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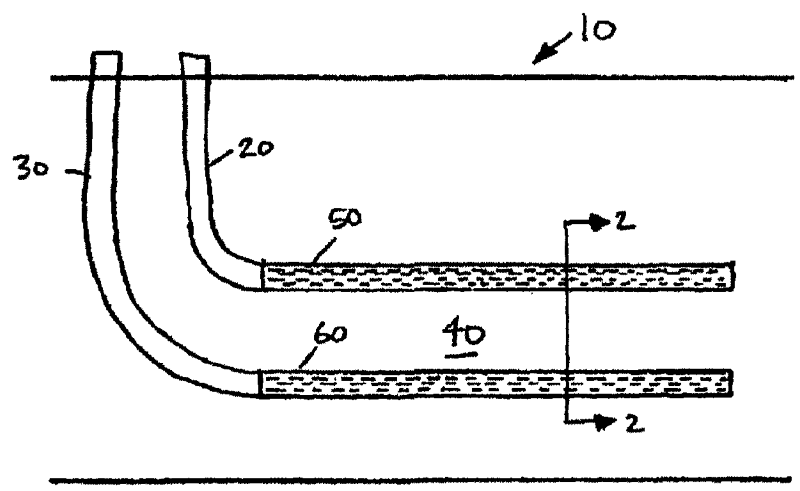
(54) Titre : ETABLISSEMENT D'UNE COMMUNICATION FLUIDE POUR LA RECUPERATION D'HYDROCARBURE A L'AIDE D'UN SURFACTANT

(54) Title: ESTABLISHING FLUID COMMUNICATION FOR HYDROCARBON RECOVERY USING SURFACTANT



(57) Abrégé/Abstract:
To establish fluid communication between horizontal wells in a bituminous sands reservoir, a surfactant is delivered into a region of the reservoir to enhance mobility of a fluid in the region. Optionally a fluid pressure is applied in the region to drive the fluid to flow from a first horizontal well to a second horizontal well, thereby establishing fluid communication between the first and second horizontal wells.

ABSTRACT OF THE DISCLOSURE

To establish fluid communication between horizontal wells in a bituminous sands reservoir, a surfactant is delivered into a region of the reservoir to enhance mobility of a fluid in the region. Optionally a fluid pressure is applied in the region to drive the fluid to flow from a first horizontal well to a second horizontal well, thereby establishing fluid communication between the first and second horizontal wells.

ESTABLISHING FLUID COMMUNICATION FOR HYDROCARBON RECOVERY USING SURFACTANT

FIELD

[0001] The present invention relates generally to hydrocarbon recovery from reservoirs of bituminous sands, and particularly to establishment of fluid communication between horizontal wells or in the case of a single well prior to hydrocarbon recovery.

BACKGROUND

[0002] Hydrocarbon resources such as bituminous sands (also commonly referred to as oil sands) present significant technical and economic recovery challenges due to the hydrocarbons in the bituminous sands having high viscosities at initial reservoir temperature. Steam-assisted gravity drainage (SAGD) is an example of an *in situ* (or in-situ) steam injection-based hydrocarbon recovery process used to extract heavy oil or bitumen from a reservoir of bituminous sands by reducing viscosity of the oil via steam injection.

[0003] A SAGD system typically includes at least one pair of steam injection and oil production wells (a "well pair") located in a reservoir of bituminous sands. The injection (upper) well has a generally horizontal section used for injecting a fluid such as steam into the reservoir for softening the bitumen in a region of the reservoir and reducing the viscosity of the bitumen. Heat is transferred from the injected steam to the reservoir formation, which softens the bitumen. The softened bitumen and condensed steam can flow and drain downward due to gravity, thus leaving behind a porous region, which is permeable to gas and steam and is referred to as the steam chamber. Subsequently injected steam rises from the injection well, permeates the steam chamber, and condenses at the edge of the steam chamber. In the process, more heat is transferred to the bituminous sands and the steam chamber grows over time. The mobilized hydrocarbons and condensate that drain downward under gravity are collected by a generally horizontal section of the production well, which is typically disposed below the injection well and from which the hydrocarbons (oil) are (is) produced.

[0004] Several well pairs may be arranged within the reservoir to form a well pattern or pad. Additional injection or production wells, such as a well drilled using Wedge Well™ technology, may also be provided.

[0005] To permit drainage of the mobilized hydrocarbons and condensate to the production well, fluid communication between the wells in the well pair must be established (referred to as the start-up process or stage in a SAGD operation). Fluid communication refers to fluid flow between the injection and production wells. Establishment of such fluid communication typically involves mobilizing viscous hydrocarbons in the reservoir to form a reservoir fluid and removing the reservoir fluid to create a porous pathway between the wells. Viscous hydrocarbons may be mobilized by heating such as by injecting pressurized steam or hot water through the injection well or the production well. In some cases, the start-up process involves injecting steam and producing returned fluids from both the injection and production wells. A pressure differential may be applied between the injection and production wells to promote steam/hot water penetration into the porous geological formation that lies between the wells of the well pair. The pressure differential promotes fluid flow and convective heat transfer to facilitate communication between the wells. However, establishment of fluid communication between the wells in a well pair can be challenging, for example due to poor fluid mobility at initial reservoir conditions, due to the presence of reservoir heterogeneity, or due to the presence of reservoir rocks with varying wettability. It may take several days, weeks or even months before enough heat can be transferred to the reservoir to establish such fluid communication.

[0006] Instead of a well pair, one or more single horizontal or vertical wells may be used for injection and production in in-situ hydrocarbon recovery processes such as, but not limited to, steam-assisted gravity drainage (SAGD) or a solvent aided process (SAP). For example, CA 2,844,345 to Gittins, *et al.* discloses a thermal/solvent oil recovery process for producing hydrocarbons using a single vertical or inclined well. The process may be preceded by start-up acceleration techniques to establish communication in the formation between an injection means and a production means within the single well.

[0007] In general, start-up time can be accelerated by modifying the porous formation (e.g., via dilation), or by reducing fluid (bitumen or water) viscosity, thus increasing mobility. For example, CA 2,757,125 to Abbate, *et al.* discloses a process for establishing communication between wells in a well pair in oil sands by dilation with steam or water circulation at elevated pressures. CA 2,698,898 to Pugh, *et al.* teaches the addition of solvents such as xylene, benzene, toluene or phenol for reducing bitumen viscosity during establishment of fluid communication between the wells in a well pair. CA 2,831,928 to Bracho Dominguez, *et al.* describes the use of one or more microorganisms to increase overall fluid mobility in a near-wellbore region in an oil sands reservoir, for example in connection with a start-up process associated with SAGD.

SUMMARY

[0008] In one aspect of the present invention, there is provided a method for establishing or accelerating fluid communication between a pair of horizontal wells in a bituminous sands reservoir, the method comprising delivering a surfactant into a region of the reservoir between the horizontal wells; and forming a reservoir fluid in the region. The surfactant is used to enhance mobility of fluid in the region, such as by reducing interfacial tension (IFT) between reservoir fluids or between one or more fluids and formation rock. A reservoir fluid flows from a first one of the horizontal wells to a second one of the horizontal wells, or flows to a nearby thief zone or in general within a portion of the reservoir that has limited mobility, e.g., when driven by gravity or by an applied fluid pressure, thereby establishing the fluid communication between the first and second horizontal wells.

[0009] In another aspect, there is provided a method for establishing fluid communication between a pair of horizontal wells in a bituminous sands reservoir, the method comprising delivering a surfactant into a region of the reservoir between the horizontal wells; and forming a reservoir fluid in the region. The fluid flows from a first one of the horizontal wells to a second one of the horizontal wells, thereby establishing the fluid communication between the first and second horizontal wells. At least a region near the first well is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase mobility of a hydrocarbon in the region before applying a fluid pressure to drive the fluid flow from the first well to the second well.

[0010] In another aspect, there is provided a method of assisting establishment of fluid communication between a pair of wells in a bituminous sands reservoir, comprising delivering a surfactant into the reservoir. A reservoir fluid is formed in a region of the reservoir near a first one of the wells. A fluid pressure is applied to drive the reservoir fluid to flow from the first well to a second one of the wells thereby establishing fluid communication between the first and second wells. The surfactant is mixed with the reservoir fluid and is selected to reduce interfacial tension between the reservoir fluid and formation rock and enhance mobility of the reservoir fluid in the reservoir. At least the region near the first well is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase the mobility of the reservoir fluid in the region before applying the fluid pressure to drive the reservoir fluid to flow from the first well to the second well.

[0011] As noted above, fluid communication between the wells in a well pair can be accelerated by modifying the porous formation or by reducing fluid viscosity, thus increasing mobility. The application of a surfactant targets a complementary phenomenon: by reducing interfacial tension between fluids and between fluids and

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formation rock, use of a surfactant can enhance the mobility of oil, water and steam, facilitate heat transfer, and assist bitumen drainage at lower temperatures. This can accelerate establishment of the fluid communication, and may permit such communication to be achieved at a lower energy cost than is normally required to heat and mobilize the inter-well portion of the reservoir.

[0012] In addition to accelerating establishment of the fluid communication between the wells, an embodiment of the present invention can also provide for the improvement of such fluid communication in those embodiments where fluid communication already exists between the wells in a well pair, but to an insufficient degree or extent to support a sufficient rate of flow of oil between the injection well (or from the steam chamber) to the production well. In another aspect of the present invention, there is provided a method for establishing fluid communication between an injection means and a production means in a single well in a bituminous sands reservoir, the method comprising delivering a surfactant into a region of the reservoir between the injection means and the production means; and forming a reservoir fluid in the region; wherein the fluid flows from the injection means to the production means, thereby establishing the fluid communication between the injection means and the production means, wherein at least a region near the injection means is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase mobility of a hydrocarbon in the region before applying a fluid pressure to drive the fluid flow from the injection means to the production means.

Other aspects, features, and embodiments of the present invention will become apparent to those of ordinary skill in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

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Fig. 1 is a schematic cross-sectional view of a SAGD well pair in a reservoir, for illustrating a method according to an embodiment of the present invention applied to the SAGD well pair;

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Fig. 2 is a schematic side cross-sectional view of the SAGD well pair in the reservoir of Fig. 1, along line 2-2; and

Fig. 3 is a schematic partial view of regions near the SAGD well pair in Fig. 2, illustrating an embodiment of the present invention.

DETAILED DESCRIPTION

[0014] Embodiments disclosed herein relate to the establishment of fluid communication between horizontal wells or in single wells in a bituminous sands reservoir, and more particularly to the use of a surfactant to facilitate or accelerate such a process, or to improve fluid communication. The surfactant reduces interfacial tension between reservoir fluids, or between a reservoir fluid and formation rock to enhance fluid mobility, thereby accelerating establishment of the fluid communication between injection and production components in a single well or improving communication along a horizontal length of a well pair. Using a surfactant to accelerate well start-up may be useful in reservoirs or reservoir regions that are not receptive to steam, have a higher than normal initial water saturation, or where other accelerated start-up techniques (e.g., steam stimulation, circulation or dilation) have failed or cannot be easily applied.

[0015] Once fluid communication between the wells in a well pair has been achieved, the wells can be employed in in-situ thermal recovery processes that use two or more wells that are required to be in fluid communication, such as in steam-assisted gravity drainage (SAGD) operations. Improved or accelerated fluid communication between wells may also be applied in other in-situ processes such as cyclic steam stimulation (CSS), steam flooding, or a solvent aided process (SAP).

[0016] In the case of single well start-up, fluid communication refers to fluid flow in the formation between the injection means (or an injection component) and the production means (or a production component) in the single well. For example, the injection and production components may be conduits, optionally tubing, and may be isolated from one another by way of a packer, by positioning the injection and production means a suitable distance apart, by positioning the injection means in the wellbore closer to the surface than the production means in the case of a vertical well, or by way of openings or perforations in the tubing or well casing over selected wellbore interval(s) to permit both outlet of injected fluids and inlet of production fluids. It will be appreciated by a person of skill in the art that the positioning of the injection and production means will depend on the particular well and formation. One or more surfactants can be used to facilitate or accelerate a single well start-up process, or to improve fluid communication.

[0017] Once fluid communication has been achieved between the injection and production components of the single well, the well can be employed in in-situ thermal recovery processes such as, but not limited to, SAGD.

[0018] In some embodiments, improvements in well conformance may be achieved by use of a surfactant during establishment of the fluid communication between the wells. Well conformance is a measure of the uniformity of fluid communication (and hence the rate of oil collection) along the length of the production well during oil extraction. As the reservoir conditions may vary along the length of the well pair, fluid communication may not be achieved uniformly along the length of the well pair. Formation of "hot spots" may result, to which regions of fluid communication may initially be limited. Use of a surfactant in the start-up process may improve well conformance by facilitating fluid communication in reservoir regions initially having relatively lower bitumen mobility.

[0019] Referring to Figs. 1 and 2, a typical SAGD recovery system 10 is shown, having an injection well 20 for injecting steam and a production well 30 completed for producing fluids from a bituminous reservoir 40. A portion of injection well 20 is open to reservoir 40 via a horizontal injection well completion 50. Similarly, a portion of production well 30 is open to reservoir 40 via a horizontal production well completion 60. These horizontal well completions typically include perforations, slotted liner, screens, outflow control devices such as in an injection well, inflow control devices such as in a production well, or a combination thereof known to one skilled in the art.

[0020] In order to assist establishment of fluid communication between injection well 20 and production well 30, a surfactant is delivered to the region of the reservoir between the horizontal wells via injection well 20 or production well 30 or both wells 20, 30.

[0021] In an embodiment, the surfactant may be co-injected with a heated fluid such as steam or hot water. The heated fluid may be injected and pressurized as in a typical SAGD start-up process, with the modification that the surfactant is added at surface or downhole to the heated fluid. For example, a surfactant may be mixed with steam or hot water before injection into well 20 or 30. In some embodiments, the concentration of the surfactant in the injected heated fluid may be from about 1 ppm to about 3,000 ppm by weight. In some embodiments, the surfactant concentration may be up to about 50,000 ppm.

[0022] The amount of surfactant used may be selected based on a cost and benefit basis. Also, the minimum required or optimum amount of a surfactant is determined based on the physical properties of the surfactant (i.e., the ability of the surfactant to reduce IFT), the presence of formation salt and other cations and anions, clays, and other species, as well as well the composition of the oil in the reservoir.

[0023] It is possible that the surfactant will be dispersed throughout the region near and between wells 20 and 30. However, it can be expected that, in some embodiments, dispersing the surfactant in a limited region near a well 20 or 30 can still have a beneficial effect on the development of fluid communication between wells 20, 30. For example, in an embodiment, the surfactant may be initially dispersed within a region that is about a few centimeters around well 20 or 30.

[0024] As is known to those skilled in the art, heating reservoir 40 such as by steam injection, or soaking reservoir 40 with a solvent, can mobilize the viscous hydrocarbons in reservoir 40, thus forming a reservoir fluid that can drain downward by gravity, and can be produced through well 20 or 30. In another embodiment, the surfactant may be injected alone or co-injected with a solvent such as butane or a heated fluid for soaking the formation.

[0025] Without being limited to any particular theory, it is expected that the presence of the surfactant can lower interfacial tension between the reservoir fluid and the formation rock, or between an aqueous phase and an oil phase of the reservoir fluid, thus facilitating or improving the flow rate of the reservoir fluid. It is also expected that the surfactant may reduce the critical saturation in the formation, thus allowing the reservoir fluid to become mobilized at a lower saturation point. The combined effects may allow the reservoir fluid to become mobilized more quickly and to move faster, as compared to a similar process but without the use of a surfactant.

[0026] The mobilized reservoir fluid may be produced through well 20 or 30 in, for example, a typical SAGD manner. Optionally, at the surface, the produced fluids may be processed or treated to separate hydrocarbons (oil), the surfactant, and water for further use.

[0027] Referring to Fig. 3, in a selected embodiment, delivery of a non-vapourized surfactant via the injection well 20a will produce a region 70 in which there is reduced interfacial tension between the reservoir fluids or between one or more reservoir fluids and formation rock to enhance mobility of the fluid(s), in which region the downward flow 90 of fluid and surfactant will be enhanced due to gravity and/or applied pressure drawdown. Delivery of a vapourized surfactant via the production well 30a will also produce a region 80 where there is reduced interfacial tension between fluid and formation rock to enhance mobility of the fluid, in which region the upward flow 100 of the vapourized surfactant will be favoured.

[0028] In some embodiments, particularly when reservoir 40 has relatively higher initial water mobility, a suitable surfactant may be injected alone, or co-injected with an unheated fluid such as water.

[0029] The surfactant may also be injected after a period of pre-heating, such as by steam or hot water injection, or by a heater located along well 20 or 30.

Surfactants

[0030] Surfactants are compounds that lower the surface tension of a liquid, the interfacial tension between two liquids, or the interfacial tension between a liquid and a solid. A surfactant can be classified according to the composition of its different chemical functional groups. The hydrophilic part of a surfactant is referred to as the head of the surfactant, while the hydrophobic part of a surfactant is referred to as the tail. Surfactants may be ionic, zwitterionic, or non-ionic. An ionic surfactant carries a net positive (cationic) or negative (anionic) charge that is balanced by a counter-ion of the opposite charge. A zwitterionic surfactant possesses a head with two oppositely charged groups, making the surfactant neutral overall. Unlike an ionic surfactant, a non-ionic surfactant does not dissociate into ions in aqueous solution.

[0031] A number of factors may be considered when selecting surfactants suitable for use in the present invention. One factor is whether the surfactant can increase the mobility of a hydrocarbon (or oil) in the region. The term "mobility" is used herein in a broad sense to refer to the ability of a substance to move about, and is not limited to the flow rate or permeability of the substance in the reservoir. For example, the mobility of oil may be increased when the oil becomes easier to detach from the sand it is attached to, or when the oil has become mobile, even if its viscosity or flow rate remains the same. The mobility of oil may also be increased when its viscosity is decreased, or when its effective permeability through the bituminous sands is increased.

[0032] Another factor is whether the surfactant can significantly reduce the IFT between oil and water and gas or between the oil or water or gas and sand or other solid materials. A further factor is whether the surfactant can serve as a wetting agent, alter the sand wettability and promote the detachment of oil from sand grains thereby increasing the flow rate of oil or the fluid mixture. A further factor is whether the critical micelle concentration (CMC) of a surfactant may be exceeded at the temperature, pressure or chemical conditions of the start-up operation. Once the CMC is exceeded, IFT reduction is inhibited and the start-up process may be less effective or excess surfactant may be wasted.

[0033] In various embodiments of the invention, the term "surfactant" refers to a compound that reduces IFT between two liquids or a liquid and a solid in bituminous sands. In various embodiments of the invention, a suitable surfactant for use has one or more of the following additional characteristics: chemical stability (e.g., at temperatures and pressures that are typical for various start-up procedures); enhancement of water-wetness of the reservoir rock; improvement of the oil relative permeability, with optional reduction of viscosity of hydrocarbon flow; compatibility with formation water; reduction of hydrocarbon-water or hydrocarbon-sand IFT at reservoir conditions; or a combination of characteristics thereof. In some embodiments, the surfactant can also be vapourizable at delivery conditions, alone or in admixture with a further component, e.g., steam.

[0034] Surfactants that are useful for the recovery of hydrocarbons from reservoirs of bituminous sands, i.e., extraction of hydrocarbons once fluid communication between the wells of a well pair has been established, are disclosed in US patent application publication No. US 2013-0081808 A1. A similar disclosure is made in "Surfactant-Steam Process: An Innovative Enhanced Heavy Oil Recovery Method for Thermal Applications", Zeidani, et al., SPE 165545, June 2013. Reference is also made to Energy Resources Conservation Board (ERCB) Supplemental Information Request application No. 1724747 (May 2012).

[0035] In one embodiment, the surfactant may be ionic (anionic or cationic). In another embodiment, the surfactant may be water-soluble.

[0036] Anionic surfactants contain anionic functional groups at the surfactant heads, such as sulfates, sulfonates, phosphates, and carboxylates.

[0037] For example, anionic surfactants include alkyl sulfates, such as ammonium lauryl sulfate, sodium lauryl sulfate (SDS, or sodium dodecyl sulfate), alkyl-ether sulfates, sodium laureth sulfate (or sodium lauryl ether sulfate, SLES), and sodium myreth sulfate.

[0038] Anionic surfactants also include docusates such as dioctyl sodium, sulfosuccinates, perfluorooctanesulfonates (PFOS), perfluorobutanesulfonates, line ar alkylbenzene sulfonates (LABs), alkyl-aryl ether phosphates, and alkyl ether phosphates.

[0039] Carboxylates include alkyl carboxylates such as sodium stearate, sodium lauroyl sarcosinates, and carboxylate-based fluorosurfactants such as perfluorononanoate (deprotonated PFNA) and perfluorooctanoate (deprotonated PFOA or PFO).

[0040] Some surfactants may include cationic head groups such as primary, secondary, or tertiary amines.

[0041] The surfactants may also include octenidine dihydrochloride,

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alkyltrimethylammonium salts such as cetyl trimethylammonium bromide (CTAB) a.k.a. hexadecyl trimethyl ammonium bromide, cetyl trimethylammonium chloride (CTAC), cetylpyridinium chloride (CPC), benzalkonium chloride (BAC), benzethonium chloride (BZT), 5-bromo-5-nitro-1,3-dioxane, dimethyldioctadecylammonium chloride, cetrimonium bromide, dioctadecyldimethylammonium bromide (DODAB).

[0042] Zwitterionic (amphoteric) surfactants have both cationic and anionic centers attached to the same molecule. The cationic part may be based on primary, secondary, or tertiary amines or quaternary ammonium cations. The anionic part can be more variable and include sulfonates, as in CHAPS (3-[(3-cholamidopropyl)dimethylammonio]-1-propanesulfonate). Other anionic groups include sultaines illustrated by cocamidopropyl hydroxysultaine, betaines such as cocamidopropyl betaine, and phosphates such as lecithin.

[0043] In another embodiment, the surfactant may be non-ionic, and optionally be vapourizable at delivery conditions. In another embodiment, a suitable surfactant is one that vapourizes at the temperature and pressure of co-injected steam.

[0044] Non-ionic surfactants include long chain alcohols such as fatty alcohols, cetyl alcohol, stearyl alcohol, and cetostearyl alcohol (consisting predominantly of cetyl and stearyl alcohols), and oleyl alcohol.

[0045] Possible surfactants also include polyoxyethylene glycol alkyl ethers such as $CH_3–(CH_2)_{10–16}–(O\text{-}C_2H_4)_{1–25}–OH$ (BRIJ™), octaethylene glycol monododecyl ether and pentaethylene glycol monododecyl ether, polyoxypropylene glycol alkyl ethers such as $CH_3–(CH_2)_{10–16}–(O\text{-}C_3H_6)_{1–25}–OH$, glucoside alkyl ethers such as $CH_3–(CH_2)_{10–16}–(O\text{-glucoside})_{1–3}–OH$ including decyl glucoside, lauryl glucoside, and octyl glucoside, polyoxyethylene glycol octylphenol ethers: $C_8H_{17}–(C_6H_4)–(O\text{-}C_2H_4)_{1–25}–OH$ such as TRITON™ X-100, polyoxyethylene glycol alkylphenol ethers such as $C_9H_{19}–(C_6H_4)–(O\text{-}C_2H_4)_{1–25}–OH$ including nonoxynol-9, glycerol alkyl esters such as glyceryl laurate, polyoxyethylene glycol sorbitan alkyl esters such as polysorbate, sorbitan alkyl esters such as spans, cocamide MEA, cocamide DEA, dodecyldimethylamine oxide, copolymers of polyethylene glycol and polypropylene glycol such as poloxamers, polyethoxylated tallow amine (POEA).

[0046] Non-limiting examples of surfactants for use in embodiments of the present invention include alcohol ethoxylates, phenol ethoxylates, alkylphenol ethoxylates, tertiary acetylenic diols including tertiary acetylenic diol ethoxylates, alkylmercaptan ethoxylates, alkylpropoxy ethoxylates, amine ethoxylates, amide ethoxylates, alcoholamides, and amino alcohols including monoethanolamine (MEA), diethanolamine (DEA), or triethanolamine (TEA).

[0047] The surfactant can be water-soluble. The surfactant can have a relatively high hydrophile-lipophile balance (HLB), such as greater than 7, greater than 8 or greater than 9. The surfactant may function at a relatively low vapour pressure, reduce IFT between different adjacent materials, and improve oil-water relative permeability.

[0048] Examples of such a surfactant include, but are not limited to, alcohol ethoxylates such as TERGITOL™ 15-S-9 (T-15-S-9), CARBOWET™ 76 (C-76), NOVELFROTH™ 190 (E-190) and NOVELFROTH™ 234 (E-234), and alkylphenol ethoxylates such as TRITON™ X-100 (TX-100), or the like. Tertiary acetylenic diol ethoxylates may also be suitable.

[0049] The surfactant can be water-insoluble, and it may also be soluble in oil. The surfactant can have a HLB less than 8, for example a HLB less than 5.5.

[0050] Examples of such a surfactant include, but are not limited to, tertiary acetylenic diols, such as SURFYNOL™ 82 (S-82) and SURFYNOL™ 104PA (S-104PA).

[0051] In various embodiments of the invention, the surfactant may be a compound represented by the chemical formula of

$$A\left[CH_2CH_2O\right]_m H,$$

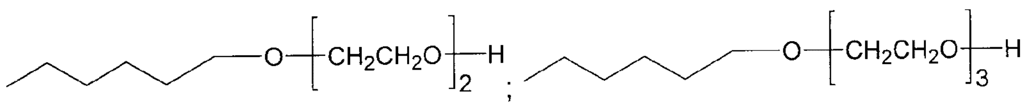
wherein (i) m is 1, and A is $-NH_2$ or $-N(H)CH_2CH_2OH$; or (ii) m is 1 or greater than 1, and A is $-OR_1$, wherein R_1 is an alkyl group.

[0052] The alcohol ethoxylate may be a primary, secondary, or tertiary alcohol ethoxylate. In various embodiments of the invention, the alcohol ethoxylate may have the chemical formula of

$$R_1-O-\left[CH_2CH_2O\right]_m-H,$$

wherein R_1 is a linear or branched alkyl group having more than 5 carbon atoms, and m is ≥1. The alcohol ethoxylate may also have the chemical formula of

$C_{12\text{-}14}H_{25\text{-}29}O[CH_2CH_2O]_9H$; $C_{12\text{-}15}H_{25\text{-}31}O[CH_2CH_2O]_{2.8}H$;



$$CH_3-(CH_2)_n-C(R_2)(R_2)-O-\left[CH_2CH_2O\right]_m-H$$

or

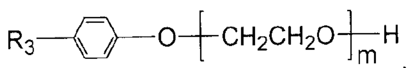
wherein m is 2 or 3, n is 2 or 3, and R_2 is methyl or ethyl.

[0053] Possible alcohol ethoxylates may also have the chemical formula of

$$CH_3-\left[CH_2\right]_n-CH_2-O-\left[CH_2CH_2O\right]_m-H,$$

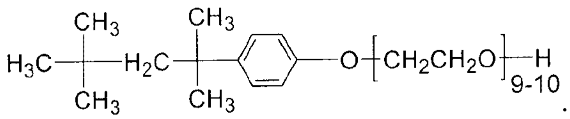
wherein n is greater than 3 and m is greater than 1.

[0054] In various embodiments of the invention, the phenol ethoxylate may have the chemical formula of

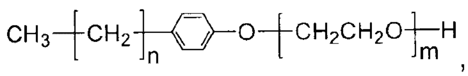


wherein R_3 is hydrogen, or a linear or branched alkyl group, and m is greater than 1. R_3 may be a linear or branched alkyl group having more than 2 carbon atoms.

[0055] The phenol ethoxylate may comprise an alkylphenol ethoxylate. The alkylphenol ethoxylate may have the chemical formula of

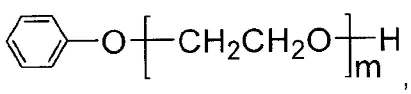


[0056] Other possible alkylphenol ethoxylates may have the chemical formula of



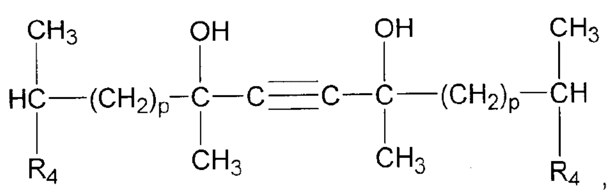
wherein m is greater than 1, and n is greater than 1.

[0057] Other possible phenol ethoxylates may have the chemical formula of



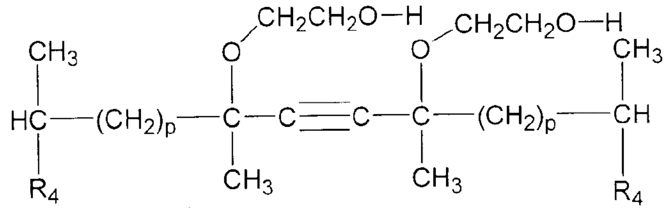
wherein m is greater than or equal to 1.

[0058] In various embodiments of the invention, the tertiary acetylenic diol may have the chemical formula of

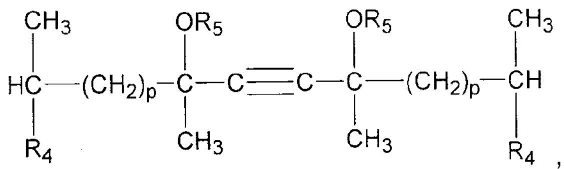


wherein R_4 is hydrogen or methyl, and p is 1 or 2.

[0059] The tertiary acetylenic diol may also have the chemical formula of

a. 

wherein R_4 is hydrogen or methyl, and p is 1–3, or

b. 

wherein R_4 is hydrogen or methyl, R_5 is hydrogen or hydroxyethyl, and p is 1 - 3 when R_5 is hydroxyethyl, or is less than 3 when R_5 is hydrogen.

[0060] In various embodiments of the invention, the alkylmercaptan ethoxylate may have the chemical formula of

$$R_7-S-\left[CH_2CH_2O\right]_m-H,$$

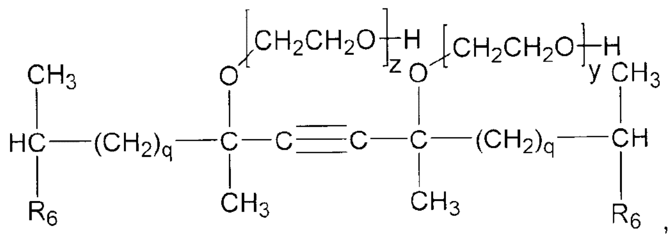
wherein R_7 is a linear or branched C_6–C_{10} alkyl group, and m is 2–4.

[0061] In various embodiments of the invention, the alkylpropoxy ethoxylate may have the chemical formula of

$$CH_3-(CH_2)_n-O-\left[CH_2CH(CH_3)O\right]_p-\left[CH_2CH_2O\right]_m-H,$$

wherein m is 2 or 3, n is 3 or 4 and p is 1 or 2.

[0062] Other non-ionic surfactants may be acetylenic diol ethoxylates having the formula

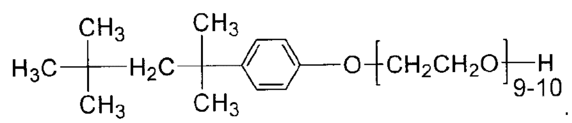


wherein R_6 is hydrogen, or a linear or branched alkyl group, q is greater than 1, and at least one of y and z is greater than or equal to 1, or a combination thereof.

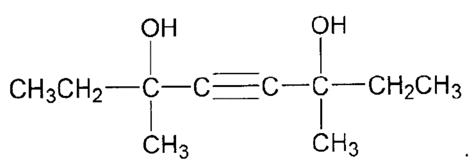
[0063] Some commercially available surfactants and their main chemical components are listed below.

[0064] T-15-S-9 contains a C_{12}–C_{14} secondary alcohol ethoxylate with nine [CH_2CH_2O-] groups, with the chemical formula of $C_{12\text{-}14}H_{25\text{-}29}O[CH_2CH_2O]_9H$.

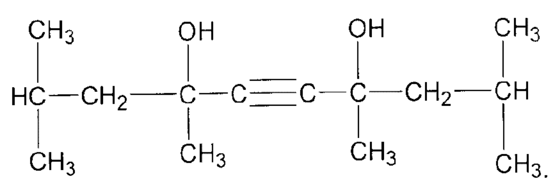
[0065] TX-100 contains is a tertiary alkylphenol ethoxylate with 9–10 [-CH_2CH_2O-] groups), with the chemical formula of



[0066] S-82 contains a tertiary acetylenic diol with the chemical formula of

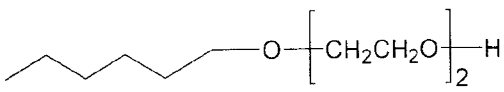


[0067] S-104PA contains a tertiary acetylenic diol with the chemical formula of

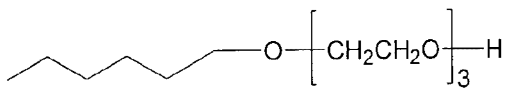


[0068] C-76 contains a C_{12}–C_{15} alcohol ethoxylate with 2.8 [$-CH_2CH_2O-$] groups, with the chemical formula of $C_{12\text{-}15}H_{25\text{-}31}O[CH_2CH_2O]_{2.8}H$.

[0069] E-190 contains a C_6 alcohol ethoxylate with 2 [$-CH_2CH_2O-$] groups, with the chemical formula of



[0070] E-234 contains a C_6 alcohol ethoxylate with 3 [$-CH_2CH_2O-$] groups, with the chemical formula of



[0071] ALFONIC™ 1012-5 (A-1012-5) has the chemical formula of

$$CH_3-\left[CH_2\right]_n-CH_2-O-\left[CH_2CH_2O\right]_m-H,$$

wherein n is 8–10 and m is 5.

[0072] Other surfactants, such as an oil-soluble monohydric alcohol, more specifically, an octylphenoxypolyethyleneoxy ethanol, may also be suitable in some applications.

[0073] In different embodiments, different surfactants may be used.

[0074] For example, in some embodiments, ammonia or amines may be used.

[0075] In some embodiments, alkylxylene sulfonates may be used.

[0076] In some embodiments, lipid surfactants may be used.

[0077] In some embodiments, a polyvinylalcohol may be used.

[0078] In some embodiments, alkoxylated surfactants may be used.

[0079] In some embodiments, sulfonates and sulfonated derivatives, such as alkyl benzene sulfonates, alkyl benzene disulfonates, alkaryl sulfonates, or alkaryl naphthenic sulfonates, may be used. They may be provided in the forms of sodium, potassium, ammonium or substituted ammonium salts.

[0080] In some embodiments, alkyl polyglycosides or aromatic alcohols may be used.

[0081] In some embodiments, acetylenic surfactants may be used.

[0082] In some embodiments, ethoxylated alkylphenols may be used.

[0083] In some embodiments, ethoxylated alcohols such as ethoxylated n-alcohols may be used.

[0084] In some embodiments, alkyl alcohols may be used.

[0085] In some embodiments, sulfates such as ethoxylated sulfates may be used. In some embodiments, alkyl ethoxy sulfates or alkyl phenol ethoxy sulfates, may be used.

[0086] In some embodiments, phosphates may be used.

[0087] In some embodiments, a surfactant may be formed in-situ from a surfactant precursor such as ammonia, or acid and alkaline compounds. The surfactant precursor may be injected with steam into the reservoir.

[0088] In some embodiments, a biosurfactant may be produced in-situ by introducing surfactant-producing bacteria, such as Bacillus species, into the reservoir. The surfactant-producing bacteria may be co-injected with steam into the reservoir.

[0089] In some embodiments, a lipopeptide surfactant may be used.

[0090] In some embodiments, ethoxylated polyoxypropylenes may be used.

[0091] In some embodiments, block copolymers of propylene or ethylene oxides may be used.

[0092] In some embodiments, polyethylene oxide or polypropylene oxide surfactants may be used.

[0093] In some embodiments, a polyoxamer such as a polyoxypropylene and polyoxyethylene block copolymer may be used.

[0094] In some embodiments, the surfactant can be used in liquid form. When the surfactant is a solid under given conditions such as at lower temperatures, it may be dissolved in a solvent to prepare a liquid solution for injection into the reservoir. Non-limiting examples of solvents for solubilizing a surfactant, such as S-82, include propylene glycol (PG), ethylene glycol (EG), isopropyl alcohol (IPA) and water, alone or in combination. Suitable solubilizing solvents or combination of solvents can be selected based on the characteristics of the solution to be obtained, such as the freezing point, and stability and viscosity at storage and injection conditions. The solvent may also be selected for its ability to reduce IFT. For example, IPA reduces oil-water IFT. PG and EG may also reduce IFT.

[0095] For example, a mixture of 50% S-82 and 50% IPA, or a ratio from about 5:95 S-82:IPA to about 95:5 S-82:IPA, may be used. It is expected that such a mixture may be more robust at low temperatures than mixtures of 50% S-82 in PG/water. While the mixtures discussed in the above paragraph do not freeze at room temperature (they have a freezing point ≤ -35°C), their viscosities at reservoir conditions are different. For instance, at -8°C, 50% S-82 in IPA has a viscosity of 120 cP, 50% S-82 in PG has a viscosity of 4,200 cP, 50% S-82 in 4:1 PG:water has a viscosity of 1,250 cP, and 50% S-82 in 2:1 PG:water has a viscosity of 700 cP. Stabilities can also differ. For example, presence of water may lead to the formation of clathrates at low temperatures.

[0096] A concentration of the surfactant effective at accelerating fluid communication can vary depending on the selection of processing conditions (e.g., injection rate and manner, temperature and pressure of co-injected steam, surfactant type and properties at reservoir conditions, reservoir properties such as permeability, or a combination thereof). In various embodiments of the invention, the surfactant may have a concentration from about 10 ppm to about 50,000 ppm by weight, measured at room temperature based on the liquid volumes of the surfactant and the carrier fluid such as steam, heated water, a solvent or a combination thereof. In some embodiments of the invention, the surfactant concentrations may be from about 10 ppm to about 10,000 ppm, such as from about 10 ppm to about 3,000 ppm.

[0097] In various embodiments of the invention, a suitable concentration of the surfactant may be defined as that sufficient to produce a reduction in IFT between fluids in the formation, or between a fluid and the formation rock. In some embodiments, IFT may be reduced to about ½, to about 1/100, or to about 1/10,000 of its original value. In various embodiments of the invention, a suitable concentration of the surfactant may be further defined as that sufficient to reduce viscosity of the oil. The amount of the surfactant to be used in a start-up process should also be selected with consideration of economic factors, such as surfactant cost or ability to recycle the surfactant for re-use.

[0098] In various embodiments of the invention, the term "surfactant" further includes a surfactant precursor, which under selected conditions may form a surfactant in-situ. A mix of two or more surfactants may be used to produce a more optimal result for a given process.

Injection

[0099] The surfactant may be delivered, such as via a horizontal well, into the surrounding reservoir, using any suitable delivery mechanism or route. For example, delivery can be achieved using the injection well, the production well, or both, or in the case of a single well, using the injection component, the production component, or both. In some embodiments of the invention, two or more surfactants may be used in combination, separately or independently.

[00100] In one embodiment, the surfactant is delivered into all or part of a near-wellbore region of the surrounding reservoir. In selected embodiments, having a well pair wherein the inter-well distance is X meters, the near-wellbore region can be defined as the volume of reservoir occupied within a radius of X/2 m from the wellbore(s) in question. For example, for a well pair in which the wells are 5 m apart, the near-wellbore region may be defined to include up to a 2.5 m radius from each of the two wellbores. In some embodiments, the near-wellbore region includes the volume defined by a radius of 2-3 m from the well, wherein this 2-3 m radius is not necessarily constant (i.e., is variable) along the length of the wellbore. In general, the near-wellbore region contains the wellbore. The near-wellbore region may be associated with: (i) an injector well of the well pair, (ii) a producer well of the well pair, or (iii) both the injector well and the producer well.

[00101] In various embodiments of the invention, the surfactant may be delivered in a number of forms. For example, the surfactant may be injected as a liquid (pre-heated or at ambient temperature) or as a vapour at the wellhead or downhole, or the surfactant may be injected as a liquid and vapourized at the wellhead, in the wellbore, or downhole.

[00102] In selected embodiments of the invention, the surfactant or a combination of surfactants may be injected as vapour separate from steam or as vapour co-injected with steam. The surfactant may be injected as a mixture of steam and surfactant (e.g., mixed ex-situ) or as separate streams for mixing in the well or mixing in-situ. In various embodiments, the surfactant may be injected as an aerosol or spray. In some embodiments, the surfactant may be co-injected with heated water or a solvent. The co-injected solvent may be a solvent suitable for soaking the reservoir prior to applying a fluid pressure to the reservoir.

[00103] In one embodiment, the surfactant is injected with steam, the steam temperature ranging from about 158.8°C to about 325°C. According to various embodiments of the invention, the surfactant may be selected such that it is chemically stable at such temperatures and therefore remains effective after co-injection.

[00104] In one embodiment, the surfactant is injected alone, but optionally water, steam, a solvent, or a combination thereof may be separately injected into the same region of the reservoir, to improve fluid mobility in the region. In one embodiment, a surfactant-containing composition delivered to the formation does not contain an additional component such as NaOH for emulsifying the oil in the reservoir.

[00105] In one embodiment, a surfactant is provided to the reservoir via an injection well, wherein the surfactant is not vapourized or remains at least partially in a liquid or solution phase when the surfactant is provided to the reservoir. The surfactant may be in a liquid form at surface and at reservoir conditions. The surfactant may be mixed with heated water or a solvent at surface, or the surfactant may be co-injected with heated water or a solvent, and provided to the reservoir as a heated liquid or solution.

[00106] In one embodiment, a surfactant is provided to the reservoir via the production well, wherein the surfactant is in vapour form or at least partially vapourized when the surfactant is provided to the reservoir. Depending on the properties of the surfactant, the surfactant may be in a solid, liquid, or gas phase at surface and may be optionally co-injected with steam to at least partially vapourize the surfactant at the wellhead, in the wellbore, or downhole.

[00107] In a further embodiment, the two embodiments above are carried out sequentially or simultaneously, i.e., a non-vapour surfactant is provided to the reservoir via the injection well, and a surfactant vapour is provided to the reservoir via the production well optionally with steam. While not wishing to be bound by theory, this combined injection technique may form a countercurrent flow of fluids between the injection and production wells to accelerate establishment of fluid communication between the wells. Injecting a surfactant in liquid or solution phase into the reservoir via an upper injection well may cause the surfactant to disperse or increase mobility of hydrocarbons between the injection and production wells and allow gravity to act in favour of fluid mobility or faster drainage of heated bitumen towards the production well. At the same time, injecting a surfactant in vapour form optionally with steam via a lower production well may cause the surfactant to disperse or increase mobility of hydrocarbons between the injection and production wells by allowing the surfactant vapour and/or steam to percolate upwards in the formation or promote upward mobility towards the injection well. Injection of surfactant(s) in this manner may lead to faster inter-well communication compared to either providing a surfactant to the reservoir (i) in the liquid phase via the injection well or (ii) in the vapour phase via the production well alone.

[00108] In one embodiment, the surfactant is water-soluble and is provided to the reservoir via the injection well. Without wishing to be bound by theory, it is believed that providing a water-soluble surfactant to the reservoir via the injection well may enhance the mobility of water present in the reservoir, allowing hot water and optionally subsequently steam to flow towards the production well.

[00109] In another embodiment, the surfactant is water-insoluble (or oil-soluble) and is provided to the reservoir via the production well. Without wishing to be bound by theory, it is believed that providing an oil-soluble surfactant to the reservoir via the production well may afford accelerated drainage of heated bitumen from the inter-well region, in turn allowing steam to percolate upward from the production well towards the injection well.

[00110] In a further embodiment, the two embodiments above are carried out sequentially or simultaneously, i.e., a water-soluble surfactant is provided to the reservoir via the injection well, and an oil-soluble surfactant is provided to the reservoir via the production well optionally with steam. Injection of surfactant(s) in this manner may lead to faster inter-well communication compared to either (i) providing a water-soluble surfactant to the reservoir via the injection well or (ii) providing an oil-soluble surfactant to the reservoir via the production well alone.

[00111] Following delivery of the surfactant, a certain period of time may be allowed to elapse for the surfactant to penetrate at least a near-wellbore region of the reservoir.

[00112] In one embodiment, during or subsequent to surfactant delivery, gravity encourages fluid mobility in the inter-well region, assisting, facilitating, or accelerating establishment of fluid communication between the injection well and the production well.

[00113] In one embodiment, a pressure differential is applied between the injection and the production wells during or subsequent to surfactant delivery to encourage mobility in the inter-well region, facilitating establishment of fluid communication between the wells.

[00114] In some embodiments, a surfactant may be delivered into a region of the reservoir, such as a near-wellbore region, before injection of any other fluid or heating of the reservoir.

[00115] In some embodiments, a mobile reservoir fluid may be formed in the reservoir after delivery of the surfactant. The reservoir fluid may be formed by heating, by solvent soaking, by injected steam or heated water, or by the surfactant.

[00116] In some embodiments, a surfactant may be delivered into the reservoir while the reservoir fluid is formed, such as by co-injecting the surfactant with steam, heated water, or a solvent.

[00117] In some embodiments, a surfactant may be delivered into the reservoir after the reservoir fluid has been formed, such as after a period of injection of steam, heated water, or a solvent.

[00118] In some embodiments, a surfactant may be delivered into the reservoir before a fluid pressure is applied to drive the reservoir fluid from one well to another well of the well pair. An initial injection pressure may be required to deliver the surfactant into the reservoir. In different embodiments, the surfactant may be delivered into the reservoir after initial communication between the wells of the well pair has been established, such as to improve, accelerate or expand fluid communication between the wells of the well pair. In the latter case, the fluid pressure may also be applied while injecting the surfactant.

[00119] In one embodiment, following injection of the surfactant a chasing fluid can be used to displace the surfactant from the well, forcing part or all of the surfactant into the formation. The chasing fluid may be a gas, for example nitrogen. Application of a pressure differential can also be used to promote displacement of the surfactant into the near-wellbore region of the reservoir.

[00120] In some embodiments, once the surfactant has been delivered, optionally alone or co-injected with steam or a solvent, a certain period of time may be allowed to elapse for the surfactant to penetrate part of the near-wellbore region of the reservoir. The near-wellbore region may for example be within an inter-well region between a first well and a second well of a well pair. This period of time (i.e., surfactant soak) can take place, for example, prior to the application of a pressure differential to establish the fluid communication between the wells of the well pair. The surfactant soak can also take place after the application of a pressure differential or injection of a chasing fluid, which promote an initial insertion of the surfactant into the near-wellbore region, the soaking period permitting the surfactant to diffuse further from the wellbore into the near-wellbore region.

[00121] In various embodiments of the invention, the injection of surfactant may comprise an injection pattern. For example, the injection pattern may comprise simultaneous injection with the steam or staged (e.g., sequential) injection at selected time intervals and at selected locations. The injection may be performed in various regions to create a target injection pattern to achieve target results at a particular location. In various embodiments of the invention, the injection may be continuous or periodic. Targeted injection may also be utilized to increase well conformance in regions of low mobility.

[00122] In one embodiment, the surfactant is injected at sub-fracturing pressures of the reservoir formation.

[00123] The surfactant or mixture of surfactants may be utilized in combination with other processes such as a solvent aided process (SAP) or a similar process in which small amounts of chemicals or solvents such as light hydrocarbons are utilized to further reduce the oil viscosity. The solvent may include one, or a combination, of alkanes, benzenes, toluenes, diesels, butane, suitable C_3-C_{15} hydrocarbons, or the like. Further solvents that can be used for co-injection are disclosed in CA 2,698,898.

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[00124] It should be mentioned that the conditions and objectives of the principal oil recovery and start-up stages are different, which can affect the selection of suitable surfactants. For example, in a typical SAGD production stage, it may be desirable to deliver a surfactant in the vapour form to the peripheral region of the steam chamber and it may be desirable for the surfactant to form an oil-in-water emulsion in the reservoir fluid that is drained downward to improve fluid mobility. At this stage, the surfactant may need to travel a long distance away from the well from which it is injected. So a surfactant with a shorter chain length, and thus, higher vapour pressure may be desirable during the SAGD production stage. It may also be desirable to use surfactants that can mix well with steam or water for this stage. In comparison, during the start-up stage, it is not necessary for the surfactant to be delivered in a vapour form, and it is not necessary for the surfactant to travel a long distance in the reservoir. The surfactant can move relatively faster near the wellbore, and does not need to mix well with water for delivery to a region near the wellbore. It is also expected that substantial shear mixing can occur in the inter-well region between the two wells of a well pair, which can help fluid movement in the region. In comparison, it is expected that there is much less shear mixing at the edges of the steam chamber far away from the wells. At the start-up stage, it is desirable to pool more oil from the formation with water for faster flow and faster communication. When a pressure differential is established between the wells, it can not only assist movement of the reservoir fluid, but can also assist delivery of the surfactant and mixing of the surfactant with the reservoir fluid.

[00125] Despite the differences between the SAGD production and start-up stages described herein, surfactant selection for start-up may also be based on a number of factors related to the ease or speed with which the operation can be switched or transitioned from the start-up phase (during which fluid communication between an injection well and a production well, or between an injection component and a production component of a single well, is sought) to a principal recovery process, such as SAGD (during which the focus is on hydrocarbon recovery). For example, a surfactant may be co-injected via the injection well, the production well, or both, into the reservoir as a vapour with steam, to establish fluid communication between the wells. The same surfactant may also be used, under the same or optionally under different operating conditions, once fluid communication is achieved to improve the rate of oil recovery. Or, for example, a surfactant may be delivered to the reservoir in liquid phase to accelerate fluid communication between the wells and then a different surfactant may be used once fluid communication is achieved to improve the rate of oil recovery.

[00126] A person skilled in the art will appreciate that the choice of surfactant(s) for accelerating start-up versus improving hydrocarbon recovery may depend on factors such as, but not limited to, the type of well configuration (e.g., well pair or single well) or the type of reservoir containing the hydrocarbons (e.g., reservoir depth, thickness, or extent of water saturation).

[00127] The surfactant or mixture of surfactants may optionally be utilized during or subsequent to a dilation process, solvent soak, microorganism injection, or another process that modifies the porous characteristics of the reservoir.

[00128] In one embodiment, injection of the surfactant into the reservoir, and the resulting acceleration in fluid communication between the wells in the well pair, is achieved without simultaneous production of hydrocarbons from the wells.

[00129] In one embodiment, E-190 (defined above) may be used as the surfactant. In another embodiment, a mixture of 50% S-82 and 50% IPA (volume/volume) may be injected into the reservoir. E-190 or the mixture of 50% S-82 and 50% IPA may be co-injected with steam. The concentration of E-190 or of the mixture of 50% S-82 and 50% IPA in the injected fluid can be e.g., up to 3,000 ppm by weight. For example, the injection fluid may contain about 2,500 ppm or up to about 2,800 ppm of the mixture of 50% S-82 and 50% IPA; or about 1,500 ppm or up to about 1,750 ppm of E-190. Conveniently, these surfactants or mixtures can be stored as liquids at about 10°C under atmosphere pressure, and can be pre-mixed with hot water or steam at surface before injection. Injection of the surfactant can take place e.g., into a steam line immediately upstream of the wellhead through an injection quill or other suitable methods. During injection of the surfactant, the BHP (bottom hole pressure) can be up to e.g., 2,600 kPa, 3,000-3,800 kPa, 4,000 kPa, or 5,500 kPa. If surfactant injection is combined with a dilation process then the BHP can be as high as 8,500 kPa or as high as the formation fracture pressure, whichever is greater.

Reservoir

[00130] In various embodiments of the invention, the term "reservoir" refers to a subterranean or underground formation comprising recoverable hydrocarbons; and the term "reservoir of bituminous sands" refers to such a formation wherein at least some of the hydrocarbons are viscous and immobile and are disposed between or attached to sands. In various embodiments of the invention, the terms "hydrocarbons" or "hydrocarbon" relate to mixtures of varying compositions comprising hydrocarbons in the gaseous, liquid or solid states, which may be in combination with other fluids (liquids and gases) that are not hydrocarbons. For example, "heavy oil", "extra heavy oil", and "bitumen" refer to hydrocarbons occurring in semi-solid or solid form and having a viscosity in the range of about 1,000 to over 1,000,000 centipoise (mPa·s) measured at original in-situ reservoir temperature. In this specification, the terms "hydrocarbons", "heavy oil", "oil" and "bitumen" are used interchangeably. Depending on the in-situ density and viscosity of the hydrocarbons, the hydrocarbons may comprise, for example, a combination of heavy oil, extra heavy oil and bitumen. Heavy crude oil, for example, may be defined as any liquid petroleum hydrocarbon having an American Petroleum Institute (API) Gravity of less than about 20° and a viscosity greater than 1,000 mPa•s. Oil may be defined, for example, as hydrocarbons mobile at typical reservoir conditions. Extra heavy oil, for example, may be defined as having a viscosity of over 10,000 mPa•s and about 10° API Gravity. The API Gravity of bitumen ranges from about 12° to about 7° and the viscosity is greater than about 1,000,000 mPa•s. Bitumen is generally non-mobile at typical native reservoir conditions.

[00131] In one embodiment, the present invention relates to the establishment of fluid communication between wells in well pairs in a SAGD system wherein the reservoir in the vicinity of one or more of the wells has not been subjected to fracture or otherwise altered so that a preferential path or channel has been created in the reservoir.

[00132] A person skilled in the art will appreciate that an immobile formation or reservoir at initial (or original) conditions (e.g., temperature or viscosity) means that the reservoir has not been treated with heat or other means. Instead, it is in its original condition, prior to the recovery of hydrocarbons. Immobile formation means that the formation has not been mobilized through the addition of heat or other means.

[00133] It will be understood that any range of values herein is intended to specifically include any intermediate value or sub-range within the given range, and all such intermediate values and sub-ranges are individually and specifically disclosed.

[00134] It will also be understood that the word “a” or “an” is intended to mean “one or more” or “at least one”, and any singular form is intended to include plurals herein.

[00135] It will be further understood that the term “comprise”, including any variation thereof, is intended to be open-ended and means “include, but not limited to,” unless otherwise specifically indicated to the contrary.

[00136] When a list of items is given herein with an "or" before the last item, any one of the listed items or any suitable combination of two or more of the listed items may be selected and used.

[00137] Of course, the above described embodiments of the invention are intended to be illustrative only and in no way limiting. The described embodiments of the invention are susceptible to many modifications of form, arrangement of parts, details and order of operation. The invention, rather, is intended to encompass all such modification within its scope, as defined by the claims.

WHAT IS CLAIMED IS:

1. A method for establishing fluid communication between a pair of horizontal wells in a bituminous sands reservoir, the method comprising:

   delivering a surfactant into a region of the reservoir between the horizontal wells; and

   forming a reservoir fluid in the region;

   wherein the fluid flows from a first one of the horizontal wells to a second one of the horizontal wells, thereby establishing the fluid communication between the first and second horizontal wells,

   wherein at least a region near the first well is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase mobility of a hydrocarbon in the region before applying a fluid pressure to drive the fluid flow from the first well to the second well.

2. The method according to claim 1, wherein the surfactant is co-injected with steam.

3. The method according to claim 1, wherein the surfactant is co-injected with the solvent.

4. The method according to claim 1, wherein the reservoir fluid comprises mobilized hydrocarbons.

5. The method according to claim 1, wherein the first horizontal well is an injection well and the second horizontal well is a production well.

6. The method according to claim 1, wherein the surfactant is delivered into the reservoir via the first horizontal well.

7. The method according to claim 1, wherein one or more surfactants are delivered into the reservoir via the first and second horizontal wells.

8. The method according to claim 1, wherein the surfactant is ionic, zwitterionic or non-ionic.

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9. The method according to claim 1, wherein the surfactant is water-soluble or oil-soluble.

10. The method according to claim 1, wherein the solvent comprises butane.

11. The method according to claim 5, wherein the surfactant is delivered to the reservoir via the injection well in a non-vapourized form.

12. The method according to claim 11, wherein a vapourizable surfactant is delivered to the reservoir via the production well.

13. The method according to claim 1, wherein the delivering comprises delivering the surfactant along a length of the horizontal wells to enhance mobility of the fluid along the length, thus improving uniformity of fluid communication between the first and second wells along the length.

14. The method according to claim 4, wherein the reservoir fluid comprises heated water or a solvent.

15. The method according to claim 1, wherein the first and second horizontal wells are configured for producing oil from the reservoir by a steam-assisted gravity drainage (SAGD) process.

16. The method according to claim 1, comprising dilating the reservoir, or injecting a solvent into the reservoir.

17. The method according to claim 1, wherein the surfactant is delivered into the region before or during the forming of the reservoir fluid.

18. The method according to claim 1, wherein the fluid pressure is applied by establishing a pressure differential in the region between the first and second horizontal wells to drive the fluid after the surfactant has been dispersed into the region.

19. The method according to claim 1, wherein a sufficient amount of the surfactant is delivered into the region to accelerate the establishment of fluid communication between the first and second horizontal wells.

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20. The method according to claim 1, wherein a mixture comprising a heated fluid and about 1 ppm to about 50,000 ppm by weight of the surfactant is injected into the region.

21. A method of assisting establishment of fluid communication between a pair of wells in a bituminous sands reservoir, comprising delivering a surfactant into the reservoir, wherein a reservoir fluid is formed in a region of the reservoir near a first one of the wells, a fluid pressure is applied to drive the reservoir fluid to flow from the first well to a second one of the wells thereby establishing fluid communication between the first and second wells, and the surfactant is mixed with the reservoir fluid and is selected to reduce interfacial tension between the reservoir fluid and formation rock and enhance mobility of the reservoir fluid in the reservoir, wherein at least the region near the first well is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase the mobility of the reservoir fluid in the region before applying the fluid pressure to drive the reservoir fluid to flow from the first well to the second well.

22. A method for establishing fluid communication between an injection means and a production means in a single well in a bituminous sands reservoir, the method comprising:

delivering a surfactant into a region of the reservoir between the injection means and the production means; and

forming a reservoir fluid in the region;

wherein the fluid flows from the injection means to the production means, thereby establishing the fluid communication between the injection means and the production means,

wherein at least a region near the injection means is soaked with the surfactant or a mixture of the surfactant and a solvent for a period of time to increase mobility of a hydrocarbon in the region before applying a fluid pressure to drive the fluid flow from the injection means to the production means.

23. The method according to claim 12, wherein the vapourizable surfactant is a non-ionic surfactant.

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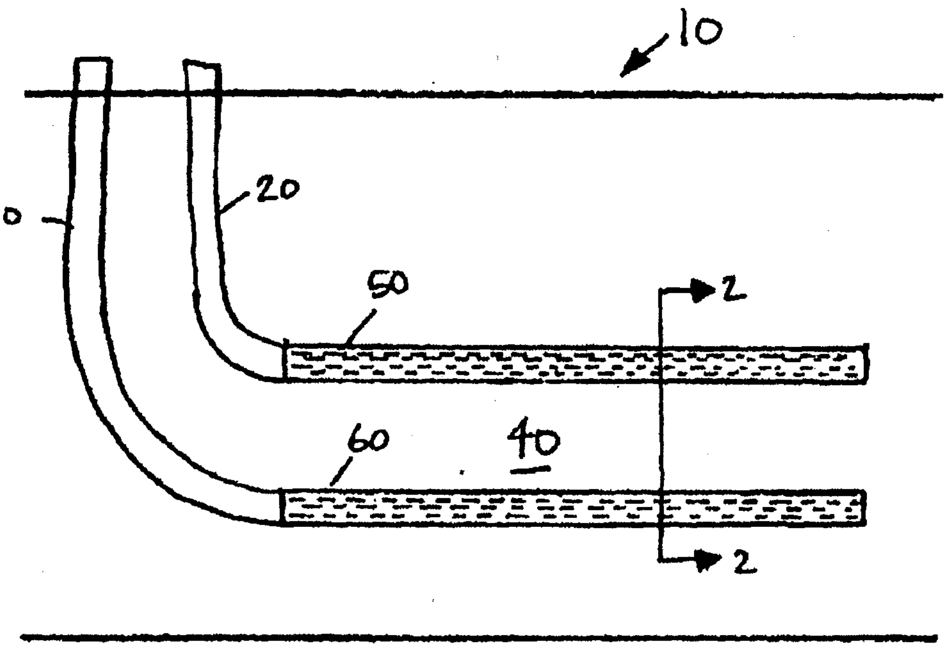

FIG. 1

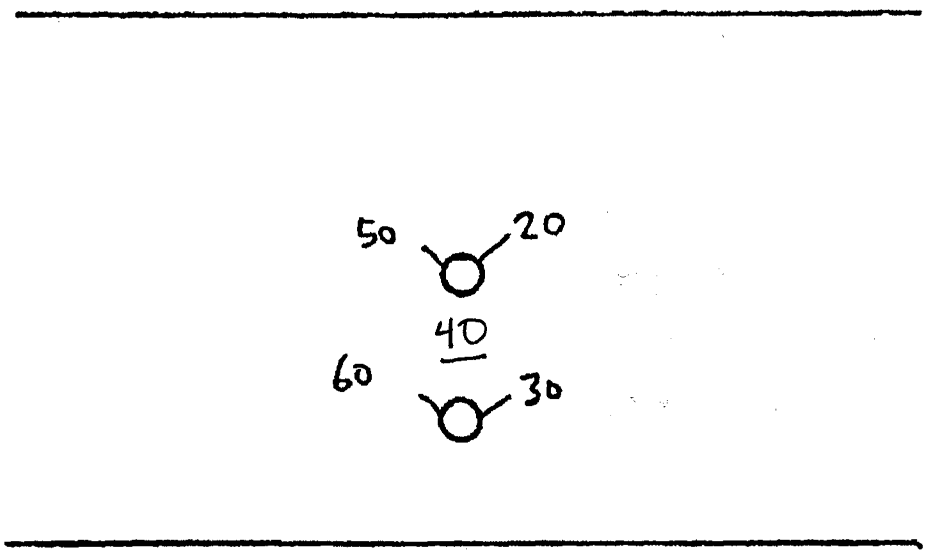

FIG. 2

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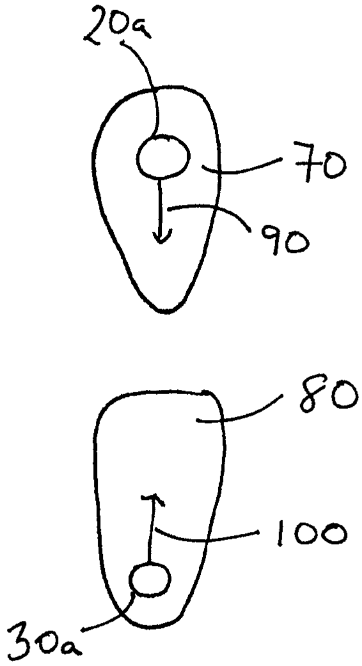
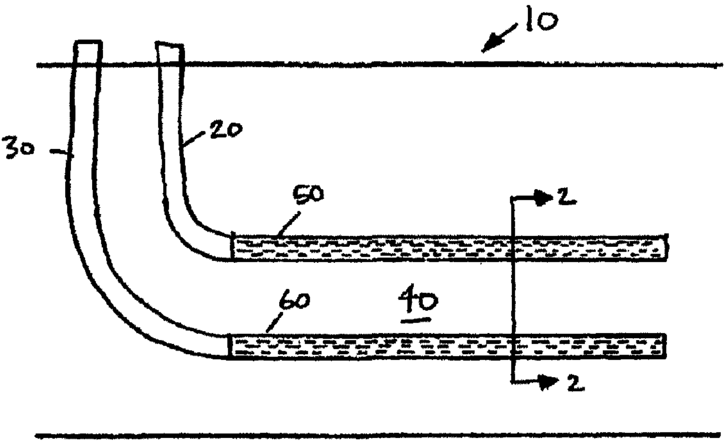


FIG.3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