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CA 2757950 C 2014/06/03

(11)(21) **2 757 950**

(12) **BREVET CANADIEN**
CANADIAN PATENT

(13) **C**

(22) **Date de dépôt/Filing Date:** 2011/11/08
(41) **Mise à la disp. pub./Open to Public Insp.:** 2013/05/08
(45) **Date de délivrance/Issue Date:** 2014/06/03

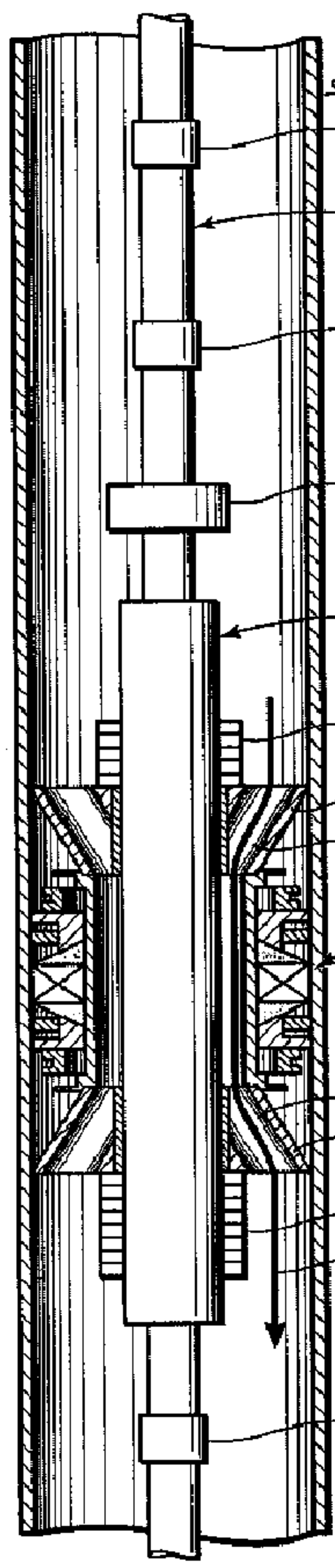
(51) **Cl.Int./Int.Cl.** *E21B 43/24* (2006.01), *E21B 33/12* (2006.01)

(72) **Inventeur/Inventor:**
OXTOBY, JOHN A., CA

(73) **Propriétaire/Owner:**
IMPERIAL OIL RESOURCES LIMITED, CA

(74) **Agent:** BORDEN LADNER GERVAIS LLP

(54) Titre : GARNITURE D'ADMISSION
(54) Title: PORTED PACKER



(57) Abrégé/Abstract:
Disclosed is a packer that is ported to provide fluid communication through the packer between the wellbore annulus above the packer and the wellbore annulus below the packer. Such a ported packer can be used to allow for pressure testing the casing and/or for controlling a failed well.

ABSTRACT

Disclosed is a packer that is ported to provide fluid communication through the packer between the wellbore annulus above the packer and the wellbore annulus below the packer. Such a ported packer can be used to allow for pressure testing the casing and/or for controlling a failed well.

PORTED PACKER

FIELD

[0001] The present disclosure relates generally to the field of well completions for use in the recovery of *in situ* hydrocarbons from a subterranean reservoir.

BACKGROUND

[0002] Viscous oil, such as heavy oil or bitumen, residing in reservoirs that are too deep for commercial mining may be recovered by *in situ* processes. Commonly, viscous oil is produced from subterranean reservoirs using *in situ* recovery processes that reduce the viscosity of the oil enabling it to flow to the wells; otherwise, an economic production rate would not be possible. In commercial *in situ* viscous oil recovery processes, the temperature or pressure is modified or a solvent is added to reduce the viscosity or otherwise enhance the flow of the viscous oil within the reservoir.

[0003] In certain processes, such as in SAGD (Steam Assisted Gravity Drainage), a dedicated injection well and a dedicated production well are used. The SAGD process involves injecting steam into the formation through an injection well or wells at a rate which forms a steam chamber and maintains a near constant operating pressure in the steam chamber. Steam at the edges of the steam chamber condenses as it heats the adjacent non-depleted formation. The mobilized oil and steam condensate flow via gravity to a separate production well located at the base of the steam chamber. An example SAGD is described in U.S. Patent No. 4,344,485 (Butler).

[0004] In other processes, such as in CSS (Cyclic Steam Stimulation), the same well is used both for injecting a fluid and for producing oil. In CSS, cycles of steam injection, soak, and oil production are employed. Once the production rate falls to a given level, the well is put through another cycle of injection, soak, and production. An example of CSS is described in U.S. Patent No. 4,280,559 (Best).

[0005] Steam Flood (SF) involves injecting steam into the formation through an injection well to provide stream drive. Steam moves through the formation, mobilizing oil as it flows toward the production well. Mobilized oil is swept to the production well by the steam drive. An example of steam flooding is described in U.S. Patent No. 3,705,625 (Whitten).

[0006] Other thermal processes include Solvent-Assisted Steam Assisted Gravity Drainage (SA-SAGD), an example of which described in Canadian Patent No. 1,246,993 (Vogel); Vapour Extraction (VAPEX), an example of which is described in U.S. Patent No. 5,899,274 (Frauenfeld); Liquid Addition to Steam for Enhanced Recovery (LASER), an example of which is described in U.S. Patent No. 6,708,759 (Leaute et al.); and combined Steam and Vapour Extraction Process (SAVEX), an example of which is described in U.S. Patent No. 6,662,872 (Gutek).

[0007] As is well known in the art, in order to prepare a well for injection or production, it is necessary to “complete” the well after the borehole is drilled. Completing a well typically includes casing the well, which means inserting a casing into a drilled section of the borehole. The casing is typically held in place by cement. Completion also typically includes inserting a tubing string within the casing, in the injection or production section of the well. The tubing string is typically sealed off from the casing with a packer. Conventionally, packers are used to provide a downhole seal between the tubing string and the surrounding casing in order to prevent the flow of fluids through a portion of a wellbore annulus defined between the tubing string and the casing. Packers are desirable for a number of uses, including providing a seal or barrier such that fluid may be selectively injected to or at a desired level in the wellbore to a desired zone within the surrounding formation.

[0008] Where the recovery process involves high-pressure steaming of wells, such as in CSS, it is necessary to conduct a casing integrity test prior to steam injection to ensure that the well will survive steaming. The main component of a casing integrity test is a pressure test of the casing. Typically, a service rig is required to remove the tubing to pressure test the well. The service rig is moved on the well and the well is killed. The pump and rod are then removed from the well. The tubing is removed and a scraper and drift assembly is run to clean the casing and test for anomalies. A packer is run and set and the casing is pressure tested. The tubing is run back into the well and then the pump and rod are run back in.

SUMMARY

[0009] Generally, the present disclosure describes a packer that is ported to provide fluid communication through the packer between the wellbore annulus above the packer and

the wellbore annulus below the packer. Such a ported packer can be used to allow for pressure testing the casing and/or for controlling a failed well.

[0010] In one aspect, the present disclosure provides a method of pressure testing a well casing, the well casing having disposed therein a packer and a tubing string, the packer having ports for providing fluid communication through the packer between a wellbore annulus above the packer and a wellbore annulus below the packer, the method comprising: injecting fluid and soluble perforation sealer balls to plug the ports in the packer; bringing the well casing up to a testing pressure to pressure test the well casing and then reducing the pressure; and shutting in the well casing until the well casing goes on vacuum indicating that the sealer balls have dissolved, thereby unplugging the ports.

[0011] In another aspect, the present disclosure provides a method of controlling a failed well having a well casing, the well casing having disposed therein a packer and a tubing string, the packer having ports for providing fluid communication through the packer between a wellbore annulus above the packer and a wellbore annulus below the packer, the method comprising: pressuring up the tubing string to create an aperture in the tubing string; pumping fluid and solid floating balls down the tubing string and out the aperture;
once the balls are below the packer, flowing the well casing to allow the balls to plug the ports; allowing a well casing pressure to drop, and then bleeding off the well casing to below fracture pressure at a break in the well casing of the failed well; maintaining pressure below fracture pressure until reservoir pressure drops to a level where the well casing can be repaired; and circulating out the balls during well casing repair.

[0012] Other aspects and features of the present disclosure will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] Embodiments of the present disclosure will now be described, by way of example only, with reference to the attached Figure.

[0014] Fig. 1 illustrates a ported packer in accordance with a disclosed embodiment.

DETAILED DESCRIPTION

[0015] The term “viscous oil” as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute (API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and bitumen are used interchangeably herein since they may be extracted using similar processes.

[0016] *"In situ"* is a Latin phrase for “in the place” and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. An *in situ* hydrocarbon recovery technique is one that recovers hydrocarbons from a reservoir within the earth.

[0017] As described above, the packer described herein is ported to provide fluid communication through the packer between the wellbore annulus above the packer and the wellbore annulus below the packer. Such a ported packer can be used to allow for pressure testing the casing and/or controlling a failed well.

[0018] **Ported Packer**

[0019] Figure 1 illustrates a ported packer in accordance with one embodiment. The packer (100) is disposed within a casing (102) and holds a tubing string (104) in place. Regular collars (106a and 106b), a NoGo collar (108), and a shaved and beveled collar (110) are also shown. Regular and shaved and beveled collars are standard equipment for joining jointed tubing together in a well. A shaved and beveled collar is a modified regular collar that has some material removed from its outside diameter and ends by turning it on a lathe to make it pass through restrictions in the wellbore more easily and with less chance of catching on sharp edges. A NoGo collar is a collar with a larger outside diameter that is larger than a restriction in the well so the tubing cannot pass that point.

[0020] The packer (100) comprises a top sub (112) and a bottom sub (114). The subs (112 and 114) are attached to the top and bottom of the packer and include top ports (120a) and bottom ports (120b). The ports (120a and 120b) allow the annular flow to bypass the packer (100). The subs (112 and 114) are threaded on their ends for attachment to the packer (100) and the seal bore.

[0021] A top seal bore (116) is attached to the top of the top sub (112). A bottom seal bore (118) is attached to the bottom of the bottom sub (114). The seal bores are tubular sections of pipe that are polished inside to allow seals to move up and down inside making a seal while preventing (or mitigating) wear of the seals. A stringer assembly (105) is part of the tubing string (104) and holds the seals that seal inside the seal bores (116 and 118) and allow thermal movement of the tubing string without loss of the ability to isolate the annulus above the packer (100) from the annulus below the packer (100).

[0022] The top sub (112) includes the top ports (120a) and the bottom sub (114) includes the bottom ports (120b) to provide fluid or gas communication through the packer (100) between the wellbore annulus above the packer (100) and the wellbore annulus below the packer (100). The size of the ports (120a and 120b) could be, for instance, half an inch in diameter to three quarters an inch in diameter. The size of the ports could be larger, depending on the size of the packer. The ports may be circular in cross-section or may be another shape. The number of ports may be, for instance, between 4 and 16, but the number may vary depending on the size of the packer and the desired pressure drop across the packer.

[0023] During steaming down the casing (102), steam flows through the top ports (120a) in the top sub (112), through the inside of the packer (100), and then out the bottom ports (120b) in the bottom sub (114) defining an annular flow path (122). The annular flow path (122) is illustrated in Figure 1. Steam flow would only be restricted by the annular flow path (122) to a small extent. The tubing (104) can float in the seal bores (116 and 118) during thermal movement.

[0024] An alternate design for the packer would be to remove the seal bores (116 and 118) and the stinger assembly (105) and replace them with a thermal tubing expansion joint above the packer. The packer would then be attached to the tubing string (104) and thermal expansion of the tubing would take place within the expansion joint. The tubing expansion joint is a tubular device which allows thermal growth or compression of the tubing string but maintains pressure containment between the tubing and the annulus.

[0025] Pressure Testing a Casing using the Ported Packer

[0026] To pressure test a casing, fluid and soluble perforation ball sealers are injected down the casing having a ported packer. A pressure pumping truck may be used to pump the fluid. The fluid may be water or another non-compressible fluid. Soluble perforation ball sealers are known in the art, and an example are BioBalls™, which are available from Santrol Oil and Gas Stimulation Products (Fresno, Texas, United States). The ball sealers should be soluble in the liquid used to pressure test the casing and should dissolve in a manner that leaves only minimal residue behind. The balls should be stable at the temperatures experienced in the wellbore at the depth of the ported packer yet dissolve in a short length of time so as not to have the well shut in for a long period of time. The balls plug the top ports in the top sub. Next, the pressure is raised to a predetermined point to test the casing and is then released. After the test, the well is shut in until it goes on vacuum indicating that the balls have dissolved. The well is then put back on production.

[0027] Controlling a Casing Failure using a Ported Packer

[0028] Such a ported packer may have the added advantage of being able to control a high-pressure casing failure. When a well fails (meaning that the casing can no longer retain pressure) because of a break in the well casing, reservoir fluid starts flowing to and out the break above the packer. After a well fails, one would land a pump, pressure up the tubing, and create an aperture in the well tubing. A common way to create such an aperture is to blow the burst. The burst is a window style pressure relief tool that, at a predetermined pressure, shears a rectangular hole out the side of the tubing giving access to the annulus from the tubing and relieves high pressure in the tubing before it gets high enough to burst the tubing. Next, floating solid ball sealers are pumped down the tubing with a fluid which could be hot water or another stable non-compressible fluid with a specific gravity low enough to ensure that the balls float. The balls are pumped out the burst. Once the ball sealers are below the packer, the casing pressure is bled off until the ball sealers plug the bottom ports in the bottom sub. Once the casing pressure drops, the casing is bled off to below fracture pressure at the break. The casing is then kept below the fracture pressure at the break until the well is at a low enough pressure to be worked on. The balls can be circulated out during casing repair.

[0029] For use in thermal oil wells, the solid floating ball sealers should be capable of floating in the pumped fluids and be stable at the high temperatures experienced in a thermal oil well. In this case, the balls should be capable of withstanding temperatures of over 300°C.

[0030] In a thermal oil well, produced water can boil or flash off leaving a scale behind that can plug off small spaces. To address a potential concern of scaling across the packer, one could use an acid wash before pressure testing to ensure the ports are not restricted.

[0031] This assembly could be run in a well after its first casing integrity check, for instance in cycle six or seven. A cycle is defined as the period of time from when steam is injected in the well to when steam is again injected into a well and includes the soaking period after steam but before production and the production period. This would allow for an analysis of the wellbore and pad damage. Subsequent casing checks could be replaced with pressure tests using a ported packer as described herein.

[0032] It would also be possible to run in a ported packer in the well before the first steam cycle and use it to pressure test the well every cycle ensuring casing integrity is good before every steam cycle.

[0033] **Hydrocarbon Recovery Processes**

[0034] The ported packer and methods described herein may be used in a variety of hydrocarbon recovery processes, including those described in the background section. As described in the background section, in recovery processes involving high-pressure steaming of wells, such as in CSS, it is necessary to periodically conduct a casing integrity test prior to steam injection to ensure that the well will survive steaming.

[0035] **Potential advantages**

[0036] By using this type of ported packer, one could check the casing integrity of a well by checking the pressure without having to pull out the tubing and could result in less downtime of the well and reduce the costs associated with testing the casing integrity.

[0037] By using this type of ported packer, one has the ability to control a casing failure in a high-pressure regime. The conventional operating procedure in response to a high pressure casing failure consists of killing the well with heavy mud. This procedure can take roughly 2 days, whereas the ported packer well control procedure may take approximately one half day.

[0038] In the preceding description, for purposes of explanation, numerous details are set forth in order to provide a thorough understanding of the embodiments. However, it will be apparent to one skilled in the art that these specific details are not required. In other instances, well-known electrical structures and circuits are shown in block diagram form in order not to obscure the understanding.

[0039] The above-described embodiments are intended to be examples only. Alterations, modifications and variations can be effected to the particular embodiments by those of skill in the art without departing from the scope, which is defined solely by the claims appended hereto.

WHAT IS CLAIMED IS:

1. A method of pressure testing a well casing, the well casing having disposed therein a packer and a tubing string, the packer having ports for providing fluid communication through the packer between a wellbore annulus above the packer and a wellbore annulus below the packer, the method comprising:

- injecting fluid and soluble perforation sealer balls to plug the ports in the packer;
- bringing the well casing up to a testing pressure to pressure test the well casing and then reducing the pressure; and
- shutting in the well casing until the well casing goes on vacuum indicating that the sealer balls have dissolved, thereby unplugging the ports.

2. The method of claim 1, further comprising, after the sealer balls have dissolved, putting the well on production.

3. The method of claim 1 or 2, wherein the packer comprises top and bottom subs having ports for providing fluid communication through the packer.

4. The method of claim 3, wherein:

the well casing has seal bores disposed therein attached to the top and bottom subs, for allowing seals to move up and down making a seal while mitigating wear of the seals; and

the tubing string comprising a stringer assembly for holding the seals inside the seal bore while allowing thermal movement of the tubing string.

5. The method of claim 4, wherein the well casing has a thermal tubing expansion joint disposed therein above the packer and attached to the tubing string, for allowing thermal expansion or compression of the tubing string while maintaining pressure containment between the tubing and the annulus.

6. The method of any one of claims 1 to 5, effected in a thermal well.

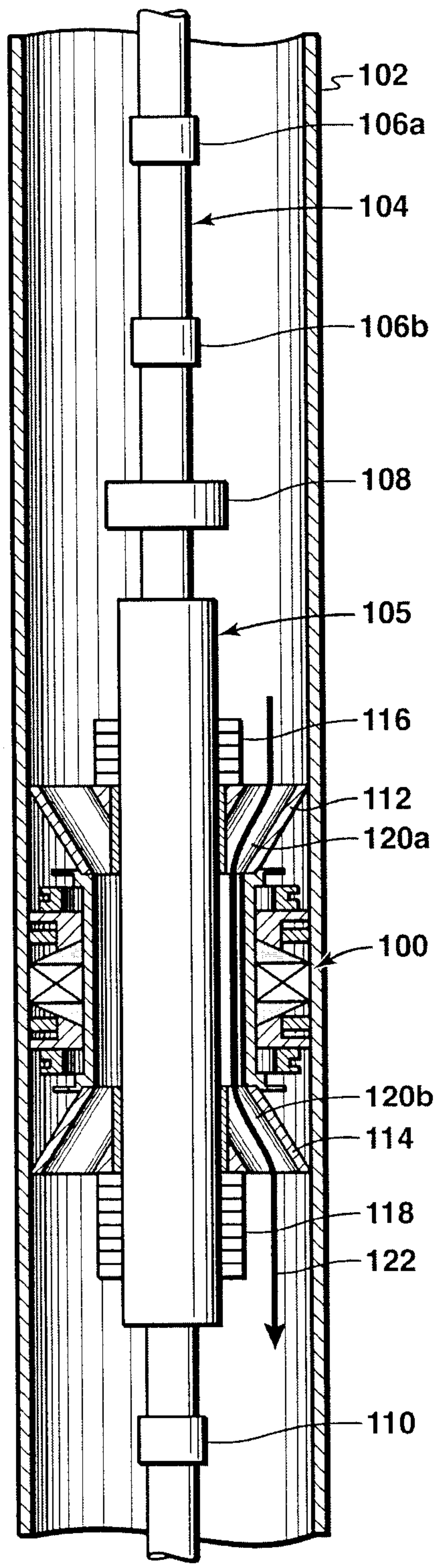
7. The method of any one of claims 1 to 6, effected in a well for producing viscous oil with a viscosity of at least 10 cP at initial reservoir conditions.

8. The method of any one of claims 1 to 7, effected in a CSS well.

9. The method of any one of claims 1 to 7, effected in a well used in one of the following processes: steam flood, SAGD, SA-SAGD, VAPEX, LASER, SAVEX, or a derivative thereof.

10. The method of any one of claims 1 to 9, wherein the ports in the packer are circular and are half an inch in diameter to three quarters an inch in diameter.

11. The method of any one of claims 1 to 10, wherein the packer comprises 4 to 16 ports.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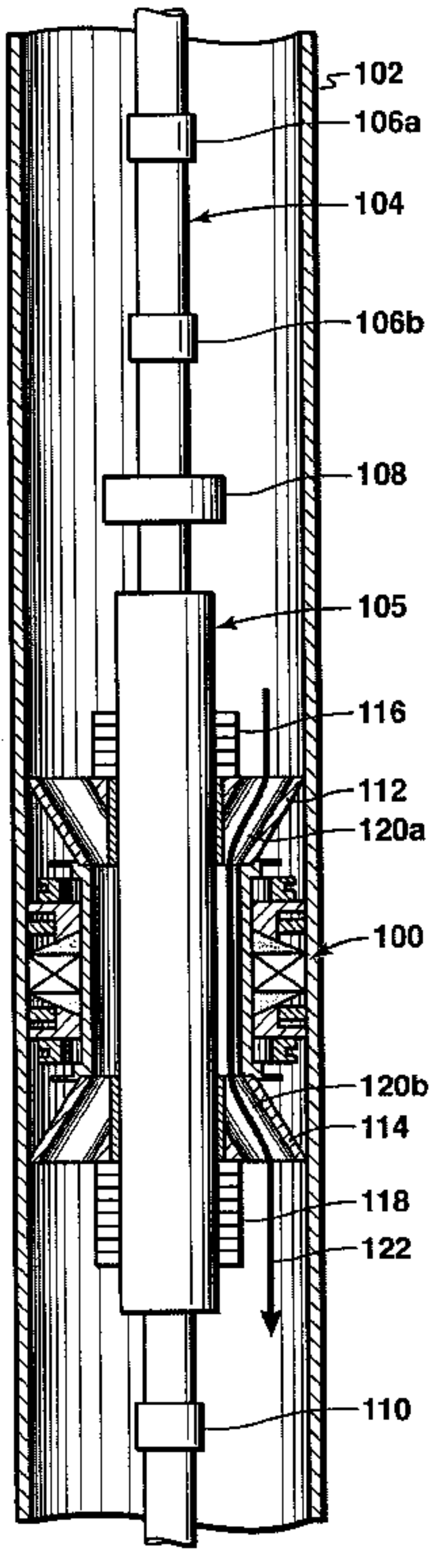
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