A device is provided for delivering and distributing injection fluids into a subsurface formation from a horizontal wellbore. The device includes one or more steam pumps having an outer sleeve and an inner sliding sleeve in concentric relationship. One or more sets of nozzles are arranged on the outer sleeve. A means is provided for actuating movement of the inner sliding sleeve within the outer sleeve, to at least partially cover one or more sets of nozzles on the outer sleeve. A method is also provided for delivering injection fluids into a subsurface formation from a horizontal wellbore. First, one or more steam pumps are introduced into the horizontal well, said steam pumps having an outer sleeve and an inner sliding sleeve with one or more sets of nozzles arranged on the outer sleeve. Next the inner sliding sleeve is moved inside the outer sleeve to at least partially cover one or more sets of nozzles on the outer sleeve. Finally, injection fluid is injected through the steam pump nozzles into formation. A further method is provided that comprises introducing into a heel location of the wellbore a first and second pairs of flow control hangers and polished bore receptacles, connected to an intermediate casing and cemented in place. The first pair of flow control hanger and polished bore receptacle are connected to an injection/production liner and one or more steam pumps are then connected to the second pair of flow control hanger and polished bore receptacle.
Introduce one or more steam pups, having an outer sleeve and an inner sliding sleeve in concentric relationship and one or more sets of nozzles arranged on the outer sleeve into the horizontal well.

Move the inner sliding sleeve inside the outer sleeve to at least partially cover one or more sets of nozzles on the outer sleeve.

Inject injection fluid through the nozzles into formation by supplying injection fluid to the steam pups via the horizontal well.

Figure 6
WELLBORE INJECTION SYSTEM

FIELD OF THE INVENTION

[0001] This invention relates to an injection device and method for the in-situ production of hydrocarbons from downhole wellbores.

BACKGROUND

[0002] Heavy oil and bitumen reservoirs are prevalent worldwide but extraction from such subsurface formations is often difficult and poses a number of challenges to efficiency and cost effectiveness. Steam or fluid injection into horizontal well bores is a known method for enhanced exploitation and recovery from oil, heavy oil or bitumen bearing unconsolidated reservoirs and subsurface formations. Generally, steam injected into heavy oil and bitumen formations assists in reducing the high viscosity of in-situ heavy oils and bitumens thereby increasing mobility out of the formation. Steam Assisted Gravity Drain (SAGD), cyclic steam stimulation (CSS) and steamflood are common exploitation methods used as enhanced oil recovery techniques. However, steam injection into horizontal well bores cannot always be distributed in an even, preferential manner. Some preferred distributions include equalized outflow distributions, specifically placed injection distributions and skewed distributions. Present technologies include steam injection via low open area slotted liners, having approximately 1% open area, and single or dual internal tubing string conveyances. These methods are commonly used with sand control screens or liners to add axial resistance to steam flow and encourage axial distribution of the steam along the horizontal wellbore and promote equalized distribution throughout the formation. However, one problem with this technology is that the injection/production liner often has too large of an open area and therefore cannot provide sufficient radial resistance to steam flow. This leads to non-uniform steam distribution into the formation.

[0003] The open area of the injection/production liner is generally designed to provide a means for controlling and preventing sand from plugging pore spaces of the reservoir either directly or indirectly above the injection/production liner. It also acts to prevent sand from infiltrating and plugging the profile of the injection/production liner during the production phase of in-situ oil recovery. Therefore the open area for sand control, which is typically 3%, but can range from 1.5%-5%, is much larger than the required open area desired for equalized steam distribution, which is typically <0.05% but can range from 0.001%-1%.

[0004] Single tubing conveyed steam injection systems tend to be positioned nearest the heel of the wellbore, and create a poorly distributed steam chamber which has a large steam chamber nearest the heel for the wellbore and very little steam distribution at the toe.

[0005] Dual tubing conveyed steam injection system provides one tubing to convey steam near the heel and a second tubing to convey steam nearer the toe of the horizontal well. This alleviates the problem of a large steam chamber only at the heel, as seen in single tubing systems. However, the dual system instead forms two large steam chambers, one nearest the heel and the other nearest the toe of the horizontal wellbore.

SUMMARY

[0006] There is therefore a need for a device and method to provide evenly distributed steam or other injection fluid along the entire length of the wellbore, in which steam distribution can be targeted as needed.

[0007] A device is taught for delivering and distributing injection fluids into a subsurface formation from a horizontal wellbore. The device includes one or more steam pumps removably located inside the horizontal wellbore. The steam pumps comprise an outer sleeve and an inner sliding sleeve in concentric relationship. One or more sets of nozzles are arranged on the outer sleeve of the steam pump through which injection fluids are injected into the formation. A means is provided for actuating movement of the inner sliding sleeve within the outer sleeve. The movement of the inner sliding sleeve within the outer sleeve acts to at least partially cover one or more sets of nozzles on the outer sleeve, thereby controlling injection fluid flow into the subsurface formation.

[0008] A method is also provided for delivering and distributing injection fluids into a subsurface formation from a horizontal wellbore. The method comprises introducing into the horizontal well one or more steam pumps, said steam pumps comprising an outer sleeve and an inner sliding sleeve in concentric relationship. One or more sets of nozzles are arranged on the outer sleeve. Next the inner sliding sleeve is moved inside the outer sleeve to at least partially cover one or more sets of nozzles on the outer sleeve, thereby controlling injection fluid flow into the subsurface formation. Finally, injection fluid is injected through the nozzles into formation by supplying injection fluid to the steam pumps via the horizontal well. Finally, a method is provided for delivering and distributing injection fluids into a subsurface formation from a wellbore or for producing fluids from the subsurface formation into the wellbore. The method comprises introducing into a heel location of the wellbore a first and second pairs of flow control hangers and polished bore receptacles, wherein the polished bore receptacles are connected to an intermediate casing and cemented in place. The first pair of flow control hanger and polished bore receptacle are connected to an injection/production liner. One or more steam pumps are then connected to the second pair of flow control hanger and polished bore receptacle, said steam pumps comprising an outer sleeve and an inner sliding sleeve in concentric relationship and one or more sets of nozzles arranged on the outer sleeve. Movement of the inner sliding sleeve within the outer sleeve is actuated to at least partially cover one or more sets of nozzles on the outer sleeve; to control fluid flow into or out of the subsurface formation. Finally, injection or production fluids are processed through the nozzles into or out of the subsurface formation via the steam pumps.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] The present invention will now be described in greater detail, with reference to the following drawings, in which:

[0010] FIG. 1 is a cross sectional view of one example of the present steam pump device;

[0011] FIG. 2 is a cross sectional view of one example of the present steam pump device, installed with one example of the present setting tool;

[0012] FIG. 3 is a perspective view of one example of the present setting tool;
FIG. 4 is a cross sectional view on the present steam pup device, showing one example of an angled nozzle in an open position;

FIG. 5 is a cross sectional view on the present steam pup device, showing one example of an angled nozzle in a closed position;

FIG. 6 is a flow diagram illustrating one embodiment of the method of the present invention;

FIG. 7 is a schematic diagram illustrating a first embodiment of the present invention as used with flow control seals and polished bore receptacle joints; and

FIG. 8 is a schematic diagram illustrating a second embodiment of the present invention as used with flow control seals and polished bore receptacle joints.

DESCRIPTION OF THE INVENTION

The present invention relates to one or more steam pumps that are remotely inserted into horizontal wellbores for controlled injection of steam or other injection fluids into the well, and also for production flows from the formation into the well. Although horizontal wellbores are preferably mentioned throughout, the present invention is equally useful in vertical and slanted wellbores and it is to be understood that these applications are encompassed by the present invention. Although the device of the present invention is referred to as a steam pup, it will be well understood by a person of skill in the art that the present device can be used for injection of steam and any other well known injection fluids, and also for production of fluids from the formation into the wellbore.

More specifically, the present device serves to manage steam or other injection fluid flow into the well and production flows from the well. The steam pumps are designed to be set and operated from the surface without removing the steam pumps from the well. The steam pumps preferably comprise two or more fluid flow settings. One setting closes off the flow areas and stops flow into or out of the wellbore. The other settings provide a range of flow rates up to full flow into or out of the wellbore. Further preferably, each steam pump can be operated or set independently, allowing the operator to either set them all to the same flow rate, or to selectively turn off flow from particular steam pumps, thereby isolating particular sections of the well.

Although steam is most commonly referred to, it is to be understood that the present device and method provide a means of injecting any suitable injection fluid into the subsurface formation. Many such injection fluids are known in the art and include steam, water, varsoil, diesel and solvents. It is therefore to be understood that the present invention encompasses any and all such known fluids.

The invention aids in improving the delivery and distribution of steam into the target formation by providing an equalized steam distribution along the wellbore, coupled with proper sand control. The present retrievable system can be used in conjunction with SAGD, steamflood, CSS or other steam exploitation processes and/or steam injection combined with injection of other fluids such as solvents. For the purposes of the present invention solvents are considered to include any chemical or biochemical that aids in reducing the in-situ oil viscosity, improving steam delivery or increasing the beneficial exploitation properties of the reservoir. The present invention further provides a means of equalizing the steam delivery, normalized into the formation by relating the axial wellbore resistance to the radial formation resistance to injection.

In the present system, fluid properties are taken into consideration when determining the desired open area for fluid injection over the length of the wellbore. By relating fluid properties to the wellbore specifications and formation properties, the nozzle size and number of open nozzles, corresponding to the open area for injection, can be specified to allow for equalized steam distribution along the horizontal wellbore. Further preferably, the system can also be designed for varying fluid properties during the course of injection and production, which allows for use of the present system in a wide range of applications.

With reference to FIG. 1, the present steam pup 2 comprises an outer sleeve 4 and an inner sliding sleeve 6. The outer sleeve 4 and inner sliding sleeve 6 are preferably made of hardened materials such as high speed steels (HSS) and other hardened steels commonly used in downhole tools and directional drilling tools.

The steam pup can be built in a number of sizes, from standard tubing sizes used in the industry up to standard and commonly known casing sizes. More particularly, steam pup diameters can range from 1 inch to 11¾ inches. The length of the steam pup also varies with application and can be from a minimum length of 1 m to a maximum of 13.5 m.

The outer sleeve 4 consists of an upper box connection and a lower pin connection (not shown) to mate with a desired casing to be run in conjunction with the steam pups 2. The outer sleeve 4 comprises at least two rows comprising one or more nozzle holes 8. The inner diameter of the outer sleeve 4 preferably comprises at least one retainer ring 10 which limits motion of the inner sliding sleeve 6 and prevents the inner sliding sleeve 6 from sliding completely out of the outer sleeve 4. The outer sleeve 4 also comprises one or more locking rings 12, for positioning the inner sliding sleeve 6 in one of a number of desired positions.

The inner sliding sleeve 6 takes the form of a mandrel which slidingly fits into the inside diameter of the outer sleeve 4. The inner sliding sleeve 6 comprises a series of o-rings 14 to minimize and prevent the flow of debris between the outer diameter of the inner sliding sleeve 6 and the inner diameter of the outer sleeve 4. The outside diameter of the inner sliding sleeve 6 comprises 2 or more machined grooves 16 that mate with the locking ring 12 to position the inner sliding sleeve in a number of different positions, corresponding to a number of different nozzle opening 8 settings. The inside diameter of the inner sliding sleeve 6 further contains one or more pins 18.

A setting tool 20 is shown in a preferred arrangement with the present steam pup 2 in FIG. 2 and on its own in more detail in FIG. 3. With reference to these figures, the setting tool 20 comprises an upper box connection (not shown) corresponding with the working string connection, and a lower open hole end 22. The outside diameter of the setting tool 20 comprises one or more grooves, or slides 24 that extend over the length of the setting tool 20 and which correspond to pins 18 on the inner sliding sleeve 6. The outside diameter of the setting tool 20 is slidingly received into the inner sliding sleeve 6 only when slides 24 are aligned with the pins 18. When the slides 24 are not aligned with the pins 18, then the open hole end 22 of the setting tool 20 abuts the pins 18 and push thereagainst.

Alternatively, movement of the inner sliding sleeve 6 within the outer sleeve 4 of the steam pup 2, may be hydraulically controlled remotely from the surface, in which case no setting tool 20 is required.
[0029] The present nozzles 8 may be oriented perpendicular to the axis of steam pup 2, as shown in FIGS. 1 and 2, or alternatively they may be angled, as shown in FIGS. 4 and 5. Any angle is possible for the nozzles and encompassed in the present invention.

[0030] With reference to FIGS. 4 and 5, the sets of nozzles may preferably be set at a 60° angle to the axis of the steam pup 2. More preferably, the orientation of each nozzle 8 in the set is alternated or the orientation of each nozzle in the set can be randomly varied. This promotes an equal distribution of steam to the formation. An angled orientation also reduces friction losses often caused by 90° turns during steam travel. The angled orientation is also preferred to reduce wear around the nozzles 8 caused from the high velocity of steam or other injection fluids. The nozzles 8 can be machined to the outer sleeve 4 as shown in the figures. Optionally, the nozzles 8 may also be part of a separate unit that is attached to the outer sleeve 4. In a preferred embodiment nozzles 8 of steam pups 2 used in the heel of a wellbore are preferably specifically designed to account for steams properties at the heel location to provide the preferential radial flow resistance to steam along the horizontal wellbore.

[0031] The present arrangement of nozzles 8 and the preferential manner in which nozzles 8 can be opened or closed allows steam to be evenly distributed along the horizontal wellbore. Further preferably, nozzle geometry may be varied and may include circular, tapered, conical, oval, square, rectangular or slot shapes. Varying nozzle geometry provides a resilient but flexible means for adjusting to potential thermal loading and plastic deformation of the nozzles under high pressure and temperature situations during the steam injection phase. The geometry may also optionally be selected to provide control of flow resistance, pressure and pressure drop.

[0032] Turning to FIGS. 4 and 5, at the point of exit from the nozzle 8 of the steam pup 2, injection fluid follows a graduated ramp 28. A hardened blast plate 30 is positioned above the nozzle 8 to protect against wear of the injection/production liner (not shown) that the steam pup 2 resides in.

[0033] Nozzle geometry and size of the present steam pup can be designed for a number of different steam injection pressures or rates. For example, steam can be injected below, at or above a fracture pressure of the reservoir. Steam can also be injected at subsonic/subcritical or sonic/critical flow regimes.

[0034] Preferably the steam pup 2 is a retrievable system which is situated within and optionally attached, thread or otherwise connected to a larger injection/production liner which interfaces with the formation. The steam pup 2 can be a closed or open ended system. Further preferably a series of steam pups can be joined together by lengths of blank casing to form a steam pup string, to allow variation in injection and production along the entire length of the wellbore, and also to preferentially isolate particular lengths of the wellbore. In this way the system can be used in watering flooding operations, creating steam isolation zones or in de-watering applications.

[0035] The present steam pup 2 assembly may be kept inside the injection/production liner after the injection phase and used for the production phase, to produce in-situ fluids, in the case of a single well design. In this case, production fluids flow in a reverse direction back into the steam pup 2, through the nozzles 8. In production, the blast plate 30 acts to reduce resistance of the production fluids as they enter the steam pups 2.

[0036] Sand control screens/liners used with the present invention can be any type of sand screen known in the art and include, but are not limited to wire-wraps, slotted liners, Meshrite™ or other sand control screens. The injection/production liner preferably interfaces the entire length of the reservoir, not simply portions thereof and there are therefore no blank lengths of pipe in the horizontal wellbore. This desirably allows for low pressure drops for producing fluids, better radial inflow, better contact with the whole reservoir, better sand control and better steam distribution along the horizontal wellbore.

[0037] Preferably, there is also provided a means of positioning and preferably centralizing the steam pup 2 within the injection/production liner by connecting one or more packers which are larger than the outside diameter of the steam pup 2, but is small enough to fit snugly within the inside diameter of the injection/production liner, which interfaces with the formation. The packers are run with the steam pups 2 and pre-determined amounts of casing and used to isolate the series of steam pups 2.

[0038] The packers are designed to allow space for milling and retrieving if required, as well as some pressure control and steam distribution control. The packers can be preferably set at the heel location, and also one third and two thirds of the way along the length of the horizontal wellbore or selectively at other locations along the wellbore, inside of the injection/production liner to maintain pressure control of the injection fluid and control of fluid distribution by sealing off the annular space between the formation and the injection/production liner and the steam pups 2. Alternatively, if packers are not used, then the present inventors estimate that the high viscosity of the in-situ oil can also provide the necessary pressure control and fluid distribution control.

[0039] In operation, the setting tool 20 is run into the well, preferably using a 2½" work string, which is commonly used in such applications. The setting tool 20 is run to a location just above a steam pup 2, indicated by a stoppage in movement corresponding to abutment of the open hole end 22 of the setting tool 20 against the pins 18. In rare occasions when the slides 24 of the setting tool 20 coincidentally align with the pins 18 on the inner sliding sleeve 6, the setting tool 20 may not abut against the inner sliding sleeve 6, but will instead bypass the steam pup 2. In such cases, the string can be raised to a position above the steam pup 2, and rotated to offset the slides 24 with the pins 18, and then lowered again.

[0040] To position the steam pup 2 to a desired nozzle setting, a force or weight is applied to the setting tool 20. Once the weight exceeds resistance from the locking ring 12, the inner sliding sleeve 6 will slide along until the locking ring 12 receives the next locking ring groove 16, or until the inner sliding sleeve 6 abuts against a downstream retainer ring 10.

[0041] Alternatively, the setting tool 20 may also be pulled up to set the steam pup 2 to a desired nozzle setting. In this case, the setting tool 20 must pass back through the inner sliding sleeve 6 first. The work string is rotated until the slides 24 line up with the pins 18 and the setting tool 20 is then lowered through the inner sliding sleeve 6. The setting tool 20 is again rotated to offset the slides 24 and the work string is raised until a resistance is felt, indicating that the setting tool 20 has abutted against the pins 18. The work string can then be raised until the resistance from the locking ring 12 is overcome and until the locking ring 12 receives a new locking ring groove 16, or until the inner sliding sleeve 6 abuts the upstream retainer ring 10.
In an alternate embodiment, the present invention can also operate without a injection/production liner, as for example in the case of a SAGD operation. In such cases, no packers are required and there is no need for a dual flow control hanger but only a single flow control hanger. For SAGD applications there is typically a “warm-up” phase or “circulation” phase, which requires that bitumen or heavy oil reserves lying between the injector well and the producer well be heated for mobility, steam chamber growth, production and fluid control. This warm up phase typically requires a significantly lower quantity and lower pressure of steam injection than during the full injection-production phase of a fully functioning SAGD well pair. In these cases, a first steam pup system can preferably be designed to provide equalized and optimized steam distribution for the warm-up phase, after which the first steam pup system may optionally either be retrieved and a second steam pup system inserted to provide high pressure steam for a full injection phase, or the first system may optionally be kept in place and the inner sliding sleeve 6 adjusted to allow for full injection through the nozzles 8, without removing the initial steam pup system.

The steam pup 2 flow settings are preferably machined to provide an open, full flow setting as a top setting, herein referred to as position “A”, a shut off flow setting as a middle setting, herein referred to as position “B”, and another partially open flow setting at a lowest setting, herein referred to as position “C”. The extent of open area for both the upper and lower settings, positions “A” and “C” are predetermined based on fluid properties including pressure, quality, temperature and loss. The complete steam pup string including packers, can be removed from the well and redesigned if required.

By creating an equalized distribution of steam along the horizontal wellbore the whole reservoir is preferentially contacted with steam providing more oil production, lower steam-oil ratios and more efficient transfer of energy into the formation.

In a preferred embodiment, the present invention can be designed for fluid injection at injection pressures that are above or below the fracture pressure of the reservoir or the invention can also accommodate subcritical or critical flow regimes.

In an alternate embodiment, the present steam pup 2 may not be attached to the injection/production liner of the wellbore. In such cases it is preferable to have pairs of flow control hangers and polished bore receptacles (PBR). The pairs of flow control hangers and polished bore receptacles are fitted together and placed one above the other in the location of the intermediate casing. The polished bore receptacles are connected to the intermediate casing and cemented in place. This system is then installed in the heel location of the horizontal wellbore to minimize leak rates and control pressure loss of steam injected at the heel location, which can be caused by high pressure steam tending to create a by-pass past a flow control hanger at the heel location. The first flow control hanger and polished bore receptacle, which are located furthest into the wellbore are connected to the injection/production liner, thereby providing a seal against leak off and to maintain pressure and at the heel location. The second flow control hanger and polished bore receptacle are connected to the steam pup and situated above, but not necessarily connected to the first flow control hanger and polished bore receptacle. These also provide a similar pressure and leak off seal.

In a further preferred embodiment, the present invention can also operate without the use of packers for centralizing the steam pups or steam pump string. This embodiment, illustrated in FIGS. 7 and 8, utilizes one or more pairs of polished bore receptacle (PBR) joints 26 and flow control (FC) seals 28 to isolate the steam pups instead of packers. For example, the one or more pairs of PBR joints 26 are run down the well with one or more slotted liners 30 run between the PBR joints 26. The number of slotted liners 30 used will depend on such factors as the formation characteristics, the length of the wellbore and costings considerations. In some cases, slotted liners 30 may be run between each PBR joint 26 in the string to allow an equal spacing of isolation zones. In other cases as few as 2 to 3 slotted liners 30 may be required. Although the term slotted liners is used herein, it would be well understood a person of skill in the art that any sand control screen type could be utilized for these purposes without departing from the scope of the present invention.

Steam liners can be connected by one or more blank casings with one or more steam pups 2, all located between the FC seals 28. The distance between PBR joints 26 in the fixed slotted liner string is set to mate with the distance between FC seals 28 on the steam liner string. The FC seals 28 can be fit to the PBR joints 26 with a positive memory seal. However, it is also possible to have a fit allowance of from 0.001" to 0.002" without causing significant steam losses. More preferably, increasing smaller inside diameter PBR joints 26 and FC seals 28 are installed within the slotted liner string, from the surface to the bottom of the wellbore. This allows clearance for all of the PBR joints 26 and FC seals 28 to be run down the wellbore. When bottom of the wellbore is reached, each FC seal 28 comes in contact with its corresponding PBR joint 26 and the sealing is complete. In this way, steam distribution and steam pressure are equalized and maintained over the length of the well bore and there is less occurrence of steam bypass. By not using packers, it is possible to avoid possibly sealing packers with too much pressure or deterioration of packers due to steam, which then requires having to mill out and retrieve failed packers. Furthermore, using PBR joints to isolate zones of the formation does not lead to undesirable wellbore diameter restrictions, as does the use of a combination of packers and piping for the same purposes. Restricted wellbore diameters can cause friction losses and impede steam distribution, increase pumping requirements and restrict the types of tools that can be used downhole. The preferred PBR/FC seal system will operate in a similar manner to a configuration with packers, in that, if there is an area of the wellbore that needs isolating, the steam pup between two FC seals is simply closed off so that the isolated area will not produce fluids and is sealed off from the rest of the wellbore.

EXAMPLES

The following examples serve merely to further illustrate embodiments of the present invention, without limiting the scope thereof, which is defined only by the claims.

Example 1

A well has an intermediate casing, known as the build section, at a depth of 600 m, and the total depth of the well is 1500 m. The pay zone, or horizontal section, of the production zone is 900 m long. Three different groups of steam pups are used for steaming, together with three packers.
The 1st packer, set at a 1200 m depth, isolates % of the nozzles in the first steam pup from 1200 m depth to 1500 m depth. The 2nd packer, set at a 900 m depth, isolates ½ of the nozzles in the second steam pup from the 900 m depth to the 1st packer at 1200 m. The 3rd packer is set at 600 m, at the bottom of the intermediate casing and isolates ¼ of the nozzles in the third steam pup between a 600 m depth and the 2nd packer at 900 m. When predetermined amounts of casing are run in conjunction with the steam pups to achieve the required lengths between the packers. By using different nozzle settings on the steam pups between the isolated packers, the operator is able to deliver steam or other injection fluids into the formation evenly.

A production cycle is required, the well can produce through the same nozzle, or the steam pups can be set to a larger open area for production. If one of the isolated zones are producing an unwanted product such as water or sand, the associated steam pups can be set to a lower flow setting or can be closed off completely.

In the foregoing specification, the invention has been described with a specific embodiment thereof; however, it will be evident that various modifications and changes may be made thereto without departing from the broader spirit and scope of the invention.

8. The device of claim 1, further comprising at least one retainer ring positioned in an inner surface of the outer sleeve, to limit motion of the inner sliding sleeve within the outer sleeve and prevent loss of the inner sliding sleeve through the outer sleeve.

9. The device of claim 1, wherein an inner surface of the outer sleeve further comprising one or more locking rings that matingly engage with corresponding locking ring grooves located an outer surface of the inner sliding rings to position the inner sliding sleeve within the outer sleeve.

10. The device of claim 1, wherein an outer surface of the inner sliding sleeve further comprises a series of o-rings to minimize and prevent flow of debris between an outer diameter of the inner sliding sleeve and an inner diameter of the outer sleeve.

11. The device of claim 1, wherein the means for actuating movement of the inner sliding sleeve within the outer sleeve comprises a setting tool that is inserted into and connects with the inner sliding sleeve of the device to thereby move the inner sliding sleeve within the outer sleeve.

12. The device of claim 11, wherein an outer diameter of the setting tool comprises one or more grooves extending over a length of the setting tool, said grooves matingly corresponding with one or more pins located on the inner sliding sleeve to allow movement of the setting tool inside the inner sliding sleeve when the one or more grooves are aligned with the one or more pins, and causing abutment of the setting tool against the inner sliding sleeve when the one or more grooves are not aligned with the one or more pins.

13. The device of claim 1, wherein the means for actuating movement of the inner sliding sleeve within the outer sleeve comprises remote, hydraulic actuation.

14. The device of claim 1, wherein the one or more sets of nozzles are set at an orientation of from 1° to 90° relative to an axis of the outer sleeve.

15. The device of claim 14, wherein the orientation of the one or more sets of nozzles is 60° to the axis of outer sleeve.

16. The device of claim 14, wherein the orientation of each nozzle in the set of nozzles is alternated.

17. The device of claim 14, wherein the one or more sets of nozzles are machined into the outer sleeve.

18. The device of claim 14, wherein the one or more sets of nozzles form part of a separate unit that is attached to the outer sleeve.

19. The device of claim 14, wherein the one or more sets of nozzles have a cross sectional geometry selected from the group consisting of circular, tapered, conical, oval, square and rectangular.

20. A method for delivering and distributing injection fluids into a subsurface formation from a wellbore or for producing fluids from the subsurface formation into the wellbore, said method comprising the steps of:

- introducing into the wellbore one or more steam pups, said steam pups comprising an outer sleeve and an inner sliding sleeve in concentric relationship and one or more sets of nozzles arranged on the outer sleeve;
- actuating movement of the inner sliding sleeve within the outer sleeve to at least partially cover one or more sets of nozzles on the outer sleeve; to control fluid flow into or out of the subsurface formation; and
- transferring injection or production fluids through the nozzles into and out of the subsurface formation via the steam pups.
21. The method of claim 20, wherein actuating movement of the inner sliding sleeve within the outer sleeve comprises inserting a setting tool into the outer sleeve and connecting with the inner sliding sleeve to thereby move the inner sliding sleeve within the outer sleeve.

22. The method of claim 21, wherein movement of the inner sliding sleeve within the outer sleeve comprises inserting the setting tool into the outer sleeve until the setting tool abuts against the inner sliding sleeve and pushing the setting tool against the inner sliding sleeve to move the inner sliding sleeve within the outer sleeve.

23. The method of claim 21, wherein movement of the inner sliding sleeve within the outer sleeve comprises inserting the setting tool into the outer sleeve and through the inner sliding sleeve; and pulling the setting tool back up against the inner sliding sleeve to move the inner sliding sleeve within the outer sleeve.

24. The method of claim 20, wherein actuating movement of the inner sliding sleeve within the outer sleeve comprises hydraulically actuating movement from a remote location.

25. The method of claim 20, wherein the method is used for SAGD applications, the method further comprising a circulation phase prior to fluid injection, in which the inner sliding sleeve is set to cover half or more of the one or more sets of nozzles on the outer sliding sleeve, to thereby provide steam at low pressure to heat production fluids in the subsurface formation to increase mobility and steam chamber growth, followed by a higher pressure steam injection phase and a production phase.

26. The method of claim 20, wherein the method is used for fluid injection into the subsurface formation at injection pressures above the fracture pressure of the subsurface formation.

27. A method for delivering and distributing injection fluids into a subsurface formation from a wellbore or for producing fluids from the subsurface formation into the wellbore, said method comprising the steps of:
   a. introducing into a heel location of the wellbore a first and second pairs of flow control hangers and polished bore receptacles, wherein the polished bore receptacles are connected to an intermediate casing and cemented in place;
   b. connecting the first pair of flow control hanger and polished bore receptacle to an injection/production liner;
   c. connecting one or more steam pups to the second pair of flow control hanger and polished bore receptacle, said steam pups comprising an outer sleeve and an inner sliding sleeve in concentric relationship and one or more sets of nozzles arranged on the outer sleeve;
   d. actuating movement of the inner sliding sleeve within the outer sleeve to at least partially cover one or more sets of nozzles on the outer sleeve; to control fluid flow into or out of the subsurface formation; and
   e. processing injection or production fluids through the nozzles into or out of the subsurface formation via the steam pups.

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