Aug. 29, 1967 H. I. HENDERSON 3,338,322

EARTH BORING DRILL

Filed Feb. 16, 1965 2 Sheets-Sheet 1

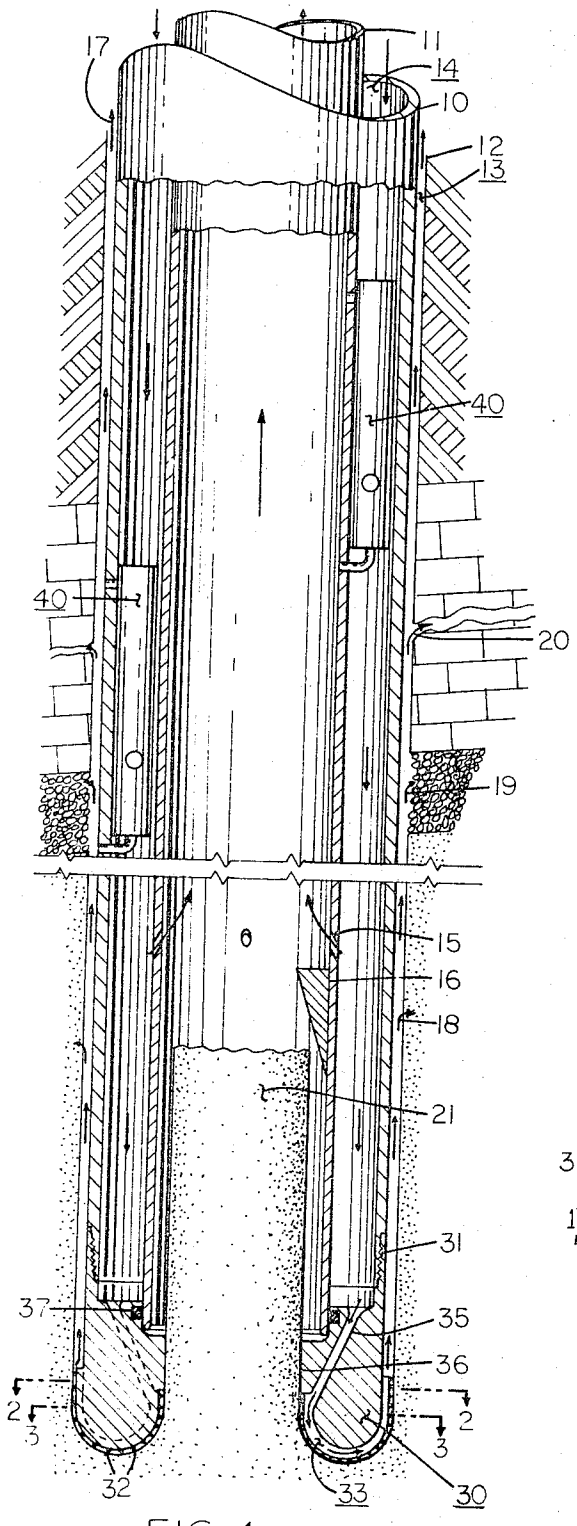


FIG. 1.

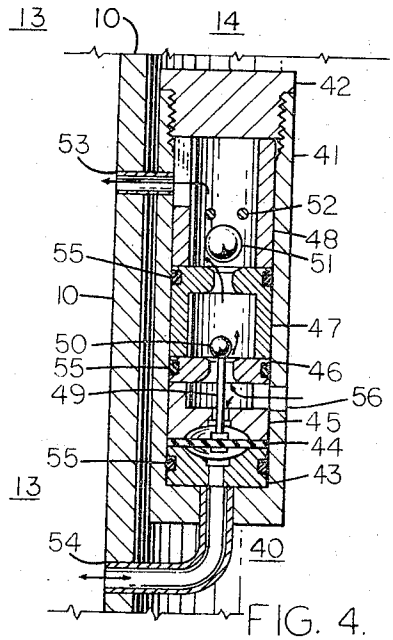


FIG. 4.

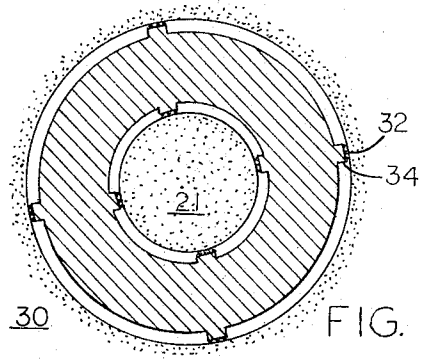


FIG. 3.

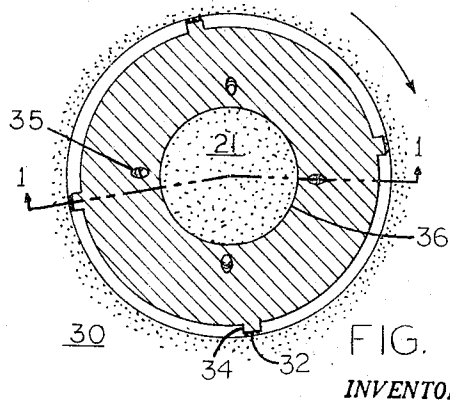


FIG. 2.

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EARTH BORING DRILL

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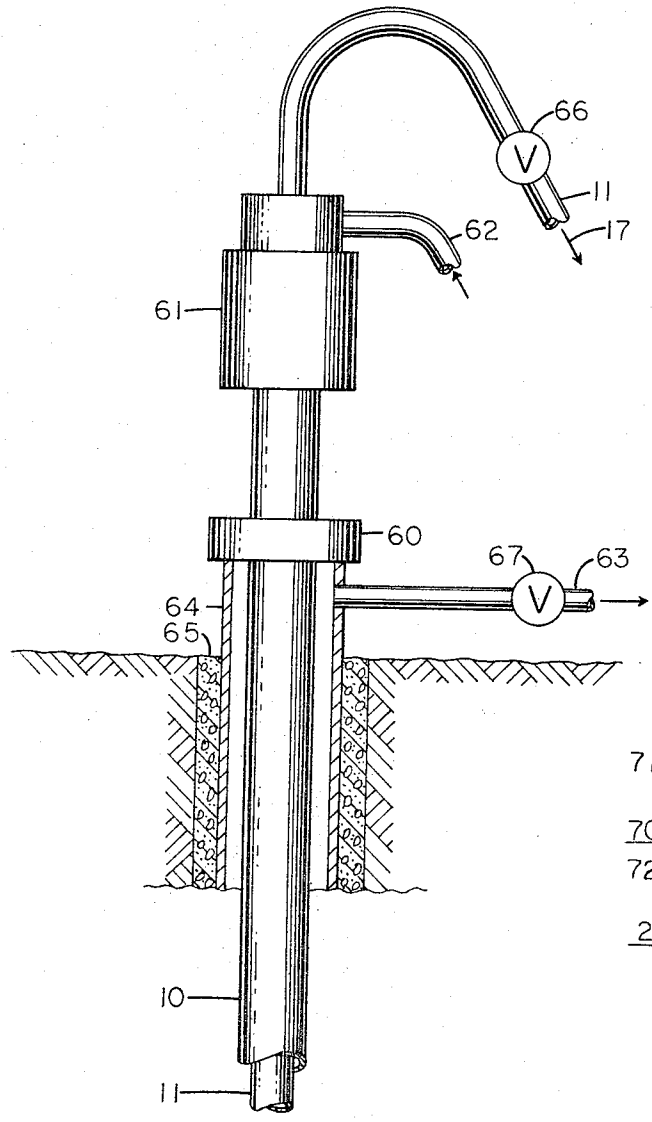


FIG. 6.

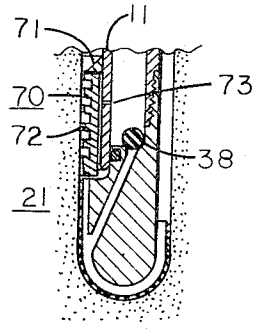


FIG. 5.

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3,338,322

EARTH BORING DRILL

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14 Claims. (Cl. 175—317)

ABSTRACT OF THE DISCLOSURE

Well drilling and coring apparatus employing dual passage drill pipe with a choke snugly embracing a core being cut to block fluid flow up the core tube and divert it to the hole annulus. Scavenging of cores and cuttings up through the core tube is accomplished by diverting a portion of the circulating fluid into the core tube through a series of ports above the bit. Gas drilling is facilitated by a series of normally open diaphragm-operated valves between flow passages so that gas pumped down one passage will force fluid up the other. The fluid head in the other passage approximately balances the gas pressure, but when it falls below the level of the valve, the valve is closed by the higher pressure in the gas flow passage.

Description

This invention relates to an earth boring drill, and more particularly, to a boring drill combining features of a dual-pipe continuous core drill and one that functions efficiently in areas wherein there is extreme loss of circulation fluid. This invention is particularly adapted to drill with a gas as the circulating fluid, and it is also adapted to drill with a liquid as the circulating fluid.

Dual-pipe core drills have long been used to drill and to continuously core while drilling. This method of drilling has been quite successful in areas having little, or no, loss-circulation formations "Thief zones." It has not been able to drill economically in areas having considerable loss-circulation "thief" formations.

The reasons why the dual-pipe type of drill has not been able to cope with areas having thief zones are twofold:

(1) Characteristic of all so-called "Reverse" circulation methods of drilling, the "return" route of the drilling fluid is within a pipe instead of being in the bore hole annulus, as in "conventional" circulation. In "conventional" circulation, the bit cuttings carried by the return stream are being constantly deposited in, or infiltered into, the hole wall pores of any thief zones, tending to plug the same. This is quite efficacious as a thief zone plugging process. Often, as a thief zone is drilled, the cuttings from the bit plug the porous hole walls almost simultaneously with the drilling. On the other hand, there is no such plugging action in "reverse" circulation drilling since the cuttings are returned within the pipe. With the "reverse" method, the thief zone is not plugged as drilled and the loss of circulation becomes greater even until all the circulation is lost to the thief zone. When this happens, bit cuttings are then carried into the thief zone, provided one continues to drill. But if one does continue to drill, the resulting cores, together with some mechanically forced cuttings continue to accumulate in and to effectively plug the core tube. This can continue until the center of the bit is also plugged and the core is taking all of the weight intended for the bit. With no weight on the bit's cutting surfaces, the drill stops making hole. It is then necessary to withdraw the pipe and unplug the bit and the core tube. To continue to fight this adverse condition is both hazardous and expensive, and there is no assurance of eventual success.

(2) With conventional circulation, it is not uncommon

to drill hundreds of feet with only a small percent of circulation being returned or even with a total loss of circulation. This is termed "blind" drilling. The fluid, together with the bit cuttings is merely carried into the pores of the thief zones, and often with no serious trouble, except for the loss of drilling fluid. When the hole has reached a depth beyond which it is known that there is normally no thief zones, the hole can thereupon be cased and cemented to isolate the upper section of the hole, and subsequently to permit normal drilling. On the other hand, "reverse" circulation drills cannot drill "blind" because of the plugging action above mentioned. Neither can the reverse drills proceed with a large portion of the circulation lost. It is necessary to have a strong return flow to flush the cores to the surfaces. Should the Driller endeavor to continue drilling by increasing the volume of fluid pumped, it has been found that the required fluid volume continues to increase with hole depth and time since the cuttings are being deposited in the pores of the thief zones. The volume of fluid required can be, and usually is, enormous. Assume the thief zone is a porous sand that is 20 feet thick, and has a porosity of 30%, and has a high permeability. Assume that the bottom one-half of the sand is water-filled and the rest is a gas at substantially atmospheric pressure. Assume that the drilling fluid is under 150 p.s.i.g. pressure (approximately ten atmospheres). If this sand section extends for miles, the volume of fluid required to fill it is excessively large:

1 acre foot=43,560 sq. ft.
Radius of a circular acre=just under 118 ft.

In ten feet of porous sand, with 30% porosity, there is a porous volume of $10\times0.30\times43{,}560=130{,}680$ cu. ft. per surface circular acre. This condition may, and does usually extend for tens, hundreds, or thousands of surface circular acres. Obviously, it is impractical to attempt to fill such a large volume.

Sometimes it happens that the thief zone, such as the sand above, has a high porosity but a low permeability. In such a case it can often be drilled satisfactorily with a liquid since the low permeability restricts the flow of liquid into the pores and the resulting pressure build-up permits successful operation. Some drilling fluid is lost, but if boring progress and core recovery are not hindered, the fluid loss is generally not considered too expensive. On the other hand, it is usually hopeless to economically drill this section with gas as the circulating fluid, due to the fact that the rate a gas under pressure will permeate even a slightly permeable formation is quite high.

In "reverse" circulation gas drilling it is essential that the gas in the bore hole annulus be held at a pressure high enough to flush the cores up the core tube to the earth's surface. At great depths this required pressure becomes considerable. Assume one is drilling a 6-inch hole with 4-inch pipe. In which case the area of the hole annulus is 0.1091 sq. ft. In each one-thousand feet of hole, there is 109.1 cu. ft. of annular space. If one is drilling with 300 p.s.i. pressure (20 atms.) then for each thousand feet of hole one needs to compress 2182 cu. ft. of gas from atmospheric pressure even though there is no thief zones. Even if one is drilling with no-cost air, this requires considerable compression time, during which time the drill rig and crew are not making hole. Another difficulty is experienced when one has drilled-off a length of pipe and stops to make a connection (add a new joint). All of the compressed gas in the pipes, hole-annulus, and permeable formations must be bled-off before one can break-out the connection. Again, lost time for the drill rig and crew. After the new length of pipe is added, and

the connection made, this gas pressure must again be built-up before drilling resumes.

One of, if not the biggest, problems in gas drilling for all types of drills, is the invasion of water in the hole. If a driller has water sands, "aquifers," in his hole, he can, with developed techniques, proceed with drilling so long as he can keep the hole from flooding. He can generally do this if he can keep his gas circulating at sufficient rate to carry the water out as fast as it enters. When he has to shut down to make a connection (add a new joint of pipe), or for repairs, the water may flood his hole. Most gas drilling is done with air, compressed at the site, and the available pressure is normally not high. If his available pressure is 300 p.s.i., his maximum depth of submergence is 300÷0.4335 (pressure of one foot of water) or, 692 feet. As a consequence, he normally has to pull his pipe until his bit is submerged only 692 feet; gas lift that water head; lower 692 ft., and gas lift that stage, and so on to the bottom of the hole.

It is, therefore, an object of this invention to provide two return paths for the circulating fluid: one up the core tube transporting the cores, and one up the hole annulus transporting the bit cuttings.

It is a further object of this invention to eliminate the necessity of keeping pressure in the bore hole annulus while drilling with "reverse" circulation.

It is a further object of this invention to provide means whereby the return fluid flow is in the bore hole annulus, and does transport the bit cuttings, and by so doing to utilize the bit cuttings to plug the pores of any thief formations.

It is a further object of this invention to provide choke means for separating the two return streams.

It is a further object of this invention to provide differential flow valves in the pipe annulus to permit, when drilling with gas, the gas-lifting of bore hole liquids even though the liquid submergence at the bit is greatly in excess of the available gas pressure.

It is a further object of this invention to provide selective means whereby the total return flow can be confined to a single channel, either the core tube, or the hole annulus.

Other objects and advantages of this invention will become apparent from the description following, when read in conjunction with the accompanying drawings wherein:

FIG. 1 is an elevational view partly in section, of the down-hole pipe and bit of a dual-pipe boring drill, embodying features of this invention.

FIG. 2 is a sectional view of the bit, taken on line 2—2 of FIG. 1.

FIG. 3 is a sectional view of the bit, taken on line 3—3 of FIG. 1.

FIG. 4 is a longitudinal sectional view of the differential flow valves of FIG. 1.

FIG. 5 is a sectional view of the bit of FIG. 1, modified in regard to the choke element and showing a plugging ball in place.

FIG. 6 is an elevational view showing the above surface, and near-surface, elements of a dual-pipe reverse circulation drill.

Referring to FIG. 1, the drill pipe used in this invention is conventional for "reverse" drills, in that there is a drill pipe **10** that carries a bit **30** threadedly secured to its lower end. Concentrically secured within the drill pipe is a core tube **11**, which is sealed at the bit by the O-ring **37**. The core tube **11**, carries a core break-off cam **16**, spaced a short distance above the bit. The above is in a conventional manner for dual pipe drills.

There is a departure from conventional in that the bit **30**, has a choke **36**, which snugly fits the core **21**. This is clearly shown in FIG. 2. The placing of the bit's nozzles **35** is also contrary to conventional dual-pipe bits in that the nozzles exhaust adjacent the core rather than adjacent the bore hole wall. The fluid flow arrows **17**, show a major departure from dual pipe drilling in that the fluid

exhausted from the nozzles **35** does not return to the earth's surface through the core tube **11**. On the contrary, the bit fluid exhaust traverses under the bit, cooling the bit's cutting edges and scavenging the rock cuttings and proceeds up the bore hole annulus, transporting the rock cuttings with it. As this stream of cuttings-laden fluid progresses up the bore hole annulus it comes into intimate contact with the various rock formations that have been drilled. If some of these formations happen to be "thief" formations, i.e. they are porous and permit the entry of the drilling fluid, the ascending fluid will enter such formations carrying the cuttings therein. These cuttings accumulate in the formation interstices and fissures to effectively plug them, a result that is highly desirable. It will be noted that arrow **18**, shows this return stream entering a porous sandstone, while arrow **19**, shows the stream entering highly porous gravel, and arrow **20**, shows the stream entering a large channel in limestone. If these thief formations are highly porous, or very thick in section, all of the return stream may enter the thief zones. However, as will be shown below, this does not interfere with the continuance of the drilling operation as it would in conventional reverse drills. As the cuttings accumulate in the porous formations, the permeability of the formations section near the bore hole becomes less and less until most, or all, of the return stream proceeds up the hole annulus **13**, to exhaust through pipe **63** at the earth's surface. However, when using this invention, the driller is not too concerned if the thief zones are never plugged, in so far as his making hole is concerned, which is quite different from his continual worry with prior equipment wherein he had to shut-down and fight loss-of-circulation.

The factor that permits continuing drilling even though all of the fluid passing through the bit is lost to thief formations is the provision of a second return stream of fluid. Spaced a short distance above the bit, in the core tube are a plurality of nozzles, **15**, permitting the passage of fluid directly from the pipe annulus **14**, into the core tube. It is this fluid that returns to the earth's surface within the core tube, carrying the cores with it. The size and number of the nozzles **15**, are determined in relation to the size and number of the bit's nozzles **35**, with due allowance for the fluid flow resistance of the bit's water courses **33**. One may elect to have 50% of the pumped fluid arriving near the bit through the annulus **14**, to pass through the nozzles **15**, and proceed to the surface via the core tubes, while the other 50% passes through the bit and on out into the bore hole annulus, and thence up to the surface. Other ratios besides 50–50 may be used, depending upon conditions: core tube area, hole annulus area, porosity of formations, type of drilling, etc. This invention requires a greater fluid flow volume, even up to double the volume of conventional dual-pipe drills, but the advantages gained greatly outweigh this minor increase of cost.

In this description it is considered that the division of the fluid stream is 50–50, and that this percentage division establishes that the fluid pressure in the core tube just above the choke **36**, is the same as the pressure just under the choke **36**, at the exhaust of the bit nozzle, **35**. In which case there is no tendency for fluid to pass from one side to the other of the choke **36**, even though there is a small clearance between the choke and the core **21**. FIG. 1 shows the nozzles **15**, located just above the core breaker cam **16**. It is customary to place the cam about 6 inches above the top of the bit. With continuous drilling, the cores will be pushed mechanically past the cam **16**, whereupon they will be caught in the return stream of the core tube to be carried to the surface. When drilling highly fractured formations, it will be desirable to place the nozzles **15**, below the cam **16**, to minimize the lodging of core segments beneath the cam.

Should the core segment in the choke **36**, be porous, the same balance of pressure will assure little or no fluid flow in the porous core.

Should a block, or partial block, develop in the hole annulus, or bit water ways; thereupon most, or all, of the total fluid flow will be forced through the nozzles **15**. This will cause a considerable rise in fluid pressure in the pipe annulus **14**. For a given cross-sectional area of a nozzle the differential flow pressure across the nozzle varies with the fluid quantity squared. Hence to double the flow in one set of nozzles, as would happen with the blocking of one return channel (in a 50–50 percent division) would result in a 4-fold increase in pressure. This in itself would place quite a dislodging pressure, hence, force, on the block. If this did not dislodge the block, the driller can close the core tube valve **66**, of FIG. 6, and place full pump pressure upon the block. The driller should lift his pipe off bottom to free his bit of the fluid-blocking core segment.

Should a jam or lodge develop in the core tube, there would be a similar 4-fold increase of pressure in the pipe annulus. If this failed to dislodge the block, the driller could then close the hole annulus valve **67**, of FIG. 6. This will place full pump pressure upon the whole system, provided there is no thief formation. This, normally, is a dangerous procedure, in that such pressure may hydraulically fracture a weak formation. It is better for the driller to drop in the pipe annulus **14**, a number of elastomer (such as neoprene) balls **38**, such as shown in FIG. 5. Upon reaching the bit these balls will be carried by the fluid stream to the mouth of the several bit nozzles **35**, whereupon the elastomer balls effectively block these nozzles, forcing all of the fluid through the core tube nozzles **15**, and up to full pump pressure is available in the core tube. If this unplugs the core tube, the driller can recover the balls by closing the hole annulus valve **67**, and pumping down the core tube **11**, forcing the fluid up through the pipe annulus **14**, which upward flow will bring the balls **38**, to the surface. Upon recovery of the balls, drilling can resume in a normal manner.

FIGS. 1, 2, and 3 show one type of diamond impregnated blade bit, wherein the blades **34**, are impregnated with diamonds **32**, and have nozzles **35**, which terminate in the water course **33**. The choke **36**, is inherent with this particular design.

FIG. 5, shows a preferred, modified form of bit wherein the choke is not incorporated with the bit but is placed in the core tube **11**, just above the bit. In this modification the choke **70**, is an annular ring free to turn, relatively, in the core tube. The surface of the core **21**, is normally quite abrasive, and it is desirable to eliminate relative rotation between the core and the choke. This eliminates much of the abrasion of the choke. To still further minimize abrasion, the inner surfaces of the choke may be coated with a hard abrasion-resistant material. When one is to drill exclusively with water or a similar lubricating liquid, I prefer to mold the choke **70**, of an elastomer such as neoprene. The choke **70**, is held rotatably in place by the annular stop **71**, and the top of the bit, as shown. The stop, **71**, may, if desired, be welded to the core tube. It is desirable to lubricate the rubbing surfaces of the choke in contact with the core tube, and this is done by admitting drilling fluid through the small bleed hole **73**. It is desirable that the inner surface of the choke be formed into a labyrinth type fluid seal as shown at **72**, to minimize fluid passage between it and the core. The inner face of the choke should be tapered as shown, to facilitate the passing of the core. The use of this modified choke, permits the use of any type of bit, (drag, roller, impregnated diamond, or surface set diamond) having the proper design characteristics, and eliminates the necessity of building an expensive choke on each individual bit. The bits can be designed to accommodate the relatively-rotating choke **70**, as revealed by FIG. 5.

FIG. 6, shows the surface equipment as is conventionally used today in dual pipe drills, and it is used in this invention but somewhat differently. A short string of surface casing **64**, is set and cemented as at **65**. The drilling-

head **60**, effects a seal between the hole-annulus **13**, and the drill pipe **10**. The power swivel **61**, provides the rotating power and packs-off the rotating drill pipe **10**, to the non-rotating pressure tube **62**. The swivel **61**, also packs-off the rotating below-swivel core tube **11**, to the non-rotating, above-swivel, core tube portion. In conventional dual-pipe drilling, the hole annulus valve **67**, of FIG. 6, is normally closed to prevent fluid flow up the hole annulus at the expense of the core-carrying return stream in the core tube. This makes the hole annulus a closed system and imposes more or less pressure on the hole annulus. Obviously, the more pressure in the hole annulus, the greater the fluid loss into thief formations. A still worse possibility is the hydraulic fracturing of weak formations to change what was a tight formation into a serious "thief" formation. In this invention, the valve **67**, is open during normal drilling, to permit the discharge of the hole annulus fluid stream. The valve **67**, is only used for emergency measures as described above. With this invention, in good drilling country, the drilling head **60**, and even the surface pipe **64**, can often be dispensed with.

FIG. 4 shows a sectional view of the differential pressure valves **40**. These valves are used only when drilling with air or low pressure gas as the drilling fluid. Assume that one is drilling with air and that his maximum available pressure is 300 p.s.i. Then the maximum head of water that he can gas-lift from the hole is 300÷0.4335 (pressure head of one foot of water) or 692 feet. If one were drilling at 3,000 feet deep, and his hole filled with water it would be necessary to pull all of his pipe except the last 692 feet. With only 692 feet of pipe in the hole, he could gas-lift this top portion of water by gas lift. He could then lower 692 ft. of pipe into the remaining water and then stop and gas lift this second 692 feet of water. This would repeat until the bit was again on bottom. He would be required to make at least 5 water-lift operations.

To eliminate this expensive multi-step water pumping, I provide differential pressure valves in the pipe annulus **14**. Preferably there are two sets of valves, one set to communicate between the annulus **14**, and the hole annulus **13**; and the other set to communicate between the pipe annulus **14**, and inside the core tube **11**. In most cases, one set of valves would accomplish the end result of gas-lifting all of the water from the hole, but two sets will do the job faster and assure a water clean-up even though one, or the other (core tube or hole annulus) channel were plugged. These valves are placed at intervals of about 50% of maximum submergence water lift. In case of 300 p.s.i. air pressure the spacing would be about 50% of 692 feet or approximately 350 ft.

The operation of these valves **40**, is shown by FIG. 4. The valve has a tubular housing **41**, on the top of which is threaded the clamping cap **42**. Within the housing **41** are five tubular members, all slidable in the housing and all clamped in place by the clamping cap **42**. The bottom tubular member **43**, and the one directly above it **45**, have clamped between them a disk diaphragm **44**, which may be made of an elastomer such as neoprene. The adjacent faces of the members **43**, and **45**, are each recessed with a semi-ellipsoidal recess, which is centered relative to the tubular periphery. The upper portion of the member **45**, has a centered cylindrical recess that is ported to communicate with the gas port **56**, in the housing **41**, as shown. Resting on the member **45**, is the member **46**, which is the gas valve seat. The gas valve ball **50**, is just above the member **46**, and the ball is connected to the center of the diaphragm **44**, by the spacing rod **49**. Resting on the member **46**, is the member **47**, which carries the check valve seat in its upper surface, as shown. The check valve ball **51**, is above the member **47**. The upper tubular member **48**, rests on tubular member **47**. Tubular member **48**, carries two confining rods **52**, to confine the check ball **51**, to the lower half of the member **48**. The upper member **48** has a slot in its upper one-half,

which slot communicates with the flow tube **53**, as shown. The pressure tube **54** communicates between the hole annulus and the interior of the differential pressure valve **40**, as shown. Three of the tubular members, **43**, **46** and **47** are pressure sealed with O-rings **55**, as shown.

In the installation shown in FIG. 4, the valve **40**, communicates between the pipe annulus **14**, and the hole annulus **13**. The valves that communicate between the pipe annulus and the core tube are identical in construction, but are mounted on the core tube, rather than the drill pipe, as shown in FIG. 1.

In FIG. 4, the valve **40**, is shown open, that is, the gas valve (seat **46**, ball **50**) is open. This is the normal position when the pressure in the hole annulus **13**, and the pipe annulus **14**, are equal. If the pressure in the hole annulus **13** should increase relative to that in the pipe annulus **14**, the gas valve, **46** and **50**, would open further due to increased pressure under the diaphragm **44**. Fluid is prevented from flowing from the hole annulus into the pipe annulus by the check valve (ball **51**, seat **47**). Any increase in pressure in the pipe annulus over and above the pressure in the hole annulus tends to close the gas valve, **50**, **46**. This is due to increase of pressure on the top of the diaphragm **44**. The exposed area of the diaphragm **44** is much greater than the effective surface area of the valve ball **50**. Actually the diaphragm is biased open, that is, it takes some definite increment of the pressure in the annulus **14** over and above that of the annulus **13**, before the gas valve **50**, **46**, closes. This is due in part to the resistance of the relatively thick elastomer diaphragm **44**, which must be stretched somewhat before the gas valve **50**, **46**, can close. It is also due in part to the effective area of the valve ball **50**, in that the pressure in the annulus **14**, reacts on this ball surface to prevent the closing of the valve **50**, **46**. Pressure under the diaphragm, which tends to open the valve, does not experience either of these two opposing forces, since the valve is open when the diaphragm is plane.

Assume that the drill pipe is in a 3,000-foot hole filled with water, and that there are valves **40** spaced at intervals of 350 feet. All of three channels: core tube, pipe annulus, and hole annulus will be filled with water since they are inter-connected at the bit. All will be in equilibrium, pressure-wise. Assume the upper valves **40**, to be 350 feet below the surface and hence they will have 350 feet of water submergence. The pressure on both sides of these valves will be, $350 \times 0.4335 = 153$ p.s.i. They, and all of the valves will be open due to the equality of pressure on both sides, and due to the fact that they are biased toward the open position.

Now if the driller will start pumping gas at a slow rate into the pipe annulus, there will ensue a slow build-up of gas pressure in the pipe annulus and a surface flow of water from both the hole annulus and the core tube. The upper valves (as well as the others) will remain open. At the start there is the same water head on both sides of the valve. As the gas pressure starts to build up, it causes a flow of liquid through the valve but the only difference of pressure across the valve is due to the friction flow loss experienced in the valve, and downstream from the valve and this (for moderate flow) is not sufficient to close the valve. As the pumping of gas continues, the gas-water interface in the pipe annulus proceeds further and further down the pipe. There is, of course, a corresponding flow of water at the surface from both core tube and pipe annulus. The pressure in the pipe annulus at the upper valves remains substantially constant. The loss of liquid head in the pipe annulus is replaced with a corresponding increase of gas pressure. If the pumping is stopped just before the gas-liquid interface reaches the upper valves it will be found that the gas pressure is 153 p.s.i., just equal to the liquid head on the outside, (hole annulus) of the upper valves. The valves will still be open. When the gas reaches the upper valves it will start flowing through the valves and it will gas lift to the surface a major portion of the liquid in the hole annulus above the valves. At first this liquid will rise as a slug and subsequently the gas will break through and carry most of the remaining liquid out as an aerated fluid. As the liquid head is removed from the outside of the valves the outside pressure drops rapidly and the upper valves close, and remain closed so long as the inside gas pressure exceeds the outside pressure, which is always the case when drilling.

After the upper valves close the gas-water interface proceeds downward, with continued pumping, toward the second pair of valves and the same valve operation is repeated over and over until all of the sets of valves are closed and the hole is substantially free of water, whereupon drilling is resumed. This is a major saving in time and expense. The valves remain ever ready to permit cleaning the hole of water at any time. These valves permit the rapid removal of water from a hole without moving the pipe, and is accomplished with air compressors of moderate pressure, whose weight, cost, and operating expense is a fraction of those high pressure multi-phase units designed for 1500 p.s.i., or higher, which have heretofore been used to gain greater submergence.

Although I have described my invention with a degree of particularity, it is understood that the present disclosure has been made only by way of example, and that numerous changes in the details of construction and the combination and arrangement of parts may be resorted to without departing from the spirit and the scope of the invention as hereinafter claimed.

Having described my invention, I claim:

1. In well drilling apparatus including a dual-passage drill pipe comprising an outer pipe adapted to be rotated from the surface and a smaller inner tube supported within the outer pipe, said inner tube forming an inner flow passage and the space between said inner and outer tubes forming an outer flow passage, an annular coring bit secured to the bottom of said drill pipe with the central opening therein in communication with said inner tube to form therewith a continuous core tube, and means for delivering drilling fluid to said outer flow passage, the improvement comprising:

means in said bit forming at least one flow duct from said outer passage to the lower cutting face of said bit adjacent said central opening,

means forming flow courses outward across said bit to a hole annulus passage,

a choke member in said core tube extending radially inward an amount sufficient to embrace snugly a core cut by said bit and form a barrier to fluid flow from said bit central opening to said inner tube, and

means forming at least one port through said core tube closely displaced from said bit cutting face to form a by-pass from said outer passage to said inner passage.

2. The well drilling apparatus defined by claim **1** where said choke member comprises:

an annular ring retained within the core tube, and free to rotate, relatively to the core tube.

3. The well drilling apparatus defined by claim **1** including:

at least one seal ring carried on the inner surface of said choke member.

4. The wall drilling apparatus defined by claim **1** including:

means in said core tube for engaging and breaking cores into relatively short lengths.

5. The well drilling apparatus defined by claim **1** wherein:

the flow capacity of said flow duct has a fixed relationship to the flow capacity of said by-pass port so as to assure sufficient flow both in the core tube to transport cores to the surface and in the hole annulus to scavenge bit cuttings.

6. The well drilling apparatus defined by claim **1** including:

means in said bit forming a valve seat around said flow duct at the inlet thereof from said outer passage,

said valve seat being of a size that a small ball engaged therein will plug said flow duct.

7. The well drilling apparatus defined by claim 1 including:

at least one normally-open gas valve supported within said drill pipe,

first and second flow conduits connecting said valve respectively to said outer passage and one of said core tube passage and/or said hole annulus passage,

said valve being conditioned to close in response to a predetermined pressure differential between said outer passage and said one passage.

8. The well drilling apparatus defined in claim 1 including:

at least one gas flow valve supported in said drill pipe, said gas flow valve comprising:

a valve body with inlet and outlet passageways,

first and second flow conduits respectively connecting said inlet passageway to said outer passage and said outlet passageway to one of said inner tube passage and said hole annulus passage,

a valve seat intermediate said flow passageways,

a normally-open valve member movable into sealing engagement with said valve seat,

a pressure-responsive member connected to said valve member and operative when biased from one side thereof to move said valve member toward closed position, and

first and second sensing duct members bringing said one side and the other side of said pressure-responsive member into communication respectively with said outer passage and said one passage.

9. In well drilling apparatus including a dual-passage drill pipe comprising an outer pipe adapted to be rotated from the surface and an inner tube supported within the outer pipe, said inner tube forming an inner flow passage, the space between said inner and outer tubes forming an outer flow passage and the annulus around said drill pipe forming a third passage, a bit secured to the bottom of said drill pipe with an opening wherein in communication with said inner tube, and means for delivering a gaseous fluid to said outer flow passage.

at least one gas flow valve supported in said drill pipe, said gas flow valve comprising:

a valve body with inlet and outlet flow passageways,

first and second flow conduits connecting respectively said inlet passageway to said outer passage and said outlet passageway to one of said inner and said third flow passages,

a first valve seat intermediate said flow passageways,

a normally-open valve member movable into sealing engagement with said valve seat,

a pressure-responsive member connected to said valve member and operative when biased from one side thereof to move said valve member toward closed position,

first and second sensing duct members bringing said one side and the other side of said pressure-responsive member into communication respectively with said outer passage and said one passage,

a second valve seat intermediate said flow passageways, and

a check valve member exposed to pressure from said outlet flow passageway and biased thereby against said second valve seat.

10. In well drilling apparatus including a dual-passage drill pipe comprising an outer pipe adapted to be rotated from the surface and an inner tube supported within the outer pipe, said inner tube forming an inner flow passage, the space between said inner and outer tubes forming an outer flow passage and the space around said drill pipe forming an annulus flow passage, a bit secured to the bottom of said drill pipe with an opening therein in communication with said inner tube, and means for delivering a gaseous fluid to said outer flow passage,

at least one gas flow valve supported in said drill pipe, said gas flow valve comprising:

a valve body with inlet and outlet flow passageways,

first and second flow conduits connecting respectively said inlet passageway to one of said flow passages,

a first valve seat intermediate said flow passageways,

a normally-open valve member movable into sealing engagement with said first valve seat,

a pressure-responsive member connected to said valve member and operative when biased from one side thereof to move said valve member toward closed position,

first and second sensing duct members bringing said one side and the other side of said pressure-responsive member into communication respectively with said one flow passage and another of said flow passages,

a second valve seat intermediate said flow passageways, and

a check valve member exposed to pressure from said outlet flow passageway and biased thereby against said second valve seat.

11. In well drilling apparatus including a drill pipe adapted to be rotated from the surface, said drill pipe forming a pipe flow passage and the space around said drill pipe forming an annulus flow passage, a bit secured to the bottom of said drill pipe with an opening therein in communication with said pipe flow passage, and means for delivering a gaseous drilling fliud to said pipe flow passage,

at least one gas flow valve supported in said drill pipe, said gas flow valve comprising:

a valve body with inlet and outlet flow passageways,

first and second flow conduits respectively connecting said inlet passageway to one flow passage and said outlet passageway to the other flow passage,

a first valve seat intermediate said flow passageways,

a normally-open valve member movable into seal ing engagement with said valve seat,

a pressure-responsive, temperature non-responsive member connected to said valve member and operative when biased from one side thereof to move said valve member toward closed position,

first and second sensing duct members bringing said one side and the other side of said pressure-responsive member into communication respectively with said one flow passage and said other flow passage, and

a second valve seat intermediate said flow passageways, and

a check valve member exposed to pressure from said outlet flow passageway and biased thereby against said second valve seat.

12. In well drilling apparatus including a dual-passage drill pipe comprising an outer pipe adapted to be rotated from the surface and a smaller inner tube supported within the outer pipe, said inner tube forming an inner pipe flow passage, the space between said inner and outer tubes forming an outer pipe flow passage and the annulus around said outer pipe forming a hole flow passage, a bit secured to the bottom of said drill pipe hav-

ing a central opening therein in communication with said inner tube to form therewith a continuous flow passage, and means for delivering drilling fluid to said outer flow passage, the improvement comprising:

means in said bit forming at least one flow duct from said outer passage to the lower cutting face of said bit adjacent said central opening,

means forming flow courses outward across said bit to a hole annulus passage,

a choke member above the cutting face of said bit extending radially an amount sufficient to engage snugly a sub-surface formation cut by said bit and form a barrier to fluid flow from said bit flow duct to one of said pipe and said hole flow passages, and

means forming at least one port through said core tube closely displaced from said bit cutting face to form a by-pass from said outer passage to said inner passage.

13. The well drilling apparatus defined by claim **12** including:

at least one normally-open gas valve supported within said drill pipe,

first and second flow conduits connecting said valve respectively to said outer pipe passage and one of said inner pipe and said hole flow passages,

said valve being conditioned to close in response to a predetermined pressure differential between said outer passage and said one passage.

14. The well drilling apparatus defined by claim **12** including:

at least one gas flow valve supported in said drill pipe,

said gas flow valve comprising:

a valve body with inlet and outlet passageways,

first and second flow conduits respectively connecting said inlet passageway to said outer pipe passage and said outlet passageway to one of said inner pipe and said hole flow passages,

a valve seat intermediate said flow conduits,

a normally-open valve member movable into sealing engagement with said valve seat,

a pressure-responsive member connected to said valve member and operative when biased from one side thereof to move said valve member toward closed position, and

first and second sensing duct members bringing said one side and the other side of said pressure-responsive member into communication respectively with said outer passage and said one passage.

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