

March 8, 1960

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2,927,638

MULTISTAGE HYDRAFRACTURING PROCESS AND APPARATUS

Filed Jan. 10, 1955

7 Sheets-Sheet 1

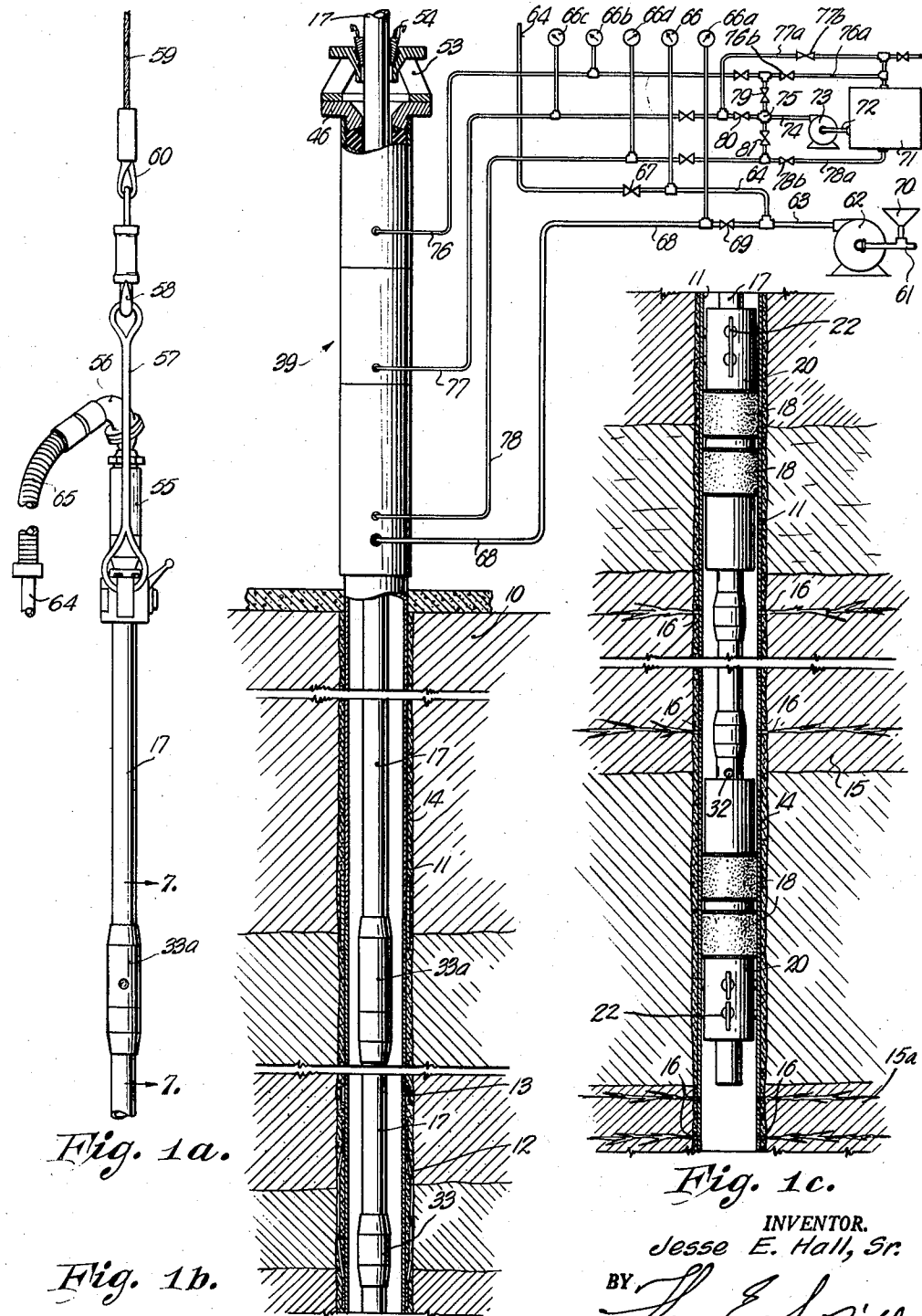


Fig. 1a.

Fig. 1b.

Fig. 1c.

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7 Sheets-Sheet 2

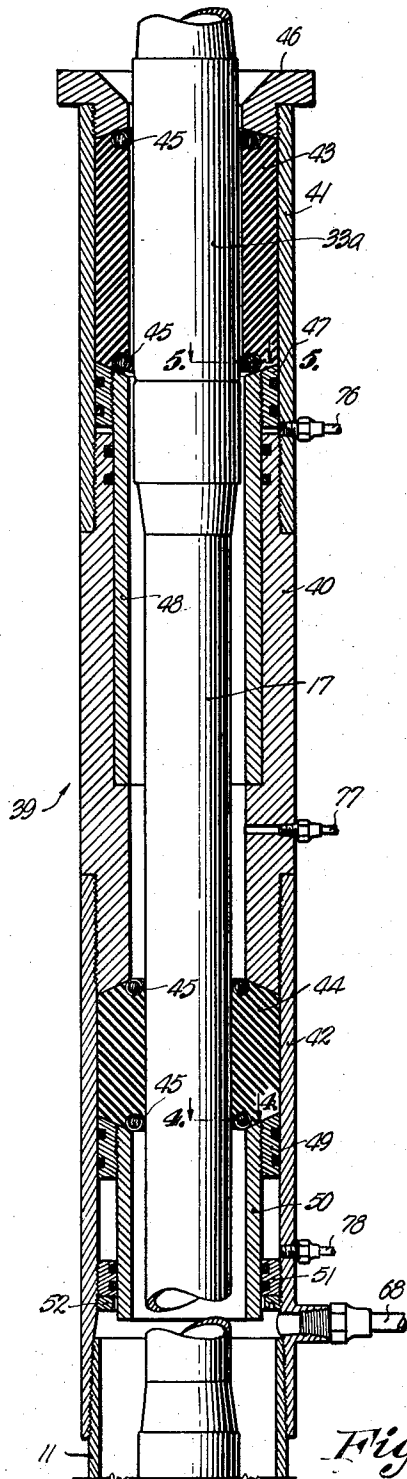


Fig. 2.



Fig. 4.

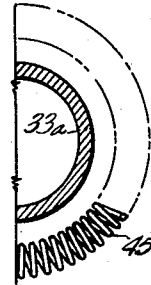


Fig. 5.

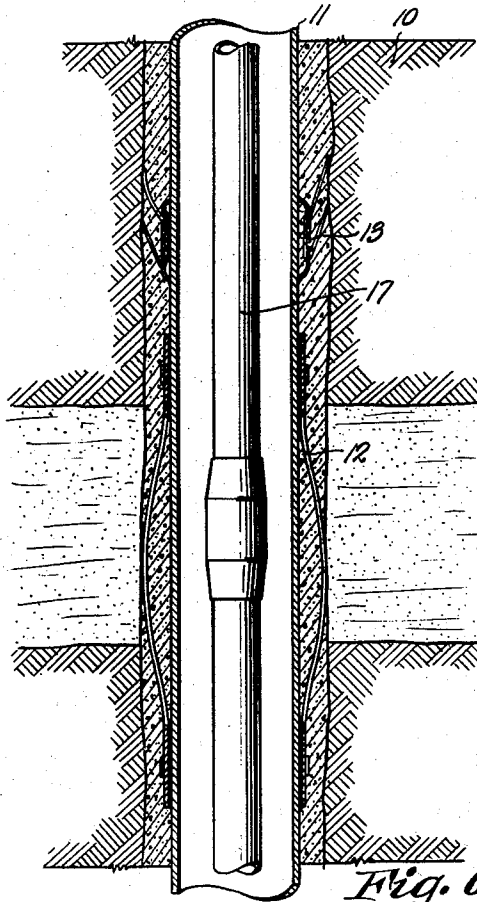


Fig. 6.

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7 Sheets-Sheet 3

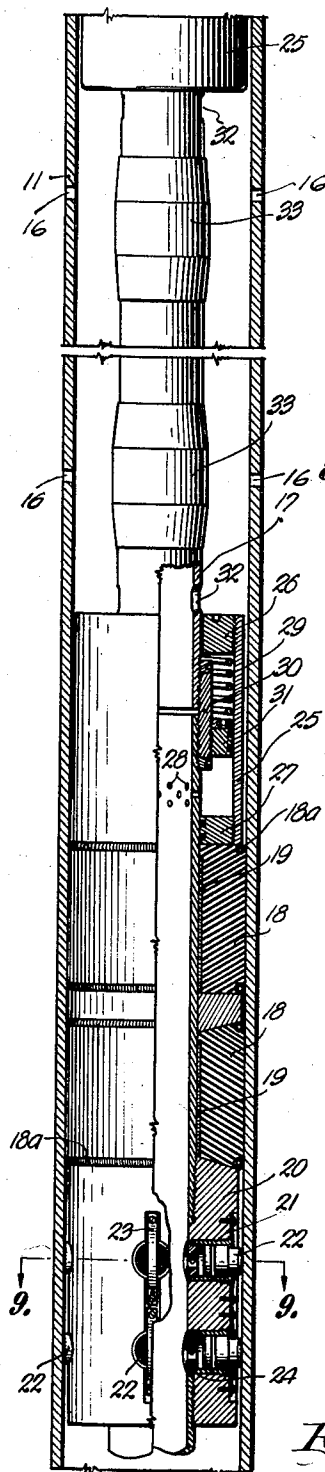


Fig. 3.

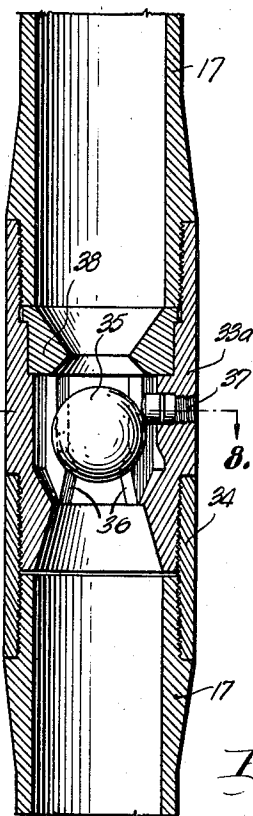


Fig. 7.

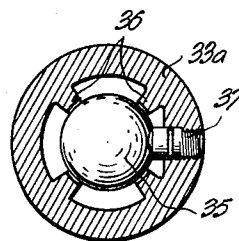


Fig. 8.

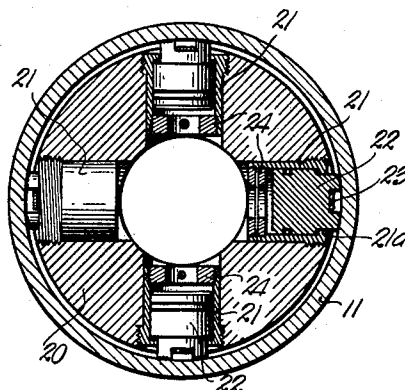


Fig. 9.

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7 Sheets-Sheet 4

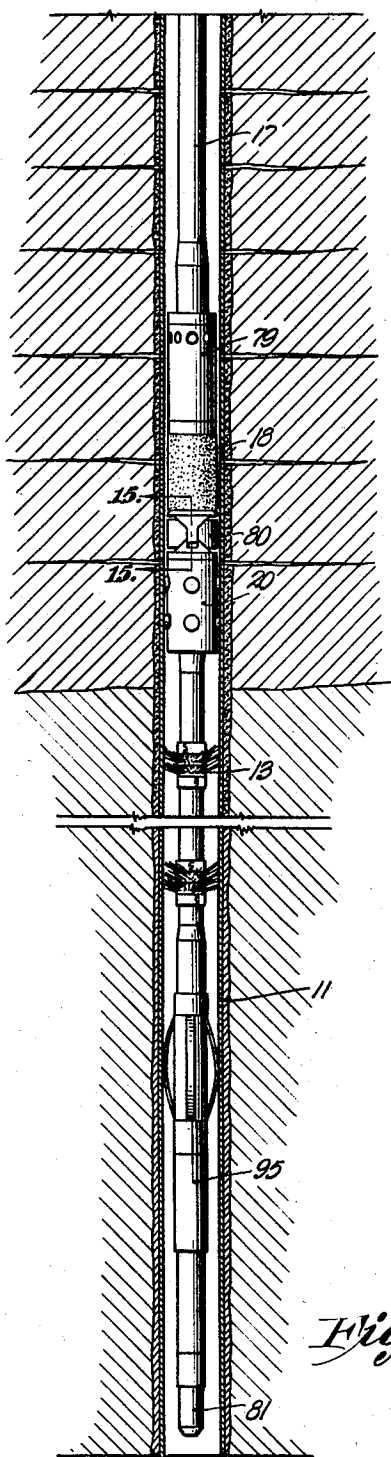


Fig. 10.

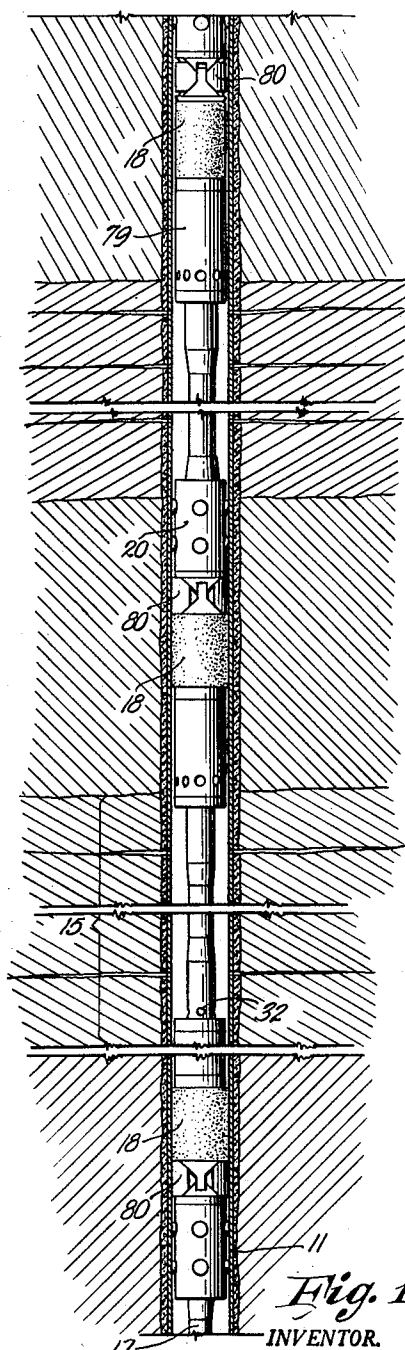


Fig. 11.

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MULTISTAGE HYDRAFRACTURING PROCESS AND APPARATUS

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7 Sheets-Sheet 5

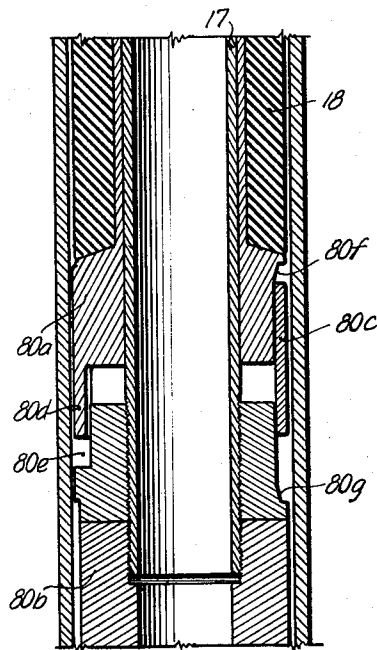
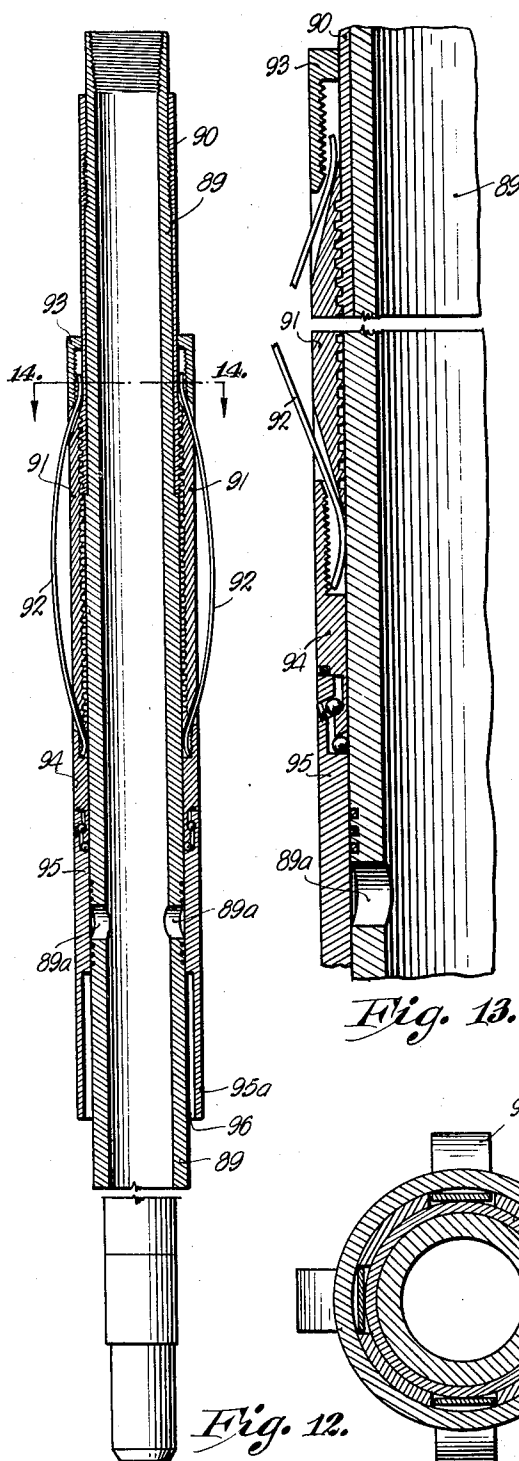


Fig. 15.

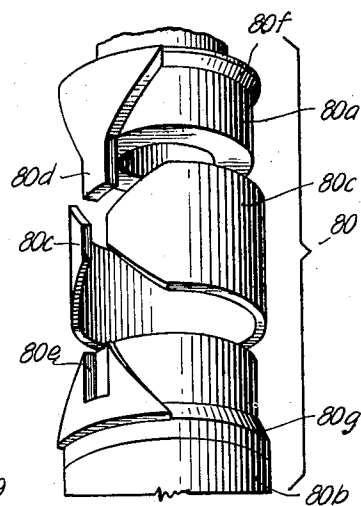


Fig. 16.

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7 Sheets-Sheet 6

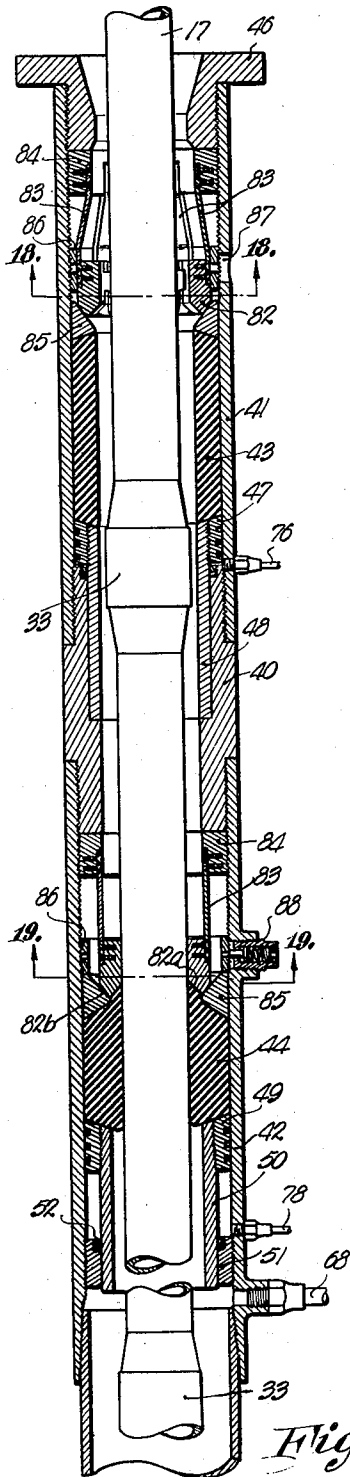


Fig. 17.

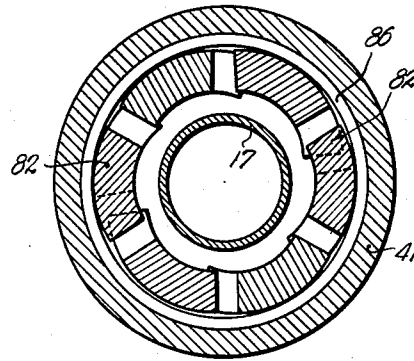


Fig. 18.

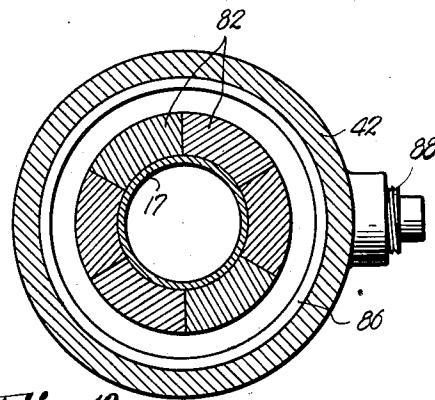


Fig. 19.

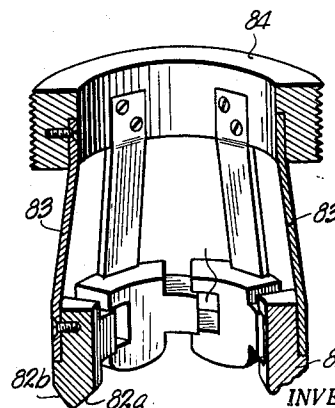


Fig. 20.

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7 Sheets-Sheet 7

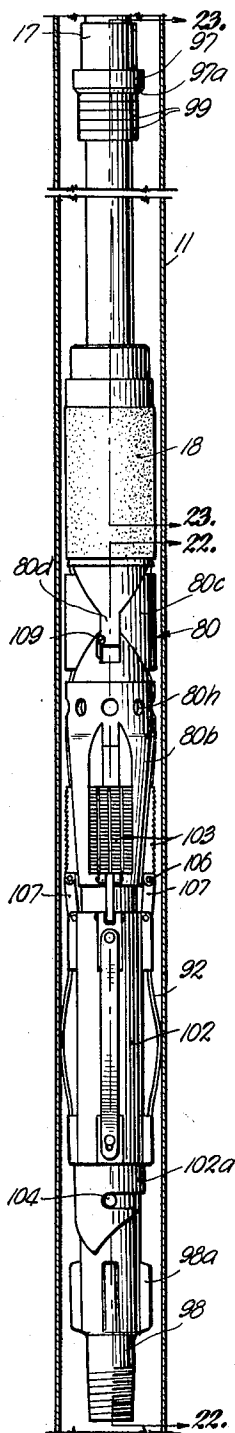


Fig. 21.

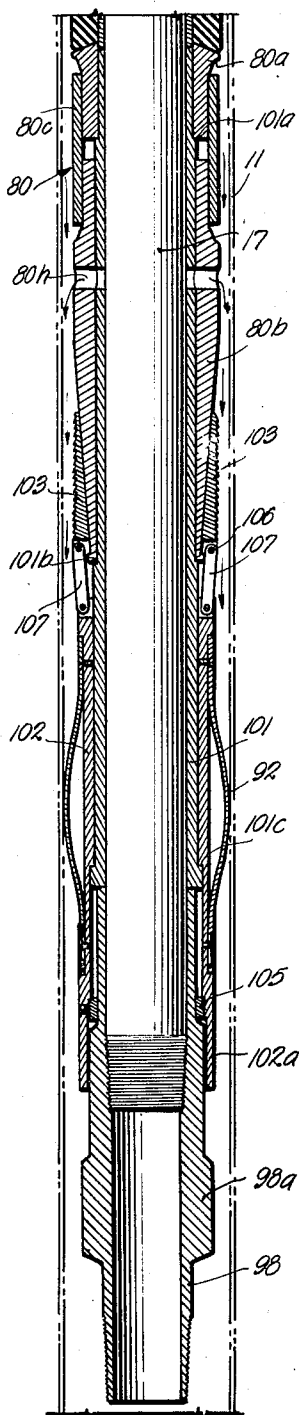


Fig. 22.

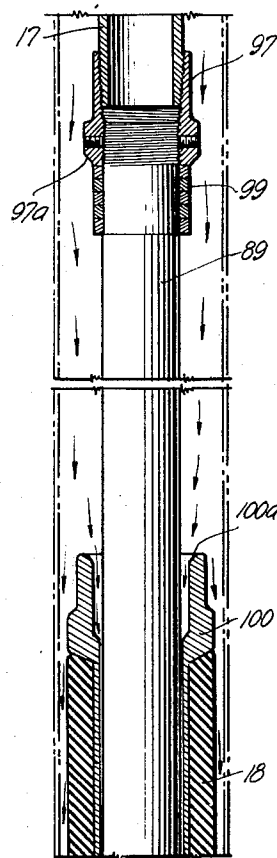


Fig. 23.

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MULTISTAGE HYDRAFRACTURING PROCESS AND APPARATUS

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Application January 10, 1955, Serial No. 480,656

6 Claims. (Cl. 166—42)

This invention relates to improvements in the fracturing of the earth formation surrounding wells and relates more particularly to a process of increasing the productivity of wells by increasing the number and size of lateral drainage channels in the producing formations adjacent the well bore. In this art of increasing such lateral channels, it is conventional to pump into selected formations surrounding the well bore fluids and mixtures of fluids and solids under high pressure and this practice is utilized in the process hereinafter disclosed.

The instant process, however, differs from what has previously been done in that a relatively narrow zone is selected and sealed off by means of packers with ports or apertures penetrating the casing within said zone. The area of these ports bears a predetermined relationship to the cross-sectional area of the tubing through which the fracturing liquid is supplied to assure high velocity and reduce the likelihood of obstructing or clogging the fluid passageways. In addition, the process is unique in that successive fracturing operations are performed while maintaining the system pressure-tight and under a closed-in pressure not substantially below pressures imposed during circulation. In other words, it is unnecessary to delay consecutive fracturing operations until the high pressure imposed during each fracturing operation subsides or is reduced sufficiently to move the sealing devices to another location without backflow of fracturing liquid and the accompanying difficulties associated therewith.

An object of the invention, therefore, is to provide a process and apparatus whereby successive formation fracturing operations may be performed while maintaining a closed-in pressure and without the necessity of the delays now necessary under present operating technique.

Another object is to provide a system in which successive thin or narrow zones of the well bore are isolated in successive operations and fractured consecutively in a relatively continuous cycle of operations.

A further object resides in maintaining a predetermined relationship between the cross-sectional area of the tubing and the area of the ports through which the fracturing fluid is introduced to the formation.

Still other objects include the provision of a pressure-retaining mechanism permitting the vertical movement of the tubing in the casing while maintaining a closed-in pressure and back pressure valves strategically positioned in the tubing which permit removing sections of the tubing at the surface without loss of system pressure.

Other objects inherent to the method and apparatus will appear from the explanation which follows.

In the drawings which form a part of the specification, like parts have been given like reference numerals in the various views.

Fig. 1a is an elevational view of the upper end of the tubing showing the pressure fluid hose connection and supporting mechanism through which fracturing fluid is introduced to the well.

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Fig. 1b shows the pressure retainer and a portion of the well bore in cross section located immediately below the lower end of the tubing shown in Fig. 1a.

Fig. 1c is an extension of Fig. 1b showing a portion of the well bore in cross section and packers used for sealing off a zone to be fractured.

Fig. 2 is an enlarged cross-sectional detail of the pressure retainer shown in Fig. 1b.

Fig. 3 is an enlarged cross-sectional detail of the lower packer shown in Fig. 1c.

Fig. 4 is a view taken along the line 4—4 in Fig. 2 in the direction of the arrows.

Fig. 5 is a view taken along the line 5—5 in Fig. 2 in the direction of the arrows.

Fig. 6 is an enlarged cross section of the well bore shown below the lower broken-away section in Fig. 1b.

Fig. 7 is a view taken along the line 7—7 in Fig. 1a in the direction of the arrows.

Fig. 8 is a view taken along the line 8—8 in Fig. 7 in the direction of the arrows.

Fig. 9 is a view taken along the line 9—9 in Fig. 3 in the direction of the arrows.

Fig. 10 is a cross-sectional view of a well bore showing the lower portion of a tubing string using primary and secondary packers above and below the formation to be fractured and a modified type of packer operating mechanism.

Fig. 11 is a cross-sectional view of a well bore showing that portion of the tubing string immediately above that shown in Fig. 10.

Fig. 12 is an enlarged cross-sectional detail of the circulating valve mechanism shown diagrammatically in Fig. 10.

Fig. 13 is an enlarged cross-sectional detail of a portion of the circulating valve mechanism shown in Fig. 12.

Fig. 14 is a sectional view taken along the line 14—14 in Fig. 12 in the direction of the arrows.

Fig. 15 is a view taken along the line 15—15 in Fig. 10 in the direction of the arrows.

Fig. 16 is an enlarged exploded view of the packer arming device.

Fig. 17 is a vertical section of a modified type of pressure retainer from that shown in Fig. 2.

Fig. 18 is an enlarged horizontal section taken along the line 18—18 in Fig. 17 in the direction of the arrows.

Fig. 19 is an enlarged horizontal section taken along the line 19—19 in Fig. 17 in the direction of the arrows.

Fig. 20 is an enlarged sectional perspective view of the segmental anti-extrusion device.

Fig. 21 is an elevational view of a modified type of packer operating mechanism.

Fig. 22 is an enlarged vertical section taken along the line 22—22 in Fig. 21.

Fig. 23 is an enlarged sectional view taken along the line 23—23 in Fig. 21.

Referring to the drawings and particularly to Figs. 1a, 1b, 1c and 6, after the well bore has been drilled through earth formations indicated generally at 10, a casing 11 is run in the hole upon which are mounted, at intervals throughout the well bore where cement is to be placed, centralizers 12 and scratchers 13. After the annulus between the casing and well wall has been cleaned of mud deposited during the drilling operation, a cement column 14 is placed in the well bore surrounding the casing to form a continuous seal, preventing the migration of contaminating fluids, such as gas and water, vertically of the well bore and into the producing sands 15 and 15a.

During the drilling of the well, conventional testing methods, such as caliper logging, for determining the

size of the well bore at different depths and other methods of logging for locating the position of pervious and impervious layers is good practice. After the cement has been placed, temperature logging, gamma ray logging and other electronic logging methods are useful to determine the character and effectiveness of the cement column and to establish locations for shooting the casing and cement column for best results in producing fluid oil from the oil producing sands. After locating the permeable horizons or suspected oil sands, the well is shot at a plurality of depths in each sand, preferably six to eight holes will be made into the formation at each zone to be fractured. The number of holes is determined by the relationship the cross-sectional area of the tubing bears to the area of the holes shot in each fracturing zone. Anticipating fracturing of the suspected oil producing formation in thin or narrow zones, the number and size of the holes in the zone to be fractured is limited in order to assure high velocity of the fluid through the ports or holes when fracturing pressure is imposed. Normally, the cross-sectional area of the holes or ports located in the fracturing zone is considerably less than the cross-sectional area of the tubing, so passage of the fracturing liquid downwardly through the tubing and laterally into the formation through the apertures shot in the casing will be at increased velocity with respect to the flow of oil through the tubing. Obviously the spacing of the holes or apertures vertically in the oil sand and the number and size of the holes made at the different levels is an important factor when thin or narrow zone fracturing is practiced. The manner in which the suspected oil producing zones is to be shot is shown diagrammatically in Fig. 1c, the apertures or ports through the casing and cement column being indicated by the numerals 16.

After the suspected production formations have been perforated by shooting as explained, a tubing 17 with suitable sealing devices or packers properly located on the tubing to seal the annulus between the tubing and casing above and below the selected zone to be fractured is run into the well. Packers used in the instant process are of improved design; their construction is shown diagrammatically in Figs. 1c, 10, 11, and in detail in Figs. 3, 17 and 21. Structurally the packer shown in Figs. 1c and 3 includes resilient sealing members 18 reinforced at their outer edges with metal coils 18a embedded and intimately bonded into the resilient material. The inner surface or core of the sealing members are reinforced by cylindrical metallic sleeves 19 shown best in Fig. 3. These sleeves and coil spring reinforcement serve to prevent flowing of the resilient material under the high pressures and temperatures to which packers are subjected. At the bottom of the lower packer and at the top of the upper packer are radial slips operating within annular closures 20 which are bored and threaded to receive cylinders 21. Operating within these cylinders are piston slips 22 whose outward movement is restricted by lips 21a (Fig. 9) at the outer ends of the cylinders abutting shoulders on the pistons. Retaining strips 23 attached to the periphery of enclosure 20 and resting in longitudinal grooves in the top of the pistons, details of which are best shown in Figs. 3 and 9, also serve to limit outward movement of the pistons. Retaining rings 24 screwed into the inner ends of the cylinders limit the inward movement of the pistons. A knurled or roughened surface at the ends of the piston seat against the smooth inner surface of the casing to hold the packer rigidly against longitudinal movement in the casing.

Packer sleeve 25 is threaded internally at its upper and lower ends to receive rings 26 and 27. The sleeve 25 and closure rings 26 and 27 form a pressure annulus or compartment around the exterior of the tubing with communication to the tubing by means of holes 28. Within the pressure annulus is a ring 30 which is screwed onto the exterior of the tubing or mandrel and on the exterior of ring 30 is threaded a stop seal ring 31 upon which is

mounted compression spring 29. In the tubing or mandrel 17 above the lower packer and below the upper packer are a series of ports or apertures 32 through which fluid under pressure is supplied to the annular space between the packers, thence to the formation to be fractured. Connecting the sections of tubing are couplings 33 whose outside diameter is somewhat larger than the outside diameter of the tubing.

At selected locations along the tubing are interposed back pressure valves 33a shown in Fig. 1a and Fig. 7. The position of these back pressure valves along the tubing is determined by the location of the suspected production zones or the zones to be fractured. The purpose of the valves is to hold pressure in the system while sections of the tubing are removed above the ground surface. The structural details of the valves shown in Figs. 7 and 8 include a body 33a having an upper internally threaded portion to screw onto the male end of the tubing. The lower end of the body is externally threaded to receive a union 34 which connects the body to the next adjacent section of tubing below, or in place of the union, the lower end of the body may be screwed directly onto an internally threaded end of the tubing section immediately below. Within the body 33a is a cavity in which a ball valve 35 is supported upon webs or fins 36. When supported upon fins the valve is held in an open position by means of a set screw 37. Upon backing off the set screw 37, the ball valve is free to seat upwardly against the beveled ring 38 and serves as an effective seal against passage of fluid upwardly through the tubing. Normally, during fracturing operation the set screw is in position shown in Fig. 7 with the ball held on the lowered position permitting free passage of fluid in either direction through the tubing.

Mounted above ground at the top of the casing is a pressure retainer mechanism 39 shown in Figs. 1b and 2. The pressure retainer serving some of the functions of a blow-out preventer comprises a shell or casing 40 externally threaded at its ends to receive sleeves 41 and 42. Within the sleeves are resilient annular rings 43 and 44 reinforced at the top and bottom internally by means of coil springs 45. Abutting the top of resilient member 43 and screwed into the top of the sleeve is a closure ring 46, while against the lower part of the resilient member is a seal ring 47 internally threaded to screw upon the upper end of sleeve 48. The upper surface of resilient ring 44 is beveled to abut the lower end of body 40. The lower end of ring 44 seats against seal ring 49 which in turn is internally threaded and screwed upon the upper end of sleeve 50. Seal ring 51 is threaded externally and screwed into sleeve 42 where it is held in place by means of lock ring 52. The lower end of sleeve 42 is internally threaded to receive the upper end of casing 11. The ring 46 enclosing the upper end of the retainer is flanged to support spider 53 (Fig. 1b) which has a tapered upper opening to accommodate slips 54 used to grip the tubing while it is being run in or out of the casing. During the fracturing operation there is attached to the upper end of the tubing, as shown at 55, in Fig. 1a, a fitting constructed to form a pressure-tight joint with the tubing and having connected thereto a universal hose connection 56. The tubing is supported by means of a yoke 57 to which hook 58, cable 59 and cable connection 60 are attached, so the lowering and raising of the tubing may be effected by the derrick draw works.

The fracturing fluid is introduced to the tubing 17 under pressure from any convenient source not shown through pipe 61, pump 62, lines 63, 64 and flexible tubing 65. Pressure gauge 66 is interposed in the line to show pressures which exist. A valve 67 interposed in line 64 is operable to divert the fluid from the tubing through pipe 68 into the annular space between the tubing and casing. When the fluid is introduced in this fashion, valve 69 is open and pressures in line 68 are determined by pressure gauge 66a. Granular material such as sand if sup-

plied with the fluid to be used during fracturing is added into pipe 61 at hopper 70 by any suitable metering means not shown.

To operate the pressure retainer 39, fluid is supplied from a reservoir or tank 71 through pipe 72, pump 73 and pressure discharge line 74. A cross-connection 75 interposed in this line provides a means for diverting the pressure-actuating fluid through pipes 76, 77 and 78 controlled by valves 79, 80 and 81, respectively. Pressures in these lines are recorded by gauges 66b, 66c and 66d. Pipes 76, 77 and 78 may function both as pressure or bleed lines. When functioning as the latter, pipes 76a, 77a and 78a, controlled by valves 76b, 77b, and 78b, return the fluid to reservoir 71 and after bleeding off the pressure and manipulating the valves in the respective lines the pressure fluid used to operate the seals of the retainer may be circulated back to the reservoir, by-passing any of the pressure lines 76, 77 and 78 as desired.

In the fracturing operations herein contemplated, any suitable type of hydraulic fluid may be used. Good results have been obtained with a relatively heavy oil having a sufficiently low viscosity to facilitate pumpability. Such fluid as is considered by the operator to be best adapted to the circumstances and conditions existing in the well should be used, and if granular material such as sand is mixed with the fluid to support or prop the channels opened by fracturing, the character and size of such granular substance is also the choice of the operator. Sixteen-mesh material has given good results and under normal conditions sand passing through a twenty-mesh screen and retained on a forty-mesh screen has proved satisfactory producing readily permeable prop or spacing substance. In the instant process the novelty resides primarily in the method of fracturing relatively narrow zones and movement of the seals or packers for isolating such zones in rapid sequence rather than in the selection of a particular type of fracturing fluid or sand.

Explaining now the fracturing operations in the apparatus just described, after the well has been drilled and logged to locate the permeable and impermeable formations, as well as the suspected oil-bearing sands, the casing is run with suitable abrading and centering tools to clean the well bore preparatory to placing a cement column around the casing and opposite those formations to be sealed off and those to be perforated and fractured. The necessity of obtaining a good cement job and satisfactory seal between the casing and well bore is an essential attribute to subsequent fracturing operations.

After the casing has been set and cemented, the well is shot at selected depths or levels where oil producing sands are suspected. The shooting should penetrate both the casing and cement column and produce clean open shot holes from the casing into the formation to permit a free unobstructed flow of fluid therethrough. The number as well as the vertical and circumferential spacing of the shot holes is critical to subsequent fracturing operations. If two-inch tubing is used to supply the fracturing fluid, eight to twelve holes should be shot in each fracturing zone in order to maintain a proper relationship between the cross-sectional area of the tubing and the shot holes. This assures the high velocity necessary through the shot holes, preventing clogging or obstruction of the ports and the accumulation of sand in the holes and annulus around the tubing between the packers often resulting in sticking of the tubing and difficulties when the tubing and packers must be moved to the next fracturing zone.

An important feature of the instant fracturing operation is the reduction and limitation of the vertical depth of the zone to be fractured. Heretofore, little or no regard has been given to the depth of this zone. Usually it is determined by the thickness of the permeable formation. Experience has shown that this is an improper criterion upon which to base the depth of the zone since thickness of more than 20 to 25 feet will normally give in different results, depending upon the depth of the well and

the character of the formation being fractured. By restricting, however, the zone within a thickness of from 10 to 20 feet, satisfactory fracturing of the formation is usually assured and adequate channeling obtained if the shot holes are within the zone and the sealing devices or packers are accurately placed.

With the casing properly perforated at the permeable formations, the gun perforator is removed from the well and the tubing is run with the packers located on the string as shown in Fig. 1c. Assuming the lowest formation 15a in Fig. 1c is to be fractured and that it has a thickness of 10 to 20 feet, and the casing and cement column have been properly perforated by holes 16, the tubing is now lowered until packers 18 are positioned above and below the formation with the perforated tubing between the packers spanning the formation 15a.

Retainer 39 has been previously mounted upon the casing above the derrick floor and the fluid pressure system shown in Fig. 1b, as well as the pressure fluid supply hose 65 have been connected up. Pressure fluid is now introduced to the tubing 17 through hose 65 from pump 62, pipes 63 and 64 with valve 67 open and valve 69 closed. As soon as the fluid pressure is applied to the tubing, pistons 22 in the gripping sections of the packer 20 are forced outwardly, immobilizing the packers in position in the casing. Simultaneously, the pressure fluid will flow through holes 32 into the annulus between the casing and tubing enclosed vertically by the upper and lower packers. Destination of this fluid is through the shot holes 16 into the formation. A portion of the pressure fluid at the same time finds its way through holes 28 shown in Fig. 3 into the pressure compartments of the packers moving sleeves 25 axially of the tubing, which compress the resilient members 18 and expand them radially against the casing. Expansion of these resilient members seals the space between the packers from the well bore below the lower packer and the annulus between the tubing and casing above the upper packer. As the pressure is increased, the sealing members tighten against the casing and under the excessive pressures required for fracturing, the necessity of reinforcing the resilient sealing member 18 by coil springs 18a and sleeves 19 can be readily appreciated. This reinforcement reduces the tendency of the resilient material, usually rubber, to flow and aids in preventing failure of the packers. Pressure upon the tubing is increased until the formation is fractured, at which time there is a reduction in pressure commensurate with the extent to which channels have been opened and the fluid permitted to expand. After fracturing, the reduced pressure or what will be termed "closed-in" pressure is maintained in the tubing and formation by closing valve 67.

To release the packers preparatory to moving them to the next fracturing zone which may be above or below that just fractured, valve 69 is opened and pressure fluid supplied by pump 62 and pipe 68 to the annular space between the tubing and casing above the upper packer. When this pressure equals or exceeds slightly the closed-in pressure existing between the packers and upon the fractured formation, tension springs 29, together with the natural retractive force or tendency of resilient members 18 will break the seals of the packers. Equalizing the pressure surrounding the tubing with that in the tubing also causes pistons 22 to release their grip upon the inside of the casing.

When the packers have been released, the tubing is immediately shifted to the next location to be fractured without delay for pressure reduction in the system since the closed-in pressure is maintained by retainer 39 at the well head. This is accomplished in spite of the difference in diameter of the tubing sections and the couplings which join them together. The operation of the retainer can best be understood by reference to Figs. 1b and 2. While fracturing pressure is being imposed on the tubing, pressure fluid is injected through pipes 76, 77 and 78 by pump 73 from reservoir 71. Fluid

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introduced through pipe 76 acting upon seal ring 47 constricts resilient annular member 43, expanding it radially against the tubing. Fluid introduced through pipe 78 shifts ring 49 and sleeve 50 longitudinally, expanding resilient member 44 to form a seal with the exterior of the tubing and that injected through pipe 77 between the seals serves to offset or equalize pressure built up in the casing and acting axially upon seal 44.

After fracturing and when the fracturing pressure has subsided to a closed-in pressure to move the tubing to the next fracturing zone requires only proper control of the flow of pressure fluid to the retainer. By valve manipulation the injection and by-passing of the pressure fluid governs the expansion and contraction of the seals 43 and 44 in proper sequence whereby a permanent seal is continually maintained at the well head while permitting the passage of the couplings through the seals as the tubing is shifted. It will be understood that the seal made by seal members 43 and 44 with the tubing when they are expanded thereagainst is of such nature that the tubing can be moved therethrough without, however, permitting the escape of fluids through the seal. The release of the seals 43 and 44 is effected by closing valves 79, 80 and 81 and opening valves in by-pass lines 76a, 77a and 78a.

To follow the procedure which is used while shifting the tubing from one fracturing location to another with the tubing initially positioned in the retainer as shown in Fig. 2 with seal member 44 expanded against the pipe and seal member 43 retracted to permit passage of back pressure valve and coupling 33a, pressure fluid charged by pump 73 through pipe 78 expands seal member 44 while that introduced through pipes 76 and 77 is by-passed to the reservoir by manipulation of the valves in the respective lines. In this fashion, seal member 43 is retracted, permitting passage of coupling and back pressure valve 33a through seal member 43. As previously explained, pressure fluid is supplied between the seals through pipe 77 only during fracturing operations when both seal members 43 and 44 are expanded. When the tubing has been shifted longitudinally through seal 44 to the next coupling below, by-pass of pressure fluid through pipe 76a is discontinued by manipulation of the valves and resilient member 43 is expanded to form a seal against the tubing while pressure fluid introduced through pipe 78 is now by-passed to retract seal member 44. The coupling below seal member 44 can now be moved through the retracted seal while pressure fluid is charged through pipe 76 to expand resilient member 43 forming a pressure-tight seal against the tubing at the upper end of the retainer. After passage of the coupling through member 44, it will again be expanded by introduction of pressure fluid through pipe 78 to form the seal against the tubing and the upper seal member 43 contracted to allow passage of the coupling therethrough.

When the distances that the tubing must be moved requires removal of tubing sections because of the limitations imposed by the height of the derrick, back pressure valves as shown in Figs. 7 and 8 strategically interposed in the tubing permit taking out sections of the tubing at the derrick floor without loss of pressure in the system. Before a section is removed, set screw 37 in the side of the back pressure valve is backed off sufficiently to permit the ball valve 35 to seat and hold pressure on the system while fitting 55 with its hose connection 56 is shifted to a lower section. Upon coupling of the fitting 55 again to the top of the tubing, set screw 37 is screwed in to unseat ball valve 35 so pressure fluid can again be charged through the hose 65.

It is contemplated that where single packers above and below the zone to be fractured do not span completely the shot holes in a formation, two packers will be used above and below, spaced apart sufficiently to maintain a pressure-tight seal. In other words, where a permeable zone has a thickness which requires a plurality of fracturing operations, it may be necessary to use additional

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packers above and below those shown in Fig. 1c spaced at proper distances so an effective seal will be maintained. An example of the use of two packers above and below the formation to be fractured is shown in Figs. 10 and 11. Fig. 10 shows the lower portion of the tubing string while Fig. 11 shows a section of the string immediately above that shown in Fig. 10 including the primary packer below the formation 15 which is being fractured with the two packers 18 above this formation. In these drawings the tubing is again indicated by the numeral 17, the packers by the numeral 18, the piston type slips which hold the packers in position in the casing by the numerals 20. Packer operating devices are diagrammatically shown at 79 and anti-extrusion devices are shown at 80. A standing valve 81 at the bottom of the string in Fig. 10 may be constructed to seat either up or down according to the desires of the operator. Under some circumstances when circulating from the tubing to the space between the casing and tubing the valve should seat up. If it is desired to circulate from the space surrounding the tubing into the tubing, the valve should seat down.

In Fig. 11 the packers 18 above and below the formation 15 which is to be fractured are operated or expanded to form a seal against the casing. The secondary packers 18, one shown between the operating device 79 and anti-extrusion device 80 in Fig. 10, the other below the anti-extrusion device 80 and above the operating device 79 at the top in Fig. 11, are retracted since the formation 15 to be fractured is relatively narrow and could be sealed off effectively by the primary packers. Where both primary and secondary packers are necessary to effectively seal the formation before fracturing, both primary and secondary packers will be expanded in the manner that the primary packers are shown in Fig. 11.

In Figs. 17, 18, 19 and 20 is shown a modified type of pressure retainer which maintains a closed-in pressure while the packers are being shifted in order to carry on a fracturing operation at a different location. The operation of the device is similar to that shown in Fig. 2 since pressure is applied to expand the lower packer or resilient seal member 44 against the tubing until a coupling 33 or valve 33a arrives just below the sealing member. At this time the upper sealing member 43 is expanded against the tubing and pressure is increased between the sealing members as explained in describing the operation of the retainer shown in Fig. 2. The lower seal 44 is then retracted and the tubing is shifted longitudinally while a pressure-tight seal is held at the upper sealing member 43. Since the lower member 44 has been retracted, the coupling 33 easily passes therethrough and movement of the tubing is stopped just below the upper sealing member. At this time the lower sealing member is again expanded to form a seal about the tubing and the upper sealing member retracted to permit passage of the coupling or valve, whichever is in position to be moved through the retracted seal 43. The structure of the modified type of pressure retainer differs from that shown in Fig. 2 in that tapered segments 82 carried by springs 83 and hung from rings 84 cooperate with back-up rings 85 to prevent extrusion of the resilient material along the tubing when high pressure is imposed to expand the sealing members and form a seal between the casing and tubing. The spring attachment rings 84 are externally threaded to be screwed into the threaded portions of sleeves 41 and 42. Adjusting rings 86 also are screwed into sleeves 41 and 42 and lie behind segments 82 to limit the upward movement of back-up rings 85. Behind the rings 86 in the sleeves 41 and 42 are holes 87 through which the rings may be adjusted by means of a drift pin. If the ring does not cover the hole, it may be necessary to have it plugged as shown at 88 in the lower hole.

In Fig. 17 the lower sealing member 44 is expanded by fluid pressure supplied through pipe 78. It will be

noted that the top edge of the resilient member 44 is reinforced and confined by the lower tapered surface of back-up ring 85 and the inwardly tapered surfaces 82a of segments 82. The outwardly tapered surfaces 82b of these segments ride along the inwardly tapered surface of the back-up ring. Also back-up ring 85 associated with the lower resilient member 44 when expanded as shown in Fig. 17 is in abutment with the limiter ring 86. When the resilient member or seal is retracted as is member 43, the back-up ring is moved downwardly away from limiter ring 86 with segments 82 riding upon the upper part of the tapered surface of the back-up ring. When retracted, the surfaces 82a present no obstruction and in fact facilitate passage of the couplings through the retracted seal.

Back-up rings 85 are longitudinally slidable within sleeves 41 and 42 and held between the top of resilient elements 43 and 44 and segments 82 of the respective packer restriction devices. Adjustment of limiter rings 86 will vary the internal diameter of the closure segments to an extent and springs 83 upon which the segments are hung have an outward tension which spreads the segments when the resilient members have been retracted to permit passage of the tube couplings. With the spreading of the segments back-up rings 85 will likewise be moved longitudinally within the sleeves to the position shown at the top of Fig. 17 where resilient element 43 is shown in a retracted position.

In Figs. 12, 13 and 14 is shown the circulating valve mechanism diagrammatically indicated at 95 in Fig. 10. Upon the tubing below the slip 20 in Fig. 10 are scratchers 13 similar to those shown in Fig. 6. Attached to the lower end of the tubing is a mandrel 89 internally threaded at the top to receive the tubing and externally threaded near the top to receive sleeve 90. This sleeve near its lower end is externally threaded for mounting of a spring cylinder 91 which surrounds the mandrel beneath the wrenching springs 92. The upper ends of springs 92 are confined beneath spring retainer cap 93; the lower ends are held beneath a lip of spring retainer 94. The lower end of retainer 94 has a reduced diameter which has bearing relationship with valve sleeve 95. Between the bearing portions of members 94 and 95 are rollers or balls to facilitate rotation of the valve sleeve. In the mandrel 89 beneath the valve sleeve are ports 89a sealed by O-rings above and below the ports. The lower end of the valve sleeve is routed out to form a skirting 95a surrounding the mandrel and a discharge annulus 96 between the skirting and mandrel. Since the bowed wrenching springs 92 have frictional engagement with the casing, when it is desired to circulate from the tubing to the annular space surrounding the tubing or from the annular space into the tubing, mandrel 89 is rotated on its axis to screw the threaded joint between the spring cylinder 91 and sleeve 90 which raises or lowers the valve sleeve 95 to cover or uncover ports 89a according to the movement of the valve sleeve. In Figs. 12 and 13 the valve is shown closed. Upward movement of the valve sleeve 95 resulting from rotation of the mandrel within the spring shell will bring ports 89a into the discharge annulus 96 beneath skirting 95, at which time fluid may be discharged from the tubing or circulated into the tubing. Rotation of the mandrel in the opposite direction will lower the valve sleeve to seal off the ports in the mandrel and prevent further circulation to or from the tubing.

In Figs. 21, 22 and 23 is shown a modified type of packer arming device and slips for positioning the tubing in the casing. In conjunction with the packer is an anti-extrusion device 80 which is detailed in Figs. 15 and 16.

Referring first to the Figs. 21, 22 and 23, screwed to the lower end of tubing 17 at the top of Fig. 23 is a coupling 97 equipped with a primary tapered valve 97a. Also connected into the coupling from below is a mandrel 89 which serves as a mounting for the mechanism and

has attached to its lower end a gudgeon coupling 98 shown in Figs. 21 and 22. This coupling has centering lugs 98a. Abutting the lower end of coupling 97 and between the coupling and a shoulder on the mandrel are a plurality of secondary valve rings 99. Slidably mounted on the mandrel below the valve rings is a packer thimble 100. At the upper end of the thimble is a tapered seat 100a and an annular space between the mandrel and thimble which serves as a seat for the secondary valve rings 99. Surrounding the sleeve portion of the thimble is the resilient packer 18. Below the packer thimble 100 and abutting its lower edge is a sleeve 101 which has three shoulders 101a, 101b and 101c. The arming wedge 80a rests upon shoulder 101a of the sleeve. The lower end of the slip body 80b sets against shoulder 101b and a shoulder formed in the slip actuating sleeve 102 abuts shoulder 101c of the sleeve 101.

As the tubing string is lowered into the well, the mechanism is in a retracted or locked position as shown in Fig. 21. The resilient packer member 18 is retracted and the primary and secondary valves 97a and 99 are raised from their seats in the packer thimble. The anti-extrusion device 80 is in a retracted position and the serrated edged slips 103 are likewise retracted against the tapered sides of the slip body 80b. The slot in the locking head 102a at the end of the slip actuating sleeve 102 is in engagement with pin 104 extending radially from the gudgeon coupling. While the mechanism is being lowered into the well, fluid is free to circulate either upwardly or downwardly about the exterior of the packer, the anti-extrusion device and throughout the length of the mandrel as well as between the mandrel and the sleeve 101 since this sleeve fits loosely upon the mandrel. When the tubing and mandrel have been lowered to a location in the well where it is desired to seat the packer, the mechanism is unlocked by rotating the mandrel counterclockwise so pin 104 disengages the slot in locking head 102a. Since the spring members 92 frictionally engage the casing, the slip actuating sleeve 102 is held firmly against longitudinal or rotative movement with respect to movement of the mandrel. An assembly ring 105 (Fig. 22) attached to the underside of actuating sleeve 102 limits the upward movement of the actuating sleeve by abutment with the lower end of sleeve 101 while downward movement of the actuating sleeve is limited by abutment of the shoulder of the actuating sleeve with shoulder 101c as previously noted. After unlocking the mandrel, it may be lowered until the rings 99 enter the annular seat in the top of the packer thimble 100. Before the valve 97a seats in the top of the packer thimble, the tapered lower end of slip body 80b forces slips 103 outwardly into engagement with the near wall of the casing. The slips are pivoted at 106 to the upper ends of links 107. The lower ends of the links are attached to the slip actuating sleeve 102. Since the actuating sleeve 102 is held against movement within the casing by springs 92 as the tapered end of the slip body 80b expands slips 103, they will firmly grip the inner wall of the casing and hold the mechanism rigidly in place.

With the slips set in the manner described, continued downward movement of the mandrel causes valve 97a in coupling 97 to seat in the top of the packer thimble and expand the resilient packer 18 against the inside wall of the casing to form a pressure-tight seal. Since valve rings 99 now seat in the annulus in the top of the packer thimble, the fluid passageways both outside of the thimble and inside of the thimble are effectively closed.

To prevent extrusion of the resilient material which forms the resilient packer 18 due to the high pressure imposed from above, there is provided below the packers an anti-extrusion device 80 detailed in Figs. 15 and 16. The upper arming wedge 80a of this device, as previously noted, abuts shoulder 101a of sleeve 101 and surrounds the upper part of the sleeve as shown in Fig. 22. The

top of the arming wedge supports the lower end of the packer and when the packer thimble is forced downwardly upon lowering of the mandrel, the packer is squeezed and expanded between the packer thimble and the top of the arming wedge 80a. Both the arming wedge 80a and the slip body 80b are freely mounted upon sleeve 101 which in turn surrounds the mandrel 89. A split expansion sleeve 80c is carried on shoulder portions of the arming wedge and slip body and is held in position by a guide tongue 80b which passes through the space between the ends of the sleeve and registers with a slot 80e in the slip body. A tapered surface 80f at the top of the arming wedge and a similar surface 80g tapered in a reverse direction spread the expansion sleeve when the packer is expanded so that the top edge of the sleeve supplements the top of the arming wedge to form a backing surface and prevent extrusion of the resilient material through the annular space between the arming wedge and casing. Ports 80h are provided in the slip body as shown in Figs. 21 and 22 to facilitate discharge of fluid circulating between the mandrel 89 and sleeve 101, while the mechanism is locked or when going into the hole. To move the packer and disengage the slips to return the mechanism to a locked position, the tubing is gradually raised to unseat the primary valve on coupling 97 from the packer thimble. The secondary valve rings remain in the annular space between the thimble and mandrel preventing a rapid rush of abrasive fluid through the valve and rapid deterioration of the valve seats. As the mandrel is moved upwardly, packer 18 will be retracted and the slips 103 disengaged from the casing wall. When the assembly ring 105 abuts the lower end of sleeve 101, the locking head 102a is in a position to be rotated into engagement with pin 104. An anti-disassembly locking screw 109 (Fig. 21) in the end of the guide tongue 80d prevents complete disengagement of the arming wedge and slip body.

Thus, it will be seen that there has been provided a process by which fracturing operations may be conducted without the delay now necessary after each operation to permit reduction of pressure upon the system. Also there is provided a process which entirely eliminates the difficulties encountered by backflow of pressure fluid and sand. Limiting of the fracturing zones to narrow thickness and maintaining a proper relationship between tubing cross-sectional area and the area of the shot holes in each zone assures effective fracturing and reduces likelihood of sand packing.

To recapitulate, after the casing has been cemented, a tubing with packers mounted thereon is lowered into the hole with the packers positioned above and below the zone to be fractured. The depth of this zone is first accurately ascertained and pin-pointed as to location by conventional logging methods. The packers are of an original and unique design being adapted to be freely moved from zone to zone in the casing, being operated from the surface by fluid pressure.

Since the fracturing operations are limited to relatively narrow zones, the process would be wholly uneconomical if operations were interrupted after each fracturing to await the necessary time for pressure reduction on the system before subsequent fracturing operations were performed. This waiting time is the normal procedure in order that the pressure maintained on the formation can be dispersed so that equipment, including packers and tubing, can be shifted to the next zone. Unless the pressure is permitted to reduce, it is impossible to prevent backflow of liquid and sand to the surface, which circumstances are hazardous to the operator and dangerous because of the high pressures being used. If, however, the packers or sealing devices can be shifted while pressure is maintained on the system and without delaying the operations by the waiting periods, fracturing can be completed in a much shorter period of time and more

effectively since the possibility of sand packing is substantially eliminated.

Thin zone fracturing hereinbefore described is advantageous in that it effectively fractures a greater amount of formation during each fracturing operation than previous fracturing methods where relatively thick zones are fractured. Also, thin zone fracturing limits to a great extent vertical fracturing of the formation which introduces the difficulties of vertical migration of fluids permitting the ingress of objectionable contaminants such as water and gas to the producing sands.

Also there has been provided an improved type of circulating valve and actuating mechanism for functioning said valves. To prevent extrusion of the resilient material used in the packers around the ends of the reinforcement elements used with the packers, there has been provided novel anti-extrusion devices. These mechanisms are adapted to greatly facilitate shifting of the tubing from formation to formation during fracturing operations without materially reducing closed-in pressure of the well and eliminate to a great extent trouble and difficulties encountered with packers sticking the tubing in the casing.

Having thus described my invention, I claim:

1. In a method for completing a well wherein a casing is set in a well bore having a plurality of hydrocarbon productive zones and the casing is perforated in more than one of said zones, the steps of inserting a tubing in said casing, sealing off the annulus between said tubing and said casing above and below the perforations at a first one of said zones, introducing fluid through said tubing into said sealed off portion of the annulus and imposing sufficient pressure thereon to fracture said first zone, closing said tubing following fracturing to maintain pressure within the tubing and in said fractured zone, introducing fluid into said annulus above and below the sealed off portion of the annulus and imposing sufficient pressure thereon to substantially equalize the pressures within and above and below said sealed off portion of the annulus, manipulating the tubing vertically while sealing against pressure escape at the top of the annulus, sealing off the annulus between said tubing and casing above and below the perforations at a second one of said zones, and reinstituting fluid flow through said tubing at a pressure sufficient to fracture said second zone.

2. In a method as in claim 1 and where the tubing is provided with spaced couplings of greater diameter than the tubing, the step wherein the sealing of the annulus at the top thereof during vertical manipulation of the tubing is accomplished by successively shifting the seal to opposite sides of the couplings as the couplings reach and move past the top of the annulus.

3. In a method as in claim 2, the step of removing sections of tubing as they move upwardly past the annulus and closing off the tubing to flow therethrough immediately below the sections to be removed prior to removal thereof.

4. Apparatus for fracturing a well having a plurality of spaced hydrocarbon productive zones, the well being lined with a casing perforated at the respective productive zones, comprising a tubing inserted in the casing, a pair of vertically spaced packers on the tubing, ports in the tubing between the packers, means for introducing fracturing fluid into the tubing and out through said ports, mechanism connected with said packers and operable upon the creation of a pressure differential between the space between the packers and above and below the packers to set the packers against the inside of the casing and upon substantial equalization of the pressure in the space between the packers and above and below same to release the packers, means for equalizing said pressures following fracturing to release said packers, mechanism for manipulating the tubing vertically in the well to shift said packers from one zone to another when the packers are released, a pressure retainer sealing the top

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of the annulus between the tubing and casing as the tubing is manipulated, and means operable to prevent loss of pressure through the tubing whereby a closed-in pressure is continuously maintained in the annulus between the casing and tubing during the successive fracturing of the plurality of zones.

5. Apparatus as in claim 4 wherein said pressure retainer includes hydraulically actuated vertically spaced seals operable alternately to seal against axially spaced portions of the tubing to permit passage of tube couplings during manipulation without loss of pressure.

6. Apparatus as in claim 4 wherein the tubing is in coupled sections, the sections being provided with back pressure valves operable to close off flow toward the surface so that a section above can be removed without loss of pressure as the tubing is moved upwardly in the well.

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