
International Application Number:  PCT/US2012/054896

Priority Data:  US/2010/019938 (US)


(21) International Application Number:  PCT/US2013/054896

(22) International Filing Date:  14 August 2013 (14.08.2013)

(25) Filing Language:  English

(26) Publication Language:  English


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(54) Title:  GAS FRACTURE INJECTION TO OVERCOME RETROGRADE CONDENSATION IN GAS WELLS

(57) Abstract:  Disclosed is a well configuration and method of forming the configuration and producing hydrocarbons from the configuration. In one embodiment, multiple fractures are formed from a wellbore in a subterranean hydrocarbon gas formation. One fracture is filled with material to create a flow barrier that modifies the flow pattern of at least one fluid within the subterranean hydrocarbon formation. Also disclosed is the process of injecting a Dew Point altering gas into the formation on one side of the barrier and producing a mixture of formation gas and injected gas from the fractures on the other side of the barrier.
GAS FRACTURE INJECTION TO OVERCOME RETROGRADE CONDENSATION IN GAS WELLS

CROSS REFERENCE TO RELATED APPLICATIONS

BACKGROUND
[0002] The present invention relates generally to hydrocarbon production and, more particularly, to a method of increasing hydrocarbon production in gas well by forming an in-situ barrier and by injecting a gas on one side of the barrier to mix with and modify the Dew Point Pressure of the resulting mixture of reservoir gas and injected gas.

[0003] In some subterranean formations, gas production with low to moderate matrix permeability to gas and high gas specific gravity suffers from retrograde condensation effects. As used in the well context, the term "retrograde condensation" refers to the formation of liquid hydrocarbons in a gas reservoir, which occurs as the pressure in the reservoir decreases below Dew Point Pressure during production.

[0004] As used herein, the term "Dew Point Pressure" is the gas pressure at which a system is at its Dew Point, that is, the pressure at a given temperature at which the first dew or liquid phase occurs. The name "retrograde" (meaning to retreat or go back) is used herein to describe a system where, at a given temperature, lowering pressure causes condensation. Condensation in gas production is sometimes described as "liquid drop out." The term "condensate banking" refers to the formation of liquids with the gas in the formation, i.e., rock matrix, in the producing intervals around the wellbore. With the retrograde condensation, the percentage of liquid begins to increase as pressure decreases and then the percentage of liquid decreases with further pressure declines. Condensate backing reduces
the apparent permeability of the matrix and reduces the total production rate for a given flowing pressure.

[0005] One method used by the industry to reduce the effects of retrograde gas condensation in the rock matrix around the wellbore is to maintain reservoir pressure above the Dew Point Pressure by injecting a fluid or gas to replace the volume produced from the formation. However, at reasonable production rates reservoir pressure cannot be maintained and condensate banking will occur in the rock matrix near the producing intervals as the pressure drops below the Dew Point Pressure.

[0006] Another method used in the industry to mitigate retrograde condensation involves flooding the reservoir with a miscible gas, such as methane or CO2. The methane gas is a byproduct of "stripping" the condensate from the produced gas. When these gases are mixed with the reservoir gas, the resulting gas mixture can result in a more phase stable gas mixture with a significantly lower Dew Point pressure.

[0007] Prior art well configurations used to deal with retrograde condensate reservoirs involve drilling separate producer and injection wells. The most common pattern is called a 5-spot pattern with the injection well surrounded by four producing wells. An injection fluid, such as methane gas, is injected from the center well.

Summary

[0008] The present invention relates generally to hydrocarbon production and, more particularly, to a method of increasing hydrocarbon production in gas well by maintaining the reservoir gas at or above its Dew Point Pressure during production.

[0009] In one embodiment, an in-situ barrier is formed and gas produced from the formation on one side of the barrier while Dew Point lowering gas is injected on the other side of the barrier to mix with and modify the Dew Point of the resulting mixture of reservoir gas and injected gas.

[0011] In an embodiment of the method, the method comprises: forming an in-situ barrier at one point along the wellbore; injecting methane or carbon dioxide gas on one side of the barrier to mix with and raise the Dew Point of the resulting mixture of reservoir gas and injected gas; and flowing the mixture of reservoir gas and injected gas into the wellbore on the opposite side of the barrier.

[0012] In an embodiment, a method comprises: forming a horizontally extending wellbore in a hydrocarbon gas bearing formation; forming an in-situ barrier at one point along the wellbore; injecting a gas on one side of the barrier to mix with and modify the Dew Point of the resulting mixture of reservoir gas and injected gas; and flowing the mixture of reservoir gas and injected gas into the wellbore on the opposite side of the barrier.

[0013] In an embodiment, a method comprises: forming an in-situ barrier at one point along the wellbore; injecting a gas on one side of the barrier to mix with and raise the Dew Point Pressure of the resulting mixture of reservoir gas and injected gas; and flowing the mixture of reservoir gas and injected gas into the wellbore on the opposite side of the barrier and selectively controlling the flow of the hydrocarbon mixture into the wellbore at the plurality of locations to maintain the produced gas mixture at a pressure above the Dew Point Pressure.

[0014] In one embodiment, valves are present that control flow based on or as a function of the phase of the hydrocarbon flow. For example, valves can be provided that limit the flow of hydrocarbon in liquid phase while permitting the flow of hydrocarbon in gaseous phase into the wellbore. At a given rate of gas production, if the formation pressure
around the producing wellbore begins to approach the Dew Point Pressure and liquids begin to be present in the production, the valves would further restrict flow into the wellbore to maintain the produced gas at a pressure above its Dew Point Pressure.

[0015] In another example, valves are present that limit the flow of hydrocarbon in gaseous phase, while permitting the flow of hydrocarbon in liquid phase into the wellbore. Valves can be installed in the wellbore that limit the flow of hydrocarbon in dry gaseous phase while permitting the flow of hydrocarbon in gases in liquid rich phase into the wellbore. In this manner, the valves can function to prevent the cycling of injected gas around the barrier and back into the wellbore, while producing formation gases in liquid rich phase.

[0016] In another embodiment, a method of producing hydrocarbons from a subterranean formation containing hydrocarbons in a gaseous phase, comprising providing a wellbore in to the subterranean hydrocarbon fluid-bearing formation; providing an in-situ barrier, wherein the in-situ barrier is disposed within the subterranean formation and modifies the flow pattern of at least one fluid within the subterranean formation; injecting a hydrocarbon fluid in gaseous state from the wellbore into the formation from one side of the barrier to mix with the formation fluids to form a hydrocarbon mixture with a lower Dew Point than the formation hydrocarbon; and flowing the hydrocarbon mixture into the wellbore on the other side of the barrier.

[0017] In a further embodiment, a method of producing hydrocarbons from a subterranean formation containing hydrocarbons in a gaseous phase, comprising providing a cased horizontal wellbore extending into the subterranean hydrocarbon fluid-bearing formation; providing an in-situ barrier adjacent the toe of the wellbore, wherein the in-situ barrier is disposed within the subterranean formation and modifies the flow pattern of at least one fluid within the subterranean formation; injecting a hydrocarbon fluid in gaseous state from the wellbore into the formation from the toe side of the barrier to mix with the formation fluids to form a hydrocarbon mixture with a lower Dew Point Pressure than the formation hydrocarbon; and flowing the hydrocarbon mixture into the wellbore at a plurality of spaced-apart locations on the heel side of the barrier and controlling the flow of the
hydrocarbon mixture into the wellbore at the plurality of locations in response to the phase of hydrocarbon in gaseous flowing into the wellbore.

[0018] In still another embodiment, a cased horizontal wellbore in subterranean if provided wherein the formation surrounding the wellbore is fractured at a plurality of spaced locations along the wellbore. A barrier is formed in one fracture located between two fractures.

[0019] The features and advantages of the present invention will be apparent to those skilled in the art. While numerous changes may be made by those skilled in the art, such changes are within the spirit of the invention.

**Brief Description of the Drawings**

[0020] These drawings illustrate certain aspects of some of the embodiments of the present invention, and should not be used to limit or define the invention. The drawings are incorporated into and form a part of the specification to illustrate at least one embodiment and example of the present invention. Together with the written description, the drawings serve to explain the principles of the invention. The drawings are only for the purpose of illustrating at least one preferred example of at least one embodiment of the invention and are not to be construed as limiting the invention to only the illustrated and described example or examples. The various advantages and features of the various embodiments of the present invention will be apparent from a consideration of the drawings in which:

[0021] **Figure 1** is a well diagram, illustrating a conventional horizontal well completion of a retrograde condensate gas reservoir, showing condensate banking during production;

[0022] **Figure 2** is a cross section view of the well completion of **Figure 1**, illustrating the condensate banking region around the wellbore;
[0023] **Figure 3** illustrates an embodiment an improved horizontal well completion, utilizing a barrier around the wellbore according to the present invention; and

[0024] **Figure 4** illustrates an alternative embodiment of an improved, horizontal well completion, utilizing a barrier around the wellbore and inflow control devices, according to the present invention.

**DESCRIPTION OF THE PREFERRED EMBODIMENTS**

[0025] The present invention relates generally to hydrocarbon production, and more particularly to a method of increasing hydrocarbon production in gas wells by forming an in-situ barrier and by injecting a gas on one side of the barrier to mix with and modify the Dew Point of the resulting mixture of reservoir gas and injected gas.

[0026] The present invention provides improved methods, systems, and materials for modifying the flow pattern in a reservoir and reducing the effects of retrograded condensation. The methods, systems, and materials can be used in either vertical, deviated or horizontal wellbores, in consolidated and unconsolidated formations, in "open-hole" and/or under reamed completions, as well as in cased wells. If used in a cased wellbore, the casing may be perforated to provide for fluid communication between the wellbore and the subterranean formation. The term "vertical wellbore" is used herein to mean the portion of a wellbore to be completed which is substantially vertical or deviated from vertical in an amount up to about 15°. The term "horizontal wellbore" is used herein to mean the portion of a wellbore to be completed which is substantially horizontal or at an angle from vertical in the range of from about 75° to about 105°. All other angular positioning relates to a deviated or inclined wellbore. Since the present invention is applicable in horizontal and inclined wellbores, the terms "upper and lower" and "top and bottom" as used herein are relative terms and are intended to apply to the respective positions within a particular wellbore, while the term "levels" is meant to refer to respective spaced positions along the wellbore. In the present description, the terms "upper," "top," and "above" refer to the portion of a wellbore nearer to the surface or wellhead while the terms "lower," "bottom," and "below" refer to the portion of a wellbore further from the surface or wellhead, irrespective of the true vertical
depth of any portion of the wellbore. The term "toe" is used to describe the lower or bottom portion of a horizontally extending wellbore. The term "heal" is used to refer to the upper or top portion of the horizontal extending portion of the wellbore. In the description and drawings, the wellbores are illustrated in diagram or schematic form, wherein the proportions are not intended to represent the actual wellbore size. For example, wellbores can extend horizontally for miles in a hydrocarbon formation and have hundreds of perforations and fractures.

[0027] Referring initially to Figure 1, there is illustrated in diagram form, a conventional, horizontally extending wellbore 100 located in a hydrocarbon gas bearing subterranean formation 102. The wellbore 100 is cased 104 and the casing perforated 106 at spaced areas spaced along the extent of the casings in the formation 102. The perforations can be formed in any conventional manner, such as by using explosives, mechanical cutting, or jetting. The lower end of the casing is blocked or closed off by a bridge plug 108.

[0028] The casing interior pressure of the gas flowing in the casing is designated as \( P_{WR} \), and the reservoir gas pressure is designated as \( P_{R} \). The reservoir gas has a Dew Point pressure of \( P_{dp} \). In the illustrated embodiment \( P_{R} > P_{dp} > P_{WR} \), as illustrated in Figure 2, during reservoir gas production, the gas moves toward the wellbore and, at some point, the gas pressure drops below its Dew Point \( P_{dp} \), causing retrograde condensation around the wellbore (the formation of a region of condensate banking around the perforated portions of the wellbore). This formation of liquids with the gas in the formation results in two-phase flow which has the effect of reducing the apparent permeability of the formation, and thus reduces the production rate at a given condition.

[0029] Figure 3 illustrates a well configuration 200, according to the teaching of the present inventions. Wellbore 200 can be drilled using conventional drilling techniques, for example, directional drilling techniques or other similar methods. The precise method used is not an important aspect of the present invention. In one certain exemplary embodiment, the wellbore 200 is lined with a casing string. The casing string may then be cemented to the formation. There are a number of factors that go into the decision of whether
to case the wellbore 200 and whether to cement the casing to the formation. A person of ordinary skill in the art should know whether the wellbore 200 needs to be cased. In most cases, it will be beneficial to do so.

[0030] In the present example, the well 200 has a vertical well portion 202 connected to horizontally extending portion 204, extending into a hydrocarbon bearing reservoir or formation 216. In this embodiment, the hydrocarbon is formation gas. The well is cemented and cased 206 and conventionally perforated 208 in the horizontal portion. The toe end of the well is plugged by a bridge plug 218, but the toe end of the casing could be completed as an open hole. Injection tubing 220 is installed in the casing and is sealed off from the casing at its lower end by a packer 222.

[0031] One or more production fractures 210 are formed in or along the horizontal wellbore portion 204, using a variety of techniques. In one exemplary embodiment, a plurality of fractures is formed by using a hydra jetting tool, such as that used in the SurgiFrac.RTM. fracturing service offered by Halliburton Energy Services, Inc. in Duncan, Oklahoma. In this embodiment, the hydra jetting tool forms each fracture, one at a time. Each fracture may be formed by the following steps: (i) positioning the hydra jetting tool in the wellbore at the location where the fracture is to be formed, (ii) perforating the reservoir at the location where the fracture is to be formed, and (iii) injecting a fracture fluid into the perforation at sufficient pressure to form a fracture along the perforation. As those of ordinary skill in the art will appreciate, there are many variations on this embodiment. For example, fracture fluid can be simultaneously pumped down the annulus while it is being pumped out of the hydra jetting tool to initiate the fracture. Alternatively, the fracturing fluid may be pumped down the annulus and not through the hydra jetting tool to initiate and propagate the fracture. In this version, the hydra jetting tool primarily forms the perforations.

[0032] In an embodiment, one or more fractures 210 may be formed by staged fracturing. Staged fracturing may be performed by a method comprising: (i) detonating a charge in the wellbore at the location where a fracture is to be formed so as to form at least one perforation in the reservoir at that location; (ii) pumping a fracture fluid into the
perforation at sufficient pressure to propagate the fracture; (iii) installing a plug in the wellbore uphole of the fracture; (iv) repeating steps (i) through (iii) until the desired number of fractures have been formed; and (v) removing the plugs following the completion of step (iv). As those of ordinary skill in the art will appreciate, there are many variants on the staged fracture method.

[0033] The fractures 210 may take a variety of geometries, but preferably the fractures extend transverse to the wellbore so that the fractures extend at a substantially right angle with respect to the wellbore longitudinal axis. In some embodiments, the fractures may be formed along natural fracture lines and may generally be parallel to one another. The fracture's shape, size and orientation can be determined by the orientation of the fluid nozzles and movement thereof. Using hydrajetting radially from a vertical wellbore, a transversely extending fracture can be formed and may extend from about 50 ft to about 1000 ft from the wellbore.

[0034] One or more barrier perforations 212 and barrier fractures 214 are formed in the horizontal well portion 204. These perforation and fractures are used to form an in-situ barrier may be formed in or along the horizontal portion 204 wellbore. The in-situ barrier is disposed within the subterranean formation and modifies the flow pattern of at least one fluid within the subterranean formation. In the illustrated embodiment, one set of fractures 214 is formed on the downhole side of the production fractures, and also on the downhole side of injection tubing 220, packer 222, gas injection 224, injection gas perforation and frac 226.

[0035] According to the present invention, the fracture 214 is opened up to extend from the wellbore. The fracture 214, in this example, is generally disk shaped, extending from the wellbore 200 in all directions. As will be described, fracturing technology exists to create open fractures from wellbores extending in selected directions, distances and having selected shapes. In an embodiment, the fracture is formed to extend from all sides, about 500 ft. to about 1,000 ft., from the wellbore though longer fractures may be possible. In this embodiment, the fracture 214 is filled with a sealant. The sealant may be pumped into the fracture 214 as part of a treatment fluid, for example, in a slurry form and also into any flow paths in the form of voids intersecting the fracture 214.
[0036] In an embodiment, the sealant used to provide the in-situ barrier may be any material capable of selectively or non-selectively reducing the flow of one or more fluids within a subterranean formation. As used in this context, a non-selective barrier is an in-situ barrier intended to substantially seal the fracture. A selective barrier is an in-situ barrier, intended to modify the permeability or relative permeability (as described above) to allow fluids to selectively flow through the fracture. The sealant may comprise a cement, a linear polymer mixture, a linear polymer mixture with cross-linker, an in-situ polymerized monomer mixture, a resin-based fluid, an epoxy based fluid, a magnesium based slurry, a clay based slurry (e.g., a bentonite based slurry), an emulsion, a precipitate (e.g., a polymeric precipitate), or an in-situ precipitate. As used herein, an in-situ precipitate is a precipitate formed within the subterranean formation, for example, using a polymeric solution that is introduced into a subterranean formation followed by an activator. All of these sealants are capable of being placed in a fluid state with the property of becoming a viscous fluid or solid barrier to fluid migration after or during placement into the fracture. In one embodiment, the sealant is H.sub.2Zero.TM., available from Halliburton Energy Services, Inc., Duncan, Oklahoma. Other sealants could include particles, drilling mud, cuttings, and slag. Exemplary particles could be ground cuttings so that a wide range of particle sizes would exist and produce a low permeability as compared to the surrounding reservoir.

[0037] As used herein, the term drilling mud includes all types of drilling mud known to those of ordinary skill in the art including, but not limited to, oil-based muds, invert emulsions, polymer based muds, clay based muds (e.g., bentonite based drilling mud), and weighted muds. In an embodiment, the sealant may comprise swellable particles. As used herein, a particle is characterized as swellable when it swells upon contact with an aqueous fluid (e.g., water), an oil-based fluid (e.g., oil) or a gas. Suitable swellable particles are described in the following references, each of which is incorporated by reference herein in its entirety: U.S. Pat. No. 3,385,367, U.S. Pat. No. 7,059,415, U.S. Pat. No. 7,578,347, U.S. Pat. App. No. 2004/0020662, U.S. Pat. App. No. 2007/0246225, U.S. Pat. App. No. 2009/0032260 and WO2005/116394.
Swellable particles suitable for use with embodiments of the present invention may generally swell by up to about 200% of their original size at the surface. Under downhole conditions, this swelling may be more, or less, depending on the conditions present. For example, the swelling may be at least 10% under downhole conditions. In some embodiments, the swelling may be up to about 50% under downhole conditions. Although the rate of swelling may be hours in some embodiments, in certain embodiments the rate of swelling may be measured in minutes. The rate of swelling is defined as the amount of time required for the swelled composition to substantially reach an equilibrium state, where swelling is within 5% of its final equilibrium state. However, as those of ordinary skill in the art with the benefit of this disclosure will appreciate, the actual swelling when the swellable particles are included in a sealant may depend on, for example, the concentration of the swellable particles included in the sealant, the temperature, the pressure, and the other components present in the wellbore.

An example of a swellable particle that may be suitable for use with embodiments of the present invention comprises a swellable elastomer that swells in the presence of an oil-based fluid or an aqueous-based fluid. Some specific examples of suitable, swellable elastomers that swell in the presence of an oil-based fluids include, but are not limited to: natural rubbers, acrylate butadiene rubbers, isoprene rubbers, chloroprene rubbers, butyl rubbers, brominated butyl rubbers, chlorinated butyl rubbers, chlorinated polyethylenes, neoprene rubbers, styrene butadiene copolymer rubbers, chlorinated polyethylene, sulphonated polyethylenes, ethylene acrylate rubbers, epichlorohydrin ethylene oxide copolymers, epichlorohydrin terpolymer, ethylene-propylene rubbers, ethylene vinyl acetate copolymers, ethylene-propylene-diene terpolymer rubbers, ethylene vinyl acetate copolymer, nitrile rubbers, acrylonitrile butadiene rubbers, hydrogenated acrylonitrile butadiene rubbers, carboxylated high-acrylonitrile butadiene copolymers, polyvinylchloridene-nitrile butadiene blends, fluoro silicone rubbers, silicone rubbers, poly 2,2,1-bicyclo heptenes (polynorbornene), alkylstyrenes, polyacrylate rubbers, such as: ethylene-acrylate copolymer, ethylene-acrylate terpolymers, fluorocarbon polymers, copolymers of poly(vinylidene fluoride) and hexafluoropropylene, terpolymers of poly(vinylidene fluoride), hexafluoropropylene, and tetrafluoroethylene, terpolymers of poly(vinylidene fluoride),...
polyvinyl methyl ether and tetrafluoroethylene, perfluoroelastomers, such as: tetrafluoroethylene perfluoroelastomers, highly fluorinated elastomers, butadiene rubber, polychloroprene rubber, polyisoprene rubber, polynorbornenes, polysulfide rubbers, polyurethanes, silicone rubbers, vinyl silicone rubbers, fluoromethyl silicone rubber, fluoro vinyl silicone rubbers, phenylmethyl silicone rubbers, styrene-butadiene rubbers, copolymers of isobutylene and isoprene known as butyl rubbers, brominated copolymers of isobutylene and isoprene, chlorinated copolymers of isobutylene and isoprene, and any combination thereof. An example of a commercially available product comprising such swellable particles may include a commercially available product from Easy Well Solutions of Norway, under the trade name "EASYWELL."

[0040] Suitable examples of useable fluoroelastomers that swell in the presence of an oil-based fluid are: copolymers of vinylidene fluoride and hexafluoropropylene and terpolymers of vinylidene fluoride, hexafluoropropylene and tetrafluoroethylene. The fluoroelastomers suitable for use in the disclosed invention are elastomers that may comprise one or more vinylidene fluoride units ("VF.sub.2" or "VdF"), one or more hexafluoropropylene units ("HFP"), one or more tetrafluoroethylene units ("TFE"), one or more chlorotrifluoroethylene ("CTFE") units, and/or one or more perfluoro(alkyl vinyl ether) units ("PAVE"), such as perfluoro(methyl vinyl ether) ("PMVE"), perfluoro(ethyl vinyl ether) ("PEVE"), and perfluoropropyl vinyl ether ("PPVE"). These elastomers can be homopolymers or copolymers. Particularly suitable are fluoroelastomers containing vinylidene fluoride units, hexafluoropropylene units, and, optionally, tetrafluoroethylene units and fluoroelastomers containing vinylidene fluoride units, perfluoroalkyl perfluorovinyl ether units, and tetrafluoroethylene units, such as the vinylidene fluoride type fluoroelastomer, known under the trade designation "AFLAS.RTM.," available from Asahi Glass Co., Ltd. Of Tokyo, Japan. Especially suitable are copolymers of vinylidene fluoride and hexafluoropropylene units. If the fluropolymers contain vinylidene fluoride units, the polymers may contain up to 40 mole % VF.sub.2 units, e.g., 30-40 mole %. If the fluropolymers contain hexafluoropropylene units, the polymers may contain up to 70 mole % HFP units. If the fluropolymers contain tetrafluoroethylene units, the polymers may contain up to 10 mole % TFE units. When the fluropolymers contain
chlorotrifluoroethylene, the polymers may contain up to 10 mole% CTFE units. When the fluoropolymers contain perfluoro(methyl vinyl ether) units, the polymers may contain up to 5 mole% PMVE units. When the fluoropolymers contain perfluoro(ethyl vinyl ether) units, the polymers may contain up to 5 mole% PEVE units. When the fluoropolymers contain perfluoro(propyl vinyl ether) units, the polymers may contain up to 5 mole% PPVE units. The fluoropolymers may contain 66%-70% fluorine. One suitable commercially available fluoroelastomer is that known under the trade designation "TECHNOFLON FOR HS.RTM.," sold by Ausimont USA, Inc. of Thorofare, New Jersey. This material contains "Bisphenol AF," manufactured by Halocarbon Products Corp. of River Edge, New Jersey. Another commercially available fluoroelastomer is known under the trade designation "VITON.RTM. AL 200," by DuPont Performance Elastomers of La Place, Louisiana, which is a terpolymer of VF:sub.2, HFP, and TFE monomers containing 67% fluorine. Another suitable, commercially available fluoroelastomer is "VITON.RTM. AL 300," by DuPont Performance Elastomers of La Place, Louisiana. A blend of the terpolymers known under the trade designations "VITON.RTM. AL 300" and "VITON.RTM. AL 600" can also be used (e.g., one-third AL-600 and two-thirds AL-300), both are available from DuPont Performance Elastomers of La Place, Louisiana. Other useful elastomers include: products known under the trade designations "7182B" and "7182D," from Seals Eastern of Red Bank, New Jersey; the product known under the trade designation "FL80-4," available from Oil States Industries, Inc. of Arlington, Texas; and the product known under the trade designation "DMS005," available from Duromould, Ltd. of Londonderry, Northern Ireland.

[0041] One process for making a swellable elastomer useful in the present invention may involve grafting an unsaturated organic acid molecule. A common example of an unsaturated, organic acid used for this purpose is maleic acid. Other molecules that can be used include mono- and di-sodium salts of maleic acid and potassium salts of maleic acid. Although in principle, other unsaturated carboxylic acids may also be grafted onto commercial, unsaturated elastomers, acids that exist in solid form may not require additional steps or manipulation, as will be readily apparent to those having reasonable skill in the chemical art. Mixing other unsaturated acids such as acrylic acid and methacrylic acid is also possible but may be more difficult since they are liquids at room temperature. Unsaturated
acids such as palmitoleic acid, oleic acid, linoleic acid, and linolenic acid may also be used. The initial reaction leads to a relatively nonporous, "acid-grafted rubber." In order to enhance the swelling of elastomers, the addition of a small amount of alkali such as soda ash, along with or separate from the unsaturated acid, leads to formation of a porous, swellable, acid-grafted rubber. Micro-porosities are formed in the composition, allowing a fluid to rapidly reach the interior region of a molded part and increase the rate and extent of swelling. An organic peroxide vulcanizing agent may be employed to produce a vulcanized, porous, swellable, acid-grafted rubber formulation. In one embodiment, 100 phr of EPDM, 5-100 phr of maleic acid, 5-50 phr of sodium carbonate, and 1-10 phr of dicumyl peroxide as vulcanizing agent showed at least 150 percent swelling of elastomer when exposed to both water at 100° C for 24 hrs. and at room temperature for 24 hrs. in kerosene. Other commercially available grades of organic peroxides, as well as other vulcanization agents, may be employed. The resulting elastomeric compositions may be described as nonporous, or porous and swelled, acid-grafted rubbers, which may or may not be vulcanized. The terms "vulcanized" and "crosslinked" are used interchangeably herein, although vulcanization technically refers to a physicochemical change resulting from crosslinking of the unsaturated hydrocarbon chain of polyisoprene with sulfur, usually with the application of heat. The relatively hydrophobic linear or branched chain polymers and relatively hydrophilic water-soluble monomers, either grafted onto the polymer backbone or blended therein, may act together to cost-effectively increase the water- and/or oil-swellability of oilfield elements that comprise one or more apparatus of the invention. In particular, the use of unsaturated organic acids, anhydrides, and their salts (for example, maleic acid, maleic anhydride, and their salts), offer a commercially feasible way to develop inexpensive composites materials with good water, and/or hydrocarbon fluid swellability, depending on the type of inorganic additives and monomers used.

[0042] Elastomers such as nitrile rubber, hydrogenated nitrile rubber (HNBR), fluororubber, or acrylate-based elastomers, or their precursors, if added in variable amounts to an EPDM polymer or its precursor monomer mixture, along with a sufficient amount (from about 1 to 10 phr) of an unsaturated organic acid, anhydride, or salt thereof, such as maleic acid, optionally combined with a sufficient amount (from 1 about to 10 phr) of
an inorganic, swelling agent, such as sodium carbonate, may produce a water-swellable elastomer, having variable low-oil swellability. Addition, to the monomer mixture or to the elastomer after polymerization, of a sufficient amount (from about 0.5 to 5 phr) of a highly acidic unsaturated compound, such as 2-acrylamido-2-methylpropane sulfonic acid (AMPS), results in a water-swellable elastomer having variable oil-swellability, and which is further swellable in low pH fluids, such as completion fluids containing zinc bromide. A second addition of a sufficient amount (from 1 to 10 phr more than the original addition) of inorganic, swelling agent enhances swellability in low pH, high concentration brines. Finally, the addition of a sufficient amount (from 1 to 20 phr), of zwitterionic polymer or copolymer of a zwitterionic monomer with an unsaturated monomer, results in a cross-linked elastomer. The amounts of the various ingredients at each stage may be varied as suited for the particular purpose at hand. For example, if one simply wishes to produce a highly cross-linked, moderately water-swellable (about 100 percent swell) elastomer, having very low oil-swellability but very high swellability in low pH fluids, one would use a recipe of 60 to 80 phr of EPDM, and 20 to 40 phr of nitrile or HNBR, and 4 to 5 phr of AMPS, as well as about 15 to 20 phr of a zwitterionic polymer or monomer.

[0043] Another reaction scheme useful in the present invention, enabling a low-cost procedure for making swellable elastomers, involves the use of AMPS monomer and like sulfonic acid monomers. Since AMPS monomer is chemically stable up to at least 350° F. (177° C), mixtures of EPDM and AMPS monomer which may or may not be grafted on to EPDM will function as a high-temperature resistant, water-swellable elastomer. The use of AMPS and like monomers may be used in like fashion to functionalize any commercial elastomer to make a high-temperature, water-swellable elastomer. An advantage of using AMPS is that it is routinely used in the oilfield industry in loss circulation fluids and is very resistant to downhole chemicals and environments.

[0044] Combinations of suitable, swellable elastomers may also be used. In certain embodiments, some of the elastomers that swell in oil-based fluids may also swell in aqueous-based fluids. Suitable elastomers that may swell in both aqueous-based and oil-based fluids, include, but are not limited to ethylene propylene rubbers, ethylene-propylene-
diene terpolymer rubbers, butyl rubbers, brominated butyl rubbers, chlorinated butyl rubbers,
chlorinated polyethylene, neoprene rubbers, styrene butadiene copolymer rubbers,
sulphonated polyethylenes, ethylene acrylate rubbers, epichlorohydrin ethylene oxide
copolymer, silicone rubbers and fluorosilicone rubbers, and any combination thereof. Those
of ordinary skill in the art, with the benefit of this disclosure, will know the appropriate fluid
to use in order to swell the particular swellable elastomer composition.

[0045] In certain embodiments, the swellable elastomers may be crosslinked and/or
lightly crosslinked. Other swellable elastomers that behave in a similar fashion with respect
to fluids may also be suitable. Those of ordinary skill in the art, with the benefit of this
disclosure, will be able to select appropriate, swellable elastomers based on a variety of
factors, including the application in which the composition will be used and the desired
swelling characteristics.

[0046] Where used, the swellable particles generally may be included in the
embodiments of the sealant in an amount sufficient to provide the desired barrier properties.
In some embodiments, the swellable particles may be placed in a fracture or void in a
treatment fluid comprising an amount up to about 50% by volume of the treatment fluid. In
some embodiments, the swellable particles may be present in a range of about 5% to about
95% by volume of the treatment fluid used to place the particles.

[0047] In addition, the swellable particles that are utilized may have a wide variety
of shapes and sizes of individual particles suitable for use with embodiments of the present
invention. By way of example, the swellable particles may have a well-defined physical
shape as well as an irregular geometry, including the physical shape of platelets, shavings,
fibers, flakes, ribbons, rods, strips, spheroids, beads, pellets, tablets, or any other physical
shape. In some embodiments, the swellable particles may have a particle size in the range of
about 5 microns to about 1,500 microns. In some embodiments, the swellable particles may
have a particle size in the range of about 20 microns to about 500 microns. However, particle
sizes outside these defined ranges also may be suitable for particular applications.

[0048] In an embodiment, the sealant may comprise a cement. Any suitable cement
known in the art may be used as the sealant. An example of a suitable cement includes
hydraulic cement, which may comprise calcium, aluminum, silicon, oxygen, and/or sulfur and which sets and hardens by reaction with water. Examples of hydraulic cements include, but are not limited to, a Portland cement, a pozzolan cement, a gypsum cement, a high alumina content cement, a silica cement, a high alkalinity cement, or combinations thereof. Preferred hydraulic cements are Portland cements of the type described in American Petroleum Institute (API) Specification 10, 5th Edition, Jul. 1, 1990, which is incorporated by reference herein in its entirety. The cement may be, for example, a class A, B, C, G, or H Portland cement. Another example of a suitable cement is microfme cement, for example, MICRODUR RU microfme cement, available from Dyckerhoff GmBH of Lengerich, Germany. Combinations of cements and swellable particles may also be used.

[0049] According to the embodiment of Figure 3, the flow of hydrocarbon fluids within the reservoir is modified through the use of an in-situ barrier comprising a fracture set 214 containing a sealant. The use of an in-situ barrier with selective or non-selective barriers to flow may be used to modify the flow pattern within an entire reservoir. Without intending to be limited by theory, it is believed that a plurality of selectively placed fractures with selective or non-selective barriers to fluid flow may be used to modify the flow regime inside the hydrocarbon reservoir to improve the volumetric sweep efficiency of fluids injected into the formation. The flow patterns within a hydrocarbon reservoir may be determined through the use of a simulator program using any simulator capable of calculating the flow regime within a subterranean environment. Suitable simulators for use in hydrocarbon reservoirs are known to those skilled in the art.

[0050] In the Figure 3 embodiment, one or more gas injection perforations and fractures 226 are formed in the wellbore 200 on the downhole side of the packer 222, in fluid communication with the tubing 220.

[0051] As pointed out previously, if the Dew Point pressure of the reservoir gas $P_{DP}$ is higher than the pressure $P_{nf}$ of the gas 250 flowing in the annulus, then condensate banking 232 can occur and restrict flow. As was previously described, reservoir gas production 217 moves toward the wellbore and, at some point, the gas pressure drops below its Dew Point.
P_{df}, causing retrograde condensation around the wellbore at 232. This formation of liquids with the gas in the formation results in two-phase flow which has the effect of reducing the apparent permeability of the formation and, thus reduces the production rate at a given condition.

[0052] In this embodiment, gas 240 is pumped from the surface, down the tubing 217 and into the formation 216 via the fracture 226 at a pressure greater than the reservoir gas pressure P_{rf}. The injected gas 224 enters the formation 216 on the downhole side of the barrier fracture 214. The barrier fracture 214 prevents the injected gas 224 from flowing along the wellbore to the production perforations 208. Instead, the injected gas 224 initially flows radially away from the wellbore and then over the barrier and into a mixing area 230 where the injected gas 224 mixes with the formation gas 217. The injected gas 224 is selected, so that, when it mixes with the reservoir gas 217, the resulting gas mixture has a dew-point pressure equal to or lower than the pressure P_{wF} of the gas 250, flowing in the annulus. In this manner, retrograde condensation around the wellbore at 232 is eliminated, at least along a portion of the wellbore.

[0053] Suitable gasses for reducing the formation gas Dew Point Pressure P_{df} include methane and carbon dioxide. In the present embodiment, methane gas is stripped from the produced gas at the surface and used as the injection gas 224.

[0054] In Figure 4, another embodiment of a wellbore assembly 300 according to the present inventions will be described. Wellbore 302 can be drilled into and along the wellbore between the boundaries 390 of a hydrocarbon bearing reservoir using conventional drilling techniques, for example, directional drilling techniques or other similar methods.

[0055] In the present example, the well 300 has a vertical well portion 304 connected to horizontal portion 306, extending into a hydrocarbon bearing reservoir or formation 216. In this embodiment, the hydrocarbon is formation gas. The vertical portion 304 of the well is cemented and cased. The lower horizontal portion 306 is supported in the wellbore 302 by external casing packers. In this embodiment, the casing is not cemented in
the wellbore 302. A plurality of inflow control devices 312 are provided spaced along the horizontal portion 306. In this embodiment, the control devices 312 are positioned between adjacent external packers 310 to control the flow from the formation in the zone formed between the packers 310. The end of the well casing is open at 324. Injection tubing 320 is installed in the casing and is sealed off from the casing at its lower end by a packer 322. The lower end of the tubing 320 is open at 224 to one or more gas injection fractures 226.

[0056] One or more production fractures 330 are formed in the reservoir at spaced locations along the horizontal portion 306 wellbore. The fractures 330 are positioned between adjacent external packers 310. A fracture 340 is formed from the wellbore into the formation and filled with barrier material to form a flow altering barrier 350 in the reservoir.

[0057] In this embodiment, gas 370 is pumped from the surface, down the tubing 320 and into the formation 390 via the fracture 326. The gas is pumped into the formation at a pressure greater than the reservoir gas pressure. The injected gas 370 enters the formation on the downhole side of the barrier 350. The barrier 350 prevents the injected gas 370 from flowing along the wellbore to the production perforations 330. Instead, the injected gas 270 initially flows radially away from the wellbore and then over the barrier and into a mixing area 380 where the injected gas 370 mixes with the formation gas 360 to reduce the Dew Point pressure of the produced gas.

[0058] The inflow control devices 312 regulate the flow along the wellbore to prevent the gas in the formation around the wellbore from dropping below the Dew Point Pressure. The interaction of these devices 312 distributes the gas flow across the wellbore. Devices 312 can be used with gas injection to maintain the formation fluids at a pressure above the Dew Point Pressure. The devices 312 can also be used for regulate hydrocarbon liquid flow into the wellbore in response to changes in phase of the hydrocarbon flowing through the devices 312.

[0059] As used herein the term "inflow control device," is used to refer to apparatus installed in the well that are capable of controlling the flow of fluids into the wellbore. Inflow control devices include apparatuses that can vary the flow rate and can either permit
or block flow. Inflow control devices 312 ideally suitable for use in this embodiment include autonomous inflow control devices that operate to control flow based on a characteristic of the produced fluids.

[0060] Ideally suited for this use are valves marketed as EquiFlow Autonomous Inflow Control Devices. These devices are provided by Haliburton Energy Services, Inc. These autonomous devices act as valve means for selectively controlling the flow of the multiphase hydrocarbon fluid mixtures into the wellbore while limiting the flow of hydrocarbons in liquid or gas phase, while permitting the flow of hydrocarbon in liquid or gas phase. These devices can autonomously vary the flow of hydrocarbon mixture into the wellbore in response to changes in the fluid flow in response to changes characteristic of the hydrocarbon mixture, such as hydrocarbon viscosity, hydrocarbon density, and/or hydrocarbon flow velocity. These devices can sense these characteristics to selectively regulate whether gaseous or liquid phase is being produced. By controlling formation inflow based on relative phase, pressure of the formation hydrocarbon gas can be maintained above the Dew Point during production.


[0062] In one example, valves are provided that restrict the flow of hydrocarbon in liquid phase, while permitting the flow of hydrocarbon in gaseous phase into the wellbore. In another example, valves can be provided that restrict the flow of hydrocarbon in gaseous phase while permitting the flow of hydrocarbon in liquid phase into the wellbore. In a further example, valves can be provided that restrict the flow of hydrocarbon in dry gaseous phase while permitting the flow of hydrocarbon in gases in liquid rich phase into the wellbore. In this manner, the valves can be utilized to control the Dew Point Pressure of formation gas and efficiently produce gas from a retrograde gas formation.

[0063] In one embodiment, the valves installed along the wellbore of the type which inhibit the inflow of hydrocarbon in liquid form and gas in a liquid rich phase. If the production rate at particular valve causes a pressure drop to or below Dew Point Pressure around the wellbore, liquid will begin to drop out of the produced formation gas. As this occurs, the valve will restrict the production rate to the point where the formation pressure around the wellbore at the valve will rise above the Dew Point Pressure, allowing gas phase to be produced.
The inflow control devices inhibit cycling of dry gas while allowing less inhibited flow of liquids rich gas. This prevents undue cycling of the dry gas, i.e., preventing production and re-injection of the same gas while improving sweep efficiency of the injected gas. As the formation production continues, the liquids rich gas will be stripped of liquid hydrocarbons at the surface and the remaining dry gas will be injected while the liquids are sold off. Eventually, the injected dry gas is mixed sufficiently with the liquids rich gas, whereby the Dew Point of the gas mixture in the formation is effectively altered to prevent retrograde condensation. Ultimately, the inflow control devices can be de-activated to allow unrestricted flow of the formation mixture gas to be produced and sold without further injection or input control.

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 or modified and all such variations are considered within the scope and spirit of the present invention. While apparatus, 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. As used herein, the words "comprise," "have," "include," and all grammatical variations thereof are each intended to have an open, non-limiting meaning that does not exclude additional elements or 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.
In the claims, the conjunction "and" is inclusive, the conjunction "or" is exclusive and the conjunction "and/or" is either inclusive or exclusive. 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.
Claims:

What is claimed is:

1. A method of producing hydrocarbons from a subterranean hydrocarbon fluid bearing formation, containing hydrocarbons in a gaseous phase, comprising:
   - providing a wellbore extending into the subterranean hydrocarbon fluid-bearing formation;
   - providing an in-situ barrier, wherein the in-situ barrier is disposed within the subterranean formation and modifies the flow pattern of at least one fluid within the subterranean formation;
   - injecting a fluid in gaseous state from the wellbore into the formation from one side of the barrier to mix with the formation fluid to form a hydrocarbon mixture with a lower Dew Point Pressure than the formation hydrocarbon; and
   - flowing hydrocarbon mixture from the formation into the wellbore on the other side of the barrier.

2. The method of claim 1, wherein the injected fluid comprises a gas with a Dew Point Pressure that is higher than the formation gas Dew Point Pressure.

3. The method of claim 1, wherein the injected fluid is selected from the group, consisting of methane and carbon dioxide.

4. The method of claim 1, additionally comprising the step of removing the hydrocarbon mixture entering the wellbore, stripping methane gas from the removed hydrocarbon mixture and using the stripped methane gas in the injecting step.

5. The method of claim 1, wherein the flowing step comprises selectively flowing hydrocarbon fluids in the gaseous phase into the wellbore, while restricting the flow into the wellbore of hydrocarbon fluids in the liquid phase.

6. The method of claim 1, wherein the flowing step comprises selectively flowing hydrocarbon fluids in liquid phase into the wellbore, while restricting the flow into the wellbore of fluids in the gaseous phase.
7. The method of claim 1, additionally comprising the steps of:
   - casing the wellbore;
   - flowing the hydrocarbon mixture into the wellbore at a plurality of locations spaced apart along the wellbore; and
   - controlling the flow of the hydrocarbon mixture into the wellbore at the plurality of locations by limiting the flow of hydrocarbon in liquid phase, while permitting the flow of hydrocarbon in gaseous phase into the wellbore.

8. The method of claim 1, additionally comprising the step of controlling the flow of the hydrocarbon mixture into the wellbore as a function of the phase of the hydrocarbon mixture.

9. The method of claim 1, wherein the flowing step comprises the step of varying the flow of hydrocarbon mixture into the wellbore in response to changes in the fluid flow characteristic of the hydrocarbon mixture, wherein the characteristics are selected from the group consisting of viscosity, density, and velocity.

10. The method of claim 1, additionally comprising providing a cased wellbore and a valve controlling the flow into the wellbore.

11. The method of claim 1, wherein the in-situ barrier comprises a fracture with a sealant disposed therein.

12. The method of claim 11, wherein the sealant comprises a relative formation permeability modifier.

13. The method of claim 1, wherein the flowing step comprises the step of varying the flow of hydrocarbon mixture into the wellbore to maintain the flowing hydrocarbon mixture in a substantially gaseous phase.
14. The method of claim 1, wherein the flowing step comprises the step of varying the flow of hydrocarbon mixture into the wellbore to maintain the flowing hydrocarbon mixture in a substantially liquid phase.

15. A subterranean well for producing hydrocarbons from a subterranean formation containing hydrocarbon fluids in a gaseous phase, comprising:

   a horizontally extending cased wellbore extending into the subterranean hydrocarbon fluid-bearing formation; the wellbore having separate fluid injection and fluid production pathways therein connected to the formation at a longitudinally-spaced location along the wellbore;

   an in-situ barrier, extending generally transversely from the wellbore, wherein the in-situ barrier is disposed within the subterranean formation and modifies the flow pattern of at least one fluid within the subterranean formation, the barrier being positioned on the wellbore between the injection and production pathway connections to the formation; and

   a valve connected to the wellbore at a subterranean location positioned to control the flow of hydrocarbon fluid into the production pathway.

16. The well of claim 15, wherein the valve comprises means for varying the fluid flow into the wellbore in response to changes in the fluid flow characteristic of the hydrocarbon fluid.

17. The well of claim 14, wherein the fluid flow characteristics are selected from the group consisting of fluid viscosity, density and velocity.

18. The well of claim 15, additionally comprising a plurality of valves connected to the wellbore at subterranean locations spaced apart along the well to control the flow of hydrocarbon fluid into the production pathway.

19. The well of claim 14, wherein the valve selectively flows fluids in the gaseous phase into the wellbore, while restricting the flow into the wellbore of fluids in the liquid phase.
20. The well of **claim 14**, wherein the valve selectively flows fluids in the liquid phase into the wellbore, while restricting the flow into the wellbore of fluids in the gaseous phase.

21. The well of **claim 13**, wherein the in-situ barrier comprises a fracture with a sealant disposed therein.

22. The well of **claim 19**, wherein the sealant comprises a relative formation permeability modifier.
INTERNATIONAL SEARCH REPORT

INTERNATIONAL APPLICATION NO.
PCT/US2013/054896

A. CLASSIFICATION OF SUBJECT MATTER
E21B 43/295(2006.01)i, E21B 43/14(2006.01)i, E21B 43/25(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED
Minimum documentation searched (classification system followed by classification symbols)
E21B 43/295; C09K 8/68; E21B 33/12; E21B 43/26; E21B 43/16; C09K 8/588; E21B 43/14; E21B 43/25

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: hydrocarbon fluid, dew point, in-situ barrier, and valve

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Further documents are listed in the continuation of Box C.

See patent family annex.

Date of the actual completion of the international search
11 November 2013 (11.11.2013)

Date of mailing of the international search report
11 November 2013 (11.11.2013)

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