)rd inclusive. The ratios of the first fluid to the second fluid depend upon the desired fracture geometry to be developed by the PAD and the fluid efficiency of the PAD. The PAD fluid efficiency depends upon the fluid type, leakoff mechanism, formation porosity and permeability, as well as any fluid loss control additives that may be added to the PAD. Accordingly, the ratio of the PAD may be any value, but one of skill in the art can select a PAD amount having the benefit of the disclosures herein and parameters ordinarily available for a formation of interest. The ratios of the second fluid to the third fluid depend upon the developed fracture geometries, how far away from the wellbore large particle sizes will travel and can be positioned. Additionally, the PAD and the fine HSCF can be utilized together—for example decreasing the PAD and increasing the fine HSCF—to develop the desired fracture geometry for the coarse HSCF. The fluid ratio amounts for a particular system vary according to formation rock and reservoir properties, pump rates, fluid/slurry leakoff rates, leakoff control materials or behaviors present in the fluids or system, viscosities of the leakoff fluids, and other parameters that are known to one of skill in the art having the benefit of the disclosures herein. Accordingly, the described fluid ratio amounts are non-limiting examples, and the ratios between each fluid amount may be higher or lower than the described ratios.

[0041] The amount of liquid phase provided in the HSCF is limited on the low end, in that sufficient fluid should be present such that the HSCF is pumpable. Additionally or alternatively, sufficient liquid may be provided to account for an amount of liquid that will leak off into the formation without premature bridging of the HSCF. The amount of liquid phase provided in the HSCF is limited on the high end by the desired properties of the HSCF. An HSCF having a greater amount of liquid will exhibit more rapid settling and eventually cease to act as an HSCF at high liquid phase amounts. Further, a minimum amount of liquid is provided in the HSCF according to the PVF of the HSCF, to ensure the HSCF is pumpable. An example system includes each of the second fluid and the third fluid have a liquid phase weight fraction of the fluid between 5% and 20% of a total fluid weight, inclusive. However, the liquid phase weight fraction of the HSCF fluids may be any value, including from 3% to 30% by weight.

[0042] The following descriptions referencing FIGS. 7 through 12 set forth one possible mechanism for complex fracture generation in a formation, where the mechanism is consistent with known theory and fluid properties. However, the disclosure herein is not limited to a particular theory of operation, and any systems, mechanisms, or operations otherwise consistent with the descriptions herein are also contemplated within the scope of the present disclosure. For example, the disclosure herein contemplates a treatment following the principles described herein, with fluids and fluid stages similar to those set forth herein, that generates complex fractures within a formation by a different mechanism, and/or that does not generate complex fractures at all within a particular formation.

[0043] Referencing FIG. 6, an example post-treatment fracture network 600 is depicted, which is schematically consistent with the type of complex fracture network that is depicted being generated in FIGS. 7 through 12 following. The fracture network 600 includes primary fractures 202, secondary fractures 204, and tertiary fractures 206 positioned in a formation 210. The fracture network 600 is schematically depicted to illustrate fractures progressing in the primary fracturing direction which is generally perpendicular to the minimum in situ stress of the formation 210, fractures in a secondary fracturing direction which is generally perpendicular to the first fracturing direction and which occurs when localized pressures in the fracture exceed the maximum horizontal in situ stress, in situ stress and tertiary fractures which generally occur in the secondary fractures where the pressure falls below the maximum horizontal in situ stress but remains above the minimum in situ stress. The tertiary fractures will generally be oriented in the same direction as the first fracturing direction, subject to heterogeneities and/or variations in the formation 210.

[0044] Referencing FIG. 7, a first fracture treatment operating condition 700 is depicted, where a primary fracture 204 is generated with an initial clean gel 206, which may be free of particulates or may include certain particulates such as breakers or fluid loss additives but will not include materials intended to bridge at the macro fracture level. Some secondary fractures 206 may be initiated at the first operating condition 700, although the size and geometry of the secondary fractures 206 will be limited. Referencing FIG. 8, a second fracture treatment operating condition 800 is depicted, where an HSCF 704 having a fine particle formulation has entered the fracture 204 and is involved in generating the fracture geometry and propagating the fracture. The fracture tip region may still include the clean gel 206. The second fracture treatment operating condition 800 includes the HSCF 706 having a coarse particle formulation entering the fracture at a stage behind the HSCF 704 having the fine particle formulation. The HSCF 704 having the fine particle formulation will bridge in the fractures 204, 206 at a relatively lower width than the HSCF 706 having the coarse particle formulation, and where some bridging occurs, the net pressure can build widening the fracture and de-bridging the HSCF 704 having the fine particle formulation. Further, the HSCF 704 having the fine particle formulation will be flowable and convey pressure therethrough at a very low liquid phase fraction of the HSCF 704. Accordingly, unlike a conventional proppant slurry fluid, significant fracture generation can occur with the HSCF 704 even after particles reach the tip of the fracture 204.

[0045] Referencing FIG. 9, a third fracture treatment operating condition 900 is illustrated schematically. The third fracture treatment operating condition 900 includes one or more of the HSCF fluids 704, 706 bridging in the fracture 204. The bridging and pressure communication of the HSCF fluids 704, 706 can generate enough net pressure to exceed the maximum horizontal stress and generate sufficient fracture width in the secondary fractures 206 that both of the HSCF fluids 704, 706 with fine and coarse particle formulations can pass into one or more secondary fractures 206. Additionally or alternatively, stresses in the fracture may exceed the overburden stress and horizontal (e.g., "pancake") fractures may also be generated (not shown). Another clean fluid stage 902 is included behind the HSCF fluid 706 having the coarse particle formulation. The clean fluid stage 902 can initiate
new fractures, re-initiate previously begun fractures, debridge and/or refluidize the HSCF fluids 704, 706, and significantly propagate fracturing including the secondary fractures 206 and tertiary fractures 208. Referencing FIG. 10, an example fourth fracture treatment operating condition 1000 includes another fluid stage 904, which is an HSCF fluid 904 having a fine particle formulation, entering the fracture. The fluid stage 904 may be the same, a similar, or a distinct fluid from the fluid stage 704.

Referencing FIG. 11, a fifth fracture treatment operating condition 1100 includes another HSCF fluid 1102 stage having a coarse particle formulation. The HSCF fluid 1102 fills and may create some propagation in the fracture network created by the clean fluid stage 902 and the HSCF fluid 904 having the fine particle formulation. Without being limited to a particular theory, FIG. 9 is an illustrative diagram of a fracture at a third fracture treatment operating condition. The number of repeats of the fluid stages including the clean fluid, fine HSCF fluid, and coarse HSCF fluid may be any number, and the sizes and fluid compositions of each of the stages or each of the sets of stages may be the same or variable. Additionally, specific fluid stages may be discrete stages or smoothly transitioned stages, ramped particle amounts, or have other non-discrete variations. Referencing FIG. 12, sixth operating condition 1200 of an example fracturing treatment is depicted. The sixth operating condition 1200 includes a conventional proppant slurry 1202 stage. The conventional proppant slurry (and/or highly permeable proppant slurry, such as a slurry having larger particles) stage 1202 may be utilized, without limitation, to generate a high conductivity portion of the fracture 704 near the wellbore, to provide a high crushing strength proppant in the fracture 704 near the wellbore where the proppant will be exposed to the highest crushing pressure, to control flowback of particulates from the fracture 704 after closure and/or during production, and/or to provide for fluid diversion (e.g. with a portion of the conventional proppant slurry stage 1202 remaining in the wellbore) for a subsequent fracture treatment or well operation. The described functions of the conventional proppant slurry stage 1202 are non-limiting examples.

The schematic flow descriptions which follow provide illustrative embodiments of performing procedures for generating complex fractures in a formation of interest. Operations illustrated are understood to be examples only, and operations may be combined or divided, and added or removed, as well as reordered in whole or part, unless stated explicitly to the contrary herein. Certain operations illustrated may be implemented by a computer executing a computer program product on a computer readable medium, where the computer program product comprises instructions causing the computer to execute one or more of the operations, or to issue commands to other devices to execute one or more of the operations.

An example procedure includes an operation to treat a formation with, in order, a first fluid which is a viscousified fluid, a second fluid which is an HSCF having a fine particle formulation, a third fluid which is an HSCF having a coarse particle formulation, and a conventional proppant slurry fluid. Each of the HSCF fluids is a fluid having a number of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65. The example procedure further includes an operation to repeat the treating the formation with the first fluid, second fluid, and third fluids before the treating the formation with the conventional proppant slurry fluid, and/or further includes an operation to repeat the treating the formation with the first fluid, second fluid, and third fluids a third time before the treating the formation with the conventional proppant slurry fluid. The example procedure further includes an operation to provide the second fluid in a volume ratio to the first fluid of second fluid: first fluid of between 1 and 5 inclusive, and/or an operation to provide the third fluid in a volume ratio to the second fluid of third fluid: second fluid of between 1 and 0.25 inclusive. An example procedure further includes an operation to treat the formation with a spacer fluid after the first fluid and before the second fluid, and/or an operation to treat the formation with a spacer fluid after the third fluid and before the conventional proppant slurry fluid.

A further example procedure includes an operation to treat a formation with a number of stage groupings, each stage grouping including, in order: a first fluid which is a viscousified fluid that generates an initial fracture geometry, a first spacer fluid that maintains separation between the first fluid and a second fluid, a second fluid which is a high solids content fluid (HSCF) having a fine particle formulation, a third fluid which is an HSCF having a coarse particle formulation, and a second spacer fluid that maintains separation between the third fluid and the first fluid for a subsequent stage grouping and a conventional proppant slurry fluid. An example procedure includes the last grouping further including the conventional proppant slurry fluid after the second spacer fluid, and a flush after the conventional proppant slurry fluid.

An example procedure further includes providing the conventional proppant slurry fluid having a proppant concentration of at least 6 pounds proppant added (PPA). In certain embodiments, the coarse particle formulation includes a largest particle size modality having an average size between 150 microns and 1,500 microns, and/or the fine particle formulation includes a largest particle size modality having an average size ratio value to the largest particle size modality of the coarse particle formulation, where the average size ratio value includes a value between 1.3 and 1:100 for fine-coarse. In certain embodiments, the coarse particle formulation and the fine particle formulation each include a packed volume fraction (PVF) which exceeds 0.65, 0.75, 0.80, 0.85, 0.90, and/or 0.95. The example procedure further includes an operation to generate a net pressure exceeding a maximum horizontal stress in the formation during the treating. In certain embodiments, the coarse particle formulation includes a number of particle size modalities, and the procedure further includes an operation to degrade at least one of the particle size modalities after the treating.

As is apparent from the figures and text presented above, a variety of embodiments according to the present disclosure are contemplated.

An example set of embodiments is a method including treating a formation with, in order, a first fluid comprising a viscousified fluid, a second fluid which is a high solids content fluid (HSCF) having a fine particle formulation, a third fluid which is an HSCF having a coarse particle formulation, and a conventional proppant slurry fluid. Each of the HSCF fluids is a fluid having a number of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65.

Certain further embodiments of the example method further include one or more of the following features. An example method includes repeating the treating the formation with the first fluid, second fluid, and third fluids before
the treating the formation with the conventional proppant slurry fluid, and/or further includes repeating the treating the formation with the first fluid, second fluid, and third fluids a third time before the treating the formation with the conventional proppant slurry fluid. An example method includes providing the second fluid in a volume ratio to the first fluid of second fluid: first fluid of between 1 and 5 inclusive, and/or providing the third fluid in a volume ratio to the second fluid of third fluid:second fluid of between 1 and $\frac{1}{2}$ inclusive. An example method includes treating the formation with a spacer fluid after the first fluid and before the second fluid, and/or treating the formation with a spacer fluid after the third fluid and before the conventional proppant slurry fluid. All these treatments may be repeated any number of times.

[0054] A further example set of embodiments is a method including treating a formation with a number of stage groupings, each stage grouping including, in order: a first fluid which is a viscousified fluid that generates an initial fracture geometry, a first spacer fluid that maintains separation between the first fluid and a second fluid, a second fluid which is a high solids content fluid (HSCF) having a fine particle formulation, a third fluid which is an HSCF having a coarse particle formulation, and a second spacer fluid that maintains separation between the third fluid and the first fluid for a subsequent stage grouping and a conventional proppant slurry fluid. The last grouping further includes the conventional proppant slurry fluid after the second spacer fluid, and a flush after the conventional proppant slurry fluid.

[0055] Certain further embodiments of the example method further include one or more of the following features. A method includes the conventional proppant slurry fluid having a proppant concentration of at least 6 pounds proppant added (PPA). In certain embodiments, the coarse particle formulation includes a largest particle size modality having an average size between 150 microns and 1,500 microns, and/or the fine particle formulation includes a largest particle size modality having an average size ratio value to the largest particle size modality of the coarse particle formulation, where the average size ratio value includes a value between 1:3 and 1:100 for fine/coarse. In certain embodiments, the coarse particle formulation and the fine particle formulation each include a packed volume fraction (PVF) which exceeds 0.65, 0.75, 0.80, 0.85, 0.90, 0.93, and/or 0.96.

[0056] An example method further includes generating a net pressure exceeding a maximum horizontal stress in the formation during the treating. In certain embodiments, the coarse particle formulation includes a number of particle size modalities, and the method further includes degrading at least one of the particle size modalities after the treating.

[0057] Another example set of embodiments is a system including a first fluid which is a viscousified fluid that generates an initial fracture geometry, a first spacer fluid that maintains separation between the first fluid and a second fluid, where the second fluid is a high solids content fluid (HSCF) having a fine particle formulation. The system further includes a third fluid which is an HSCF having a coarse particle formulation, and a second spacer fluid that maintains separation between the third fluid and either the first fluid (e.g. of a subsequent stage) and a conventional proppant slurry fluid. The system further includes a flush fluid, and a positive displacement pump fluidly coupled to a wellbore. The wellbore intersects a formation of interest, and the system includes a controller that functionally executes operations to provide complex fractures in the formation of interest. The controller provides pumping commands to deliver a number of stage groupings to the formation of interest, each stage grouping including, in order, the first fluid, the first spacer fluid, the second fluid, the third fluid, and the second spacer fluid. The positive displacement pump is responsive to the pumping commands.

[0058] Certain further embodiments of the example system further include one or more of the following features. An example controller provides the pumping commands such that a last one of the stage groupings includes a conventional proppant slurry fluid after the second spacer fluid, and a flush after the conventional proppant slurry fluid. An example system includes each HSCF fluid being a fluid having a number of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65. In certain further embodiments, the coarse particle formulation and/or the fine particle formulation each include a PVF exceeding 0.75, 0.80, 0.85, 0.90, 0.93, and/or 0.96. An example system includes the fine particle formulation having a largest particle size modality with an average size between 0.5 microns and 100 microns, and/or the coarse particle formulation having a largest particle size modality with an average size between 150 microns and 1,500 microns. An example controller provides the pump commands such that the second fluid is pumped in a volume ratio to the first fluid of second fluid: first fluid between 1 and 5 inclusive, and/or such that the third fluid is pumped in a volume ratio to the second fluid of third fluid:second fluid between 1 and $\frac{1}{2}$ inclusive. An example system includes each of the second fluid and the third fluid have a liquid phase weight fraction of the fluid between 5% and 20% of a total fluid weight, inclusive.

[0059] While the disclosure has provided specific and detailed descriptions to various embodiments, the same is to be considered as illustrative and not restrictive in character. Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures. Thus, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures.

[0060] Moreover, in reading the claims, it is intended that when words such as “a,” “an,” “at least one,” or “at least one portion” are used there is no intention to limit the claim to only one item unless specifically stated to the contrary in the claim. When the language “at least a portion” and/or “a portion” is used the item can include a portion and/or the entire item unless specifically stated to the contrary. It is the express intention of the applicant not to invoke 35 U.S.C. §112, paragraph 6 for any limitations of any of the claims herein, except for those in which the claim expressly uses the words ‘means for’ together with an associated function.

We claim:

1. A method, comprising:
treating a formation with, in order, a first fluid comprising a viscousified fluid, a second fluid comprising a high
solids content fluid (HSCF) comprising a fine particle formulation, a third fluid comprising an HSCF comprising a coarse particle formulation, and a conventional proppant slurry fluid; and wherein each HSCF fluid comprises a fluid having a plurality of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65.

2. The method of claim 1, further comprising repeating the treating the formation with the first fluid, second fluid, and third fluids before the treating the formation with the conventional proppant slurry fluid.

3. The method of claim 2, further comprising repeating the treating the formation with the first fluid, second fluid, and third fluids a third time before the treating the formation with the conventional proppant slurry fluid.

4. The method of claim 1, further comprising providing the second fluid in a volume ratio to the first fluid of second fluid: first fluid of between 1 and 5 inclusive.

5. The method of claim 4, further comprising providing the third fluid in a volume ratio to the second fluid of third fluid: second fluid of between 1 and \( \frac{1}{3} \) inclusive.

6. The method of claim 1, further comprising treating the formation with a spacer fluid after the first fluid and before the second fluid.

7. The method of claim 1, further comprising treating the formation with a spacer fluid after the third fluid and before the conventional proppant slurry fluid.

8. A method, comprising:
   treating a formation with a plurality of stage groupings, each stage grouping comprising, in order:
   a first fluid comprising a viscosified fluid structured to generate an initial fracture geometry;
   a first spacer fluid structured to maintain separation between the first fluid and a second fluid;
   a second fluid comprising a high solids content fluid (HSCF) comprising a fine particle formulation;
   a third fluid comprising an HSCF comprising a coarse particle formulation; and
   a second spacer fluid structured to maintain separation between the third fluid and the first fluid for a subsequent stage grouping and a conventional proppant slurry fluid; and wherein a last stage grouping further comprises the conventional proppant slurry fluid after the second spacer fluid, and a flush after the conventional proppant slurry fluid.

9. The method of claim 8, wherein the conventional proppant slurry fluid comprises a proppant concentration of at least 6 pounds proppant added (PPA).

10. The method of claim 8, wherein the coarse particle formulation comprises a largest particle size modality having an average size between 150 microns and 1,500 microns.

11. The method of claim 10, wherein the fine particle formulation comprises a largest particle size modality having an average size ratio value to the largest particle size modality of the coarse particle formulation, the average size ratio value comprising between 1:3 and 1:100 for fine:coarse.

12. The method of claim 8, wherein the coarse particle formulation and the fine particle formulation each comprise a packed volume fraction (PVF) exceeding a value selected from the values consisting of: 0.65, 0.75, 0.80, 0.85, 0.90, 0.93, and 0.96.

13. The method of claim 8, further comprising generating a net pressure exceeding a maximum horizontal stress in the formation during the treating.

14. The method of claim 8, wherein the coarse particle formulation comprises a plurality of particle size modalities, the method further comprising degrading at least one of the particle size modalities after the treating.

15. A system, comprising:
   a first fluid comprising a viscosified fluid structured to generate an initial fracture geometry;
   a first spacer fluid structured to maintain separation between the first fluid and a second fluid;
   a second fluid comprising a high solids content fluid (HSCF) comprising a fine particle formulation;
   a third fluid comprising an HSCF comprising a coarse particle formulation;
   a second spacer fluid structured to maintain separation between the third fluid and one of the first fluid and a conventional proppant slurry fluid;
   a flush fluid; and
   a positive displacement pump fluidly coupled to a wellbore, the wellbore intersecting a formation of interest;
   a controller structured to provide pumping commands to deliver a plurality of stage groupings to the formation of interest, each stage grouping comprising, in order, the first fluid, the first spacer fluid, the second fluid, the third fluid, and the second spacer fluid; and wherein the pump is responsive to the pumping commands.

16. The system of claim 15, wherein the controller is further structured to provide the pumping commands such that a last one of the stage groupings comprises a conventional proppant slurry fluid after the second spacer fluid, and a flush after the conventional proppant slurry fluid.

17. The system of claim 15, wherein each HSCF fluid comprises a fluid having a plurality of particle size modalities, and a packed volume fraction (PVF) of greater than 0.65.

18. The system of claim 17, wherein the coarse particle formulation and the fine particle formulation each comprise a PVF exceeding a value selected from the values consisting of: 0.75, 0.80, 0.85, 0.90, 0.93, and 0.96.

19. The system of claim 17, wherein the fine particle formulation comprises a largest particle size modality having an average size between 0.5 microns and 100 microns.

20. The method of claim 17, wherein the coarse particle formulation comprises a largest particle size modality having an average size between 150 microns and 1,500 microns.

21. The system of claim 15, wherein the controller is further structured to provide the pump commands such that the second fluid is pumped in a volume ratio to the first fluid of second fluid: first fluid between 1 and 5 inclusive.

22. The system of claim 21, wherein the controller is further structured to provide the pump commands such that the third fluid is pumped in a volume ratio to the second fluid of third fluid: second fluid between 1 and \( \frac{1}{3} \) inclusive.

23. The system of claim 15, wherein each of the second fluid and the third fluid have a liquid phase weight fraction of the fluid between 5% and 20% of a total fluid weight, inclusive.

24. A method, comprising:
   treating a formation with a plurality of stage groupings, each stage grouping comprising, in order:
   a first fluid comprising a viscosified fluid structured to generate an initial fracture geometry,
a second fluid comprising a high solids content fluid (HSCF) comprising a fine particle formulation;
a third fluid comprising an HSCF comprising a coarse particle formulation; and
wherein a last stage grouping further comprises a conventional proppant slurry.

25. A system, comprising:
a first fluid comprising a viscosified fluid structured to generate an initial fracture geometry;
a second fluid comprising a high solids content fluid (HSCF) comprising a fine particle formulation;
a third fluid comprising an HSCF comprising a coarse particle formulation;
a second spacer fluid structured to maintain separation between the third fluid and one of the first fluid and a conventional proppant slurry fluid;
a flush fluid; and
a positive displacement pump fluidly coupled to a wellbore, the wellbore intersecting a formation of interest;
a controller structured to provide pumping commands to deliver a plurality of stage groupings to the formation of interest, each stage grouping comprising, in order, the first fluid, the second fluid, the third fluid; and
wherein the pump is responsive to the pumping commands.