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(54) **METHODS FOR CONTROLLING UNCONSOLIDATED PARTICULATES IN A SUBTERRANEAN FORMATION**

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(57) **ABSTRACT**

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Methods of treating a wellbore in a subterranean formation comprising unconsolidated particulates including providing a treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator; wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein at least a portion of the stimuli-delayed acid generator is a liquid; introducing the treatment fluid into the wellbore in the subterranean formation; and stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin; wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates.

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METHODS FOR CONTROLLING UNCONSOLIDATED PARTICULATES IN A SUBTERRANEAN FORMATION

BACKGROUND

[0001] The present invention relates to methods for consolidating particulate material in a subterranean formation. Specifically, the present invention relates to curing furan-based resins using stimuli-delayed acid generators.

[0002] Subterranean wells (e.g., hydrocarbon producing wells, water producing wells, and injection wells) are often stimulated by hydraulic fracturing treatments. In hydraulic fracturing treatments, a viscous treatment fluid is pumped into a portion of a subterranean formation at a rate and pressure such that the subterranean formation breaks down and one or more fractures are formed. While the treatment fluid used to initiate the fracture is generally solids-free, typically, particulate solids, such as graded sand, are introduced in a later portion of the treatment fluid and then deposited into the fractures. These particulate solids, or “proppant particulates,” serve to prop the fracture open (e.g., keep the fracture from fully closing) after the hydraulic pressure is removed. By keeping the fracture from fully closing, the proppants aid in forming conductive paths through which produced fluids, such as hydrocarbons, may flow.

[0003] Hydraulic fracturing of subterranean wells is often performed in formations that contain unconsolidated particulates. The unconsolidated particulates may migrate out of the subterranean formation and be produced with production fluids. The presence of unconsolidated particulates in a formation during production is undesirable because they may damage or abrade producing equipment or reduce well production. For example, unconsolidated particulates may migrate into wellbore casings, perforations, or the interstitial spaces between packed proppants within a fracture and clog or hinder well production. As used herein, the term “unconsolidated particulates” refers to any loose or loosely bonded particulates that move freely with production fluids. Unconsolidated particulates may include, for example, sand, gravel, proppant particulates, and/or formation fines.

[0004] One method of controlling unconsolidated particulates in hydraulic fractured subterranean formations is to perform a gravel-packing treatment. In gravel-packing treatments, particulates are deposited into unconsolidated or weakly consolidated formation zones to create a physical barrier to the transport of unconsolidated particulates with the produced fluids. Typical gravel-packing treatment include placing a screen in a wellbore and packing the annulus between the screen and the wellbore with particulates of a certain size so as to prevent the transport of unconsolidated particulates with the produced fluids without compromising the conductivity of the well. Gravel-packing treatments, however, involve placement of additional unconsolidated particulates into the wellbore which may not be adequately maintained, for example, by a screen and which may, therefore, migrate along with the produced fluids, thus, contributing to the problem the gravel-packing treatment was attempting to solve.

[0005] Another method of controlling unconsolidated particulates is to resin treat the wellbore. In resin treatments, a resin is placed into the wellbore in order to stabilize unconsolidated particulates. Typically, the resin is used to enhance grain-to-grain or grain-to-formation contact of the unconsolidated particulates such that they are immobilized or at least

resistant to flow pressures of produced fluids. Typically, either an epoxy-based resin or a furan-based resin treatment is utilized. Epoxy-based resins require a curing agent in order to cure the resin and function as a consolidating agent. The curing agent may pose problems in certain subterranean formations due to premature curing resulting in poor or no consolidation of unconsolidated particulates and a reduction in the concentration of any curing agent that reaches the desired interval of the wellbore. Premature curing of the epoxy-based resin may also clog or damage production equipment. The curing agent may also cause the resin to become too viscous to inject into the subterranean formation. Additionally, epoxy-based resins may not be able to be injected into low permeability formations due to the viscosity of the resin. The resin may contain an internal hardener that causes the resin to become more viscous as it is exposed to downhole temperatures, preventing its use in such formations. Moreover, epoxy-based resins are extremely costly and are not preferred in the industry for that reason.

[0006] Furan-based resins may cure independently of a curing agent at extremely high temperatures, typically greater than 270° F. However, many subterranean formations do not reach such temperatures and furan-based resins traditionally require a curing agent at temperatures less than 250° F. Therefore, in practice, traditional furan-based resin treatments suffer from the same premature curing issues that epoxy-based resin treatments suffer from when internal curing agents are used. The use of an acid flush to cure furan-based resins is often used to overcome premature curing issues. Often, though, the furan-based resin and the acid may not contact one another within a subterranean formation, thus preventing the furan-based resin from fully curing or curing at all. Additionally, the uncured or partially cured furan-based resin may hinder flow of produced fluids.

[0007] However, furan-based resins are substantially less costly than epoxy-based resins and are capable of consolidating low permeable formations. Thus, a furan-based resin treatment that may be used to consolidate unconsolidated particulates without the use of a curing agent and in low temperature subterranean formations may be of benefit to one of ordinary skill in the art.

SUMMARY OF THE INVENTION

[0008] The present invention relates to methods for consolidating particulate material in a subterranean formation.

[0009] In one embodiment, the present invention provides a method comprising: providing a wellbore in a subterranean formation comprising unconsolidated particulates; providing a treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator; wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein the stimuli-delayed acid generator is a liquid or a liquid and solid combination; introducing the treatment fluid into the wellbore in the subterranean formation; and stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin; wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates.

[0010] In other embodiments, the present invention provides a method comprising: providing a wellbore in a subterranean formation comprising unconsolidated particulates; providing a treatment fluid comprising a furan-based resin; introducing the treatment fluid into the wellbore in the sub-

terranean formation; placing a stimuli-delayed acid generator into the wellbore in the subterranean formation; wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein the stimuli-delayed acid generator is a liquid or a liquid and solid combination; and stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin; wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates.

[0011] In still other embodiments, the present invention provides a method comprising: providing a wellbore in a subterranean formation comprising unconsolidated particulates; providing a treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator; wherein the furan-based resin is selected from the group consisting of a furan resin; a furfuryl alcohol resin; a furan-aldehyde; a furan-phenolic resin; and any combinations thereof, and wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein the stimuli-delayed acid generator is a liquid or a liquid and solid combination; introducing a pre-flush fluid into the wellbore in the subterranean formation; introducing the treatment fluid into the wellbore in the subterranean formation; stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin; wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates; and introducing a post-flush fluid into the wellbore in the subterranean formation.

[0012] The features and advantages of the present invention will be readily apparent to those skilled in the art upon a reading of the description of the preferred embodiments that follows.

DETAILED DESCRIPTION

[0013] The present invention relates to methods for consolidating particulate material in a subterranean formation. More particularly, the present invention relates to furan-based resin systems capable of curing and consolidating unconsolidated particulates in a subterranean formation.

[0014] In some embodiments, the present invention provides a method of treating a wellbore in a subterranean formation having unconsolidated particulates. A treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator is introduced into the wellbore in the subterranean formation and the stimuli-delayed acid generator is stimulated such that the stimuli-delayed acid generator generates acid and the furan-based resin cures and consolidates the unconsolidated particulates. The stimuli-delayed acid generator may be stimulated by subterranean formation conditions including pH, temperature, salinity, and the like. One of ordinary skill in the art, with the benefit of this disclosure, will recognize what stimuli-delayed acid generator to use depending on the properties of a particular subterranean formation.

[0015] In some embodiments, the present invention provides a method of treating a subterranean formation having unconsolidated particulates comprising providing a treatment fluid comprising a furan-based resin. The treatment fluid is then placed into the subterranean formation prior to introducing the stimuli-delayed acid generator into the treatment fluid. This method may be utilized if the subterranean formation has unpredictable properties (e.g., if the formation has fluctuating temperature intervals and the stimuli-delayed acid generator would cure prior to getting to its desired loca-

tion). One of ordinary skill in the art, with the benefit of this disclosure, will recognize whether a particular treatment operation would benefit from introducing the furan-based resin and the stimuli-delayed acid generator concomitantly or separately in a staggered fashion in accordance with the methods of the present invention.

[0016] In some embodiments, the treatment fluids of the present invention may further comprise a base fluid. The base fluid may be used so as to enhance pumpability of the treatment fluid and/or to provide an adequate delivery system for the furan-based resins of the present invention into a subterranean formation. In addition, a base fluid may be used to dilute the furan-based resins of the present invention to workable concentrations for use in the methods disclosed herein. Suitable base fluids for use in conjunction with the present invention may include, but not be limited to, oil-based fluids; aqueous-based fluids; aqueous-miscible fluids; water-in-oil emulsions; or oil-in-water emulsions. Suitable oil-based fluids may include alkanes; olefins; aromatic organic compounds; cyclic alkanes; paraffins; diesel fluids; mineral oils; desulfurized hydrogenated kerosenes; and any combination thereof. Suitable aqueous-based fluids may include fresh water; saltwater (e.g., water containing one or more salts dissolved therein); brine (e.g., saturated salt water); seawater; and any combination thereof. Suitable aqueous-miscible fluids may include, but not be limited to, alcohols; (e.g., methanol, ethanol, n-propanol, isopropanol, n-butanol, sec-butanol, isobutanol, and t-butanol); glycerins; glycols (e.g., polyglycols, propylene glycol, and ethylene glycol); polyglycol amines; polyols; any derivative thereof; any in combination with salts (e.g., sodium chloride, calcium chloride, calcium bromide, zinc bromide, potassium carbonate, sodium formate, potassium formate, cesium formate, sodium acetate, potassium acetate, calcium acetate, ammonium acetate, ammonium chloride, ammonium bromide, sodium nitrate, potassium nitrate, ammonium nitrate, ammonium sulfate, calcium nitrate, sodium carbonate, and potassium carbonate); any in combination with an aqueous-based fluid; and any combination thereof. Suitable water-in-oil emulsions, also known as invert emulsions, may have an oil-to-water ratio from a lower limit of greater than about 50:50, 55:45, 60:40, 65:35, 70:30, 75:25, or 80:20 to an upper limit of less than about 100:0, 95:5, 90:10, 85:15, 80:20, 75:25, 70:30, or 65:35 by volume in the base fluid, where the amount may range from any lower limit to any upper limit and encompass any subset therebetween. Examples of suitable invert emulsions include those disclosed in U.S. Pat. No. 5,905,061 entitled "Invert Emulsion Fluids Suitable for Drilling" filed on May 23, 1997; U.S. Pat. No. 5,977,031 entitled "Ester Based Invert Emulsion Drilling Fluids and Muds Having Negative Alkalinity" filed on Aug. 8, 1998; U.S. Pat. No. 6,828,279 entitled "Biodegradable Surfactant for Invert Emulsion Drilling Fluid" filed on Aug. 10, 2001; U.S. Pat. No. 7,534,745 entitled "Gelled Invert Emulsion Compositions Comprising Polyvalent Metal Salts of an Organophosphonic Acid Ester or an Organophosphonic Acid and Methods of Use and Manufacture" filed on May 5, 2004; U.S. Pat. No. 7,645,723 entitled "Method of Drilling Using Invert Emulsion Drilling Fluids" filed on Aug. 15, 2007; and U.S. Pat. No. 7,696,131 entitled "Diesel Oil-Based Invert Emulsion Drilling Fluids and Methods of Drilling Boreholes" filed on Jul. 5, 2007, each of which are incorporated herein by reference in their entirety. It should be noted that for water-in-oil and oil-in-water emulsions, any mixture of the above may be used including the

water being and/or comprising an aqueous-miscible fluid. The use of an emulsion base fluid with the furan-based resins and stimuli-delayed acid generators of the present invention may beneficially aid in their placement within the subterranean formation and/or may beneficially alter their reactivity. Additionally, when a stimuli-delayed acid generator is selected for use in the present invention that is not water soluble or miscible, it may beneficially aid in controlling leakoff.

[0017] The present invention consolidates unconsolidated particulates using a furan-based resin treatment. The furan-based resins enhance grain-to-grain adherence and grain-to-formation adherence of the unconsolidated particulates in order to prevent or reduce the likelihood of the unconsolidated particulates being produced with production fluids. Furan-based resins are oligomeric products prepared from compounds containing a furan ring, which are capable for forming crosslinked, hardened polymers upon encountering an acid "activator." Suitable furan-based resins for use in the present invention include, but are not limited to, a furan resin; a furfuryl alcohol resin; a furan-aldehyde; a furan-phenolic resin; and any combinations thereof. One of ordinary skill in the art, with the benefit of this disclosure, will recognize a suitable resin depending on the specifics of the particular application and subterranean formation. In some embodiments of the present invention, the furan-based resin is present in an amount from about 1% to about 99% by weight of the treatment fluid. In preferred embodiments, the furan-based resin is present in an amount from about 5% to about 50% by weight of the treatment fluid.

[0018] The stimuli-delayed acid generator of the present invention is capable of releasing acid upon encountering a particular stimuli specific to the stimuli-delayed acid generator chosen. The stimulus may be, for example, the pH, temperature, or salinity of the subterranean formation, and the like. Suitable stimuli-delayed acid generators for use in the present invention may include, but are not limited to, a polylactic acid; a polyglycolic acid; a poly(3-hydroxybutyrate); a polysuccinate ester; a polyanhydride; a maleic anhydride; an orthoester; a formate ester-diethylene glycol diformate; an ethyl lactate; a methyl lactate; an acetate ester; a L-dilactide; a glucono-delta-lactone; a lactate ester butyl lactate; poly(lactic-co-glycolic acid); a poly(glycolic-co-caprolactone); a polycaprolactone; a poly(glycolic-co-trimethylene carbonate); a poly(lactic-co-caprolactone); a poly(lactic-co-trimethylene carbonate); a polyglyconate; a polyglactin; a poly(lactic-co-glycolic acid)-methoxy-poly(ethyleneglycol) copolymer; a polydioxanone; copolymers thereof; and any combinations thereof. In preferred embodiments, the stimuli-delayed acid generator of the present invention is in the form of a liquid. The stimuli-delayed acid generator may be in the form of a liquid itself or because it is in a base fluid. Liquid stimuli-delayed acid generators are preferred because they can be placed into a subterranean formation directly in contact with the resin and will leak off with the resin so as to ensure adequate contact. In other embodiments, the stimuli-delayed acid generator of the present invention may be in the form of a solid, including a semi-solid. Solid stimuli-delayed acid generators may be included in order to cure the resin as well as serve as a fluid loss and/or diverting agent. The solid stimuli-delayed acid generators of the present invention may additionally comprise a plasticizer. Any plasticizer known in the art that does not interfere with the stimuli-delayed acid generators of the present invention may be used in the meth-

ods of the present invention. In some embodiments, a liquid and a solid stimuli-delayed acid generator are included in the methods of the present invention so as to synergistically operate together to provide a greater degree of control and operational flexibility.

[0019] In preferred embodiments, the stimuli-delayed acid generator for use in the present invention is an ethyl lactate; a methyl lactate; a L-dilactide; a glucono-delta-lactone; any derivatives thereof; and any combinations thereof. In certain embodiments, the stimuli-delayed acid generator of the present invention is present in an amount from about 0.01% to about 30% by weight of the furan-based resin. In preferred embodiments, the stimuli-delayed acid generator of the present invention is present in an amount from about 1% to about 20% by weight of the furan-based resin. One of ordinary skill in the art, with the benefit of this disclosure, will recognize the type and amount of stimuli-delayed acid generator to include in the treatment fluids based on, among other things, the desired amount of delay time

[0020] In addition to consolidating unconsolidated particulates in a subterranean formation, the furan-based resin included in the treatment fluids of the present invention include the advantage of operating as self-diverting agents. The furan-based resin may be cured by the acid released by the stimuli-delayed acid generators of the present invention at particular intervals in the subterranean formation and function to temporarily block other stimulation operation fluids from that interval and divert them to other, desired intervals within the formation. For example, the cured furan-based resins of the present invention may divert stimulation operation fluids from highly permeable intervals of a subterranean formation to less permeable intervals by effectively sealing the highly permeable interval with the cured furan-based resins of the present invention. The furan-based resins of the present invention may be repeatedly placed into a subterranean formation until the desired intervals are sealed.

[0021] In some embodiments, the methods of the present invention may also include a silane coupling agent. The silane coupling agent may facilitate adhesion of the unconsolidated particulates with the furan-based resin after it is cured by the stimuli-delayed acid generator. Therefore, the silane coupling agent may act as a mediator to bond the furan-based resin to unconsolidated particulates and the formation to aid in preventing production of unconsolidated particulates with produced fluids. Generally, any suitable silane coupling agent may be used in accordance with particular embodiments of the present invention. Examples of suitable silane coupling agents include, but are not limited to, N-β-(aminoethyl)-γ-aminopropyl trimethoxysilane, N-2-(aminoethyl)-3-aminopropyltrimethoxysilane; 3-glycidoxypropyltrimethoxysilane; gamma-aminopropyltriethoxysilane; N-beta-(aminoethyl)-gamma-aminopropyltrimethoxysilanes; aminoethyl-N-beta-(aminoethyl)-gamma-aminopropyl-trimethoxysilanes; gamma-ureidopropyl-triethoxysilanes; beta-(3-4 epoxy-cyclohexyl)-ethyl-trimethoxysilane; gamma-glycidoxypropyltrimethoxysilanes; vinyltrichlorosilane; vinyltris(beta-methoxyethoxy) silane; vinyltriethoxysilane; vinyltrimethoxysilane; 3-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; 3-aminopropyl-triethoxysilane; N-phenyl-r-aminopropyltrimethoxysilane; r-mercaptopro-

pyltrimethoxysilane; r-chloropropyltrimethoxysilane; vinyltris(beta-methoxyethoxy) silane; r-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylid iethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; r-aminopropyltriethoxysilane; N-[3-(trimethoxysilyl)propyl]-ethylenediamine; and any combinations thereof. An example of a commercially-available silane coupling agent suitable for use in the present invention may include, but is not limited to, SILQUEST® A-1120 Silane available from Momentive Performance Materials Inc. of Wilton, Conn. The silane coupling agent may be included in the treatment fluids of the present invention in an amount capable of sufficiently bonding the furan-based resin to the unconsolidated particulates within the subterranean formation. In some embodiments, the silane coupling agent may be present in the treatment fluids of the present invention in an amount from about 0.01% to about 5% by weight of the furan-based resin. In preferred embodiments, the silane coupling agent may be present in the treatment fluids of the present invention in an amount from about 0.1% to about 1% by weight of the furan-based resin.

[0022] In certain embodiments, the treatment fluids of the present invention may additionally contain a surfactant to further facilitate adhesion of the furan-based resin onto unconsolidated particulates. The surfactant may wet the unconsolidated particulates and enhance the coating of the furan-based resin onto the unconsolidated particulates. Suitable surfactants for use in the treatment fluids of the present invention may include, but are not limited to, an alkyl phosphonate surfactant (e.g., a C12-C22 alkyl phosphonate surfactant); an ethoxylated nonyl phenol phosphonate ester; a cationic surfactant; a nonionic surfactant; and any combinations thereof. Examples of commercially-available surfactants suitable for use in the treatment fluids of the present invention may include, but are not limited to 19N™ Chemical Additive and ES-5™ Surfactant, both available from Halliburton Energy Services, Inc. of Houston, Tex. The surfactant may be present in the treatment fluids utilized in the methods of the present invention in any amount to sufficiently wet unconsolidated particulates to aid in coating the furan-based resin thereon. In some embodiments, the surfactant may be present in the treatment fluids in an amount from about 0.01% to about 10% by volume of the treatment fluid. In preferred embodiments, the surfactant may be present in the treatment fluids in an amount from about 0.1% to about 3% by volume of the treatment fluid.

[0023] The treatment fluids of the present invention may be premixed before injection into the subterranean formation or mixed on the fly during injection into the subterranean formation. In other embodiments, the treatment fluid may be placed in the subterranean formation in two parts, first adding the furan-based resin into the formation, followed by the stimuli-delayed acid generator. One of ordinary skill in the art, with the benefit of this disclosure, will recognize which introduction method should be used for a particular application.

[0024] Prior to the introduction of the treatment fluid of the present invention, a pre-flush fluid may first be introduced into the subterranean formation. Pre-flush fluids may aid in removing debris from the flow path, displacing reservoir fluids, preconditioning the unconsolidated particulates for accepting the furan-based resins of the present invention,

and/or changing the stimulus conditions which stimulate the stimuli-delayed acid generators of the present invention. Suitable examples of pre-flush fluids for use in the methods of the present invention may include, but are not limited to aqueous fluids, solvent-based fluids, or gas-based fluids. The aqueous pre-flush fluid may comprise, for example, fresh water; salt-water; brine (e.g., air, nitrogen, and the like); and any combinations thereof. The aqueous pre-flush fluids may be from any source, provided that they do not contain components that adversely affect the stability and/or performance of the treatment fluids of the present invention. In other embodiments, solvent-based pre-flush fluids may comprise a glycol ether solvent, such as diethylene glycol monomethyl ether; diethylene glycol dimethyl ether; ethylene glycol monobutyl ether; dipropylene glycol monomethyl ether; or any combinations thereof. In those embodiments where a gas pre-flush fluid is applied, the fluid may be applied in an amount from about 25 to about 200 cubic feet per foot of the interval to be treated, depending on the temperature and pressure of the interval of interest. The pre-flush fluids of the present invention may additionally comprise a pH-adjusting agent, such as an acid or a buffer. In accordance with the teachings of the present invention, a pre-flush may be performed multiple times, as needed. Multiple pre-flush treatments may include the same or different pre-flush fluids.

[0025] The pre-flush fluids may additionally comprise any surfactant suitable for use in the treatment fluids of the present invention. In some preferred embodiments, the surfactant included in the pre-flush fluid is identical to the surfactant included in the treatment fluid, where one is included. In those embodiments where a gas pre-flush fluid is applied, the fluid may be applied in an amount from about 25 to about 200 cubic feet per foot of the interval to be treated, depending on the temperature and pressure of the interval of interest. In some embodiments, the surfactant may be present in the pre-flush fluids in an amount from about 0.01% to about 10% by volume of the pre-flush fluid. In preferred embodiments, the surfactant may be present in the pre-flush fluids in an amount from about 0.1% to about 3% by volume of the pre-flush fluid. In some embodiments, the pre-flush fluid may be applied in an amount from about 1 to about 6 times the volume of the treatment fluid. In particular embodiments, the pre-flush fluid is applied in an amount of about 3 times the volume of the treatment fluid.

[0026] Introduction of the treatment fluid of the present invention may be followed by the application of a post-flush fluid. The post-flush fluid may facilitate removal of excess treatment fluid from the pore spaces in the subterranean formation and/or to reduce permeability loss between consolidated particulates (e.g., between the interstitial spaces between the unconsolidated particulates that have been consolidated using the methods of the present invention). Examples of suitable post-flush fluids include, but are not limited to, a gas (e.g., air, nitrogen, and the like); a foamed aqueous fluid (e.g., a brine); and a hydrocarbon fluid (e.g., diesel, kerosene, and the like). In those embodiments where a gas post-flush fluid is applied, the fluid may be applied in an amount from about 25 to about 200 cubic feet per foot of the interval to be treated, depending on the temperature and pressure of the interval of interest. In embodiments where a foamed aqueous post-flush fluid is applied, the fluid may be applied in an amount from about one to two times the volume of the treatment fluids used. One of ordinary skill in the art, with the benefit of this disclosure, will recognize the appro-

appropriate type and amount of post-flush fluid to include in the methods of the present invention.

[0027] In some embodiments, the pre-flush, treatment, and post-flush of the present invention may further comprise an additive suitable for use in the particular subterranean operation. Any additives useful in a subterranean operation may be included in the pre-flush, treatment, and post-flush of the present invention provided that they do not interfere with the furan-based resin or the stimuli-delayed acid generator. Suitable additives may include, but are not limited to, a salt, a weighting agent, an inert solid, a fluid loss control agent, an emulsifier, a dispersion aid, a corrosion inhibitor, an emulsion thinner, an emulsion thickener, a viscosifying agent, a gelling agent, a surfactant, a particulate, a proppant, a gravel particulate, a lost circulation material, a foaming agent, a gas, a pH control additive, a breaker, a biocide, a crosslinker, a stabilizer, a chelating agent, a mutual solvent, an oxidizer, a reducer, a friction reducer, a clay stabilizing agent, and any combinations thereof.

[0028] The pre-flush, treatment, and post-flush fluids of the present invention may be prepared by any method suitable for a given subterranean operation. For example, certain components of the treatment fluids may be provided in a pre-blended powder, solid, or liquid form, which may be combined with the treatment fluids of the present invention at a subsequent time. In general, the pre-flush, treatment, and post-flush fluids of the present invention may be bullheaded into the well (i.e., pumped into the wellbore without the use of isolation tools or barrier devices) or placed using coiled tubing or jointed pipe to treat specific intervals of interest. In some embodiments, a pressure pulsing or rotating hydrojetting tool may be coupled with the coiled tubing or jointed pipe to aid in placement of the treatment or post-flush fluids in the subterranean formation.

[0029] To facilitate a better understanding of the present invention, the following examples of preferred or representative embodiments are given. In no way should the following examples be read to limit, or to define, the scope of the invention.

Example 1

[0030] In order to demonstrate the effectiveness of the methods of the present invention in consolidating unconsolidated particulates, two treatment fluids were prepared in accordance with the methods of the present invention.

[0031] Two treatment fluids samples were prepared comprising a base fluid, a furan-based resin, a surfactant, and a silane coupling agent. Sample 1 served as the control and contained no stimuli-delayed acid generator. Sample 2 contained a stimuli-delayed acid generator. Sample 1 was prepared using 80 mL of 3% KCl brine containing 20 mL of furfuryl alcohol, 0.25 mL of 19N™ Chemical Additive cationic nonemulsifier used in acids and other aqueous fluids to help prevent acid and oil emulsions available from Halliburton of Houston, Tex., and 1 mL of SILQUEST® A-1120 Silane available from Momentive Performance Materials Inc. of Wilton, Conn. Sample 2 was identical to Sample 1, but additionally comprised 2 g of maleic anhydride.

[0032] Two Oklahoma No. 1 dry sand packs (“Test 1 OK#1 sand pack” and “Test 2 OK#1 sand pack”) were prepared by placing 100 grams of OK#1 into a 1-inch ID rubber sleeve. Gravel with a mesh size of 40/70 was packed at the bottom and top of the OK#1 sand. Wire mesh screen pieces of 100 mesh size were placed at the bottom and top of the gravel. The

Test 1 and Test 2 OK#1 sand packs were first flushed with a pre-flush fluid comprising 150 mL of a 3% KCl brine solution containing 0.25% 19N™ at 3 mL/min. To the Test 1 OK#1 sand pack, 100 mL of Sample 1 was added at 3 mL/min. To the Test 2 OK#1 sand pack, 100 mL of Sample 2 was added at 3 mL/min. The treated OK#1 sand packs were subjected to a temperature of 230° F. for 24 hours.

[0033] The consolidation strength of each OK#1 treated sand pack was measured for unconfined compressive strength (“UCS”) in the middle of the sand packs and loss on ignition (“LOI”). The OK#1 sand pack had a USC-Middle of 120 psi and a LOI of 1.81% whereas the OK#2 sand pack had a USC-Middle of 1790 psi and a LOI of 4.53%. That is, OK#2, containing 2 g of the stimuli-delayed acid generator maleic anhydride, exhibited almost 19 times greater compressive strength and 2.5 times greater LOI, indicating that the presence of the stimuli-delayed acid generator maleic anhydride greatly improved the consolidation of the OK#1 sand pack as compared to a treatment fluid containing no stimuli-delayed acid generator.

Example 2

[0034] In another experiment, the compressive strength and permeability (“K”) of two 88:10:2 sand packs were (88:10:2 parts by weight respectively of OK#1 sand, fine silica flour, and bentonite) (“Test 3 88:10:2 sand pack” and “Test 4 88:10:2 sand pack”) were prepared by placing 100 grams of 88:10:2 sand into a 1-inch ID rubber sleeve. Gravel with a mesh size of 40/70 was packed at the bottom and top of the OK#1 sand. Wire mesh screen pieces of 100-mesh size were placed at the bottom and top of the gravel. The 88:10:2 sand packs were treated with Sample 2 from Example 1 (including 2 g of maleic anhydride, a stimuli-delayed acid generator) at 100-psi pressure. The Test 3 and Test 4 88:10:2 sand packs were prepped by treatment with approximately 1000 mL of 7% KCl brine solution at a rate of 15 mL/min, followed by the introduction of nitrogen for 2 min, followed by a final treatment of approximately 1500 mL of 7% KCl brine solution at a rate of 15 mL/min, representing $K_{initial}$ for permeability testing. The Test 3 and Test 4 88:10:2 sand packs were then preheated to 230° F.

[0035] After prepping the Test 3 and Test 4 88:10:2 sand packs, each was pre-flushed with 120 mL of a 3% KCl brine solution containing 0.25% 19N™ at 3 mL/min. To each of the Test 3 and Test 4 88:10:2 sand packs, 80 mL of Sample 1 was added at 3 mL/min. The Test 3 88:10:2 sand pack was post-flushed with nitrogen gas for 3 minutes, representing $K_{end\ post-flush}$ for Test 3. Whereas, the Test 4 88:10:2 sand pack was post-flushed with 40 mL of a 3% KCl brine containing 0.25% 19N™ at 3 mL/min, representing $K_{end\ post-flush}$ for Test 4. The Test 3 and Test 4 88:10:2 sand packs were subjected to a temperature of 230° F. for 24 hours and each washed with 100 mL of a 7% KCl brine at 15 mL/min to determine the retained permeability of the sand packs, representing K_{final} . The screens were then removed from the bottom of the cells, representing $K_{final\ (screen\ removed)}$.

[0036] The consolidation strength based UCS, LOI, and tensile strength along different intervals of the Test 3 and Test 4 88:10:2 sand packs were measured. The results are shown in Table 1.

TABLE 1

CONSOLIDATION STRENGTH OF 88:10:2 TREATED SAND PACKS				
Test #	USC - Middle (LOI)	Tensile - Top (LOI)	Tensile - Middle (LOI)	Tensile - Bottom (LOI)
3	1220 psi (10.48%)	317 psi (8.67%)	305 psi (10.98%)	233 psi (7.9%)
4	288 psi (10.41%)	62 psi (8.31%)	194 psi (10.22%)	228 psi (11.62%)

[0037] As shown in Table 1, a post-flush with nitrogen gas (Test 3) resulted in stronger consolidation of the 88:10:2 sand packs as compared to a post-flush of 3% KCl brine solution containing 0.25% 19N™ (Test 4) without significantly affecting the LOI content.

[0038] The permeability (“K”) of the Test 3 and Test 4 88:10:2 sand packs was measured at different time intervals during preparation of the sand packs. A regained permeability test was performed comparing $K_{initial}$ to both K_{final} and K_{final} (screen removed), represented as $K_{regained}$ and $K_{regained}$ (screen removed). The results are shown in Table 2.

TABLE 2

PERMEABILITY OF 88:10:2 TREATED SAND PACKS						
Test #	K initial (mD)	K end post-flush (mD)	K final (mD)	K final (screen removed) (mD)	K regained (%)	K regained (screen removed) (%)
3	327	60	121	216	37	66
4	263	75	72	114	27	43

[0039] As shown in Table 2, the nitrogen post-flush represented a better permeability regain of the 88:10:2 sand packs as compared to as compared to a post-flush of 3% KCl brine solution containing 0.25% 19N™. Therefore, a nitrogen gas post-flush may be preferred method for use in the present invention in order to achieve strong consolidation and better permeability regain.

[0040] Therefore, the present invention is well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered, combined, or modified and all such variations are considered within the scope and spirit of the present invention. The invention illustratively disclosed herein suitably may be practiced in the absence of any element that is not specifically disclosed herein and/or any optional element disclosed herein. While compositions and methods are described in terms of “comprising,” “containing,” or “including” various components or steps, the compositions and methods can also “consist essentially of” or “consist of” the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and

any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, “from about a to about b,” or, equivalently, “from approximately a to b,” or, equivalently, “from approximately a–b”) disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles “a” or “an,” as used in the claims, are defined herein to mean one or more than one of the element that it introduces. If there is any conflict in the usages of a word or term in this specification and one or more patent or other documents that may be incorporated herein by reference, the definitions that are consistent with this specification should be adopted.

1. A method comprising:

providing a wellbore in a subterranean formation comprising unconsolidated particulates;

providing a treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator,

wherein the stimuli-delayed acid generator is selected from the group consisting of a polylactic acid; a polyglycolic acid; a poly(3-hydroxybutyrate); a polysuccinate ester; a polyanhydride; a maleic anhydride; an orthoester; a formate ester-diethylene glycol diformate; an ethyl lactate; a methyl lactate; an acetate ester; a L-dilactide; a glucono-delta-lactone; a lactate ester butyl lactate; poly(lactic-co-glycolic acid); a poly(glycolic-co-caprolactone); a polycaprolactone; a poly(glycolic-co-trimethylene carbonate); a poly(lactic-co-caprolactone); a poly(lactic-co-trimethylene carbonate); a polyglyconate; a polyglactin; a poly(lactic-co-glycolic acid)-methoxy-poly(ethylene glycol) copolymer; a polydioxanone; an ethyl lactate; a methyl lactate; a L-dilactide; a glucono-delta-lactone; any copolymers thereof; any derivatives thereof; and any combinations thereof, and

wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein at least a portion of the stimuli-delayed acid generator is a liquid;

introducing the treatment fluid into the wellbore in the subterranean formation; and

stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin;

wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates.

2. The method of claim 1, wherein the treatment fluid further comprises a base fluid.

3. The method of claim 1, wherein the furan-based resin is selected from the group consisting of a furan resin; a furfuryl alcohol resin; a furan-aldehyde; a furan-phenolic resin; and any combinations thereof.

4. The method of claim 1, wherein the treatment fluid further comprises a silane coupling agent.

5. The method of claim 4, wherein the silane coupling agent is selected from the group consisting of N-β-(aminoethyl)-γ-aminopropyl trimethoxysilane, N-2-(aminoethyl)-3-aminopropyltrimethoxysilane; 3-glycidoxypropyltrimethoxysilane; gamma-aminopropyltriethoxysilane; N-beta-(aminoethyl)-gamma-aminopropyltrimethoxysilanes; aminoethyl-N-beta-(aminoethyl)-gamma-aminopropyl-tri-

methoxysilanes; gamma-ureidopropyl-triethoxysilanes; beta-(3-4 epoxy-cyclohexyl)-ethyl-trimethoxysilane; gamma-glycidoxypropyltrimethoxysilanes; vinyltrichlorosilane; vinyltris(beta-methoxyethoxy) silane; vinyltriethoxysilane; vinyltrimethoxysilane; 3-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; 3-aminopropyl-triethoxysilane; N-phenyl-r-aminopropyltrimethoxysilane; r-mercaptopropyltrimethoxysilane; r-chloropropyltrimethoxysilane; vinyltris(beta-methoxyethoxy) silane; r-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; r-aminopropyltriethoxysilane; N-[3-(trimethoxysilyl)propyl]-ethylenediamine; and any combinations thereof.

6. The method of claim 1, wherein the treatment fluid further comprises a surfactant.

7. The method of claim 6, wherein the surfactant is selected from the group consisting of an alkyl phosphonate surfactant; an ethoxylated nonyl phenol phosphonate ester surfactant; a cationic surfactant; a nonionic surfactant; and any combinations thereof.

8. The method of claim 1, further comprising introducing a pre-flush fluid into the wellbore in the subterranean formation prior to the introduction of the treatment fluid.

9. The method of claim 1, further comprising introducing a post-flush fluid into the wellbore in the subterranean formation subsequent to stimulating the stimuli-delayed acid generator.

10. A method comprising:

providing a wellbore in a subterranean formation comprising unconsolidated particulates;

providing a treatment fluid comprising a furan-based resin; introducing the treatment fluid into the wellbore in the subterranean formation;

placing a stimuli-delayed acid generator into the wellbore in the subterranean formation;

wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein at least a portion of the stimuli-delayed acid generator is a liquid; and

stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin;

wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates.

11. The method of claim 10, wherein the treatment fluid further comprises a base fluid.

12. The method of claim 10, wherein the furan-based resin is selected from the group consisting of a furan resin; a furfuryl alcohol resin; a furan-aldehyde; a furan-phenolic resin; and any combinations thereof.

13. The method of claim 10, wherein the treatment fluid further comprises a silane coupling agent selected from the group consisting of N-β-(aminoethyl)-γ-aminopropyl trimethoxysilane, N-2-(aminoethyl)-3-aminopropyltrimethoxysilane; 3-glycidoxypropyltrimethoxysilane; gamma-aminopropyltriethoxysilane; N-beta-(aminoethyl)-gamma-

aminopropyltrimethoxysilanes; aminoethyl-N-beta-(aminoethyl)-gamma-aminopropyl-trimethoxysilanes; gamma-ureidopropyl-triethoxysilanes; beta-(3-4 epoxy-cyclohexyl)-ethyl-trimethoxysilane; gamma-glycidoxypropyltrimethoxysilanes; vinyltrichlorosilane; vinyltris(beta-methoxyethoxy) silane; vinyltriethoxysilane; vinyltrimethoxysilane; 3-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; 3-aminopropyl-triethoxysilane; N-phenyl-r-aminopropyltrimethoxysilane; r-mercaptopropyltrimethoxysilane; r-chloropropyltrimethoxysilane; vinyltris(beta-methoxyethoxy) silane; r-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; r-aminopropyltriethoxysilane; N-[3-(trimethoxysilyl)propyl]-ethylenediamine; and any combinations thereof.

14. The method of claim 10, wherein the treatment fluid further comprises a surfactant selected from the group consisting of an alkyl phosphonate surfactant; an ethoxylated nonyl phenol phosphonate ester surfactant; a cationic surfactant; a nonionic surfactant; and any combinations thereof.

15. The method of claim 10, further comprising introducing a pre-flush fluid into the wellbore in the subterranean formation prior to the introduction of the treatment fluid.

16. The method claim 10, further comprising introducing a post-flush fluid into the wellbore in the subterranean formation subsequent to stimulating the stimuli-delayed acid generator.

17. A method comprising:

providing a wellbore in a subterranean formation comprising unconsolidated particulates;

providing a treatment fluid comprising a furan-based resin and a stimuli-delayed acid generator,

wherein the stimuli-delayed acid generator is selected from the group consisting of a polylactic acid; a polyglycolic acid; a poly(3-hydroxybutyrate); a polysuccinate ester; a polyanhydride; a maleic anhydride; an orthoester; a formate ester-diethylene glycol diformate; an ethyl lactate; a methyl lactate; an acetate ester; a L-dilactide; a glucono-delta-lactone; a lactate ester butyl lactate; poly(lactic-co-glycolic acid); a poly(glycolic-co-caprolactone); a polycaprolactone; a poly(glycolic-co-trimethylene carbonate); a poly(lactic-co-caprolactone); a poly(lactic-co-trimethylene carbonate); a polyglyconate; a polyglactin; a poly(lactic-co-glycolic acid)-methoxy-poly(ethyleneglycol) copolymer; a polydioxanone; an ethyl lactate; a methyl lactate; a L-dilactide; a glucono-delta-lactone; any copolymers thereof; any derivatives thereof; and any combinations thereof,

wherein the furan-based resin is selected from the group consisting of a furan resin; a furfuryl alcohol resin; a furan-aldehyde; a furan-phenolic resin; and any combinations thereof, and

wherein the stimuli-delayed acid generator generates acid upon encountering a wellbore stimulus and wherein at least a portion of the stimuli-delayed acid generator is a liquid;

introducing a pre-flush fluid into the wellbore in the subterranean formation;

introducing the treatment fluid into the wellbore in the subterranean formation;

stimulating the stimuli-delayed acid generator so as to generate acid and at least partially cure the furan-based resin;

wherein the at least partial curing of the furan-based resin at least partially consolidates the unconsolidated particulates; and

introducing a post-flush fluid into the wellbore in the subterranean formation.

18. The method of claim 17, wherein the treatment fluid further comprises a base fluid.

19. The method of claim 17, wherein the treatment fluid further comprises a silane coupling agent selected from the group consisting of N- β -(aminoethyl)- γ -aminopropyl trimethoxysilane, N-2-(aminoethyl)-3-aminopropyltrimethoxysilane; 3-glycidoxypropyltrimethoxysilane; gamma-aminopropyltriethoxysilane; N-beta-(aminoethyl)-gamma-aminopropyltrimethoxysilanes; aminoethyl-N-beta-(aminoethyl)-gamma-aminopropyl-trimethoxysilanes; gamma-ureidopropyl-triethoxysilanes; beta-(3-4 epoxy-cyclohexyl)-ethyl-trimethoxysilane; gamma-glycidoxypropyl-

trimethoxysilanes; vinyltrichlorosilane; vinyltris(beta-methoxyethoxy) silane; vinyltriethoxysilane; vinyltrimethoxysilane; 3-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; 3-aminopropyl-triethoxysilane; N-phenyl-r-aminopropyltrimethoxysilane; r-mercaptopropyltrimethoxysilane; r-chloropropyltrimethoxysilane; vinyltris(beta-methoxyethoxy) silane; r-metacryloxypropyltrimethoxysilane; beta-(3,4 epoxy-cyclohexyl)-ethyltrimethoxysilane; r-glycidoxypropyltrimethoxysilane; r-glycidoxypropylmethylidiethoxysilane; N-beta-(aminoethyl)-r-aminopropyltrimethoxysilane; N-beta-(aminoethyl)-r-aminopropylmethylidimethoxysilane; r-aminopropyltriethoxysilane; N-[3-(trimethoxysilyl)propyl]-ethylenediamine; and any combinations thereof.

20. The method of claim 17, wherein the treatment fluid further comprises a surfactant selected from the group consisting of an alkyl phosphonate surfactant; an ethoxylated nonyl phenol phosphonate ester surfactant; a cationic surfactant; a nonionic surfactant; and any combinations thereof.

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