METHOD AND APPARATUS FOR COMPLETING AND FLUID TREATING A WELLBORE

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Publication Classification

Int. Cl. E21B 33/00 (2006.01)

U.S. Cl. 166/285; 166/281; 166/177.4

ABSTRACT

A wellbore fluid treatment apparatus capable of being actuated by a sealing device. The apparatus includes a casing including a bore and a casing port opened through the wall of the casing. The apparatus also includes a sleeve located within the casing bore. The sleeve includes a sleeve port opened through the wall of the sleeve and a baffle seat forming an inner flow area and configured to receive the sealing device. The sleeve is moveable by the sealing device between a closed position preventing fluid flow from the bore through the casing port and an open position allowing fluid flow from the bore through the sleeve port and casing port. The apparatus also includes a reverse cement shoe attached to the casing. The reverse cement shoe has a valve that allows the casing to be cemented by displacing cement only on the outside of the casing.
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CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] Not Applicable.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not Applicable.

BACKGROUND

[0003] In general, when drilling a wellbore in the earth, a drilling fluid is pumped down a drill string and through a drill bit attached to the end of the drill string. The drilling fluid may also flow through a bottom hole assembly ("BHA") located in the drill string above the bit. The BHA may house any number of tools or sensors for performing operations while the drill string is in the wellbore. The drilling fluid is generally used for lubrication and cooling of drill bit cutting surfaces while drilling, transportation of "cuttings" (pieces of formation dislodged by the cutting action of the teeth on a drill bit) to the surface, controlling formation pressure to prevent blowouts, maintaining well stability, suspending solids in the well, minimizing fluid loss into and stabilizing the formation through which the well is being drilled, fracturing the formation in the vicinity of the well, and displacing the fluid within the well with another fluid. When drilling is completed, the wellbore remains filled with the drilling fluid.

[0004] After drilling, casing is often placed in the wellbore to facilitate the production of oil and gas from the formation. The casing is a string of pipes that extends down the wellbore, through which the oil and gas will eventually be extracted. A casing shoe is typically attached to the end of the casing string when the casing string is run into the wellbore. The casing shoe may be a "float" shoe, which has an open bottom with a check valve to prevent flow into the casing as the casing is run into the wellbore.

[0005] The region between the casing and the wellbore itself is known as the casing annulus. To fill up the casing annulus and secure the casing in place, the casing is usually "cemented" in the wellbore. Traditionally cementing is done by pumping a cement slurry down the inside of the casing. As the slurry reaches the bottom of the casing, it flows out of the casing and into the casing annulus between the casing and the wellbore wall. As the cement slurry flows up the annulus, it displaces any fluid in the wellbore. To ensure no cement remains inside the casing, devices called "wipers" are pumped through the inside of the casing after the cement. The wiper contacts the interior surface of the casing and pushes any remaining cement out of the casing. Wipers, however, require a near uniform inside surface to be effective because the wipers must maintain contact with the inside surface of the casing to push the cement out. The cementing process is complete when cement slurry reaches the surface, and the annulus is completely filled with the slurry. When the cement hardens, it provides support and sealing between the casing and the wellbore wall. Once installed, the casing is perforated to permit inflow through the openings created by perforating and into the casing.

[0006] Another method for cementing a casing in a wellbore is called "reverse cementing." Reverse cementing is a term of art used to describe a method where the cement slurry is pumped down the casing annulus instead of the inside casing. The cement slurry displaces any fluid as it is pumped down the annulus. The annulus fluid is forced down the annulus, into the casing, and then back up to the surface. When reverse cementing, the valve on the float shoe must be adjusted to allow flow into the casing and then sealed after the process is complete. Because of the changing requirements for the float shoe, the valve must be a complex device. Once slurry is pumped to the bottom of the casing, the reverse cementing process is complete.

[0007] Before and even after casing is installed, the well may require wellbore treatment that is referred to as stimulation. Stimulation involves pumping stimulation fluids such as fracturing fluids, acid, cleaning chemicals, and/or proppant laden fluids into the formation to improve wellbore production. The stimulation fluids are pumped through the casing and then into the wellbore. If the casing is installed and more than one zone of interest of the formation is treated, tools must be run into the casing to isolate fluid flow at each zone.

[0008] Instead of stimulating the formation after installing casing, the well operator may choose to stimulate an uncased portion of a wellbore. To do so, the operator may run a liner extending from the surface into the uncased section of the wellbore with inflatable element packers to isolate the portions of the wellbore. Multiple packers allow the operator to isolate segments of the uncased portion of the wellbore so that each segment may be individually treated to concentrate and control fluid treatment along the wellbore.

[0009] Such inflatable packers may be limited with respect to pressure capabilities as well as durability under high pressure conditions. Generally, the packers are run for a wellbore treatment, but must be moved after each treatment if it is desired to isolate other segments of the well for treatment. This process can be expensive and time consuming. Furthermore, it may require stimulation pumping equipment to be at the well site for long periods of time or for multiple visits. This method can be very time consuming and costly.

[0010] The tubing string, which conveys the treatment fluid, can include ports or openings for the fluid to pass into the wellbore. Where more concentrated fluid treatment is desired in one position along the wellbore, a small number of larger ports may be used. Where it is desired to distribute treatment fluids over a greater area, a perforated tubing string may be used having a plurality of spaced apart perforations through its wall. The perforations can be distributed along the length of the tube or only at selected segments. The open area of each perforation can be pre-selected to control the volume of fluid passing from the tubing during.

[0011] In previous systems, it is necessary to run the tubing string into the bore hole with the ports or perforations already opened. This is especially true where a distributed application of treatment fluid is desired such that a plurality of ports or perforations must be open at the same time for passage therethrough of fluid.

[0012] Another method of treating a formation with or without an uncased wellbore involves running a non-casing fluid treatment tubing string with packers into the wellbore. The string includes at least one section of ports that are openable when desired to permit fluid flow into the wellbore. A sleeve or sleeves are located inside the tubing at each section of ports in the tubing and include ports that correspond with the ports in the tubing. The sleeves are initially axially offset from the tubing ports so that the tubing ports are
closed to fluid flow. The sleeves include annular seats of differing diameters. To open a given set of ports, at least one packer is set to isolate the annulus between the tubing string and the formation or casing around the section of ports. A ball is then pumped down and landed on the annular seat of the given sleeve. If more than one sleeve is used, the diameters of the annular seats are staged with decreasing diameters. Thus, a ball with a diameter for landing on the given sleeve will pass through the annular seats of any previous sleeves as it passes through the tubing. With the ball landed on the annular seat of the desired sleeve, fluid pressure is applied to form a seal preventing fluid flow past the sleeve. The fluid pressure also moves the sleeve axially, thus matching up the ports in the sleeve with the ports in the tubing and allowing fluid flow from the tubing to pass through the sleeve ports, through the tubing ports, and into the wellbore.

[0013] This method, however, is limited to using a non-casing tubing string with packers however. The method may not be used with a casing string cemented in place using traditional cementing. As described above, the annular seats on the sleeves prevent the ability of wipers to effectively clean the cement from the inside of the tubing string.

SUMMARY OF THE INVENTION

[0014] Disclosed herein is a wellbore fluid treatment apparatus capable of being actuated by a sealing device, the apparatus comprising a casing including a bore and a casing port opened through the wall of the casing, a sleeve located within the casing bore and including a sleeve port opened through the wall of the sleeve, a baffle seat forming an inner flow area and configured to receive the sealing device, and the sleeve being moveable by the sealing device between a closed position preventing fluid flow from the bore through the casing port and an open position allowing fluid flow from the bore through the sleeve port and casing port, and a reverse cement shoe attached to the casing and including a valve allowing the casing to be cemented by displacing cement only on the outside of the casing.

[0015] Also disclosed herein is a method of fluid treating a wellbore, the method comprising running a casing into the wellbore, the casing comprising a bore, a casing port opened through the wall of the casing, and a sleeve located in the casing bore, wherein the sleeve includes a sleeve port and is in a closed position preventing fluid flow from the bore through the casing port, cementing the casing in the wellbore by flowing cement from the surface down the casing annulus, with cement being displaced only on the outside of the casing, running a sealing device through the casing bore and into engagement with a baffle seat of the sleeve, moving the sleeve from closed position to an open position, the sleeve port allowing fluid flow from the bore through the casing port in the open position, and flowing well treatment fluids from the bore into the formation through the casing port.

[0016] Also disclosed herein is a well system including more than one string of casing, at least one string of casing including a wellbore fluid treatment apparatus capable of being actuated by a sealing device, the wellbore fluid treatment apparatus including a casing including a bore and a casing port opened through the wall of the casing, a sleeve located within the casing bore and including a sleeve port opened through the wall of the sleeve, a baffle seat forming an inner flow area and configured to receive the sealing device, the sleeve being moveable by the sealing device between a closed position preventing fluid flow from the bore through the casing port and an open position allowing fluid flow from the bore through the sleeve port and casing port, and a reverse cement shoe attached to the casing, the float shoe allowing the casing to be cemented by displacing cement only on the outside of the casing.

[0017] Also disclosed herein is a method of producing fluid from a formation through a wellbore, the method including running a casing into the wellbore, the casing including a bore and a casing port opened through the wall of the casing, running a sleeve located in the casing bore into the wellbore with the casing, the sleeve including a sleeve port and being in a closed position preventing fluid flow from the bore through the casing port, cementing the casing in the wellbore, allowing fluids to flow into the casing bore through a reverse cement shoe with cement being displaced only on the outside of the casing, flowing a sealing device through the casing bore and into engagement with a baffle seat of the sleeve, moving the sleeve from closed position to an open position, the sleeve port allowing fluid flow from the bore through the casing port in the open position, flowing well treatment fluids from the bore into the formation through the casing port, and allowing fluids to flow from the formation through the casing ports and into the casing bore.

[0018] Further disclosed herein is a method of servicing a wellbore, including running a ported casing into the wellbore wherein one or more ports may be in a closed position, pumping cement from the surface down the casing annulus, isolating a portion of the casing prior to or after pumping the treatment fluid, and pumping a treatment fluid from the surface through the casing and out one or more ports into the formation.

BRIEF DESCRIPTION OF THE DRAWINGS

[0019] For a more detailed description of the embodiments, reference will now be made to the following accompanying drawings:

[0020] FIG. 1 is a schematic cross-section drawing of a well system including a wellbore fluid treatment apparatus;

[0021] FIG. 2A is a close-up cross section drawing illustrating an example of a reverse cement casing shoe in a flow-through position;

[0022] FIG. 2B is a close-up cross section drawing illustrating an example of a reverse cement casing shoe in a closed position;

[0023] FIG. 3 is a close-up cross-section drawing of a wellbore treatment system;

[0024] FIG. 4 is a close-up cross-section drawing of an individual wellbore isolation segment that is part of the wellbore treatment system;

[0025] FIG. 5 is a close-up cross-section drawing illustrating an alternative wellbore fluid treatment apparatus configuration;

[0026] FIG. 6 is a close-up cross-section drawing illustrating a wellbore fluid treatment at a first formation zone using an isolation sleeve and sealing device; and

[0027] FIG. 7 is a close-up cross-section drawing illustrating a wellbore fluid treatment at a second formation zone using an isolation sleeve and a sealing device.

DETAILED DESCRIPTION OF THE EMBODIMENTS

[0028] In the drawings and description that follows, like parts are marked throughout the specification and drawings.
with the same reference numerals, respectively. The drawing figures are not necessarily to scale. Certain features of the invention may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness. The present invention is susceptible to embodiments of different forms. Specific embodiments are described in detail and are shown in the drawings, with the understanding that the present disclosure is to be considered an exemplification of the principles of the invention, and is not intended to limit the invention to that illustrated and described herein. It is to be fully recognized that the different teachings of the embodiments discussed below may be employed separately or in any suitable combination to produce desired results. Unless otherwise specified, any use of any form of the terms “connect”, “engage”, “couple”, “attach”, or any other term describing an interaction between elements is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described. In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . .”. Reference to up or down will be made for purposes of description with “up”, “upper”, “upwardly” or “upstream” meaning toward the surface of the well and with “down”, “lower”, “downwardly” or “downstream” meaning toward the terminal end of the well, regardless of the well bore orientation. The various characteristics mentioned above, as well as other features and characteristics described in more detail below, will be readily apparent to those skilled in the art upon reading the following detailed description of the embodiments, and by referring to the accompanying drawings.

[0029] Referring to FIG. 1, a cross-sectional view of a wellbore 1 and casing 11 is shown. The wellbore 1 is drilled below the earth’s surface 7. A surface casing 2 is inserted a short distance below the surface 7 into the wellbore 1. A blow out preventer 3 is attached to the top of the surface casing 2 which extends slightly above the surface 7. A swag nipple 8 is attached to the top of the blow out preventer 3 or may be attached to the primary casing 11. A return line 9 extends from the top of the swag nipple 8, and a casing flow meter 6 monitors the flow rate in the return line 9. A pump line 10 has an annulus pressure meter 4 and an annulus flow meter 5. The casing 11 is suspended in the wellbore 1 below the blow out preventer 3. A pump 60 is used to pump cement slurry from a slurry mixing device 61 into the annulus 14 for cementing operations discussed below. The pump 60 could be any suitable pump, such as but not limited to, a low pressure pump or a centrifugal pump. It should be appreciated that the current description is not necessarily limited to the configuration shown in FIG. 1, and that other well configurations are possible and other surface equipment configurations may be used as well.

[0030] Referring to FIGS. 1, 2A, and 2B, a reverse cement shoe 12 is attached to the lower end of the casing 11. The shoe 12 includes a base 30 having an inner bore 37 formed by an inner surface 31. The base 30 is held in place in the casing 11 using any suitable means, such as an interference fit or locking pins. Extending from the base 30 is a flow sleeve 32 with a central bore 42 and at least one offset bore 34, with two offset bores 34 being shown. Each offset bore 34 includes an inlet 46 and is in fluid communication with the base inner bore 37. The shoe 12 further includes a central valve member 36. As shown in FIG. 2A, the central valve member 36 is initially held in place in the flow sleeve central bore 42 by the use of shear pins 44. Also, a seal 40 on the outside of the central valve member 36 forms a seal with the inside of the flow sleeve 32. As illustrated in FIG. 2A, as long as the flow sleeve offset bores 34 remain unobstructed, fluid may flow in through the offset bore inlets 46 and into the base inner bore 37 as shown by the flow direction arrows in FIG. 2A. The fluid may then continue up the base bore 16 of the casing 11.

[0031] Referring to FIGS. 1 and 3, a wellbore fluid treatment apparatus 20 is shown. Included in the apparatus 20 is the reverse cement shoe 12 described above. The wellbore fluid treatment apparatus 20 also includes at least a portion of the casing 11. The wellbore fluid treatment apparatus 20 also includes at least one casing port 21 opened through the wall of the casing 11 to the annulus 14. As shown, there may be more than one casing port 21. Additionally, the casing ports 21 may be grouped in sets and may be spaced apart axially along the casing 11 as shown with casing ports 21a and 21b.

[0032] The wellbore fluid treatment apparatus 20 also includes a pressure sleeve 17 located within the casing bore 16. As shown in FIG. 3, the pressure sleeve 17 includes at least one sleeve port 19 opened through the wall of the sleeve 17. The sleeve 17 is shown in FIG. 3 as being in an open position where the sleeve ports 19 are axially aligned with the set of casing ports 21a, thus allowing fluid flow from the casing bore 16 through the casing ports 21a. Although not shown, the sleeve 17 includes seals that form a seal against the inside surface of the casing 11 on the outside of the casing ports 21a. When initially run in, however, the sleeve 17 is in a closed position where the sleeve ports 19 are axially offset from the set of casing ports 21a, thus preventing fluid flow from the casing bore 16 through the casing ports 21a. The sleeve 17 further includes a reduced inner diameter that allows the pressure sleeve 17 to be moved from the closed position to the open position shown upon a sufficient pressure differential across the pressure sleeve 17.

[0033] The wellbore fluid treatment apparatus 20 also includes at least one sleeve 22 located within the casing bore 16. As shown in FIG. 3, the wellbore fluid treatment apparatus 20 only includes one sleeve 22. However, the wellbore fluid treatment apparatus 20 may also include more than one sleeve 22 as described further below. The sleeve 22 includes at least one sleeve port 23 opened through the wall of the sleeve 22. The sleeve 22 is shown in FIG. 3 as being in a closed position where the sleeve ports 23 are axially offset from a set of casing ports 21b, thus preventing fluid flow from the casing bore 16 through the casing ports 21b. Although not shown, the sleeve 22 includes seals that form a seal against the inside surface of the casing 11 on the outside of the casing ports 21b. As shown, although there is a sleeve 22 initially preventing fluid flow through a set of casing ports 21b, there are also a set of casing ports 21a that do not have a corresponding sleeve 22 to prevent fluid flow. The sleeve 22 further includes a baffle seat 25 that forms an inner flow area 27. As will be discussed in more detail below, the baffle seat 25 is configured to receive a sealing device 29 shown in FIG. 4.

[0034] Referring to FIGS. 1, 2A, and 2B, the casing 11 is run into the wellbore 1, and the casing-by-hole-annulus 14 may be isolated with common well blow out prevention equipment such as blow out preventer 3. The wellbore 1 is prepared for cementing by circulating a conventional mud
slurry in the conventional direction down through the inside of the casing 11 and up the annulus 14 until the annulus fluid is sufficiently clean. Pumping line 10 is connected at the surface 7 for flowing the fluid in the wellbore 1. Return line 9 is installed to the top of the casing 11 and may flow to a return tank or pit (not shown). A flow meter 6 may be installed in the return line 9 to monitor the flow rate.

[0035] After the annulus 14 is sufficiently cleaned, circulation fluid, rather than cement slurry, is pumped down the annulus 14. The circulation fluid is reverse-circulated down the annulus 14 and up the inside diameter of the casing 11. The annulus flow meter 5 and/or casing flow meter 6 are monitored to determine the fluid flow rate.

[0036] Once the circulation fluid is sufficiently in place, the cement slurry from the slurry mixing device 61 is then pumped down the annulus 14 using the pump 60. The cement slurry may be pumped at any suitable rate, for example, 1 bbl/min to 15 bbl/min. As used in this description, the word “pumping” broadly means to flow the slurry into the annulus 14. Circulation fluid initially in the annulus 14 is displaced from the annulus 14 as it flows into the casing 11 through the reverse cement shoe 12 and up to the surface 7. Thus, no cement is displaced inside the casing 11 during the cementing operation.

[0037] Just before the cement slurry is pumped into the annulus 14, at least one stopper 48 is inserted into the circulation fluid. Examples of suitable stoppers include plugs or balls made of composite, rubber, metal, or other suitable material. As the cement slurry flows down the annulus 14, the stoppers 48 flow ahead of the cement slurry. The return flow from the casing 11 is monitored using the flow meter 9. Once the stoppers 48 reach the reverse cement shoe 12, they land and seal on the inlets 46 of the flow sleeve offset bores 34. Once landed and sealed, the stoppers 48 prevent fluid from flowing into the reverse cement shoe 12 and the return flow rate will slow as indicated by the flow meter 6. Additional fluid pressure on the reverse cement shoe 12 acts not only upon the stoppers 48, but also upon the central valve member 36. Once a sufficient pressure differential across the central valve member 36 is reached, the valve member 36 shears the shearing pins 44 holding the central valve member 36 in place. The central valve member 36 then travels within the flow sleeve central bore 42 and into the base inner bore 37. The central valve member 36 includes a base seal 38 that forms a seal between the central valve member 36 and the base seal surface 50. Fluid pressure acting on the central valve member 36 pushes the central valve member 36 into the base 30 until an extension 52 on the central valve member 36 lands on the base inner surface 31, preventing further travel of the central valve member 36. Forming a seal to prevent flow through the reverse cement shoe 12 with the central valve member 36 prevents the flow of cement slurry into the casing 11 should the stoppers 48 unseat from the inlets 46 once the cement slurry is pumped in place but before the cement sets. Once the central valve member 36 is landed on the base 30, the casing 11 is landed in a casing hanger or wellhead and the cement job is complete.

[0038] Because the reverse circulation cementing process pumps the cement slurry directly down the annulus 14, rather than pumping it up the annulus 14 from the reverse cement shoe 12, no incremental work to lift the dense cement slurry in the casing-by-hole annulus 14 by high-pressure surface pumping equipment is needed. With this process, only a pump 60 is used to transfer the cement slurry from a slurry mixing or holding device 61 to the well 1. A low-pressure pump 60, such as a centrifugal pump, may be used for this purpose. Because low-pressure pumps and flow lines may be used, safety is inherently built into the system. It is not necessary to certify that the pumps and flow lines will operate safely at relatively higher pressures.

[0039] As shown in FIG. 1, a centrifugal pump 60 may be used to pump cement slurry from a slurry mixing device 61 into the primary annulus 14. One or more 6×4 centrifugal pumps 60 (six inch suction x four inch discharge), which may operate between about 40 psi and about 80 psi, may be used to pump the cement slurry from the slurry mixing device 61 to the well 1. Two or more centrifugal pumps 60 may be connected in series to produce a pump pressure of about 160 psi or more. This pressure may be required as the leading edge of the cement slurry is pumped into the annulus 14. The pressure may then be reduced as more of the cement slurry enters the annulus 14. Gravity acting on the relatively heavy cement slurry tends to pull the cement slurry down the annulus 14 so that less pump pressure is needed.

[0040] It should be appreciated that other configurations of a reverse cement shoe 12 than discussed above may be used. All configurations, however, will allow the casing 11 to be cemented in place without flowing the cement slurry through the inner bore 16 of the casing 11, but instead by displacing cement slurry on the outside of the casing 11 in the annulus 14.

[0041] Referring to FIGS. 3 and 4, once the casing 11 is installed, the wellbore fluid treatment operations may be performed. It should be appreciated that wellbore fluid treatment may involve any type of fluid treatment to the formation 18. For example, the fluid treatment may be wellbore stimulation to increase the ability of the formation 18 to produce hydrocarbons by using stimulation fluids such as one or more of acid, gelled acid, gelled water, gelled oil, carbon dioxide, nitrogen, and any of these fluids containing proppants, such as, for example, sand or bauxite.

[0042] Before installation, the casing 11 is designed to include the one or more casing ports 21 at selected locations depending on the specific zones of interest of the formation 18 to be treated. For example, one or more segmented of ported casing may be placed at one or more intervals along the casing string. To treat the formation 18, fluid communication between the casing 11 and the formation 18 must be established. Treating or servicing fluids, such as acid or a fracturing fluid, may be pumped through the casing ports 21 that break down the hardened cement in the casing annulus 14. Only the cement adjacent to the casing ports 21 is broken down, however, allowing the well operator to specifically target areas of the formation 18 adjacent to the casing ports 21.

[0043] As shown in FIG. 3, there is one set of casing ports 21a closed by the sleeve 17. For the initial wellbore fluid treatment, the area of the formation 18 adjacent the open casing ports 21a will be treated. Fluid pressure inside the casing 11 above the sleeve 17 is increased to create a differential pressure across the sleeve 17 to move the sleeve 17. Moving the sleeve 17 aligns the sleeve ports 19 with the casing ports 21a, allowing fluid contact with the casing ports 21a. After this initial pressure is released, the wellbore treatment fluids are pumped down the casing bore 16 and through the uncovered casing ports 21a. The wellbore treatment fluid breaks up the cement in the annulus 14, establishing fluid communication between the casing bore 16 and the formation 18 adjacent the casing ports 21a. The same or
different wellbore treatment fluids may then be pumped into the formation 18 adjacent the casing ports 21a, treating the formation 18 to enhance the production capabilities. Alternatively, to establish fluid communication with the formation 18 through the casing ports 21a, a perforating device attached to the casing 11 may be used instead of the wellbore treatment fluids to break up the cement.

[0044] Once wellbore treatment at the initial location is complete, a different location of the formation 18 may then be treated. A same or different wellbore treatment fluid may be needed for the new location in the formation 18. Additionally, it may not be desirable to perform any additional treatment procedures on the initial location of the formation 18. Thus, it may be desirable to isolate the initial location of the formation 18 already treated from wellbore treatment fluids in the casing bore 16 before treating the new location.

[0045] To isolate the first portion of treated formation adjacent ports 21a, a sealing device 29 is pumped down the casing bore 16 and into engagement with the baffle seat 25 of the sleeve 22 while the sleeve 22 is in the closed position. Once landed onto the baffle seat 25, fluid pressure within the casing 11 causes the sealing device 29 to form a seal against the baffle seat 25 that prevents fluid flow through the inner flow area 27. The sealing device 29 may be any suitable device that may be pumped into the casing 11 and landed on the baffle seat 25 to form a fluid tight seal. For example, the sealing device may be a bail or a plug and may be made of ferrous metal, composite, polymer, phenolic foam, or any combination of these. Forming the seal with the sealing device 29 prevents fluid flow past the sleeve 22 and thus isolates the initially treated area of the formation 18 adjacent ports 21a from any fluids in the casing 11 above the sleeve 22.

[0046] Once the initially treated area of the formation 18 is isolated, wellbore treatment procedures may proceed at the new location without affecting the initially treated location. As shown in FIG. 3, the sleeve 22 is initially in a closed position and held in place with sleeve shearing pins 28. The sleeve 22 also includes guides 24 that travel within corresponding grooves 26 on the inside of the casing 11. The grooves 26 contact and landing surface that limits the travel of the guides 24 and thus also limit the travel of the sleeve 22. To treat the formation 18 adjacent the casing ports 21b covered by the sleeve 22, fluid communication must be established between the formation 18 and the casing bore 16 above the sealing device 29. To establish fluid communication, the sleeve 22 is moved from the initial closed position as shown in FIG. 3 to an open position as shown in FIG. 4. The sleeve 22 is moved to the open position by increasing the fluid pressure above the sealing device 29 and creating a pressure differential across the sleeve baffle seat 25 such that the force acting on the sleeve 22 shears the sleeve shear pins 28 and moves the sleeve 22 relative to the casing 11 to substantially align the sleeve and casing ports. Once in the open position, the sleeve ports 23 allow fluid flow from the casing bore 16 through the casing ports 21. Again, initially fluid is pumped through the casing ports 21 to deteriorate the cement in the annulus 14 and allow fluid to flow between the area of the formation 18 adjacent the casing ports 21b and the casing bore 16. With fluid communication established, wellbore treatment fluids may then be pumped into the casing bore 16 and into the formation 18 through the casing ports 21b. The fluids treat the formation 18 and enhance the production capabilities of the formation 18.

[0047] When wellbore treatment operations are complete, fluid pressure within the casing 16 is lowered to less than the fluid pressure of fluids in the formation 18. Fluids from the formation 18 are then allowed to enter the casing 11 through the casing ports 21. When the fluid pressure is high enough from the flow of formation fluids in the casing bore 16, the sealing device 29 is unseated from the baffle seat 25 and fluids from both above and below the sleeve 22 flow through the casing bore 16 to the surface 7. The sealing device 29 is pumped by the formation fluids flowing in the casing bore 16 toward the surface 7. If the sealing device 29 makes it to the surface, appropriate equipment at the surface, such as a sealing device catcher, may be used to retrieve the sealing device 29 from the fluid flow. Sometimes, however, the sealing device 29 is destroyed before reaching the surface 7 and no retrieval is necessary.

[0048] It should be appreciated that more than two zones of interest of the formation 18 may be treated. Although FIG. 3 only shows two sets of casing ports 21a and 21b and one sleeve 22, there may be as many sets of casing ports 21 and corresponding sleeves 22 as appropriate. There also need not be an initially open set of casing ports 21a, but the casing ports 21 may all be associated with sleeves 22 (e.g., multiple sleeve/port assemblies may be placed at intervals along the casing). Thus, the wellbore fluid treatment apparatus 20 is not limited by the embodiment illustrated in FIGS. 3 and 4.

[0049] For example, FIGS. 5, 6, and 7 show an alternate embodiment of the wellbore fluid treatment apparatus 20. Like parts are given like reference numerals and the operation of the wellbore fluid treatment apparatus 20 is similar to the operation above with further explanation below.

[0050] As shown in FIGS. 5, 6, and 7, instead of one sleeve 22, the wellbore fluid treatment apparatus 20 includes two sleeves 22a and 22b that correspond with the two sets of casing ports 21a and 21b. The casing ports 21a are spaced apart axially along the casing 11 as previously described and thus allow two different locations within the formation 18 to be treated with wellbore fluids. The operation of the wellbore fluid treatment apparatus 20 shown in FIGS. 5-7 differs in that the initial sealing device 29a must flow past the baffle seat 25 of at least one sleeve 22b before being seated on a subsequent sleeve 22a. As shown in FIG. 5, the initial sealing device 29a must flow through the inner flow area 27 of the uppermost sleeve 22b before landing on the lowermost sleeve baffle seat 25. To allow the initial sealing device 29a to pass the upper sleeve 22b, the baffle seat 25 of the upper sleeve 22a has a larger inner flow area 27. The inner flow area 27 of the sleeves 22a are different sizes and progressively decrease in size with each sleeve 22.

[0051] As shown in FIG. 5, the casing 11 is installed with the sleeves 22 in the closed position such that none of the casing ports 21 are open. As previously described, appropriate seals on the outside of the sleeves 22 seal the casing ports 21 from the casing bore 16. The first zone of interest of the formation 18 is then ready to be treated.

[0052] To flow wellbore treatment fluid into the first zone of the formation 18, a first sealing device 29a is inserted into the casing bore 16 and pumped downhole to the wellbore fluid treatment apparatus 20. Again, the sealing device 29 may be any suitable device that may be pumped into the casing 11 and landed on the baffle seat 25 to form a fluid tight seal. As shown in FIGS. 6 and 7, the sealing device 29 is a ball, but need not be limited to that configuration. As shown in FIG. 6, the inner
flow area 27 of the initial sleeve 22b is large enough to allow the initial sealing device 29a to pass through to the set sleeve 22a. The inner flow area 27 of the lower baffle seat 25, however, is smaller such that the initial sealing device 29a lands on the lower baffle seat 25 as previously described. Fluid pressure within the casing bore 16 is then increased to create a pressure differential across the lower sleeve baffle seat 25 such that the force acting on the sleeve 22a shears the sleeve shear pins 28 and moves the sleeve 22a relative to the casing 11. The lower sleeve 22a is thus moved from the initial closed position as shown in FIG. 5 to an open position as shown in FIG. 6 to establish fluid communication between the casing ports 21a and the sleeve ports 23a of the lower sleeve 22. Once in the open position, fluid is pumped in the casing bore 16 past the upper sleeve 22 and through the lower set of casing ports 21 to deteriorate the cement in the annulus 14 and allow fluid to flow between the formation 18 and the casing bore 16. With fluid communication established, wellbore treatment fluids may then be pumped into the casing bore 16, past the upper sleeve 22b, and into the formation 18 through the casing ports 21a to treat the formation 18 and enhance the production capabilities of the formation 18.

[0053] Once wellbore treatment at the initial location is complete, a different location of the formation 18 may be treated. A different wellbore treatment fluid may be needed for the new location in the formation 18. Additionally, it may not be desirable to perform any additional treatment procedures on the initial location of the formation 18. Thus, it may be desirable to isolate the initial location of the formation 18 already treated from wellbore treatment fluids in the casing bore 16 before treating the new location.

[0054] To isolate the already treated formation, another sealing device 29b is pumped down the casing bore 16 and into engagement with the baffle seat 25 of the upper sleeve 22b while the sleeve 22b is in the closed position. Because the inner flow area 27 of the upper sleeve 22b is larger than the lower sleeve 22a, the subsequent sealing device 29b is larger than the initial sealing device 29a. Once landed on the baffle seat 25 of the upper sleeve 22b, fluid pressure within the casing 11 causes the subsequent sealing device 29b to form a seal against the baffle seat 25 that prevents fluid flow through the inner flow area 27 of the upper sleeve 22b. Again, the sealing device 29 may be any suitable device that may be pumped into the casing 11 and landed on the baffle seat 25 to form a fluid tight seal. As shown in FIGS. 6 and 7, the sealing device 29b is a ball, but need not be limited to that configuration. Forming the seal with the sealing device 29b prevents fluid flow past the upper sleeve 22b and thus isolates the initially treated area of the formation 18 from any fluids in the casing 11 above the upper sleeve 22b.

[0055] Once the initially treated area of the formation 18 is isolated, wellbore treatment procedures may be performed without affecting the initially treated location. To treat the formation 18 adjacent the casing ports 21b covered by the upper sleeve 22b, fluid communication must be established between the formation 18 and the casing bore 16 above the subsequent sealing device 29b. As shown in FIG. 6, the upper sleeve 22b is initially in a closed position and held in place with sleeve shearing pins 28. The upper sleeve 22b is then moved from the initial closed position as shown in FIG. 6 to an open position as shown in FIG. 7. The upper sleeve 22b is moved to the open position by increasing the fluid pressure above the subsequent sealing device 29b and creating a pressure differential across the sleeve baffle seat 25 such that the force acting on the sleeve 22b shears the sleeve shear pins 28 and moves the upper sleeve 22b relative to the casing 11. Once in the open position, the sleeve ports 23b allow fluid flow from the casing bore 16 through the upper set of the casing ports 21b. Again, initially fluid is pumped through the casing ports 21b to deteriorate the cement in the annulus 14 and allow fluid to flow between the area of the formation 18 adjacent the casing ports 21 and the casing bore 16. With fluid communication established, wellbore treatment fluids may then be pumped into the casing bore 16 and into the formation 18 through the casing ports 21 to treat the formation 18 and enhance the production capabilities of the formation 18.

[0056] When the decision is made that wellbore treatment operations are complete, fluid pressure within the casing 16 is lowered to less than the fluid pressure of fluids in the formation 18. Fluids from the formation 18 are then allowed to enter the casing 11 through all the casing ports 21. When the fluid pressure is high enough from the flow of formation fluids in the casing bore 16, the sealing devices 29 are unseated from the baffle seats 25 and fluids from both above and below the upper sleeve 22 flow through the casing bore 16 to the surface 7. The sealing devices 29 are pumped by the formation fluids flowing in the casing bore 16 toward the surface 7. If the sealing devices 29 make it to the surface, appropriate equipment at the surface, such as a sealing device catcher, may be used to retrieve the sealing devices 29 from the fluid flow. Sometimes, however, the sealing devices 29 are destroyed before reaching the surface 7, and no retrieval is necessary.

[0057] It should be appreciated that more than two zones of interest of the formation 18 may be treated. Although FIGS. 5-7 only show two sets of casing ports 21 and two sleeves 22, there may be as many sets of casing ports 21 and corresponding sleeves 22 as appropriate. There may also be an initially open set of casing ports 21a (e.g., not associated with a sleeve assembly) as shown in FIG. 3. Thus, the wellbore fluid treatment apparatus 20 is not limited by the embodiment illustrated in FIGS. 5-7.

[0058] While specific embodiments have been shown and described, modifications can be made by one skilled in the art without departing from the spirit or teaching of this invention. The embodiments as described are exemplary only and are not limiting. Many variations and modifications are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited to the embodiments described, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims.

What is claimed is:
1. A wellbore fluid treatment apparatus capable of being actuated by a sealing device, the apparatus comprising:
a casing including a bore and a casing port opened through the wall of the casing;
a sleeve located within the casing bore and including:
a sleeve port opened through the wall of the sleeve;
a baffle seat forming an inner flow area and configured to receive the sealing device; and
the sleeve being moveable by the sealing device between a closed position preventing fluid flow from the bore through the casing port and an open position allowing fluid flow from the bore through the sleeve port and casing port; and
a reverse cement shoe attached to the casing and including
a valve allowing the casing to be cemented by displacing cement only on the outside of the casing.
2. The apparatus of claim 1, further comprising:
   more than one casing port; and
   wherein the sleeve includes sleeve ports corresponding with the casing ports.
3. The apparatus of claim 1, further comprising:
   more than one casing port spaced apart axially along the casing;
   more than one sleeve corresponding to spaced apart casing ports, each sleeve baffle seat being configured to receive a different size sealing device; and
   the size of baffle seat inner flow areas progressively decreasing such that a sealing device may flow through at least one sleeve before reaching a subsequent sleeve.
4. The apparatus of claim 1, wherein the sleeve is axially slideable between the closed and open positions.
5. The apparatus of claim 1, wherein the sleeve is moveable from the closed position to the open position upon a pressure differential across the baffle seat.
6. The apparatus of claim 1, wherein the baffle seat is configured to form a fluid tight seal with the sealing device, preventing fluid flow past the baffle seat.
7. The apparatus of claim 1, wherein wellbore treatment fluid may flow from the bore into the formation with the sleeve in the open position.
8. The apparatus of claim 7, wherein the wellbore treatment fluid is a fracturing fluid, an acidized fluid, or any combination of the two.
9. A method of fluid treating a wellbore, the method comprising:
   running a casing into the wellbore, the casing comprising a bore, a casing port opened through the wall of the casing, and a sleeve located in the casing bore, wherein the sleeve includes a sleeve port and is in a closed position preventing fluid flow from the bore through the casing port;
   cementing the casing in the wellbore by flowing cement from the surface down the casing annulus, with cement being displaced only on the outside of the casing;
   flowing a sealing device through the casing bore and into engagement with a baffle seat of the sleeve;
   moving the sleeve from closed position to an open position, the sleeve port allowing fluid flow from the bore through the casing port in the open position; and
   flowing well treatment fluids from the bore into the formation through the casing port.
10. The method of claim 9, wherein cementing the casing in the wellbore further comprises allowing fluids to flow into the casing bore through a reverse cement shoe.
11. The method of claim 9, further comprising preventing fluid flow through an inner flow area of the baffle seat by forming a fluid tight seal with the sealing device.
12. The method of claim 9, wherein the casing further includes:
   a set of casing ports; and
   wherein the sleeve includes sleeve ports corresponding to the casing ports.
13. The method of claim 9, further including:
   the casing including more than one casing port spaced apart axially along the casing;
   wherein running a casing into the wellbore includes running in more than one sleeve corresponding to each casing port, each sleeve baffle seat inner flow area being a different size and progressively decreasing with each sleeve; and
   flowing the sealing device through at least one sleeve before engaging a subsequent sleeve.
14. The method of claim 13, further including flowing more than one sealing device in the casing bore, each sealing device engaging a different sleeve.
15. The method of claim 14, further including:
   moving each sleeve from the closed position to the open position by creating a pressure differential across the sleeve baffle seats, the sleeve ports allowing fluid flow from the bore through the casing port in the open position; and
   flowing well treatment fluids from the bore into the formation through the casing ports.
16. The method of claim 9, moving the sleeve further including axially sliding the sleeve between the closed and open positions.
17. The method of claim 9, further including creating a pressure differential across the baffle seat to move the sleeve from the closed position to the open position.
18. The method of claim 9, wherein flowing wellbore treatment fluid includes flowing wellbore treatment fluid selected from at least one of the group consisting of acid, gelled acid, gelled water, gelled oil, carbon dioxide, nitrogen, and any of these fluids containing proppants.
19. The method of claim 9, further including flowing the sealing device back to the surface.
20. The method of claim 9, further including allowing fluids to flow from the formation through the casing ports and into the casing bore.
21. A method of servicing a wellbore, including:
   running a ported casing into the wellbore, wherein one or more ports may be in a closed position;
   pumping cement from the surface down the casing annulus;
   isolating a portion of the casing prior to or after pumping the treatment fluid; and
   pumping a treatment fluid from the surface through the casing and out one or more ports into the formation.
22. The method of claim 21, further including opening one or more ports.

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