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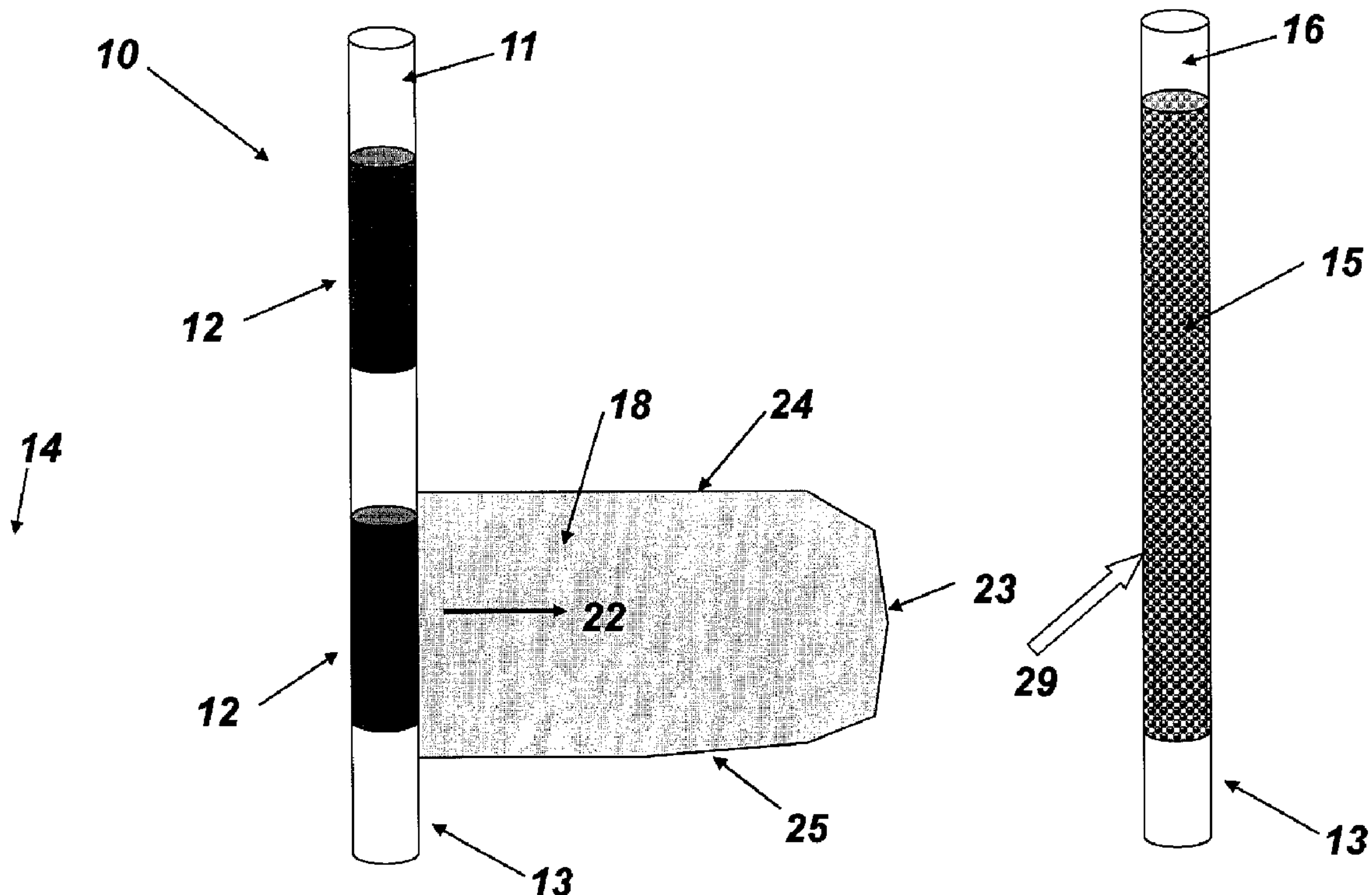
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(54) Titre : RECUPERATION D'HYDROCARBURES AMELIOREE A PARTIR DE PUITs MULTIPLES PAR INJECTION DE VAPEUR DANS DES FORMATIONS DE SABLES BITUMINEUX

(54) Title: ENHANCED HYDROCARBON RECOVERY FROM MULTIPLE WELLS BY STEAM INJECTION OF OIL SAND FORMATIONS



(57) Abrégé/Abstract:

The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by steam injection into highly permeable vertical inclusion planes in the oil sand formation, and heating the heavy oil and bitumen, which flow by



(57) **Abrégé(suite)/Abstract(continued):**

gravity to the wells. The inclusion is propagated into a portion of the formation having a Skempton's B parameter of greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p is a mean effective stress in MPa at the depth of the inclusion. The inclusion planes can be propagated from only the central well, or from all wells, being the central well and the periphery wells. The inclusion planes are propagated into the formation to intersect and coalesce to provide hydraulic connection between the central well and the periphery wells. Steam is injected continuously in the central well, and liquids are produced continuously from all wells, whilst maintaining a liquid head over production tubing for steam trap control. By injection of solvents and other gases and controlling the reservoir temperature and pressure, a particular fraction of the in situ hydrocarbon reserve is extracted and water inflow into the heated zone is minimized.

5 **ENHANCED HYDROCARBON RECOVERY FROM MULTIPLE WELLS BY
STEAM INJECTION OF OIL SAND FORMATIONS**

ABSTRACT OF THE DISCLOSURE

10 The present invention is a method and apparatus for enhanced recovery of petroleum
fluids from the subsurface by steam injection into highly permeable vertical inclusion planes in
the oil sand formation, and heating the heavy oil and bitumen, which flow by gravity to the
wells. The inclusion is propagated into a portion of the formation having a Skempton's B
parameter of greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa
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the central well and the periphery wells. Steam is injected continuously in the central well, and
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production tubing for steam trap control. By injection of solvents and other gases and
20 controlling the reservoir temperature and pressure, a particular fraction of the in situ hydrocarbon
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**ENHANCED HYDROCARBON RECOVERY FROM MULTIPLE WELLS BY
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TECHNICAL FIELD

The present invention generally relates to enhanced recovery of petroleum fluids from the subsurface by steam injection into permeable propped vertical inclusions, thereupon heating the oil sand formation and the viscous heavy oil and bitumen in situ, with steam injection and liquid
15 production both being continuous processes, resulting in increased production of petroleum fluids from the subsurface formation. Steam is injected in a central well, and liquids are produced from the central and periphery wells. By operating the process at near ambient reservoir pressure, minimizes water inflow into the heated zone and well bore,

20 **BACKGROUND OF THE INVENTION**

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
25 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

5 cohesionless sands with minimal grain to grain cementation. The hydrocarbons are extracted from the oils sands either by mining or in situ methods.

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
10 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
15 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
20 Darcy, thus upon heating, the heavy oil becomes mobile and can easily drain from the deposit.

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
25 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

5 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 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
10 the asphaltene fraction to the original oil in place. Deasphalting 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.

In situ methods of hydrocarbon extraction from the oil sands consist of cold production,
15 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
20 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
25 methods.

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-

5 soak in Mene 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. Patent No. 3,739,852 to *Woods et al*, U.S. Patent No.
4,280,559 to *Best*, U.S. Patent No. 4,519,454 to *McMillen*, U.S. Patent No. 4,697,642 to *Vogel*,
and U.S. Patent No. 6,708,759 to *Leaute et al*. The CSS process raises the steam injection
10 pressure above the formation fracturing pressure to create fractures within the formation and
enhance the surface area access of the steam to the bitumen. Successive 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
15 along the long length of the horizontal well bore.

Descriptions of the SAGD process and modifications are described in U.S. Patent No.
4,344,485 to *Butler*, and U.S. Patent No. 5,215,146 to *Sanchez* and thermal extraction methods in
U.S. Patent No. 4,085,803 to *Butler*, U.S. Patent No. 4,099,570 to *Vandergrift*, and U.S. Patent
No. 4,116,275 to *Butler et al*. The SAGD process consists of two horizontal wells at the bottom
20 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
25 difficulty of controlling the growth of the steam chamber.

A thermal steam extraction process referred to a HASDrive (heated annulus steam drive)
and modifications thereof heat and hydrogenate the heavy oils insitu in the presence of a metal

5 catalyst. See U.S. Patent No. 3,994,340 to *Anderson et al.*, U.S. Patent No. 4,696,345 to *Hsueh*,
U.S. Patent No. 4,706,751 to *Gondouin*, U.S. Patent No. 5,054,551 to *Duerksen*, and U.S. Patent
No. 5,145,003 to *Duerksen*. 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 hydrogenate and thermal crack at least a portion of the
10 petroleum in the formation.

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,
15 involves recycling costs and energy use. Therefore a less energy intensive oil recovery process is
desirable.

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
20 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
25 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 asphaltenes behind within the oil sand pore space with little loss of inherent

5 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 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.

10 Solvent assisted recovery of hydrocarbons in continuous and cyclic modes are described including the VAPEX process and combinations of steam and solvent plus heat. See U.S. Patent No. 4,450,913 to *Allen et al*, U.S. Patent No. 4,513,819 to *Islip et al*, U.S. Patent No. 5,407,009 to *Butler et al*, U.S. Patent No. 5,607,016 to *Butler*, U.S. Patent No. 5,899,274 to *Frauenfeld et al*, U.S. Patent No. 6,318,464 to *Mokrys*, U.S. Patent No. 6,769,486 to *Lim et al*, and U.S. Patent
15 No. 6,883,607 to *Nenniger 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.
20 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.

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
25 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 pyrolysis the oil shales. See U.S. Patent No. 2,780,450 to *Ljungström*, U.S. Patent No. 4,597,441 to *Ware*

5 *et al*, U.S. Patent No. 4,926,941 to *Glandt et al*, U.S. Patent No. 5,046,559 to *Glandt*, U.S. Patent
 No. 5,060,726 to *Glandt et al*, U.S. Patent No. 5,297,626 to *Vinegar et al*, U.S. Patent No.
 5,392,854 to *Vinegar et al*, U.S. Patent No. 6,722,431 to *Karanikas et al*. In situ combustion
 processes have also been disclosed see U.S. Patent No. 5,211,230 to *Ostapovich et al*, U.S.
 Patent No. 5,339,897 to *Leaute*, U.S. Patent No. 5,413,224 to *Laali*, and U.S. Patent No.
 10 5,954,946 to *Klazinga et al*.

In situ processes involving downhole heaters are described in U.S. Patent No. 2,634,961
 to *Ljungström*, U.S. Patent No. 2,732,195 to *Ljungström*, U.S. Patent 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. Patent No. 2,548,360 to *Germain*,
 15 U.S. Patent No. 4,716,960 to *Eastlund et al*, U.S. Patent No. 5,060,287 to *Van Egmond*, U.S.
 Patent No. 5,065,818 to *Van Egmond*, U.S. Patent No. 6,023,554 to *Vinegar* and U.S. Patent No.
 6,360,819 to *Vinegar*. Flameless downhole combustor heaters are described, see U.S. Patent No.
 5,255,742 to *Mikus*, U.S. Patent No. 5,404,952 to *Vinegar et al*, U.S. Patent No. 5,862,858 to
Wellington et al, and U.S. Patent No. 5,899,269 to *Wellington et al*. Surface fired heaters or
 20 surface burners may be used to heat a heat transferring fluid pumped downhole to heat the
 formation as described in U.S. Patent No. 6,056,057 to *Vinegar et al* and U.S. Patent No.
 6,079,499 to *Mikus et al*.

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
 25 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

5 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
10 increase the efficiency of such processes and CSS methods involving fracturing are described in U.S. Patent No. 3,739,852 to *Woods et al*, U.S. Patent No. 5,297,626 to *Vinegar et al*, and U.S. Patent 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.
15 Maintaining reservoir pressure during heating of the oil sands has the significant benefit of minimizing water inflow to the heated zone and to the well bore.

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. Patent No. 3,137,347 to *Parker*, involving a horizontal hydraulic fracture filled with conductive proppant and with the
20 use of two (2) wells to electrically energizing the fracture and raise the temperature of the oil shale to pyrolyze the organic matter and produce hydrocarbon from a third well, in U.S. Patent 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 proppant and the electric current passes through the conductive proppant to a surface ground and the
25 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. Patent No. 6,148,911 to *Gipson et al*. with a single well configuration in a gas hydrate formation with predominantly a horizontal fracture

5 filled with conductive proppant and the electric current passes through the conductive proppant 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. Patent No. 7,331,385 to *Symington et al.* in U.S. Patent 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
10 proppant 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 proppant and non-electrically conductive non-permeable cement. The single well systems described above all
15 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.

20 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 into these planes, heating
25 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. Steam injection into multiple azimuth vertical permeables planes has been disclosed earlier in U.S. Patent No.

5 7,591,306 to *Hocking*; however the method cited is for a single well being both a steam injector and liquids producer, whereas the current invention contains multiple wells with the significant advantage of much faster production and lower SOR.

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. Patent No. 6,216,783 to *Hocking et al*, U.S. Patent No. 6,443,227 to *Hocking et al*, U.S. Patent No. 6,991,037 to *Hocking*, U.S. Patent No. 7,404,441 to *Hocking*, U.S. Patent No. 7,640,975 to *Cavender et al.*, U.S. Patent No. 7,640,982 to *Schultz et al.*, U.S. Patent No. 7,748,458 to *Hocking*, U.S. Patent No. 7,814,978 to *Steele et al.*, U.S. Patent No. 7,832,477 to *Cavender et al.*, U.S. Patent No. 7,866,395 to *Hocking*, U.S. Patent No. 7,950,456 to *Cavender et al.*, U.S. Patent No. 8,151,874 to *Schultz 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

5 sediments behave substantially different from brittle rocks from which most of the hydraulic fracturing experience is founded.

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.

10 Weakly cemented sediments are primarily frictional materials since they have minimal cohesive strength. An uncemented 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.

15 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.

20 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.

Geological strong materials, such as relatively strong rock, behave as brittle materials at
25 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

5 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.

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
10 "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
15 are backfilled with proppant.

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
20 treatment fluid around the well and with deformation or compaction of the host formation.

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.

25 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

5 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.

Accordingly, there is a need for a method and apparatus for enhancing the extraction of hydrocarbons from oil sands in a single well and in multiple wells by steam injection into permeable vertical inclusions combined with gas and/or solvent injection or a mixture thereof
10 and controlling the subsurface environment, both temperature and pressure to optimize the hydrocarbon extraction in terms of produced rate, efficiency and produced product quality, as well as limit water inflow into the process zone.

SUMMARY OF THE INVENTION

15 The present invention is a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by injecting steam into multiple vertical inclusion planes containing proppant in the oil sand formation and thus heating the heavy oil and bitumen, which drain under gravity and are produced to the surface. In one embodiment of this invention, multiple propped vertical inclusions are constructed at various azimuths from a central well and propagate into the
20 oil sand formation and filled with a proppant. The vertical inclusions are propagated to intersect and connect with circumferential wells, on azimuth and depth from the central well. Additional vertical inclusions filled with the same proppant are initiated in the central well at progressively shallower depths but on azimuth with the lower propped inclusions, such that they propagate laterally and vertical into the formation and intersect and coalesce with the lower inclusions, and
25 intersect the on azimuth circumference well. Steam is injected in the central well, heating the inclusions and oil sand formation, lowering the viscosity of the heavy oil and bitumen, which flows by gravity to all wells, where it is produced to the surface.

5 In another embodiment multiple propped vertical inclusions are constructed at various azimuths from a central well and propagate into the oil sand formation and filled with a proppant. Vertical inclusions filled with the same proppant are constructed from circumferential wells, on azimuth and depth to intersect and coalesce with the inclusions from the central well. Additional vertical inclusions filled with the same proppant are initiated in the central well at
10 progressively shallower depths but on azimuth with the lower propped inclusions, such that they propagate laterally and vertical into the formation and intersect and coalesce with the lower inclusions. Additional vertical inclusions filled with the same proppant are initiated in the circumferential wells at progressively shallower depths but on azimuth with the lower propped inclusions, such that they propagate laterally and vertical into the formation and intersect and
15 coalesce both with the lower inclusion and the inclusions from the central well. Steam is injected in the central well, heating the inclusions and oil sand formation, lowering the viscosity of the heavy oil and bitumen, which flows by gravity to all wells, where it is produced to the surface.

 The heating of the formation and in place heavy oil and bitumen is via the condensing steam and in order to limit loss of heat by conduction to overlying formations, a non condensing
20 gas can be injected to remain in the uppermost portions of the heated process zone. The steam injection is planned to be continuous at near ambient reservoir pressures to limit water inflow into the heated zone, with the continuous extraction of liquids.

 Although the present invention contemplates the formation of vertical propped inclusions which generally extend laterally away from a vertical or near vertical well penetrating an earth
25 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 fractures and the well bores can extend in directions other than vertical.

5 Therefore, the present invention provides a method and apparatus for enhanced recovery of petroleum fluids from the subsurface by steam injection into propped permeable inclusions, thereupon heating the oil sand formation and the viscous heavy oil and bitumen in situ, which drain under gravity and are produced to the surface.

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

5 BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic isometric view of a multiple well system and associated method embodying principles of the present invention with a central injection well and circumferential relief wells;

10 FIG. 2 is a schematic isometric view of a multiple well system and associated method embodying principles of the present invention with a central injection well and circumferential injection wells;

FIG. 3 is a schematic isometric view of the multiple well system with a lower inclusion propagating towards a circumferential relief well;

15 FIG. 4 is a schematic isometric view of the multiple well system with a completed lower inclusion intersecting a circumferential relief well;

FIG. 5 is a schematic isometric view of the multiple well system completed with a lower inclusion, and an upper inclusion propagating towards a circumferential relief well;

FIG. 6 is a schematic isometric view of the multiple well system with completed lower and upper inclusions intersecting a circumferential relief well;

20 FIG. 7 is a schematic isometric view of the multiple well system with a first lower inclusion propagating towards a circumferential injection well;

FIG. 8 is a schematic isometric view of the multiple well system with the completed first lower inclusion, and a second lower inclusion propagating from the circumferential injection well towards the first inclusion;

25 FIG. 9 is a schematic isometric view of the multiple well system with a completed lower inclusion, and an upper inclusion propagating towards a circumferential injection well;

5 FIG. 10 is a schematic isometric view of the multiple well system with completed lower and upper inclusions.

5 DETAILED DESCRIPTION OF THE DISCLOSED EMBODIMENT

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 subsurface by steam injection into propped vertical inclusions in the oil sand formation, and 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 wells and are produced to surface.

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 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 wells.

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 producing heavy oil **42** from 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

5 than 100 centipoise and a density of less than 20 degrees API gravity (greater than about 900 kilograms/cubic meter).

As depicted in FIG. 1, a central vertical well has been drilled into the formation 14 and the well casing 11 has been cemented in the formation 14, and circumferential vertical wells have been drilled into the formation and the well casings 16 have been cemented into 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, conductive or non-conductive made of any material (such as steel, aluminum, polymers, composite materials, etc.), and may be expanded or unexpanded, etc.

15 The central well casing string 11 has an expansion device 12 and a sump section 13 interconnected therein. The circumferential relief wells casing string 16 have an open section 15 and a sump section 13 interconnected therein. The open section 15 could be a perforated section of the casing, a screen, slotted liner, etc providing hydraulic connection between the circumferential well and the formation 14. The open section 15 of the well is maintained at a lower pressure and independently of the injected fluid 22 pressure. The expansion device 12 operates to expand the casing string 11 radially outward and thereby dilate the formation 14 proximate the device, in order to initiate forming of generally vertical and planar inclusions 18 extending outwardly from the wellbore at various azimuths. Suitable expansion devices for use in the well system 10 are described in U.S. Patent Nos. 6,216,783, 6,330,914, 6,443,227, 25 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

5 this reference. Other expansion devices may be used in the well system **10** in keeping with the principles of the invention.

Once the device **12** is operated to expand the casing string **11** radially outward, fluid **22** is forced 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** is an eight (8) wing inclusion well system **10**, with eight (8) inclusions **18** formed. The well system **10** does not necessarily need to consist of eight (8) inclusions at the same depth orientated at various azimuths, but could consist of one, two, three, four, five, six or even seven vertical planar inclusions at various azimuths at the same depth, 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 at a particular azimuth, whereas there could be other upper inclusions on the same azimuth, and in fact there could be numerous of these upper inclusions at progressively shallower depths.

Typically, the lower inclusions **18** are constructed first, with each wing of the eight (8) inclusions **18** injected independently of the others. As the inclusions **18** are propagated into the formation **14**, the open section **15** of the on azimuth circumferential well acts as a pore pressure sink and thus attracts and accelerates the lateral propagation of the inclusion **18**, so as to intersect with the circumferential relief well, and thus stop the lateral propagation of the 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 open section **15** allows mobile formation pore fluids and the injected fluid **22** to enter the relief well at **15** at a

5 reduced pressure, with 15 being at a lower pressure and independent of the injected fluid 22 pressure. Upon the inclusions reaching the open section 15, its lateral tip propagation will stop. 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 of upper inclusions constructed at progressively shallower
10 depths, depending on the formation thickness, the distribution of hydrocarbons within the formation 14, and/or economic benefit.

The injected fluid 22 carries the proppant to the extremes 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
15 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 than 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 well bore.

The behavioral characteristics of the injected viscous fluid 22 are preferably controlled to
20 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
25 while still maintaining directional and geometric control over the inclusions. The viscosity and volumetric rate of the injected fluid 22 needs 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

5 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
10 of permeability of the propped inclusion.

The well system **10**, has steam injected **31** in the central well through a vacuum insulated tubing **32** placed inside of the casing **11**. . Heated heavy oil and bitumen will thus be mobilized and flow under gravity through the inclusions and the formation towards the wells and enter the sumps **13** and pumped to surface via a PCP (progressive cavity pump), ESP (electrical
15 submersible pump), gas lift or natural lift **41**, depending on operating temperatures, pressures and depth, via a production tubing **40** in all of the wells, both the central well and the circumferential wells.

The selected range of temperatures and pressures to operate the process will depend on reservoir depth, ambient conditions, quality of the in place heavy oil and bitumen, and the
20 presence of nearby water bodies. The process can be operated at a low temperature range of $\sim 100^{\circ}\text{C}$ for a heavy oil rich oil sand deposit and at a moderate temperature range of $\sim 150^{\circ}\text{C}$ - 180°C for a bitumen rich oil sand deposit, basically to reduce the heavy oil and bitumen viscosity and thus mobilized the in place oil. However, the process can be operated at much higher temperatures $>270^{\circ}\text{C}$ to pyrolysis the in place hydrocarbon in the presence of H_2 , CO and/or
25 catalysts. Thus the proppant could contain such catalysts, or these catalysts could be incorporated into a canister in line with the production tubing in the well. Such catalysts are really available as

5 HDS (hydrodesulfurization) metal containing catalysts, and FCC (fluid catalytic cracking) rare earth aluminum silica catalysts.

The operating pressure of the process may be selected to closely match the ambient reservoir conditions to minimize water inflow into the process zone and the well bore by the injection of steam, gas or vaporized solvent. The process zone can be injected with a vaporized
10 hydrocarbon solvent, such as ethane, propane or butane and mixed with a diluent gas, such as methane, nitrogen and carbon dioxide. The solvent will contact the in situ bitumen at the edge of the process zone, diffusive into and soften the bitumen, so that it flows by gravity to the well bore. Dissolved solvent and product hydrocarbon are produced and further solvent and diluent gas injected into the process zone. The elevated temperature of the process zone will
15 significantly accelerate the diffusion process of the solvent diffusing into the bitumen compared to ambient reservoir conditions. The solvent and diluent gas will be injected at near reservoir pressures to minimize water inflow into the process zone. The solvent vapor in the injection gas is maintained saturated at or near its dew point at the process operating temperatures and pressures.

20 As depicted in FIG. 2, is an alternate configure of the well system 10, with all wells being vertical injection wells as regards proppant injection, drilled into the formation 14 and the central well casing 11 has been cemented in the formation 14, and circumferentially vertical wells have been drilled into the formation 14 and the well casings 17 have been cemented into the formation 14. In this configuration, typically the multiple propped vertical inclusions 18 are constructed at
25 various azimuths first from the central well and propagate into the oil sand formation 14, filled with a proppant, and the injection of the propagating fluid 22 is stopped when the inclusion is approximately midway between the central well and its circumferential well. The fluid in the

5 lowermost inclusion 18 loses its viscosity over time due to breakers placed in the injected fluid
22. Common breakers consist of enzymes, catalyzed oxidizers, and organic acids. 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
10 its viscosity and the formation permeability. Thus during propagation of the opposing inclusion
18' from the circumferential well, the inclusion 18 pore fluid's viscosity is low due to the action
of the breaker, then inclusion 18 acts a large pore pressure sink, due to size, relative permeability
to the formation, mobility of its and the formation's pore fluids, and hydraulic connection to the
central well, resulting in the intersection and coalescence of 18' and 18 irrespective of slight
15 discrepancies in their azimuthal orientations.

The well system 10 does not necessarily need to consist of eight (8) inclusions at the
same depth orientated at various azimuths, but could consist of one, two, three, four, five, six or
even seven vertical planar inclusions at various azimuths at the same depth, with such choice of
the number of inclusions constructed depending on the application, formation type and/or
20 economic benefit. Also there is only one inclusion at a particular azimuth, whereas there could
be other upper inclusions on the same azimuth, and in fact there could be numerous of these
upper inclusions at progressively shallower depths.

The well system 10, has steam injected 31 in the central well through a vacuum insulated
tubing 32 placed inside of the casing 11. . Heated heavy oil and bitumen will thus be mobilized
25 and flow under gravity through the inclusions and the formation towards the wells and enter the
sumps 13 and pumped to surface via a PCP (progressive cavity pump), ESP (electrical
submersible pump), gas lift or natural lift 41, depending on operating temperatures, pressures and

5 depth, via a production tubing 40 in all of the wells, both the central well and the circumferential wells.

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
10 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
15 form a continuous planar inclusion on 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 MegaPascas (MPa)
20 plus 0.4 times the mean effective stress (p') in MPa at the depth of propagation.

$$c < 3MPa + 0.4p' \quad (1)$$

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
25 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.

5 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.

10 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.

15 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:

$$\begin{aligned}
 \Delta u &= B \Delta p \\
 B &= (K_u - K) / (\alpha K_u) \\
 \alpha &= 1 - (K / K_s)
 \end{aligned}
 \tag{2}$$

20 where Δu is the increment of pore pressure, B the Skempton B parameter, Δp the increment of mean stress, K_u is the undrained formation bulk modulus, K the drained formation bulk modulus, α is the Biot-Willis poroelastic parameter, and K_s 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.

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

$$B > 0.95 \exp(-0.04 p') + 0.008 p' \quad (3)$$

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, resulting in reduced flow of formation fines into the wellbore.

20 Proppant is carried by the injected fluid, resulting in a highly permeable planar inclusion. Such proppants are typically clean sand or specialized manufactured particles (generally ceramic in composition), and depending on the size composition, closure stress and proppant type, the permeability of the fracture can be controlled. Either type of proppant could be resin coating to provide for bonding between proppant 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 by two orders of magnitude.

5 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
10 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. Patent No. 3,059,909 to *Wise*. Other suitable cross-linking agents are chromium, iron, aluminum, and zirconium (see U.S. Patent No. 3,301,723 to *Chrisp*) and titanium (see U.S. Patent No. 3,888,312 to *Tiner et al*). A breaker is added to the
15 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 the system **10** during the propagation of only one of the lowermost inclusions **18**, to provide a clearer description of the process used to construct the system **10**. The
20 viscous fluid propagation process in these sediments involves the unloading of the formation **14** in the vicinity of the tips **23, 24, 25** of the propagating viscous fluid **22**, causing dilation of the formation **14**, which generates pore pressure gradients towards this dilating zone. As the formation **14** dilates at the tips **23, 24, 25** of the advancing viscous fluid **22**, the pore pressure decreases dramatically at the tips, resulting in increased pore pressure gradients surrounding the
25 tips.

 The pore pressure gradients at the tips **23, 24, 25** of the inclusion **18** result in the liquefaction, cavitation (degassing) or fluidization of the formation **14** immediately surrounding

5 the tips. That is, the formation **14** in the dilating zone about the tips **23, 24, 25** 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 **23, 24, 25** 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
10 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
15 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 **23** propagation rate is generally much greater than the upward tip **24** propagation rate and the downward tip **25** propagation rate. However, these tips **23, 24, 25** propagation rates can change due to heterogeneities in the formation **14**, pore pressure gradients
20 especially associated with pore pressure sinks, and stress, stiffness and strength contrasts in the formation **14**.

During propagation of the inclusion **18**, the pore pressure in the overall formation **14** will rise due to the injection of the fluid **22**. As the inclusion **18** propagates, the open section **15** of the on azimuth circumferential relief well acts as a pore pressure sink, and mobile formation pore
25 fluids and injected fluid **22** flow towards **15** as shown by **29**. The open section **15** thus attracts and accelerates the lateral tip **23** propagation rate of the inclusion **18**. The inclusion **18** grows

5 laterally towards the open section 15, and upon reaching the relief well, the inclusion lateral tip propagation stops.

Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 4. The inclusion 18 has intersected the circumferential relief well and its lateral propagation has stopped. By shutting in the circumferential relief well, the inclusion 18
10 can be thickened if desired by the process of tip screen-out.

Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 5. This view depicts the system 10 during the propagation of only one of the uppermost inclusions 19, to provide a clearer description of the process used to construct the system 10. The lowermost inclusion 18 has been constructed to its final dimension, and the fluid
15 within the inclusion 18 has lost its viscosity due to breakers placed in the injected fluid 22. Common breakers consist of enzymes, catalyzed oxidizers, and organic acids. 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
20 its viscosity and the formation permeability. Thus during propagation of the uppermost inclusion 19, and provided the lowermost inclusion pore fluid's viscosity is low due to the action of the breaker, then the lowermost inclusion 18 acts a large pore pressure sink, due to size, relative permeability to the formation, mobility of its and the formation's pore fluids, as does the open section 15 in the circumferential relief well.

25 During propagation of the uppermost inclusion 19, the pore pressure in the overall formation will rise due to the injection of the fluid 22. The lowermost inclusion 18 will act as a pore pressure sink and thus attract and accelerate the downward propagating tip 28, and ensure

5 that the propagating uppermost inclusion **19** intersects and coalesces with the lowermost inclusion **18**, even if there are slight discrepancies in their respective azimuthal orientations. Upon coalescence of the downward propagating tip **28** with the lowermost inclusion **18**, the tip **28** will stop propagating in the area of coalescence due to leakoff of the injected fluid **22** to the highly permeable pore pressure sink, inclusion **18**. As the inclusion **19** further propagates, the
10 open section **15** of the on azimuth circumferential relief well acts as a pore pressure sink, and mobile formation pore fluids and injected fluid **22** flow towards **15** as shown by **29**. The open section **15** thus attracts and accelerates the lateral tip **26** propagation rate of the inclusion **19**. The inclusion **19** grows laterally towards the open section **15**, and upon reaching the relief well, the inclusion lateral tip propagation stops. At completion of the injection of fluid **22** in inclusions **19**,
15 the system **10** configuration will contain continuous vertical coalescence of inclusions **18** with its respective on azimuth inclusions **19**.

Referring further to an enlarged scale isometric view of the system **10** is representatively illustrated in FIG. **6**. The inclusion **19** has intersected and coalesced with the lower inclusion **18**, and intersected the circumferential relief well and thus its lateral propagation has stopped. By
20 shutting in the circumferential relief well, the inclusion **19** can be thickened if desired by the process of tip screen-out.

Referring further to an enlarged scale isometric view of the system **10** is representatively illustrated in FIG. **7** in an alternate configuration. In this alternate configuration, the circumferential well is an injection well and not a relief well as shown earlier in FIG. **2**. The
25 lower inclusion **18** is propagating into the formation and the injection fluid **22** flow rate is stopped when the inclusion is approximately midway between the central well and the

5 circumferential injection well. The inclusion 18 can be thickened at this stage by the process of tip screen-out if desired.

Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 8. This view depicts the system 10 during the propagation of the lowermost inclusion 18' from the circumferential injection well. The lowermost inclusion 18 has been
10 constructed to its final dimension, and the fluid within the inclusion 18 has lost its viscosity due to breakers placed in the injected fluid 22. Common breakers consist of enzymes, catalyzed oxidizers, and organic acids. 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
15 the formation pore water is quite high, due to its viscosity and the formation permeability. Thus during propagation of the lowermost inclusion 18', and provided the lowermost inclusion pore fluid's viscosity is low due to the action of the breaker, then the lowermost inclusion 18 acts a large pore pressure sink, due to size, relative permeability to the formation, mobility of its and the formation's pore fluids, resulting in the intersect and coalescence of 18' and 18 irrespective
20 of slight discrepancies in their azimuthal orientations.

Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 9. This view depicts the system 10 during the propagation of only one of the uppermost inclusions 19, to provide a clearer description of the process used to construct the system 10. The lowermost inclusions 18 and 18' have been constructed to their final dimensions,
25 and the fluid within the inclusions 18 and 18' have lost its viscosity due to breakers placed in the injected fluid 22. Thus during propagation of the uppermost inclusion 19, and provided the lowermost inclusions pore fluid's viscosity is low due to the action of the breaker, then the

5 lowermost inclusions 18 and 18' acts as large pore pressure sinks, due to size, relative permeability to the formation, mobility of its and the formation's pore fluids. Thus inclusion 19 intersects and coalesces with inclusions 18 and 18'. The injected fluid 22 flow rate is stopped once the inclusion 19 is approximately midway between the central well and the circumferential injection well.

10 Referring further to an enlarged scale isometric view of the system 10 is representatively illustrated in FIG. 10. This view depicts the system 10 for the completion of all inclusions, 18, 18', 19, 19' showing the coalescence of the inclusions both vertically and laterally.

 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
15 from the scope and spirit of the appended claims.

WE CLAIM:

1. A method of improving production of hydrocarbon liquids from a subterranean formation of weakly cemented sediments, the method comprising the steps of:
 - a) propagating a substantially vertical first inclusion by injecting a fluid filled with proppant particles into the formation in a first preferential direction having an azimuth from a substantially vertical central wellbore intersecting the formation;
 - b) after the viscosity of the injected fluid in the first inclusion has substantially reduced, propagating a substantially vertical second inclusion filled with proppant particles in the same but opposite preferential direction as the first inclusion initiated from a circumferential wellbore, the second vertical inclusion to intersect and coalesce with the first vertical inclusion in the same formation;
 - c) injecting steam into the central wellbore and into a process zone in the formation; and
 - d) producing heated hydrocarbon liquids up the wellbores.
2. The method of claim 1, wherein the method includes propagating a plurality of first and second inclusions at varying azimuths and a plurality of circumferential wellbores at the same varying azimuths.
3. The method of claim 1 or 2, wherein the method includes propagating a plurality of inclusions propagated from the wellbores at progressively shallower depths after the viscosity of the injected fluid in the immediate lower inclusion has reduced substantially, so that the shallower depth inclusions intersect and coalesce with the inclusions immediately beneath on their respective azimuths.

4. The method of claim 3, wherein the method includes propagating a plurality of inclusions at varying azimuths and a plurality of circumferential wellbores at the same varying azimuths.
5. The method of any one of claims 1 to 4, wherein the proppant particles ranging in size from #4 to #100 U.S. mesh are sand, ceramic beads, resin coated sand and resin coated ceramic beads or mixture thereof.
6. The method of any one of claims 1 to 5, wherein the steam injection is a continuous injection, and the production of hydrocarbon liquids is also continuous.
7. The method of any one of claims 1 to 6, wherein the steam injection is a pressure pulsed cyclic injection or intermittent injection.
8. The method of any one of claims 1 to 7, wherein steam pressure in the process zone is at ambient reservoir pressure.
9. The method of any one of claims 1 to 8, wherein the method includes injecting into the process zone a non-condensing gas or a hydrocarbon solvent in a vaporized state or a mixture thereof.
10. The method of claim 9, wherein the solvent is one of a group of ethane, propane, butane or a mixture thereof.
11. The method of claim 9 or 10, wherein the solvent is mixed with a diluent gas.
12. The method of claim 11, wherein the diluent gas is non-condensable under the process conditions.
13. The method of claim 12, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbon liquid than the saturated hydrocarbon solvent.

14. The method of any one of claims 11 to 13, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas or a mixture thereof.
15. The method of any one of claims 1 to 14, wherein the method includes injecting a hydrogenizing gas into the wellbore and thus into the fluids in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the hydrocarbon fluids in the process zone.
16. The method of claim 15, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.
17. The method of claim 15 or 16, wherein the method includes catalyzing the hydrogenation and thermal cracking reactions of at least a portion of the petroleum fluids in the process zone.
18. The method of claim 17, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.
19. The method of claim 18, wherein the catalyst is contained in a canister in tubing inside of the wellbore.
20. The method of claim 18 or 19, wherein the proppant particles in the inclusions contain the catalyst for the hydrogenation and thermal cracking reactions.
21. A method of improving production of hydrocarbon liquids from a subterranean formation of weakly cemented sediments, the method comprising the steps of:
 - a) propagating a substantially vertical first inclusion by injecting a fluid filled with proppant particles into the formation in a first preferential direction at an azimuth from a substantially vertical central wellbore intersecting the formation;

- b) propagating the substantially vertical first inclusion to intersect a circumferential relief wellbore operated at a reduced pressure and on azimuth with the propagating inclusion;
 - c) injecting steam into the central wellbore and into a process zone in the formation; and
 - d) producing the heated hydrocarbon liquids up the wellbores.
22. The method of claim 21, wherein the method includes propagating a plurality of first inclusions at varying azimuths and a plurality of circumferential relief wellbores at the same varying azimuths.
23. The method of claim 21 or 22, wherein the method includes propagating a plurality of inclusions propagated from the central wellbore at progressively shallower depths after the viscosity of the injected fluid in the immediately lower inclusion has substantially reduced, so that the shallower depth inclusions intersect and coalesce with the inclusions immediately beneath on their respective azimuths.
24. The method of claim 23, wherein the method includes propagating a plurality of inclusions at varying azimuths and a plurality of circumferential relief wellbores at the same varying azimuths.
25. The method of any one of claims 21 to 24, wherein the proppant particles ranging in size from #4 to #100 U.S. mesh are sand, ceramic beads, resin coated sand and resin coated ceramic beads or mixture thereof.
26. The method of any one of claims 21 to 25, wherein the steam injection is a continuous injection, and the production of hydrocarbon liquids is also continuous.
27. The method of any one of claims 21 to 26, wherein the steam injection is a pressure pulsed cyclic injection or intermittent injection.

28. The method of any one of claims 21 to 27, wherein steam pressure in the process zone is at ambient reservoir pressure.
29. The method of any one of claims 21 to 28, wherein the method includes injecting into the process zone a non-condensing gas or a hydrocarbon solvent in a vaporized state or a mixture thereof.
30. The method of claim 29, wherein the solvent is one of a group of ethane, propane, butane or a mixture thereof.
31. The method of claim 29 or 30, wherein the solvent is mixed with a diluent gas.
32. The method of claim 31, wherein the diluent gas is non-condensable under the process conditions.
33. The method of claim 32, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbon deposit liquid than the saturated hydrocarbon solvent.
34. The method of claim 33, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas or a mixture thereof.
35. The method of any one of claims 21 to 34, wherein the method includes injecting a hydrogenizing gas into the wellbore and thus into the fluids in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the petroleum fluids in the process zone.
36. The method of claim 35, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.
37. The method of claim 35 or 36, wherein the method includes catalyzing the hydrogenation and thermal cracking of at least a portion of the petroleum fluids in the process zone.

38. The method claim 37, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.
39. The method of claim 38, wherein the catalyst is contained in a canister in tubing inside of the wellbore.
40. The method of claim 38 or 39, wherein the proppant particles in the inclusions contain the catalyst for the hydrogenation and thermal cracking reactions.
41. The method of any one of claims 1 to 20, wherein a portion of the formation in which the first inclusion is formed has a Skempton B parameter greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the first inclusion and the water saturation in the formation pores is greater or equal to 10%.
42. The method of any one of claims 21 to 41, wherein a portion of the formation in which the first inclusion is formed has a Skempton B parameter greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the first inclusion and the water saturation in the formation pores is greater or equal to 10%.
43. A production well system for improving production of hydrocarbon liquids from a subterranean formation of weakly cemented sediments having an ambient reservoir pressure and temperature comprising:
- a) a substantially vertical central bore hole in the formation to a predetermined depth;
 - b) an injection casing grouted in the central bore hole depth to create a substantially vertical central wellbore, the injection casing being radially expandable by the introduction of a fluid;

- c) a substantially vertical first inclusion created by injecting a fluid filled with proppant particles into the formation in a first preferential direction having an azimuth from the substantially vertical central wellbore intersecting the formation;
 - d) a substantially vertical circumferential bore hole in the formation to a predetermined depth;
 - e) an injection casing grouted in the circumferential bore hole depth to create a substantially vertical circumferential wellbore, the injection casing being radially expandable by the introduction of a fluid;
 - f) a substantially vertical second inclusion created by injecting the fluid filled with proppant particles from the circumferential wellbore, the second inclusion oriented in the same but opposite preferential direction as the first inclusion and oriented to intersect and coalesce with the first vertical inclusion in the same formation after the viscosity of the injected fluid in the first inclusion has substantially reduced, wherein the first inclusion and the second inclusion to form a process zone; and
 - g) means for injecting steam into the central wellbore and into the process zone in the formation, thereby producing heated hydrocarbon liquids up the wellbores.
44. The production well system of claim 43, wherein the production well system includes a plurality of first and second inclusions at varying azimuths and a plurality of circumferential wellbores at the same varying azimuths.
45. The production well system of claim 43 or 44, wherein the production well system includes a plurality of inclusions propagated from the central and circumferential wellbores at progressively shallower depths after the viscosity of the injected fluid in the immediate lower

inclusion has reduced substantially, so that the shallower depth inclusions intersect and coalesce with the inclusions immediately beneath on their respective azimuths.

46. The production well system of claim 45, wherein the production well system includes propagating a plurality of inclusions at varying azimuths and a plurality of circumferential wellbores at the same varying azimuths.
47. The production well system of any one of claims 43 to 46, wherein the proppant particles ranging in size from #4 to #100 U.S. mesh are sand, ceramic beads, resin coated sand, and resin coated ceramic beads or mixture thereof.
48. The production well system of any one of claims 43 to 47, wherein the means for injecting the steam injects the steam continuously, and the production of hydrocarbon liquids is also continuous.
49. The production well system of any one of claims 43 to 48, wherein the means for injecting the steam injects the steam intermittently as a pressure pulsed cycle.
50. The production well system of any one of claims 43 to 49, wherein steam pressure in the process zone is at ambient reservoir pressure.
51. The production well system of any one of claims 43 to 50, wherein the production well system includes means for injecting into the process zone a non-condensing gas, a hydrocarbon solvent in a vaporized state, or a mixture thereof.
52. The production well system of claim 51, wherein the solvent is one of a group of ethane, propane, butane, or a mixture thereof.
53. The production well system of claim 51 or 52, wherein the solvent is mixed with a diluent gas.

54. The production well system of claim 53, wherein the diluent gas is non-condensable under the process conditions.
55. The production well system of claim 54, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbon liquid than the saturated hydrocarbon solvent.
56. The production well system of any one of claims 53 to 55, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas, or a mixture thereof.
57. The production well system of any one of claims 43 to 56, wherein the production well system includes means for injecting a hydrogenizing gas into the central wellbore and thus into the fluids in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the hydrocarbon fluids in the process zone.
58. The production well system of claim 57, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.
59. The production well system of claim 57 or 58, wherein the production well system includes means for catalyzing the hydrogenation and thermal cracking reactions of at least a portion of the petroleum fluids in the process zone.
60. The production well system of claim 59, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.
61. The production well system of claim 60, wherein the catalyst is contained in a canister in tubing inside of the central wellbore.
62. The production well system of claim 60 or 61, wherein the proppant particles in the inclusions contain the catalyst for the hydrogenation and thermal cracking reactions.

63. A production well system for improving production of hydrocarbon liquids from a subterranean formation of weakly cemented sediments having an ambient reservoir pressure and temperature comprising:
- a) a substantially vertical central bore hole in the formation to a predetermined depth;
 - b) an injection casing grouted in the central bore hole depth to create a substantially vertical central wellbore, the injection casing being radially expandable by the introduction of a fluid;
 - c) a substantially vertical circumferential relief bore hole in the formation to a predetermined depth;
 - d) an injection casing grouted in the circumferential relief bore hole depth to create a substantially vertical circumferential relief wellbore, the injection casing being radially expandable by the introduction of a fluid;
 - e) a substantially vertical first inclusion created by injecting a fluid filled with proppant particles into the formation in a first preferential direction at an azimuth from the substantially vertical central wellbore intersecting the formation, wherein the substantially vertical first inclusion intersects the circumferential relief wellbore operated at a reduced pressure and on azimuth with the first inclusion form a process zone; and
 - f) means for injecting steam into the central wellbore and into the process zone in the formation, thereby producing the heated hydrocarbon liquids up the wellbores.
64. The production well system of claim 63, wherein the production well system includes a plurality of first inclusions at varying azimuths and a plurality of circumferential relief wellbores at the same varying azimuths.

65. The production well system of claim 63 or 64, wherein the production well system includes a plurality of inclusions propagated from the central wellbore at progressively shallower depths after the viscosity of the injected fluid in the immediately lower inclusion has substantially reduced, so that the shallower depth inclusions intersect and coalesce with the inclusions immediately beneath on their respective azimuths.
66. The production well system of claim 65, wherein the production well system includes propagating a plurality of inclusions at varying azimuths and a plurality of circumferential relief wellbores at the same varying azimuths.
67. The production well system of any one of claims 63 to 66, wherein the proppant particles ranging in size from #4 to #100 U.S. mesh are sand, ceramic beads, resin coated sand, and resin coated ceramic beads or mixture thereof.
68. The production well system of any one of claims 63 to 67, wherein the means for injecting the steam injects the steam continuously, and the production of hydrocarbon liquids is also continuous.
69. The production well system of any one of claims 63 to 68, wherein the means for injecting the steam injects the steam intermittently as a pressure pulsed cycle.
70. The production well system of any one of claims 63 to 69, wherein steam pressure in the process zone is at ambient reservoir pressure.
71. The production well system of any one of claims 63 to 70, wherein the production well system includes means for injecting into the process zone a non-condensing gas, a hydrocarbon solvent in a vaporized state, or a mixture thereof.

72. The production well system of claim 71, wherein the solvent is one of a group of ethane, propane, butane, or a mixture thereof.
73. The production well system of claim 71 or 72, wherein the solvent is mixed with a diluent gas.
74. The production well system of claim 73, wherein the diluent gas is non-condensable under the process conditions.
75. The production well system of claim 74, wherein the non-condensable diluent gas has a lower solubility in the hydrocarbon deposit liquid than the saturated hydrocarbon solvent.
76. The production well system of claim 75, wherein the diluent gas is one of a group of methane, nitrogen, carbon dioxide, natural gas, or a mixture thereof.
77. The production well system of any one of claims 63 to 76, wherein the production well system includes means for injecting a hydrogenizing gas into the wellbore and thus into the fluids in the process zone to promote hydrogenation and thermal cracking reactions of at least a portion of the petroleum fluids in the process zone.
78. The production well system of claim 77, wherein the hydrogenising gas consists of one of the group of H₂ and CO or a mixture thereof.
79. The production well system of claim 77 or 78, wherein the production well system includes means for catalyzing the hydrogenation and thermal cracking of at least a portion of the petroleum fluids in the process zone.
80. The production well system of claim 79, wherein a metal-containing catalyst is used to catalyze said hydrogenation and thermal cracking reactions.

81. The production well system of claim 80, wherein the catalyst is contained in a canister in tubing inside of the wellbore.
82. The production well system of claim 80 or 81, wherein the proppant particles in the inclusions contain the catalyst for the hydrogenation and thermal cracking reactions.
83. The production well system of any one of claims 43 to 82, wherein a portion of the formation in which the first inclusion is formed has a Skempton B parameter greater than $0.95 \exp(-0.04 p') + 0.008 p'$, where p' is a mean effective stress in MPa at the depth of the first inclusion and the water saturation in the formation pores is greater or equal to 10%.

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10 Oct 2013

Drawing

Unscannable items received with this application
(Request original documents in File Prep. Section on the 10th floor)

fun

Documents reçu avec cette demande ne pouvant être balayés
(Commander les documents originaux dans la section de la préparation
des dossiers au 10^{ième} étage)

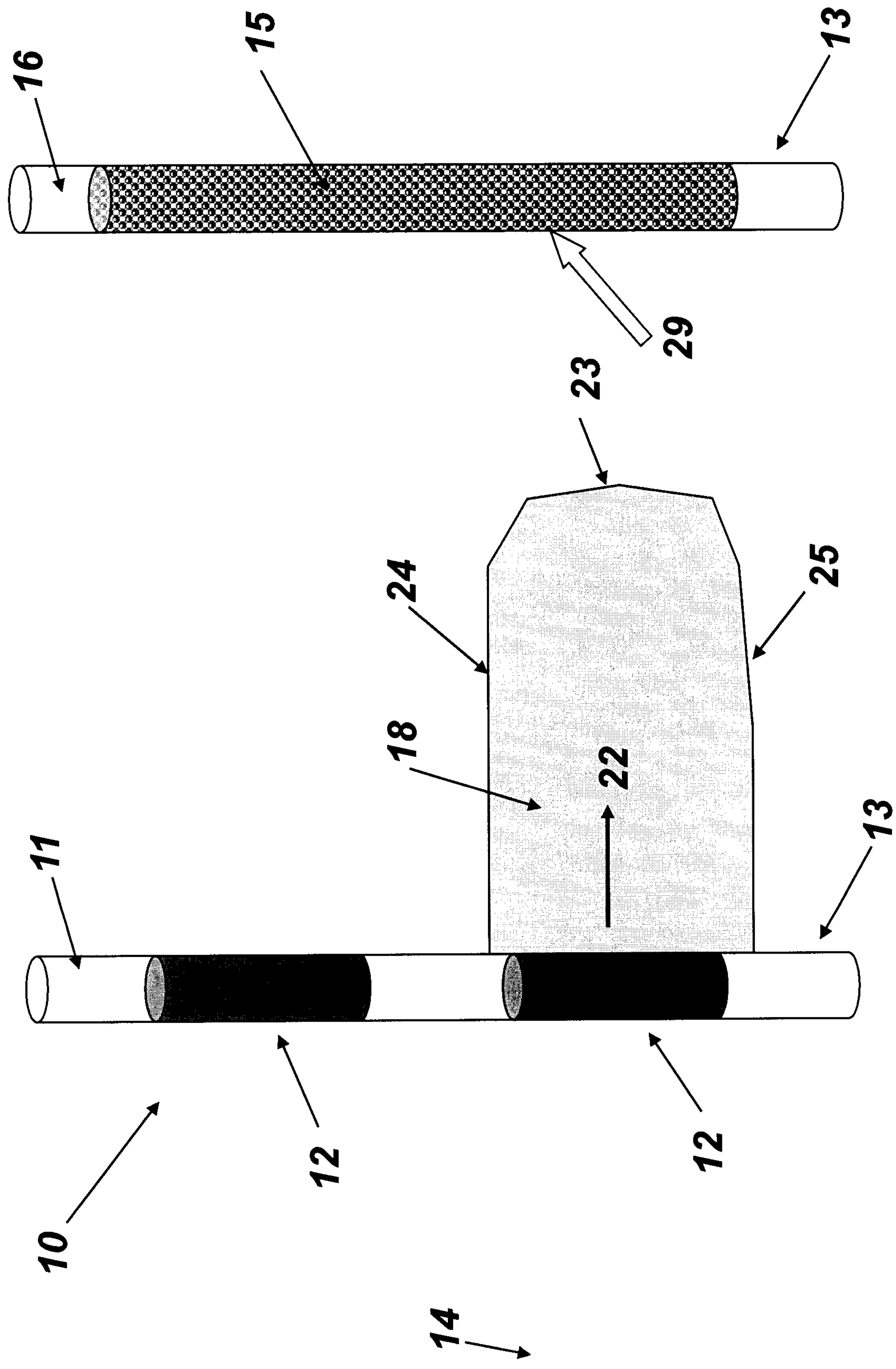


FIG. 3

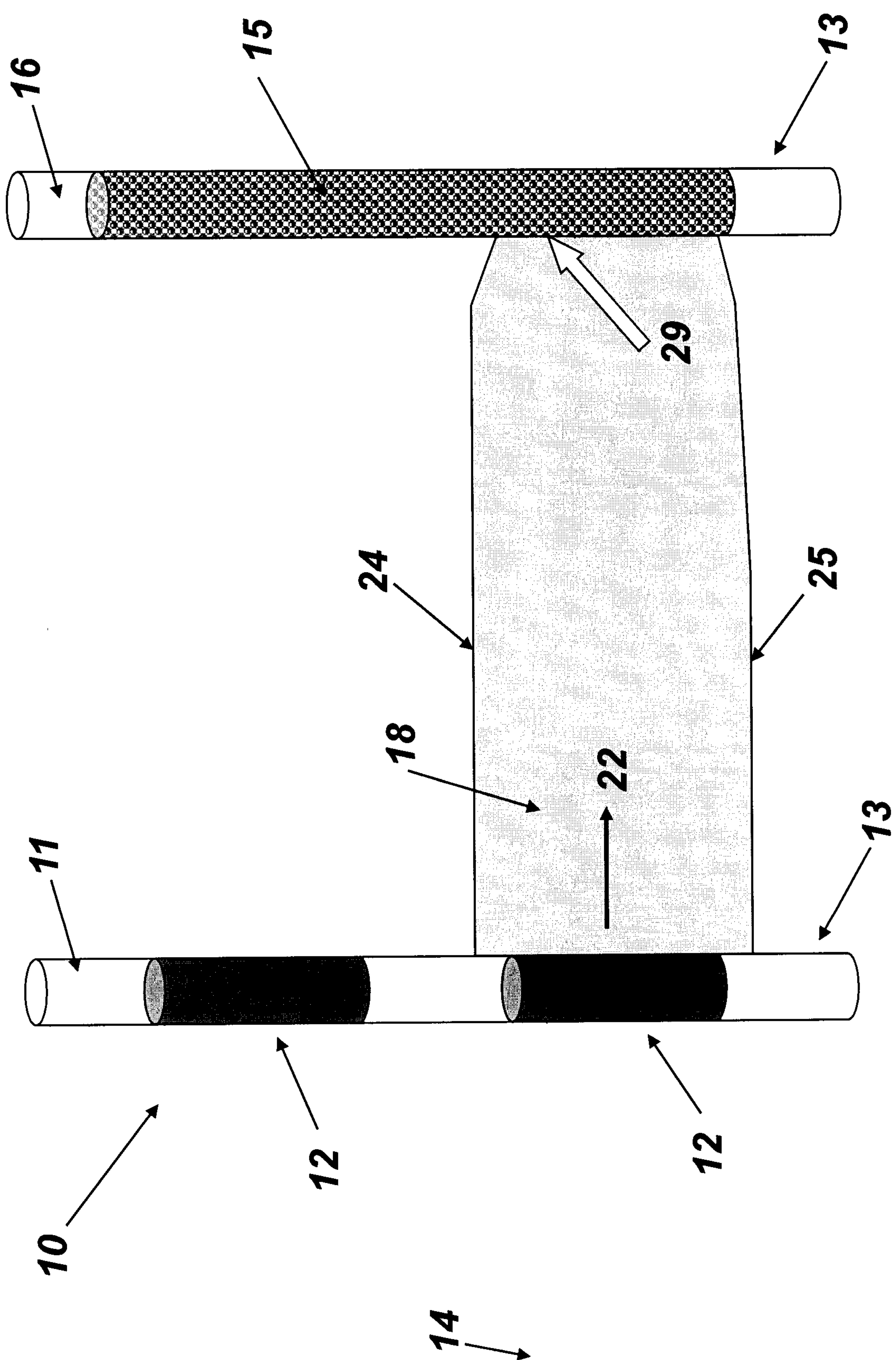


FIG. 4

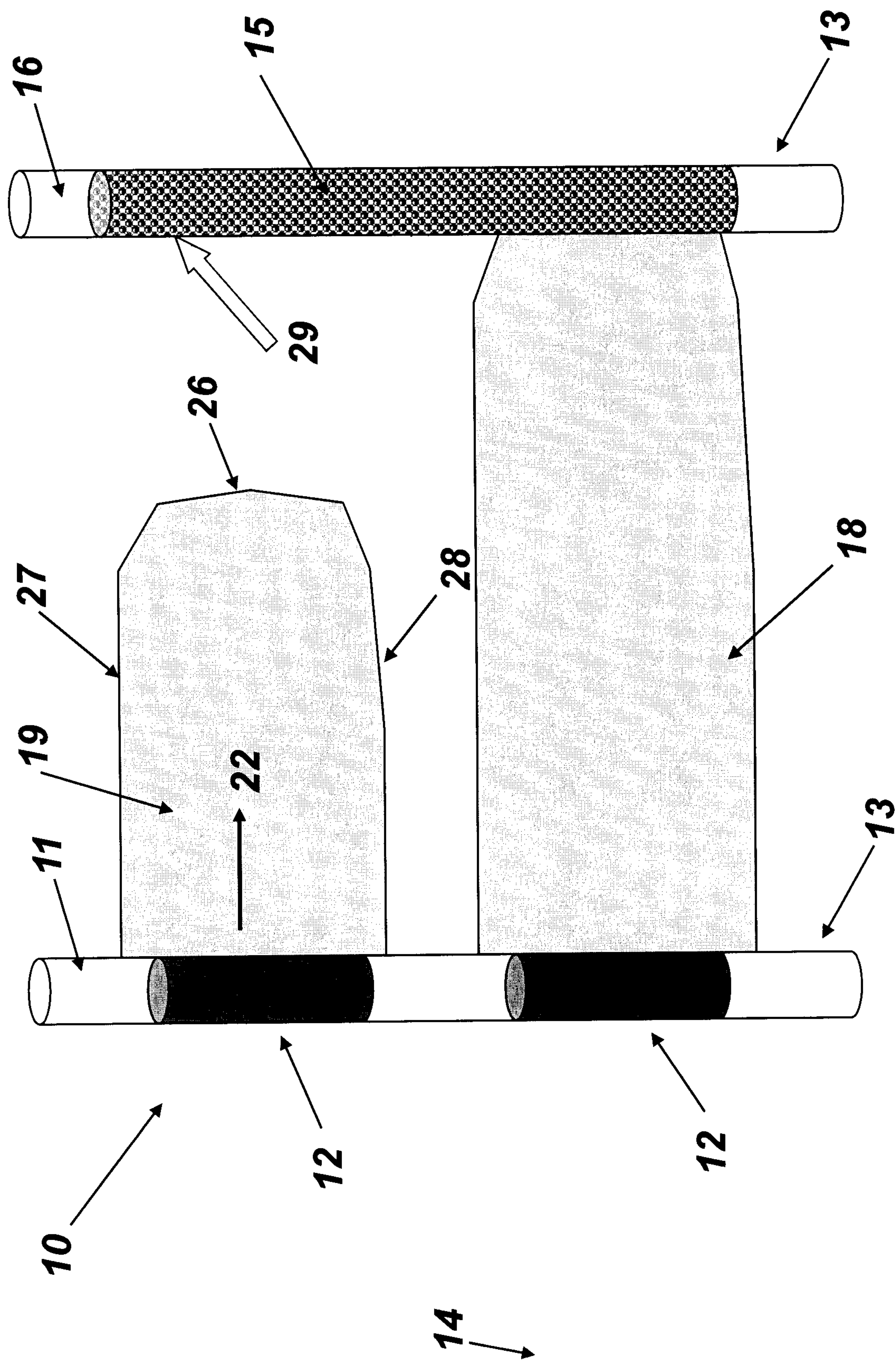


FIG. 5

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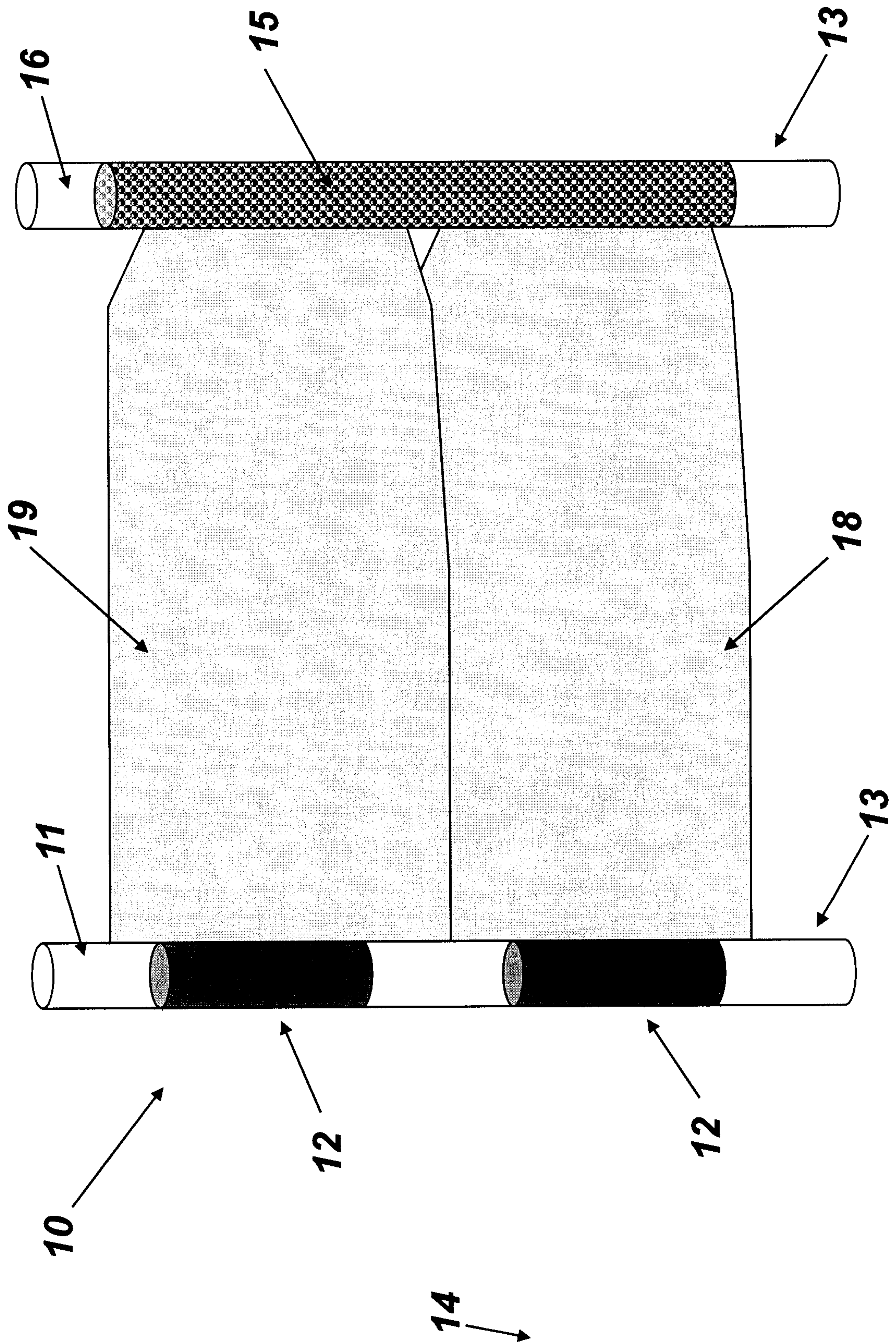


FIG. 6

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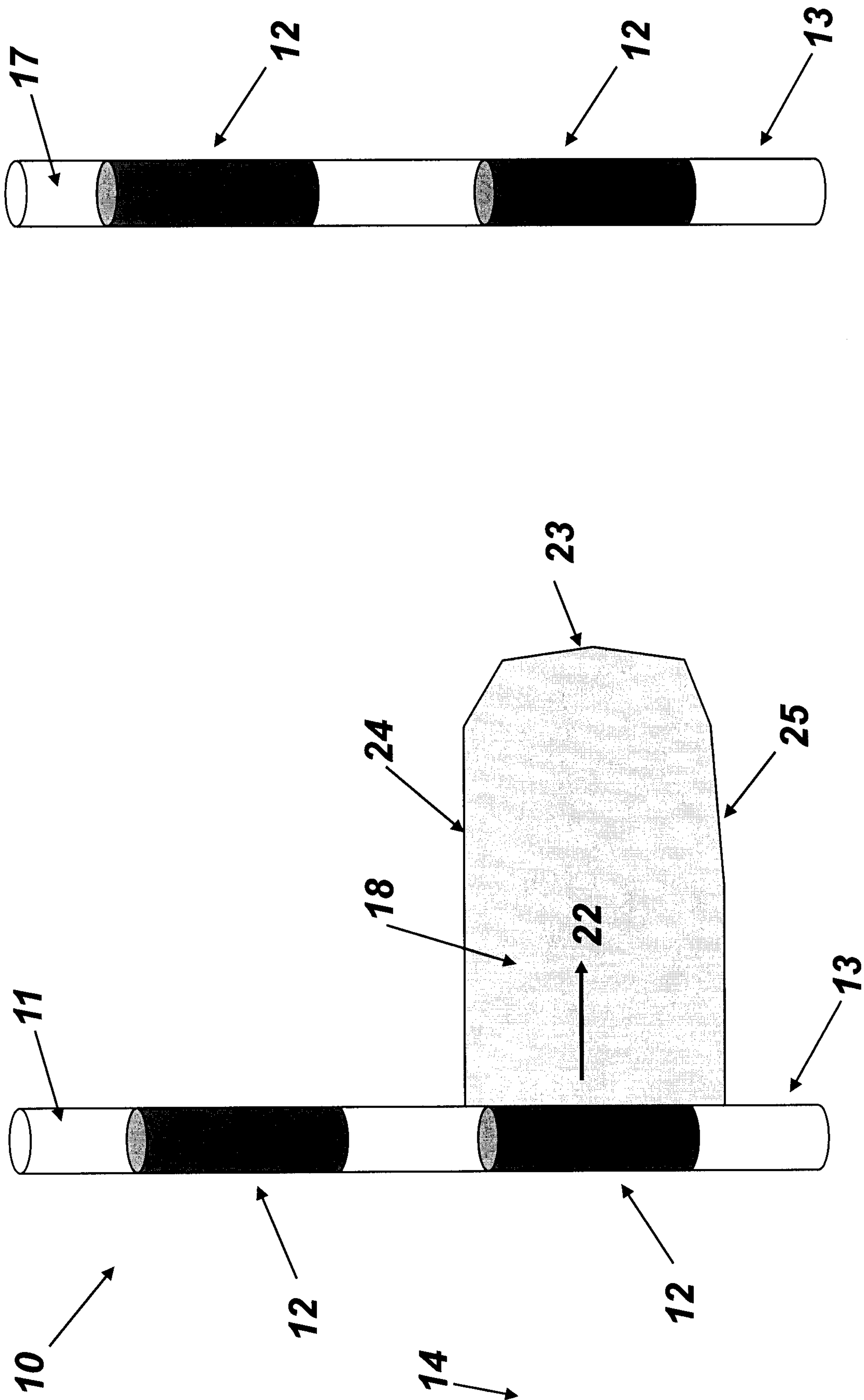


FIG. 7

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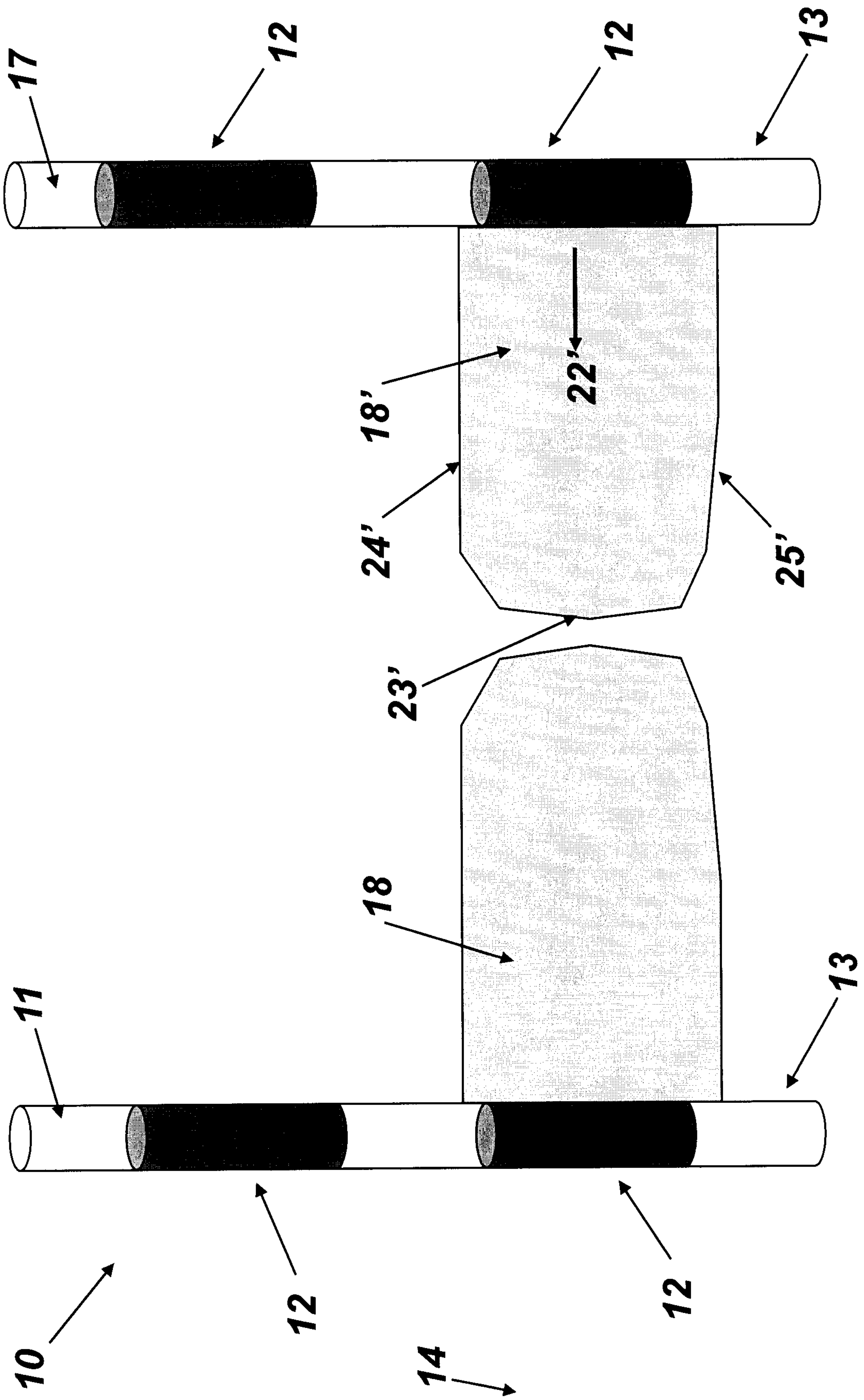


FIG. 8

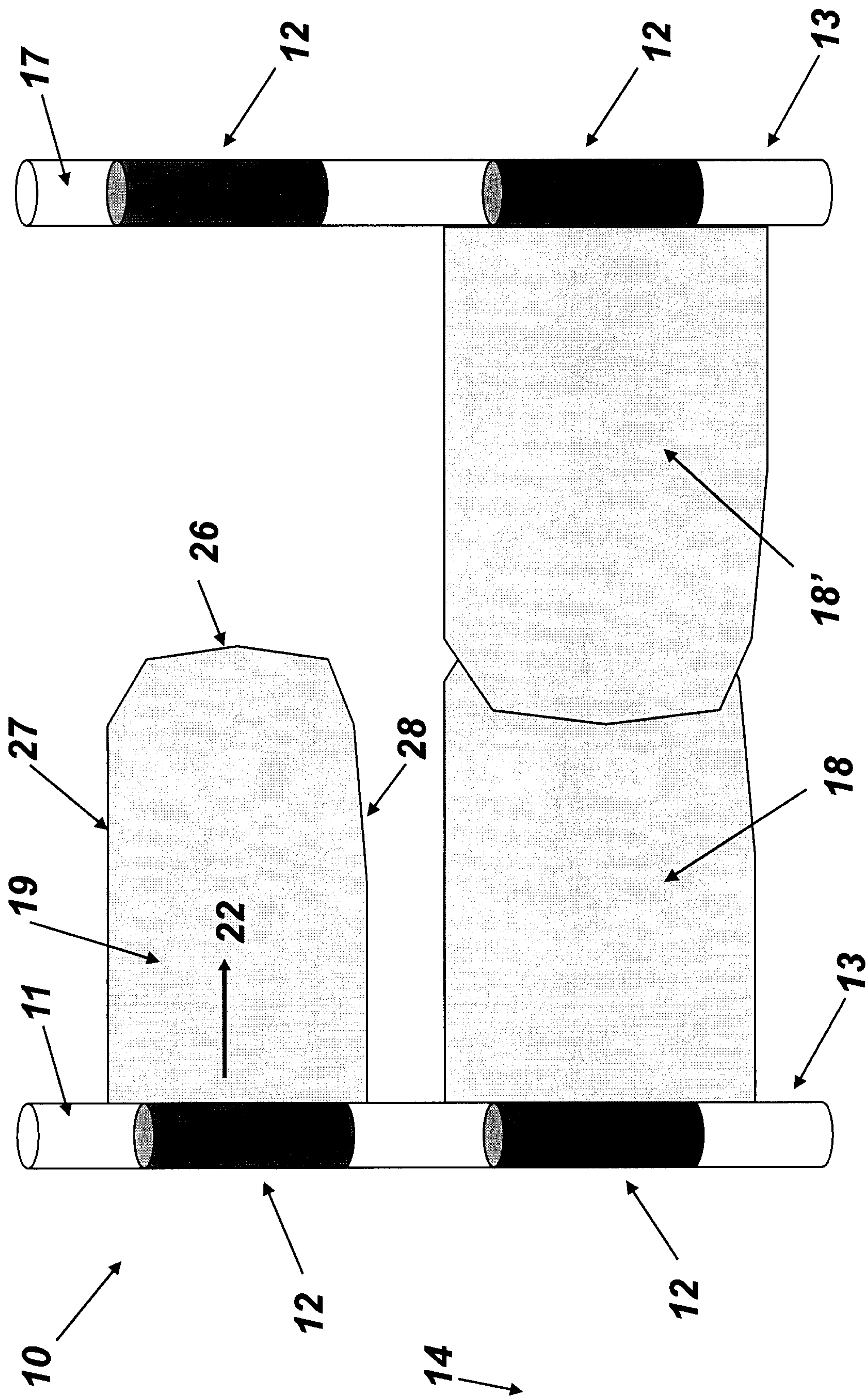


FIG. 9

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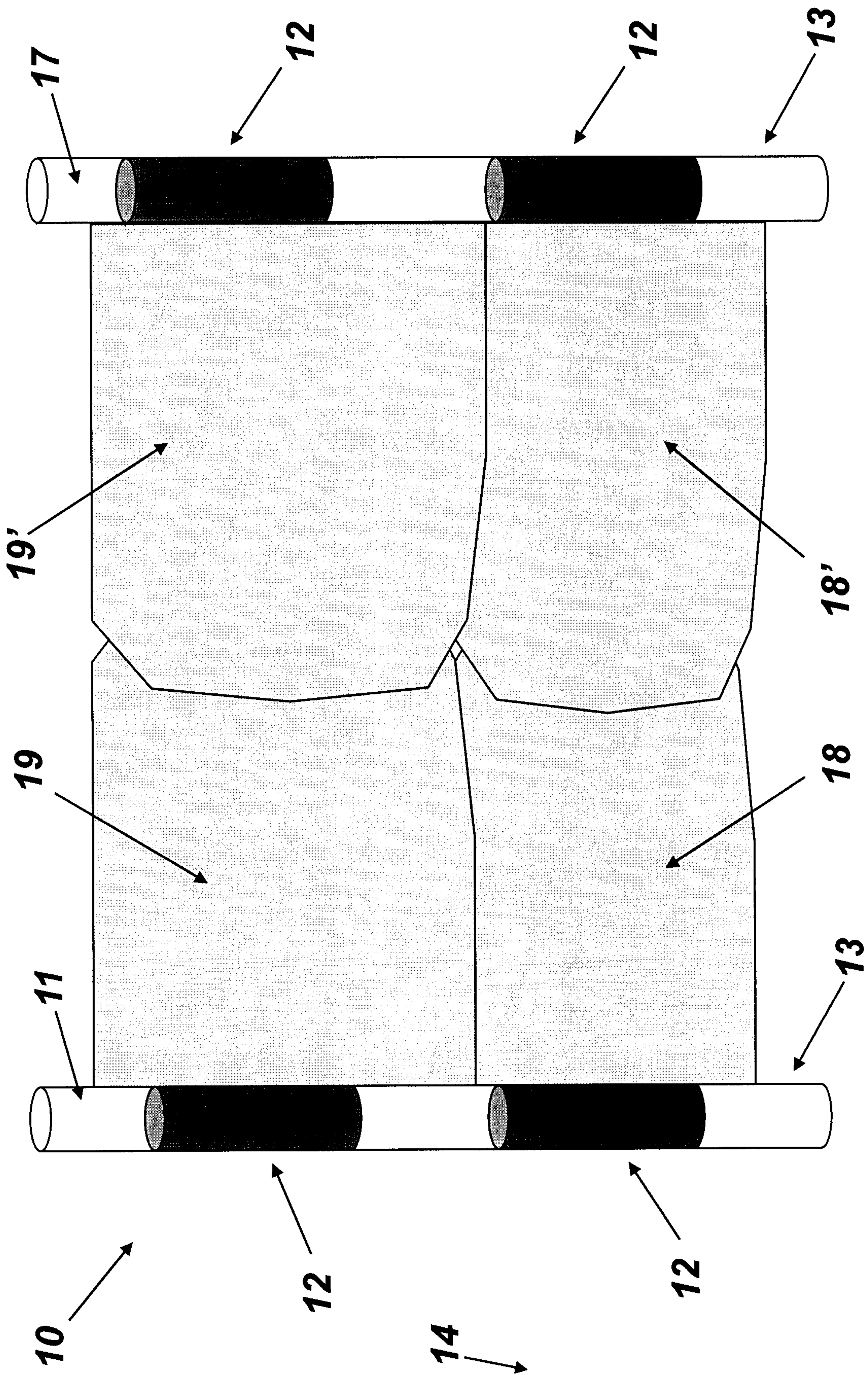


FIG. 10

