Nov. 26, 1968 D. E. YOUNG 3,412,801

RETRIEVABLE WELL PACKER APPARATUS

Filed Nov. 8, 1966 3 Sheets-Sheet 1

Fig. 1A

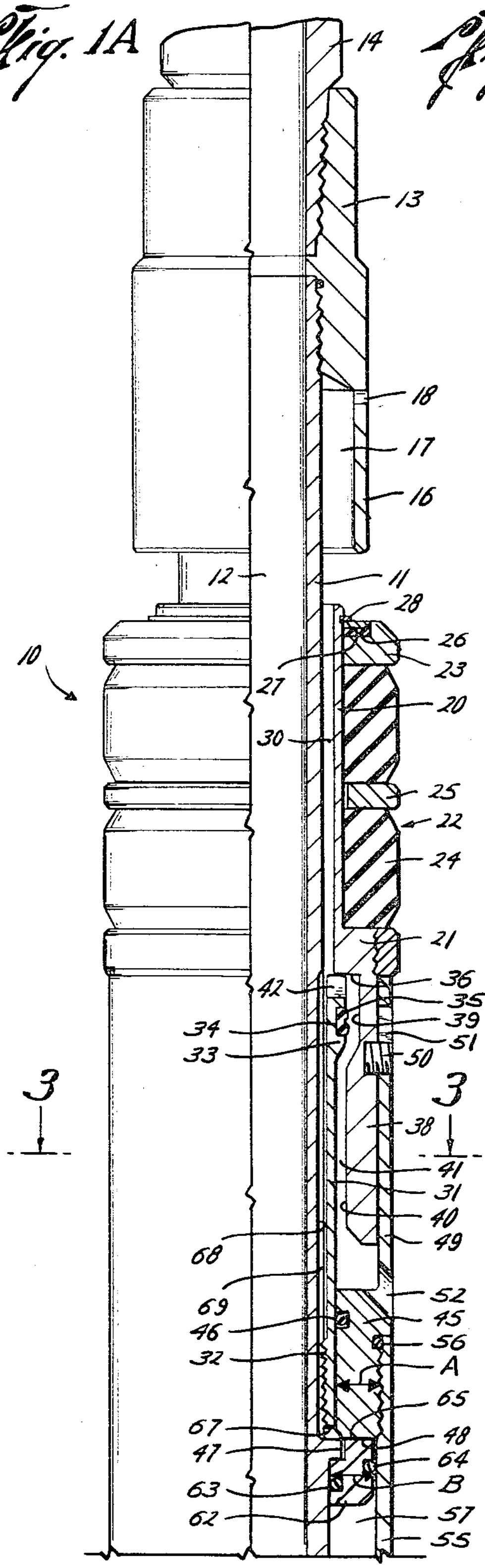
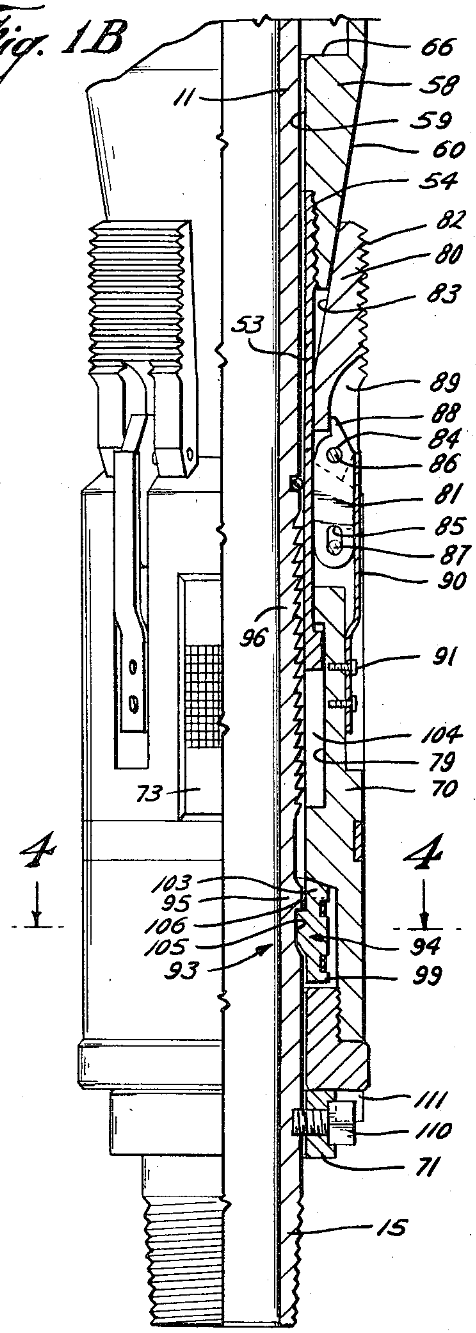


Fig. 1B



David E. Young
INVENTOR.

BY David L. Moseley

ATTORNEY

RETRIEVABLE WELL PACKER APPARATUS

Filed Nov. 8, 1966 3 Sheets-Sheet 2

Fig. 2A

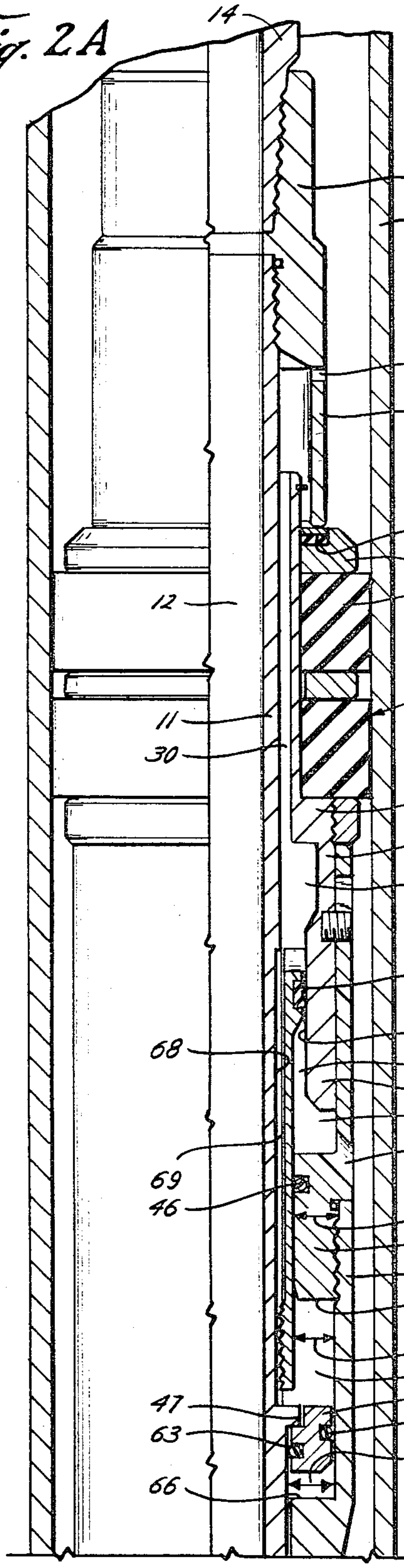
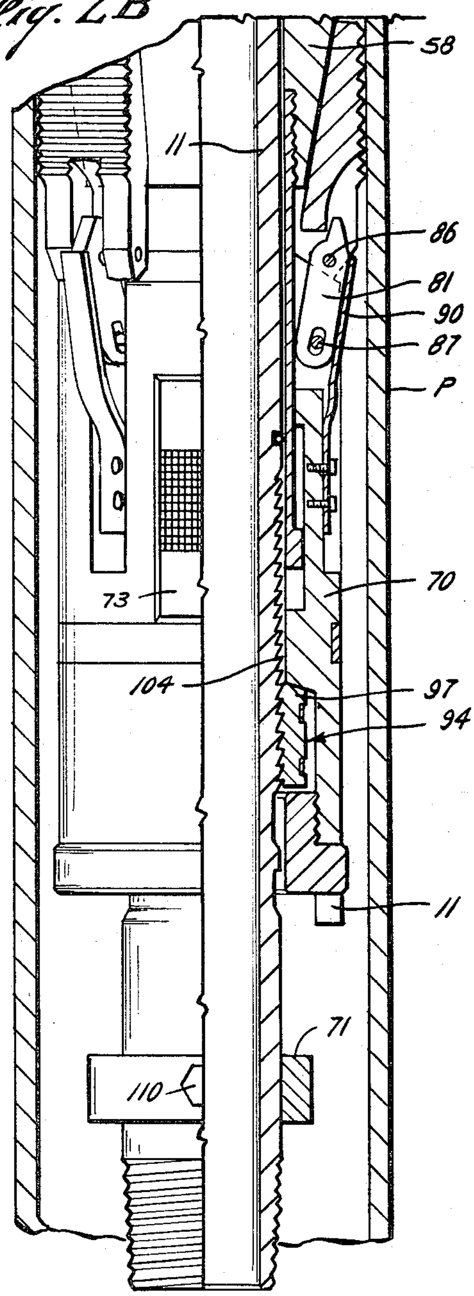


Fig. 2B



David E. Young
INVENTOR.

BY David L. Moseley

ATTORNEY

Nov. 26, 1968 D. E. YOUNG 3,412,801

RETRIEVABLE WELL PACKER APPARATUS

Filed Nov. 8, 1966 3 Sheets-Sheet 3

Fig. 7

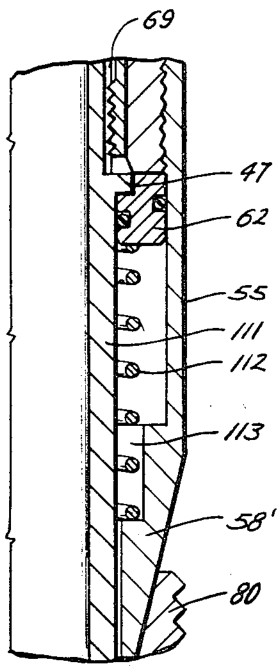


Fig. 3

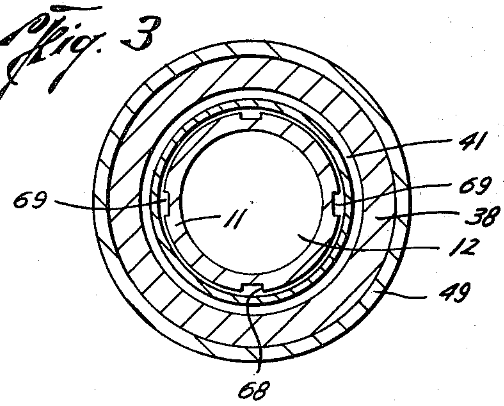
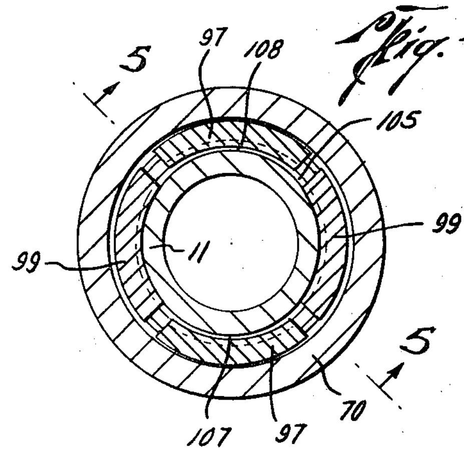


Fig. 4



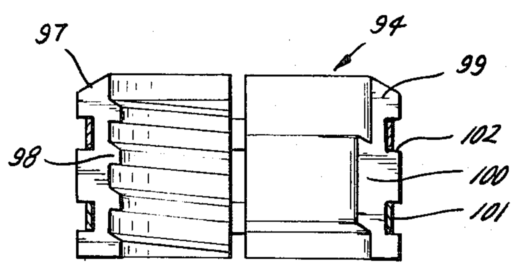
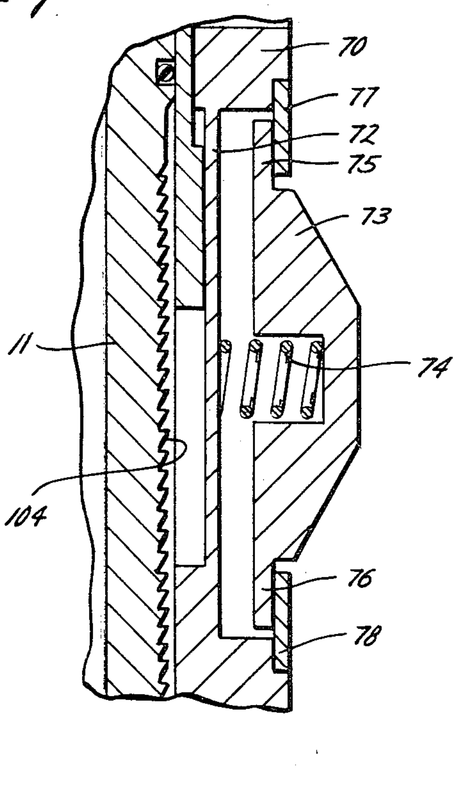


Fig. 5

Fig. 6



David E. Young
INVENTOR.

BY David L. Moseley

ATTORNEY

United States Patent Office

3,412,801

Patented Nov. 26, 1968

3,412,801

RETRIEVABLE WELL PACKER APPARATUS

David E. Young, Houston, Tex., assignor to Schlumberger Technology Corporation, Houston, Tex., a corporation of Texas

Filed Nov. 8, 1966, Ser. No. 592,803
25 Claims. (Cl. 166—120)

ABSTRACT OF THE DISCLOSURE

Well packer apparatus for use in a well bore including a body member, slip and expander means for anchoring against movement and expansible packing means for sealing off the well bore, a closable bypass passage extending between said body member and said packing means, and hydraulically operable means connected to said expander means and responsive to differences in fluid pressures above and below said packing means for exerting downwardly directed force on said expander means.

This invention relates generally to subsurface well tools and more particularly to a new and improved well packer for use in a well conduit.

To perform production operations in a well, an apparatus commonly called a packer can be lowered into a cased well bore on a tubing string. The packer has a pliant and deformable sealing element which can be expanded against the well casing to prevent vertical movement of fluids past its sealing point. Normally, the packer will also have casing gripping anchors which can engage the casing to prevent any substantial vertical movement of the packer itself. The tubing string on which the packer is lowered into the well bore provides a flow conductor for transporting formation fluids to the surface from regions below the packer.

During production of a well, the pressrue of fluids within the casing-to-tubing annulus may exceed the pressure of fluids in the tubing string. For example, a relatively heavy control fluid may remain in the annulus after the packer is set and while formation fluids are being conducted through the tubing string to the surface. The hydrostatic pressure of the control fluid can impose a downward force on the packer structure tending to move the packer structure downwardly in the casing. Also, the well may be "swabbed" by artifically lifting fluids in the tubing string toward the surface, thereby reducing the pressure within the tubing string to a value lower than the annulus pressure. In either case, the higher pressure in the annulus exerts a downward force on the packer structure. On the other hand, the pressure of fluids within the tubing string and below the packer may exceed annulus pressures. For example, the pressure of fluids below the packer in a dual completion well can be higher than those in a zone above the packer. Also, there may not be any fluids in the annulus, in some cases, so that fluids below the packer exert upward pressure on the packer. Moreover, the higher pressures during water flooding or other injection operations, which can be carried out using a production packer, can act from below the packer as forces in an upward direction.

The net force in either direction tends to cause the well packer to move or shift within the casing. Any substantial movement in either direction is undesirable because such movement may cause the tubing to part or cause the packer to become unseated.

Moreover, it is desirable that well packers of the type described be provided with a fluid bypass and pressure equalizing means to facilitate insertion into a fluid-filled well bore and equalization of fluid pressures across the tool when desired. Prior art devices have resorted to a fluid by-

pass which is a separate tool from the packer, and which is located in the tubing string above the packer. This type of fluid bypass imposes several limitations. During extended periods of fluid flow, normally suspended solid particles in fluids in the annulus may settle on top of the well packer, and hinder proper operation when it is desired to retrieve the packer to the surface. Also, plugging substances such as sand may build up within the bore of the packer and within the tubing string above the packer so that a fluid bypass located at this point will not operate properly to equalize tubing-to-annulus pressure differentials when it is desired to retrieve the well packer. An additional tool in the pipe string can also add to the complexity of surface manipulations required to operate the tools and thereby increase the probabilities of malfunction.

An object of the present invention is to provide a new and improved full-bore retrievable well packer for effecting an annulus seal between a tubing and a well conduit.

Another object of the present invention is to provide a new and improved well packer of the type described having only a single anchor mechanism yet which will remain immovably anchored in a well when subjected to pressures from either above or below.

Yet another object of the present invention is to provide a new and improved well packer of the type described having an integral fluid bypass and pressure equalizing means which can be positively operated to equalize pressures across the packing element and through which fluids can be circulated to wash away any sediment above the well packer or plugging substances within the packer itself. Moreover, fluid pressure differences across the packing element can be equalized so that the packer can be retrieved even though the bore therethrough has become plugged with sand or other plugging substances.

Briefly, a well packer apparatus in accordance with the concepts of the present invention includes a sleeve member having an external recess and an elastomer packing element in the recess adapted for expansion to seal against a surrounding well conduit wall. A tubular body member is movable within the sleeve member and is arranged to provide a fluid passage space exteriorly of the body member and interiorly of the sleeve member. A passage closing means is normally open and can be operated by longitudinal movement of the body member for closing off the passage space. Anchors on the body member are normally retracted and can be expanded by an expander against the well conduit wall to anchor the well packer against movement. Hydraulic means are connected to the expander and are responsive to pressure differentials across the expanded packing element for exerting force on the anchors in a direction to hold the anchors engaged. Another passage around the passage closing means communicates the hydraulic means with well annulus pressures even though the passage closing means is closed.

The present invention has other objects and advantages which will become apparent in connection with the following detailed description thereof. The novel features of the present invention are set forth with particularity in the appended claims. The invention, both as to its organization and manner of operation, may be best understood by way of illustration and example of an embodiment thereof when taken in conjunction with the accompanying drawings, in which:

FIGURE 1A is a longitudinal section, with portions in side elevation, of the upper portion of the well packer embodying principles of the present invention and with parts in retracted positions;

FIGURE 1B is a view similar to FIGURE 1A of the lower portion of the well packer and forms a lower continuation of FIGURE 1A;

FIGURE 2A is a longitudinal section, with portions in side elevation, of a well packer in accordance with the present invention set in a well casing:

FIGURE 2B forms a lower continuation of FIGURE 2A;

FIGURE 3 is a cross section taken on line 3—3 of FIGURE 1B;

FIGURE 4 is a cross section taken on line 4—4 of FIGURE 1B;

FIGURE 5 is a cross section taken on line 5—5 of FIGURE 4;

FIGURE 6 is a fragmentary sectional view of the drag mechanism of the present invention; and

FIGURE 7 is a fragmentary sectional view of modified construction of the present invention.

Referring to FIGURE 1, a well packer **10** embodying the principles of the present invention includes a tubular body member or mandrel **11** which extends throughout the length of the well packer and which has a bore **12** therethrough providing a fluid passageway. The upper end of the mandrel **11** is connected to a sub **13** with a threaded box portion to which the lower end of a tubing string **14** may be connected. The lower end portion of the mandrel **11** can be threaded as at **15** for coupling to a string of pipe or another well tool. The bore **12** of the mandrel **11** can have an inner diameter at least as great as the drift diameter of the tubing string **14** to provide an unrestricted passageway therethrough. An annular sleeve member **16** is provided on the sub **13** and has an inner surface laterally spaced from the outer periphery of the mandrel **11** to provide an annulus **17** therebetween. Several side ports **18** in the sleeve member **16** communicate the annulus **17** with the exterior of the sleeve member **16**.

An annular compression sleeve **20** surrounds the mandrel **11** and has an outwardly extending flange **21** intermediate its ends. An elastomeric packing structure **22** is mounted around the compression sleeve **20** with its lower end abutting against the flange **21** and its upper end abutting against an abutment ring **23**. Although the packing structure **22** can take any desired form, it is shown for convenience of illustration as comprising several rubber or elastomer rings **24** separated by spacer rings **25**. The abutment ring **23** is slidably mounted on the compression sleeve **20** and has an upwardly facing recess **26** which can contain a suitable thrust bearing **27**. An snap ring **28** in the compression sleeve **20** engages the upper face of the bearing **27** to limit upward movement of the abutment ring **23** along the compression sleeve. It will be appreciated that advancement of the abutment ring **23** along the compression sleeve **20** toward the flange **21** will serve to compress the packing rings **24** and expand them outwardly.

The inner periphery of the compression sleeve **20** is laterally spaced from the outer surface of the mandrel **11** so that an annular fluid passageway **30** is formed therebetween for bypassing fluids around the packing structure **22**. An annular valve head **31** is provided for controlling fluid flow through the bypass passageway **30**. The valve head **31** can be in the form of a sleeve which is coupled to the mandrel **11** so that it can be moved longitudinally by the mandrel, the coupling being, for example, threads **32**. The upper end portion **33** of the sleeve **31** is of enlarged section and has an annular groove **34** in its outer surface which receives a suitable sealing element **35**. An inner shoulder **36** on the compression sleeve **20** normally engages the upper end of the valve head **31** to limit downward movement of the compression sleeve **20** along the mandrel **11**.

An annular portion **38** of the compression sleeve **20** extends downwardly over the valve head **31** and has an internal annular recess **39** formed adjacent to the enlarged portion **33** of the valve head when the parts are in the relative positions shown in FIGURE 1A. The inner surface **40** of the lower portion **38** below the recess **39** is laterally spaced from the lower portion of the valve head **31** to form a fluid passage space **41** which continues the bypass passageway **30**. The inner surface **40** is also sized relative to the valve head seal element **35** so that when the valve head **31** is moved downwardly relative to the compression sleeve **20**, the seal element will seal against the surface **40** to close the bypass passageway to fluid flow. The valve head **31** can have a plurality of radially cut slots **42** in its upper end through which fluids can flow when the seal element **35** is adjacent to the recess **39**.

An annular hydraulic member **45** is slidably received on the lower portion of the valve head **31** and a suitable seal, for example an O-ring **46**, seals between the hydraulic member and the outer periphery of the lower portion. The inner diameter of the hydraulic member **45** can be sized such that an outwardly extending shoulder **47** on the mandrel **11** can engage the lower face **48** of the hydraulic member **45** to limit its downward movement relative to the mandrel. Extending upwardly from the hydraulic member **45** is a connector sleeve **49** which can be slidably disposed on the lower portion **38** of the compression sleeve **20**, the upper end of the connector sleeve extending into engagement with the compression sleeve flange **21**. A lug **50** can extend into an elongated slot **51** in the sleeve **49** to corotatively secure the compression sleeve **20** and the hydraulic member **45** to one another. A plurality of side ports **52** extend through the wall of the connector sleeve **49** above the hydraulic member **45** to communicate the bypass passageways **30, 41** with the exterior of the well packer below the packing structure **22**.

A sleeve member **55** is threadedly coupled to the hydraulic member **45** and a suitable seal element **56** makes the connection fluid tight. The sleeve member **55** extends downwardly in a manner to form an annulus **57** relative to the mandrel **11** and its lower end is attached to a generally frusto-conically shaped expander cone **58**. The expander cone **58** has a bore **59** which is sized for sliding reception on the mandrel **11** and has outer inclined surfaces **60** which converge downwardly and inwardly toward the mandrel **11**.

An annular, floating piston member **62** is movably received within the annulus **57**. Suitable seal elements **63** and **64** seal between the inner periphery of the piston member **62** and the outer surface of the mandrel **11**, and between the outer periphery of the piston member **62** and the inner surface of the sleeve member **55**, respectively. It will be appreciated that a chamber **65** is formed between the piston member **62** and the hydraulic member **45**. Upward movement of the floating piston member **62** is limited by its engagement with the mandrel shoulder **47** and downward movement is limited by engagement with the upper face **66** of the expander cone **58**.

The chamber **65** is placed in fluid communication with the well annulus above the packing structure **22** so that pressures in the well annulus can act on the lower face of the hydraulic member **45** and on the upper face of the floating piston member **62**. To accomplish this, the valve head or sleeve **31** is coupued to the madnrel **11** so that its lower end **67** is spaced a small distance away from the outwardly extending shoulder **47** on the mandrel **11**. A pressure communicating passage **69** is provided between the sleeve **31** and the mandrel **11** and can be a plurality of circumferentially spaced grooves **68** which extend along the length of the sleeve **31** and through the threads **32**. The passage **69** and the space between the end of the sleeve and the upper face of the shoulder **47** thereby function to communicate fluid pressures to the chamber **65** from that portion of the bypass passageway **30** located above the valve head seal element **35**. As previously pointed out, the bypass passageway **30** is in communication with the well annulus above the packing structure **22** via the sleeve annulus **17** and the side ports **18** in the sleeve member **16**. Therefore, it can be appreciated that pressures of fluids in the annulus above the packing **22** are always reflected in the chamber **65** whether the valve head **31** is in its bypass opening or closing position.

As shown in FIGURE 1B, a tubular cage member **70** is carried by the lower end portion of the mandrel **11** with its lower end normally engaging a stop ring **71** on the mandrel. An internal annular recess **79** in the cage member **70** can be sized to slidably receive the lower end of a stop sleeve **53** which extends upwardly and can be joined to the expander cone **58** by threads **54**. The stop sleeve **53** functions to limit upward movement of the expander cone **58**, the hydraulic member **45** and the compression sleeve **20** along the mandrel **11** so that the valve head **31** can not close the bypass passageway **30, 41** while the parts of the well packer **10** are in their normally retracted positions. Referring momentarily to FIGURE 6, the cage member **70** can have a plurality of circumferentially spaced, radially directed recesses **72**, each of which receives a conventional drag block **73**. The drag blocks **73** are pressed outwardly by compression springs **74** for frictional engagement with the well casing and outward movement can be limited by tangs **75, 76** which engage bands **77** and **78** around the cage member **70**. The drag blocks **73** function to resist both rotational and longitudinal movement of the cage member **70** within the casing in a conventional manner.

A plurality of slip members **80**, for example three, are carried by the cage member **70** and are pivotally attached to its upper end by links **81**. The slip members **80** can have wickers or teeth **82** on their outer peripheries which are adapted to bite into and grip the well casing to resist longitudinal movement in either direction. Inclined surfaces **83** on the inner peripheries of each slip member **80** converge downwardly and inwardly toward the mandrel **11** and are complementary in shape to the inclined surfaces **60** on the expander cone **58** in a manner whereby relative movement between the expander cone **58** and the slip members **80** will cause lateral shifting of the slip members. The links **81** have pinholes **84** and **85** which receive pivotal mounting pins **86** and **87** engaging in each slip member **80** and in the cage member **70**, respectively. The lower pinholes **85** are formed as slots to permit each slip member **80** to move outwardly while still being supported by the cage member **70**. The upper end of each link **81** has an upwardly extending shoulder or projection **88** which engages in a radially extending recess **89** in each slip member **80**. Cantilever springs **90** can be attached to the cage member **70** by screws **91** or other suitable fasteners, the springs having their free ends pressing against each link **81**. The inward biasing force of each spring **90** is transferred to a respective slip member **80** through the shoulder **88** on each link **81** and through the upper pin **86** to hold the slip members in their normally retracted positions as shown in FIGURE 1B. It will be appreciated that since the spring force is applied to two spaced points on each slip element **80**, viz., the pin hole **84** and the recess **89**, the slip elements will not tend to cant or cock in their retracted positions and thereby be capable of hanging on a conduit wall projection. Moreover, the lower slots or pinholes **85** permit enough lost motion as the slip members **80** are moved outwardly so that the slip members can still be supported by the upper end of the cage member **70** when they are in their expanded position.

To control relative longitudinal motion between the cage member **70** and the mandrel **11**, a clutch mechanism is provided, the clutch mechanism being referenced generally in the drawings by the numeral **93**. The clutch mechanism **93** includes a split nut member **94**, the nut member being alternatively engageable with lower and upper cam portions **95** and **96**, respectively, on the mandrel **11**. The nut member **94** is preferably composed of four segments with opposite segments **97** having downwardly facing buttress form threads **98** as shown in FIGURE 5, and the other two opposite segments **99** having an upwardly facing cam tooth **100**. Band springs **101** or other suitable inward biasing means are received in grooves **102** around the periphery of the nut member **94** to permit it to expand while urging inward contraction. Downwardly extending lugs **103** (FIGURE 1B) on the cage member **70** can engage between segments of the nut member **94** so that the nut member can not rotate relative to the cage member.

The upper cam portion **96** of the mandrel **11** can be a length of left-hand threads forming upwardly facing teeth **104** which are normally located above the nut member **94**. The mandrel teeth **104** are companion in form to the teeth **98** on the nut segments **97**. The lower cam portion **95** on the mandrel **11** includes an elliptically formed recess **105** in which the cam tooth **100** on each segment **99** can engage. The upper end of the recess **105** diverges downwardly and outwardly to form a shoulder **106** which engages the top surfaces of each cam tooth **100** on the segments **99**. When the parts are in the positions shown in FIGURE 1B, the cage member **70** can not move upwardly relative to the mandrel **11** as the packer **10** is lowered into a well bore. Accordingly, the slip members **80** can not be prematurely set without deliberate rotation of the mandrel **11**. As shown in FIGURE 4, the elliptical recess **105** opens on its opposite sides **107** and **108** to the diameter of the mandrel **11**. Thus it will be appreciated that rotation of the mandrel **11** a quarter-turn relative to the cage member **70** will cam or shift the segments **99** out of engagement with the recess **105** and free the mandrel for downward movement relative to the cage member **70**.

When the two cam tooth segments **99** are engaging in the mandrel recess **105**, the two threaded segments **97** of the nut member **94** are not engaging and are being held in expanded positions by the mandrel shoulder **106**. However, downward movement of the mandrel **11** after its release as above described will cause the mandrel threads **104** to ratchet downwardly through the nut member **94**, the lower inclined surfaces of the teeth **104** urging all four nut segments in radially outward directions. Due to the form of the teeth **104** and **98** on the mandrel and on the opposed nut segments **97**, respectively, the threaded segments **97** can engage the mandrel teeth **104** to "trap" the mandrel **11** in the lowermost position to which it is moved. Upward movement of the mandrel **11** relative to the cage member **70** can then only be effected by right-hand rotation of the mandrel which serves to unthread the mandrel teeth **104** upwardly and out of engagement with the nut segments **97**.

To properly position the cam segments **99** relative to the elliptical recess **105** as the packer **10** is lowered into the well, a stud **110** can be threaded into the stop ring **71** and engage a lug **111** which extends downwardly from the lower end of the cage member **70**. With the stud **110** engaging the lug **111**, the mandrel **11** is properly oriented, rotationally speaking, so that the deep portions of the recess **105** are radially aligned with the cam segments **99** of the nut member **94**. So positioned, the cam segments **99** can prevent upward movement of the cage member **70** along the mandrel **11** until the cam segments are released.

OPERATION

In operation, the well packer is assembled as shown in the drawings and lowered on the tubing string **14** to a selected setting point within the well casing P. During lowering, the drag blocks **73** slide in frictional engagement with the well casing wall. The packing structure **22** is retracted and well fluids can bypass around the outside thereof and through the bypass passageways **30, 41** behind the packing structure. The cage member **70** can not move upwardly along the mandrel **11** due to the engagement of the cam tooth segments **99** of the nut member **94** within the recess **105** on the mandrel. Accordingly, the slip members **80** can not move toward the expander cone **58** and be prematurely shifted outwardly thereby.

At setting depth, the mandrel can be torqued or turned by manipulation of the tubing string **14** at the earth's surface to cause the cam tooth segments **99** to be shifted from engagement with the mandrel. With the mandrel **11** thereby released for downward movement relative to the cage member **70**, lowering of the mandrel moves the expander cone **58** downwardly and behind the slip members **80** to shift them outwardly as shown in FIGURES 2A and 2B. When the slip members actually engage the well casing, the wickers or teeth **82** will bite into and grip the casing so that further downward movement of the expander cone **58**, the hydraulic member **45** and of the compression sleeve **20** is precluded. Continued downward movement of the mandrel **11** positions the seal element **35** on the valve head **31** adjacent to the inner surface **40** of the lower sleeve portion **38** to close the bypass passageway **30, 41** to fluid flow. The mandrel sleeve **16** also engages the thrust bearing **27** on the abutment ring **23**.

Then the weight of the tubing string **14** can be let down on the mandrel **11** to advance the abutment ring **23** along the compression sleeve **20** toward the flange **21** to compress and expand the packing rings **24** outwardly. As the mandrel moves downwardly, the mandrel threads **104** ratchet downwardly through the nut member **94** and the threaded segments **97** of the nut member "trap" the mandrel in its lowermost position to trap the compression energy in the packing structure **22**. When the packing structure **22** is in firm sealing engagement with the well casing the well packer **10** is locked in a set condition. Inasmuch as the bore **12** through the mandrel **11** has at least the cross-sectional area of the tubing string bore, an unrestricted access passage is provided to regions of the well bore below the packer from the earth's surface.

Should fluid pressures in the tubing string **14** and below the packer **10** exceed the pressures of fluids in the annulus above the packer, the higher pressures act on the upper face of the hydraulic member **45** as well as upwardly on the lower face of floating piston member **62**. The lower fluid pressures are communicated through the mandrel sleeve ports **18**, the upper portion of the bypass passageway **30**, the grooves **68** behind the valve head **31**, and into the chamber **65** to act on the lower face **48** of the hydraulic member **45** and on the upper face of the floating piston member **62**. The pressure difference will thus act over the area A as downward force on the expander cone **58**. The upward force on the piston member **62** due to pressure difference acting on the area B will cause the piston member to engage the mandrel shoulder **47**. The downward force on the expander cone **58** increases the outward holding forces on the slip members **80** so that they will remain in firm and immovable engagement with the well casing. Upward forces on the mandrel **11** due to high pressure from below are transferred by the nut segments **97** and the cage member **70** directly to the slip members **80** which are gripping the well casing.

On the other hand, if pressure in the annulus above the well packer **10** should exceed the tubing pressure, the floating piston member **62** can move downwardly to engage the upper face **66** of the expander cone **58** and the downward forces on the expander cone can exceed those being exerted upwardly on the hydraulic member **45** so that the net force is in a downward direction to increase the holding force on the slip members **80**. Moreover, the pressure difference is acting on the expanded packing structure **22** tending to move it downwardly and thus drive the expander cone downwardly. Thus it will be appreciated that the packer **10** is firmly anchored to resist movement in either direction in the casing responsive to pressure from above or below.

If it is desired to release the well packer **10**, it is necessary to rotate the mandrel **11** in a right-hand direction to unthread the mandrel teeth **104** upwardly and out of the nut member **94**. Frictional resistance to such rotation is minimized by thrust bearing **27** on the abutment ring **23** which is axially loaded by the inherent tendency of the

packing rings **24** to retract. Movement of the mandrel **11** in an upward direction will position the seal element **35** on the valve head **31** adjacent to the recess **39** to open the bypass passageway **30, 41** for equalizing any existing pressure differentials across parts of the well packer. Of course, pressures on the cone holding hydraulic member **45** are equalized as well as those across the floating piston member **62**. With the bypass passageway **30, 41** open, any sediment in the annulus and on top of the packer can be washed away and full mandrel circulation or reverse circulation is permitted.

As the mandrel **11** moves upwardly, the compression force on the packing structure **22** is relieved and it will inherently retract. Eventually the mandrel shoulder **47** will engage the lower face **48** of the hydraulic member **45** to pull the expander cone **58** from behind the slip members **80**. As the expander cone **58** moves upwardly, the springs **90** will cause the slip members **80** to retract from the casing and the well packer **10** is free. The lower end of the cage member **70** will engage the stop ring **71** on the mandrel **11** and the various parts of the well packer **10** are in their retracted positions for longitudinal movement in the well casing.

It will be appreciated that although the well packer **10** has been shown and described for compression setting, e.g., by applying the weight of the tubing string **14** to move the mandrel **11** downwardly and expand the slip elements **80** and the packing ring **24**, it will be apparent that the tool can be inverted in its entirety and set in tension, if desired. In this case, the tubing string **14** can be coupled to the mandrel threads **15** for lowering into the well bore. After releasing the clutch mechanism **94** at setting depth, an upward strain can be taken on the tubing string **14** to move the mandrel **11** upwardly for expanding parts of the well packer. High pressure in the annulus will act upwardly on the hydraulic member **45** to increase the holding force on the slip elements **80** and high pressure below the well packer can moe the floating piston member **62** into engagement with the expander cone **58**. In the latter situation, the effective pressure area B of the floating piston member **62** can be constructed and arranged to exceed the effective pressure A of the hydraulic member **45** so that the net force is in an upward direction to increase the holding force on the slip elements **80**.

After the well packer **10** has maintained a set condition over a considerable length of time, it is possible that the packing rings **24** can lose resiliency and be permanently deformed, in which case there can be a decrease in the outward pressure being exerted by the expander cone **58** on the slip elements **80**. Accordingly, it may be desirable, as shown in FIGURE 7, to include a compression spring **112** surrounding the mandrel **11** with its upper end pressing against the floating piston member **62** and its lower end pressing against the expander cone **58**. The expander cone **58** can be provided with an internal annular recess **113** for receiving the lower portion of the compression springs **112**. The spring **112** is capable of exerting a predetermined magnitude of force on the expander cone when the parts of the packer are in set condition. In this manner, the compression spring **112** can function to maintain holding force on the slip elements **80**, even though the packing rings have relaxed, to aid in keeping the well packer **10** anchored in the well casing.

A new and improved well packer has been disclosed for sealing off the annulus between two flow conductors in a well. The well packer is of the full-bore, retrievable type having only a single anchoring mechanism yet which will remain immovable in a well although subjected to pressure from above or below. An integral bypass is provided which can be selectively operated for passing fluid through the packing element. Since certain modifications or changes may be made in the disclosed embodiment of the present invention without departing from the concepts involved, it is intended that the appended claims cover all such modifications or changes falling within the true spirit and scope thereof.

What is claimed is:

1. A well packer for use in a well bore comprising: sleeve means having an external recess and sealing means in said recess adapted to be expanded against a well bore wall; a body member movable within said sleeve means and providing a fluid passage space with said sleeve member through which well fluids can flow from the exterior of said device around said sealing means; passage closing means between said sleeve means and body member for selectively opening and closing said fluid passage space; normally retracted anchor means shiftable outwardly of said body member into engagement with the well conduit wall for anchoring said well packer in the well conduit; expander means movable relative to said anchor means for shifting said anchor means outwardly and for exerting force on said anchor means; hydraulic means connected to said expander means and responsive to a pressure difference across said sealing means in its expanded condition for increasing the outward force on said anchor means to hold said anchor means engaged with the well conduit wall; and other passage means around said closing means and separate from said passage space for communicating well annulus pressures to said hydraulic means when said passage space closing means closes said passage space.

2. The well packer of claim 1 wherein said passage closing means includes a valve head on said body member and seal means on said valve head engageable with a portion of said sleeve means.

3. The well packer of claim 2 wherein said other passage means is located between said valve head and said body member.

4. The well packer of claim 2 wherein said valve head comprises a sleeve member attached to said body member for movement therewith, said sleeve member having an enlarged portion, said sealing means being on said enlarged portion.

5. The well packer of claim 4 wherein said other passage means is located between said sleeve member and said body member.

6. The well packer of claim 5 wherein said other passage means includes at least one groove extending longitudinally along said sleeve member.

7. A well packer comprising: sleeve means having a deformable sealing element arranged for expansion to seal against a surrounding well conduit wall; a tubular body member adapted for connection to a tubing string, said body member being movable within said sleeve means; a fluid passageway between said body member and sleeve member permitting flow of fluids around said sealing element; passageway closing means between said body member and sleeve member for selectively opening and closing said passageway; normally retracted slip members shiftable outwardly of said body member into gripping engagement with a well conduit wall for anchoring said well packer in a well conduit; expander means movable relative to said slip members for shifting them outwardly; hydraulic means connected to said expander means responsive to a pressure difference across said sealing element in its sealing condition for exerting outward force on said gripping members, said hydraulic means including a sleeve piston movable on said body member on one side of said sealing element and responsive to fluid pressure in the well bore on one side; means on said body forming a chamber with said sleeve piston; and means for communicating fluid pressure in the well bore on the other side of said sealing element with said chamber.

8. The well packer of claim 7 wherein said chamber forming means comprises an annular member between said sleeve piston and said body member; and seal means sealing between said annular member and said sleeve piston.

9. The well packer of claim 8 wherein said annular member is movable along said body member; and means to limit movement of said annular member along said body member.

10. The well packer of claim 7 wherein said passageway closing means includes a valve head on said body member and seal means on said valve head engageable with a portion of said sleeve means.

11. The well packer of claim 10 wherein said pressure communicating means is located between said valve head and said body member.

12. The well packer of claim 10 wherein said valve head comprises a sleeve member attached to said body member and movable therewith, said sleeve member having an enlarged portion, said sealing means being on said enlarged portion.

13. The well packer of claim 12 wherein said pressure communicating means includes at least one recess inside said sleeve member extending longitudinally along said body member.

14. The well packer of claim 7 further including a tubular member movable relative to said body member for supporting said normally retracted slip members; and means operable by manipulation of said body member for controlling relative movement between said tubular member and said body member.

15. The well packer of claim 14 further including linkage means for connecting said normally retracted slip members to said tubular member, said linkage means including a lost-motion connection to permit said tubular member to engage said slip members when said slip members are shifted outwardly.

16. In a well packer adapted for use in a well bore, the combination comprising: a first member; means carried by said first member adapted to seal off a well conduit; a second member movable relative to said first member; normally retracted wall engaging means cooperable with said second member to resist movement of said second member within the well bore; cage means movably mounted on said first member; link means pivotally connecting said wall engaging means to said cage means, said link means including a lost-motion connection so that upon expansion of said wall engaging means said cage means can engage said wall engaging means; and means engageable with said wall engaging means to retract said wall engaging means from the wall of the well bore.

17. In a well tool, the combination comprising: a first member; a second member movable relative to said first member; normally retracted wall engaging means cooperable with said second member for movement between a first retracted position and a second wall engaging position, said wall engaging means in said second position functioning to resist movement within a well bore; cage means movably mounted on said first member; linkage means for connecting said wall engaging means to said cage means, said linkage means including a lost-motion connection to said cage means to permit said wall engaging means to move to said second position while being supported by said cage means, said linkage means further including means cooperable with said wall engaging means in said first position to prevent pivotal movement of said wall engaging means relative to said first member.

18. In a well tool, the combination comprising: a body member; normally retracted means shiftable outwardly of said body member; means for shifting said normally retracted means outwardly of said body member; cage means on said body member and adapted for supporting said normally retracted means; linkage means pivotally connecting said normally retracted means to said cage means, said linkage means including a lost-motion connection whereby said normally retracted means can be shifted outwardly while being supported by said cage

means; and resilient biasing means for urging said normally retracted means toward retracted positions.

19. The combination of claim **18** further including inclined surfaces on said cage means and normally retracted means for supporting engagement when said normally retracted means are shifted outwardly.

20. The combination of claim **19** further including a shoulder on said linkage means engaging said normally retracted means, when retracted, for preventing pivotal movement of said normally retracted means relative to said body member.

21. In a well tool, a mandrel; a cage member on said mandrel including means for frictionally engaging the wall of a well conduit; locking means between said cage member and said mandrel including first means forming interlocking surfaces between said mandrel and cage member to prevent relative longitudinal movement in one direction, said first means being disengageable upon relative rotation between said mandrel and cage member where said relative rotation is less than 180°; and second means including threaded interlocking connections on said mandrel and cage member for preventing relative longitudinal movement in an opposite direction, one of said threaded interlocking connections being displaced longitudinally from the other of said threaded interlocking connections.

22. The well tool of claim **21** further including orienting means cooperate between said cage means and said mandrel for positioning said interlocking surfaces for engagement, said orienting means being operable by movement of said mandrel.

23. In a well tool, a mandrel; a cage member on said mandrel including means for frictionally engaging the wall of a well conduit; and locking means between said cage member and said mandrel to permit selective positioning of said mandrel and cage means including a segmented nut member having at least two pairs of opposed segments, one of said pairs of opposed segments having surfaces capable of interlocking engagement in a recess in said mandrel to prevent relative longitudinal movement in one direction, said interlocking engagement being disengageable upon relative rotation between said mandrel and cage means of less than 180°, the other of said pairs of opposed segments having threads formed thereon capable of threaded engagement with a threaded portion of said mandrel for preventing relative longitudinal movement in an opposite direction, said threaded engagement being releasable by relative rotation between said mandrel and cage means of more than 180°.

24. A well packer apparatus comprising: a mandrel adapted for connection to a pipe string; expander means and normally retracted slip means shiftable by said expander means into gripping contact with a well conduit wall in order to anchor against movement in the well conduit; expansible packing means for sealing off the annulus between said mandrel and the well conduit wall; bypass passage means extending between said mandrel and said packing means and between locations above and below said packing means; passage closing means on said mandrel for closing off said bypass passage means when said packing means is expanded; and hydraulic means connected to said expander means, said hydraulic means including a piston member having upper and lower surfaces exposed to fluid pressures in the well bore respectively below and above said packing means to enable greater fluid pressures below said packing means to exert downward force on said expander means tending to shift said slip means outwardly.

25. A well packer apparatus comprising: a mandrel; expander means and slip means which can be shifted outwardly by said expander means into gripping engagement with a well conduit wall; packing means about said mandrel which can be expanded into sealing engagement with a well conduit wall; means cooperable with said mandrel for releasably locking said packing means in expanded condition; bypass passage means between said mandrel and said packing means for bypassing well fluid past packing means and to enable equalizing pressure differentials across said packing means; coengageable means for closing off said passage means when said packing means is expanded; piston means on said expander means having upper and lower surfaces, said upper surface being exposed to fluid pressure in the well bore below said packing means; and means for exposing said lower face of said piston means to fluid pressure in the well bore above said packing means when said packing means is locked in expanded condition.

References Cited

UNITED STATES PATENTS

2,753,943	7/1956	Morgan	166—139
2,917,114	12/1959	Levendoski	166—139
3,223,169	12/1965	Roark	166—129
3,253,656	5/1966	Brown	166—129
3,279,542	10/1966	Brown	166—139
3,338,308	8/1967	Elliston et al.	166—129
3,339,637	9/1967	Holden	166—128

JAMES A. LEPPINK, *Primary Examiner.*