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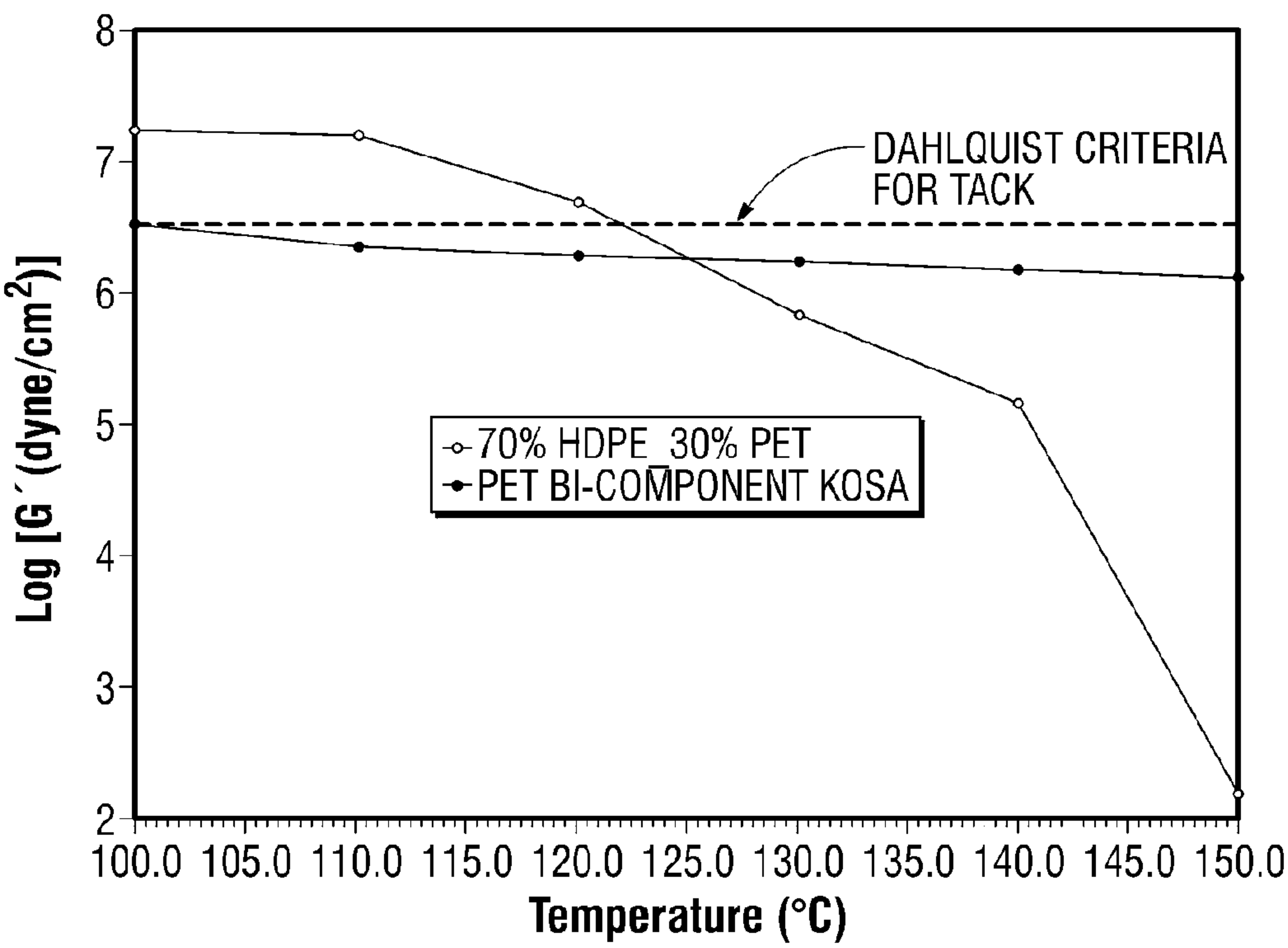

(57) Abrégé/Abstract:
Methods of contacting a subterranean formation are described which provide improved control or reduction of particulate migration, transport or flowback in wellbores and reservoirs, and which may do so without sacrificing substantial hydraulic conductivity. One method comprises injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least a portion of the first component or second component being provided as at least one multicomponent article having an aspect ratio greater than 1:1.1; forming a network comprising the first component; and binding the network with the second component.

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(54) Title: METHODS OF CONTACTING AND/OR TREATING A SUBTERRANEAN FORMATION

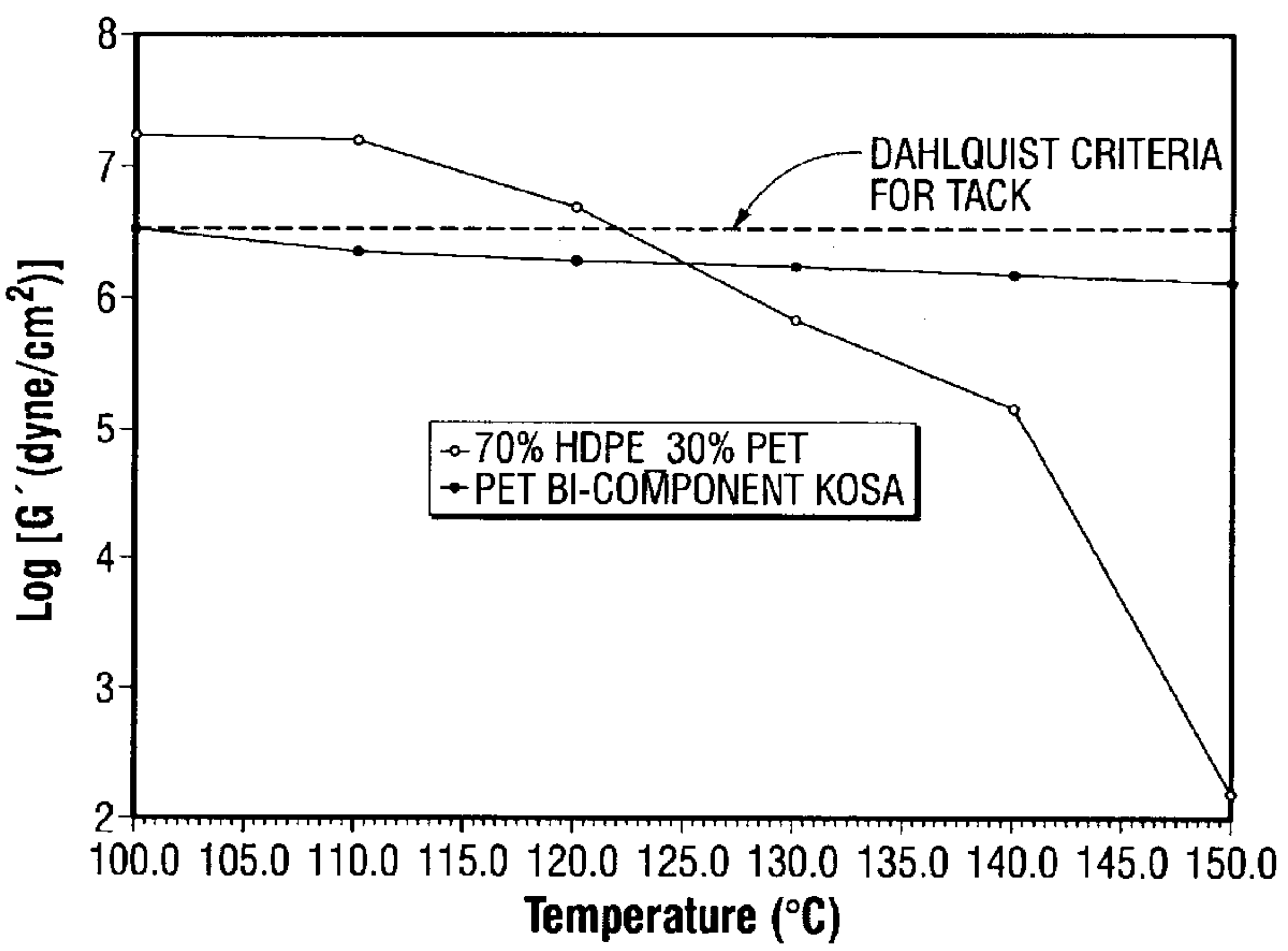

FIG. 3

(57) Abstract: Methods of contacting a subterranean formation are described which provide improved control or reduction of particulate migration, transport or flowback in wellbores and reservoirs, and which may do so without sacrificing substantial hydraulic conductivity. One method comprises injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least a portion of the first component or second component being provided as at least one multicomponent article having an aspect ratio greater than 1:1.1; forming a network comprising the first component; and binding the network with the second component.

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Methods of Contacting and/or Treating a Subterranean Formation

[0001] **Background**

[0002] This disclosure relates to the recovery of hydrocarbons from subterranean formations. More particularly, the disclosure relates to methods of using fluid compositions to recover hydrocarbons from subterranean formations.

[0003] Undesired transport or flowback of formation or particulate solids during the production of oil or other fluids from a subterranean formation can be a problem in production operations. For example, transported particulate solids from the formation may restrict flow in a wellbore, limiting or completely stopping production of the fluid. Additionally, the solids being transported may substantially increase fluid friction, thereby increasing pumping requirements, and may cause significant wear in production equipment, particularly in the pumps and seals used in the production process. Finally, undesired particulate solids in a recovered product fluid must be separated to render the product fluid commercially useful.

[0004] In some instances, undesired particulate flowback may be the result, not of formation characteristics, such as a lack of consolidation, but of the flowback of proppant utilized in a fracturing operation. When flowback of proppant occurs, the proppant particles become undesirable contaminants in the manner of any undesired formation particulate solids, since they can cause the same operational difficulties.

[0005] Numerous procedures and compositions have been developed in order to overcome the problem of undesirable particulate transport or flowback. For example, in unconsolidated formations, it is common practice to provide a filtration bed of gravel in the area near the bottom of the wellbore to inhibit transport of unconsolidated formation particulates in the wellbore fluids. Typically, such so-called "gravel packing" operations involve the pumping and placement of a quantity of gravel and/or sand having a mesh size between 10 and 60 mesh (U.S. Standard Sieve Series) into the unconsolidated formation adjacent the bottom of the wellbore. In other instances, gravel or proppant particles may be bound together to form a porous matrix, thus facilitating the filtering out and retention of the bulk of the unconsolidated particles transported to the wellbore area. Occasionally, the gravel particles or proppant particles are resin-coated, the resin being pre-cured or cured in situ by a flush of a chemical binding agent. In other cases, binding agents have been applied to gravel particles to form the porous matrix.

[0006] As will be evident, gravel packing can be an expensive and elaborate procedure, and, unfortunately, does not completely eliminate the production of formation particulates. Additionally, some wellbores are not stable, and thus cannot be gravel packed.

[0007] US Patent Numbers 5,330,095; 5,439,055; 5,501,275; and 5,782,300 provide a different approach for reducing particulate flowback. These patents disclose the use of fibrous and other materials, suitably dispersed in a porous pack, for inhibiting particulate flowback. Materials employed include, but are not limited to, fibers of glass, ceramics, carbon, and polymers, and platelets of glass, metal, and polymers. So far as is currently known, however, "multicomponent" fibers have not been used or suggested for use in any downhole well servicing applications. By "multicomponent" fibers we mean fibers that have two or more distinct phases, regions, or chemical compositions; in other words, two or more regions that are distinct either physically, chemically, or both physically and chemically. Because multicomponent fibers have at least two distinct regions they may be engineered to have multiple beneficial properties, and these properties can be tuned to a greater extent than that of a single component material fiber. As one of many examples, the material in the inner core of a core-sheath fiber can be selected for strength, flexibility and robustness, while the outer layer can be selected for its adhesive qualities.

[0008] Notwithstanding the efficacy of the approaches described in previous patents using fibers for particulate solids transport control, there is room for even greater efficiency in controlling or inhibiting particulate solids transport at the beginning of, during or after well treatments, and in other downhole treatment operations. This disclosure, therefore, is directed to methods to provide improved control or reduction of particulate migration, transport or flowback at the beginning of, during, and after a variety of well servicing operations, under a variety of conditions. The present disclosure also addresses these problems in the context of maintaining substantially the same hydraulic conductivity in the formation.

[0009] **Summary**

[0010] In accordance with the present disclosure, methods of contacting a subterranean formation are described which may provide improved control or reduction of particulate migration, transport or flowback in wellbores and reservoirs, and which may do so without sacrificing substantial hydraulic conductivity.

[0011] One aspect of the disclosure are methods of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least a portion of the first component or at least a portion of the second component being provided as at least one multicomponent article having an aspect ratio greater than 1:1.1 (in some embodiments, greater than 1:5, 1:10, 1:50, 1:100, or even 1:150);

forming a network comprising the first component; and

binding the network with the second component.

[0012] Methods in accordance with this aspect of the disclosure include those wherein the at least one multicomponent article has an exposed outer surface at least a portion of which comprises at least a portion of the first component. In certain embodiments, the forming and binding may be performed subsequent to injecting. In certain others embodiments, the methods further comprise modifying at least one of the first or second components by at least one controlled modification process. At least some of the multicomponent articles may have a shape selected from hollow, prismatic, cylindrical, lobed, rectangular, polygonal, dog-boned, faceted, combinations of these, and mixtures thereof. Other methods within this aspect include those wherein at least some of the multicomponent articles are different from other multicomponent articles in the same fluid composition injected into the wellbore, wherein the difference may be in composition, shape, texture, aspect ratio, physical properties, and the like, and any combination of these. In certain embodiments, at least some of the multicomponent articles may have a shape different from the other multicomponent articles. In other embodiments, at least some multicomponent articles may comprise the first component and the second component, and other multicomponent articles may comprise a third component and a fourth component. In certain embodiments, one of the first and second components may be the same as one of the third and fourth components. In yet other embodiments, at least one of the first and second components may be an activated adhesive, and in these embodiments the activated adhesive may selected from pressure-sensitive adhesives, temperature-sensitive adhesives, moisture-sensitive adhesives, and curing agent-sensitive adhesives. In certain methods, one of the first component and second component may be selected to be tacky at a specific downhole temperature and have a modulus of less than about 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60ºC. In certain methods the fluid composition may further comprise proppant.

[0013] Another aspect of the disclosure are methods of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a multicomponent article dispersed in a carrier fluid wherein the multicomponent article has an aspect ratio greater than 1:5 (in some embodiments, greater than 1:10, 1:50, 1:100, or even 1:150) and comprises a:

a core having a softening point of at least 130℃; and

a sheath having a softening point up to 130℃.

[0014] Another aspect of the disclosure are methods of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a multicomponent article dispersed in a carrier fluid wherein the multicomponent article has an aspect ratio greater than 1:5 (in some embodiments, greater than 1:10, 1:50, 1:100, or even 1:150) and comprises a:

a core having a softening point of at least 130°C;

an outer sheath that is at least one of (a) inert relative to the carrier fluid or (b) degradable under the subterranean formation conditions; and

an intermediate sheath positioned between the core and the outer sheath, the intermediate sheath having a softening point up to 130°C.

[0015] Another aspect of the disclosure are methods of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein the first component and the second component are provided as separate articles to the carrier fluid separately prior to injection;

forming a network comprising at least one first component article in direct contact with another first component article; and

binding the network with the second component.

[0016] Methods in accordance with an aspect of the disclosure include methods further comprising modifying at least one of the first or second components by at least one controlled modification process. The modification process may be selected from chemical, physical, mechanical, radiation, and combinations thereof. The modification process may be selected from temperature activation, chemical activation, pressure activation, mechanical activation, curing, exposure to electromagnetic fields, exposure to electromagnetic radiation, exposure to ionizing radiation, physical entanglement, degradation, concurrent application of at least two of these processes, consecutive application of at least two of these processes, and combinations thereof. Certain methods further comprise modifying at least one of the first or second components upon injection into the well-bore. In some embodiments, the method comprises modifying at least one of the first or the second components over a period of time after injection into the well-bore. In other embodiments, the method further comprises modifying at least one of the first or second components in stages after injection into the well-bore. In certain embodiments, at least one of the first component or second component may be an activated adhesive as described in relation to methods within the previous aspect of the disclosure. In certain methods, at least one of the first component or second components may comprise a degradable polymer. In certain other embodiments, the first component may be selected from thermoplastic and thermoset materials. Thermoplastic materials useful in the disclosure as first components may be selected from polyester, polyamide, polyolefin, copolymers thereof, and physical mixtures thereof. In certain embodiments, the second component may be selected from polyolefins, polyolefin copolymers, polyurethanes, epoxies, polyesters, polyamides, polyacrylates, and mixtures there of. In yet other embodiments, the fluid composition may comprise an acid. At least one of the first or second components may be selected from polylactic acid and polyglycolic acid. In certain embodiments, the fluid composition may further comprise proppant.

[0017] Another aspect of the disclosure are methods of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid;

forming a network comprising the first component; and

binding the network with the second component,

wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60ºC.

[0018] Methods in accordance with this aspect of the disclosure include methods wherein the first component and second component may be blended together. As used herein “blended together” includes, but is not limited to, at least the following embodiments: intermixed; intertwined; adjacent each other; self-adhered to each other; adhered to each other by a third component; and mixtures thereof. In certain embodiments, at least a portion of the first component and a portion of the second component may be provided in at least one multicomponent article. In some embodiments, at least one multicomponent article may comprise the first element, the article having an exterior surface, and wherein the first element is exposed for at least a portion of the exterior surface. In certain embodiments, the fluid composition may further comprise proppant.

[0019] Another aspect of the disclosure are methods of treating a subterranean formation comprising:

pumping under pressure into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid;

forming a network comprising the first component; and

binding the network with the second component, wherein

at least a portion of the first component and a portion of the second component are provided as multicomponent articles having an aspect ratio greater than 1:1.1 (in some embodiments, greater than 1:5, 1:10, 1:50, 1:100, or even 1:150).

[0020] Methods in accordance with this aspect of the disclosure may further comprise contacting a surface of a fracture in the subterranean formation with the fluid composition, wherein the fluid composition may further comprise proppant. In certain embodiments, the fluid composition may comprise a fluid loss additive. In certain other embodiments, the fluid composition may comprise acid. In certain other embodiments, the methods further comprise placing proppant in a fracture in the subterranean formation. In certain embodiments, the methods may further comprise modifying at least one of the first or second components by at least one controlled modification process. In other embodiments, one of the first component and second component may be an activated adhesive. In certain embodiments, the second component may be selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60ºC. In yet other methods, at least some multicomponent articles may comprise the first component and the second component and other multicomponent articles may comprise a third component and a fourth component. In yet other embodiments, one of the first or second component may be the same as one of the third or fourth components.

[0021] Yet another aspect of the disclosure are methods of reducing migration of solids comprising:

providing a fluid composition into a well-bore, the well-bore intersecting a subterranean formation, the fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least one of the first component and second component having an aspect ratio greater than 1:1.1 (in some embodiments, greater than 1:5, 1:10, 1:50, 1:100, or even 1:150), wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60ºC;

forming a network comprising the first component;

binding the network with the second component; and

contacting the subterranean formation with the fluid composition.

[0022] Methods in accordance with this aspect of the disclosure include those methods wherein the forming and binding are performed prior to contacting. In certain methods the forming and binding may be performed upon or after contacting. In yet other methods at least some of the first component may comprise staple fibers, prolate spheroids, needles, strips, platelets, ribbons, sheets, tubes, capsules, combinations of more than one of these together in an article, and mixtures thereof. In certain embodiments, at least a portion of the first component and a portion of the second component may be provided in the same multicomponent article. In other embodiments, at least one multicomponent article may comprise the first element, the article has an exterior surface, and the first element may be exposed on at least a portion of the exterior surface. In certain embodiments, the second component may be an activated adhesive as described in previous aspects. Certain method embodiments include those further comprising modifying the second component after providing into the well-bore; methods further comprising modifying the second component over a period of time; and methods further comprising modifying the second component in stages. In certain embodiments, the solids may comprise formation fines, and in certain other embodiments the solids may comprise proppant. In certain embodiments, the second component may be modified by a process selected from, for example, temperature activation, chemical activation, pressure activation, mechanical activation, curing, exposure to electromagnetic fields, exposure to electromagnetic radiation, exposure to ionizing radiation, physical entanglement, degradation, concurrently application of at least two of these processes, consecutive application of at least two of these processes, and combinations thereof.

[0023] The carrier fluid may be water-based, oil-based, or mixture thereof, and may or may not comprise one or more gases or vapors dissolved or dispersed in a liquid, or other common oilfield additives, such as surfactants, rheology modifiers, and the like. The carrier fluid may be of any pH, temperature, and pressure, as long as the first and second components (and optionally other components, such as proppant particles) are able to be dispersed therein and are not significantly adversely affected by the pH, temperature and pressure of the carrier fluid. The network formed comprises at least a first component (sometimes referred to herein as a network component) and a second component (sometimes referred to herein as a modifiable component) designed as stated. The design includes embodiments wherein the first component is coated (fully or partially) with the second component; embodiments wherein the first and second components are intermixed; embodiments wherein the first and second components are intertwined; embodiments wherein the first and second components are placed adjacent each other; embodiments wherein the first and second components are self-adhered to each other; embodiments wherein the first and second components are adhered to each other by a third component; embodiments wherein at least some portions of the network are multicomponent articles; and mixtures thereof.

[0024] By “multicomponent” is meant having two or more regions of phase and/or chemical compositions; in other words, two or more regions that are distinct either physically, chemically, or both physically and chemically (for example regions having different glass transition temperatures, Tg). Because multicomponent articles have at least two distinct regions they may be designed to have multiple beneficial properties, and these properties may be tuned to a greater extent than that of a single component material. As one of many examples, in the case of multicomponent fibers, the material in the inner core of a core-sheath fiber may be selected for strength, flexibility and robustness, while the outer layer may be selected for its adhesive qualities. As another example, a side-by-side bicomponent fiber may have one component selected for strength, flexibility and robustness, while the other component may be selected for its adhesive qualities. Other suitable multicomponent articles include those wherein the least robust material is enclosed in a more robust sheath; those wherein polymers such as PLA and polyglycolic acid is enclosed in a sheath comprised of polyester, polyamide, and/or polyolefin thermoplastic; those wherein a sensitive adhesive, for example a pressure-sensitive adhesive, temperature-sensitive adhesive, moisture-sensitive adhesive, or curing agent-sensitive adhesive is enclosed in a degradable sheath, such as a polymer sheath; and those wherein one of the components is selected to be tacky at a specific downhole temperature, such as the bottomhole static temperature (BHST), and have a modulus of less than 3 $x10^6$ dynes/cm^2 (3 x 10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C.

[0024a] The present disclosure further relates to a method of contacting a subterranean formation comprising: injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least a portion of the first component and at least a portion of the second component being provided as multi-component core sheath fibers; after injecting, forming a network comprising the first component; and binding the network with the second component; wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

[0024b] The present disclosure further relates to a method of contacting a subterranean formation comprising: injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein the first component and the second component are provided in multi-component core sheath fibers prior to injection; and after injecting, forming a network comprising at least one first component in direct contact with another first component; and binding the network with the second component; wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

[0024c] The present disclosure further relates to a method of contacting a subterranean formation comprising: injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein at least a portion of the first component and at least a portion of the second component are provided in multi-component core sheath fibers; after injecting, forming a network comprising the first component; and binding the network with the second component, wherein the second

component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C; and wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

[0024d] The present disclosure further relates to a method of reducing migration of solids comprising: providing a fluid composition into a well-bore, the well-bore intersecting a subterranean formation, the fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein at least a portion of the first component and at least a portion of the second component are provided in multi-component core sheath fibers, wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C; contacting the subterranean formation with the fluid composition; subsequently, forming a network comprising the first component; and binding the network with the second component; wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

[0025] Certain fluid compositions useful in certain method embodiments may comprise proppant. Methods within this aspect of the disclosure include those wherein proppant is combined with the fluid composition prior to and/or during injecting the fluid composition into the wellbore. Other methods within the disclosure include those wherein the injecting comprises pumping the fluid composition into the wellbore under pressure, either with or without a proppant in the fluid composition. Exemplary methods of the disclosure comprise modifying at least a substantial portion of the modifiable component near a percentage of fractures after injecting the fluid composition plus proppant into the wellbore, thereby reducing proppant flowback from that percentage of fractures. The percentage may range from 10 percent to 100 percent.

[0026] Methods within the disclosure include methods of controlling (in certain embodiments reducing or eliminating) particle or fluid flow between the subterranean wellbore and a subterranean formation. Certain methods of the disclosure are those wherein the controlling particle flow comprises reducing fines migration from the subterranean formation into the wellbore. The controlling may be effected by modifying at least a portion of the modifiable component.

[0027] In methods of the disclosure the multicomponent articles in the fluid compositions may all be the same, or mixtures of two or more different multicomponent articles. For example, the modifiable component may be the same or different from one multicomponent article to the other in the same fluid composition. Furthermore, the network component may be the same or different from one multicomponent article to the other in the same fluid composition. Alternatively, methods of the disclosure may comprise injecting a first fluid composition within the disclosure, followed sequentially by one or more additional fluid compositions within the disclosure, each fluid composition within the disclosure having a different network component, or a different modifiable component, or both.

[0028] Oilfield operations within the disclosure include completion operations, acidizing, fracturing, flow diverting and other operations. The environmental conditions of the wellbore during running and retrieving may be the same or different from the environmental conditions during use in the wellbore or at the surface. Methods of the disclosure include those comprising using a first fluid composition of the disclosure downhole to perform a first task, a second fluid composition of the disclosure to perform a second task downhole, and so on.

[0029] The various aspects of the disclosure will become more apparent upon review of the brief description of the drawings, the detailed description of the disclosure, and the claims that follow.

[0030] **Brief Description of the Drawings**

[0031] The manner in which the objectives of the disclosure and other desirable characteristics can be obtained is explained in the following description and attached drawings in which:

[0032] FIGS. 1A-1D are schematic cross-sections of four prior art multicomponent fibers useful in methods of the disclosure;

[0033] FIGS. 2A-2G are schematic perspective views of various multicomponent articles useful in methods of the disclosure;

[0034] FIG. 3 is a schematic plot of modulus (dynes/cm^2) vs. temperature (^oC) comparing measurable bond strength to parallel plates of two different multicomponent fibers useful in the disclosure, illustrating that these fibers had measurable bond strength and in addition satisfied the Dahlquist criteria for tack; and

[0035] FIG. 4 is a plot of fiber concentration versus proppant pack flow during flowback tests.

[0036] **Detailed Description**

[0037] In the following description, numerous details are set forth to provide an understanding of the present disclosure. However, it will be understood by those skilled in the art that the present disclosure may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible.

[0038] Described herein are methods of using fluid compositions comprising one or more multicomponent articles or materials for downhole well servicing. Also described are networks made from the fluid compositions after the fluid compositions are pumped downhole and exposed to one or more modifying conditions. As used herein the term “oilfield” includes land based (surface and sub-surface) and sub-seabed applications, and in certain instances seawater applications, such as when exploration, drilling, or production equipment is deployed through a water column. The term “oilfield” as used herein includes oil and gas reservoirs, and formations or portions of formations where oil and gas are expected but may ultimately only contain water, brine, or some other composition.

[0039] It should be understood that methods of the disclosure may be conducted under one or more conditions of high pressure, high temperature, high shear, and high corrosion. “Well operation” as used herein includes, but is not limited to, well stimulation operations, such as hydraulic fracturing, acidizing, acid fracturing, fracture acidizing, fluid diversion, sand control gravel packing, gravel pack improvement, particulate migration reduction, completion operations using completion tools and/or completion tool accessories, or any other well treatment, whether or not performed to restore or enhance the productivity of a well.

[0040] Solids migration can be a significant issue in subterranean well construction, intervention and stimulation operations. These solids, usually of a granular nature, can be composed of many different materials of many different sizes. They may be the actual proppant pumped during a fracturing treatment, or the finer grained material produced by the crushing of these proppants. They may also be grains or fines spalled or eroded from the subterranean rock surface. They may be composed of salts or scale precipitates. In some cases they can be of an organic nature, such as asphaltene, lignitic, Kerogenic, and anthracitic in nature. They may also be introduced into the formation. For example they may be finely ground sand, mica, or other mineral materials used as fluid loss agents.

[0041] In many situations it is desirable that these granular materials are immobilized and prevented from migrating. For example, after many hydraulic fracture treatments are completed it is a common occurrence that some of the proppant can flow back. This reduces the overall effectiveness of the treatment, and the flowing proppant can cause damage to the subterranean and/or surface equipment.

[0042] In other situations, it is desirable that formation fines are prevented or reduced from migrating to the degree possible. Fines production is a common occurrence in many weak formations including that of coal seams. Although it is practically unavoidable that some fines are produced, they cause the greatest damage when large quantities of these fines are generated and are allowed to migrate and clog up the pores of the hydraulic fracture. In some situations it may be much better if these fines were localized close to their place of origin, and were not allowed to migrate and accumulate.

[0043] Another example where solids immobilization is useful is for the creation and placement of “filtercakes” and fluid leakoff additives. Often materials are added to wellbore construction, intervention and stimulation processes with the express intent of blocking or impeding fluid flow across a rock surface. These materials include but are not limited to finely ground sand, finely ground limestone, spun limestone, rock wool, sized calcium and magnesium carbonate particles, benzoic acid flakes, and the like. It is best if the materials added stay in place, first so that less material is used, and second so that migration of this material does not cause damage somewhere else in the fracture or wellbore.

[0044] In the following discussion, while the focus is on multicomponent fibers, it will be appreciated by those of skill in the art that the discussion is equally applicable to other multicomponent articles of the disclosure having aspect ratio greater than 1:1.1 (in some embodiments, greater than 1:5, 1:10, 1:50, 1:100 or even 1:150), including prolate spheroids, needles, strips, platelets, ribbons, sheets, capsules, pellets, and the like, and mixtures thereof, which may have any number of shapes viewed in perspective view, such as prismatic, cylindrical, lobed, rectangular, faceted, and the like. Some of these other shapes are illustrated in FIG. 2, discussed further herein.

[0045] One useful set of multicomponent articles are multicomponent core-sheath fibers having (or which may be modified to have) a tacky external sheath. These fibers are comprised of two or more materials. In an example of a two component fiber one material supplies a flexible to rigid network under the well conditions, while the second material serves to adhere to other fibers, proppant, rock and/or other interfaces in the well. The fiber components are chosen to achieve performance in the specific well conditions, and this is what is meant by “designed” herein. Having the second material allows the formation of “netting” or a network of first component connected by portions of the second material produced in-situ downhole such that oil, gas or other fluids may pass through but particulate matter will not. The flexible “backbone” of the fibers helps the reinforced proppant pack withstand stress cycling. Also as a result of the tacky component debris that might otherwise pass through the “netting” will become adhered to the fibers.

[0046] Four examples of multicomponent fibers useful in the methods and systems of the disclosure are illustrated in FIGS. 1A-D. For example, embodiment 10 of FIG. 1A comprises a pie-wedge fiber having a circular cross-section 12, and a first component 14a and 14b, a second component 16a and 16b, and a third component 18a and 18b. FIG. 1B illustrates a fiber 20 having a circular cross-section 22 that may have two or more components: a single component sheath 24, and one or more other components in more interior fibers 26. FIG. 1C illustrates an embodiment 30 also having a circular cross-section 32, with four layered regions 34a, 34b, 36a, and 36b, which may comprise two, three, or four different compositions, phases, and the like. FIG. 1D illustrates another bi-component fiber embodiment 40 having a core-sheath structure (also sometimes referred to as sheath-core structure; the terms are considered equivalent structures and structural equivalents herein) having a sheath 44 and a core 46.

[0047] Multicomponent articles useful in the disclosure are not limited to fibers. FIGS. 2A-G illustrate perspective views of other structures. FIG. 2A illustrates an article 50 having a triangular cross-section 52, wherein a first component 54 exists in one region, and a second component 56 is positioned adjacent first component 54, and where one of components 54 and 56 is modifiable. FIG. 2B illustrates an embodiment 60 having an outer capsule or pellet shape 62. Embodiment 60 comprises a core region 64 having a first composition, and an outer region 68 comprising a second composition surrounding core 64. Optionally, a coating 66 may comprise a third composition. At least one of components 64, 66 and 68 is modifiable. FIG. 2C illustrates a ribbon-shaped embodiment 70 having a generally rectangular cross-section and an undulating shape 72. A first layer 74 comprises a first composition, while a second layer 76 comprises a second composition, where one of components 72 and 74 is modifiable. FIG. 2D illustrates a coiled or crimped fiber embodiment 80 having a first component 82 along side a second component 84, where one of components 82 and

84 is modifiable. The distance between coils, 86, may be adjusted according to the properties desired. FIG. 2E illustrates a platelet embodiment 90 of irregular shape having a first layer 92, a second layer 94, and a third layer 96 each having different compositions, where at least one of components 92 and 94 is modifiable. In some embodiments, the first or second component may be non-polymeric and the third layer being an inert material such as finely divided calcium carbonate, mica, or fatty acids. In such embodiments, the third layer may serve as a barrier to adhesion until conditions (such as squeezing or pinching of the fiber between grains of proppant) occur to alter its integrity.

[0048] It should be noted that each component need not have the same shape, length, width or thickness. FIG. 2F illustrates an embodiment 100 having a cylindrical shape, and having a first annular component 102, a second annular component 104, the latter component defining hollow core 106. Hollow core may optionally be partially or fully filled with an additive, such as a tackifier, curing agent or the like for one of the components 102, 104, where at least one of components 102 and 104 is modifiable. FIG. 2G illustrates a lobed-structure 110 having five lobes 112. A first component 114 exists in the outer portions of lobes 112, while a second component 116 fills the remainder of the structure. At least one of components 114 and 116 is modifiable. These are merely representative examples of multicomponent articles useful in the disclosure, and are not intended to be limiting in any way. Methods of making these structures, as well as more complicated structures, are considered well-known to the skilled artisan.

[0049] In some multicomponent articles useful in the disclosure, one component or region of the article may be tacky, or is designed to have latent tackiness (in other words tack can be increased by exposure to one or more conditions during or after deployment through a wellbore). The tack properties of articles useful in the disclosure may be controlled by at least two methods, which may be used individually or in combination. The first method is temperature activation of the polymer comprising an external sheath as it warms up in the wellbore or in the fracture. Certain embodiments may be activated at or near the bottomhole static temperature (BHST). A number of the multicomponent fibers are known which have been developed as binders for the nonwoven fabrics business. Some examples include: a) a segmented fiber comprised of about 70 percent high density polyethylene/30 percent polyethylene terephthalate; and b) a core-sheath fiber composed of two polyester resins, marketed under the trade designation “KOSA T-259”, by KoSa, Salisbury, NC.

[0050] Tack is defined as the property of a material that enables it to form a bond of measurable strength after it is brought into contact under pressure with another material. Tack is deemed a desirable property of fibers and other multicomponent articles useful in the disclosure, and in situ networks useful in the disclosure, for solids migration control, as it is thought to create a bond between solids, for example proppant, fines, precipitates, and the like, and the walls of the fractured borehole. Using a stress-controlled rheometer (model AR2000 manufactured by TA Instruments, New Castle, DE), a test method was developed to measure the bond strength of various fibers as a function of temperature. The results are illustrated in FIG. 3 for the two fibers mentioned previously. Results for the 70 percent high density polyethylene/30 percent polyethylene terephthalate fibers are represented by the solid line in FIG. 3, while results for the a core-sheath fiber composed of two polyester resins, marketed under the trade designation "KOSA T-259" are represented by the dashed line in FIG. 3. In the test, a plurality of fibers were placed between two 20mm parallel plates of a rheometer and a sinusoidal frequency of 1 Hz at 1% strain applied over a temperature range of 100-150°C. Results are shown in FIG. 3 plotted as modulus (dynes/cm^2) vs. temperature (°C.). The two samples had measurable bond strength and in addition satisfied the Dahlquist criterion for tack. This criterion stipulates that at a given temperature the modulus of any tacky adhesive is less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz.

[0051] Methods and systems for applying heat to a region of a wellbore are known and described for example in US Patent Number 6,023,554 (George et al.) and in Published US Patent Application Publication Number 2005/0269090 (Vinegar et al.).
Heated fluids useful in the disclosure that function to deliver heat to regions of a formation may be selected from gases, vapors, liquids, and combinations thereof, and may be selected from water, organic chemicals, inorganic chemicals, steam, and mixtures thereof.

[0052] A second method is chemical activation. In these embodiments a solvent or tackifying agent is added to the fluid to soften and tackify one of the polymers comprising the fiber or other article. This may be performed in combination with temperature activation. The solvent may be combined with other components of fluid compositions useful in methods of the disclosure, or pumped in separately as a slug. Another method is stress or contact pressure activation of adhesion, for example by the pinching of fiber between adjacent grains of proppant, or between grains of proppant and the wall of the fracture.

[0053] Tackifiers typically comprise an organic material having a glass transition temperature of no less than about 120°C. (in certain embodiments, no less than about 150°C.) and a diluent present in sufficient amount to give the tackifier a kinematic viscosity ranging from about 3,000 to about 5,000 centistokes at 100°C. The diluent may be an organic oil, such as a mineral oil (i.e., a hydrocarbon oil derived from petroleum, such as paraffin oils, naphthenic oils, and the like, or a coal oil or rock oil). One particularly useful mineral oil is slate oil. Another particularly useful mineral oil is seneca oil. These oils will generally have a kinematic viscosity ranging from about 100 to about 300 centistokes at 100°C., and some will have a kinematic viscosity ranging from about 150 to about 250 centistokes. As used herein "kinematic viscosity" has its generally accepted meaning, the absolute viscosity (sometimes referred to as the dynamic viscosity) of the fluid divided by its mass density. In certain embodiments, the diluent may comprise one or more light-colored naphthenic oils. The amount of tackifier present in a multicomponent article useful in practicing the disclosed methods preferably ranges from about 0.5 to about 2 weight percent, or from about 0.5 to about 1 weight percent of the total weight of a multicomponent article. An adhesion agent may also be present, the amount of adhesion agent ranging from about 0.5 to about 5 weight percent of the multicomponent article weight, the balance being organic oil. The organic material component of tackifiers useful in the disclosure may be selected from organic monomers, oligomers or polymers having a glass transition temperature (Tg) no less than about 120°C., in some embodiments, no less than about 150°C. Two categories of organic polymeric materials useful in tackifier compositions are polyalkylene resins and polycycloalkene resins, the latter group including aromatic organic resins. Useful polyalkylene resins include polybutene resins, dipentene resins, terpolymers of ethene, 1-propene, and 1,4-hexadiene, and the like. Useful polycycloalkene resins include phenol-aldehyde resins; polyterpene resins; rosins, including rosin acids and esters, and hydrogenated rosins; polyethylene rosin esters; phenolic polyterpene resins; limonene resins; pinene resins such as alpha and beta pinene resins; styrenated terpene resins, and the like. An example of a tackifier useful in compositions methods of the disclosure comprises a terpolymer of ethene, 1-propene, and 1,4-hexadiene adjusted to the above preferred kinematic viscosity with a light-colored naphthenic oil, such as the naphthenic oil known under the trade designation "HS-500", available from Cross Oil & Refining Co., Smackover, AR. Other suitable tackifiers and their ingredients are discussed in US Patent Number 5,362,566 (George et al.).

[0054] A second set of useful multicomponent articles are multicomponent fibers having an outer protective sheath. Many of the low cost polymers that would be useful for subterranean application are of the type known as condensation polymers. Polyamides and polyesters are two examples. These materials often have suitable mechanical properties for proppant flowback control but are prone to hydrolytic degradation (either main polymer chain degradation, side chain degradation, or both) in subterranean environments. Furthermore, many of their degradation products can precipitate out with divalent cations in the formation or in the production line causing damage or a reduction in productivity. Phenol-formaldehyde and melamine-based resins on the other hand, although more impervious to chemical degradation, have less desirable mechanical properties and are more difficult to fabricate and handle in the fibrous form.

[0055] In these versions of useful multicomponent articles, the multicomponent articles comprise an inner material coated with a second composition, for example the inner material being relatively more prone to hydrolysis than the outer material. In one embodiment, the articles may be multicomponent coated fibers, which are particularly useful for reducing solids migration – in particular for proppant flowback control. The inner material may be selected for its mechanical properties, its cost and its ease of fabrication. The outer, coating material may be selected for its ability to withstand hydrolytic degradation. Two examples are given. A first example, which may have structure such as illustrated in FIG. 1D, is a polylactic acid fiber as core 46 of a multicomponent fiber, co-extruded with a polyamide or PET shell as sheath 44. A second example may be a polyamide core covered by a phenolic or melamine based resin system.

[0056] Another set of multicomponent articles that may be useful in practice of methods of this disclosure are multicomponent fibers comprising at least one curable component. These embodiments are similar to embodiments described herein comprising core-sheath fibers having (or which may be modified to have) a tacky external sheath, however in embodiments comprising a curable component, during the time that a fluid composition of the disclosure is pumped into a wellbore, the outer surface of the fibers or other articles are in an uncured state, or in a partially cured state, or contain components that may initiate curing through action of a latent curing agent. An example is a coating comprising an uncured epoxy resin having dispersed therein a latent, heat activated curing agent. The advantage is similar to the embodiments employing tacky materials but the surface bonds to the proppant grains, to other fibers, or the wall of the fracture would be stronger and more permanent. The underlying fiber gives flexibility to the bonded structure that would help the proppant pack withstand stress cycling.

[0057] Another set of multicomponent articles that may be useful in the practice of the disclosure are multicomponent articles comprising at least one degradable component. As used herein degradable may mean degradable by physical, chemical (including pH), mechanical, radiation means, and combinations thereof. In some applications it would be advantageous for one or more of the article components to be degradable or soluble in the subterranean environment. Polylactic acid (PLA) is an example of a polymer that is degradable and soluble in downhole conditions. Polyvinyl alcohol may be extruded into soluble fibers. One example where this would be advantageous would be that very tacky strips of polyvinyl alcohol could be covered in PLA to facilitate handling, well site delivery and mixing. In this way thin strips or films of very highly tacky or curable resin with high surface area to volume ratios could be placed into the fracture or on surfaces within the wellbore or bottom hole assembly. The soluble PLA minimizes the total volume of material left in the pore space, thereby minimizing hydraulic conductivity damage.

[0058] The degradable component functions to dissolve when exposed to the wellbore conditions in a user controlled fashion, i.e., at a rate and location controlled by the structure of the first component. In this way, zones in a wellbore, or the wellbore itself or branches of the wellbore, may be blocked for periods of time uniquely defined by the user. The degradable second component may comprise a degradable inorganic material, a degradable organic material, and combinations thereof. Degradable water-soluble organic materials may comprise a water-soluble polymeric material, for example, poly(vinyl alcohol), poly(lactic acid), and the like. The water-soluble polymeric material may either be a normally water-insoluble polymer that is made soluble by hydrolysis of side chains, or the main polymeric chain may be hydrolysable.

[0059] Certain fluid compositions useful in the disclosure may comprise multicomponent articles comprised of a thermoplastic materials covered by a fully cured or partially cured thermosetting material. In embodiments wherein the thermosetting material is only partially cured while the fluid is being pumped downhole, the thermosetting materials may be fully cured by bottomhole conditions.

[0060] Fluid compositions and multicomponent articles useful in the disclosure may comprise metallic fibers or nonmetallic fibers coated with a thermosetting material. Suitable nonmetallic fibers include glass fibers, carbon fibers, mineral fibers, synthetic or natural fibers formed of heat resistant organic materials, or fibers made from ceramic materials. The metallic and nonmetallic fibers may be "hydrocarbon resistant" organic fibers, meaning they are resistant to, or resistant to breaking down, under the wellbore conditions. Examples of useful natural organic fibers include wool, silk, cotton, or cellulose. Examples of useful synthetic organic fibers include polyvinyl alcohol fibers, polyester fibers, rayon fibers, polyamide fibers, acrylic fibers, aramid fibers, and phenolic fibers. Generally, any ceramic (i.e., glass, crystalline ceramic, glass-ceramic, and combinations thereof) fiber is useful in applications of the present disclosure. An example of a ceramic fiber suitable for the present disclosure is available from the 3M Company, St. Paul, MN under the trade designation "NEXTEL". Glass fibers may be used, at least because they impart desirable characteristics to the articles and are relatively inexpensive. Furthermore, suitable interfacial binding agents exist to enhance adhesion of glass fibers to thermoplastic materials, such as a silane coupling agent, to improve the adhesion to the thermoplastic material. Examples of silane coupling agents include those available under the trade designations "Z-6020" and "Z-6040," from Dow Corning Corp., Midland, MI.

[0061] Other suitable multicomponent articles include those wherein the least robust material is enclosed in a more robust sheath; those wherein polymers such as PLA and polyglycolic acid is enclosed in a sheath comprised of polyester, polyamide, and/or polyolefin thermoplastic; those wherein a sensitive adhesive, for example a pressure-sensitive adhesive, temperature-sensitive adhesive, moisture-sensitive adhesive, or curable adhesive is enclosed in a degradable polymer sheath; and those wherein one of the components is selected to be tacky at a specific downhole temperature, such as the bottomhole static temperature (BHST), and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60ºC, the tacky component embedded in a degradable polymer sheath. Sensitive adhesives such as pressure-sensitive adhesives, temperature-sensitive adhesives, and moisture-sensitive adhesive, as well as curable adhesives, are well-known to those in the adhesives and fibers arts, and require no further explanation herein.

[0062] Suitable multicomponent articles are also described, for example, in US Provisional Patent Application having Serial Number 61/014,004 (Attorney Docket No. 63584US002; entitled "Multi-Component Fibers"), filed the same date as the instant application.

[0063] Under some circumstances it may be advantageous to deploy downhole pre-fabricated woven or non-woven assemblies, for example, mats, from materials such as those described herein comprising a first (network) component and second (modifiable) component. In general, the size of these assemblies is limited only by the practicalities of deploying the materials downhole. One deployment method may entail pumping a fluid composition comprising one or more prefabricated assemblies. Another deployment method may entail attaching the assembly to the end or near the end of a tubing, such as coiled tubing, running the tubing into the wellbore, and placing the assembly at a desired location.

[0064] Example

[0065] A testing apparatus comprising the following assemblies was used: a flowback cell for containing the proppant pack being testing; a circulation system for pumping fluid through the proppant pack in the cell; and a hydraulic press to apply a uniaxial closure stress onto the proppant pack. The flowback cell consisted of a rectangular body that had an interior 5.25 in x 5.25 in (13.3 cm x 13.3 cm) working area which held the proppant pack. After the cell was filled with the proppant pack, a square piston was inserted into the body on top of the proppant pack. Water was pumped through the rectangular proppant pack from an upstream inlet side through to the discharge side. On the upstream side of the cell, there were three 13 mm inlets for the inflow of water. On the discharge side of the cell there was a 10 mm outlet that represents a perforation. In this configuration, the proppant pack was free to move if it had insufficient strength to withstand the stresses generated by the flow of water. After the flowback cell was filled and assembled, it was placed in the hydraulic press which then applied a designated closure stress to the proppant pack. The test apparatus was computer controlled, and data acquired included measurements of pack width, flow rate and upstream pressure.

[0066] The proppant flowback stability measurements were performed on a sand pack made from a fracturing sand of 20/40 mesh (API RP 56) obtained from Badger Mining Corporation, Berlin, WI, and the flowback control additives. The total mass of the solids in the pack (sand plus flowback control additives) was set at 400 grams. The uniaxial closure stress was set to 4000 psi (27.6 MPa), and the tests were performed at 90°C. At the start of each test the flow rate of water was zero. As the test progressed the flow rate of water was continuously increased at a rate of 4 L/min. till pack failure was observed. The flow rate at the pack failure was used as a characteristic of the flowback stability of the proppant pack.

[0067] Fibers were added to the proppant pack and tested for flowback. A single component nylon fiber, having a length of 17 mm long and a diameter of 6 mm and a bicomponent polyamide/ionomeric fiber having length of 17 mm and diameter of 6 micrometers were tested. The single component fiber was provided by 3M Company, St. Paul Minnesota, while the bicomponent fiber was a nylon core with SURLYN™ (mark of DuPont Corporation) sheath provided by 3M Company, St. Paul, Minnesota. In order to compare the different fibers, test results were normalized according to the linear concentration of fibers in meters per gram of proppant in the test cell. FIG. 4 shows the test results where the flow rate at pack failure is plotted against the linear fiber concentration in the pack. Pure sand started flowing at rates as low as 0.5 L/min. under these conditions. The results showed that the bicomponent fibers significantly improved pack strength even at lower fiber concentration. With 18–22.5 meters of single component fiber per gram of proppant, the packs begin to fail at flow rates of 2.9 – 3.9 L/min. With the bicomponent fibers, it was possible to increase the up to 4.9 L/min. at half the linear fiber concentrations (9 m/gram). When 18 m/gram bicomponent fiber was used, the flow rate was 5.7 L/min. at failure.

[0068] Multicomponent articles and fluid compositions comprising same may be employed in methods of the disclosure for solids and/or fluid control in reservoirs. Multicomponent articles such as multicomponent fibers comprising a tacky and/or curable adhesive surface may include porous proppants impregnated with a tackifying substance or curing agent for controlled release. When used for solids mobility control (for example, proppant flowback control, and/or fines migration control) the solids adhere to the surface of the fibrous material. The fiber may comprise a part of a homogeneous fiber-proppant network (pumped during proppant stage) or the fibers or other articles may be used without proppant as networks in or part of a filter-cake, or pumped downhole during the pad stage. The networks may be temporary in nature by releasing a tacky or curable coating upon dissolution covering the proppant pack, or the fiber or other article may be partially soluble by coating the surrounding proppant while maintaining the integrity of the fibrous network.

[0069] While the bulk of this discussion has been about proppant flowback control, methods of the disclosure relate to any method or process of treating an underground formation penetrated by a wellbore comprising designing a fluid composition of the disclosure; pumping or otherwise deploying the fluid composition downhole through a wellbore; depositing the fluid composition in the formation; and forming within the formation a 2- or 3-dimensional network comprising the first and second components. This may include fracturing methods; methods wherein the designing of the fluid composition comprises designing a gravel pack fluid composition, pumping the gravel pack fluid composition downhole through a wellbore, depositing a gravel pack fluid; methods comprising designing a fluid composition able to increase competency of a granular pack in a wellbore, comprising providing a fluid composition of the disclosure to the pack, and modifying the modifiable component. Methods within this aspect include those wherein the pack comprises materials selected from proppant previously placed in fractures in a subterranean formation, sand in the subterranean formation, a gravel pack, and combinations thereof.

[0070] Other methods of the disclosure comprise preparing and/or pretreating the surface of a fracture. That is, the fluid composition is deployed early in the treatment prior to the addition of proppant.

[0071] In other methods of the disclosure, a fluid composition may be deployed in combination with one or more conventional fluid loss additives (for example fine sand or the like) for application to the surface of the fracture or the surface of the wellbore.

[0072] Further methods of the disclosure include deploying a composition of the disclosure in combination with single component elongated elements, for example single component fibers (wherein the modifiable component of the multicomponent articles functions as a binder for conventional fibrous materials within a proppant pack, fiber plug, or the like).

[0073] Further methods of the disclosure include deploying two different compositions of the elongated articles intermingled in the fluid, with or without proppant. Once these articles are place in the formation they can act synergistically to create a network structure. For example one of the multicomponent fibers could contain an epoxy resin and the second could contain a curing agent. Alternatively, for example, one of the multicomponent fibers could contain a temperature activated melt-bondable adhesive material that acts over a period of time and another multicomponent fiber could contain an epoxy adhesive that acts over a different period of time.

[0074] In other methods of the disclosure, a fluid composition may be deployed in acid fracturing applications, and fracture acidizing applications. Acidizing means the pumping of acid into the wellbore to remove near-well formation damage and other damaging substances. Acidizing commonly enhances production by increasing the effective well radius. When performed at pressures above the pressure required to fracture the formation, the procedure is often referred to as acid fracturing. Fracture acidizing is a procedure for production enhancement in which acid, usually hydrochloric (HCl), is injected into a carbonate formation at a pressure above the formation-fracturing pressure. Flowing acid tends to etch the fracture faces in a nonuniform pattern, forming conductive channels that remain open without a propping agent after the fracture closes. The length of the etched fracture limits the effectiveness of an acid-fracture treatment. The fracture length depends on acid leakoff and acid spending. If acid fluid-loss characteristics are poor, excessive leakoff will terminate fracture extension. Similarly, if the acid spends too rapidly, the etched portion of the fracture will be too short. The major problem in fracture acidizing is the development of wormholes in the fracture face; these wormholes increase the reactive surface area and cause excessive leakoff and rapid spending of the acid. To some extent, this problem can be overcome by using inert fluid-loss additives to bridge wormholes or by using viscosified acids. Fracture acidizing is also called acid fracturing or acid-fracture treatment. Compositions of the disclosure maybe used in these applications, as the acidic solution may decompose the composition selectively rather than other components or geologic formations.

[0075] Traditional (single component) fibers or other single component shaped particles may be used, in conjunction with the fluid compositions, multicomponent articles, and methods of the disclosure, to strengthen, reinforce, or bind filter cakes and fluid leakoff additives in the wellbore, in downhole networks of the disclosure, or in the fracture itself. What follows is a brief discussion of single-component staple fibers and their properties.

[0076] Single-component staple fibers may comprise crimped or non-crimped thermoplastic organic fibers comprising polyamide and polyester fibers, although it is also known to use other fibers such as rayon.

[0077] Melt-bondable fibers may be used to help stabilize the networks in the wellbore and may facilitate trapping particulate materials. Melt-bondable fibers useful in the present disclosure may be made of polypropylene or other low-melting polymers such as polyesters as long as the temperature at which the melt-bondable fibers melt and thus adhere to the other fibers in the network construction is lower than the temperature at which the staple fibers or melt-bondable fibers degrade in physical properties under wellbore conditions. Suitable and preferable melt-bondable fibers include those described in US Patent Number 5,082,720 (Hayes). Melt-bondable fibers suitable for use in this disclosure must be activatable at elevated temperatures below temperatures which would adversely affect other ingredients. Typically, melt-bondable fibers have a concentric core and a sheath. Alternatively, melt-bondable fibers may be of a side-by-side construction or of eccentric core and sheath construction.

[0078] The length of the organic fibers employed is primarily dependent on upon the limitations of the pumping equipment. However, depending on types of equipment, fibers of different lengths, or combinations thereof, very likely can be utilized in forming the networks downhole having the desired ultimate characteristics specified herein. For pumping applications the best fiber length is below 20 mm, in certain embodiments, less than 19 mm, in certain other embodiments, less than 12 mm, and in other embodiments, around 6 mm.

[0079] Fluid compositions may be pumped into the well from the surface using any of a number of pumping systems which are not a part of the disclosure per se.

[0080] The fluid portion of fluid compositions useful in the disclosure that does not form a network downhole comprises fluid that must be returned to the surface. In many formations this may be accomplished naturally due to the residual pressure after the fracturing treatment is completed, or due to high reservoir pressure. This may be accomplished artificially using a downhole pump. One option is to use an electrical submersible pump ("ESP"), such as pumping systems known under the trade designation AXIA™, from Schlumberger Technology Corporation, Sugar Land, TX.

[0081] When desired, proppant may be pumped into the formation, either combined with the compositions of the disclosure, or combined in situ. As has been indicated above, the function of a proppant is to "prop" the walls adjacent a fracture in a subterranean formation apart so that the fracture is not closed by the forces which are extent in the formation. It is advantageous for the walls adjacent the fracture to be "propped" apart so that the formation can be worked, usually to remove oil or natural gas. In general the fluid compositions, multicomponent articles therein, methods, and networks of the disclosure perform well with any known proppant, but may be particularly effective when using the least expensive proppant, siliceous sand. At greater stresses, it is believed, the sand particles are disintegrated, forming fines which then may plug the formation, reducing its permeability and resulting in costly well cleanouts, or even abandoning the well. This is discussed in US Patent Number 3,929,191 (Graham et al.).
Sintered bauxite has also been used as a proppant, and may be preferable to siliceous sand because of its ability to withstand higher stresses without disintegration. However, sintered bauxite can be less desirable than siliceous sand as a proppant because it is substantially more expensive and is less generally available. The use of sintered bauxite as a proppant is disclosed in US Patent Number 4,068,718 (Cooke et al.).

[0082] Other suitable proppants are described, for example, in US Patent Numbers 6,406,789 (McDaniel et al.); 6,582,819 (McDaniel et al.); and 6,632,527(McDaniel et al.).
As the '789 patent explains, three different types of propping materials (i.e., proppants) are currently employed. The first type of proppant is a sintered ceramic granulation/particle, usually aluminum oxide, silica, or bauxite, often with clay-like binders or with incorporated hard substances such as silicon carbide (e.g., US Patent Number 4,977,116 (Rumpf et al.), EP Patents 0 087 852, granted April 2, 1986, 0 102 761, published March 14, 1984, or 0 207 668, granted April 5, 1984). The ceramic particles have the disadvantage that the sintering must be done at high temperatures, resulting in high energy costs. The second type of proppant is made up of a large group of known propping materials from natural, relatively coarse, sands, the particles of which are roughly spherical, such that they can allow significant flow (English "frac sand") (see US Patent Number 5,188,175 (Sweet) for the state of the technology). The third type of proppant includes samples of type one and two that may be coated with a layer of synthetic resin (US Patent Number 5,420,174 (Deprawshad et al); US Patent Number 5,218,038 (Johnson et al.); US Patent Number 5,639,806 (Johnson et al.); and EP Patent No. 0 542 397,published May 19, 1993).
As discussed herein, in some hydraulic fracturing circumstances, the precured proppants in the well would flow back from the fracture, especially during clean up or production in oil and gas wells. Some

of the proppant can be transported out of the fractured zones and into the well bore by fluids produced from the well. This transportation is known as flow back. Flowing back of proppant from the fracture is undesirable and has been controlled to an extent in some instances by the use of a proppant coated with a curable resin which will consolidate and cure underground. Phenolic resin coated proppants have been commercially available for some time and used for this purpose. Thus, resin-coated curable proppants may be employed to "cap" the fractures to prevent such flow back. The resin coating of the curable proppants is not significantly crosslinked or cured before injection into the oil or gas well. Rather, the coating is designed to crosslink under the stress and temperature conditions existing in the well formation. This causes the proppant particles to bond together forming a 3-dimensional matrix and preventing proppant flow back. These curable phenolic resin coated proppants work best in environments where temperatures are sufficiently high to consolidate and cure the phenolic resins. However, conditions of geological formations vary greatly. In some gas/oil wells, high temperature (>180°F.(82°C.)) and high pressure (>6,000 psi (41MPa)) are present downhole. Under these conditions, most curable proppants can be effectively cured. Moreover, proppants used in these wells need to be thermally and physically stable (i.e., do not crush appreciably at these temperatures and pressures). Curable resins include (i) resins which are cured entirely in the subterranean formation and (ii) resins which are partially cured prior to injection into the subterranean formation with the remainder of curing occurring in the subterranean formation. Many shallow wells often have downhole temperatures less than 130°F (54°C.), or even less than 100°F (38°C.).

[0083] Due to the diverse variations in geological characteristics of different oil and gas wells, no single proppant possesses all properties which can satisfy all operating requirements under various conditions. The choice of whether to use a precured or curable proppant or both is a matter of experience and knowledge as would be known to one skilled in the art. In use, the proppant is suspended in the fracturing fluid. Thus, interactions of the proppant and the fluid will greatly affect the stability of the fluid in which the proppant is suspended. The fluid needs to remain viscous and capable of carrying the proppant to the fracture and depositing the proppant at the proper locations for use. However, if the fluid prematurely loses its capacity to carry, the proppant may be deposited at inappropriate locations in the fracture or the well bore. This may require extensive well bore cleanup and removal of the mispositioned proppant. It is also important that the fluid breaks (undergoes a reduction in viscosity) at the appropriate time after the proper placement of the proppant. After the proppant is placed in the fracture, the fluid shall become less viscous due to the action of breakers (viscosity reducing agents) present in the fluid. This permits the loose and curable proppant particles to come together, allowing intimate contact of the particles to result in a solid proppant pack after curing. Failure to have such contact will give a much weaker proppant pack. Foam, rather than viscous fluid, may be employed to carry the proppant to the fracture and deposit the proppant at the proper locations for use. The foam is a stable foam that can suspend the proppant until it is placed into the fracture, at which time the foam breaks. Agents other than foam or viscous fluid may be employed to carry proppant into a fracture where appropriate. Also, resin coated particulate material (e.g., sands) may be used in a wellbore for "sand control." In this use, a cylindrical structure is filled with the proppants (e.g., resin coated particulate material) and inserted into the wellbore to act as a filter or screen to control or eliminate backwards flow of sand, other proppants, or subterranean formation particles. Typically, the cylindrical structure is an annular structure having inner and outer walls made of mesh. The screen opening size of the mesh being sufficient to contain the resin coated particulate material within the cylindrical structure and let fluids in the formation pass therethrough.

[0084] Fluid compositions useful in methods of the disclosure may be used with and/or employ any of a number of well treatments or well completions. As used herein the terms “well completion” and “completion” are used as nouns except when referring to a completion operation. Well completions within the disclosure include, but are nor limited to, casing completions, commingled completions, hydraulic fracturing, coiled tubing completions, dual completions, high temperature completions, high pressure completions, high temperature/high pressure completions, multiple completions, natural completions, artificial lift completions, partial completions, primary completions, tubingless completions, and the like.

[0085] In the oilfield context, a “wellbore” may be any type of well, including a producing well, a non-producing well, an injection well, a fluid disposal well, an experimental well, an exploratory well, and the like. Wellbores may be vertical, horizontal, deviated some angle between vertical and horizontal, and combinations thereof, for example, a vertical well with a non-vertical component.

[0086] In an implementation of the methods of the present invention, a wellbore treatment can be designed considering characteristics of the target subterranean formation, desired outcome resulting from contacting the formation with the fluid composition, chemistry and characteristics of the fluid composition, well-bore geometry, and equipment to be used to inject the fluid composition to determine the appropriate concentration and type of components to use to in the methods embodied herein.

[0087] In performing an operation at a well-bore, the first and second components are typically metered, either together or separately, into the fluid composition at a surface location prior to injection into the well-bore. If proppant is provided, the first and second components are normally metered into the fluid composition separately from the proppant. In many cases the fiber concentration in the fluid would be less than 5% by weight of the proppant, often less than about 2% by weight of the proppant, and on occasion less than about 1% by weight of the proppant. Generally the ratio of fiber to proppant would remain the same throughout the operation, with the fiber concentration increasing in proportion to the proppant concentration in the fluid composition. It is advantageous to add the first and second components to the fluid composition in a continuous process. Use of high shear-rate mixers is preferred to rapidly mix the first and second components with the fluid composition, and optionally proppant, to disperse the components thoroughly within the fluid composition. As the methods of the present invention are conducive to rapid turnaround, field operations would be aided by the use of dual choke or dual flow equipment to permit quick fluid production from the well-bore.

[0088] Although only a few exemplary embodiments of this disclosure have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the exemplary embodiments without materially departing from the novel teachings and advantages of this disclosure. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

55395-4

CLAIMS:

1. A method of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, at least a portion of the first component and at least a portion of the second component being provided as multi-component core sheath fibers;

after injecting, forming a network comprising the first component; and

binding the network with the second component;

wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

2. The method of claim 1 further comprising modifying at least one of the first or second components by at least one controlled modification process after injection into the wellbore.

3. The method of claim 1 wherein at least some of the multi-component core sheath fibers are different from other multi-component core sheath fibers in the fluid composition.

4. The method of claim 1 wherein at least some multi-component core sheath fibers comprise a third component and a fourth component.

5. The method of claim 1 wherein at least some of the multi-component core sheath fibers further comprise a third component.

6. The method of claim 1 wherein at least one of the first or second components is an activated adhesive.

7. The method of claim 6 wherein the activated adhesive is selected from pressure-sensitive adhesives, temperature-sensitive adhesives, moisture-sensitive adhesives, and curing agent-sensitive adhesives.

8. The method of claim 1 wherein one of the first component and second component have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C.

9. The method of claim 1 wherein the fluid composition further comprises proppant.

10. A method of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein the first component and the second component are provided in multi-component core sheath fibers prior to injection; and

after injecting, forming a network comprising at least one first component in direct contact with another first component; and

binding the network with the second component;

wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

11. The method of claim 10 further comprising modifying at least one of the first or second components by at least one controlled modification process upon or after injection into the wellbore.

12. The method of claim 11 wherein the modification process is selected from chemical, physical, mechanical, radiation, and combinations thereof.

13. The method of claim 12 wherein the modification process is selected from temperature activation, chemical activation, pressure activation, mechanical activation, curing, exposure to electromagnetic fields, exposure to electromagnetic radiation, exposure to ionizing radiation, physical entanglement, degradation, concurrently application of at least two of these processes, consecutive application of at least two of these processes, and combinations thereof.

14. The method of claim 10 further comprising modifying at least one of the first or second components upon injection into the well-bore.

15. The method of claim 10 further comprising modifying at least one of the first or the second components over a period of time after injection into the well-bore.

16. The method of claim 10 further comprising modifying at least one of the first or second components in stages after injection into the well-bore.

17. The method of claim 10 wherein at least one of the first component or second component is an activated adhesive.

18. The method of claim 17 wherein the activated adhesive is selected from pressure-sensitive adhesives, temperature-sensitive adhesives, moisture-sensitive adhesives, and curing agent-sensitive adhesives and combination thereof.

19. The method of claim 10 wherein at least one of the first component or second components comprises a degradable polymer.

20. The method of claim 10 wherein the first component is selected from the group consisting of a thermoplastic material and a thermoset material.

21. The method of claim 20 wherein the first component is selected from the group consisting of polyesters, polyamides, polyolefins, copolymers thereof, and physical mixtures thereof.

22. The method of claim 10 wherein the second component is selected from the group consisting of polyolefins, polyolefin copolymers, polyurethanes, epoxies, polyesters, polyamides, polyacrylates, and mixtures there of.

23. The method of claim 10 wherein the fluid composition comprises acid.

24. The method of claim 23 wherein at least one of the first or second components is selected from polylactic acid and polyglycolic acid.

25. The method of claim 10 wherein the fluid composition further comprises proppant.

26. A method of contacting a subterranean formation comprising:

injecting into a well-bore intersecting the subterranean formation a fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein at least a portion of the first component and at least a portion of the second component are provided in multi-component core sheath fibers;

after injecting, forming a network comprising the first component; and

binding the network with the second component,

wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C; and

wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

27. The method of claim 26 wherein the fluid composition further comprises proppant.

28. The method of claim 1, wherein the contacting comprises

pumping under pressure into the well-bore.

29. The method of claim 28 further comprising contacting a surface of a fracture in the subterranean formation with the fluid composition.

30. The method of claim 28 wherein the fluid composition further comprises proppant.

31. The method of claim 28 wherein the fluid composition comprises a fluid loss additive.

32. The method of claim 28 wherein the fluid composition comprises acid.

33. The method of claim 28 further comprising placing proppant in a fracture in the subterranean formation.

34. The method of claim 28 further comprising modifying at least one of the first or second components by at least one controlled modification process after injection into the wellbore.

35. The method of claim 28 wherein one of the first component and second component is an activated adhesive.

36. The method of claim 28 wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3×10^6 dynes/cm^2 (3×10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C.

37. A method of reducing migration of solids comprising:

providing a fluid composition into a well-bore, the well-bore intersecting a subterranean formation, the fluid composition comprising a first component and a second component dispersed in a carrier fluid, wherein at least a portion of the first component and at least a portion of the second component are provided in multicomponent core sheath fibers, wherein the second component is selected to be tacky at a specific downhole temperature and have a modulus of less than 3 × 10^6 dynes/cm^2 (3 x 10^5 N/m^2) at a frequency of about 1 Hz at a temperature greater than -60°C;

contacting the subterranean formation with the fluid composition;

subsequently, forming a network comprising the first component; and

binding the network with the second component;

wherein the network is in the form of netting that allows oil, gas, or other fluids to pass through relative to particulate matter.

38. The method of claim 37 wherein the second component is an activated adhesive.

39. The method of claim 38 wherein the activated adhesive is selected from pressure-sensitive adhesives, temperature-sensitive adhesives, moisture-sensitive adhesives, and curing agent-sensitive adhesives.

40. The method of claim 37 further comprising modifying the second component after providing the fluid composition into the well-bore.

41. The method of claim 37 further comprising modifying the second component after providing the fluid composition into the well-bore.

42. The method of claim 37 further comprising modifying the second component in stages.

43. The method of claim 37 wherein the solids comprise formation fines.

44. The method of claim 37 wherein the solids comprise proppant.

45. The method of claim 40 wherein the second component is modified by a process selected from temperature activation, chemical activation, pressure activation, mechanical activation, curing, exposure to electromagnetic fields, exposure to electromagnetic radiation, exposure to ionizing radiation, physical entanglement, degradation, concurrently application of at least two of these processes, consecutive application of at least two of these processes, and combinations thereof.

46. The method of claim 37 wherein the fluid composition further comprises proppant.

47. The method of claim 1, wherein the fluid composition does not include proppant.

48. The method of claim 10, wherein the fluid composition does not include proppant.

49. The method of claim 26, wherein the fluid composition does not include proppant.

50. The method of claim 37, wherein the fluid composition does not include proppant.

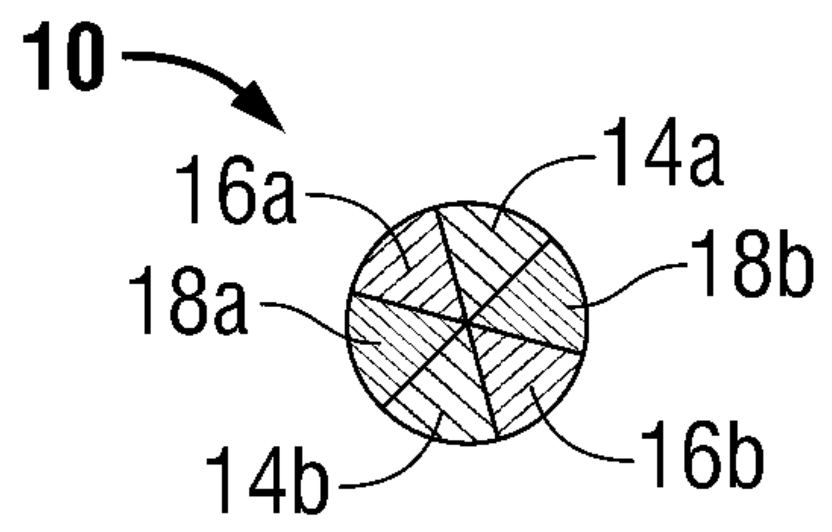


FIG. 1A

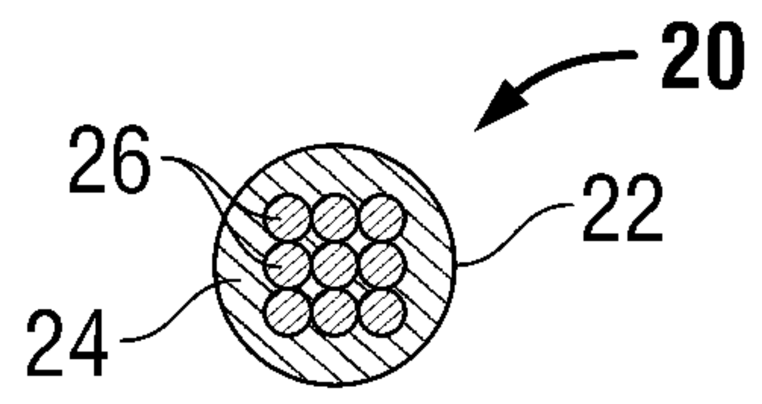


FIG. 1B

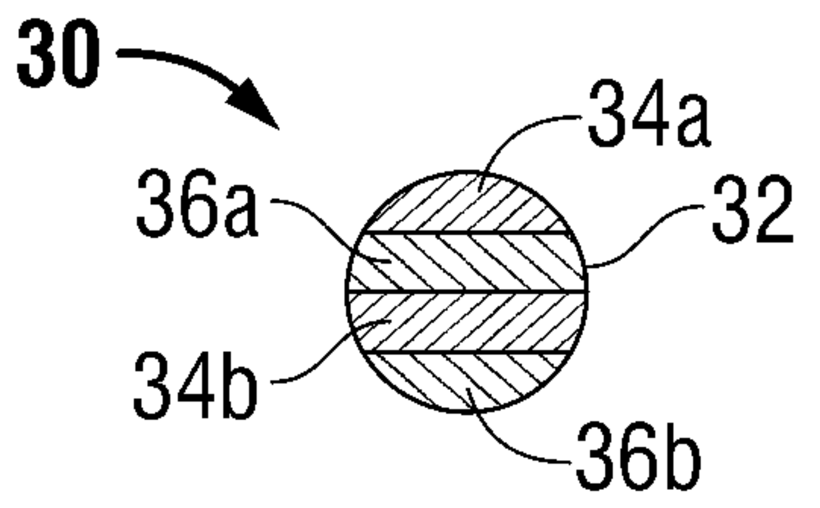


FIG. 1C

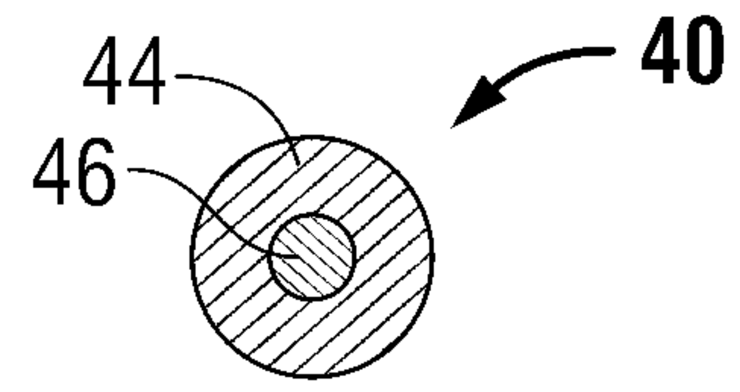


FIG. 1D

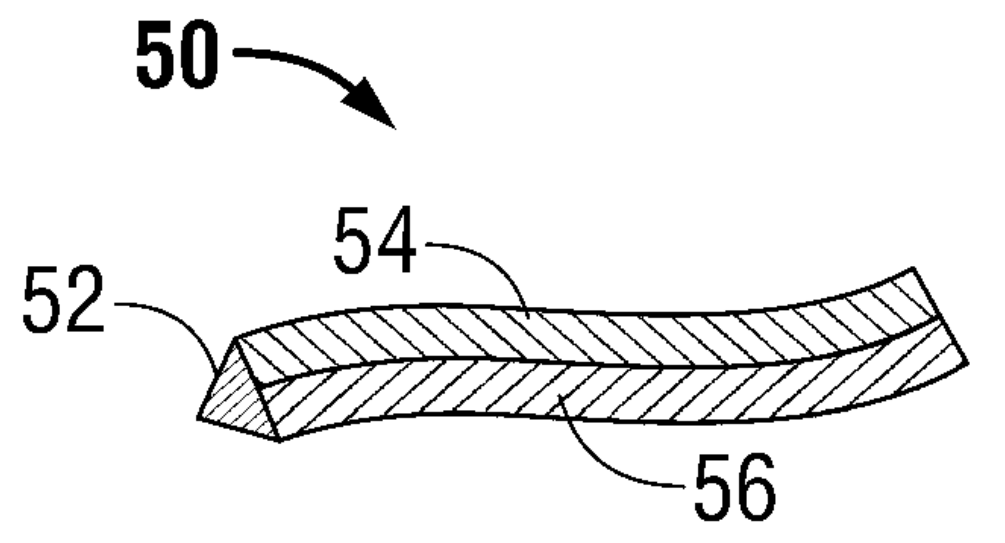


FIG. 2A

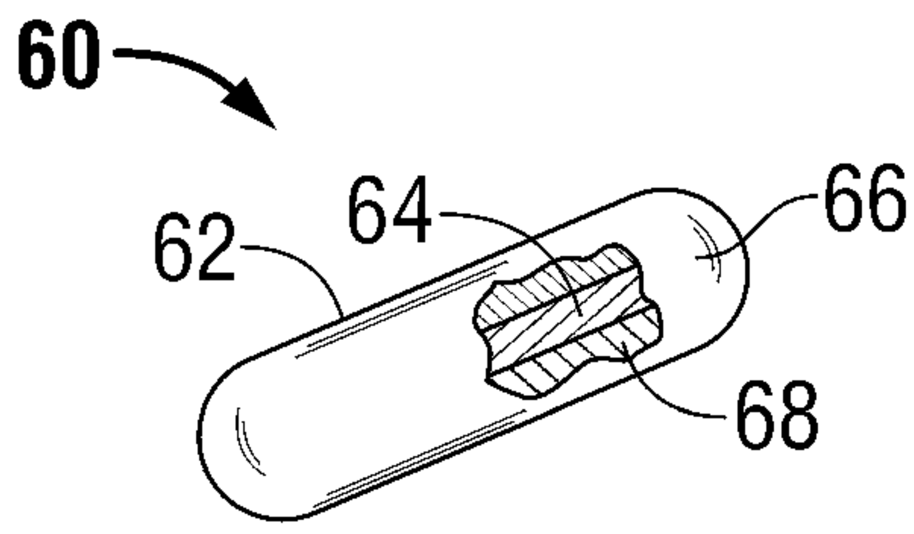


FIG. 2B

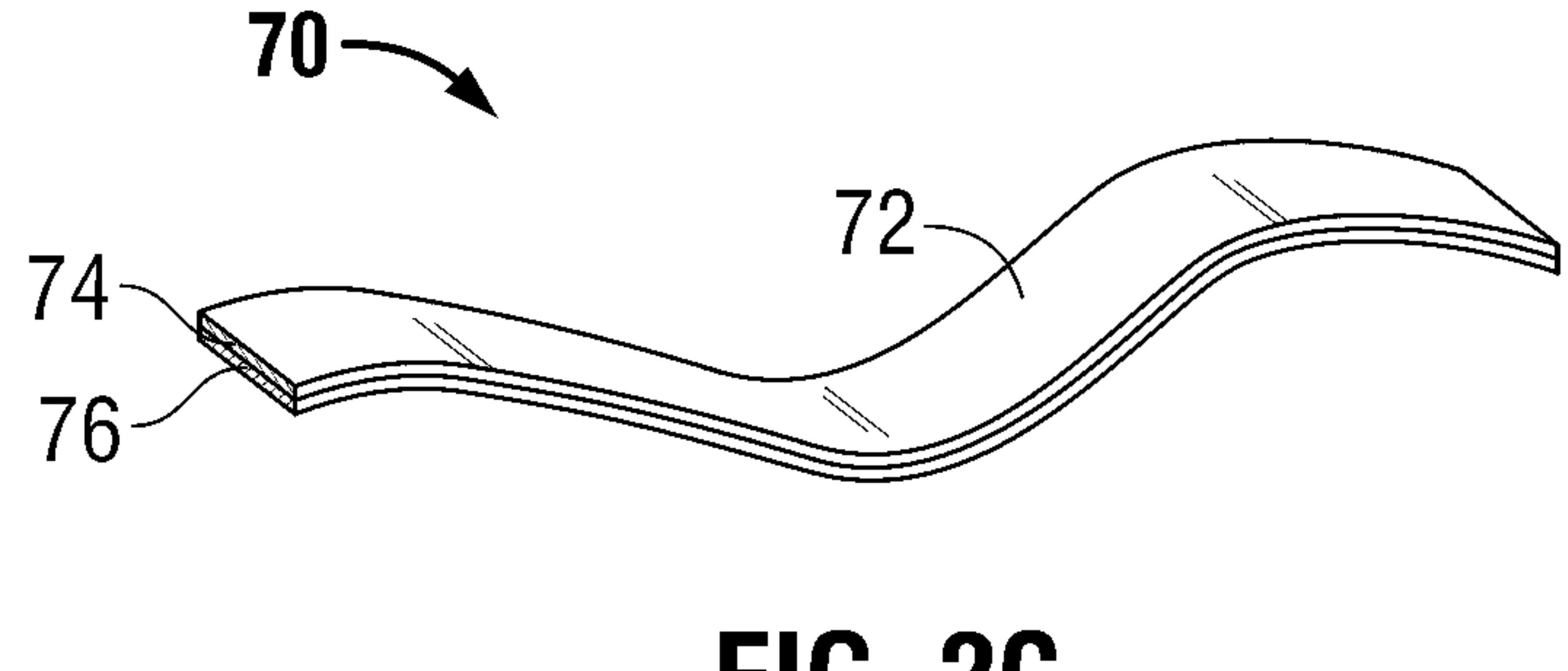


FIG. 2C

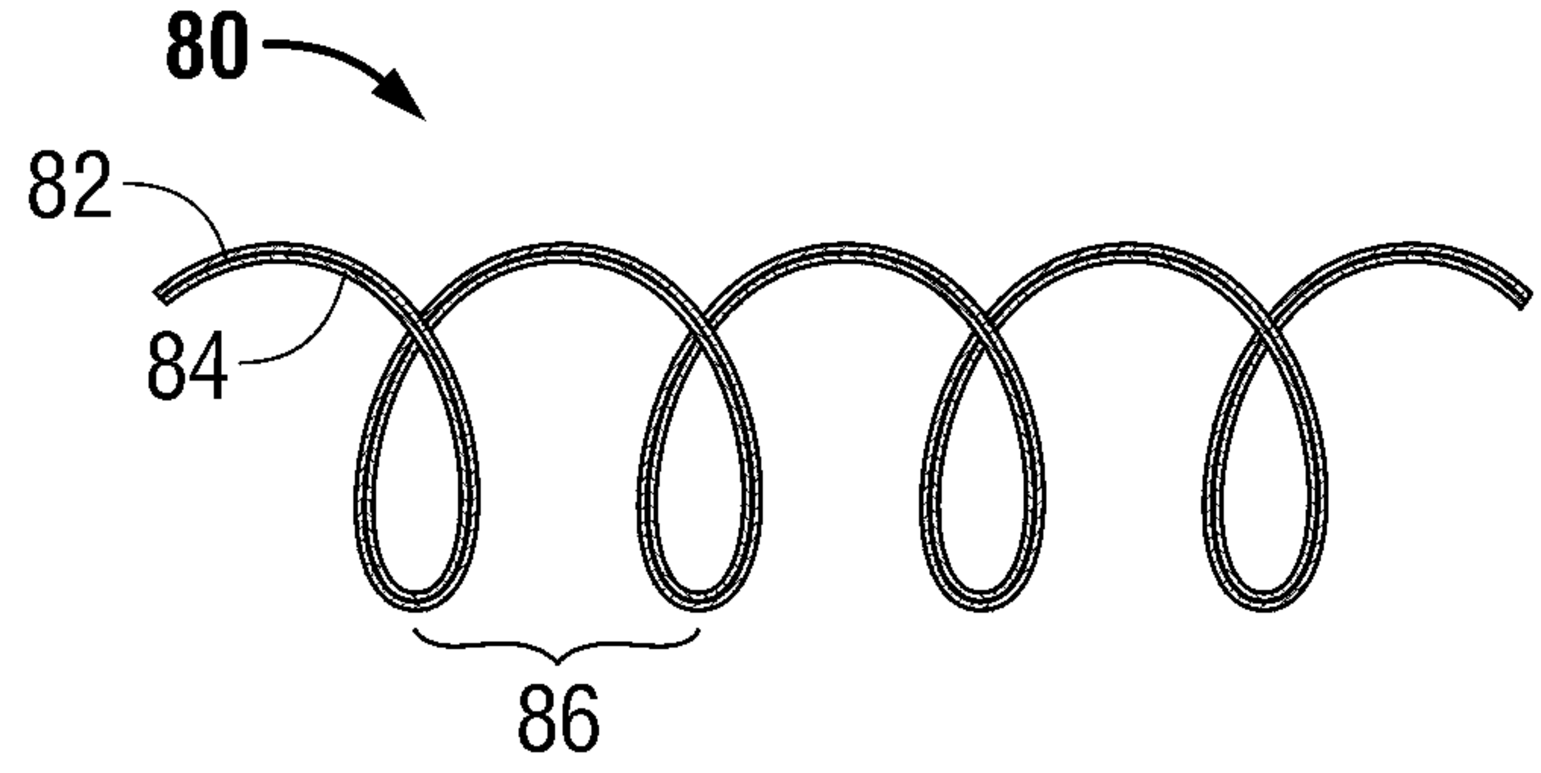


FIG. 2D

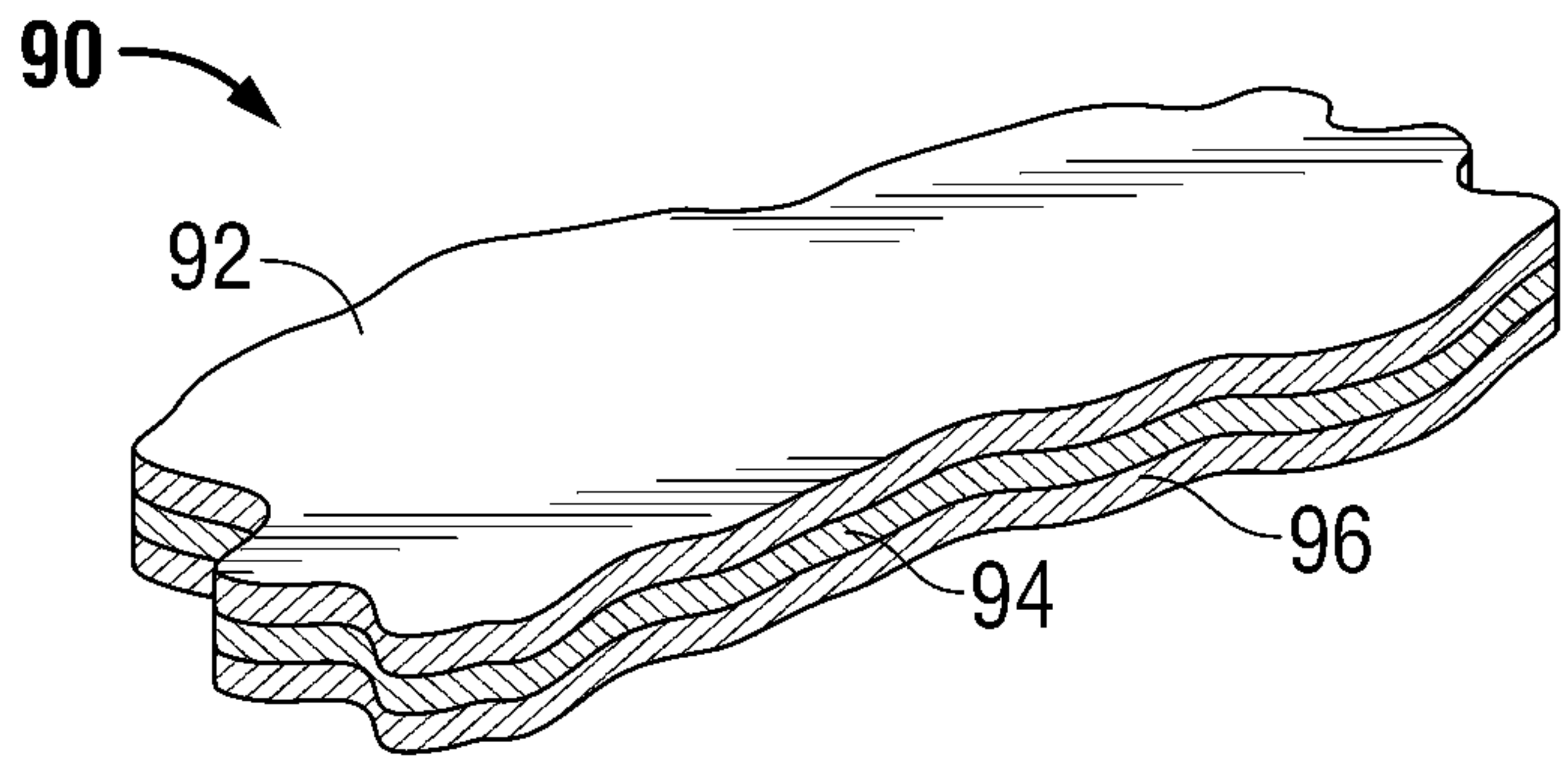


FIG. 2E

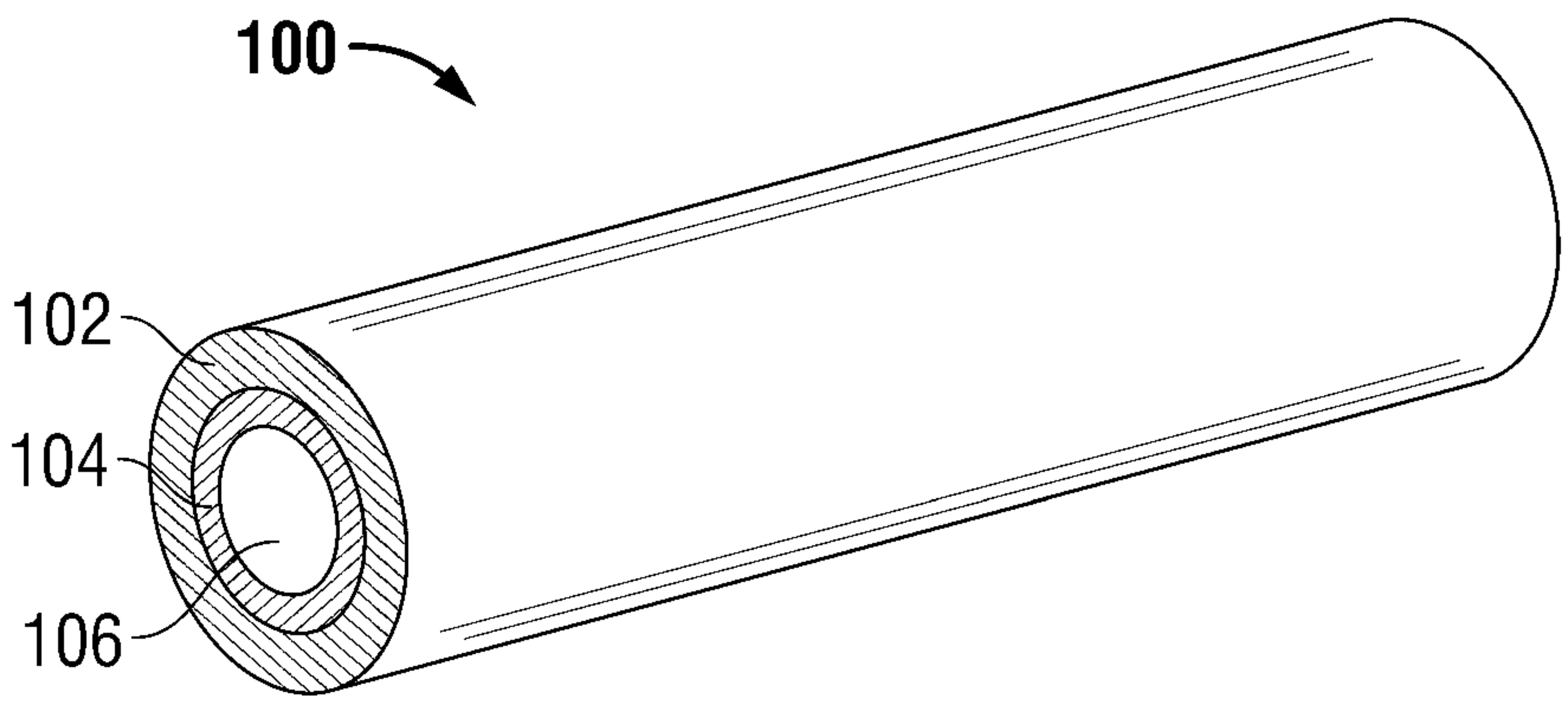


FIG. 2F

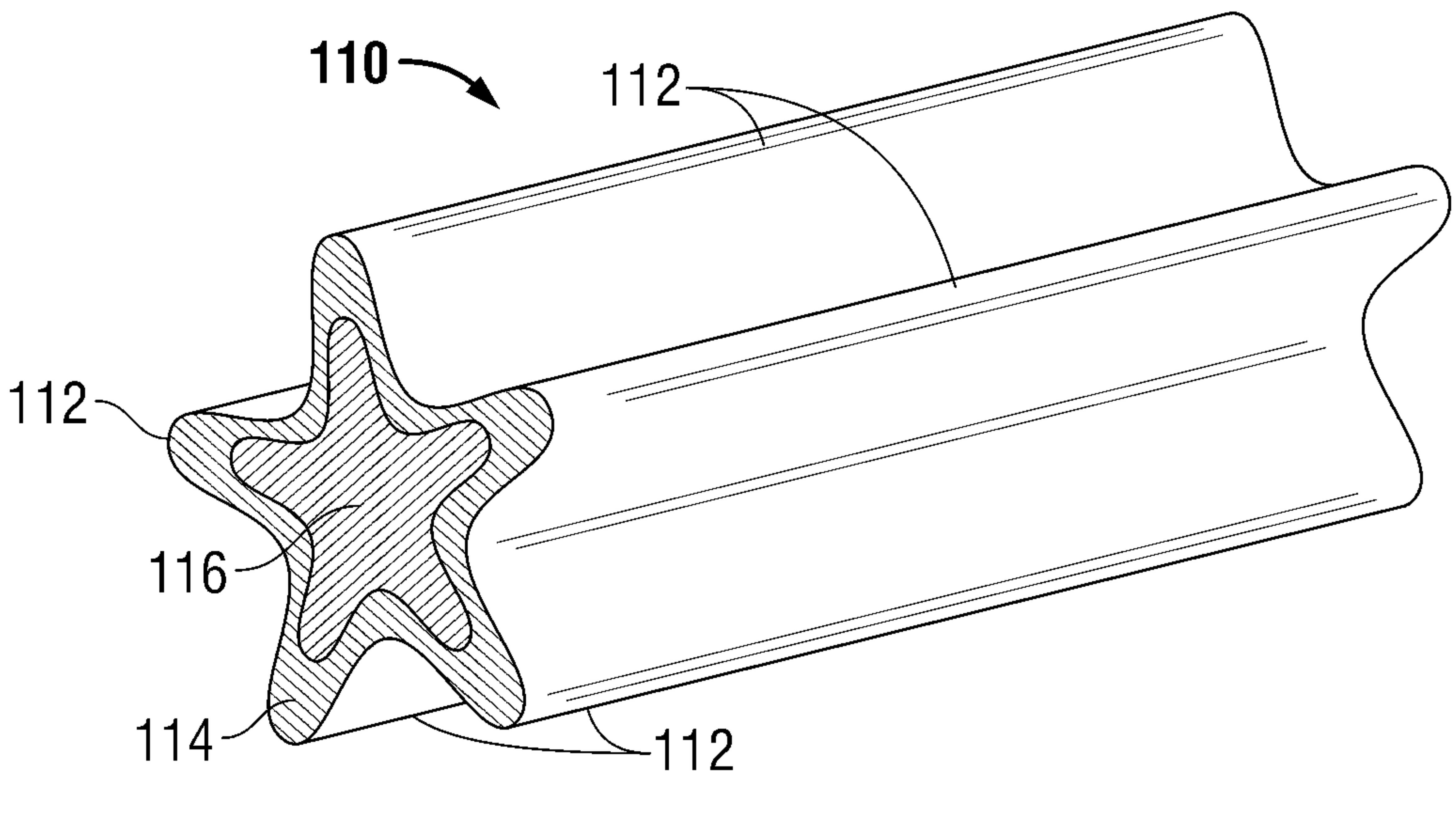


FIG. 2G

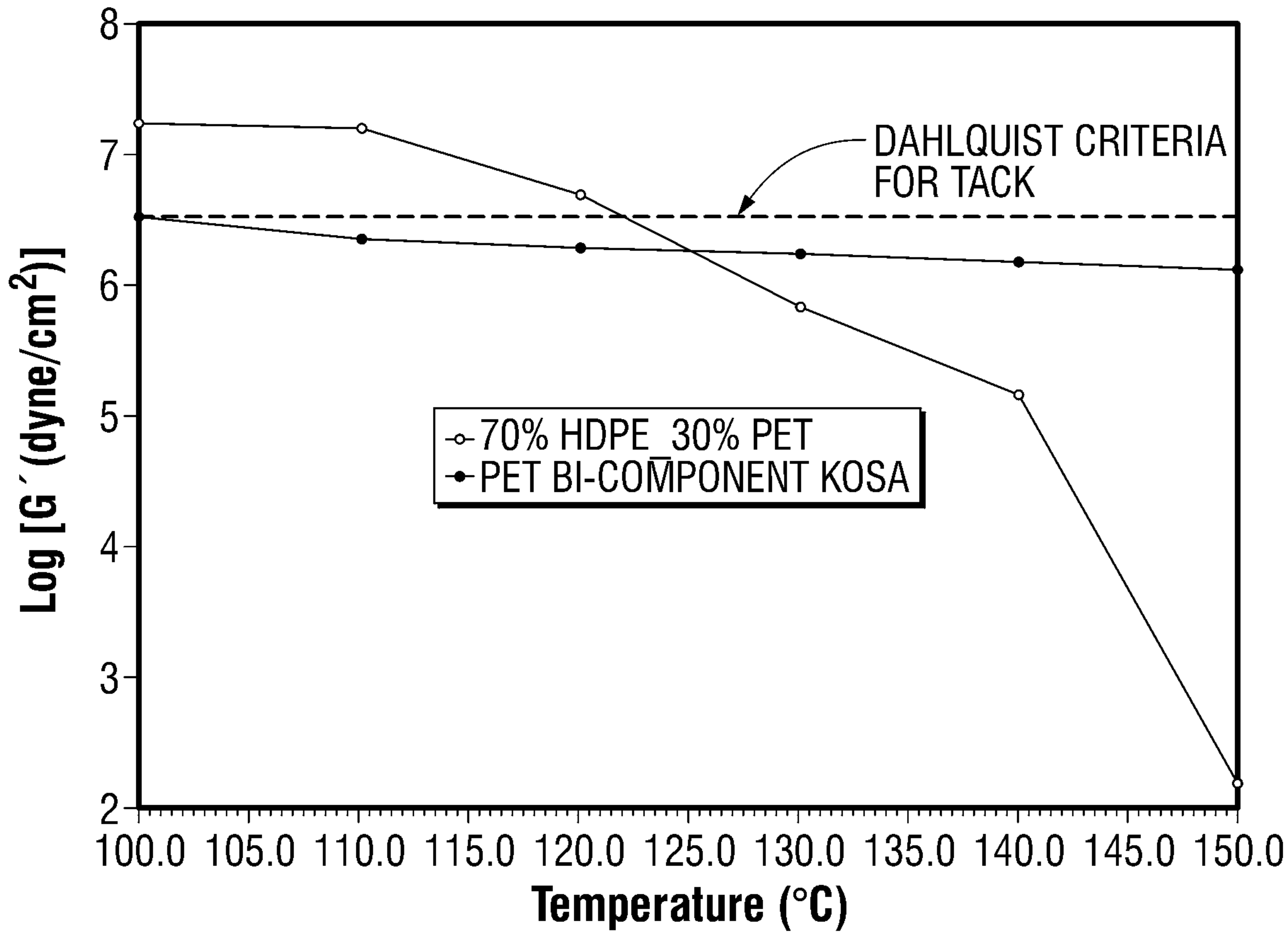

DAHLQUIST CRITERIA FOR TACK
70% HDPE_30% PET
PET BI-COMPONENT KOSA
Log [G´ (dyne/cm²)]
Temperature (°C)
8
7
6
5
4
3
2
100.0
105.0
110.0
115.0
120.0
125.0
130.0
135.0
140.0
145.0
150.0

FIG. 3

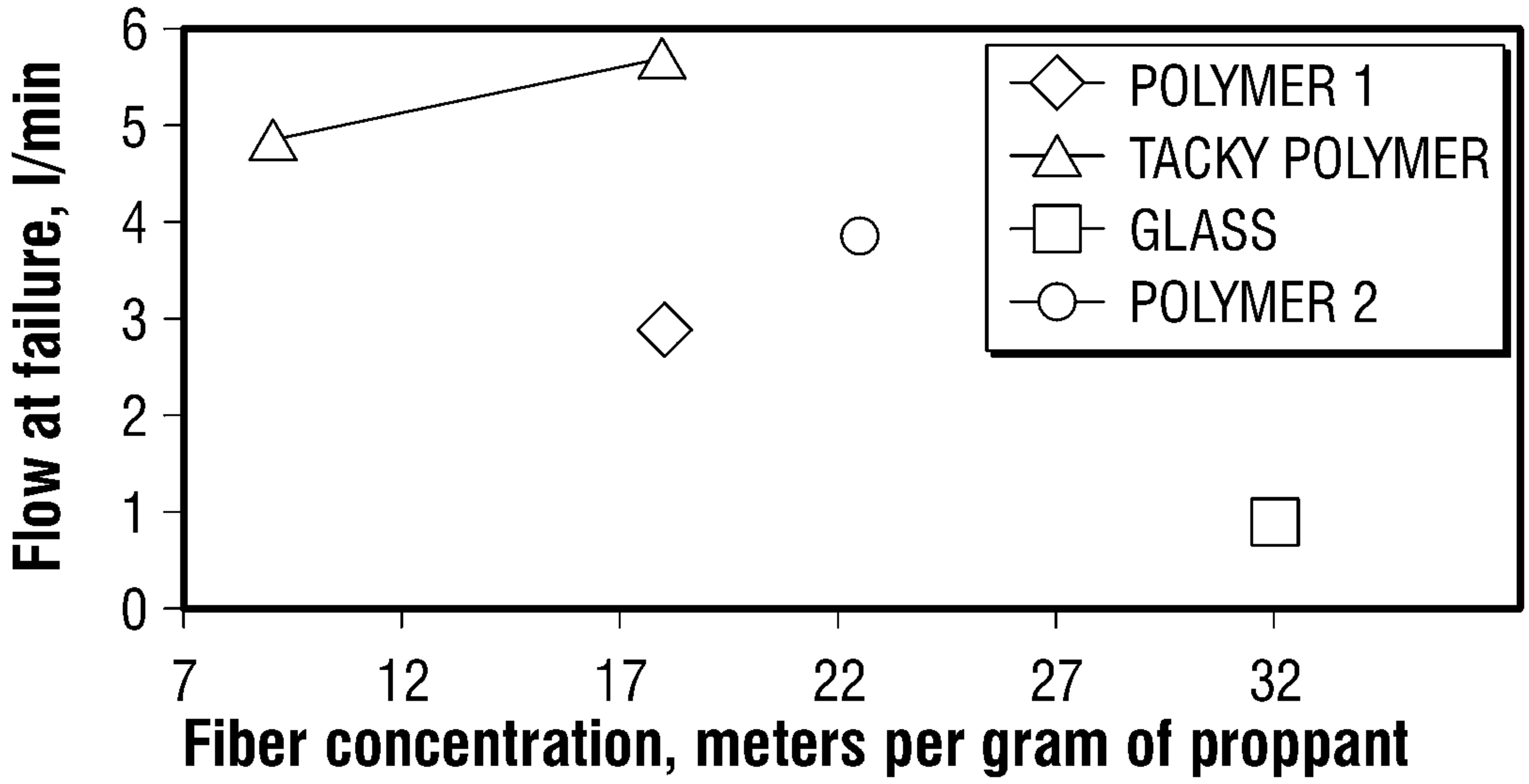
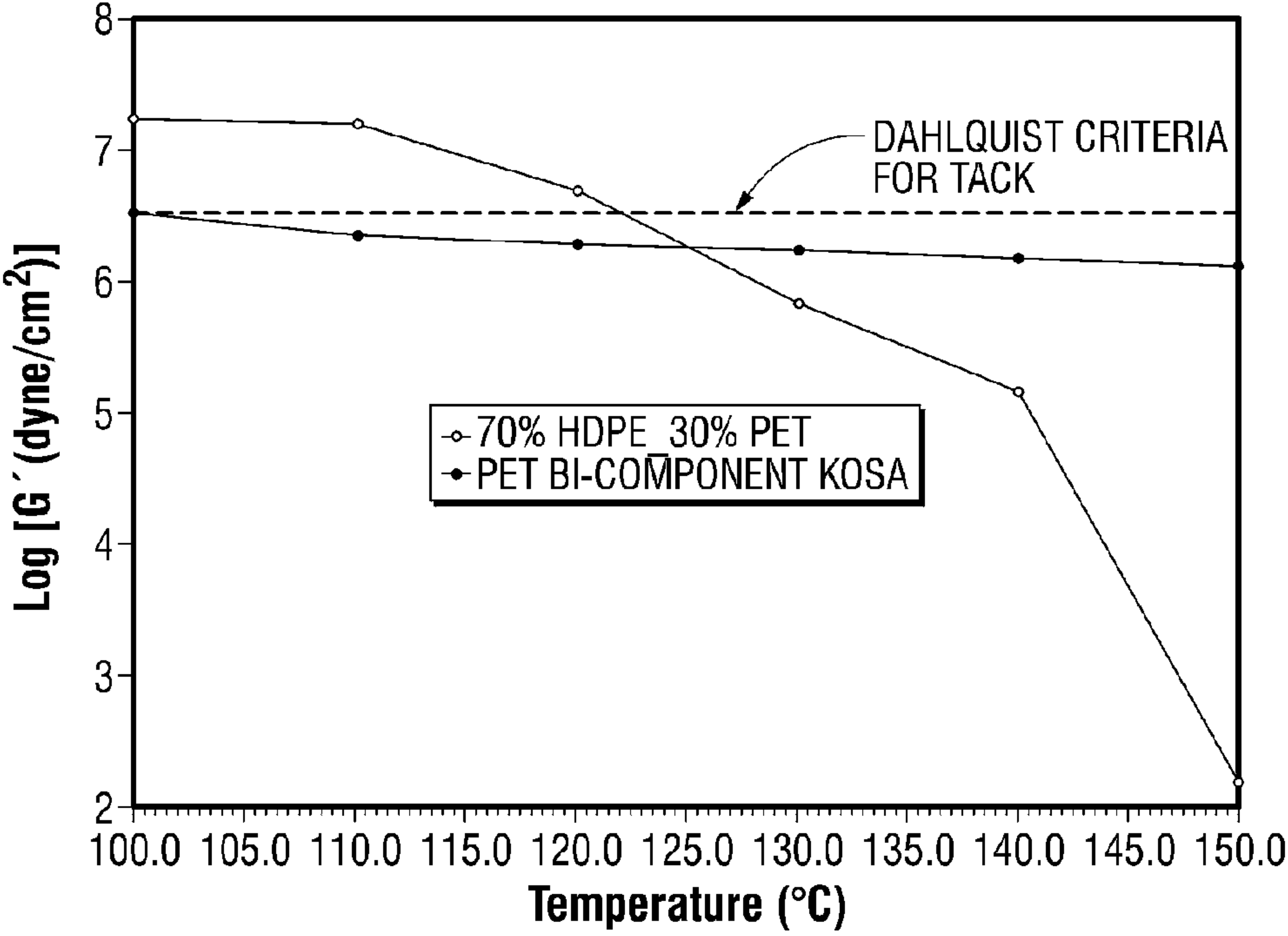

POLYMER 1
TACKY POLYMER
GLASS
POLYMER 2
Flow at failure, l/min
Fiber concentration, meters per gram of proppant
6
5
4
3
2
1
0
7
12
17
22
27
32

FIG. 4



DAHLQUIST CRITERIA
FOR TACK
70% HDPE_30% PET
PET BI-COMPONENT KOSA
Log [G´(dyne/cm2)]
8
7
6
5
4
3
2
100.0
105.0
110.0
115.0
120.0
125.0
130.0
135.0
140.0
145.0
150.0
Temperature (°C)