USE OF FOAM WITH IN SITU COMBUSTION PROCESS

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ABSTRACT

The present invention relates to a novel method of maintaining a steady and/or proper water-gas ratio for the wet in situ combustion process for oil recovery. In particular, the method comprises mixing water with a foaming agent, or some other colloid capable of generating foam, in addition to gas. The foam carries the water through heated reservoirs more efficiently and prevents separation from the gas. As such, more heat can be scavenged, thus an increased amount of steam is generated and transferred to the oil to increase its recovery.
OL PRODUCTION DRY AIR INJECTION

HEATED DRY AIR

OL BANK

HEATED RESERVOIR ROCK

COMBUSTION FRONT

HEATED OIL BANK

OIL PRODUCTION

FIG. 1
OL PRODUCTION WATER AND AIR INJECTION

WATER AND AIR INJECTION

WATER + AIR

STEAM

HEATED RESERVOIR ROCK

COMBUSTION FRONT

HEATED OIL BANK

OIL PRODUCTION

FIG. 2
WATER, FOAMING AGENT, AND AIR/O2 INJECTION

WATER + FOAM + AIR/O2

COOLED ROCK FROM HEAT SCAVENGING

COMBUSTION FRONT

STEAM

HEATED OIL BANK

FIG. 3
USE OF FOAM WITH IN SITU COMBUSTION PROCESS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a non-provisional application which claims benefit under 35 USC §119(e) to U.S. Provisional Application Ser. No. 61/750,253 filed Jan. 8, 2013, entitled “USE OF FOAM WITH IN SITU COMBUSTION PROCESS,” which is incorporated herein in its entirety.

FEDERALLY SPONSORED RESEARCH STATEMENT

[0002] Not applicable.

REFERENCE TO MICROFICHE APPENDIX

[0003] Not applicable.

FIELD OF THE INVENTION

[0004] The invention relates to methods of improving the effectiveness of wet in situ combustion (ISC) processes to accelerate oil production and particularly to an improved wet in situ combustion process utilizing foam. Water containing a foaming agent is injected along with an oxygen-containing gas to maintain a consistent water-gas ratio, to facilitate water-reservoir rock contact and to prevent separation of water and gas.

BACKGROUND OF THE INVENTION

[0005] Conventional oil reserves are preferred sources of oil because they provide a high ratio of extracted energy over energy used in regards to the extraction and refining processes it undergoes. Unfortunately, due to the physics of fluid flow, not all conventional oil can be produced. Additionally, as conventional oil sources become scarce or economically non-viable due to depletion, unconventional oil sources are becoming a potential supply of oil. But, unconventional oil production is also problematic because it consists of extra heavy oils having a consistency ranging from that of heavy molasses to a solid at room temperature and may also be located in the reservoir rocks. These properties make it difficult to simply pump the oil out of the ground; thus, its production is a less efficient process than conventional oil.

[0006] As a result, enhanced oil recovery (EOR) techniques are often employed to increase the amount of subterranean crude oil extracted. Using EOR, 30-60% or more of the original oil can be extracted. Additionally, EOR finds applications in both conventional and unconventional oil reserves.

[0007] During EOR, compounds not naturally found in the reservoir are injected into the reservoir in a well other than the producing well to assist in oil recovery. Simply stated, EOR techniques overcome the physical forces holding the oil hydrocarbons underground. There are many types of EOR techniques that are categorized by the compound being injection: gas injection, chemical injection, microbial injection or thermal recovery. While there are many types of EOR techniques, reservoirs containing heavier crude oils tend to be more amenable to thermal EOR methods, which heat the crude oil to reduce its viscosity and thus decrease the mobility ratio. The increased heat reduces the surface tension of the oil and increases the permeability of the oil. A summary of various EOR techniques is presented in Table 1.

<table>
<thead>
<tr>
<th>TABLE 1 Enhanced Oil Recovery (EOR) Techniques</th>
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<tbody>
<tr>
<td>CSS</td>
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<tr>
<td>SAGD</td>
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<tr>
<td>VAPEX</td>
</tr>
<tr>
<td>ISC</td>
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<tr>
<td>THAI</td>
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<tr>
<td>COGD</td>
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<td>EM</td>
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</table>
[0008] One technique less commonly used is in situ combustion (ISC), which involves the oxidative generation of heat within the reservoir itself. During a dry in situ combustion (FIG. 1), an oxygen-containing gas such as air is injected into an underground oil reservoir and burned with part of the hydrocarbons to create heat. The fire can be started by either lowering an incendiary device, such as a phosphorous bomb or a gas burner, into the well, or the injection of a large amount of air can cause spontaneous combustion. Once burning, large volumes of air, or other oxygen source gas, must be continually injected into the reservoir to sustain the fire. This combustion reaction also creates steam that, along with light hydrocarbons, condenses and releases heat to the nearby oil. During ISC, a frontal advance containing different layers of combustion gases, steam, and heated oil is created. This frontal advance acts as a production drive, thus driving the heated oil towards producing wells.

[0009] Firehose projects are not extensively used due to the difficulty in controlling the flame front and a propensity to set the producing wells on fire. However, the method uses less freshwater, produces 50% less greenhouse gases, and has a smaller footprint than other production techniques. Thus, there is a certain interest in further developing combustion based methods for future use.

[0010] ISC can either be forward or reverse combustion. In forward combustion, the fire and injected oxygen source gas originate at the injection well. Thus, the gas flow, combustion front and oil flow advance in the same horizontal direction towards the producing well. In reverse combustion, the gas flow is counter-current to the combustion front.

[0011] The main cost associated with dry ISC is the cost of compression for the air injection system. Furthermore, the effectiveness of this technique depends on the velocity and stability of the frontal advance, as well as the heat generated from the combustion. During the dry ISC process, as the oil is produced, depleted volumes remaining in the reservoir rock are primarily filled with air, steam and other gases resulting from the combustion. The rock absorbs much of the energy resulting from the heat of combustion reaction and heat of condensation of the steam. Thus, this energy is wasted because it is not used to further produce oil, resulting in inefficiencies in the dry ISC process.

[0012] Other novel techniques have been developed to increase the efficiency of EOR oil production through the use of liquids instead of gases.

[0013] Water has also been utilized in dry ISC methods. A polymer colloidal system mixed with water was used to transport ozone gas into the reservoir.[1] This system allowed for quicker autoignition of the dry ISC process.

[0014] Also, the injection of water for a wet in situ combustion process (FIG. 2) has been found to improve oil production. In the wet ISC process, water and an oxygen gas source are injected together into the reservoir. The heat in the reservoir converts the water into steam. The generated steam from the water combines with the frontal advance to help drive the oil. Additionally, water acts in scavenging the heat left in the reservoir rock after the combustion front has advanced through. The water is heated by the rock, which creates more steam that can condense in the burning front and transfer heat to nearby oil, resulting in increased oil production. The addition of injected water also reduces the gas injection rates, thereby reducing compression costs seen in dry ISC.

[0015] However, a disadvantage of the wet combustion process is the difficulty in maintaining proper water-gas ratios. If water-gas ratio is too low, then there is not enough water to effectively recover all of the available energy in the reservoir rock. If the water-gas ratio is too high, then there is too much water that is not converted into steam and interferes with the combustion front by cooling the temperature or extinguishing the combustion front. Thus, an optimum water-gas ratio would effectively recover the energy stored in the reservoir rock by converting the water to steam, but not cool or quench the combustion front such that it is extinguished. Furthermore, the proper ratio will all reduce the amount of fuel needed, which decreases the gas requirements needed to heat the oil.

[0016] Another disadvantage of the wet combustion process is the separation of water and the gas in the reservoir. This separation is also dependent on the water-gas ratio. If the water does not travel horizontally or vertically through the reservoir to scavenge the heat, then only gas will reach the combustion front, which will essentially be a dry combustion. If there is too much water, then the gas cannot travel through the reservoir to reach the combustion front, thus potentially allowing water to extinguish the combustion front. Also, because water is denser, it could cumulate at the base of the reservoir and not reach hotter rock. As such, it is imperative that a proper water-gas ratio is maintained for the water and the gas travel through the oil reserve for optimal oil production efficiencies.

[0017] Finding the optimum water-gas ratio is difficult because the reservoir heterogeneities and gravity override can affect the fluid movement. Usually, water and gas injection rates are varied until a reasonable water-gas ratio is found. The rates are then adjusted throughout the wet ISC to maintain this ratio. This method produces inconsistent results, nor is there a method to quickly determine the proper ratio or injection rates.

[0018] U.S. Pat. No. 4,691,773 discloses a wet in situ combustion method wherein a non-oxygen containing fluid, such as water, is introduced along with air cyclically to produce periodic high volume rates of injected fluid. However, both techniques can result in over-injecting water and extinguishing the combustion front can occur, leading to a loss of time and money to re-start the process.

[0019] U.S. Pat. No. 7,882,893 discloses the use of surfactant, salt brine and oxygen to create a foam during ISC. The foam decreases the mobility of the displacing fluid (brine) in the higher permeability zones and diverts more oxygen-containing gas into the lower permeability zones. Thus, the foam prevents the water from segregating from the oxygen gas. As
the displacing fluid evaporates from the foam, the foam breaks and becomes an oxygen-rich steam and alkaline brine.

Additionally, the foam will also prevent the water and gas from separating in the reservoir, thus preventing a dry ISC process. Additionally, the foam can also contain oxygen, which will help in providing a consistent amount of oxygen to the combustion front.

In a preferred embodiment, the oxygen-containing gas is air. Further preferred embodiments include generating foam on the surface before injection into the subterranean oil formation.

In one embodiment, the water being mixed with the foaming agent is brine water recovered from the reservoir being treated. Alternatively, surface water or sea water can be used.

In another embodiment, the foaming agent contains oxygen, which will aid in maintaining a consistent amount of oxygen at the combustion front.

In yet another embodiment, the water and foaming agent are injected some time after the oxygen-containing gas and optional additional gases have been injected into the subterranean formation.

In the present disclosure, the foaming agent can generate foam on the surface before injection into the oil formation. In another variation, the foaming agent can generate foam in situ in the subsurface after injection into the oil formation.

The invention also describes the use of the above methods to recover more oil from steam assisted gravity drainage (SAGD) depleted reservoirs.

The foaming agent can include, but is not limited to, other colloidal foams, aerosols, hydroxids, emulsions, or dispersions capable of creating a suitable foam. Preferred foam components have thermal and chemical properties that are stable at the high temperatures (>200°C) used in ISC and should have low adsorption onto reservoir rock/clay surfaces. Additionally, the foaming capabilities should be effective at the particular reservoir brine pH. Thus, the foaming agent can be any foaming agent that is stable under reservoir conditions, and increases the transport of water, thus maintaining a consistent water-to-gas ratio.

Foam agents can be surfactant- or alkali-based. Thermally and chemically stable, non-ionic, anionic, cationic, and amphoterically/ampholytic surfactants including, but are not limited to, alkyl benzene, aromatic sulfonates, alpha internal olefin, sulfonates, alkyl aryl sulfonates, and alkyl sulfate salts can be used. High alkyl chain lengths should be chosen since the efficiency of foam generation increases with increases in chain length.

Examples of alkali-based components are alkaline metal carbonates, bicarbonates and hydroxides, including but not limited to, sodium carbonate, sodium bicarbonate, sodium hydroxide, potassium carbonate, potassium bicarbonate, potassium hydroxide, magnesium carbonate, and calcium carbonate.

Other agents that can be used are in other colloidal foams, aerosols, hydroxids, emulsions, or dispersions which could create a suitable and stable foam.

The chosen foaming agent will depend on the characteristics of the reservoir. Because the foaming agent is being used to increase the sweep efficiency of the water/gases, the foaming agent should not react with the formation. For example, cationic and amphoterically surfactants have strong interactions with sand particles, thus they would not be ideal foaming agents for a sandy reservoir. Interactions with reser-
vior formation will result in an increase in concentration of foaming agent and will be cost prohibited, or at least less cost effective.

[0040] The chosen foaming agent also depends on the water. High salinity water can cause precipitation of surfactant molecules, especially when high divalent ion concentrations are present. Non-ionic surfactants and alkali-based surfactants are considered to be more resistant to high salinity water.

[0041] Many high temperature surfactant- and alkali-based foaming agents are commercially available from vendors such as BASF, ChemEOR Inc., Down Chemical Company, Huntsman Corporation, OilChem Technologies, Sasol and Tiorco.

[0042] The desired properties of the generated foam are densities in the range of 0.000598-0.0770 g/cm3 and viscosities in the range of 0.0123-0.0216 cP. The lightness of the foam enables it to transport/lift the water and gas(es) being injected instead of blocking the high permeability zones in the reservoir. This will maintain the water-gas ratio as it moves through the reservoir.

[0043] The foam can be generated on the surface or subsurface. Sub-surface methods for generating foam include a static mixer downhole, foam generation through a perforation in the well, natural mixing in the well, in situ foam generation in the reservoir or any combination thereof.

[0044] Additionally, the foaming agent/water mix can be injected at the same time as the gas(es), or can be injected some time after the gas(es) has been injected. Furthermore, the foaming agent/water can be injected continuously or in slugs. Also, the foaming agent/water can be injected into vertical or horizontal wells to improve the wet ISC process, including both forward and reverse combustion.

[0045] An oxygen-containing gas is injected to fuel the combustion process in the reservoir. Typical gases include air, oxygen, carbon dioxide, carbon monoxide or any combination thereof. An additional non-oxygen containing gas can also be injected to fill in gas drive, including hydrogen, nitrogen, methane, hydrogen sulfide, propane, butane, natural gas, flue gas and any combination thereof. Gases may be in a liquid form, a liquid/gas mixture, or gas form.

[0046] As used herein, “oil,” “crude oil,” and “hydrocarbons” are used interchangeably to describe the hydrocarbons remaining in oil reservoirs after conventional drilling methods.

[0047] As used herein, “foaming agent” means an additive to water used to generate foam either above the surface before injection or sub-surface using a mechanical or natural mixing method. The additive can include, but is not limited to, colloidal foams, aerosols, hydrosols, emulsions, or dispersions.

[0048] As used herein, “oxygen-containing gas” or “oxygen source gas” mean a gas containing oxygen and capable of igniting and fueling the combustion front within the reservoir.

[0049] The use of the word “a” or “an” when used in conjunction with the term “comprising” in the claims or the specification means one or more than one, unless the context dictates otherwise.

[0050] The term “about” means the stated value plus or minus the margin of error of measurement or plus or minus 10% if no method of measurement is indicated.

[0051] The use of the term “or” in the claims is used to mean “and/or” unless explicitly indicated to refer to alternatives only or if the alternatives are mutually exclusive.

[0052] The terms “comprise”, “have”, “include” and “contain” (and their variants) are open-ended linking verbs and allow the addition of other elements when used in a claim.

[0053] The phrase “consisting of” is closed, and excludes all additional elements.

[0054] The phrase “consisting essentially of” excludes additional material elements, but allows the inclusions of non-material elements that do not substantially change the nature of the invention.

[0055] The following abbreviations are used herein:

<table>
<thead>
<tr>
<th>ABBREVIATION</th>
<th>TERM</th>
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<tbody>
<tr>
<td>ISC</td>
<td>In situ combustion</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam assisted gravity drainage</td>
</tr>
<tr>
<td>PSI</td>
<td>Pounds per square inch</td>
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</table>

[0056] FIG. 1 depicts a dry forward ISC. Here, dry air is injected into a reservoir to fuel the combustion process and help push the combustion front towards the oil production well. Note that the heat formed during the combustion process is absorbed by the reservoir rock. Also, the heated oil bank, i.e. displaced oil, has not traveled close to the oil production well.

[0057] In contrast, the addition of water to the air injection results in the contact of water with heated reservoir rock, as shown in FIG. 2. After contacting the heated rock, the water is converted into steam and is pushed forward the water-air injection. As the steam contacts cooler rock in the reservoir, it condenses and transfers heat to the nearby oil. This additional heat results in the heated oil bank travelling further towards the oil production well than the dry forward ISC depicted in FIG. 1.

[0058] FIG. 3 depicts the present invention—use of a foaming agent in the water. Here, the foaming agent helps carry the water into the reservoir, thus facilitating increased contact with the heated reservoir rock. Furthermore, the foaming agent prevents the water and air from separating due to differences in density. As such, the oil is able to move towards the oil production well more efficiently than either a water-air injection or air only injection.

[0059] The following references are incorporated by reference in their entirety.


[0063] U.S. Pat. No. 3,993,133

[0064] U.S. Pat. No. 3,994,345

[0065] U.S. Pat. No. 4,691,773

[0066] U.S. Pat. No. 7,882,893

[0067] U.S.20090194278
What is claimed is:

1. An in situ combustion method of recovery of hydrocarbons from a subterranean oil containing formation penetrated by at least one injection well and at least one production well, which comprises:
   - igniting the hydrocarbons to form a combustion front by injecting oxygen-containing gas and heat into the formation through an injection well;
   - injecting a water through an injection well and in contact with a fluid that is at least one of a foam, an aerosol, a hydrosol, an emulsion and a colloidal dispersion and has a density and viscosity to carry the water via buoyancy forces; and
   - recovering hydrocarbons and other fluids at a production well.

2. The method of claim 1, wherein the density of the fluid is between 0.000598-0.0770 g/cm³ and the viscosity is between 0.0123-0.0216 cP.

3. The method of claim 1, further comprising injecting an agent into the injection well to form the fluid in situ.

4. The method of claim 3, wherein said agent is a surfactant.

5. The foaming agent of claim 4, wherein the surfactant is chosen from a group comprising alkyl benzene, aromatic sulfonates, alpha/ internal olefin, sulfonates, alkyl aryl sulfonates, alkoxy sulfates or any combination thereof.

6. The method of claim 3, wherein said agent is an alkali-based salt.

7. The foaming agent of claim 6, wherein the alkali-based salt is chosen from a group comprising sodium carbonate, sodium bicarbonate, sodium hydroxide, potassium carbonate, potassium bicarbonate, potassium hydroxide, magnesium carbonate, calcium carbonate or any combination thereof.

8. The method of claim 3, wherein said water containing said agent is injected continuously.

9. The method of claim 3, wherein said water containing the agent is injected into vertical or horizontal wells.

10. The method of claim 3, wherein said water containing said agent is injected in a slug.

11. The method of claim 9, wherein said water comprises oilfield brine, produced water, seawater, aquifer water, and river water.

12. The method of claim 1, further comprising injecting a non-oxygen containing gas.

13. The method in claim 1, further comprising injecting hydrogen, nitrogen, methane, hydrogen sulfide, propane, butane, natural gas, flue gas, or any combination thereof, and wherein said oxygen-containing gas is air, oxygen, carbon dioxide, carbon monoxide, or any combination thereof.

14. An in situ combustion method of recovery of hydrocarbons from a Steam Assisted Gravity Drainage (SAGD) depleted reservoir penetrated by at least one injection well and at least one production well, which comprises:
   - igniting the hydrocarbons to form a combustion front by injecting oxygen-containing gas and heat into the formation through an injection well;
   - scavenging heat from a rock formation by injecting a water containing an agent to generate a fluid that is at least one of a foam, an aerosol, a hydrosol, an emulsion and a colloidal dispersion; and,
   - recovering hydrocarbons and other fluids at a production well.

15. An improved method of wet in situ combustion oil recovery, the method comprising igniting oil in a formation to form a burning front and injecting water behind said burning front to capture heat and drive oil towards a production well wherein the improvement comprises injecting water behind said burning front and in contact with a fluid that is at least one of a foam, an aerosol, a hydrosol, an emulsion and a colloidal dispersion and has a density and viscosity to carry the water via buoyancy forces.