METHODS FOR TREATING WELLBORE AND WELLBORE OPERATION FLUIDS

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ABSTRACT

Method comprising providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation; providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid; combining the wellbore treatment fluid with a a plurality of bacteriocins; placing the wellbore treatment fluid into a wellbore in the portion of the subterranean formation; reducing the first formation bacterial count to a second formation bacterial count; and reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.
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BACKGROUND

[0001] The present invention relates to methods for combating biological contamination in a wellbore or surrounding subterranean formation and in wellbore operation fluids using bacteriocins.

[0002] Oil well stimulation, drilling, recovery, and cleanup operations are often negatively affected by the presence of bacterial contaminants. These contaminants may be present in the liquid treatment fluids or equipment (e.g., tanks, pumps, structural members, etc.) used for well operations, the subterranean formation itself, or flowback fluids. Bacterial contaminants may cause numerous problems, such as increased corrosion rates and plugging of conduits, filters, and pumps, reservoir souring, etc. They may additionally interfere with the desired operational qualities of a particular liquid treatment fluid or additive within the treatment fluid. Some bacteria release enzymes that degrade polymers commonly used in well operations and interfere with those operations. For example, degradation of a gel stabilizer polymer in a treatment fluid could result in a loss in viscosity of the fluid and decrease in ability of the fluid to effectively transport necessary additives. Therefore, it is often desirable to inhibit microbial growth in liquids and substrates (e.g., metal equipment that comes into contact with the liquids) in well operations.

[0003] A number of methods have been used for reducing or eliminating bacterial contaminants in well operations, such as introducing biocides downhole or using biocides to sterilize flowback fluids. However, biocides pose significant risk to human health and the environment. Great care is required when handling biocides, necessitating appropriate protective clothing and hazardous disposal practices. Additionally, biocides may have severe and lasting impacts on water sources and ecosystems, which may be a particular problem should a well operation fail or the recovered liquids become uncontained. Bacterial contaminants have also been mitigated by irradiation of well operation treatment fluids and flowback fluids with ultraviolet light ("UV"). UV irradiation is safer to use than biocides for controlling bacterial contamination. However, UV irradiation requires special UV light sources at the well site and may not effectively kill bacterial contaminants. For example, even if UV irradiation wholly eradicates all bacterial contaminants from well operation fluids or equipment, any contaminants in the wellbore itself still remain and may propagate in the treatment fluids after they are introduced. Moreover, well operation equipment may house bacterial contaminants and introduce those contaminants into already irradiated treatment fluids. Therefore, a method of effectively inhibiting bacterial contaminants in well operations that is safe for human handling and the environment may be beneficial to one of ordinary skill in the art.

SUMMARY OF THE INVENTION

[0004] The present invention relates to methods for combating biological contamination in a wellbore or surrounding subterranean formation and in wellbore operation fluids using bacteriocins.

[0005] In some embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation; providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid; combining the wellbore treatment fluid with a plurality of bacteriocins; placing the wellbore treatment fluid into a wellbore in the portion of the subterranean formation; reducing the first formation bacterial count to a second formation bacterial count; and reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

[0006] In other embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation; providing a flowback fluid that has previously been present in a portion of a subterranean formation wherein the flowback fluid has a first bacterial count as a result of the presence of a plurality of bacteria; combining the flowback fluid with a plurality of bacteriocins; and reducing the first bacterial count to a second bacterial count.

[0007] In still other embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation; providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid; providing particulates having a coating of bacteriocins thereon and a coating of degradable material atop the coating of bacteriocins; wherein the degradable coating is a polysaccharide, a cellulose, a chitin, a chitosan, a protein, an aliphatic polyester, a poly(lactide), a poly(glycolide), a poly(e-caprolactone), a poly(ethylene glycol), a poly(anhydride), an aliphatic polycarbonate, a poly(orthoester), a poly(α-amino acid), a poly(ethylene oxide), a poly(vinylidene chloride), a poly(phosphazene), or a combination thereof; and combining the wellbore treatment fluid with a plurality of bacteriocins; combining the wellbore treatment fluid with the coated particulates; placing the wellbore treatment fluid comprising the coated particulates into a portion of the subterranean formation; releasing the bacteriocins as the degradable coating degrades; reducing the first formation bacterial count to a second formation bacterial count; and reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

[0008] 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

[0009] The present invention relates to methods for combating biological contamination in a wellbore or surrounding subterranean formation using bacteriocins. The methods of the various embodiments of the present invention may combat biological contamination in a wellbore and flowback fluids, while reducing or eliminating reliance on hazardous biocides or less effective antibacterial treatments.

[0010] In some embodiments, the methods disclosed herein may be used in any type of hydrocarbon recovery operation where disinfecting a treatment fluid or formation face is desired, including, but not limited to, pipeline operations, well servicing operations, upstream exploration and produc-
tion operations, downstream refining, processing, storage and transportation applications, and sterilization of flowback fluids.

[0011] As used herein, the term “bacteriocin” refers to a protein or peptide produced by a gram-positive or a gram-negative bacterium that is bactericidal and/or bacteriostatic against organisms related to the producer bacterium, but that does not act against the producer bacterium itself. Bacteriocins, thus, are naturally occurring antibacterial agents. Additionally, bacteriocins are generally produced by non-pathogenic bacteria naturally found in the human body. Therefore, they are prime candidates for medicinal and food-related applications and are safe for human consumption. Indeed, the bacteriocin nisin is listed as a Generally Recognized as Safe by the U.S. Food and Drug Administration. The present invention relates to a novel use of bacteriocins in well operations. Not only are bacteriocins useful as an antibacterial agent, they are also generally categorized as food-grade, ensuring that any inadvertent exposure to the bacteriocins would not be hazardous to flora, fauna, or human life.

[0012] The wellbore treatment fluids of the present invention may be any suitable treatment fluids capable of use in a well operation. Suitable treatment fluids may include, but are not limited to, aqueous-based fluids, aqueous-miscible fluids, water-in-oil emulsions, or oil-in-water emulsions. 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 are not 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. Nos. 5,905,061, 5,977,031, 6,828,279, 7,534,745, 7,645,723, and 7,696,131, each of which are incorporated in their entirety herein by reference. 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.

[0013] The wellbore treatment fluids of the present invention may additionally contain an additive or combination of additives including, but 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 viscosity-increasing 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 scale inhibitor, a gas hydrate inhibitor, a mutual solvent, an oxidizer, a reducer, a friction reducer, a clay stabilizing agent, and any combination thereof.

[0014] The wellbore treatment fluids of the present invention may include drilling fluids, lost circulation fluids, stimulation fluids, sand control fluids, completion fluids, acidizing fluids, scale inhibiting fluids, water-blocking fluids, clay stabilizing fluids, fracturing fluids, free-pack fluids, gravel packing fluids, wellbore strengthening fluids, acidizing fluids, and sag control fluids. The methods and compositions of the present invention may be used in full-scale fluids or as pills. As used herein, a “pill” is a type of relatively small volume of specially prepared treatment fluid placed or circulated in the wellbore.

[0015] In some embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation; providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteriocins in the wellbore treatment fluid; combining the wellbore treatment fluid with a plurality of bacteriocins; placing the wellbore treatment fluid into a wellbore in the portion of the subterranean formation; reducing the first formation bacterial count to a second formation bacterial count; and reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

[0016] Because of the mechanism through which bacteriocins work, gram-positive produced bacteriocins generally, but not always, serve as a bactericide to gram-positive bacteria and gram-negative produced bacteriocins generally serve as a bactericide gram-negative bacteria. Depending on the conditions of the environment, treatment fluid, wellbore conditions, and other well operation parameters, gram-positive bacteriocins, gram-negative bacteriocins, or a combination of both may be used in accordance with the present invention to inhibit bacterial growth.

[0017] Suitable gram-positive bacteriocins include, but are not limited to, acidocin; actidarginc; bovicin; brochocin; butyribovircin; carnobacteriocin; carnocin; carnoeocylin; circularin; clasticin; cuaaglin; curvacin; curvaticin; cytolysin; diversin; divergenc; duramycin; enteriocin; enteriain; epicidin; epidermidin; eplphencin; ericin; gallidermin; garvecin; gassercin; haloduracin; hiracin; hominecin; ipomicin; lactecoin; lactoecolin; lactoeycin; lanbiotico; laeucocin; lichenicidin; listericin; lysostaphin; mesenteriecin; microbisporicin; munditcin; mutacin; nisin; paemibacillin; pediocin; pep5 lantibiotic; piscicin; plantaricin; sakacin; salivaricin; sib; staphylococcin; and any combination thereof. Suitable gram-negative bacteriocins include, but are not limited to, capristuin; colcin; microcin; pyrocins; serracin; and any combination thereof. Any gram-positive bacteriocin may be combined with any gram-negative bacteriocin to produce the desired effects for a particular well operation. In some embodiments, the bacteriocin is present in the wellbore treatment fluid in an amount from about 0.1 μg/ml to about 300 μg/ml. In preferred embodiments, the bacteriocin is present in the wellbore treatment fluid in an amount from about 0.1 μg/ml to about 100 μg/ml.

[0018] Bacterial contamination in a well operation may exist in the treatment fluids themselves or the well (e.g., the subterranean formation). The treatment fluids containing
bacteriocins of the present invention may serve as a bactericide to both because the bacteriocins may be effective against any surface which the treatment fluid contacts.

[0019] The bacteriocins may additionally be used to treat flowback fluids for bacterial contamination. In some embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation; providing a flowback fluid that has previously been present in a portion of a subterranean formation; wherein the flowback fluid has a first bacterial count as a result of the presence of a plurality of bacteria; combining the flowback fluid with a plurality of bacteriocins; and reducing the first bacterial count to a second bacterial count.

[0020] As used herein, the term “flowback fluid” refers to any fluids that flow from a wellbore following treatment with a wellbore treatment fluid, either in preparation for a subsequent phase of treatment or in preparation for cleanup. Flowback fluids may be any wellbore treatment fluid disclosed herein, including any additive or additives included therein, that flow from the wellbore and to the surface. Additionally, Flowback fluids may include produced water or other fluids from the formation, but does not include produced fluids that are obtained during well production (e.g., hydrocarbons).

[0021] Some well operations take place under conditions having extreme pH or temperature levels. Although any suitable buffering agent that does not interfere with the particular well operation may be used in accordance with the present invention to control pH, particular bacteriocins are able to operate at extreme pH levels. For example, enterocin may be stable at low pH levels (2.0-5.0) and carnobacterin may be stable at high pH levels (8.5-9.5). Like pH, bacteriocins are also able to operate at extreme temperatures. For example, bacteriocins produced by Lactobacillus plantarum are thermotolerant at 100°C for at least 90 minutes and 121°C for at least 20 minutes. (Porada et al., Brazilian Archives of Bio. & Tech. 50:521-542 (2007)).

[0022] Bacteriocin activity may be enhanced by the use of a chelating agent and/or a surfactant in combination with the bacteriocin. The use of a chelating agent and/or a surfactant in combination with a bacteriocin can enhance the potency and range of the bacteriocin as a bactericide. Suitable chelating agents include, but are not limited to EDTA, CaEDTA, CaNa$_2$EDTA, alkyldiamine tetraacetates, IGT, citrate, and any combination thereof. In some embodiments, the chelating agent is present in an amount from about 0.1 mM to about 30 mM of the wellbore treatment fluid or flowback fluid. The surfactants used in the present invention may be ionic or nonionic. Suitable ionic surfactants include, but are not limited to emulsifiers, fatty acids, quaternary compounds, anionic surfactants (e.g., sodium dodecyl sulphate), amphoteric surfactants (e.g., cocamidopropyl betaine), and any combination thereof. Suitable nonionic surfactants include, but are not limited to, polyoxyalkylphenols (e.g., Triton X-100), polyoxyalkylsorbitans (e.g., Tween), glycerides (e.g., monolaurin and dioleates), and any combination thereof. In some embodiments, one or more surfactants are present in the wellbore treatment fluids and/or flowback fluids of the present invention in an amount from about 0.01% to about 5.0% of the wellbore treatment fluids. In other embodiments, the surfactants are present from about 0.1% to about 1.0% of the wellbore treatment fluids and/or flowback fluids.

[0023] In some embodiments, the present invention provides a method comprising: providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation; providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid; providing particulates having a coating of bacteriocins thereon and a coating of a degradable material atop of the coating of bacteriocins; wherein the degradable coating is a polysaccharide, a cellulose, a chitin, a chitosan, a protein, an aliphatic polyester, a poly(lactide), a poly(glycolide), a poly(e-caprolactone), a poly(hydroxybutyrate), a poly(anhydride), an aliphatic polycarbonate, a poly(orthoester), a poly(amino acid), a poly(ethylene oxide), a poly(vinylidene chloride), a polyphosphazene, or a combination thereof combining the wellbore treatment fluid with a plurality of bacteriocins; combining the wellbore treatment fluid with the coated particulates; placing the wellbore treatment fluid comprising the coated particulates into a portion of the subterranean formation; releasing the bacteriocins as the degradable coating degrades; reducing the first formation bacterial count to a second formation bacterial count; and reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

[0024] In such embodiments, the bacteriocins may be advantageously delivered to a desired location in a subterranean formation along with particulates (such as proppant or gravel). In these particulate embodiments, it may be desirable to coat at least a portion of the particulates with bacteriocins absorbed thereon with a degradable coating that will degrade over time and thus release the bacteriocins over time. Suitable degradable coatings include degradable polymers, waxes, and latexes. Degradable polymers suitable for use in the present invention are capable of undergoing an irreversible degradation down hole. The terms “irreversible” as used herein means that the degradable material, once degraded down hole, should not recrystallize or reconsolidate while down hole, e.g., the degradable material should degrade in situ but should not recrystallize or reconsolidate in situ. The terms “degradation” or “degradable” refer to both the two relatively extreme cases of hydrolytic degradation that the degradable material may undergo, i.e., heterogeneous (or bulk erosion) and homogeneous (or surface erosion), and any stage of degradation in between these two. This degradation can be a result of a physical change, chemical process, or a thermal process. Suitable examples of degradable polymers that may be used in accordance with the present invention include, but are not limited to, polysaccharides; cellulose; chitosans; proteins; aliphatic polyesters; poly(lactides); poly(glycolides); poly(e-caprolactones); poly(hydroxybutyrates); poly(anhydrides); aliphatic polycarbonates; poly(orthoesters); poly(amino acids); poly(ethylene oxides); poly(vinylidene chloride); and polyphosphazenes. Of these suitable polymers, aliphatic polyesters and poly(anhydrides) may be preferred. Additional detail regarding acceptable degradable polymers can be found in U.S. Pat. No. 7,044,220, the entire disclosure of which is hereby incorporated by reference.

[0025] In still other embodiments, the bacteriocins may be coated directly onto a solid fluid loss control agents used in a subterranean treatment fluid. By placing the bacteriocins onto fluid loss control particles, the methods of the present invention are able to place the bacteriocins directly at, for example, a fracture face, thus potentially stopping the influx of harmful bacteria before they reach producing zones. Any solid fluid loss control agent known in the art may be used to deliver the
bacteriocins in these embodiments of the present invention. Some common fluid loss control agents include silica, mica, calcite, aliphatic polyester, polylactic acid; a poly(lactide), a poly(orthoester), a surfactant-based fluid loss control agent (such as those described in U.S. Pat. No. 7,413,013, the entire disclosure of which is hereby incorporated by reference), carboxymethylcellulose, carboxyethylcellulose, and polyacrylates.

[0026] Once of skill in the art will recognize that where a coated particulate embodiment of the present invention is used, a chelating agent and/or a surfactant may be combined with the bacteriocin before it is coated onto the particulate.

[0027] 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.

The invention claimed is:

1. A method comprising:
   providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation;
   providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid;
   combining the wellbore treatment fluid with a plurality of bacteriocins;
   placing the wellbore treatment fluid into a wellbore in the portion of the subterranean formation;
   reducing the first formation bacterial count to a second formation bacterial count; and
   reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

2. The method of claim 1, wherein the bacteriocins are gram-positive bacteria produced bacteriocins, gram-negative bacteria produced bacteriocins, or a combination thereof.

3. The method of claim 1, wherein the bacteriocins are gram-positive bacteria produced bacteriocins selected from the group consisting of: acidocin; actagardine; bovicin; brochcin; butyrivibrioicin; carnobacteriocin; carnocin; carnocycin; circularin; cloticin; coagulin; curvacin; curvaticin; cytolyisin; divenicin; divergiecin; duramycin; enterocin; entianin; epicidin; epidermin; epilance; ericin; gallidermin; garvacin; gassericin; hakuoracin; hiracin; hominicin; ipomicin; lactacin; lactocin; lactocycin; lantibiotic; leuconin; lichenicidin; listeriocin; lysostaphin; mesentericin; microbisporicin; mundicin; mutacin; nisin; paenibacillicin; pediocin; pep5 lan-
12. The method of claim 9, wherein the bacteriocins are gram-negative bacteria produced bacteriocins selected from the group consisting of: capistruin; colicin; microcin; pyrococcin; serracin; and any combination thereof.

13. The method of claim 9, wherein the flowback fluid further comprises a chelating agent selected from the group consisting of: EDTA; CaEDTA; CaNa₂EDTA; alkyl diamine tetraacetate; EGTA; citrate; and any combination thereof.

14. The method of claim 9, wherein the flowback fluid further comprises an ionic surfactant selected from the group consisting of: an emulsifier; a fatty acid; a quaternary compound; an anionic surfactant; an amphoteric surfactant; and any combination thereof.

15. The method of claim 9, wherein the flowback fluid further comprises a nonionic surfactant selected from the group consisting of: a polyoxyalkylphenol; a polyoxyalkysorbitan; a glyceride; and any combination thereof.

16. A method comprising:

- providing a portion of a subterranean formation having a first formation bacterial count as a result of the presence of a plurality of bacteria in the formation;
- providing a wellbore treatment fluid having a first wellbore treatment fluid bacterial count as a result of the presence of a plurality of bacteria in the wellbore treatment fluid;
- providing particulates having a coating of bacteriocins thereon and a coating of degradable material atop of the coating of bacteriocins;
- wherein the degradable coating is a polysaccharide, a cellulose, a chitin, a chitosan, a protein, an aliphatic polyester, a poly(lactide), a poly(glycolide), a poly(ε-caprolactone), a poly(hydroxybutyrate), a poly(anhydride), an aliphatic polycarbonate, a poly(orthoester), a poly(amino acid), a poly(ethylene oxide), a poly(vinylidene chloride), a polyphosphate, or a combination thereof combining the wellbore treatment fluid with a plurality of bacteriocins;
- combining the wellbore treatment fluid with the coated particulates;
- placing the wellbore treatment fluid comprising the coated particulates into a portion of the subterranean formation;
- releasing the bacteriocins as the degradable coating degrades;
- reducing the first formation bacterial count to a second formation bacterial count; and
- reducing the first wellbore treatment fluid bacterial count to a second wellbore treatment fluid bacterial count.

17. The method of claim 16, wherein the bacteriocins are gram-positive bacteria produced bacteriocins, gram-negative bacteria produced bacteriocins, or a combination thereof.

18. The method of claim 16, wherein the bacteriocins are gram-positive bacteria produced bacteriocins selected from the group consisting of: acidocin; actagardine; bovicin; brochocin; butyrilvibriocin; carnobacteriocin; carnocin; carnocyclin; circularin; clostriciin; coagulin; curvacin; curvaticin; cytolysin; divercin; divergicin; duramycin; enterocin; entianin; epidocin; epidermin; epilancin; ercin; gallidermin; garvicin; gassericin; haloduracin; hiracin; hominicin; ipomicin; lactacin; lactocin; lactocyclin; lantibiotic; leucocin; lichenicidin; listeriocin; lysostaphin; mesentericin; microbisporicin; mundticin; mutacin; nisin; paenibacillin; pediocin; pep5 lantibiotic; piscicolin; plantaricin; sakacin; salivaricin; smb; staphylococcin; and any combination thereof.

19. The method of claim 16, wherein the bacteriocins are gram-negative bacteria produced bacteriocins selected from the group consisting of: capistruin; colicin; microcin; pyrococcin; serracin; and any combination thereof.

20. The method of claim 16, wherein the bacteriocins are gram-positive bacteria produced bacteriocins and gram-negative bacteria produced bacteriocins and are in a combined presence of about 0.1 μg/ml to about 300 μg/ml of the wellbore treatment fluid.