The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by initiating and propagating vertical permeable inclusions in a plane substantially orthogonal to the borehole axis. These inclusions containing proppant are thus highly permeable and enhance drainage of heavy oil from the formation, and also by steam injection into these planes, enhance oil recovery by heating the oil sand formation, the heavy oil and bitumen, which will drain under gravity and be produced. Multiple propped vertical inclusions are constructed at various locations along a substantially horizontal wellbore by dilation of the formation in the plane of the intended inclusion by radial expansion and axial extension of the formation by an expanding packer system that expands both radially and axially. In another embodiment of the invention, the expansion device is part of a casing string or liner and is in contact with the formation by a swellable elastomer, or by a cement or polymer based grout. The expansion device is expanded by an inflatable packer and the device expands both radially outward and extensionally in the axial direction, giving rise to a dilated extensional plane in the formation which is substantially orthogonal to the well bore axis. Injected fluid propagates preferentially in this dilated and extensional plane within the formation.
INCLUSION PROPAGATION BY CASING EXPANSION GIVING RISE TO FORMATION DILATION AND EXTENSION

TECHNICAL FIELD

[0001] The present invention generally relates to enhanced recovery of petroleum fluids from the subsurface by initiating and propagating vertical permeable inclusions in a plane substantially orthogonal to the borehole axis. These inclusions containing propellant are thus highly permeable and enhance drainage of heavy oil from the formation, and also by steam injection into these planes, enhance oil recovery by heating the oil sand formation, the heavy oil and bitumen, which will drain under gravity and be produced. Multiple propped vertical inclusions are constructed at various locations along a substantially horizontal wellbore by dilation of the formation in the plane of the intended inclusion by radial expansion and axial extension of the formation. This diluted and extended plane within the formation provides a preferential pathway for injected fluid to propagate in the formation.

BACKGROUND OF THE INVENTION

[0002] Heavy oil and bitumen oil sands are abundant in reservoirs in many parts of the world such as those in Alberta, Canada, Utah and California in the United States, the Orinoco Belt of Venezuela, Indonesia, China and Russia. The hydrocarbon reserves of the oil sand deposit is extremely large in the trillions of barrels, with recoverable reserves estimated by current technology in the 300 billion barrels for Alberta, Canada and a similar recoverable reserve for Venezuela. These vast heavy oil (defined as the liquid petroleum resource of less than 20° API gravity) deposits are found largely in unconsolidated sandstones, being high porosity permeable cohesionless sands with minimal grain to grain cementation. The hydrocarbons are extracted from the oil sands either by mining or in situ methods.

[0003] The heavy oil and bitumen in the oil sand deposits have high viscosity at reservoir temperatures and pressures. While some distinctions have arisen between tar or oil sands, bitumen and heavy oil, these terms will be used interchangeably herein. The oil sand deposits in Alberta, Canada extend over many square miles and vary in thickness up to hundreds of feet thick. Although some of these deposits lie close to the surface and are suitable for surface mining, the majority of the deposits are at depth ranging from a shallow depth of 150 feet down to several thousands of feet below ground surface. The oil sands located at these depths constitute some of the world’s largest presently known petroleum deposits. The oil sands contain a viscous hydrocarbon material, commonly referred to as bitumen, in an amount that ranges up to 15% by weight. Bitumen is effectively immobile at typical reservoir temperatures. For example at 15°C, bitumen has a viscosity of ~1,000,000 centipoise. However at elevated temperatures the bitumen viscosity changes considerably to be ~350 centipoise at 100°C. Down to ~10 centipoise at 180°C. The oil sand deposits have an inherently high permeability ranging from ~1 to 10 Darcy, thus upon heating, the heavy oil becomes mobile and can easily drain from the deposit.

[0004] Solvents applied to the bitumen soften the bitumen and reduce its viscosity and provide a non-thermal mechanism to improve the bitumen mobility. Hydrocarbon solvents consist of vaporized light hydrocarbons such as ethane, propane or butane or liquid solvents such as pipeline diluents, natural condensate streams or fractions of synthetic crudes. The diluent can be added to steam and flashed to a vapor state or be maintained as a liquid at elevated temperature and pressure, depending on the particular diluent composition. While in contact with the bitumen, the saturated solvent vapor dissolves into the bitumen. This diffusion process is due to the partial pressure difference between the saturated solvent vapor and the bitumen. As a result of the diffusion of the solvent into the bitumen, the oil in the bitumen becomes diluted and mobile and will flow under gravity. The resultant mobile oil may be deasphalted by the condensed solvent, leaving the heavy asphaltene behind within the oil sand pore space with little loss of inherent fluid mobility in the oil sands due to the small weight percent (5-15%) of the asphaltene fraction to the original oil in place. Deasphalting the oil from the oil sands produces a high quality product by 3°-5° API gravity. If the reservoir temperature is elevated the diffusion rate of the solvent into the bitumen is raised considerably being two orders of magnitude greater at 100°C compared to ambient reservoir temperatures of ~15°C.

[0005] In situ methods of hydrocarbon extraction from the oil sands consist of cold production, in which the less viscous petroleum fluids are extracted from vertical and horizontal wells with sand exclusion screens, CHOPS (cold heavy oil production system) cold production with sand extraction from vertical and horizontal wells with large diameter perforations thus encouraging sand to flow into the well bore, CSS (cyclic steam stimulation) a Huff and Puff cyclic steam injection system with gravity drainage of heated petroleum fluids using vertical and horizontal wells, steamflood using injector wells for steam injection and producer wells on 5 and 9 point layout for vertical wells and combinations of vertical and horizontal wells, SAGD (steam assisted gravity drainage) steam injection and gravity production of heated hydrocarbons using two horizontal wells, VAPEX (vapor assisted petroleum extraction) solvent vapor injection and gravity production of diluted hydrocarbons using horizontal wells, and combinations of these methods.

[0006] Cyclic steam stimulation and steamflood hydrocarbon enhanced recovery methods have been utilized worldwide, beginning in 1956 with the discovery of CSS, Huff and Puff or steam-soak in Meme Grande field in Venezuela and for steamflood in the early 1960s in the Kern River field in California. These steam assisted hydrocarbon recovery methods including a combination of steam and solvent are described in U.S. Pat. No. 3,739,852 to Woods et al, U.S. Pat. No. 4,280,559 to Best, U.S. Pat. No. 4,519,454 to McMillen, U.S. Pat. No. 4,697,642 to Vogel, and U.S. Pat. No. 6,708,759 to Leante et al. The CSS process raises the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance the surface area access of the steam to the bitumen. Successful steam injection cycles reenter earlier created fractures and thus the process becomes less efficient over time. CSS is generally practiced in vertical wells, but systems are operational in horizontal wells, but have complications due to localized fracturing and steam entry and the lack of steam flow control along the length of the horizontal well bore.

wells at the bottom of the hydrocarbon formation, with the injector well located approximately 10-15 feet vertically above the producer well. The steam injection pressures exceed the formation fracturing pressure in order to establish connection between the two wells and develop a steam chamber in the oil sand formation. Similar to CSS, the SAGD method has complications, albeit less severe than CSS, due to the lack of steam flow control along the long section of the horizontal well and the difficulty of controlling the growth of the steam chamber.

[0008] A thermal steam extraction process referred to a HASIDrive (heated annulus steam drive) and modifications thereof heat and degasify the heavy oils in situ in the presence of a metal catalyst. See U.S. Pat. No. 3,994,340 to Anderson et al., U.S. Pat. No. 4,696,345 to Hsueh, U.S. Pat. No. 4,706,751 to Gondouin, U.S. Pat. No. 5,054,551 to Dueksen, and U.S. Pat. No. 5,145,003 to Dueksen. It is disclosed that at elevated temperature and pressure the injection of hydrogen or a combination of hydrogen and carbon monoxide to the heavy oil in situ in the presence of a metal catalyst will degasify and thermal crack at least a portion of the petroleum in the formation.

[0009] Thermal recovery processes using steam require large amounts of energy to produce the steam, using either natural gas or heavy fractions of produced synthetic crude. Burning these fuels generates significant quantities of greenhouse gases, such as carbon dioxide. Also, the steam process uses considerable quantities of water, which even though may be reprocessed, involves recycling costs and energy use. Therefore less energy intensive oil recovery process is desirable.

[0010] Solvents applied to the bitumen soften the bitumen and reduce its viscosity and provide a non-thermal mechanism to improve the bitumen mobility. Hydrocarbon solvents consist of vaporized light hydrocarbons such as ethane, propane or butane or liquid solvents such as pipeline diluents, natural condensate streams or fractions of synthetic crudes. The diluent can be added to steam and flashed to a vapor state or be maintained as a liquid at elevated temperature and pressure, depending on the particular diluent composition. While in contact with the bitumen, the saturated solvent vapor dissolves into the bitumen. This diffusion process is due to the partial pressure difference in the saturated solvent vapor and the bitumen. As a result of the diffusion of the solvent into the bitumen, the oil in the bitumen becomes diluted and mobile and will flow under gravity. The resultant mobile oil may be deshafted by the condensed solvent, leaving the heavy asphaltenes behind within the oil sand pore space with little loss of inherent fluid mobility in the oil sands due to the small weight percent (5-15%) of the asphaltene fraction to the original oil in place. Deshafting the oil from the oil sands produces a high grade quality product by 3-5° API gravity. If the reservoir temperature is elevated the diffusion rate of the solvent into the bitumen is raised considerably being two orders of magnitude greater at 100° C. compared to ambient reservoir temperatures of ~15° C.

[0011] Solvent assisted recovery of hydrocarbons in continuous and cyclic modes is described including the VAPEX process and combinations of steam and solvent plus heat. See U.S. Pat. No. 4,450,913 to Allen et al., U.S. Pat. No. 4,513,819 to Islip et al., U.S. Pat. No. 5,407,009 to Butler et al., U.S. Pat. No. 5,607,016 to Butler, U.S. Pat. No. 5,899,274 to Frauenfeld et al., U.S. Pat. No. 6,318,464 to Mokryk, U.S. Pat. No. 6,769,486 to Lim et al., and U.S. Pat. No. 6,883,607 to Neniger et al. The VAPEX process generally consists of two horizontal wells in a similar configuration to SAGD; however, there are variations to this including spaced horizontal wells and a combination of horizontal and vertical wells. The startup phase for the VAPEX process can be lengthy and take many months to develop a controlled connection between the two wells and avoid premature short circuiting between the injector and producer. The VAPEX process with horizontal wells has similar issues to CSS and SAGD in horizontal wells, due to the lack of solvent flow control along the long horizontal well bore, which can lead to non-uniformity of the vapor chamber development and growth along the horizontal well bore.

[0012] Direct heating and electrical heating methods for enhanced recovery of hydrocarbons from oil sands and oil shales have been disclosed in combination with steam, hydrogen, catalysts and/or solvent injection at temperatures to ensure the petroleum fluids gravity drain from the formation and at significantly higher temperatures (300° to 400° range and above) to pyrolyze the oil shales. See U.S. Pat. No. 2,780,450 to Ljungström, U.S. Pat. No. 4,597,441 to Ware et al., U.S. Pat. No. 4,926,941 to Glandt et al., U.S. Pat. No. 5,046,559 to Glandt, U.S. Pat. No. 5,060,726 to Glandt et al., U.S. Pat. No. 5,297,626 to Vaneg et al., U.S. Pat. No. 5,392,854 to Vaneg et al., U.S. Pat. No. 6,722,431 to Carmona et al. In situ combustion processes have also been disclosed see U.S. Pat. No. 5,211,230 to Ostrovich et al., U.S. Pat. No. 5,339,897 to Leoutre, U.S. Pat. No. 5,413,224 to Laali, and U.S. Pat. No. 5,954,946 to Klazinga et al.

[0013] In situ processes involving downhole heaters are described in U.S. Pat. No. 2,634,961 to Ljungström, U.S. Pat. No. 2,732,195 to Ljungström, U.S. Pat. No. 2,780,450 to Ljungström. Electrical heaters are described for heating viscous oils in the forms of downhole heaters and electrical heating of tubing and/or casing, see U.S. Pat. No. 2,548,360 to Germain, U.S. Pat. No. 4,716,960 to Eastlund et al., U.S. Pat. No. 5,060,287 to Vaneg, U.S. Pat. No. 5,065,818 to Vaneg, U.S. Pat. No. 6,023,554 to Vinegar and U.S. Pat. No. 6,360,819 to Vinegar. Flameless downhole combustor heaters are described, see U.S. Pat. No. 5,255,742 to Mikus, U.S. Pat. No. 5,404,952 to Vinegar et al., U.S. Pat. No. 5,862,858 to Wellington et al., and U.S. Pat. No. 5,899,269 to Wellington et al. Surface fired heaters or surface burners may be used to heat a heat transferring fluid pumped downhole to heat the formation as described in U.S. Pat. No. 6,056,057 to Vinegar and U.S. Pat. No. 6,079,499 to Mikus et al.

[0014] The thermal and solvent methods of enhanced oil recovery from oil sands, all suffer from a lack of surface area access to the in place bitumen. Thus the reasons for raising steam pressures above the fracturing pressure in CSS and during steam chamber development in SAGD, are to increase surface area of the steam with the in place bitumen. Similarly the VAPEX process is limited by the available surface area to the in place bitumen, because the diffusion process at this contact controls the rate of softening of the bitumen. Likewise during steam chamber growth in the SAGD process the contact surface area with the in place bitumen is virtually a constant, thus limiting the rate of heating of the bitumen. Therefore both methods (heat and solvent) or a combination thereof would greatly benefit from a substantial increase in contact surface area with the in place bitumen. Hydraulic fracturing of low permeable reservoirs has been used to increase the efficiency of such processes and CSS methods involving fracturing are described in U.S. Pat. No. 3,739,852.
to Woods et al., U.S. Pat. No. 5,297,626 to Vinegar et al., and U.S. Pat. No. 5,392,854 to Vinegar et al. Also during initiation of the SAGD process overpressurized conditions are usually imposed to accelerate the steam chamber development, followed by a prolonged period of underpressurized condition to reduce the steam to oil ratio. Maintaining reservoir pressure during heating of the oil sands has the significant benefit of minimizing water inflow to the heated zone and to the wellbore.

[0015] Electrical resistive heating of oil shale and oil sand formations utilizing a hydraulic fracture filled with an electrically conductive material are described in U.S. Pat. No. 3,137,347 to Parker, involving a horizontal hydraulic fracture filled with conductive propellant and with the use of two (2) wells to electrically energize the fracture and raise the temperature of the oil shale to pyrolyze the organic matter and produce hydrocarbons from a third well, in U.S. Pat. No. 5,620,049 to Gipson et al. with a single well configuration in a hydrocarbon formation predominantly a vertical fracture filled with conductive temperature setting resin coated propellant and the electric current passes through the conductive propellant to a surface ground and the single well is completed to raise the temperature of the oil in-situ to reduce its viscosity and produce hydrocarbons from the same well, in U.S. Pat. No. 6,148,911 to Gipson et al. with a single well configuration in a gas hydrate formation with predominantly a horizontal fracture filled with conductive propellant and the electric current passes through the conductive propellant to a surface ground, raising the temperature of the formation to release the methane from the gas hydrates and the single well is completed for methane production, in U.S. Pat. No. 7,331,358 to Symington et al. in U.S. Pat. No. 7,631,691 to Symington et al. and in Canadian Patent No 2,738,873 to Symington et al. all with a predominantly vertical fracture filled with conductive propellant and the conductive fracture is electrically energized by contact with at least two (2) wells or in the case of a single well presumably through the well and surface ground with the oil shale raised to a temperature to pyrolyze the organic matter into producible hydrocarbons, with the electrically conductive fracture composed of electrically conductive propellant and non-electrically conductive non-permeable cement in the single well systems described above all suffer from low efficiency and high energy loss due to the current passes through a significant distance of the formation from the conductive fracture to the surface ground. Also the systems with two or more wellbores do not disclosed how the electrode to conductive fracture contact will be other than a point contact resulting in significant energy loss and overheating at such a contact.

[0016] It is well known that extensive heavy oil reservoirs are found in formations comprising unconsolidated, weakly cemented sediments. Unfortunately, the methods currently used for extracting the heavy oil from these formations have not produced entirely satisfactory results. Heavy oil is not very mobile in these formations, and so it would be desirable to be able to form increased permeability planes in the formations and by injecting steam or solvents into these planes and/or by direct electrical resistive heating of the plate, heating the formation and thus increase the mobility of the heavy oil in the formation and by drainage through the permeable planes to the wellbore for production up the well.

[0017] However, techniques used in hard, brittle rock to form fractures therein are typically not applicable to ductile formations comprising unconsolidated, weakly cemented sediments. The method of controlling the azimuth of a vertical hydraulic planar inclusion in formations of unconsolidated or weakly cemented soils and sediments by slotting the well bore or installing a pre-slotted or weakened casing at a predetermined azimuth has been disclosed. The method disclosed that a vertical hydraulic planar inclusion can be propagated at a pre-determined azimuth in unconsolidated or weakly cemented sediments and that multiple orientated vertical hydraulic planar inclusions at differing azimuths from a single well bore can be initiated and propagated for the enhancement of petroleum fluid production from the formation. See U.S. Pat. No. 6,216,783 to Hocking et al., U.S. Pat. No. 6,443,227 to Hocking et al., U.S. Pat. No. 6,991,037 to Hocking, U.S. Pat. No. 7,404,441 to Hocking, U.S. Pat. No. 7,640,975 to Cavender et al., U.S. Pat. No. 7,748,458 to Schultze et al., U.S. Pat. No. 7,814,978 to Steele et U.S. Pat. No. 7,832,477 to Cavender et al., U.S. Pat. No. 7,866,395 to Hocking, U.S. Pat. No. 7,950,456 to Cavender et al., U.S. Pat. No. 8,151,874 to Schultze et al. The method disclosed that a vertical hydraulic planar inclusion can be propagated at a pre-determined azimuth in unconsolidated or weakly cemented sediments and that multiple orientated vertical hydraulic planar inclusions at differing azimuths from a single well bore can be initiated and propagated for the enhancement of petroleum fluid production from the formation. It is now known that unconsolidated or weakly cemented sediments behave substantially different from brittle rocks from which most of the hydraulic fracturing experience is found. The above methods cited, disclose a method to create a planar inclusion that is parallel to the borehole axis, and these methods do not disclose how such an inclusion can be initiated and propagated orthogonal to the borehole axis.

[0018] The methods disclosed above find especially beneficial application in ductile rock formations made up of unconsolidated or weakly cemented sediments, in which it is typically very difficult to obtain directional or geometric control over inclusions as they are being formed. Weakly cemented sediments are primarily frictional materials since they have minimal cohesive strength. An unconsolidated sand having no inherent cohesive strength (i.e., no cement bonding holding the sand grains together) cannot contain a stable crack within its structure and cannot undergo brittle fracture. Such materials are categorized as frictional materials which fail under shear stress, whereas brittle cohesive materials, such as strong rocks, fail under normal stress.

[0019] The term "cohesion" is used in the art to describe the strength of a material at zero effective mean stress. Weakly cemented materials may appear to have some apparent cohesion due to suction or negative pore pressures created by capillary attraction in fine grained sediment, with the sediment being only partially saturated. These suction pressures hold the grains together at low effective stresses and, thus, are often called apparent cohesion.

[0020] The suction pressures are not true bonding of the sediment's grains, since the suction pressures would dissipate due to complete saturation of the sediment. Apparent cohesion is generally such a small component of strength that it cannot be effectively measured for strong rocks, and only becomes apparent when testing very weakly cemented sediments.

[0021] Geological strong materials, such as relatively strong rock, behave as brittle materials at normal petroleum reservoir depths, but at great depth (i.e. at very high confining
stress) or at highly elevated temperatures, these rocks can behave like ductile frictional materials. Unconsolidated sands and weakly cemented formations behave as ductile frictional materials from shallow to deep depths, and the behavior of such materials are fundamentally different from rocks that exhibit brittle fracture behavior. Ductile frictional materials fail under shear stress and consume energy due to frictional sliding, rotation and displacement.

[0022] Conventional hydraulic dilation of weakly cemented sediments is conducted extensively on petroleum reservoirs as a means of sand control. The procedure is commonly referred to as “Frac-and-Pack.” In a typical operation, the casing is perforated over the formation interval intended to be fractured and the formation is injected with a treatment fluid of low gel loading without proppant, in order to form the desired two winged structure of a fracture. Then, the proppant loading in the treatment fluid is increased substantially to yield tip screen-out of the fracture. In this manner, the fracture tip does not extend further, and the fracture and perforations are backfilled with proppant.

[0023] The process assumes a two winged fracture is formed as in conventional brittle hydraulic fracturing. However, such a process has not been duplicated in the laboratory or in shallow field trials. In laboratory experiments and shallow field trials what has been observed is chaotic geometries of the injected fluid, with many cases evidencing cavity expansion growth of the treatment fluid around the well and with deformation or compaction of the host formation.

[0024] Weakly cemented sediments behave like a ductile frictional material in yield due to the predominantly frictional behavior and the low cohesion between the grains of the sediment. Such materials do not “fracture” and, therefore, there is no inherent fracturing process in these materials as compared to conventional hydraulic fracturing of strong brittle rocks.

[0025] Linear elastic fracture mechanics is not generally applicable to the behavior of weakly cemented sediments. The knowledge base of propagating viscous planar inclusions in weakly cemented sediments is primarily from recent experience over the past ten years and much is still not known regarding the process of viscous fluid propagation in these sediments.

[0026] Accordingly, there is a need for a method and apparatus for enhancing the extraction of hydrocarbons from oil sands by constructing vertical planar permeable inclusions with planes that are orthogonal to the borehole axis and are thus of greater assistance in enhancing recovery methods such as SAGD. The SAGD system with such inclusions installed would not require a steam circulation period to hydraulically connect the injector and producer wells, since startup in SAGD mode with the permeable inclusions would be immediate. Also these inclusions would penetrate horizontal shale layers, which otherwise may be a barrier to upward steam chamber growth and limit SAGD production and impair its performance. The vertical permeable inclusions extending through such shale layers would greatly enhance SAGD performance. The immediate drainage and increase in effective drainage height due to the vertical permeable inclusions will also enhance the productivity and lower the SOR of the SAGD system.

SUMMARY OF THE INVENTION

[0027] The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by initiating and propagating vertical permeable inclusions in a plane substantially orthogonal to the borehole axis. These inclusions containing proppant are thus highly permeable and enhance drainage of heavy oil from the formation, and also by steam injection into these planes, enhance oil recovery by heating the oil sand formation, the heavy oil and bitumen, which will drain under gravity and be produced. In one embodiment of this invention, multiple propped vertical inclusions are constructed at various locations along a substantially horizontal wellbore by dilation of the formation in the plane of the intended inclusion by radial expansion and axial extension of the formation by an expanding packer system that expands both radially and axially. In another embodiment of the invention, the expansion device is part of a casing string or liner and is in contact with the formation by a swellable elastomer, or by a cement or polymer based grout. The expansion device is expanded by an inflatable packer and the device expands both radially outward and axially in the axial direction, giving rise to a dilated extensional plane in the formation which is substantially orthogonal to the well bore axis. Injected fluid propagates preferentially in this dilated and extensional plane within the formation. The vertical inclusions are propagated to intersect and connect with neighboring horizontal wells to eliminate the non-productive startup phase of SAGD. Also the inclusion could be filled with an electrically conductive proppant and fibers and by placing an alternating current through the inclusions heat the inclusions by electrical resistive heating and thus heat the oil sand formation.

[0028] Although the present invention contemplates the formation of vertical propped inclusions which generally extend laterally away from a substantially near horizontal well penetrating an earth formation and in a generally vertical plane, those skilled in the art will recognize that the invention may be carried out in earth formations wherein the inclusions and the well bores can extend in directions other than horizontal, and/or that the well bore axis could vary in orientation and depth along its length.

[0029] Other objects, features and advantages of the present invention will become apparent upon reviewing the following description of the preferred embodiments of the invention, when taken in conjunction with the drawings and the claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0030] FIG. 1 is a schematic isometric view of a horizontal well system and associated method embodying principles of the present invention;
[0031] FIG. 2 is a schematic isometric view of a dual expanding packer system, that expands both radially and axially;
[0032] FIG. 3 is a schematic isometric view of the casing expansion device with weakening slots and latches to limit the extent of opening and inhibit closure;
[0033] FIG. 4 is a schematic isometric view of the casing expansion device expanded by an inflatable packer.

DETAILED DESCRIPTION OF THE DISCLOSED EMBODIMENT

[0034] Several embodiments of the present invention are described below and illustrated in the accompanying drawings. The present invention involves a method and apparatus for enhanced recovery of petroleum fluids from the sub-
face by construction of propped vertical inclusions in the oil sand formation from a substantially horizontal wellbore for enhancing drainage of heavy oil from the formation and/or to provide a means of injecting steam, thus heating the oil sand formation and the heavy oil and bitumen in situ, and at much reduced viscosity the hydrocarbon flow by gravity drainage to the well and are produced to surface.

[0035] It is well known that extensive heavy oil reservoirs are found in formations comprising unconsolidated, weakly cemented sediments. Unfortunately, the methods currently used for extracting the heavy oil from these formations have not produced entirely satisfactory results. Heavy oil is not very mobile in these formations, and so it would be desirable to be able to form highly permeable planes in the formations and by injecting steam or solvents into the permeable planes, heating the formation and in-situ hydrocarbons and thus increase the mobility of the heavy oil in the formation and by gravity drainage through the permeable planes to the wellbore for production up the well.

[0036] Representatively illustrated in FIG. 1 is a well system 10 and associated method which embody principles of the present invention. The system 10 is particularly useful for constructing permeable planes 18 in a formation 14. The formation 14 may comprise unconsolidated and/or weakly cemented sediments for which conventional fracturing operations are not well suited. The term “heavy oil” is used herein to indicate relatively high viscosity and high density hydrocarbons, such as bitumen. Heavy oil is typically not recoverable in its natural state (e.g., without heating or diluting) via wells, and may be either mined or recovered via wells through use of steam and solvent injection, in situ combustion, etc. Gas-free heavy oil generally has a viscosity of greater than 100 centipoise and a density of less than 20 degrees API gravity (greater than about 900 kilograms/cubic meter).

[0037] As depicted in FIG. 1, a substantially horizontal well has been drilled into the formation 14 and the well casing 11 has been cemented in the formation 14. The term “casing” is used herein to indicate a protective lining for a wellbore. Any type of protective lining may be used, including those known to persons skilled in the art as liner, casing, tubing, etc. Casing may be segmented or continuous, jointed or unjointed, conductor or non-conductor made of any material (such as steel, aluminum, polymers, composite materials, etc.), and may be expanded or unexpanded, etc.

[0038] The horizontal well casing string 11 has expansion devices 12 interconnected therein. The expansion device 12 operates to expand the casing string 11 radially outward and axially in extension and thereby dilate the formation 14 proximate the device, in order to initiate forming of generally vertical and planar inclusion 18 extending outwardly from the wellbore in a plane substantially orthogonal to the well axis. Suitable expansion devices for use in the well system 10 for initiating and propagating inclusions on planes parallel to the well axis are described in U.S. Pat. Nos. 6,216,783, 6,330, 914, 6,443,227, 6,991,037, 7,404,441, 7,640,975, 7,640,982, 7,748,458, 7,814,978, 7,832,477, 7,866,395, 7,950,456 and 8,151,874. The entire disclosures of these prior patents are incorporated herein by this reference. The current invention differs from the earlier cited disclosures, in that the expansion devices expands both radially outward and also in extension axially, to develop a dilated extensional zone in the formation substantially orthogonal to the wellbore axis. Other expansion devices may be used in the well system 10 in keeping with the principles of the invention.

[0039] Once the device 12 is operated to expand the casing string 11 radially outward and extensionally axially, fluid 22 is injected into the dilated formation 14 to propagate the inclusions 18 into the formation. It is not necessary for the inclusions 18 to be formed simultaneously. Shown in FIG. 1 are three (3) inclusions 18 in the well system 10, positioned at differing locations along the well. The well system 10 does not necessarily need to consist of three (3) inclusions at the same depth oriented at the same azimuth, but could consist of numerous vertical planar inclusions at various azimuths at the same depth as would be the case if the well was curved in plan, with such choice of the number of inclusions constructed depending on the application, formation type and/or economic benefit. Also there is only one inclusion shown at each distinct position along the well; whereas that inclusion could intersect and coalesce with an inclusion on the same azimuth from a neighboring well.

[0040] Typically, the inclusions 18 located furthest from the well head are constructed first, with each inclusion 18 injected independently as progressed up the well. As the inclusions 18 are propagated into the formation 14, the inclusions 18 may intersect and coalesce with previous installed inclusions on similar azimuths from nearby well. These earlier placed inclusions acts as a pore pressure sink and thus attract and accelerate the propagation of the inclusion 18, so as to intersect with the earlier nearby installed inclusion. The formation 14, pore space may contain a significant portion of immobile heavy oil or bitumen generally up to a maximum oil saturation of 90%; however, even at these very high oil saturations of 90%, i.e. very low water saturation of 10%, the mobility of the formation pore water is quite high, due to its viscosity and the formation permeability. The well system 10 is shown with inclusions 18 constructed at only a single depth, this well system 10 is cited as only one example of the invention, since there could be alternate forms of the invention containing numerous number of inclusions constructed at progressively shallower depths from shallow wells, depending on the formation thickness, the distribution of hydrocarbons within the formation 14, and/or economic benefit.

[0041] The injected fluid 22 carries the proppant to the extremities of the inclusions 18. Upon propagation of the inclusions 18 to their required lateral and vertical extent, the thickness of the inclusions 18 may need to be increased by utilizing the process of tip screen out. The tip screen out process involves modifying the proppant loading and/or inject fluid 22 properties to achieve a proppant bridge at the inclusion tips. The injected fluid 22 is further injected after tip screen out, but rather then extending the inclusion laterally or vertically, the injected fluid 22 widens, i.e. thickens, and fills the inclusion from the inclusion tips back to the wellbore.

[0042] The behavioral characteristics of the injected viscous fluid 22 are preferably controlled to ensure the propagating viscous inclusions maintain their azimuth directionality, such that the viscosity of the injected fluid 22 and its volumetric rate are controlled within certain limits depending on the formation 14, proppant 20 specific gravity and size distribution. For example, the viscosity of the injected fluid 22 is preferably greater than approximately 100 centipoise. However, if foamed fluid is used, a greater range of viscosity and injection rate may be permitted while still maintaining directional and geometric control over the inclusions. The viscosity and volumetric rate of the injected fluid 22 need to be sufficient to transport the proppant 20 to the extremities of the inclusions. The size distribution of the proppant 20 needs
to be matched with that of the formation 14, to ensure formation fines do not migrate into the propped pack inclusion during hydrocarbon production. Typical size distribution of the proppant would range from #12 to #20 U.S. Mesh for oil sand formations, with an ideal proppant being sand or ceramic beads. Ceramic beads coated with a resin such as phenol formaldehyde, being heat hardenable, is capable of mechanically binding the proppant together 21 in the presence of steam without loss of permeability of the propped inclusion.

As depicted in FIG. 2, is one configuration of the well system 10, with the expansion device 12 consisting of two (2) inflatable packers 15 lowered into an open wellbore on a tubing string 13. The inflatable packers are expanded radially outward to contact the formation 14, then expanded further radially outwards but also pushed axially apart 15, to place the formation in a dilatation and extensional state in a plane orthogonal to the well axis. Injected fluids 22 are injected into the formation and propagate preferentially in this dilated and extensional plane created by the expansion device 12 and thus form the inclusion 18.

The formation 14 could be comprised of relatively hard and brittle rock, but the system 10 and method find especially beneficial application in ductile rock formations made up of unconsolidated or weakly cemented sediments, in which it is typically very difficult to obtain directional or geometric control over inclusions as they are being formed.

However, the present disclosure provides information to enable those skilled in the art of hydraulic fracturing, soil and rock mechanics to practice a method and system 10 to initiate and control the propagation of a viscous fluid in weakly cemented sediments, and importantly for the propagating inclusion to intersect and coalesce with earlier placed permeable inclusions and thus form a continuous planar inclusion with a particular azimuth from within a single well or between multiple wells.

The system and associated method are applicable to formations of weakly cemented sediments with low cohesive strength compared to the vertical overburden stress prevailing at the depth of interest. Low cohesive strength is defined herein as no greater than 3 MegaPascal (MPa) plus 0.4 times the mean effective stress (p') in MPa at the depth of propagation.

\[ c = 3 \text{ MPa} + 0.4p' \]  

where c is cohesive strength in MPa and p' is mean effective stress in the formation.

Examples of such weakly cemented sediments are sand and sandstone formations, mudstones, shales, and siltstones, all of which have inherent low cohesive strength. Critical state soil mechanics assists in defining when a material is behaving as a cohesive material capable of brittle fracture or when it behaves predominantly as a ductile frictional material.

Weakly cemented sediments are also characterized as having a soft skeleton structure at low effective mean stress due to the lack of cohesive bonding between the grains. On the other hand, hard strong stiff rocks will not substantially decrease in volume under an increment of load due to an increase in mean stress.

In the art of poroelasticity, the Skempton B parameter is a measure of a sediment's characteristic stiffness compared to the fluid contained within the sediment's pores. The Skempton B parameter is a measure of the rise in pore pressure in the material for an incremental rise in mean stress under undrained conditions.

In stiff rocks, the rock skeleton takes on the increment of mean stress and thus the pore pressure does not rise, i.e., corresponding to a Skempton B parameter value of at or about 0. But in a soft soil, the soil skeleton deforms easily under the increment of mean stress and, thus, the increment of mean stress is supported by the pore fluid under undrained conditions (corresponding to a Skempton B parameter of at or about 1).

The following equations illustrate the relationships between these parameters in equations denoted as (2) as follows:

\[ 
\Delta u = B\Delta p \\
B = (K_n - K)/(\alpha K_o) \\
\alpha = 1 - (K/K_o) 
\]

where \( \Delta u \) is the increment of pore pressure, B the Skempton B parameter, \( \Delta p \) the increment of mean stress, \( K_n \) is the undrained formation bulk modulus, \( K \) the drained formation bulk modulus, \( \alpha \) is the Biot-Willis poroelastic parameter, and \( K_o \) is the bulk modulus of the formation grains. In the system and associated method, the bulk modulus \( K \) of the formation for inclusion propagation is preferably less than approximately 5 GPa.

For use of the system 10 and method in weakly cemented sediments, preferably the Skempton B parameter is as follows with \( p' \) in MPa:

\[ B = 0.95e^{0.04(0.04 p' + 0.008p')} \]

The system and associated method are applicable to formations of weakly cemented sediments (such as tight gas sands, mudstones and shales) where large extensive propped vertical permeable drainage planes are desired to intersect thin sand lenses and provide drainage paths for greater gas production from the formations. In weakly cemented formations containing heavy oil (viscosity>100 centipoise) or bitumen (extremely high viscosity>100,000 centipoise), generally known as oil sands, propped vertical permeable drainage planes provide drainage paths for cold production from these formations, and access for steam, solvents, oils, and heat to increase the mobility of the petroleum hydrocarbons and thus aid in the extraction of the hydrocarbons from the formation. In highly permeable weak sand formations, permeable drainage planes of large lateral length result in lower drawdown of the pressure in the reservoir, which reduces the fluid gradients acting towards the wellbore resulting in less drag on fines in the formation and resulting in reduced flow of formation fines into the wellbore.

Propellant is carried by the injected fluid, resulting in a highly permeable planar inclusion. Such propellants are typically clean sand or specialized manufactured particles (generally ceramic in composition), and depending on the size composition, closure stress and propellant type, the permeability of the fracture can be controlled. Either type of propellant could be resin coating to provide for bounding between propellant particles 21 at elevated temperatures and also to reduce the steam dissolution of the particle over time. The permeability of the propped inclusions 18 will typically be orders of magnitude greater than the formation 14 permeability, generally at least two orders of magnitude.
The injected fluid 22 varies depending on the application and can be water, oil or multi-phased based gels. Aqueous based fracturing fluids consist of a polymeric gelling agent such as solvatable (or hydratable) polysaccharide, e.g. galactomannan gums, glycomannan gums and cellulose derivatives. The purpose of the hydratable polysaccharides is to thicken the aqueous solution and thus act as viscosifiers, i.e. increase the viscosity by 100 times or more over the base aqueous solution. A cross-linking agent can be added which further increases the viscosity of the solution. The borate ion has been used extensively as a cross-linking agent for hydrated guar gums and other galactomannans, see U.S. Pat. No. 3,059,909 to Wise. Other suitable cross-linking agents are chromium, iron, aluminum, and zirconium (see U.S. Pat. No. 3,301,723 to Chrip) and titanium (see U.S. Pat. No. 3,888,312 to Tinea et al.). A breaker is added to the solution to controllably degrade the viscous fracturing fluid. Common breakers are enzymes and catalyzed oxidizer breaker systems, with weak organic acids sometimes used.

An enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 3. This view depicts another embodiment of the system 10, consisting of an expansion device 12 that is connected to the casing string 11 and the casing 11 is either cemented in the wellbore or the expansion device 12 is coated with a swellable elastomer, swellable in the presence of water or paraffins or swellable on the application of heat. Such swellable elastomers are commonly used for the production of hydrocarbons for a variety of well completion systems. By either means the expansion device 12 is in contact with the formation 14. The expansion device 12 could be constructed from a variety of materials, but a yieldable metal, such as steel is considered a preferred choice. The expansion device 12 has slots cut through its thickness in the axial direction as axial slots 31 and in the circumferential direction as circumferential slots 32. The slots 31, 32 are either machined, or cut by laser or waterjet, are narrow in width in the range of 0.040" to 0.080" approximately 1" to 1 1/2" in length, depending on the diameter of the expansion device 12 and the intended application. The slots 31, 32 could be cut through the entire thickness of the expansion device 12, or only partially cut through the depth of the expansion device wall thickness.

The slots 31, 32 shown consist of three (3) rows of slots offset from each other both along and orthogonal to the slot orientation, but could be different multiples of slots depending on the opening amount required. The axial slots 31 are shown as four (4) sets of slots 31 being oriented 90° apart. Depending on the casing diameter and application the axial slots 31 could consist of any number of sets of slots, e.g. three (3) sets 120° apart or six (6) sets 60° apart. Likewise the circumferential slots 32 are shown as three (3) sets of slots, whereas there could be any number of sets of circumferential slots 32, from one (1) set and upwards depending on the required opening, casing diameter and application. Straps, latches and braces 33, 34, 35, are welded to the expansion device 12 and restrict the amount of opening of the slots 31, 32 and upon their opening inhibit closure. The straps, latches or braces could be strips of strain hardening material, such as stainless steel, that provides for all the slots to open evenly and inhibit closure of the slots, due to the stainless steel high strain before failure and its strain hardening properties. Alternate latches have been cited earlier in the incorporated references and consist of latches that lock in place upon a certain amount of opening, inhibit further opening and hold the slot locked in the open position and inhibit closure of the slots.

An enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 4. This view depicts the expansion device 12 of the system 10, consisting of a casing string 11 grouted into the formation 14 by cement or in contact with the formation by a swellable elastomer. A packer 15 connected to tubing 13 is lowered into the well and the packer 15 is set in proximity to the expansion device 12. The packer 15 is inflated to give rise to yielding of the slots 31, 32 and activation of the straps, latches and braces 33, 34, 35, so that the expansion device 12 expands radially outward due to the axial slots 31 but also extends axially externally due to the circumferential slots 32. The radial expansion and axial extension of the expansion device 12 develops a zone in the formation 14 substantially orthogonal to the wellbore axis in a dilated and extensional state for the preferential propagation of injected fluids 22 to propagate in the formation to form the inclusions 18.

The pore pressure gradients at the tips of the inclusions 18 result in liquefaction, cavitation (degassing) or fluidization of the formation 14 immediately surrounding the tips. That is, the formation 14 in the dilating zone about the tips acts like a fluid since its strength, fabric and in situ stresses have been destroyed by the fluidizing process, and this fluidized zone in the formation immediately ahead of the viscous fluid 22 propagating tips is a planar path of least resistance for the viscous fluid to propagate further. In at least this manner, the system 10 and associated method provide for directional and geometric control over the advancing inclusions 18.

The behavioral characteristics of the injected viscous fluid 22 are preferably controlled to ensure the propagating viscous fluid does not overrun the fluidized zone and lead to a loss of control of the propagating process. Thus, the viscosity of the fluid 22 and the volumetric rate of injection of the fluid should be controlled to ensure that the conditions described above persist while the inclusions 18 are being propagated through the formation 14. The propagation rate of the inclusion 18 due to the injected fluid 22, varies depending on direction, in general due to gravitation effects, the lateral tip propagation rate is generally much greater than the upward tip propagation rate and the downward tip propagation rate. However, these tips propagation rates can change due to heterogeneities in the formation 14, pore pressure gradients especially associated with pore pressure sinks, and stress, stiffness and strength contrasts in the formation 14.

Finally, it will be understood that the preferred embodiment has been disclosed by way of example, and that other modifications may occur to those skilled in the art without departing from the scope and spirit of the appended claims.

1. A method of forming at least one inclusion in a subterranean formation, the method comprising the steps of: installing an expansion control device in a wellbore with a well casing; expanding the device both radially outward and axially in extension in the wellbore, and inject fluid into the formation.

2. The method of claim 1, wherein the expansion control device includes dual inflation packers placed in an open wellbore.
3. The method of claim 1, wherein the expansion control device includes an expansion casing segment interconnected to the well casing, with the expansion casing segment in contact with the formation.

4. The method of claim 3, wherein the expansion casing segment is in contact with the formation by placing an infill material between the casing segment and the formation before the expansion step.

5. The method of claim 4, wherein the infill material is a swellable elastomer.

6. The method of claim 4, wherein the infill material is a cement based grout.

7. The method of claim 4, wherein the infill material is a polymer based grout.

8. The method of claim 3, wherein the expansion casing segment is expanded by an inflatable packer.

9. The method of claim 3, wherein the expansion step of the casing segment includes widening of at least one axially aligned opening in a sidewall of the casing section, and widening at least one circumferentially aligned opening in the sidewall of the casing section, displacing latch members in circumferential and axial directions respectively, the widening being a first direction; and preventing a narrowing of the openings after the expansion step, the latch members resisting displacement thereof in a second narrowing direction opposite to the first widening direction.

10. (canceled)

11. The method of claim 9, wherein the expansion step further comprises limiting a width of the axial and circumferential openings.

12. The method of claim 11, wherein the width limiting step includes engaging a stop member with a shoulder, and further comprising the step of integrally forming the stop member and latch member.

13. The method of claim 11, wherein the width limiting step includes yielding a strain hardening latch member.

14. The method of claim 9, wherein the latch member is attached to the casing section on a first side of the opening, and wherein at least one shoulder is attached to the casing section on a second side of the opening opposite from the first side of the opening.

15. The method of claim 11, wherein the resisting displacement step further comprises the latch member engaging the shoulder.

16. The method of claim 15, wherein the shoulder is formed adjacent at least one aperture in the expansion control device for each opening, and wherein the expansion step further comprises drawing the latch member through the aperture.

17. The method of claim 15, wherein the shoulder is formed on an abutment structure of the expansion control device attached to the casing section.

18. The method of claim 17, wherein the abutment structure includes multiple shoulders and apertures extending longitudinally along and circumferentially around the casing section.

19. The method of claim 18, wherein the expansion control device includes multiple latch members configured for engagement with the multiple shoulders.

20. The method of claim 9, wherein the expansion step further comprises forming the openings by parting the casing section sidewall along at least one axial and one circumferential slot formed in the sidewall, and wherein the slot extends only partially through the casing section sidewall.

21. The method of claim 9, wherein the expansion step further comprises forming the openings by parting the casing section sidewall along at least one axial and one circumferential slot formed in the sidewall, and wherein the slot extends completely through the casing section sidewall.

22. The method of claim 21, further comprising a separate strip of material extending across the slot, and wherein the expansion step further comprises parting the strip.