A wellbore servicing system comprising a flowpath comprising a first conduit from a water source to a mixer, a first fluid stream being communicated via the first conduit, the mixer, a wellbore servicing fluid being mixed within the mixer, and a second conduit from the fluid mixer to a wellbore, a wellbore servicing fluid stream being communicated via the second conduit, wherein at least a portion of the first fluid stream, the wellbore servicing fluid, the wellbore servicing fluid stream, or combinations thereof, are in contact with a quantity of template-assisted crystallization beads.
PROVIDING A SERVICING FLUID TREATMENT SYSTEM AT A WELLBORE

OPTIONALLY, CONTACTING A WELLBORE SERVICING FLUID COMPONENT (E.G., WATER) WITH A QUANTITY OF TEMPLATE-ASSISTED CRYSTALLIZATION BEADS

FORMING A WELLBORE SERVICING FLUID

OPTIONALLY, CONTACTING THE WELLBORE SERVICING FLUID WITH A QUANTITY OF TEMPLATE-ASSISTED CRYSTALLIZATION BEADS

DELIVERING THE WELLBORE SERVICING FLUID INTO A WELLBORE PENETRATING A SUBTERRANEAN FORMATION, THE SURROUND FORMATION, OR BOTH

FIG. 4
WELLBORE SERVICING SYSTEM AND METHODS OF USE

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] The subject matter disclosed herein is related to U.S. patent application Ser. No. [Att'y Docket No. HES 2011-1P-050223U1], by Weaver et al. and entitled "Method and System for Servicing a Wellbore," which is filed concurrently herewith, and which is incorporated herein by reference in its entirety.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

REFERENCE TO A MICROFICHE APPENDIX

[0004] Not applicable.

BACKGROUND

[0005] Suitable fluid supplies are sometimes required to prepare wellbore servicing fluids employed in the performance of various wellbore servicing operations. Water supplies may be provided from varying sources, such as municipal water, surface water and flowback water from the wellbore. The sources of water used in the preparation of wellbore servicing equipment may include multivalent cations, such as hard ions containing, for example, calcium and magnesium. For instance, flowback water from a subterranean formation may carry with it entrained hard ions from the formation. Relatively high concentrations of hard ions may lead to the damaging of wellbore servicing equipment through corrosion and the formation of scale on the inner flow surfaces of the wellbore servicing equipment. Accordingly, there is a need for effectively lowering the concentration of multivalent cations, such as hard ions, within fluid streams used in the preparation of wellbore servicing equipment.

SUMMARY

[0006] Disclosed herein is a wellbore servicing system comprising a flowpath comprising a first conduit from a water source to a mixer, a first fluid stream being communicated via the first conduit, the mixer, a wellbore servicing fluid being mixed within the mixer, and a second conduit from the fluid mixer to a wellbore, a wellbore servicing fluid stream being communicated via the second conduit, wherein at least a portion of the first fluid stream, the wellbore servicing fluid, the wellbore servicing fluid stream, or combinations thereof, are in contact with a quantity of template-assisted crystallization beads.

[0007] Also disclosed herein is a wellbore servicing method comprising communicating a first fluid to at least one component of wellbore servicing equipment via a first conduit, adding at least one component of a wellbore servicing fluid to the first fluid to form the wellbore servicing fluid, communicating the wellbore servicing fluid to a wellbore via a second conduit, wherein at least a portion of the first fluid, the at least one component of wellbore servicing fluid, the wellbore servicing fluid, or combinations thereof, are in contact with a quantity of template-assisted crystallization beads.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] For a more complete understanding of the present disclosure and the advantages thereof, reference is now made to the following brief description, taken in connection with the accompanying drawings and detailed description:

[0009] FIG. 1 is a simplified schematic view of a wellbore and a servicing fluid treatment system for the treatment of a wellbore servicing fluid according to an embodiment of the disclosure;

[0010] FIG. 2A is a simplified schematic view of a servicing fluid treatment system according to an embodiment of the disclosure;

[0011] FIG. 2B is a simplified schematic view of a fluid treatment unit according to an embodiment of this disclosure;

[0012] FIG. 3 is a simplified schematic view of a servicing fluid treatment system according to an alternative embodiment of the disclosure; and

[0013] FIG. 4 is a flowchart of a method according to an embodiment of the invention.

DETAILED DESCRIPTION OF THE EMBODIMENTS

[0014] In the drawings and description that follow, like parts are typically marked throughout the specification and drawings with the same reference numerals, respectively. In addition, similar reference numerals may refer to similar components in different embodiments disclosed herein. The drawing figures are not necessarily to scale. Certain features of the invention may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness. The present invention is susceptible to embodiments of different forms. Specific embodiments are described in detail and are shown in the drawings, with the understanding that the present disclosure is not intended to limit the invention to the embodiments illustrated and described herein. It is to be fully recognized that the different teachings of the embodiments discussed herein may be employed separately or in any suitable combination to produce desired results.

[0015] Unless otherwise specified, use of the terms "connect," "engage," "couple," "attach," or any other like term describing an interaction between elements is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described.

[0016] Unless otherwise specified, use of the terms "up," "upper," "upward," "up-hole," "upstream," or other like terms shall be construed as generally from the formation toward the surface or toward the surface of a body of water; likewise, use of "down," "lower," "downward," "down-hole," "down-stream," or other like terms shall be construed as generally into the formation away from the surface or away from the surface of a body of water, regardless of the wellbore orientation. Use of any one or more of the foregoing terms shall not be construed as denoting positions along a perfectly vertical axis.

[0017] Unless otherwise specified, use of the term "subterranean formation" shall be construed as encompassing both
areas below exposed earth and areas below earth covered by water such as ocean or fresh water.

[0018] Relatively large amounts of fluid (e.g., water) may be needed for the preparation of wellbore servicing fluids, such as drilling fluid, completion fluid, clean-out fluids, cementitious slurries, stimulation fluids (for example, fracturing and/or perforating fluids), acidizing fluids, gravel-packing fluids, or the like. Common fluid sources used for preparing wellbore servicing fluids include water co-produced in the production of oil and gas, hereinafter referred to as produced water, surface water, well water, and municipal water. Water obtained from any such sources may contain concentrations of dissolved multivalent ions, including hard ions (e.g., calcium ions, magnesium ions, strontium ions, aluminum ions, etc.). A fluid containing concentrations of dissolved multivalent ions, such as hard ions, may adversely affect the intended function of a wellbore servicing fluid formed therefrom and may contribute to the degradation and/or failure wellbore servicing equipment in contact with the fluid, such as through corrosion and/or the formation of scale (e.g., in the form of calcium and/or magnesium carbonates) on flow surfaces of such wellbore servicing equipment. Further, concentrations of such multivalent ions, including hard ions, may adversely affect the intended function of a wellbore servicing fluid and/or render the fluid unusable for use in wellbore servicing operations and/or for use in the production of a wellbore servicing fluid.

[0019] Disclosed herein are embodiments of wellbore servicing apparatus, compositions, systems, and methods of using the same. Particularly, embodiments of a servicing fluid treatment system for the treatment of a wellbore servicing fluid and/or one or more components thereof, will be disclosed herein.

[0020] FIG. 1 schematically illustrates an embodiment of an environment in which a servicing fluid treatment (SFT) system may be deployed. In the embodiment of FIG. 1, such an operating environment comprises a wellsite 100 including a wellbore 115 penetrating a subterranean formation 125 for the purpose of recovering hydrocarbons, storing hydrocarbons, disposing of carbon dioxide, injecting wellbore servicing fluids, or the like. In the embodiment of FIG. 1, a SFT system 110 for the treatment of a wellbore servicing fluid is deployed at a wellsite 100 and is fluidly coupled to the wellbore 115 via a wellhead 160. The wellbore 115 may be drilled into the subterranean formation 125 using any suitable drilling technique. In an embodiment, a drilling or servicing rig 130 may generally comprise a derrick with a rig floor through which a tubular string 135 (e.g., a drill string, a work string, such as a segmented tubing, coiled tubing, jointed pipe, or the like; a casing string; or combinations thereof) having an inner flow surface or bore 137 may be lowered into the wellbore 115. A wellbore servicing apparatus 140 configured for one or more wellbore servicing operations (e.g., a cementing or completion operation, a clean-out operation, a perforating operation, a fracturing operation, production of hydrocarbons, etc.) may be integrated within the tubular string 135 for the purpose of performing one or more wellbore servicing operations. Additional downhole tools may be included with and/or integrated within the wellbore servicing apparatus 140 and/or the tubular string 135, for example, one or more isolation devices 145 (for example, a packer, such as a swellable or mechanical packer) may be positioned within the wellbore 115 for the purpose of isolating a portion of the wellbore 115.

[0021] The drilling or servicing rig may be conventional and may comprise a motor driven winch and other associated equipment for lowering the tubular string 135 and/or wellbore servicing apparatus 140 into the wellbore 115. Alternatively, a mobile workover rig, a wellbore servicing unit (e.g., coiled tubing units), or the like may be used to lower the tubular string 135 and/or wellbore servicing apparatus 140 into the wellbore 115 for the purpose of performing a wellbore servicing operation.

[0022] The wellbore 115 may extend substantially vertically away from the earth’s surface 150 over a vertical wellbore portion, or may deviate at any angle from the earth’s surface 150 over a deviated or horizontal wellbore portion. Alternatively, portions or substantially all of the wellbore 115 may be vertical, deviated, horizontal, and/or curved. In some instances, a portion of the tubular string 135 may be secured into position within the wellbore 115 in a conventional manner using cement 155; alternatively, the tubular string 135 may be partially cemented in wellbore 115; alternatively, the tubular string 135 may be uncemented in the wellbore 115. In an embodiment, the tubular string 135 may comprise two or more concentrically positioned strings of pipe (e.g., a first pipe string such as jointed pipe or coiled tubing may be positioned within a second pipe string such as casing cemented within the wellbore). It is noted that although one or more of the figures may exemplify a given operating environment, the principles of the devices, systems, and methods disclosed may be similarly applicable in other operational environments, such as offshore and/or subsea wellbore applications.

[0023] In an embodiment, the SFT system 110 may be coupled to the wellhead 160 via a conduit 165 having an inner flow surface or bore 167, and the wellhead 160 may be connected to (e.g., fluidly) the tubular string 135. In various embodiments, the tubular string 135 may comprise a casing string, a liner, a production tubing, coiled tubing, a drilling string, the like, or combinations thereof. The tubular string 135 may extend from the earth’s surface 150 downward within the wellbore 115 to a predetermined or desirable depth, for example, such that the wellbore servicing apparatus 140 is positioned substantially proximate to a portion of the subterranean formation 125 to be serviced (e.g., into which a fracture 170 is to be introduced). Flow arrows 180 and 175 indicate a route of fluid communication from the SFT system 110 to the wellhead 160 via conduit 165, from the wellhead 160 to the wellbore servicing apparatus 140 via tubular string 135, and from the wellbore servicing apparatus 140 into the wellbore 115 and/or into the subterranean formation 125 (e.g., into fractures 170). The wellbore servicing apparatus 140 may be configured to perform one or more servicing operations, for example, fracturing the formation 125, hydraulic fracturing and/or perforating casing (when present) and/or the formation 125, expanding or extending a fluid path through or into the subterranean formation 125, producing hydrocarbons from the formation 125, or other servicing operation. In an embodiment, the wellbore servicing apparatus 140 may comprise one or more ports, apertures, nozzles, jets, windows, or combinations thereof suitable for the communication of fluid from a flowbore of the tubular string 135 and/or a flowbore of the wellbore servicing apparatus 140 to the subterranean formation 125. In an embodiment, the wellbore servicing apparatus 140 is actuable (e.g., opened or closed), for example, comprising a housing comprising a plurality of housing ports and a sleeve being movable with
respect to the housing, the plurality of housing ports being selectively obstructed or unobstructed by the sliding sleeve so as to provide a fluid flowpath to and/or from the wellbore servicing apparatus 140 into the wellbore 115, the subterranean formation 125, or combinations thereof. In an embodiment, the wellbore servicing apparatus 140 may be configurable for the performance of multiple wellbore servicing operations.

In an embodiment, the SFT system generally comprises a flowpath in which a wellbore servicing fluid and/or a component thereof is brought into contact with a quantity of template assisted crystallization (TAC) beads. FIGS. 2A and 3 schematically illustrate embodiments of the SFT system 110. In the embodiment of FIG. 2A, the SFT system 110 generally comprises a flowpath from (e.g., via fluidly connecting) a fluid source 200 (e.g., a water source), a fluid treatment unit (FTU) 220, one or more storage vessels (such as storage vessels 210, 310, 320, and 330) a blender 340, a wellbore services manifold 350, and one or more high-pressure (HP) pumps 360. Alternatively, in the embodiment of FIG. 3, the SFT system 110 generally comprises a flowpath from a fluid source 200 (e.g., a water source), one or more storage vessels (such as storage vessels 210, 320, and 330) a blender 340, a wellbore services manifold 350, and one or more HP pumps 360. In an alternative or additional embodiment, an SFT system may comprise any suitable additional components, or any suitable combination of any of these or any additional components.

In the embodiment of FIG. 2A, the FTU 220 is fed a fluid (e.g., water), either directly or indirectly, from fluid source 200. Water from the FTU 220 is introduced, either directly or indirectly, into the blender 340 where the water is mixed with various wellbore servicing fluid components and/or additives to form a wellbore servicing fluid. The wellbore servicing fluid is introduced into the wellbore services manifold 350, pressurized in the one or more HP pumps 360 which are in fluid communication with the wellbore services manifold, and then communicated to the wellhead 160 via conduit 165. Alternatively, in the embodiment of FIG. 3, a fluid (e.g., water) is introduced, either directly or indirectly, from the fluid source 200 into the blender 340. As will be described herein, the fluid communication between two or more components of the SFT system 110 and/or the FTU 220 may be provided by any suitable flowline or conduit having an inner flow surface generally defining a flowpath or flowbore. Persons of ordinary skill in the art with the aid of this disclosure will appreciate that the flowlines described herein may include various configurations of piping, tubing, etc. that are fluidly connected, for example, via flanges, collars, welds, etc. These flowlines may include various configurations of pipe tees, elbows, and the like. These flowlines fluidly connect the various wellbore servicing fluid process equipment described herein.

In an embodiment, an SFT system like SFT system 110 may be configured for any suitable wellbore servicing operation, such as a drilling operation, a hydrajetting or perforating operation, a remediation operation, a fluid loss control operation, a primary or secondary cementing operation, or combinations thereof. For example, in the embodiment of FIG. 1, the SFT system is illustrated as configured for a subterranean formation stimulation operation (e.g., perforating and/or fracturing), for example, for initiating, forming, or extending a fracture (such as fractures 170 of FIG. 1) within a hydrocarbon-bearing portion of a subterranean formation (such as subterranean formation 125), or a portion thereof. In such a stimulation operation (e.g., a hydraulic fracturing operation), a wellbore servicing fluid, such as a particle (e.g., proppant) laden fluid (e.g., a fracturing fluid), may be introduced, at a relatively high-pressure, into the wellbore 115. The particle laden fluids may then be introduced into a portion of the subterranean formation 125 at a rate and/or pressure sufficient to initiate, create, or extend one or more fractures 170 within the subterranean formation 125. Proppants (e.g., grains of sand, glass beads, shells, ceramic particles, etc.) may be mixed with the wellbore servicing fluid, for example, so as to keep the fractures open (e.g., to “prop” the fractures) such that hydrocarbons may flow into the wellbore 115 so as to be produced from the subterranean formation 125. Hydraulic fracturing may create high-conductivity fluid communication between the wellbore 115 and the subterranean formation 125, for example, to enhance production of fluids (e.g., hydrocarbons) from the formation.

In an embodiment, the fluid source 200 (e.g., a water source) may comprise a source for produced water, flowback water, surface water, well water, potable water, municipal water, or combinations thereof. For example, in an embodiment, the water obtained from the fluid source 200 may comprise produced water that has been extracted from the wellbore 115 while producing hydrocarbons from the wellbore 115. As discussed above, produced water may comprise dissolved multivalent ions, such as hard ions (e.g., calcium ions, magnesium ions, strontium ions, aluminum ions, etc.) and/or other natural or synthetic constituents that are displaced from a hydrocarbon formation during the production of the hydrocarbons or from a wellbore servicing operation. In an additional or alternative embodiment, water obtained from the fluid source 200 may comprise flowback water, for example, water that has previously been introduced into the wellbore 115 during a wellbore servicing operation and subsequently flowed back or returned to the surface. In addition, the flowback water may comprise hydrocarbons, gelling agents, friction reducers, surfactants, and/or remnants of wellbore servicing fluids previously introduced into the wellbore 115 during wellbore servicing operations.

In another additional or alternative embodiment, water obtained from the fluid source 200 may comprise local surface water contained in natural and/or manmade water features (such as ditches, ponds, rivers, lakes, oceans, etc.). Further, water obtained from the fluid source 200 may comprise water obtained from water wells or a municipal source. Water obtained from the fluid source 200 may comprise water that originated from near the wellbore 115 and/or may be water or another liquid (e.g., a non-aqueous fluid) that has been transported to an area near the wellbore 115 from any distance. Still further, water or another fluid obtained from the fluid source 200 may comprise water stored in local or remote containers. In some embodiments, water obtained from the fluid source 200 may comprise any combination of produced water, flowback water, local surface water, and/or container-stored water. As discussed earlier, local surface water, municipal water, water from local or remote containers, etc., may also include multivalent ions, such as hard ions. In an embodiment, for example, in the embodiment of FIG. 2A, the water from fluid source 200 may be introduced via a conduit 202 having an inner flow surface 204 into an untreated water storage vessel 210 where it may be temporarily stored prior to being pumped to FTU 220 via a conduit 212 having an inner flow surface 214; alternatively, the water may be introduced
directly from the fluid source 200 into the FTU 220. Alternatively, for example, in the embodiment of FIG. 3, the water from the fluid source 200 may be introduced via the conduit 202 having an inner flow surface 204 into the untreated water storage vessel 210 where it may be temporarily stored prior to being pumped into the blender 340 via conduit 312 having an inner flow surface 314; alternatively, the water may be introduced directly from the fluid source into the blender 340.

[0029] In an embodiment, the FTU 220, as will be disclosed herein with reference to FIG. 2B, may be configured to treat a fluid (e.g., water) obtained from the fluid source 200 in order to render the water suitable for use in preparing a wellbore servicing fluid and/or for utilization in a wellbore servicing operation. For example, as will be disclosed herein, the FTU 220 may be configured to remove one or more constituents within the water (e.g., hard ions) that may negatively affect the performance of the wellbore servicing equipment that the water contacts. In an embodiment, after treatment via the FTU 220, the water may be introduced via a conduit 222 having an inner flow surface 224 into an intermediate storage vessel 310 for treated water; alternatively, the water may be routed to one or more other components of the SFT system 110.

[0030] In the embodiments of FIGS. 2A and 3, the water may be introduced into a mixer or blender 340 from a storage vessel (e.g., the intermediate storage vessel 310 in the embodiment of FIG. 2A or storage vessel 210 in the embodiment of FIG. 3) via a conduit 312 having an inner flow surface 314. Alternatively, in the embodiment of FIG. 2A, the water may be introduced into the blender 340 directly from the FTU 220. In an embodiment, the blender 340 may be configured to mix solid and fluid components to form a well-blended wellbore servicing fluid. As depicted in the embodiments of FIGS. 2A and 3, water from a storage vessel (e.g., storage vessel 210 and/or 310), a wellbore servicing fluid component from storage vessel 320, and one or more other components such as additives from storage vessel 330 may be fed into the blender 340 via conduits 321 or 312, 322 and 332, respectively. The blender 340 may comprise any suitable type and/or configuration of blender. The mixing conditions of the blender 340, including time period, agitation method, pressure, and temperature of the blender 340, may be chosen by one of ordinary skill in the art with the aid of this disclosure to produce a homogeneous blend having a desirable composition, density, and viscosity. In alternative embodiments, however, sand or proppant (e.g., wellbore servicing fluid components), water, and additives may be premixed and/or stored in a storage tank before entering the blender 340. For example, in an embodiment an Advanced Dry Polymer (ADP) blender may be utilized to dry blend one or more dry components, which may then be dry fed into the blender 340. In another embodiment, additives may be pre-blended with water or other liquids, for example, using a GEL PRO blender, which is a commercially available from Halliburton Energy Services, Inc., to form a liquid gel concentrate that may be fed into the blender 340. In the embodiment of FIGS. 2A and 3, the blender 340 is in fluid communication with a wellbore services manifold 350 via a conduit 342 having an inner flow surface 344.

[0031] In the embodiments of FIGS. 2A and 3, the wellbore servicing fluid may be introduced into the wellbore services manifold 350 from the blender 340 via conduit 342. As used herein, the term “wellbore services manifold” may include a mobile vehicle, such as a truck and/or trailer, comprising one or more manifolds for receiving, organizing, and/or distributing wellbore servicing fluids during wellbore servicing operations. In the embodiment illustrated by FIGS. 2A and 3, the wellbore services manifold 350 is coupled to eight HP pumps 360 and outlet conduits 352 having inner flow surfaces 354 and inlet conduits 362 having inner flow surfaces 364. In alternative embodiments, however, there may be more or fewer HP pumps 360 used in a wellbore servicing operation. The HP pumps 360 may comprise any suitable type of high pressure pump, a nonlimiting example of which is a positive displacement pump. Outlet conduits 352 are outlet faces from the wellbore services manifold 350 that supply fluid to the HP pumps 360. Inlet conduits 362 are inlet lines from the HP pumps 360 that supply fluid to the wellbore services manifold 350. In an embodiment, the HP pumps 360 may be configured to pressurize the wellbore servicing fluid to a pressure suitable for delivery into the wellhead 160. For example, the HP pumps 360 may increase the pressure of the wellbore servicing fluid to a pressure of about 10,000 p.s.i., alternatively, about 15,000 p.s.i., alternatively, about 20,000 p.s.i. or higher.

[0032] From the HP pumps 360, the wellbore servicing fluid may reenter the wellbore services manifold 350 via inlet conduits 362 and be combined so that the wellbore servicing fluid may have a total fluid flow rate that exits from the wellbore services manifold 350 through conduit 165 to the wellbore 115 of between about 1 BPM to about 200 BPM, alternatively from between about 50 BPM to about 150 BPM, alternatively about 100 BPM.

[0033] In the embodiment of FIG. 2A, the SFT system 110 comprises a FTU, particularly, FTU 220. In an embodiment, the FTU 220 may be configured to contact a fluid (e.g., from fluid source 200), such as water and a quantity of PAC beads, for example, at a rate and/or ratio sufficient to remove at least a portion of one or more constituents (e.g., hard ions) therefrom. For example, in an embodiment, the FTU 220 is configured to lower the concentration of dissolved multivalent ions, such as hard ions, within a fluid (e.g., from fluid source 200) introduced to the FTU 220. Particularly, in an embodiment as will be disclosed herein, the FTU 220 may be configured to lower the concentration of dissolved multivalent ions, such as hard ions, with a fluid without injecting or dispersing any other fluid or chemical reactant (e.g., a water softener) into the water stream introduced to the FTU 220. Additionally, in an embodiment the FTU 220 may be configured to retain the PAC beads within the FTU 220.

[0034] Referring to FIG. 2B, an embodiment of the FTU 220 is illustrated. In the embodiment of FIG. 2B, the FTU 220 generally comprises at least one fluid column 230 including a plurality of PAC beads 235. For example, in the embodiment of FIG. 2B, the FTU 220 comprises two fluid columns 230; alternatively, a FTU may comprise any suitable number of columns (e.g., one, three, four, five, six, seven, eight, nine, ten, or more columns). In the embodiment of FIG. 2B, the columns 230 are arranged in parallel; alternatively, a plurality of fluid columns may be configured in any suitable arrangement (e.g., in series, or both in series and in parallel). In an embodiment, the fluid columns 230 may be situated on a common structural support, alternatively multiple, separate structural supports. Examples of a suitable structural support or supports for these units may include a trailer, truck, skid, barge or combinations thereof.

[0035] In the embodiment of FIG. 2B, an untreated water stream 211 may be introduced into the fluid columns 230 via the conduit 212. In an embodiment, each of the one or more fluid columns 230 generally comprises a housing 233 having
a cross-sectional area 238 and having a quantity of TAC beads 235 disposed therein. For example, in such an embodiment, each of the one or more columns 230 may comprise a packed column. In such an embodiment, the fluid columns 230 are configured to contact the untreated water stream 211 with the quantity of TAC beads. In an embodiment, the columns may comprise one or more inlets 232 and one or more outlets 234. Also, in such an embodiment, each of the fluid columns 230 are also configured to retain the quantity of TAC beads 235 therein. For example, in the embodiment of FIG. 2b, the columns 230 both support the TAC beads and prevent and/or restrict the loss of any TAC beads, alternatively, the loss of a substantial amount of the TAC beads, therefrom. For instance, the columns may comprise one or more screens, filters, meshes, supports, trays, or combinations therein, which may be placed within the fluid columns 230, at an inlet 232 and/or outlet 234 of the column, upstream and/or downstream from the column 230, or combinations thereof. In such an embodiment, the pore or opening sizes of such a screen, filter, and/or mesh may be chosen based on the sizing, type and/or volume of the TAC beads within the fluid column 230. For instance, in an embodiment, the fluid column 236 may contain one or more of a screen, filter, filter or mesh which may have pore/opening size ranging from about 60 mesh to about 10 mesh, alternatively, about 48 mesh, about 40 mesh, about 35 mesh, about 32 mesh, about 30 mesh, about 28 mesh, about 24 mesh, about 22 mesh, about 20 mesh, about 18 mesh, about 16 mesh, about 14 mesh, or about 12 mesh, or combinations thereof. As used herein, the term “mesh” refers to the sizing of a material, according to the standardized Tyler mesh size, that will pass through some specific mesh (e.g., such that any particle of a larger size will not pass through this mesh) but will be retained by some specific tighter mesh (e.g., such that any particle of a smaller size will pass through this mesh).

In an embodiment, the fluid columns 230 may be characterized as being sized, for example, to accommodate a desired flow rate. For example, the fluid columns may be configured to retain a suitable volume of TAC beads. For example, each of the columns may comprise a quantity of TAC beads ranging from about 25 lbs. to about 300 lbs., alternatively, from about 75 lbs. to about 250 lbs., alternatively, from about 125 lbs. to about 200 lbs. Also, in an embodiment, the fluid columns may be configured to provide contact between a fluid stream being treated and the quantity of TAC beads retained therein at a suitable rate and/or for a suitable duration. For example, the fluid columns 230 may be characterized as having a flow-area (in which the quantity of TAC beads 235 is retained) having a suitable length, a suitable cross-sectional area, and a suitable length to cross-sectional area ratio. As will be appreciated by one of skill in the art upon viewing this disclosure, and not intending to be bound by theory, increases in the length of the flow-area of the fluid column 230 may generally increase the duration of the exposure (e.g., contact time) of the fluid being treated to the TAC beads (e.g., at a given flow-rate), and increases in the cross-sectional area 238 of the fluid column may increase the flow-rate of fluid that may be exposed to the TAC beads. For example, in an embodiment, the flow-area of the fluid columns 230 may be in the range of from about 10 gal. to about 200 gal., alternatively, from about 50 gal. to about 160 gal., alternatively, from about 90 gal. to about 120 gal. Also, in an embodiment the cross-sectional area (e.g., the area of a cross-section 238 generally perpendicular to the direction of fluid flow) of the fluid columns 230 may be in the range of from about 120 in² to about 2,000 in², alternatively, from about 250 in² to about 1,800 in², alternatively, from about 450 in² to about 1,500 in², alternatively, from about 600 in² to about 1,000 in². Also, in an embodiment the ratio of length to cross-sectional area flow-area of the fluid columns 230 may be in the range of from about 2:1 to about 1:150, alternatively, from about 1:4 to about 1:1, alternatively, from about 1:3 to about 1:2.

In an embodiment, the flow area of each of the fluid columns 230 may comprise a suitable volume of TAC beads. For example, the fluid columns may each comprise a volume of TAC beads of from about 200 in³ to about 18,000 in³, alternatively, from about 720 in³ to about 9,000 in³, alternatively, from about 2,000 in³ to about 6,000 in³. In an embodiment, the TAC beads may packed within the flow-area so as to provide a suitable volume of interstitial space (e.g., fluid flow space, for example a void space or volume, at the interstices between adjacent or otherwise proximate TAC beads). For example, the ratio of the volume of TAC beads within the flow-area to the pore volume within the flow-area may be in the range of from about 1:10 to about 2:1, alternatively, from about 1:4 to about 1:1, alternatively, from about 4:7 to about 5:6. Thus, the FTU 210 may be sized to treat a suitable volume of fluid (e.g., untreated water), for example, the FTU 210 may be configured for the treatment of from about 100 gal/min to about 200 gal/min, alternatively, from about 150 gal/min to about 1,000 gal/min.

In an embodiment, each fluid column 230 may further include an inlet valve 236 and an outlet valve 237. Inlet valves 236 and outlet valves 237 may allow for the flow rate through each of the columns 230 to be controlled independently and/or for an individual fluid column 230 to be isolated (e.g., allowing for the total flow rate via the FTU 220 to be scaled-up or scaled-down).

In an embodiment, the FTU 220 may further comprise one or more filtration devices, for example, located upstream from the one or more fluid columns 230. In such an embodiment, the filtration device may be configured to remove particulate material, sediment, or various other contaminants from a fluid stream, for example, prior to introduction of the fluid stream into the fluid columns 230.

In an embodiment, the pH of the one or more streams may be monitored. For example, in an embodiment, the pH of the untreated water stream 211 may be monitored prior to being introduced into the fluid columns 230. In addition, if the pH of the water stream is not within a suitable pH range, the pH of the water may be adjusted. Such a suitable pH may be from about 6.0 to about 9.0, alternatively, from about 6.5 to about 8.5, alternatively, from about 7.0 to about 8.0. In such an embodiment, the pH may be adjusted via the introduction of an additive, such as one or more of various basic and/or acidic compositions, as may be appreciated by one of skill in the art with the aid of this disclosure, for example, to bring the pH of the water stream within the desired pH range.

Referring to FIGS. 2A and 2B, while in the embodiment of FIG. 2A the FTU 220 is shown upstream of the blender 340, in alternative embodiments the FTU 220 may be located in alternative positions within the SFT system 110. For instance, in an embodiment the FTU 220 may be located downstream from a first blender like blender 340 and, optionally, upstream from a second blender. In such an embodiment, a fluid stream comprising one or more pre-blended wellbore servicing fluid components (e.g., non-particulate, liquid com-
ponents) may be introduced into the FTU 220 for treatment. Also, in such an embodiment, the FTU 220 is configured to reduce the concentration of dissolved multivalent ions, such as hard ions, within the fluid.

[0042] While in the embodiment of FIG. 213, the FTU 220 comprises a fluid column 230, in an alternative embodiment the FTU 220 may comprise other wellbore servicing equipment configured to provide contact between a quantity of TAC beads and a fluid stream (e.g., untreated water stream 211). For example, the FTU 220 may comprise other types of wellbore servicing equipment that may be configured to contact a fluid stream with a quantity of TAC beads, such as a pressure vessel, a water storage tank, or combinations thereof.

[0043] In an alternative embodiment, a FTU like FTU 220 may be absent from the SFT system 110. For example, in the embodiment of FIG. 3, the SFT system does not include a FTU. Alternatively, for example, in the embodiment of FIGS. 2A and/or 3, the SFT system may comprise one or more flowpaths having a quantity of TAC beads disposed on one or more flow surfaces thereof. For instance, in the embodiment of FIGS. 2A and/or 3, at least a portion of the quantity of TAC beads may be disposed on any of the inner flow surfaces of the flow path (for example, flow surfaces 204, 214, 224, 314, 342, 352, 362, flow surfaces of the blower 340, the wellbore services manifold 350, the HP pumps, and/or the wellhead 160, and/or internal surfaces of a storage tank, such as storage tank 210) or combinations thereof. Additionally, in an embodiment, at least a portion of the TAC beads may also be disposed on the inner flow surface 137 of the tubular string 135. In an embodiment, the quantity of TAC beads may be retained on one or more of such flow surfaces by any suitable method or apparatus. For example, in an embodiment, at least a portion of the quantity of TAC beads may be included in a fluid (e.g., as a suspension) and applied, for example, via a pneumatic sprayer or other suitable apparatus) to one or more surfaces, for example, as disclosed herein. In an embodiment, the fluid in which the TAC beads are suspended may be volatile (e.g., alcohol or water) such that the fluid may dissipate, leaving the quantity of TAC beads. Additionally, in an embodiment a binder may be included within the suspension, for example, to aid in causing the TAC beads to be retained on the surface to which they have been applied. In an embodiment, the TAC beads may be applied of one or more surfaces within the wellbore services manifold 350, the HP pumps, and/or the wellhead 160 coated with a plurality of TAC beads, may be configured to contact a fluid moving via the route of fluid communication provided by that flow surface. For instance, TAC beads disposed on inner surface 137 may contact a wellbore servicing fluid displaced into wellbore 115 through tubular string 135. Further, TAC beads disposed on inner surface 137 may contact formation fluid produced from fractures 170 of subterranean formation 125. In such an embodiment, fluids (e.g., produced water) from the wellbore may be treated or substantially treated, for example, upon exiting the wellbore. As such, such produced fluids may be suitable for use (e.g., in the preparation of a servicing fluid or the like) without the necessity of further treating such fluids. In an embodiment, inner flow surfaces with TAC beads disposed thereon may be configured to contact the plurality of TAC beads with a fluid stream, such as untreated fluid stream 211 or a wellbore servicing fluid formed in blender 340.

[0044] For example, on an inner flow surface (e.g., flow surfaces 204, 214, 224, 314, 342, 352, 362, 137, or combinations thereof and/or flow surfaces of the blower 340, the wellbore services manifold 350, the HP pumps, and/or the wellhead 160) coated with a plurality of TAC beads, may be configured to contact a fluid moving via the route of fluid communication provided by that flow surface. For instance, TAC beads disposed on inner surface 137 may contact a wellbore servicing fluid displaced into wellbore 115 through tubular string 135. Further, TAC beads disposed on inner surface 137 may contact formation fluid produced from fractures 170 of subterranean formation 125. In such an embodiment, fluids (e.g., produced water) from the wellbore may be treated or substantially treated, for example, upon exiting the wellbore. As such, such produced fluids may be suitable for use (e.g., in the preparation of a servicing fluid or the like) without the necessity of further treating such fluids. In an embodiment, inner flow surfaces with TAC beads disposed thereon may be configured to contact the plurality of TAC beads with a fluid stream, such as untreated fluid stream 211 or a wellbore servicing fluid formed in blender 340.

[0045] In an embodiment, a FTU 220 including a fluid column 230 may or may not be included with surfaces having TAC beads applied thereto. For example, while the embodiment of FIG. 3 illustrates a flowpath having a quantity of TAC beads disposed on one or more flow surfaces thereof, in an alternative embodiment, a flowpath having a quantity of TAC beads disposed on one or more flow surfaces thereof may be utilized in conjunction with a FTU like FTU 220.

[0046] In an embodiment, the TAC beads may be effective to reduce the concentration of dissolved multivalent ions, such as hard ions (e.g., calcium ions, magnesiu ions, strontium ions, aluminum ions, etc.) present within a solution or composition. In an embodiment, the TAC beads may be characterized as having a size (e.g., a diameter) of ranging from about 0.500 mm to about 0.900 mm, alternatively, from about 0.550 mm to about 0.850 mm, alternatively, from about 0.600 mm to about 0.800 mm. In an embodiment, the quantity of TAC beads may be characterized as having a mesh size ranging from about 20/40 mesh to about 16/30 mesh. As used herein, the term “mesh” refers to the sizing of a material, according to the standardized Tyler mesh size, will pass through some specific mesh (e.g., such that any particle of a larger size will not pass through this mesh) but will be retained by some specific tighter mesh (e.g., such that any particle of a smaller size will pass through this mesh).

[0047] In an embodiment, the TAC beads generally comprise a generally spheroidal body having an outer surface. The generally spheroidal body may comprise a polymeric material. For example, in an embodiment, the generally spheroidal body of the TAC beads comprises a modified acrylic copolymer. Examples of a suitable modified acrylic copolymer include, but are not limited to, methacrylate, methyl acrylate, ethyl acrylate, butyl acrylate, hydroxethyl methacrylate monomers. In an embodiment, the outer, generally spheroidal surface of a given TAC bead may comprise a plurality of templates (e.g., dimples) disposed on and/or at least partially within the outer surface of the generally spheroidal body (e.g., similar in appearance to a golf ball). In an embodiment, the templates may comprise a plurality of curved, concave surface depressions distributed (e.g., uniformly, evenly, or randomly) about the surface of the spheroidal body. In an embodiment, the depressions may be sized effectively to form a template for (e.g., to cause) the crystallization of ions.

[0048] Not seeking to be bound by theory, the TAC beads may be configured to convert dissolved multivalent ions into inert crystalline solids. For example, not intending to be bound by theory, the templates may act as a site for heterogeneous nucleation. For example, the surface geometry of the templates is configured to provide a lower energy path for the formation of a crystalline solid from a plurality of multivalent ions through the process of nucleation. During nucleation at or within a template disposed on a TAC bead, a nucleus of solute molecules (e.g., multivalent ions) is formed and reaches a critical size so as to stabilize within the solvent. Not intending to be bound by theory, once a nucleus has reached the critical size, where the crystalline structure has begun to
form, crystal growth of the nucleus may continue until the size of the forming crystal reaches a point where it breaks free from the template of the TAC bead. Once the crystal (e.g., an inert crystalline solid) has broken free from the template, it may continue absorbing other dissolved ions within the solvent, acting as a site for homogenous nucleation. Not intending to be bound by theory, crystals formed from TAC beads may be kept in the fluid stream, and with their presence, may further accelerate the conversion of dissolved ions into crystals within the fluid stream. As such, the quantity of TAC beads may aid in converting dissolved multivalent ions into inert crystalline solids. An example of suitable TAC beads is commercially available from Next™ Filtration Technologies, Inc. of Lake Worth, Fla. as ScaleStop™. The TAC beads may be provided in a dry form, alternatively, as solution or slurry.

[0049] For example, not intending to be bound by theory, the reaction by which a multivalent ion is converted into a crystal (e.g., an inert crystalline solid) at a nucleation site of a TAC bead may react according to the formula:

$$\text{Ca}^{2+} + 2\text{HCO}_3^- \rightarrow \text{CaCO}_3 + \text{H}_2\text{O} + \text{CO}_2$$

Formula I

Thus, in the nonlimiting example set forth in Formula I, a multivalent cation (e.g., Ca^{2+}) is transformed into a crystal (e.g., CaCO_3). In addition, the one or more of the products of the reaction set forth in Formula I may react according to the formula:

$$\text{CO}_3^- + \text{H}_2\text{O} \rightarrow \text{H}_2\text{CO}_3$$

Formula II

Further, in the nonlimiting example set forth in Formula II, byproducts of the reaction set forth in Formula II (e.g., H_2O and CO_2) may react yield carbonic acid (e.g., H_2CO_3), thereby lowering the pH of the fluid stream. In an embodiment, a reduction the pH of the fluid stream may lead to dissolution of existing scale (e.g., scale present within the fluid pathway) with one or more wellbore servicing equipment components (e.g., tubular member 135, wellbore servicing apparatus 140, or various other wellbore servicing equipment).

[0050] One or more embodiments of a SFT system 110 having been disclosed, one or more embodiments of a wellbore servicing method employing such a SFT system 110 is also disclosed herein. Referring to FIG. 4, a method 400 for servicing a wellbore is generally described. In the embodiment of FIG. 4, the wellbore servicing method generally comprises the steps of providing, or otherwise procuring, a SFT system at a wellbore (step 410); optionally, contacting a wellbore servicing fluid component with a quantity of TAC beads (420); forming a wellbore servicing fluid (step 430); optionally, contacting the wellbore servicing fluid with a quantity of TAC beads (440); and delivering the wellbore servicing fluid into a wellbore penetrating a subterranean formation, the surrounding formation, or both (step 450). In an additional embodiment, a wellbore servicing method like wellbore servicing method 400 may further comprise producing a formation fluid (e.g., water) from the subterranean formation and, optionally, contacting the produced formation fluid with a quantity of TAC beads.

[0051] In an embodiment, the wellbore servicing method 400 begins, at step 410, with providing, or otherwise procuring, a SFT system, such as the SFT system 110 illustrated with respect to FIGS. 1, 2A, 2B, and 3, at a wellsite. In an embodiment, the step of providing a SFT system at a wellsite may comprise providing and/or obtaining access to a wellsite, for example, like wellsite 100 illustrated in FIG. 1, having a wellbore 115 penetrating a subterranean formation 125 or a portion thereof. In an embodiment, such a wellbore 115 may comprise a tubing string like tubing string 135 positioned within the wellbore 115 and a wellhead like wellhead 160 providing access to the tubing string 135. Alternatively, a tubing string may be absent from the wellbore and may later be positioned therein (e.g., via a mobile, coiled-tubing rig or the like), for example, for the purpose of communicating the wellbore servicing fluid into the wellbore and/or the formation. In another embodiment, the step of providing a SFT system at a wellsite may comprise transporting one or more components of the SFT system to the wellsite. For example, one or more components of wellbore servicing equipment, such as the storage vessels 210, 310, 320, and/or 330, the blender 340, the wellbore servicing manifold 350, the HP pumps 360, the FTU 220, various other servicing equipment, or combinations thereof may be transported to or otherwise provided at the wellsite. In such an embodiment, one or more of any such components may be configured for transport, for example, one or more of such components may be positioned on a truck, a trailer, a skid, a barge, a boat, or other support thereby rendering the servicing equipment mobile. In yet another embodiment, the step of providing a SFT system at a wellsite may comprise accessing a fluid source, such as the fluid source 200 illustrated in FIGS. 2A and 3. In such an embodiment and as noted above, the water from the fluid source 200 may comprise flowback water from the formation, municipal water, surface water, other sources of water, or combinations thereof. In an alternative embodiment, for example, in an embodiment where the wellbore servicing fluid comprises a non-aqueous fluid (e.g., an oleaginous fluid), the fluid source may comprise a fluid vessel containing a stored fluid. In still another embodiment, the step of providing a SFT system at a wellsite may comprise fluidly coupling the components of the SFT system (e.g., the storage vessels 210, 310, 320, and/or 330, the blender 340, the wellbore servicing manifold 350, the HP pumps 360, the FTU 220, or combinations thereof) to each other, to the fluid source, and/or to the wellbore 115 (e.g., via the wellhead 160), for example, as illustrated in FIGS. 2A and 3.
embodiment, contacting the fluid with the quantity of TAC beads may comprise both communicating the fluid via a flow-path having a quantity of TAC beads disposed on one or more flow surfaces thereof and introduction into a FTU like FTU 220.

[0053] In an embodiment, at step 430, a wellbore servicing fluid is formed. In an embodiment, such a wellbore servicing fluid may generally comprise a fluid (e.g., a base fluid), a wellbore servicing fluid component, one or more additives, or combinations thereof.

[0054] In an embodiment, the base fluid may comprise a non-oleaginous fluid (such as a substantially aqueous fluid), an oleaginous fluid, an emulsion, an invert emulsion, or combinations thereof.

[0055] In an embodiment where the base fluid comprises a non-oleaginous fluid, the non-oleaginous fluid generally comprises a suitable aqueous fluid, alternatively, a substantially aqueous fluid (e.g., water, as disclosed herein). In an embodiment, a substantially aqueous fluid comprises less than about 50% of a nonaqueous component, alternatively less than about 45%, 40%, 35%, 30%, 25%, 20%, 15%, 10%, 5%, 4%, 3%, 2% or 1% of a nonaqueous component. Examples of suitable non-oleaginous fluids include, but are not limited to, sea water, freshwater, naturally-occurring and artificially-created brines containing organic and/or inorganic dissolved salts, liquids comprising water-miscible organic compounds, and combinations thereof.

[0056] In an embodiment, the base fluid comprises an aqueous brine. In such an embodiment, such an aqueous brine generally comprises water and an inorganic monovalent salt, an inorganic multivalent salt, or both. Such an aqueous brine may be naturally occurring or artificially-created. Examples of suitable brines include, but are not limited to, chloride-based, bromide-based, or formate-based brines containing monovalent and/or polyvalent cations and combinations thereof. Examples of suitable chlorides-based brines include, but are not limited to, sodium chloride and calcium chloride. Examples of suitable bromide-based brines include, but are not limited to, sodium bromide, calcium bromide, and zinc bromide. Examples of suitable formate-based brines include, but are not limited to, sodium formate, potassium formate, and cesium formate. The salt or salts in the aqueous fluid may be present in an amount ranging from about 0% by weight to a saturated salt solution. In a particular embodiment, the salt or salts in the water may be present within the base fluid in an amount sufficient to yield a saturated brine, alternatively, a nearly saturated brine.

[0057] In an embodiment where the base fluid comprises an oleaginous fluid, the oleaginous fluid generally comprises any suitable oil. Examples of suitable oleaginous fluids include, but are not limited to, petroleum oils, natural oils, synthetically-derived oils, or combinations thereof. More particularly, examples of a suitable oleaginous fluid include, but are not limited to, diesel oil, kerosene oil, mineral oil, synthetic oil, such as polyolefins (e.g., alpha-olefins and/or internal olefins), polydiorganosiloxanes, esters, diesters of carboxylic acid, paraffins, or combinations thereof.

[0058] In an embodiment, the base fluid may comprise both oleaginous and non-oleaginous phases, for example, in the form of an emulsion and/or an invert emulsion. In an embodiment where the base fluid comprises an emulsion and/or an invert emulsion, the concentration of the oleaginous fluid may be present in an amount of less than about 99% by volume of the invert emulsion, alternatively, from about 30% to about 70%, alternatively, about 50% by volume of the emulsion or invert emulsion. Also, in such an embodiment, the non-oleaginous fluid may be present in an amount of less than about 99% by volume of the emulsion or invert emulsion, alternatively, from about 30% to about 70%, alternatively, about 50% by volume of the emulsion or invert emulsion.

[0059] In an embodiment, the base fluid may, optionally, comprise one or more additives or additional components, as may be suitable depending upon the end use of the base fluid. In such an embodiment, suitable additives may include an acid (e.g., a hydrochloric acid or a muratic acid), an iron control additive (e.g., citric acid), a surfactant (e.g., a borate salt), a gum (e.g., hydroxyethyl cellulose), a pH adjusting agent (e.g., sodium or potassium carbonate), a corrosion inhibitor (e.g., n,n-dimethyl formamide), a crosslinker (e.g., a borate salt), or combinations thereof.

[0060] In an embodiment, the base fluid may be present in the wellbore servicing fluid in a suitable amount. For example, in an embodiment, the base fluid may comprise from about 1% to about 99% of the wellbore servicing fluid by volume, alternatively, from about 30% to about 90% by volume, alternatively, from about 40% to about 80% of the wellbore servicing fluid by volume. In an embodiment, the base fluid may comprise the remainder or balance of the wellbore servicing fluid when all other components thereof are considered.

[0061] In an embodiment, the wellbore servicing fluid component may comprise at least one wellbore servicing fluid component, for example, depending on the wellbore servicing operation. For example, in an embodiment where the wellbore servicing operation comprises a hydraulic fracturing operation, the at least one wellbore servicing fluid component may comprise a quantity of proppant. Nonlimiting examples of suitable proppants include resin coated or uncoated sand, sintered bauxite, ceramic materials, glass beads, shells, hulls, plastics, or combinations thereof. In an embodiment, the proppant may be present within the wellbore servicing fluid (e.g., a fracturing fluid) in a range from about 1 pounds of proppant per gallon of fracturing fluid to about 10 pounds of proppant per gallon of fracturing fluid, alternatively, from about 3 pounds/gallon to about 8 pounds/gallon, alternatively, from about 5 pounds/gallon to about 6 pounds/gallon.

[0062] In other alternative embodiments, the wellbore servicing fluid may comprise any suitable additional type or formulation of fluid as may be suitable for use in a wellbore servicing operation, such as a drilling operation, a hydrajecting or perforating operation, a remediation operation, a fluid loss control operation, a primary or secondary cementing operation, or combinations thereof. For example, in an embodiment, the wellbore servicing fluid may comprise a drilling fluid, a hydrajecting or perforating fluid, a fluid loss control fluid, a remedial fluid, a sealant composition, a cementitious slurry, or combinations thereof. One of skill in the art, upon viewing this disclosure, will recognize one or more wellbore servicing fluid components that may be included within the wellbore servicing fluid to yield a wellbore servicing fluid (for example, of the types set forth herein) so as to be suitable for use in the performance of a wellbore servicing operation.

[0063] In an embodiment, the one or more additives may comprise any suitable additive or combination of additives. Nonlimiting examples of such additives include, but are not limited to, polymers, crosslinkers, friction reducers, defom-
ers, foaming surfactants, fluid loss agents, weighting materials, latex emulsions, dispersants, vitrified shale and other fillers such as silica flour, sand and slag, formation conditioning agents, hollow glass or ceramic beads, elastomers, carbon fibers, glass fibers, metal fibers, minerals fibers, of combinations thereof. One of skill in the art will appreciate that one or more of such additives may be added, alone or in combination, and in various suitable amounts to yield a wellbore servicing fluid of a desired character and/or composition.

[0064] In an embodiment, the step of forming a wellbore servicing fluid comprises introducing the base fluid and, where present the wellbore servicing fluid component and/or additives, into the blender 340 and mixing or blending to yield a sufficiently well-mixed composition. In an embodiment, the base fluid, the wellbore servicing fluid component (e.g., propellant, or other components), and/or the additives may be added and mixed in any suitable order to form the wellbore servicing fluid. In an embodiment, the order of mixing the components of the WSF may vary. Additionally or alternatively, in an embodiment two or more of the base fluid, the wellbore servicing fluid component (e.g., propellant, or other components), and/or the additives may be pre-mixed (e.g., to form a concentrate, such as a gel concentrate) prior to mixing with one or more other components of the wellbore servicing fluid.

[0065] In an embodiment, at step 440, a wellbore servicing fluid may be contacted with a quantity of TAC beads subsequent to formation of the wellbore servicing fluid. Alternatively, in an embodiment where only a portion of the components of the wellbore servicing fluid are mixed, for example, to form a premixed component, such a premixed component may be contacted with a quantity of TAC beads. For example, in an embodiment, contacting the fluid with the quantity of TAC beads may comprise communicating the wellbore servicing fluid via a flowpath having a quantity of TAC beads disposed on one or more flow surfaces thereof, for example, as disclosed with respect to FIG. 3. In an additional or alternative embodiment, contacting the wellbore servicing fluid (and/or a premixed component thereof) with the quantity of TAC beads may be in addition or alternative to contacting a fluid with a quantity of TAC (for example, as disclosed above, with reference to FIGS. 2A and 2B and/or with reference to FIG. 3).

[0066] In an embodiment, at step 430, the wellbore servicing fluid is delivered into either a subterranean formation (e.g., formation 125), a wellbore formed within the subterranean formation (e.g., wellbore 115), or both. In an embodiment, the step of delivering the wellbore servicing fluid into the wellbore, the subterranean formation, or both may comprise pressurizing the wellbore servicing fluid for example, via the operation of one or more high-pressure pumps (e.g., HP pump 360) and a wellbore manifold (e.g., wellbore services manifold) to a pressure suitable for performing the wellbore servicing operation.

[0067] For example, in an embodiment where the wellbore servicing fluid is utilized in the performance of a fracturing operation, the wellbore servicing fluid may be delivered at a pressure and rate sufficient to form or extend a fracture (e.g., fracture 170) in a subterranean formation and to deposit a proppant layer.

[0068] In additional or alternative embodiments, the wellbore servicing fluid may be delivered into the wellbore, the subterranean formation, or combinations thereof, in manner suitable for the performance of any suitable wellbore servicing operation (such as a drilling operation, a hydrajetting or perforating operation, a remediation operation, a fluid loss control operation, a primary or secondary cementing operation, or combinations thereof).

[0069] In an embodiment, additionally, a formation fluid (e.g., hydrocarbons and/or water) may be produced from the subterranean formation. For example, in an embodiment where the wellbore servicing fluid comprises a fracturing fluid as disclosed herein, a formation fluid may be allowed to flow (e.g., via a formed, propped fracture) into the wellbore and to the surface (e.g., via the wellbore). In such an embodiment, where a quantity of TAC beads is disposed on a flow surface of a tubular member (e.g., a production string), the wellbore, or any of the flow surfaces, for example, as disclosed herein, the formation fluid may contact a plurality of TAC beads. In such an embodiment, as the formation fluid contacts at least a portion of the TAC beads, the concentration of multivalent ions (e.g., hard ions) within the formation fluid may thereby be reduced.

[0070] In an embodiment, a servicing fluid treatment system, such as the SFT system 110, a wellbore servicing method, such as wellbore servicing method 400 employing the SFT system 110, or combinations thereof may be advantageously employed in the performance of a wellbore servicing operation. As noted above, a fluid (e.g., water) that contains various contaminants, such as those mentioned above, may adversely affect the intended function of a wellbore servicing fluid formed therefrom and/or adversely affect wellbore servicing equipment in contact with such a fluid (e.g., water) and/or such a wellbore servicing fluid, such as through the formation of scale on the inner flow surfaces of the wellbore servicing equipment. As disclosed herein, a concentration of multivalent ions, such as hard ions (e.g., calcium ions, magnesium ions, strontium ions, aluminum ions, etc.) may be substantially reduced within a fluid stream, for example, via the systems, apparatuses, and/or methods disclosed herein. Conventional means of reducing the concentration of multivalent ions, for example, various chemicals, such as water softening chemicals, may also not be effective when included within a wellbore servicing fluid and/or may undesirably alter the character or composition of the wellbore servicing fluid, and the present disclosure provides a suitable alternative. Further, the addition of such chemicals to a wellbore servicing fluid may adversely affect the performance of such a fluid and/or be harmful to the environment. As such, the instantly-disclosed systems, apparatuses, and/or methods allow for a reduction of multivalent ions in wellbore servicing fluids (or component fluids thereof) and/or produced (e.g., formation) fluids, thereby decreasing the incidence of scaling of various servicing equipment, within the wellbore, and/or within the formation. As such, the instantly-disclosed compositions and methods allow for improved productivity of formation fluids and decreased downtime resulting from scaling, corrosion, or other damage due to the present of multivalent ions.

ADDITIONAL DISCLOSURE

[0071] The following are nonlimiting, specific embodiments in accordance with the present disclosure:

[0072] A first embodiment, which is a wellbore servicing system comprising: a flowpath comprising a first conduit from a water source to a mixer, a first fluid stream being communicated via the first conduit; the mixer, a wellbore servicing fluid being mixed within the mixer; and a second
A conduit from the fluid mixer to a wellbore, a wellbore servicing fluid stream being communicated via the second conduit; wherein at least a portion of the first fluid stream, the wellbore servicing fluid, the wellbore servicing fluid stream, or combinations thereof, are in contact with a quantity of template-assisted crystallization beads.

[0073] A second embodiment, which is the system of the first embodiment, wherein the flowpath further comprises a pump, a fluid manifold, or combinations thereof.

[0074] A third embodiment, which is the system of the second embodiment, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the pump, the fluid manifold, or combinations thereof.

[0075] A fourth embodiment, which is the system of one of first through the third embodiments, wherein the flowpath further comprises a tubular string disposed within the wellbore, the wellbore servicing fluid being communicated via the tubular string.

[0076] A fifth embodiment, which is the system of the fourth embodiment, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the tubular string.

[0077] A sixth embodiment, which is the system of one of the first through the fifth embodiments, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the first conduit, the mixer, the second conduit, or combinations thereof.

[0078] A seventh embodiment, which is the system of one of the first through the sixth embodiments, further comprising a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.

[0079] An eighth embodiment, which is the system of the seventh embodiment, wherein at least a portion of the first fluid stream is disposed within the fluid treatment unit.

[0080] A ninth embodiment, which is the system of the seventh embodiment, wherein at least a portion of the wellbore servicing fluid stream is disposed within the fluid treatment unit.

[0081] A tenth embodiment, which is the system of one of the first through the ninth embodiments, wherein the flowpath further comprises a route of fluid communication within a subterranean formation.

[0082] An eleventh embodiment, which is the system of the tenth embodiment, where the route of fluid communication comprises a fracture.

[0083] A twelfth embodiment, which is a wellbore servicing method comprising: communicating a first fluid to at least one component of wellbore servicing equipment via a first conduit; adding at least one component of a wellbore servicing fluid to the first fluid to form the wellbore servicing fluid; communicating the wellbore servicing fluid to a wellbore via a second conduit, wherein at least a portion of the first fluid, the at least one component of wellbore servicing fluid, the wellbore servicing fluid, or combinations thereof, are in contact with a quantity of template-assisted crystallization beads.

[0084] A thirteenth embodiment, which is the method of the twelfth embodiment, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the first conduit, the at least one component of wellbore servicing equipment, the second conduit, or combinations thereof.

[0085] A fourteenth embodiment, which is the method of one of the twelfth through the thirteenth embodiments, wherein the at least one component of wellbore servicing equipment comprises a pump, a fluid manifold, a mixer, or combinations thereof.

[0086] A fifteenth embodiment, which is the method of the fourteenth embodiment, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the pump, the fluid manifold, the mixer, or combinations thereof.

[0087] A sixteenth embodiment, which is the method of one of the twelfth through the fourteenth embodiments, further comprising communicating the wellbore servicing fluid into the wellbore via a tubular string disposed within the wellbore.

[0088] A seventeenth embodiment, which is the method of the sixteenth embodiment, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the tubular string.

[0089] An eighteenth embodiment, which is the method of the sixteenth embodiment, further comprising communicating the wellbore servicing fluid into a subterranean formation.

[0090] A nineteenth embodiment, which is the method of one of the twelfth through the eighteenth embodiments, wherein the first fluid is communicated to the at least one component of wellbore servicing equipment from a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.

[0091] A twentieth embodiment, which is the method of one of the twelfth through the nineteenth embodiments, wherein the wellbore servicing fluid is communicated to the wellbore from a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.

[0092] While embodiments of the invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit and teachings of the invention. The embodiments described herein are exemplary only, and are not intended to be limiting. Many variations and modifications of the invention disclosed herein are possible and are within the scope of the invention. Where numerical ranges or limitations are expressly stated, such express ranges or limitations should be understood to include iterative ranges or limitations of like magnitude falling within the expressly stated ranges or limitations (e.g., from about 1 to about 10 includes 2, 3, 4, etc.; greater than 0.10 includes 0.11, 0.12, 0.13, etc.). For example, whenever a numerical range with a lower limit, R1, and an upper limit, R2, is disclosed, any number falling within the range is specifically disclosed. In particular, the following numbers within the range are specifically disclosed: R1+ks*(R2-R1), wherein k is a variable ranging from 1 percent to 100 percent with a 1 percent increment, i.e., k is 1 percent, 2 percent, 3 percent, 4 percent, 5 percent, . . . 95 percent, 96 percent, 97 percent, 98 percent, 99 percent, or 100 percent. Moreover, any numerical range defined by two R numbers as defined in the above is also specifically disclosed. Use of the term “optionally” with respect to any element of a claim is intended to mean that the subject element is required, or alternatively, is not required. Both alternatives are intended to be within the scope of the claim. Use of broader terms such as comprises, includes, having, etc. should be understood to provide support for
narrower terms such as consisting of, consisting essentially of, comprised substantially of, etc.

Accordingly, the scope of protection is not limited by the description set out above but is only limited by the claims which follow, that scope including all equivalents of the subject matter of the claims. Each and every claim is incorporated into the specification as an embodiment of the present invention. Thus, the claims are a further description and are an addition to the embodiments of the present invention. The discussion of a reference in the Detailed Description of the Embodiments is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. The disclosures of all patents, patent applications, and publications cited herein are hereby incorporated by reference, to the extent that they provide exemplary, procedural or other details supplementary to those set forth herein.

What is claimed is:

1. A wellbore servicing system comprising:
   a flowpath comprising:
     a first conduit from a water source to a mixer, a first fluid stream being communicated via the first conduit;
     the mixer, a wellbore servicing fluid being mixed within the mixer, and
     a second conduit from the fluid mixer to a wellbore, a wellbore servicing fluid stream being communicated via the second conduit;

   wherein at least a portion of the first fluid stream, the wellbore servicing fluid, the wellbore servicing fluid stream, or combinations thereof, are in contact with a quantity of template assisted crystallization beads.

2. The system of claim 1, wherein the flowpath further comprises a pump, a fluid manifold, or combinations thereof.

3. The system of claim 2, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the pump, the fluid manifold, or combinations thereof.

4. The system of claim 1, wherein the flowpath further comprises a tubular string disposed within the wellbore, the wellbore servicing fluid being communicated via the tubular string.

5. The system of claim 4, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the tubular string.

6. The system of claim 1, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the first conduit, the mixer, the second conduit, or combinations thereof.

7. The system of claim 1, further comprising a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.

8. The system of claim 7, wherein at least a portion of the first fluid stream is disposed within the fluid treatment unit.

9. The system of claim 7, wherein at least a portion of the wellbore servicing fluid stream is disposed within the fluid treatment unit.

10. The system of claim 1, wherein the flowpath further comprises a route of fluid communication within a subterranean formation.

11. The system of claim 10, where the route of fluid communication comprises a fracture.

12. A wellbore servicing method comprising:
   communicating a first fluid to at least one component of wellbore servicing equipment via a first conduit;
   adding at least one component of wellbore servicing fluid to the first fluid to form the wellbore servicing fluid;
   communicating the wellbore servicing fluid to a wellbore via a second conduit,

   wherein at least a portion of the first fluid, the at least one component of wellbore servicing fluid, the wellbore servicing fluid, or combinations thereof, are in contact with a quantity of template assisted crystallization beads.

13. The method of claim 12, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the first conduit, the at least one component of wellbore servicing equipment, the second conduit, or combinations thereof.

14. The method of claim 12, wherein the at least one component of wellbore servicing equipment comprises a pump, a fluid manifold, a mixer, or combinations thereof.

15. The method of claim 14, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the pump, the fluid manifold, the mixer, or combinations thereof.

16. The method of claim 12, further comprising communicating the wellbore servicing fluid into the wellbore via a tubular string disposed within the wellbore.

17. The method of claim 16, wherein at least a portion of the quantity of template assisted crystallization beads are disposed on a flow surface of the tubular string.

18. The method of claim 16, further comprising communicating the wellbore servicing fluid into a subterranean formation.

19. The method of claim 12, wherein the first fluid is communicated to the at least one component of wellbore servicing equipment from a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.

20. The method of claim 12, wherein the wellbore servicing fluid is communicated to the wellbore from a fluid treatment unit, the fluid treatment unit comprising at least a portion of the quantity of template assisted crystallization beads.