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J. A. VARNEY ET AL

3,303,893

MEANS FOR CONTROLLING OPERATION OF TURBODRILL

Filed March 27, 1964

4 Sheets-Sheet 1

Fig. 1.

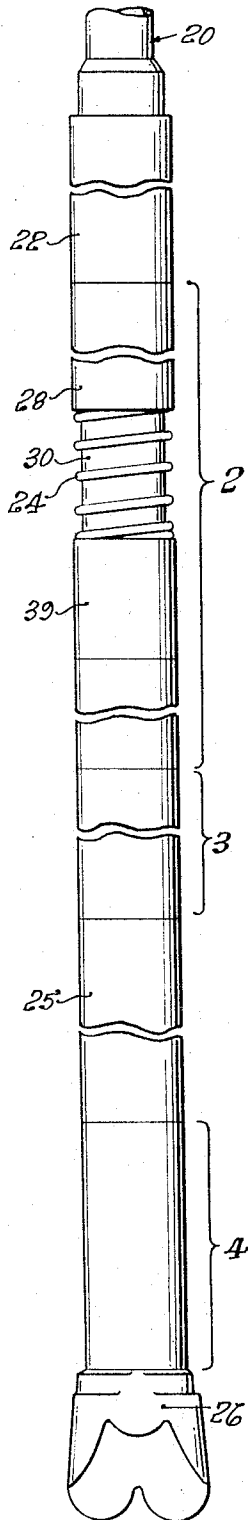
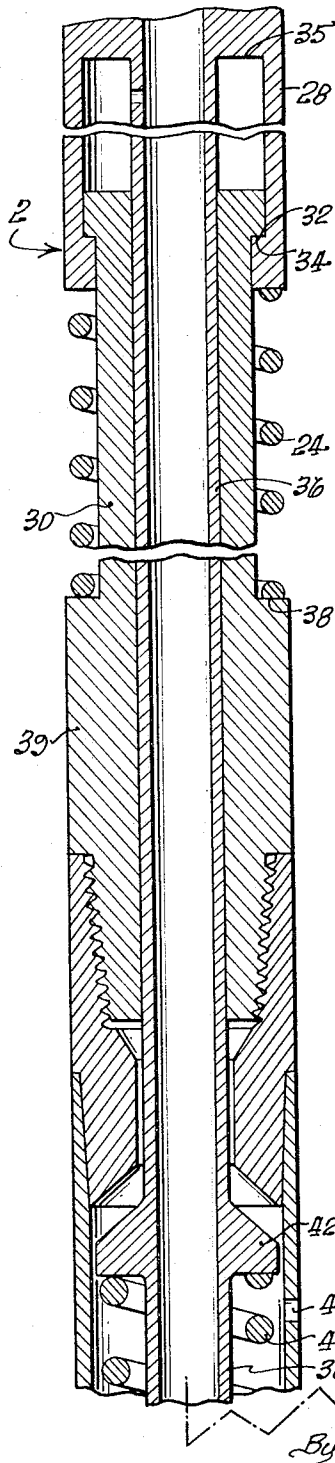
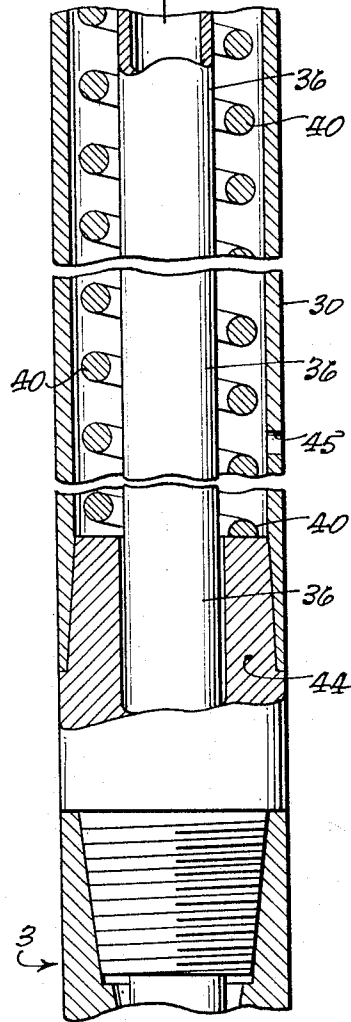


Fig. 2.



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Fig. 3.

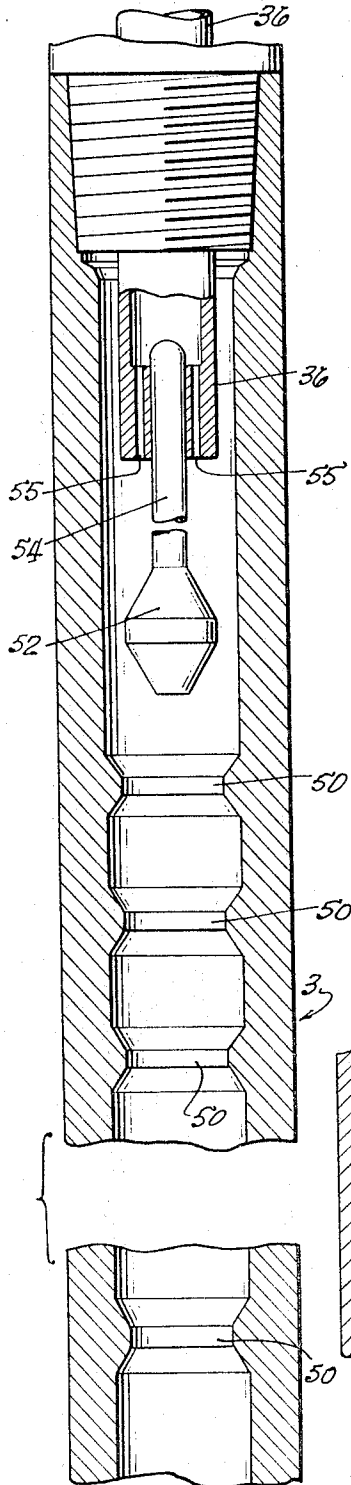


Fig. 4.

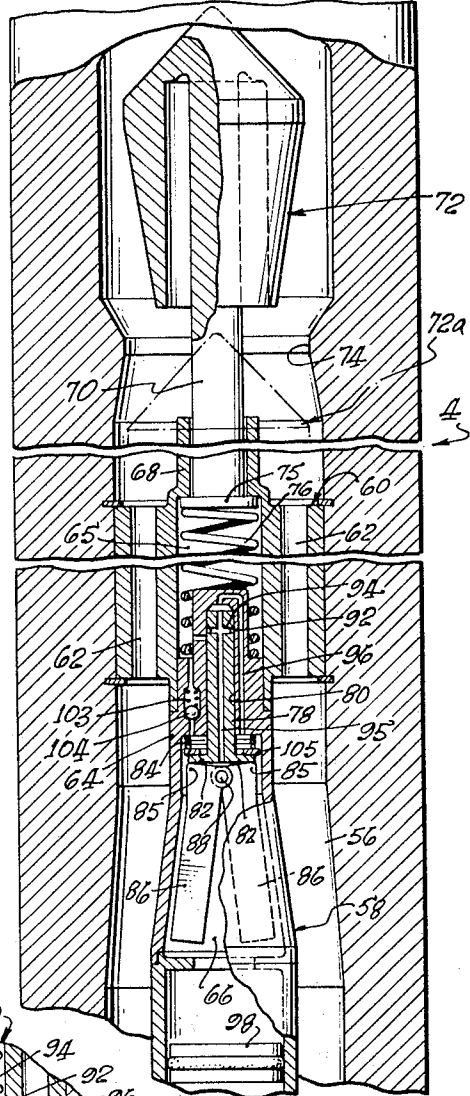
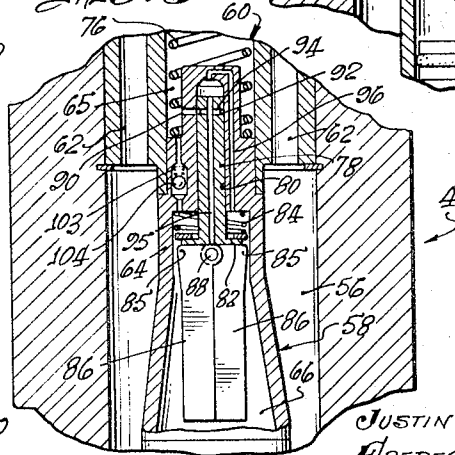


Fig. 5.



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FIG. 6.

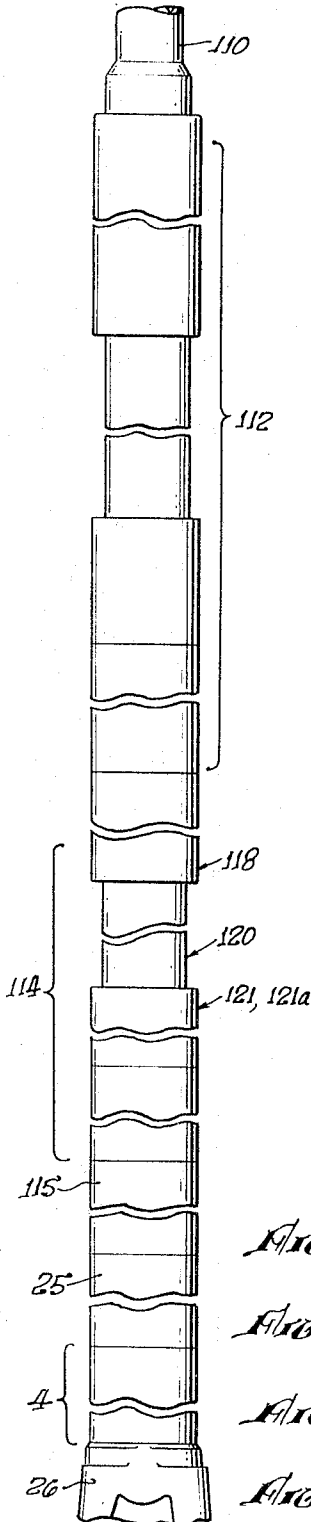


FIG. 7.

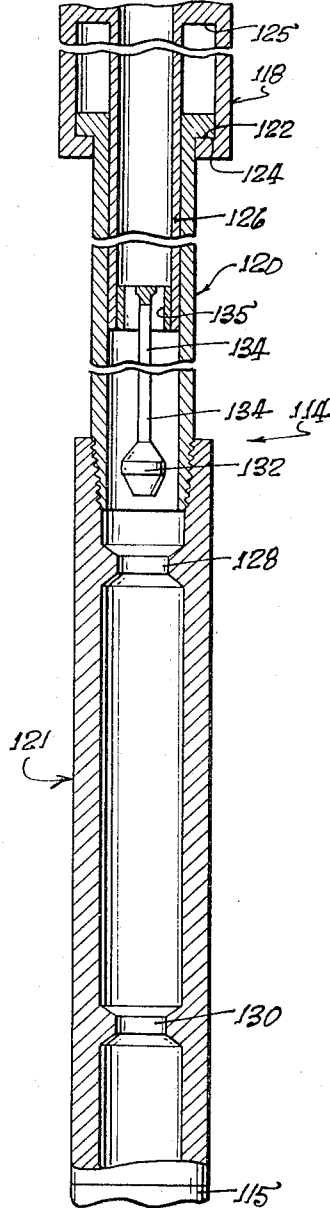


FIG. 8.

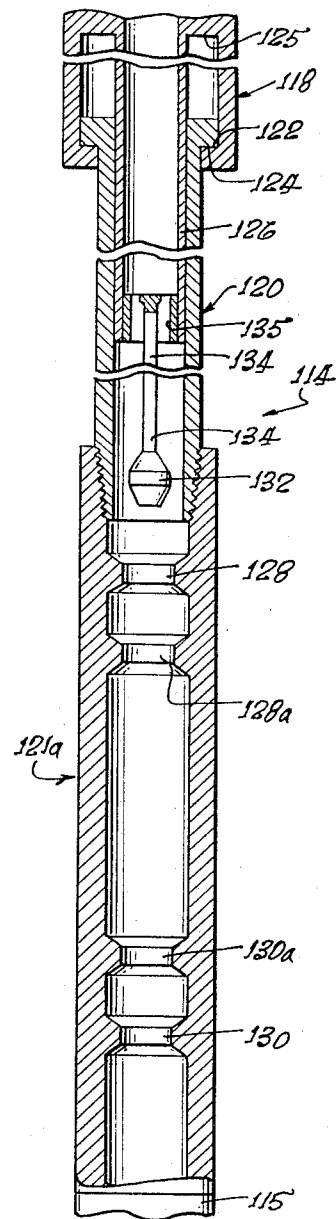


FIG. 9.

FIG. 10.

FIG. 11.

FIG. 12.

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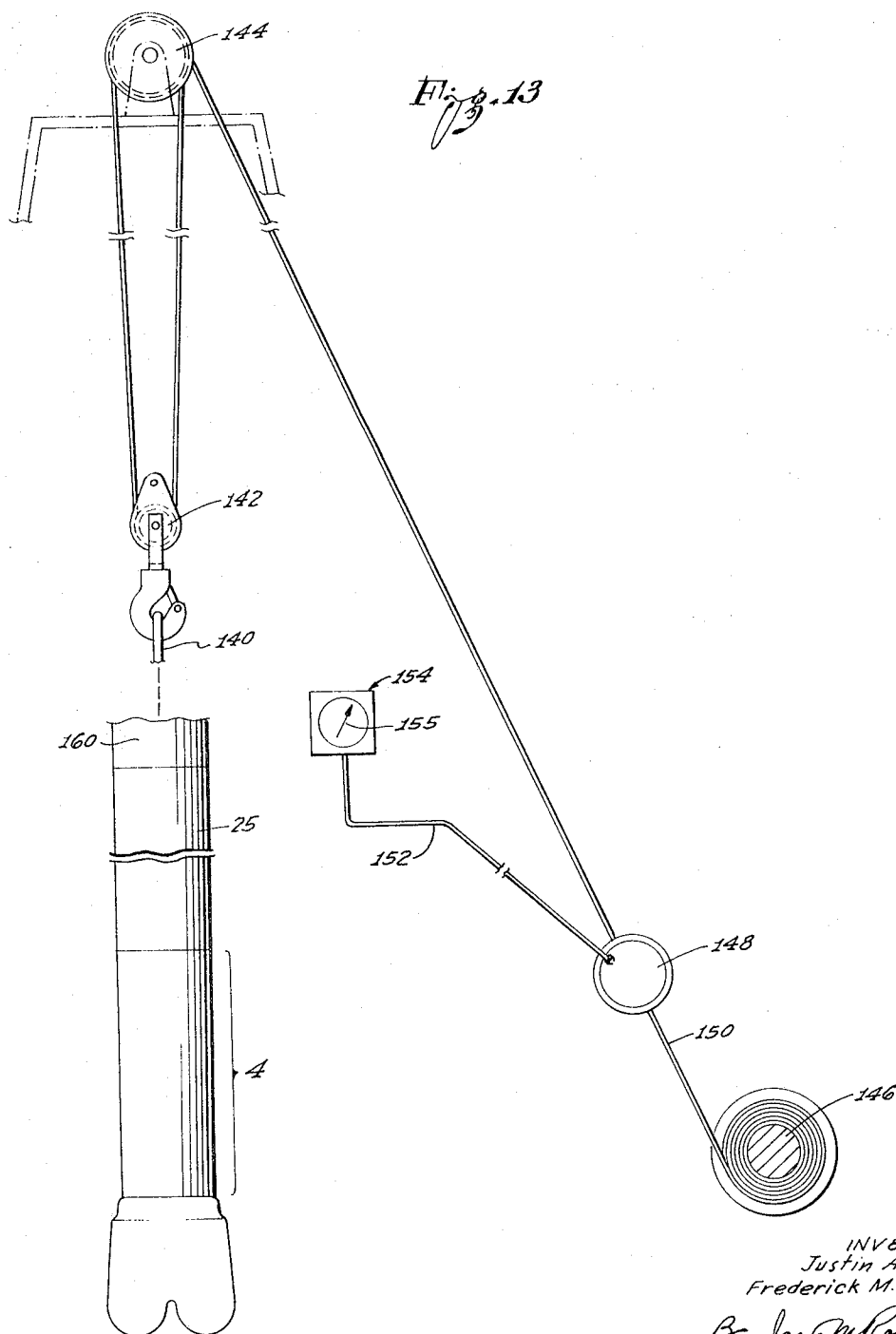
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MEANS FOR CONTROLLING OPERATION OF TURBODRILL

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22 Claims. (Cl. 175-26)

This invention relates to the control of cutting or drilling operations in a well bore with special reference to control of the rate of rotation of the cutting tool. The invention has special utility for a drilling operation where-in a cutting tool is powered for rotation independently of the drill string, for example, where a turbodrill is employed.

It is well known that the amount of weight imposed on a drill bit at the bottom of a well bore is a factor of primary importance to both rate of penetration and directional control in drilling operations. Obviously, the optimum weight varies with such factors as the character of the formation that is being penetrated, the type of drill bit that is being used, and desired rate of rotation of the bit. The difficulty of controlling the weight imposed on a drill bit at the bottom of a well bore, and especially a deep well bore, may be understood by considering a typical situation.

The optimum thrust on the drill bit under given conditions for drilling through a given formation occurs when some given portion of the total weight of the drill string is imposed on the drill bit. Under these circumstances the lower portion of the drill string below a neutral point is under compressive stress and the portion of the drill string above the neutral point is suspended under tension from the top of the well.

It would seem that the weight imposed on the drill bit would be simply the difference between the indicated weight of the drill string as determined by the conventional weight indicator at the rig floor with the bit just off the bottom of the borehole, and the indicated weight when the bit is on bottom and therefore carrying a certain portion of the total weight of the drill string. Under these circumstances, it would seem that the driller could maintain a given weight on the drill bit by simply manipulating the drill string draw works to hold a given indicated differential weight at the drop of the well. Unfortunately, however, such indicated weight can be grossly different from the actual weight carried by the bit in given situations. A major contribution to this erroneous indication is the friction of the drill string against the wall of the well bore, the magnitude of which friction is unknown. In a crooked well bore or a well bore at a high slant angle, the friction or proportion of the drill string supported by resting on the side walls of the bore hole may be of such high magnitude as to completely obscure the true value of weight carried by the bit to the point that it may not even be possible to detect whether or not the bit is actually bearing on the bottom of the bore hole. When a turbodrill is used, the fact that the drill string is not rotating permits very high static friction forces to develop, further compounding the problem relative to the conventional rotating drill string situation. The driller then is forced largely to guess what the magnitude of weight on bit may be and the guess may be far wrong with the consequence that either far too little weight or far too much weight may be imposed on the drill bit. In fact, the weight may readily exceed a value at which a turbodrill continues to rotate at an optimum rate and not infrequently causes stalling of the turbine.

The weight on the drill bit may be controlled by making the portion of the drill string near its bottom end longitudinally extensible and contractible and by provid-

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ing means, preferably resilient yielding means, to progressively increase the downward thrust on the drill bit in response to progressive longitudinal contraction of the drill string. Since the thrust against the drill bit in such an arrangement varies directly with the longitudinal contraction of the drill string, the thrust may be measured indirectly by detecting and signaling the degree of longitudinal contraction.

As will be explained, restricting means may be provided to choke the stream of drilling fluid to create pressure signals in the drill stream, the signals being created at selected points in the range of longitudinal contraction of the drill string. Thus the different pressure signals indicate different magnitudes of thrust on the drill bit.

In the preferred practice of the invention all weight that is variably imposed on the drill bit is located near the end of the drill string, whereby the drill string above such portion is at all times maintained and known to be in tension—a centrally important advantage of the present invention. It is well known that to allow the drill pipe—that portion of the drill string above the drill collars—to accept compressive loads can lead to buckling and consequent early failure of the drill pipe. Since the weight indicating mechanism is located at the lower end of the drill string, the cooperation of the various parts for varying the weight of the drill bit is not affected by any friction that develops along the major portion of the length of the drill string. Similarly, variation in density of drilling fluid, which may reach values as high as twice that of water, and consequent variation in effective mass of the drill string, is no longer of consequence to weight indication. It will be appreciated that the closer the drilling fluid density approaches that of the steel or aluminum in the drill pipe, the less indicative of actual weight on bit a conventional surface measurement will be. Moreover, since drilling mud density can change considerably during drilling, the weight on the bit can actually change appreciably while a surface weight indicator continues to register a constant value as maintained by the driller.

The rate of rotation of the drill bit is to be considered along with the magnitude of the imposed weight. At one extreme, for example, a diamond drill will operate best in a given situation when rotating at relatively high speed under a relatively light weight load. At the other extreme, efficient drilling through a given formation with a given drill bit may require rotation of the drill bit at only a moderate rate under extremely high bit loading. In conventional drilling where the whole drill string is rotated from the top of the well, the average rate of rotation of the drill bit is known, but if a turbodrill is employed on a non-rotating drill string in a conventional manner, the driller cannot be sure that a cutting tool is rotating at all nor can he readily ascertain the rate of rotation if the cutting tool is actually operating. Although various means for detecting and transmitting to the surface turbodrill revolutions per minute have been employed experimentally, these devices offer problems of durability, reliability and interpretation of signals transmitted and therefore do not in practice represent an optimum solution to the problem of detecting and controlling desired weight-on-bit versus r.p.m. values.

The present invention resides solely in means for use with a turbodrill or the like and includes means to detect a selected or critical rate of rotation of the cutting tool and to choke or restrict the stream of drilling fluid to send a pressure signal to the top of the well whenever the rate of rotation falls below that rate. The detecting means, for example, may be centrifugal weight means. In some instances, the selected rate may be close to zero to indicate when the cutting tool actually stalls. In other instances the selected rate of rotation may be a relatively high rate, for example, a rate just under the optimum

rate for the given cutting tool and the given formation.

In one mode of operation of a turbodrill, the driller is guided both by pressure signals that indicate the weight on the cutting tool and by pressure signals that indicate when the rate of rotation of the cutting tool drops below the selected critical value. Preferably, the two types of signals are suitably distinguished from each other. Thus the two types of signals may differ in magnitude, duration, number, or rate of change of pressure.

In a typical procedure, the driller progressively lowers the upper end of the drill string while the turbodrill is operating until the bit touches bottom. Thereafter, the driller is kept informed by pressure signals of the rising magnitude of thrust imposed on the cutting tool, each pressure pulse indicating an incremental addition of weight. When the rising rate of thrust results in a pressure signal indicating that the turbodrill has slowed down below the selected critical r.p.m., the magnitude of the thrust at that time as deduced from the number of pressure pulse signals received since the bit touched bottom is noted by the driller. The driller then raises the drill string to take all weight off the drill bit and briefly stops or sharply reduces drilling fluid circulation. He then again energizes the pumps, to resume rotation of the drill bit, and lowers the drill string under guidance of the succession of pressure signals to resume drilling with the imposed weight regulated at a value somewhat under the previously noted value which caused excessive reduction of the turbodrill r.p.m. Thus, with the critical rate of rotation properly selected for the particular formation and the particular cutting tool, and with knowledge of how much imposed weight slows the cutting tool down to the critical rate of rotation, no special skill is required to operate the turbodrill in an optimum manner under the guidance of the pressure signals that automatically indicate changes in the imposed weight. The operator simply lowers the drill string periodically to allow the advancing cutting tool, the time for each increment of lowering of the drill string being signaled by the weight-on-bit detection device to keep the thrust on the drill within the desired range of magnitude. When the formation changes drastically to require a substantial change in the rate of rotation of the cutting tool, the signaling means may be adjusted at the next bit change to respond to a different rate of rotation of the cutting tool. Similarly, if a change in weight-on-bit to maintain a given rate of rotation of the bit is required by changing drilling conditions, such a change can be effected as indicated above for establishing maximum allowable weight and thereafter may be maintained as long as desired.

In one arrangement, the drill string is made longitudinally extensible and contractible by incorporating a series of telescoping sections in the drill string, each pair of sections being adapted to extend and each pair being provided with means to create pressure signals in the drill stream when the pair contracts. When such a drill string is lowered into the borehole and the drill bit reaches the bottom of the well bore, and then the drill string is progressively lowered still further, the telescoping pairs of sections collapse in sequence beginning with the lowermost pair and the collapse of each pair imposes added weight on the drill bit. Thus, the signals created by the successive collapse of the pairs of telescoping sections indicate known successive increments of additional thrust on the drill bit.

In another arrangement, only one pair of collapsible sections is required, although more pairs may be used if desired. Suitable energy-storing means is interposed between the two relatively movable sections, for example coil spring means, to create rising thrust force in response to progressive contraction of the pair. Preferably, a plurality of coil springs may be arranged for simultaneous compression, the overall spring rate being the sum of the spring rates of the individual coil springs.

The two telescoping sections are adapted to create pressure signals in the drill stream at selected points in their range of relative movement thereby to indicate changes in the magnitude of thrust against the drill bit.

Referring now specifically to the present invention, it is apparent that the signal means that responds to the rate of rotation of the turbodrill may be used separately in a drill string that is not adapted for longitudinal contraction and where the conventional surface weight indicator is adequate for control. With the turbodrill bottomed in the well bore, the driller may simply lower the non-rotating drill string progressively while noting the decreasing weight at the top of the well until a pressure signal indicates that the turbodrill has fallen below the selected critical rate of rotation. The driller notes the magnitude of the critical suspended weight at the top of the well at which the pressure signal occurs. The driller then reduces circulation or stops the pumps momentarily, takes the weight off the turbodrill by slightly lifting the drill string and returns to normal circulation rate to resume operation of the turbodrill. Then the driller lowers the drill string under guidance of the weight indicator to resume drilling with the drill string manipulated to keep the suspended weight at the top of the well regulated to a value somewhat below the weight value found to cause reduction of turbodrill r.p.m. below the critical value. Drilling can now be continued until conditions change to cause another signal from the turbodrill rate of rotation warning device or, alternately, weight on bit can be increased to advantage.

The features and advantages of the invention may be understood from the following detailed description together with the accompanying drawings.

In the drawings, which are to be regarded as merely illustrative:

FIG. 1 is a fragmentary elevational view of the lower end portion of a drill string illustrating the present preferred embodiment of the invention;

FIG. 2 is a longitudinal sectional view of that portion of the structure in FIG. 1 that is generally designated by numeral 2, the structure including coil springs for varying the weight imposed on the drill bit;

FIG. 3 is a longitudinal sectional view of the signaling section in FIG. 1 that is indicated by the numeral 3, the view showing the structure for creating pressure signals at various degrees of compression of the springs shown in FIG. 2;

FIG. 4 is a greatly enlarged longitudinal section of the warning section in FIG. 1 that is generally designated by the numeral 4, the view showing the means for creating pressure signals in the drill stream when the rotation of the cutting tool drops below a selected critical rate, the signal means being in its normal ineffective position;

FIG. 5 is a view similar to FIG. 4 showing the signal controlling means in its alternate or second position;

FIG. 6 is a side elevational view of a second embodiment of the invention in which a plurality of pairs of telescoping sections without springs are incorporated in the drill string;

FIG. 7 is a sectional view of a signaling bumper sub that is generally indicated by numeral 114 in FIG. 6;

FIG. 8 is a sectional view of a signaling bumper sub that is generally designated by numeral 112 in FIG. 6;

FIGS. 9 to 12 are graphs illustrating various types of pressure signals that may be created in the stream of drilling fluid; and

FIG. 13 is a diagrammatic view showing how the stall indicator may be used with a conventional indicator of the weight of the drill string.

FIG. 1 illustrating one arrangement that incorporates the invention shows the lower end of a drill string 20 with the following components connected thereto: at least one drill collar 22 to provide adequate weight for imposition on the drill bit; a bumper sub, generally designated 2, incorporating at least one coil spring 24 for

creating variable force for application to the drill bit; a signaling section, generally designated 3; a turbine drive unit, generally designated 25, to rotate a drill bit or cutting tool 26; and a warning unit, generally designated 4, that rotates with the drill bit.

The bumper sub 2 which is shown in detail in FIG. 2 is of the general construction of a renewable spline type bumper sub manufactured by Baash-Ross Division of Joy Manufacturing Company. In the construction shown the bumper sub 2 provides a telescoping joint in the drill string which includes an upper bumper sub body 28 and a mandrel 30 telescopically connected to the body, the body and mandrel constituting two telescoping sections of the drill string.

In the construction shown, the mandrel 30 is fixedly connected to the lower signaling section 3 which may be regarded as a part of the mandrel. The signaling section 3, in turn, is connected to the turbine drive unit 25 and, if desired, an additional drill collar to apply weight to the drill bit may be interposed between the signaling section and the turbine drive unit.

The upper end of the mandrel 30 is provided with an outer circumferential shoulder 32 which engages a co-operating inner circumferential shoulder 34 of the bumper sub body 28 to limit the downward longitudinal extension of the mandrel relative to the body. At this lower limit position the two telescoping sections are fully extended.

The upper end of the mandrel 30 is free to slide telescopically in the bumper sub body 28 to a second upper limit position (not shown) at which the upper end of the mandrel abuts an inner circumferential shoulder 35 of the bumper sub body. At this second upper limit position, the two telescoping sections are fully contracted and the whole weight of the drill string may be imposed on the drill bit 26.

In a well known manner, the bumper sub body 28 is provided with what is termed a wash pipe 36 which telescopes into the mandrel 30 throughout the range of extension and contraction of the mandrel to provide a suitable channel for the drilling fluid between the two telescoping sections. The range of extension and contraction of the mandrel relative to the bumper sub is preferably relatively extensive and may have a dimension of 5 to 10 feet.

The previously mentioned coil spring 24 surrounds the mandrel 30 under compression between the lower end of the bumper sub body 28 and a lower outer circumferential shoulder 38 that is formed by a collar 39 of the mandrel. A second coil spring 40 surrounds the wash pipe 36 inside the mandrel 30 below the collar 39 and acts in compression between a radial flange 42 of the wash pipe and a lower collar or end fitting 44 of the mandrel. Thus the two coil springs 24 and 40 are arranged for simultaneous compression when the bumper sub 2 is contracted, the spring rates of the two springs being additive.

It is apparent that either of the two springs 24 and 40 may be omitted if a single spring suffices to provide the required force. It is also apparent that the mandrel 30 may be lengthened downward to accommodate a third spring between the mandrel and the wash pipe if a third spring is desirable. The mandrel 30 is provided with at least one radial port 45 for pressure equalization and drainage.

As shown in FIG. 3, the signaling section 3, which is connected to the lower end of the mandrel 30 and may be considered as an extension of the mandrel, is formed with a series of spaced choke rings 50 for cooperation with a choke head 52 that is fixedly connected to the bumper sub body 28. In the construction shown, the choke head or enlargement 52 is mounted on a downwardly extending axial rod 54 that is connected to the lower end of the wash pipe 36 by a suitable apertured fitting or spider 55.

When the drill string equipped with the described com-

ponents is lowered initially into a well bore, the bumper sub 2 is fully extended as indicated in FIG. 2 with the circumferential shoulder 32 of the mandrel 30 resting on the inner circumferential shoulder 34 of the bumper sub body 28 to support all of the components that are below the telescoping joint. At this time the choke head 52 is above the uppermost choke ring 50 as shown in FIG. 3.

When the drill string is bottomed in the well bore and the upper end of the drill string is lowered, the signaling section 3 along with the mandrel 30 becomes stationary and the bumper sub body 28 continues to descend to move the choke head 52 downward through the signaling section 3. The choke head 52 passes first through the uppermost choke ring 50 to restrict the downwardly flowing stream of drilling fluid with the consequence that the back pressure of the drilling fluid rises to create a pressure pulse which travels as a wave to the top of the well, the pressure rise terminating as the choke head passes beyond the choke ring. The pressure wave may be detected at the top of the well by means of a pressure gauge in communication with the interior of the drill string.

As the two telescoping sections continue to collapse, the choke head 52 passes successively through the remaining choke rings 50 to produce a corresponding succession of pressure signals each of which indicates a stage in the contraction of the two telescoping sections. Since the total force exerted by the two springs 24 and 40 to thrust the drill bit 26 against the bottom of the well bore increases progressively with the progressive contraction of the two telescoping sections, it is apparent that the successive pressure signals created by the choke head 52 in cooperation with the choke rings 50 indicate different degrees of magnitude of the weight imposed on the drill bit.

The turbine drive unit 25 may be of a well known construction and need not be described in detail. The drive unit may, for example, be of the construction shown in the Gianalloni, Jr. Patent 2,963,099 dated December 6 1960 or of the type presently in commercial use by the Eastman Oil Well Survey Company.

The warning section or unit 4 shown in FIG. 4 is united with the rotor of the turbine drive unit 25 for rotation therewith and connects the rotor to the drill bit or cutting tool 26. The warning unit forms a fluid channel 56 for transmitting the stream of drilling fluid from the drive unit 25 to the drill bit 26 in a well known manner.

An elongated cylindrical instrument case 58 filled with instrument fluid such as a suitable oil is supported concentrically in the fluid channel 56 by radial support means 60 that is provided with suitable longitudinal passages 62 for fluid flow therethrough. The instrument case 58 is divided by a valve body casting 64 into an upper locking chamber 65 and a lower variable chamber 66.

The upper end of the instrument case 58 forms a guide sleeve 68 for a plunger 70 that carries a choke head 72 for cooperation with a choke ring 74. In the construction shown the choke head 72 is of hollow configuration to permit the choke head to be retracted into overlapping relation with the guide sleeve 68. The lower end of the plunger 70 is formed with a stop flange 75 that limits the upward movement of the plunger and a suitable coil spring 76 in the locking chamber 65 acts under compression between the stop flange and the body casting 64 to urge the plunger towards its uppermost position. The coil spring 76 is strong enough to elevate the plunger 70 along with the choke head 72 when the drill stream is not active but readily yields to permit downward retraction of the plunger under the impact of the actively flowing drill stream against the upper surface of the choke head 72.

A tubular sleeve valve 78 is slidably mounted in the blind axial bore 80 in the valve body casting 64 to control flow between the locking chamber 65 and the variable chamber 66. It is apparent that when the sleeve valve 78 is in its upper closed position shown in FIG. 4 to prevent escape of instrument fluid from the locking chamber 65

the fluid trapped in the locking chamber effectively locks the plunger 70 at an upper position in opposition to the impact force on the plunger head 72 by the downwardly flowing drill stream. In FIG. 4, the drill bit is rotating at relatively high speed with suitable centrifugal weights means holding the sleeve valve 78 at its upper closed position. In the construction shown the sleeve valve 78 is formed with a lower radial flange 82 and a coil spring 84 urges the sleeve valve downward against the heels 85 of a pair of centrifugal weights 86 that are pivotally mounted on a common cross pin 88.

With the moving parts of the warning unit in their positions shown in FIG. 4 with the drill bit rotating at high speed, the slowing down of the drill bit to a selected critical speed permits the two centrifugal weights 86 to react by swinging movement towards each other for downward retraction of the two heels 85 to permit the sleeve valve 78 to be moved by the spring 84 to its open position shown in FIG. 5. In FIG. 5 the instrument fluid is free to flow from the locking chamber 65 through the radial bore 90 into an inner circumferential groove 92 in the axial bore 80. From the inner groove 92 the fluid is free to flow through radial bores 94 of the sleeve valve 78 into the axial passage 95 of the sleeve valve that leads to the lower variable chamber 66. In the meantime a small passage 96 in the valve body casting 64 permits instrument fluid to flow from the variable chamber 66 to the blind end of the axial bore 80 as the space in the blind bore is increased by the retracting sleeve valve. The lower end of the variable chamber 66 is closed by a suitable free piston 98 that equalizes the pressure of the confined instrument fluid with the pressure of the surrounding drilling fluid, the piston shifting up and down in accord with changes in the volume of the instrument fluid in the variable chamber.

Preferably a bypass 103 is provided in the valve body casting 64 between the two chambers to permit rapid upward extension of the plunger 70 by the spring 76. The bypass 103 is provided with a check valve 104 which prevents reverse flow when the plunger retracts into the locking chamber 65.

The manner in which the described structure functions for its purpose may be readily understood from the foregoing description.

In a typical operating procedure, the driller lowers the drill string until the seating of the lower end of the drill ring on the bottom of the well bore causes the bumper 2 to contract progressively in opposition to the resistance of the two springs 24 and 40. As the choke head 2 of the signaling section 3 moves downward correspondingly it creates a pressure signal in the drill stream as it reaches and passes each of the successive choke rings 50. Thus each of the successive pressure signals indicates a given magnitude of downward thrust on the drill bit. The increasing downward thrust eventually causes the rotating drill bit to slow down to the predetermined critical speed at which the centrifugal weights 86 relax to permit the spring 84 to open the sleeve valve 78.

The opening of the sleeve valve 78 permits instrument fluid to flow from the locking chamber 65 through the sleeve valve into the variable chamber 66 and thus unlocks the plunger 70 to permit the impact of the downwardly flowing drill stream on the choke head 72 to force the plunger downward into the locking chamber against the opposition of the spring 76. When the choke head 72 retracts into the region of the choke ring 74, the choke head restricts the downwardly flowing drill stream and thus creates a pressure signal in the drill stream that travels to the top of the well to indicate that the rotation of the drill bit has dropped to the selected critical speed.

The driller then stops the pumps, takes the weight off the drill bit by raising the drill string slightly and pauses for a suitable time interval to permit the spring 76 to return the plunger 70 to its upper starting position. The spring is strong enough for this purpose since the stopping

of the pumps stops the opposing downward flow of the drill stream. Instrument fluid flows freely from the variable chamber 66 to the locking chamber 65 through the check valve 104 as the plunger 70 moves upward.

The driller then again starts the pumps to resume the downward flow of the drilling fluid and to resume rotation of the drill bit. Then the driller lowers the drill string under the guidance of pressure signals created by the signaling section 3 until the driller knows that the rising thrust by the springs 24 and 40 on the drill bit approaches the magnitude at which it was previously noted that the rotation of the drill bit dropped to the selected critical speed. If the selected critical speed of rotation of the drill bit at which the choke head 72 retracts is just below the optimum speed of rotation of the drill bit for the given formation, the described procedure enables the driller to regulate the weight imposed on the bit in a manner to cause the drill bit to rotate at close approximation to its optimum speed. When the rotation of the drill bit is resumed in this procedure, the centrifugal weights 86 kick the sleeve valve 78 upward to its closed position, the instrument fluid in the blind bore 80 that is displaced by the upwardly moving sleeve valve flowing downward through the small passage 96 to the variable chamber 66.

It is to be noted that when the pumps are started with the choke head 72 at an elevated position and with the sleeve valve 78 in open position, the choke head 72 may start to retract downward under the impact of the drill stream before centrifugal weights 86 have an opportunity to close the sleeve valve to lock the choke head 72 against downward retraction. This preliminary downward movement of the choke head, however, is at a retarded rate because of the restricted flow of the instrument fluid from the locking chamber to the variable chamber and in practice the slight downward movement of the choke head is not troublesome.

Preferably the choke head 72 is free to drop to the dotted position indicated 72a, at which position the choke head is far enough below the choke ring 74 to permit normal flow of the drilling fluid. Thus the arrangement is fail-safe in the sense that the choke head does not interfere with the drilling operation if any failure of the warning mechanism permits the choke head to drop to its lower limit position and to remain there.

Since the amplitude of a pressure signal in the drill stream depends upon the degree to which the drill stream is restricted by a choke head and a cooperative choke ring, the drill stream may be restricted to two different degrees for two kinds of signals. Thus two different signal magnitudes permit the driller to distinguish the pressure signals created by the choke head 52 in the signaling section 3 from the pressure signals created by the choke head 72 in the warning section 4. For example, the choke head 52 may be dimensioned to cooperate with the choke rings 50 to cause the pressure of the drill stream to rise 200 p.s.i. above its normal pressure and the choke head 72 may be dimensioned to cooperate with the choke ring 74 for greater restriction of the drill stream to cause the pressure of the drill stream to rise to 400 p.s.i. above the normal pressure.

With such an arrangement, a signal created by the passage of the choke head 52 through a choke ring 50 may be of the magnitude shown in FIGS. 9 and 10. FIG. 9 represents a pressure signal of relatively short duration when the choke head moved rapidly through the cooperating choke ring and FIG. 10 represents a more prolonged pressure signal caused by slower movement of the choke head through the choke ring. The higher magnitude pressure signal created by the choke head 72 of the warning section 4 is indicated in FIGS. 11 and 12. FIG. 11 shows a warning pressure signal alone and FIG. 12 shows a warning pressure signal superimposed on the pressure signal shown in FIG. 10. It is apparent that the driller may readily distinguish between the two kinds of pressure signals.

The described warning unit may be adjusted in various ways to change the critical rate of rotation at which a warning signal is created. Thus, different sets of centrifugal weights 86 may be provided for interchangeable use or different value springs 84 may be used interchangeably. For the purpose of adjustment, FIGS. 4 and 5 show a washer 105 under the valve spring 84. This washer may be removed or more washers may be added to vary the spring pressure and thereby vary the critical speed at which a warning signal is created.

In FIG. 6 which illustrates another arrangement, the lower end of a drill string 110 carries the following components in sequence: an upper signaling bumper sub 112, the construction of which is indicated in FIG. 8; a lower signaling bumper sub 114, the construction of which is indicated in FIG. 7; a drill collar 115 to cooperate with other members below the signaling bumper sub 114 to provide a minimum weight on the drill bit; the usual turbine drive unit 25; the previously described warning units 4; and the drill bit 26. For simplicity, FIG. 6 shows only the two signaling bumper subs 112 and 114 but usually there will be more signaling bumper subs to provide the desired number of increments of weight to be imposed on the drill bit.

When such a drill string is bottomed in a well bore and then the upper end of the drill string is lowered progressively, the signaling bumper subs collapse in succession beginning with the lowermost bumper sub and the collapse of each signal bumper sub adds a predetermined increment of weights on the drill bit. In FIG. 6 the drill string has been lowered against the bottom of the well bore far enough for partial collapse of the lowermost signaling bumper sub 114, the remaining bumper subs above the signaling bumper sub 114 being fully extended.

As indicated in FIG. 7, the construction of the lowermost signaling bumper sub 114 is largely similar to the construction of the previously described bumper sub 2 and the associated signaling section 3. Thus in FIG. 7 the structure includes a bumper sub body 118 and a mandrel 120 telescopically connected to the body, the body and mandrel constituting two telescoping sections of the drill string. The mandrel 120 is fixedly connected to a lower signaling section 121 which may be regarded as a part of the mandrel. The lower signaling section 121 is connected, in turn, to the drill collar 115.

In the usual manner, the upper end of the mandrel 120 is provided with an outer circumferential shoulder 122 which engages a cooperating inner circumferential shoulder 124 of the bumper sub body 118 to limit the downward longitudinal extension of the mandrel relative to the body. At this lower limit position the two telescoping sections are fully extended.

The upper end of the mandrel 120 is free to slide telescopically in the bumper sub body 118 to a second upper limit position (not shown) at which the upper end of the mandrel abuts an inner circumferential shoulder 125 of the bumper sub body. At this second upper limit position, the two telescoping sections are fully contracted.

The bumper sub body 118 is provided with the usual wash pipe 126 which telescopes into the mandrel 120 throughout the range of extension and contraction of the mandrel to provide a suitable channel for the drilling fluid between the two telescoping sections.

The signaling section 121 may be formed with an upper choke ring 128 and a lower choke ring 130 for cooperation with a choke head 132. In the previously described manner, the choke head or enlargement 132 is mounted on a downwardly extending axial rod 134 that is connected to the lower end of the wash pipe 126 by a suitable apertured fitting or spider 135.

Initial contraction of the lowermost signaling bumper sub 114 causes the choke head 132 to pass through the upper choke ring 128 and as the signaling bumper sub approaches maximum contraction the choke head passes

through the second lower choke ring 130. Thus the described arrangement provides a first pressure signal to indicate initial collapse and a second pressure signal to indicate approach to maximum collapse of the signaling bumper sub.

The second signaling bumper sub 112 which is shown in FIG. 8 is largely identical to the construction of the first signaling bumper sub 114 as indicated by the use of corresponding numerals to indicate corresponding parts. The sole difference is that the signaling section 121a has two closely spaced upper choke rings 128a instead of a single choke ring and in like manner has a pair of lower choke rings 130a instead of a single choke ring 130. It is apparent that initial collapse of the second signaling bumper sub 112 creates two pressure signals and approach to full collapse produces a second pair of signals. In a typical installation there may, for example, be three additional signaling bumper subs above the signaling bumper sub 112, the third signaling bumper sub from the bottom creating three pressure signals at each end of its range of contraction, the fourth signaling bumper sub from the bottom creating four pressure signals at each end of its range of contraction and the fifth bumper sub creating five pressure signals at the beginning and end of its range of contraction.

It is apparent that this second embodiment of the invention operates in substantially the same manner as the first embodiment. With the drill bit bottomed in the well bore, the driller lowers the upper end of the drill string and is informed by successive pressure signals of the successive increments of weight that are imposed on the drill bit. With increased imposition of weight, eventually the warning unit 4 creates a pressure signal to indicate that the rotation of the drill bit has dropped to the critical speed and the driller then notes the magnitude of the signaled weight for further guidance in the manner heretofore described.

A feature of the invention is that either of the two embodiments may be used without any means whatsoever to signal changes in the thrust imposed on the drill bit. The driller knows that when he continues to lower the drill string with consequent contraction of the drill string the weight imposed on the drill bit rises progressively with either of the two embodiments of the invention and the warning unit 4 will indicate when the rise in pressure results in lowering the speed of rotation of the drill bit to the selected critical speed. At that point the driller may note the magnitude of the suspended weight of the drill string at the top of the well and may thereafter be guided by the suspended weight in manipulating the drill string for imposing maximum weight on the drill bit without causing the rotation of the drill bit to drop to the critical speed.

A conventional weight indicator for this purpose is shown in FIG. 13 where a bail 140 at the upper end of a drill string is connected to a traveling block 142 of a cable system that includes the usual crown block 144 and calf wheel 146. A weight indicator of a well known type includes a hydraulic unit 148 that engages the cable 150 and measures the stress in an offset portion of the cable. A hydraulic hose 152 connects the hydraulic unit 148 to an indicator 154, the pointer 155 of which indicates the weight of the drill string.

It is also apparent that if the turbine drive unit 25 and the warning unit 4 are employed on a conventional drill string that is not collapsible, the driller may progressively lower the drill string until a warning signal is created and may then note the suspended weight of the drill string at the top of the well for guidance in maintaining the drill bit under optimum weight.

FIG. 13 shows such an arrangement in which the turbine drive unit 25 and the warning unit 4 are placed on the lower end of a conventional drill string 160. The upper end of the drill string 160 is supported in the previously described manner by a cable 150 that is equipped

with a weight indicator. The tension on the cable is sensed by the hydraulic unit 148 and indicated by the pointer 155. Once the critical indicated weight is found that causes the rotary drill to stall, the operator may hereafter control the paying out of the cable 150 to maintain the indicated rate at a value below the critical weight and thus operate in an optimum manner.

As heretofore noted, a collapsible drill string either of the character shown in the first arrangement or of the character shown in the second arrangement may be employed with a deviation detector and a drill bit that is rotated by the drill string. The deviation detector indicates when the well bore deviates from true vertical and the pressure signals indicate the maximum weight that may be imposed on the drill bit without causing excessive deviation.

As heretofore indicated, the turbine drive unit includes a rotor (not shown) that is operatively connected to the drill bit by means of the warning unit 4. Typically the rotor is journaled by suitable means including a heavy duty thrust bearing (not shown). Since the pressure of the stream of drilling fluid upstream from the rotor greatly exceeds the fluid pressure below the rotor due to removal of energy from the drilling fluid stream by the turbine, there is a pressure differential of relatively high magnitude across the rotor which imposes a heavy load on the thrust bearing. With this high pressure and the abrasive character of the drilling fluid, it is understandable that the thrust bearing wears fast and this wear is an important factor limiting the continuous service of a turbodrill in a well bore to a relatively short interval of time.

Another thrust bearing, or set of thrust bearings, is included in typical turbodrill constructions to accept thrust loads upwardly directed from the drill bit. The thrust with which the drill bit is forced against the bottom of the borehole for fracturing or cutting the rock is retracted by this second set of thrust bearings in the turbodrill. As in the case of the first-mentioned thrust bearings accepting downwardly directed hydraulic thrust deriving from pressure drop across the turbine, wear of the second set of thrust bearings can be quite rapid, especially if the weight imposed on the bit is high and in consequence the upwardly directed thrust reacting this load on the bit greatly exceeds the downwardly directed hydraulic thrust.

A feature of the present invention resides in the fact that the two thrust loads mentioned above can be deliberately equated in operation by using the weight control means described and depicted herein, with the result that neither set of thrust bearings is required to accept high loads producing rapid wear. This equating of oppositely directed thrust loads may be accomplished by virtue of the fact that at any given rate of flow of drilling fluid through a turbodrill, the pressure drop across the turbine is of known value, within quite close limits. Therefore, the magnitude of the downwardly-directed hydraulic thrust resulting from such pressure drop is likewise known. If the driller, using the precise knowledge of weight imposed on the bit afforded by the weight control means described herein, applies a weight on the bit of the same magnitude in pounds as the known value of hydraulic thrust at the given rate of flow of drilling fluid, then the upwardly-directed reaction from the bit and the downwardly-directed hydraulic thrust value will be equated and the thrust bearings substantially relieved of any load whatever. It is of value to note that even though the lubricant effective on such thrust bearings is, as indicated above, normally contaminated with abrasive solids, in the absence of high compressive loads in the thrust bearings as achieved through the method herein described, such abrasive solids produce relatively little wear and the effective service life of the thrust bearings may be greatly increased. It is further of value to note that the magnitude of hydraulic thrust developed in operation of turbodrills in current practice is within the same order of magnitude in pounds as

the permissible weight applied to drill bits driven by turbodrills, as determined by magnitude of torque developed by the turbine under acceptable rates of flow and the tendency of such turbines to slow up and eventually stall completely if weight-on-bit values are permitted to rise above certain relatively low values. Therefore, the method of relieving thrust loads taught herein is of eminent practicality in light of current turbodrill practice.

Our description in specific detail of the selected embodiments of the invention will suggest various changes, substitutions and other departures from our disclosure within the spirit and scope of the appended claims.

We claim:

1. In an apparatus to carry out a mechanical operation in a well bore, the combination of:
 - a pipe string adapted for lowering into the well bore, the pipe string being longitudinally extensible and contractible;
 - a rotary processing tool in the lower end of the a pipe string to perform the mechanical operation;
 - power means to rotate the processing tool relative to the pipe string;
 - means to vary the weight imposed on the rotary processing tool in response to extension and contraction of the pipe string whereby the weight imposed on the rotary tool may be varied by raising and lowering the upper end of the pipe string;
 - signal means responsive to extension and contraction of the pipe string to indicate the magnitude of the weight imposed on the rotary processing tool;
 - signal means responsive to rotation of the cutting tool relative to the pipe string to indicate when the rate of rotation of the processing tool drops to a predetermined degree, whereby the two responsive means cooperate to indicate the critical magnitude of weight imposed on the processing tool at which the rotation of the processing tool drops to the predetermined degree.
2. In an apparatus for operation in a well bore, the combination of:
 - a drill string having a rotary cutting tool on its lower end powered for rotation relative to the drill string, the drill string having telescoping sections for longitudinal extension and contraction of the drill string;
 - means to exert force to extend the drill string with progressive rise of the force in response to progressive contraction of the drill string whereby progressive contraction of the drill string by manipulation of the upper end of the drill string progressively increases the downward thrust of the drill string on the cutting tool;
 - signal means responsive to extension and contraction of the drill string to indicate changes in the thrust on the cutting tool;
 - and signal means responsive to rotation of the cutting tool to indicate when the angular velocity of the cutting tool drops below a predetermined magnitude whereby the two signal means cooperate to indicate the maximum magnitude of thrust on the cutting tool that permits the predetermined magnitude of angular velocity of the cutting tool.
3. A combination as set forth in claim 2 in which the means to exert force to extend the drill string includes resilient yielding means acting between the telescoping sections of the drill string.
4. A combination as set forth in claim 2 in which the yielding means comprises a plurality of individual springs arranged for simultaneous deflection, the effective spring rate of the spring means being the sum of the spring rates of the individual springs.
5. In an apparatus for operation in a well bore, the combination of:
 - a drill string having a rotary cutting tool on its lower end powered for rotation relative to the drill string, the drill string having a plurality of telescoping

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joints, each capable of extension and contraction whereby with the drill string bottomed on the bottom of the well bore and with all of the telescoping joints extended, the upper end of the drill string may be lowered to collapse the telescoping joints in sequence beginning with the lowermost joint thereby to progressively increase the proportion of the weight of the drill string that is imposed on the cutting tool; signal means responsive to different degrees of contraction of the drill string to indicate changes in the thrust on the cutting tool;

and signal means responsive to rotation of the cutting tool to indicate when the angular velocity of the cutting tool drops below a predetermined magnitude, whereby the two signal means cooperate to indicate the maximum magnitude of thrust of the drill string on the cutting tool that permits the predetermined magnitude of angular velocity of the cutting tool.

6. In an apparatus for operation in a well bore, the combination of:

a drill string having a rotary drilling tool on its lower end powered for independent rotation, the drill string including a series of pairs of telescoping sections, each pair having a range of longitudinal extension and contraction whereby lowering the drill string to bottom the cutting tool in the well bore and then continuing to lower the upper end of the drill string causes the telescoping pairs of sections to contract in sequence beginning with the lowermost pair with the contraction of each pair imposing on the cutting tool the weight of the drill string below the pair whereby the weight imposed on the cutting tool rises by stages as the upper end of the drill string is lowered;

means to force a stream of drilling fluid down through the drill string;

means responsive to the contraction of each of the pairs of sections to create pressure signals in the drill string thereby to indicate the changes in the weight imposed on the cutting tool;

and signal means responsive to rotation of the cutting tool to indicate when the rate of rotation of the cutting tool drops below a predetermined rate, whereby the two responsive means cooperate to indicate the critical magnitude of imposed weight on the cutting tool at which the rotation of the cutting tool drops below the predetermined rate.

7. In an apparatus for operation in a well bore, the combination of:

a drill string having a rotary cutting tool on its lower end powered for rotation relative to the drill string, the drill string having longitudinally telescoping sections whereby with the drill string bottomed in the well bore the upper end of the drill string may be raised and lowered for axial extension and contraction of the drill string;

means responsive to progressive contraction of the drill string to progressively increase the thrust of the cutting tool against the bottom of the well bore whereby the thrust of the cutting tool may be increased by lowering the drill string and vice versa; means to force a stream of drilling fluid down the drill string;

and means responsive to rotation of the cutting tool to create pressure signals in the stream to indicate when the thrust causes the angular velocity of the cutting tool to drop to a predetermined magnitude.

8. A combination as set forth in claim 7 which includes means responsive to extension and contraction of the drill string to create pressure signals in the stream to indicate changes in the magnitude of the thrust on the cutting tool.

9. In an apparatus for operation in a well bore, the combination of:

a drill string carrying a rotary cutting tool powered

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for independent rotation, the drill string having telescoping sections for relative longitudinal movement for longitudinal extension and contraction of the drill string;

means to exert force to extend the drill string with progressive rise of the force in response to progressive contraction of the drill string whereby progressive contraction of the drill string by progressive lowering of the drill string against the bottom of the well bore progressively increases the downward thrust on the cutting tool and vice versa;

means to force a stream of drilling fluid downward through the drill string;

and signal means responsive to rotation of the cutting tool to create pressure signals in the stream to indicate when the thrust of the cutting tool causes the angular velocity of the cutting tool to drop below a predetermined magnitude.

10. A combination as set forth in claim 9 in which the signal means comprises:

means to restrict the stream of drilling fluid to increase the pressure thereof to create pressure signals therein; and centrifugal means connected with the cutting tool to operate the restricting means in response to drop in the angular velocity of the cutting tool.

11. A combination as set forth in claim 9 which includes cooperating means carried by telescoping sections respectively of the drill string to choke the stream of drilling fluid in response to longitudinal relative movement between the sections to send pressure signals up the stream to indicate changes in extension and contraction of the drill string thereby to indicate changes in the thrust on the cutting tool.

12. In an apparatus for operation in a well bore, the combination of:

a drill string carrying a rotary cutting tool powered for independent rotation, the drill string having telescoping sections for relative longitudinal movement for longitudinal extension and contraction of the drill string;

means to exert force to extend the drill string with progressive rise of the force in response to progressive contraction of the drill string whereby progressive contraction of the drill string by progressive lowering of the drill string against the bottom of the well bore progressively increases the downward thrust on the cutting tool;

means to force a stream of drilling fluid downward through the drill string;

restriction means in the drill string movable longitudinally of the stream between a normal position and a second position and adapted to restrict the stream to create a pressure signal therein in response to its movement to its second position;

yielding means urging the signal means toward its normal position, the signal means being exposed to the stream for movement by impact of the stream from its normal position to its second position in opposition to the yielding means;

means to releasably lock the restricting means at its normal position;

and means responsive to rotation of the cutting tool to unlock the restricting means when the angular velocity of the cutting tool drops below a predetermined magnitude.

13. A combination as set forth in claim 12 in which said locking means is a hydraulic locking means including means to confine a locking body of hydraulic fluid and valve means to release the body of fluid.

14. A combination as set forth in claim 13 which includes means to control the release flow of the hydraulic fluid to prevent prompt movement of the restricting means from its normal position to its second position in response to initiation both of flow of the stream and of rotation of the cutting tool.

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15. Signal means for an apparatus to carry out a cutting operation in a well bore, wherein the apparatus includes a drill string, a rotary cutting tool at the lower end of the drill string, means to force a stream of drilling fluid down the drill string, and power means to rotate the cutting tool independently of the drill string, said signal means comprising:

restriction means in the drill string movable longitudinally of the stream between a normal position and a second position and adapted to restrict the stream to create a pressure signal therein in response to its movement to its second position;

yielding means urging the signal means towards its normal position, the signal means being exposed to the stream for movement by impact of the stream from its normal position to its second position in opposition to the yielding means;

means to releasably lock the restricting means to its normal position;

and means responsive to rotation of the cutting tool to unlock the restricting means when the angular velocity of the cutting tool drops below a predetermined magnitude.

16. A combination as set forth in claim 15 in which said locking means is a hydraulic locking means including means to confine a locking body of hydraulic fluid and valve means to release the body of fluid.

17. Signal means for an apparatus to carry out a cutting operation in a well bore, wherein the apparatus includes a drill string, a rotary cutting tool at the lower end of the drill string, means to force a stream of drilling fluid down through the drill string, and power means to rotate the cutting tool independently of the drill string, said signal means comprising:

a plunger in the stream of drilling fluid movable longitudinally of the stream between a normal position and a second position;

a casing telescopically mounting the plunger for movement between its two positions, the casing containing hydraulic fluid for displacement by the plunger, the casing being variable in its effective volume to accommodate displacement of the fluid by the plunger;

yielding means acting between the plunger and the casing to urge the plunger to its normal position when the stream is not flowing, the plunger being exposed to the stream for movement by the impact of the stream from its normal position to its second position in opposition to the yielding means;

means cooperative with the plunger to restrict the stream in response to movement of the plunger from its normal position to its second position thereby to create a pressure signal in the stream;

valve means to cut off displacement flow in the casing to hydraulically lock the plunger at its normal position;

and centrifugal means connected with the cutting tool for rotation simultaneously therewith to open the valve for movement of the plunger to its second position in response to reduction of the rate of rotation of the cutting tool below a predetermined rate.

18. A combination as set forth in claim 17 which includes spring means to bias the valve to its closed position;

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and in which the centrifugal means is adapted to overcome the spring means when the rate of rotation of the cutting tool is above the predetermined rate.

19. Signal means for an apparatus to carry out a cutting operation in a well bore, wherein the apparatus includes a drill string, a rotary cutting tool at the lower end of the drill string, means to force a stream of drilling fluid down through the drill string, and power means to rotate the cutting tool independently of the drill string, said signal means comprising:

a plunger in the stream of drilling fluid movable longitudinally of the stream between a normal position and a second position;

a casing in the stream confining hydraulic fluid and telescopically mounting the plunger, the casing being connected with the cutting tool for rotation simultaneously therewith, the casing having a locking chamber receiving the plunger and a second variable chamber to receive fluid displaced from the locking chamber by the plunger;

yielding means acting between the plunger and the casing to urge the plunger to its normal position when the stream is not flowing, the plunger being exposed to the stream for movement by the impact of the stream from its normal position to its second position in opposition to the yielding means;

means cooperative with the plunger to restrict the stream in response to movement of the plunger from its normal position to its second position thereby to create a pressure signal in the stream;

releasable locking means to cut off flow from the locking chamber to the variable chamber to hydraulically lock the plunger at its normal position;

centrifugal weight means rotatable with the casing and movable from a first relaxed position to a second effective position in response to rotation of the cutting tool, the centrifugal weight means being operatively connected with the locking means to release the locking means in response to movement of the centrifugal weight means towards its relaxed position.

20. A combination as set forth in claim 19 in which said yielding means is in the locking chamber.

21. A combination as set forth in claim 19 in which the centrifugal weight means is in the variable chamber.

22. A combination as set forth in claim 19 which includes a second yieldable means in the casing to urge the locking means to its release position, the centrifugal weight means being adapted to overcome the second yielding means by movement from its relaxed position to its effective position.

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