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April 5, 1966 D. H. FLICKINGER 3,244,234

APPARATUS FOR REDUCING HYDRAULIC FRICTION

Filed Feb. 26, 1962 4 Sheets-Sheet 1

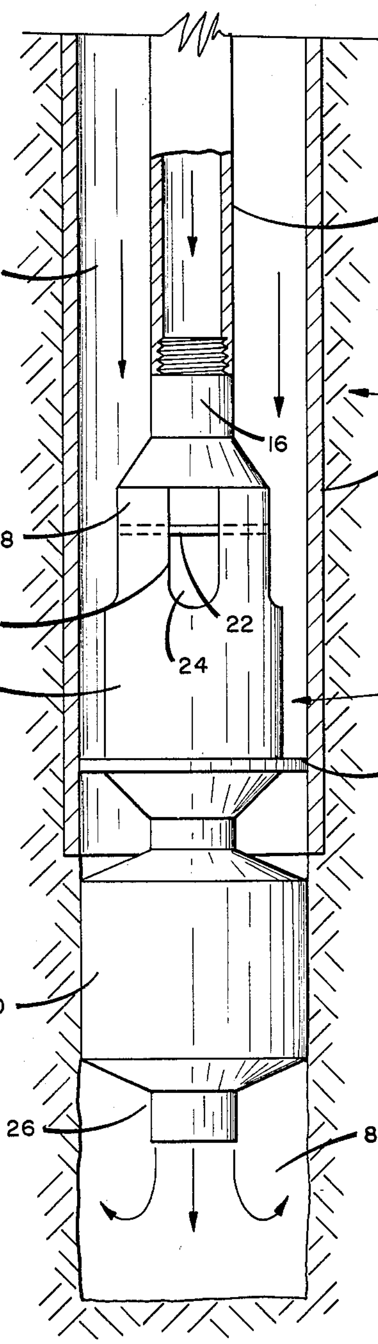

FIG. - 1

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Filed Feb. 26, 1962 4 Sheets-Sheet 2

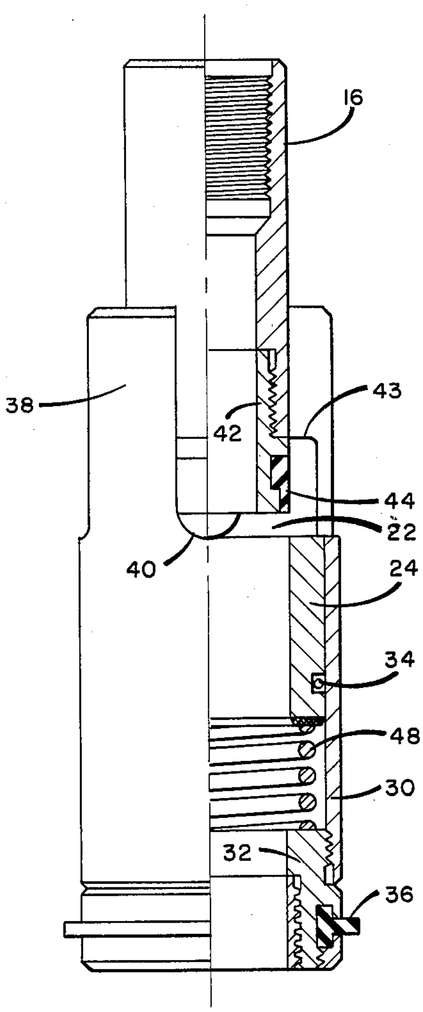

FIG. - 3

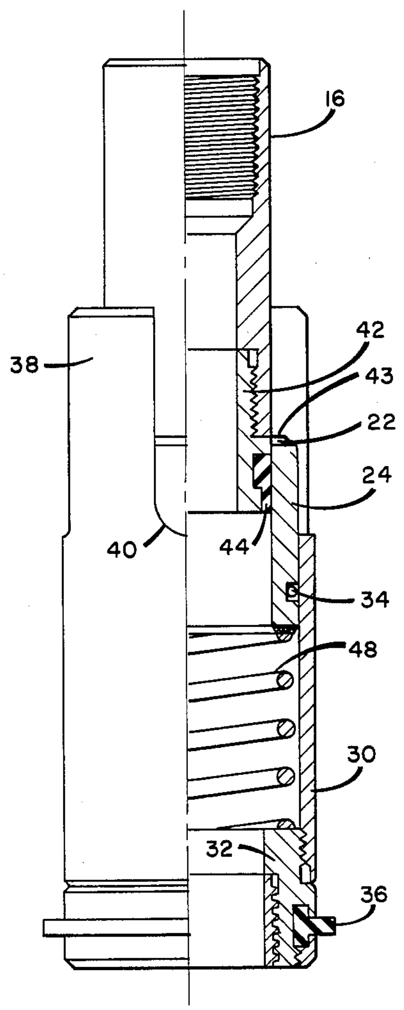

FIG. - 2

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APPARATUS FOR REDUCING HYDRAULIC FRICTION

Filed Feb. 26, 1962 4 Sheets-Sheet 3

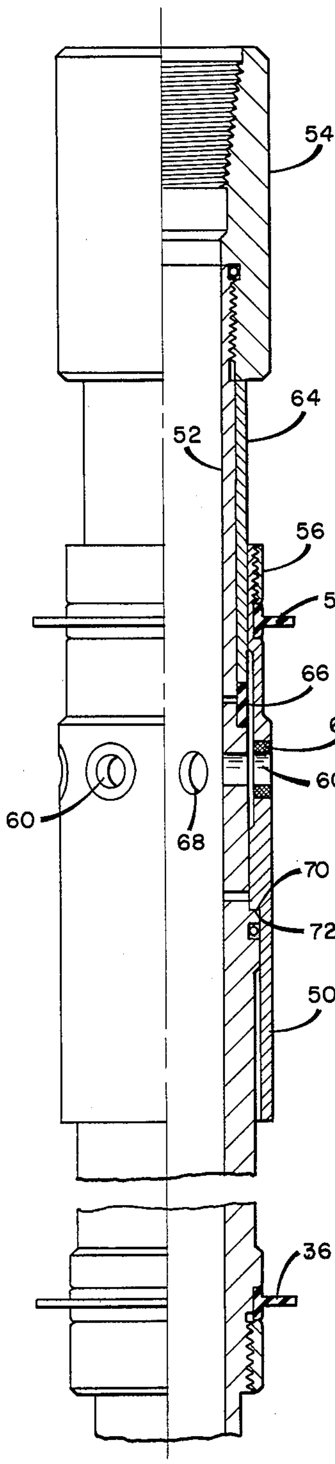

FIG. - 5

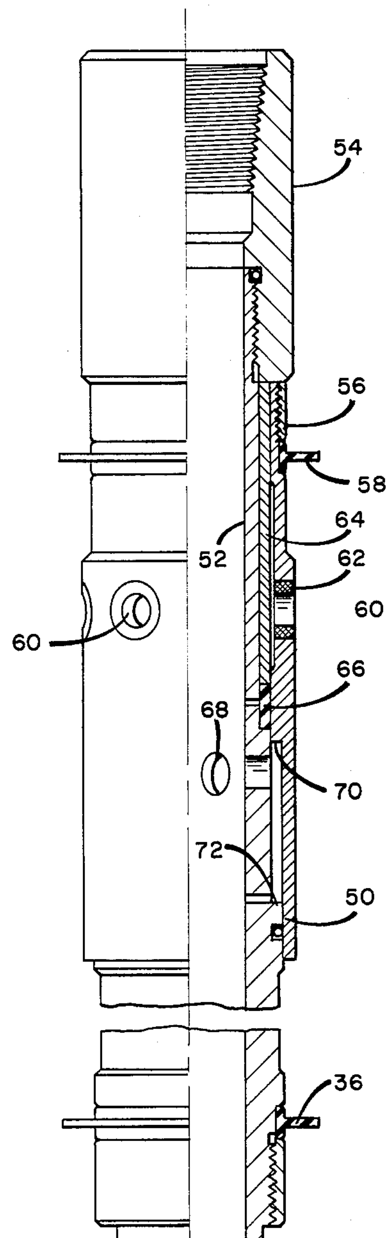

FIG. - 4

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APPARATUS FOR REDUCING HYDRAULIC FRICTION

Filed Feb. 26, 1962 4 Sheets-Sheet 4

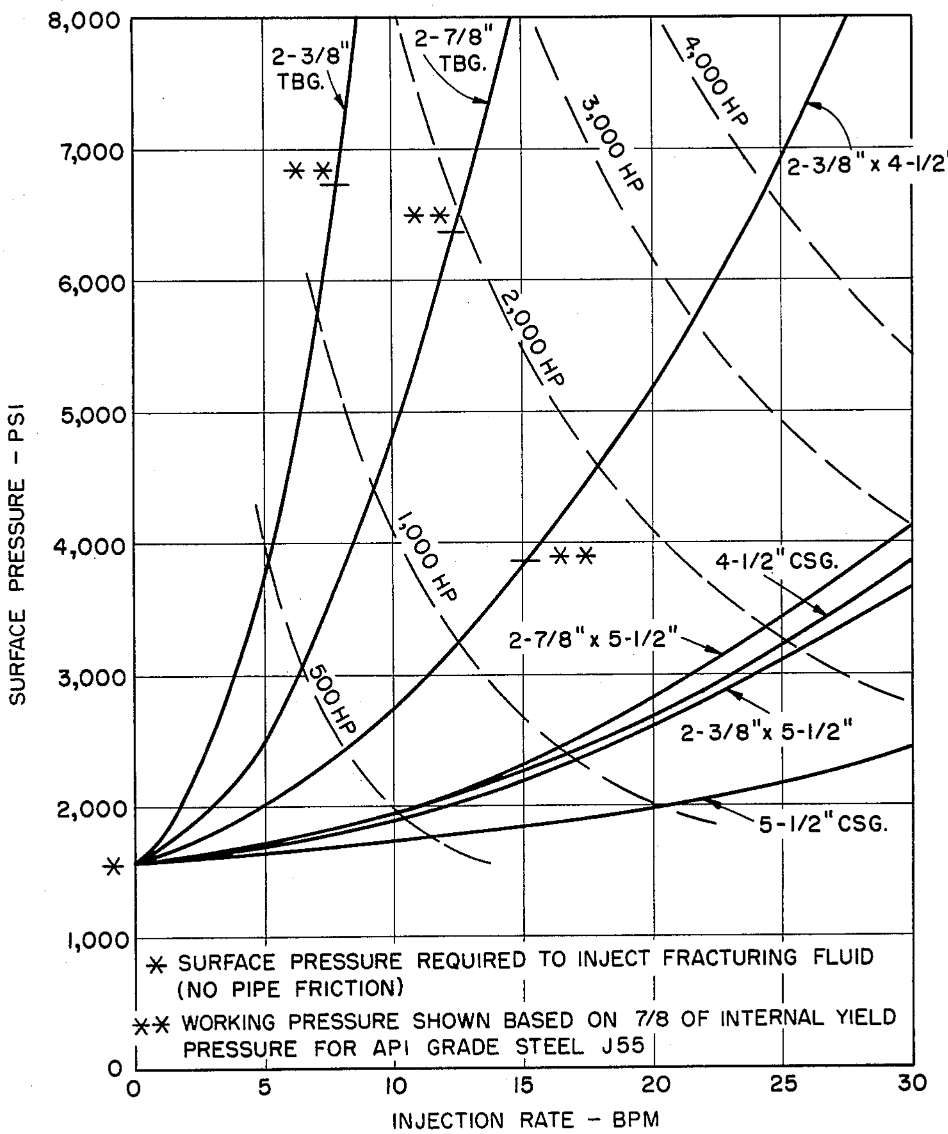

FIGURE - 6

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APPARATUS FOR REDUCING HYDRAULIC FRICTION

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4 Claims. (Cl. 166—224)

The present invention relates to an apparatus for the treatment of underground formations, such as petroleum-bearing reservoirs. More particularly, it is concerned with a novel tool for injecting fluids into such formations with minimum power requirements and also for circulating fluids from the annulus to the tubing under certain types of well completion conditions.

In procedures for treating oil-bearing formations such as—for example—in acidizing and hydraulic fracturing, relatively high pressures are employed. In some instances the pressures required to accomplish the desired result are less than the safe working pressure of the casing and, accordingly, treatment of the formation through the casing via perforations, etc., can be effected without complications. On numerous occasions, however, the pressure required far exceeds the operating pressure of the casing and, therefore, it has been the practice to inject the treating fluid through tubing with the packer set in the casing or open hole at a level near the end of the tubing. Although this procedure avoids possible damage to the casing while still permitting adequate pressures to be applied to the formation face being treated, the power requirements for accomplishing the desired results are often excessive. Stated in another way, after initial formation break-down in the case of fracturing operations, for example, the bottom hole injection pressure decreases sharply so that the working pressure of the casing is then adequate for subsequent injection of fluids. However, the packer which was necessary in the first phase of the fracturing operation, now prevents the simultaneous injection of fluids down the tubing and annulus. This condition results in a limited injection rate and a large percentage of available horsepower is required to overcome the friction loss of the fracturing fluid traveling through the relatively small diameter tubing. The matter of additional horsepower to deliver a fracturing fluid at the proper pressure to a formation where the operation is to be performed can become not only a substantial item of expense but points up the inefficiency of present methods of carrying out jobs of this sort. For example, in a well having casing perforations at 3185 feet, it was found that 58 percent of the total horsepower needed for a fracturing job at that level was expended in friction loss to pump the fluid through two-inch tubing in accordance with current practice.

It is, therefore, an object of my invention to provide an apparatus by which a well-treating fluid under pressure can be simultaneously introduced down both the tubing and annulus and delivered to a packed-off zone. Another object of my invention is to provide a suitable apparatus by which the aforementioned savings in horsepower requirements can be effected. It is still another object of my invention to provide a tool to accomplish this reduction in horsepower requirements which involves the use of a valve arrangement operated by differential pressure. It is a further object of my invention to provide a system which involves the use of a packer equipped with check valves permitting fluids to pass therethrough at pressure below the casing working pressures but which close automatically when the tubing pressure begins to exceed a safe casing working pressure. Another object of the invention is to provide a means in cases where tubing is set on a packer whereby fluids in the annulus and/or

tubing may be circulated from the well by means of a surface-controlled operation.

In the accompanying drawings,

FIGURE 1 is a vertical fragmentary view, partly in section, of one embodiment of my invention in assembled form ready for use;

FIGURE 2 is a longitudinal sectional view of another embodiment of my invention in which communication with the interior of the element illustrated is controlled by means of a pressure-responsive sleeve valve located within the element, and which in this view is in closed position;

FIGURE 3 is the same tool as shown in FIGURE 2 except that it is illustrated in an open position;

FIGURE 4 is another embodiment of my invention shown in a vertical elevational view, partly in section, in which the tool is in a closed position and wherein the sleeve valve is positioned externally of the main body of the tool;

FIGURE 5 is a view of the same tool as shown in FIGURE 4 except it is in an open position;

FIGURE 6 is a plot showing the hydraulic friction generated and horsepower required to pump fluids at varying rates through different sizes and combinations of tubular goods in a typical 7,000 foot well and how such rates can be improved by the simultaneous flow of fluid through both the tubing and well annulus.

In carrying out my invention, the treating fluid is first injected under high surface pressure down the tubing with a packer set just above the end of the tubing. After the initial formation break-down, the bottom hole injection pressure decreases sharply. This then permits the simultaneous injection of fluid down the annulus and the tubing. A short distance above the end of the tubing, the packer thereon diverts all fluid in the annulus to flow through the tubing, entering the latter at a cross-over tool which is a part of the tubing string, as set out in detail below. This practice can be modified slightly by having a packer with a check valve therein designed to close when the tubing pressure substantially exceeds that existing in the annulus.

In FIGURE 1, the arrangement shown employs an embodiment of my invention illustrated, for example, in FIGURES 2 and 3. However, in principal the tool used could be that in FIGURES 4 and 5 or any other device employing a system whereby differential pressure will permit fluid to pass from the annulus into the tubing. In this embodiment, the tool assembly **2** is lowered into well **4** in which casing **6** has been run most of the way, leaving open hole section **8**. The tool, as generally shown, comprises a packer element **10** below differential pressure-operated cross-over valve **12**, which is connected to tubing **14** by means of a back-off or tool joint **16**. The arrows indicate the flow of fluid in the tubing and down annulus **20**. It will be seen that fluid in the annulus contacting the exposed area of sleeve valve **24** at opening **22** causes reciprocating sleeve valve **24** to be forced down to a level where said fluid flows on through the tool and into open hole section **8** via tube **26** in a manner which will be described in greater detail below.

The apparatus shown in FIGURES 2 and 3 generally comprises a tubular member **30**, at the base of which is a spacer ring **32**, threadedly engaged to said member. A reciprocating sleeve valve **24** fits into the top of tubular member **30** and has an O-ring or equivalent seal **34** interposed between the lower end of sleeve valve **34** and the upper end of member **30**. At the base of the tool there is attached a radially extending flexible sand retainer ring **36**, intended to have substantially the same diameter as the casing in which the tool is placed. Also at the upper end of tubular member **30** is a series of finger-like projections **38**, forming openings **40** therebetween. The upper inside portion of sleeve valve **24**, when the tool is in a closed position, engages nipple **42** in fluid-tight relationship by means of seal **44** positioned between the inner surface of sleeve valve **24** and the lower portion of nipple **42**. Sleeve valve **24** is urged in an upwardly direction against shoulder **43** of tubular member **30** by means of coiled spring **48** resting on spacer ring **32**.

A packer—not shown—but used in conjunction with the operation of the tools shown in FIGURES 2 to 5, inclusive, may be attached in any known manner at the base of the tool just below the sand retainer ring **36**.

FIGURES 4 and 5 comprise still another embodiment of the cross-over tool of my invention in which outer sleeve valve **50** is slidably mounted around inner tubular member **52** threadedly engaged at its upper end to tool joint **54**. At the top of sleeve valve **50** is a threaded retainer ring **56** abutting against the base of tool joint **54** serving to hold in place sleeve valve energizer **58** which surrounds said sleeve and abuts against ring **56**. Also in sleeve valve **50** are spaced ports **60** which are lined with an abrasive-resistant material **62** such as, for example, tungsten carbide. At this point, it should be emphasized that both designs shown in FIGURES 2 to 5, inclusive, the area of the ports through which the fluid flows from the annulus into the cross-over tool, should be at least about half the cross-sectional area of the tubing string, of which said tool is a part, in order that the pressure loss across said ports will not be excessive.

Between tubular member **52** and sleeve valve **50**, there is interposed a spacer **64** which serves to hold seal **66** in place. Farther down in the tool are ports **68** through which direct communication with fluid outside the tool is secured when ports **60** are aligned with ports **68**. Inside the lower portion of sleeve **50** is a shoulder stop **70** which halts downward movement of the sleeve at shoulder **72** when the tool is in the "open" position. Near the base of the tool is a radially extending sand retainer ring **36** which prevents sand, etc. from collecting on top of the packer (not shown) set on the same string below which could interfere with proper operation of the packer.

In operation of the embodiment shown in FIGURES 2 and 3 fracturing liquid is, for example, injected down the annulus after initial break-down of the formation has been secured by displacement of fluid through the tubing. The fracturing fluid is desirably injected into the tubing and annulus through a suitable manifold so that the wellhead pressure will be the same for both systems. Similarly, the rate of flow automatically adjusts so that the hydraulic friction is the same in each system. When the fluid in the annulus enters opening **22**, reciprocating sleeve **24** is forced downwardly, increasing the size of said opening **22** until equilibrium flow conditions are attained. The maximum opening formed at **22** extends from the base of nipple **42** down to the base of openings **40**. When the flow of fluid via the annulus decreases, spring **48** forces sleeve valve **24** back toward its original position. When flow discontinues, further upward movement of valve **24** effects a seal at **44**.

In employing the modification of my invention, shown in FIGURES 4 and 5, fluid is displaced down tubing **14** (FIGURE 1) at pressures sufficient to break down the formation and in excess of the casing working pressure. After the initial fracturing of the formation, the sleeve valve **50** is opened by applying hydraulic pressure which acts on the differential area **70** causing the sliding sleeve **50** to move downward until the ports **60** pass the upper fluid seal **66**. Fluid will then flow past the sleeve energizer **58**, causing sleeve valve **50** to move downward until it is halted by differential area or stop **70** coming to rest on shoulder **72**. When in this position, ports **60** are brought into register with ports **68** in tubular member **52**. In this position, the tool permits flow of fluid through it from the annulus. Sleeve valve **50** is moved

back to its "closed" position by discontinuing flowing of fluid down the annulus while continuing flow through the tubing. Under these conditions, fluid flows out through ports **60** and **68**, contacting energizer **58** and forcing sleeve valve **50** upward until it engages seal **66** and then hydraulic pressure acting on differential area **70** will cause sleeve valve **50** to move upward until it contacts the base of tool joint **54**.

In contrast to 58 percent lost in horsepower due to hydraulic friction occurring in the 3185 foot well in the example mentioned earlier, I have found that when operating under the same well conditions in accordance with my invention, the required horsepower to overcome friction decreases to only 17 percent of the total horsepower used. Since it is, of course, desirable to increase the horsepower applied at the formation face when fracturing, my invention permits using a packer to isolate the casing from the high formation breakdown pressure, but allows simultaneous injection of fluid down the tubing and the annulus, or selective injection into either the tubing or annulus with no interruption in pumping operations.

Under present-day economic conditions, hydraulic power costs are to be figured at about $1.00 per horsepower. If one is limited to injection of fluids through the tubing, power costs become uneconomical at pumping rates much above 5 barrels per minute, which rates are frequently insufficient for many acidizing and fracturing jobs. This relationship of power requirements to pumping rate in a tubing or casing of given size is demonstrated in the curves of FIGURE 6 in which studies were made with untreated water as the fracturing fluid. Thus it is seen in the example depicted in FIGURE 6, that injecting water at a rate of 5 barrels per minute down 2⅜" tubing requires about 500 horsepower and a surface pressure of approximately 3750 p.s.i. However, if fluid is injected simultaneously down the 2⅜" tubing and the annulus (5½" casing), the surface pressure required is approximately 1700 p.s.i. and less than 250 horsepower is required. Similar differences in horsepower requirements for a given pumping rate are illustrated by comparing the curves plotting the 2⅜" and 2⅞" tubing with those involving combinations of such tubing with 4½" and 5½" casing. In the case of the curves where both the tubing and casing sizes are shown, a manifold system was used connecting the pumps to both the tubing and annulus.

I claim:

1. A tool for a well comprising an open-ended tubular member adapted to form a part of a conduit string to be disposed in an at least partially cased well,

a pressure-responsive valve carried by said member which opens when the external pressure about said member is greater than that inside said member, and

a flexible sand retainer ring having a permanent diameter affixed to and surrounding the base of said valve.

2. A tool comprising a tubular member adapted to form a part of a conduit string to be disposed in an at least partially cased well, a pressure-responsive valve carried by said member, a flexible sand retainer ring of permanent diameter affixed to and surrounding the base of said tool, said ring having approximately the same diameter as the interior diameter of said casing, whereby the flow of solid particles past said ring is prevented when said tool is in use.

3. A tool for treating a zone adjacent the bore of an at least partially cased well comprising

a tubular member adapted to form a part of a conduit string which defines an annular conduit between said string and the wall of said well bore, said member having a side port,

a differential pressure-responsive reciprocating sleeve valve within said member closing said side port but adapted to slide downwardly from a closed position to a port-opening position when a fluid pressure in said annular conduit exceeds that in said string,

a flexible annular member affixed to and surrounding the base of said tool, said annular member having approximately the same diameter as the internal diameter of said casing, whereby the flow of solid particles past said annular member is prevented when said tool is in use, and

means for urging said valve in an upward direction to a closed position when the fluid pressure outside said member falls below a predetermined value.

4. A tool for treating a zone adjacent the bore of an at least partially cased well comprising

a tubular member adapted to form a part of a conduit string to be disposed in said well, thereby defining an annular conduit between said string and the wall of said well bore, said member having a first side port,

a differential pressure-responsive sleeve valve surrounding and carried by said member and having a second side port therein, said valve being slideable downwardly to bring said first and second ports into registry with one another when the fluid pressure in said annular conduit exceeds that in said string, and

a flexible sand retainer ring affixed to and surrounding the base of said tool, said sand retainer ring having approximately the same diameter as the interior diameter of said casing, whereby the flow of solid particles past said ring is prevented when said tool is in use.

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