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(54) **MULTI-STAGE WELL ISOLATION AND FRACTURING**

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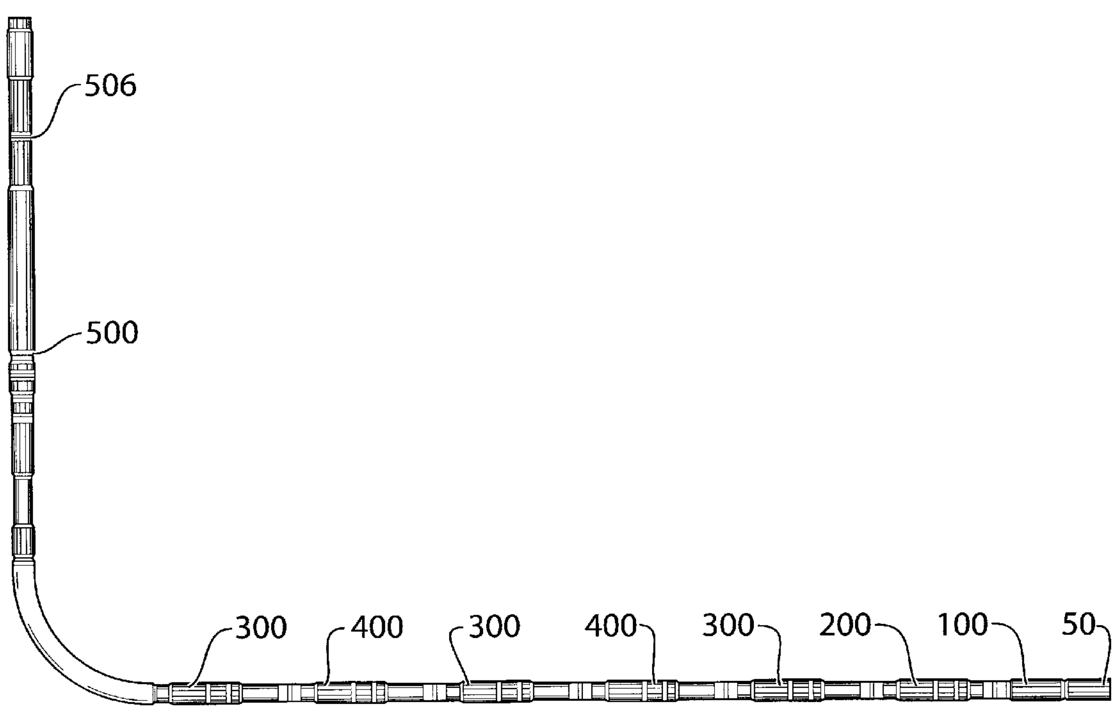
(57) **ABSTRACT**

An activation tool is provided for use in a well isolation and stimulation string, The activation tool has a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat. A first stage frac valve tool is also provided having a stationary outer body and an internal piston movable between an closed and an open position. A singular tool is further provided having a float shoe, an activation tool and integrally built with the float shoe and a first stage frac integrally built with the activation tool. A cased hole packer is further provided having an integral setting tool.



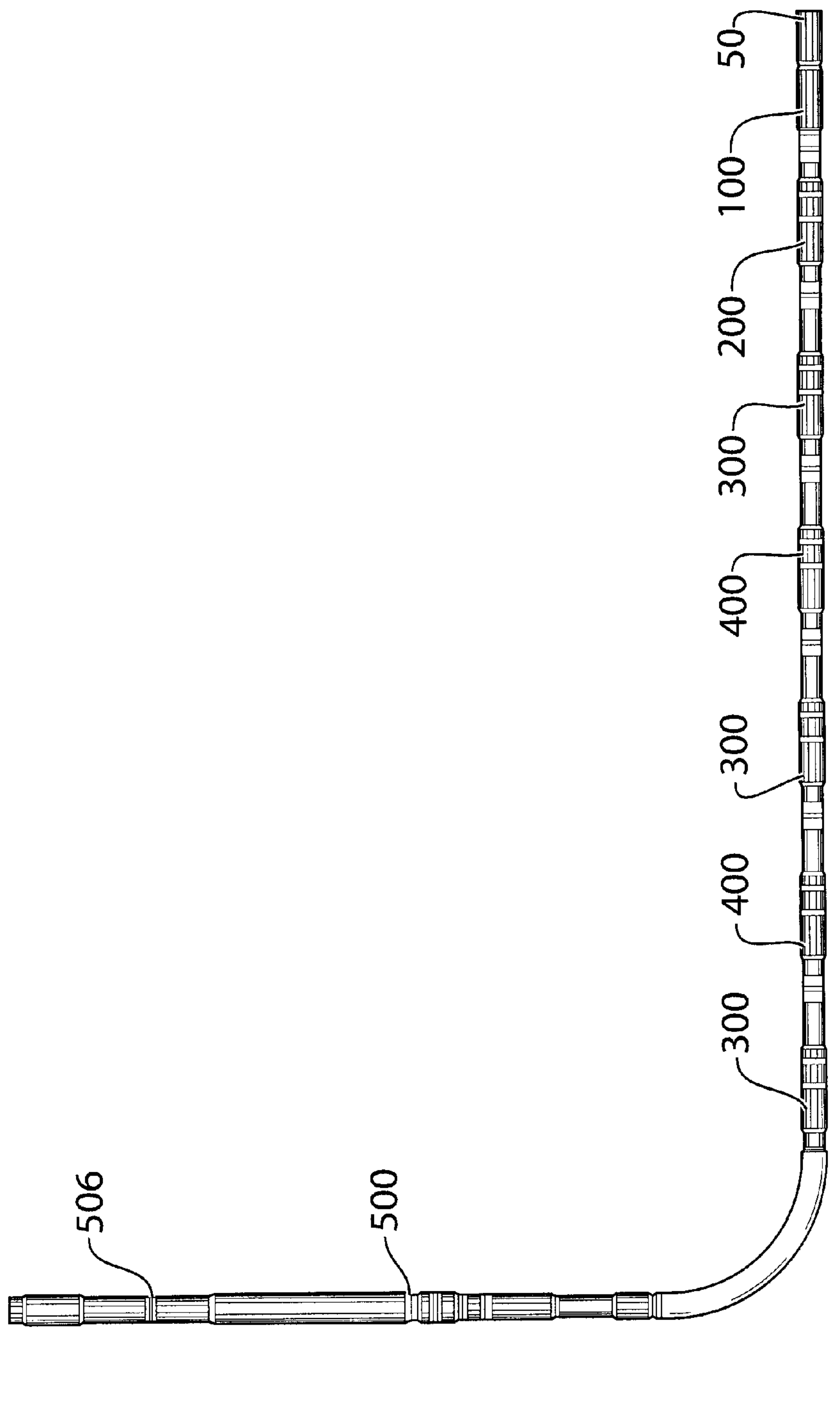
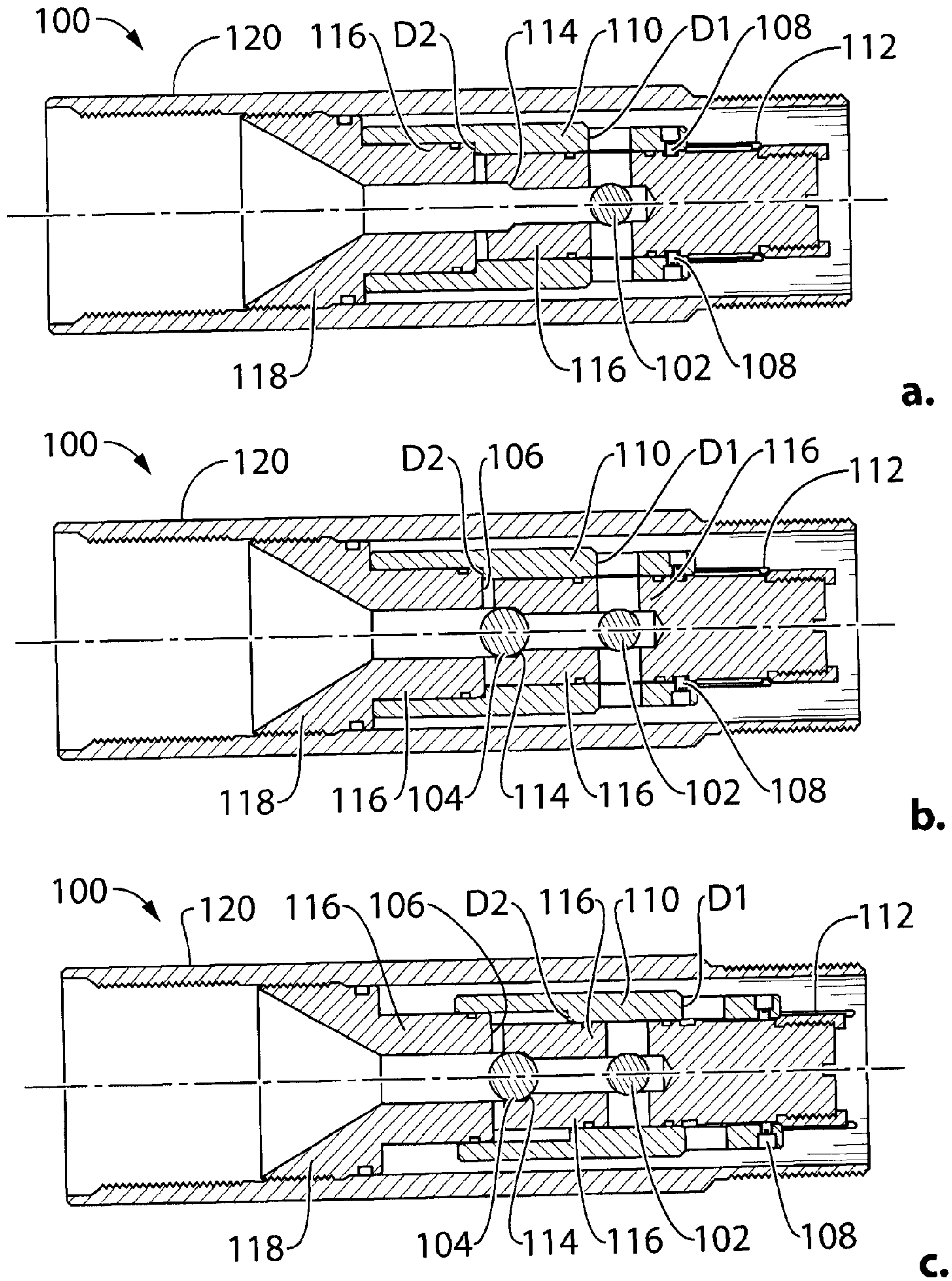


FIG. 1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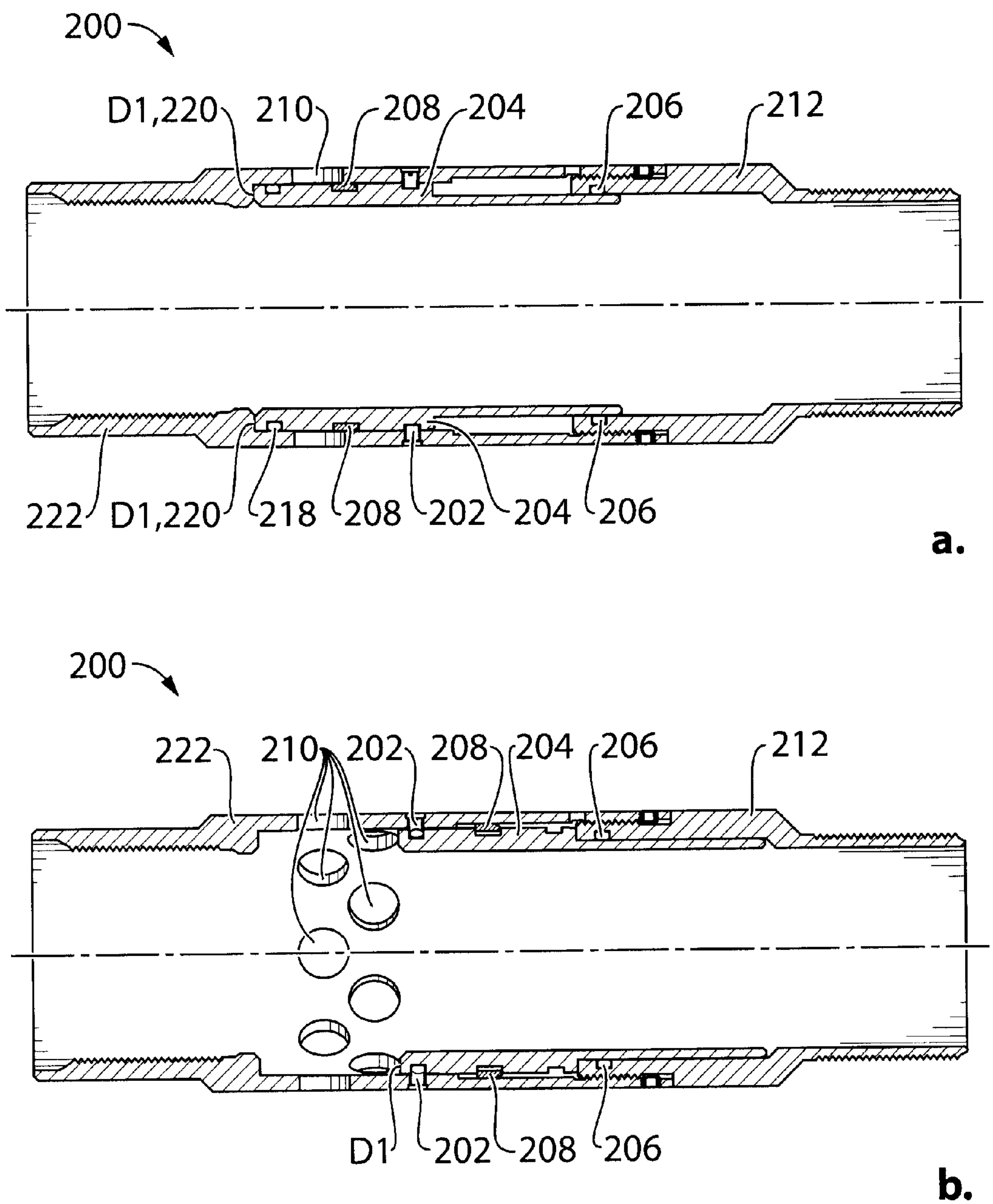
120
116
D2
114
110
D1
108
112
118
116
102
108
a.
100
120
D2
106
110
D1
116
112
118
116
104
114
116
102
108
b.
100
120
116
106
D2
116
110
D1
112
118
104
114
116
102
108
c.

FIG.2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D1,220
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208
204
206
212
222
D1,220
218
208
202
204
206
a.
200
222
210
202
208
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D1
202
208
206
b.

FIG.3

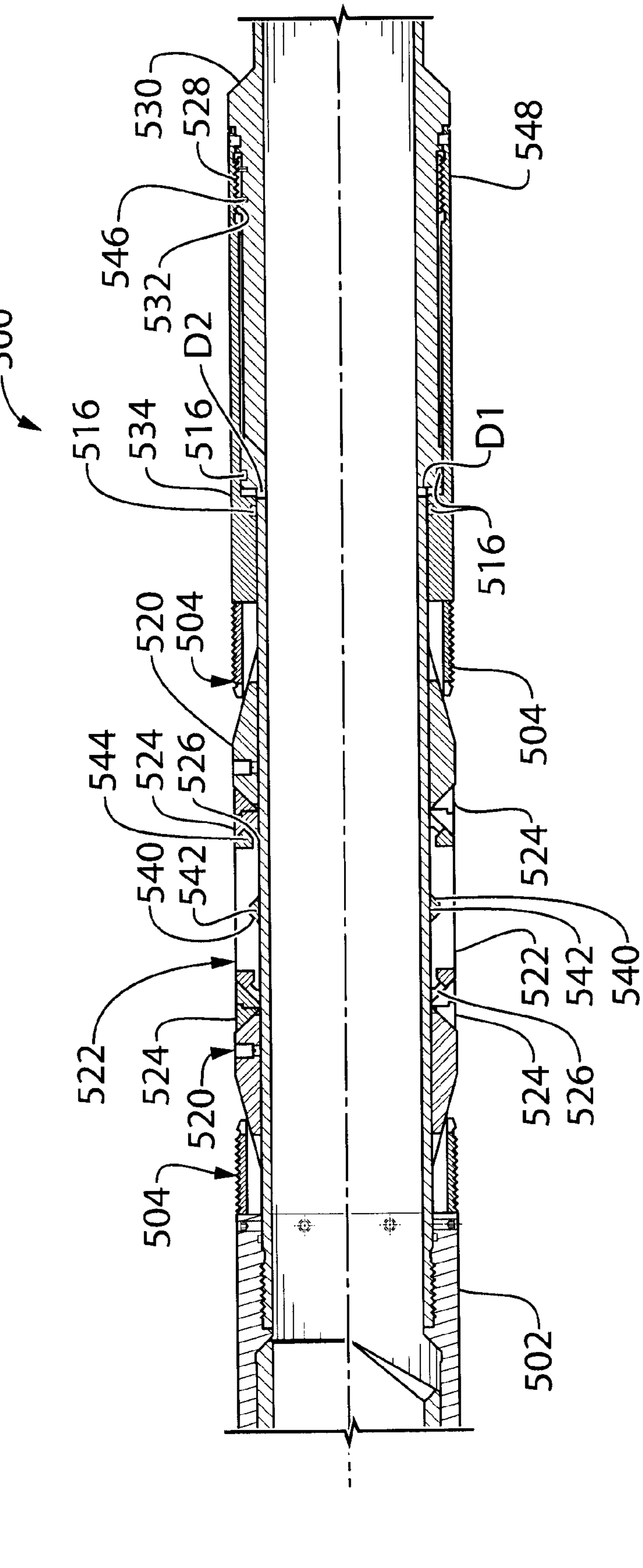
500
530
528
546
532
548
D2
516
534
516
D1
516
520
504
504
544
524
526
524
540
542
522
542
540
522
524
520
504
524
526
502

FIG.4

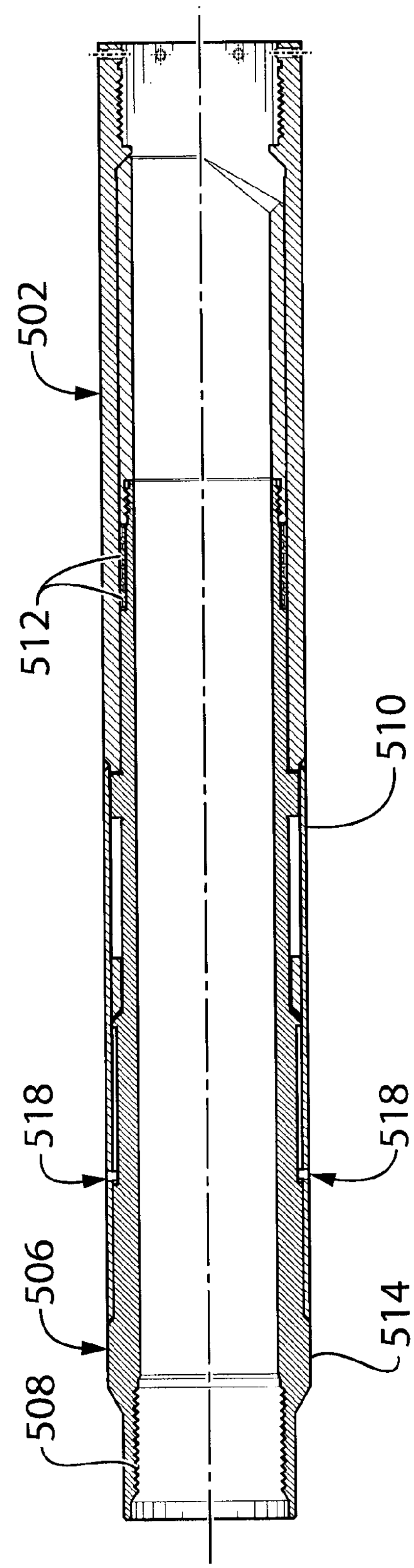

FIG.5

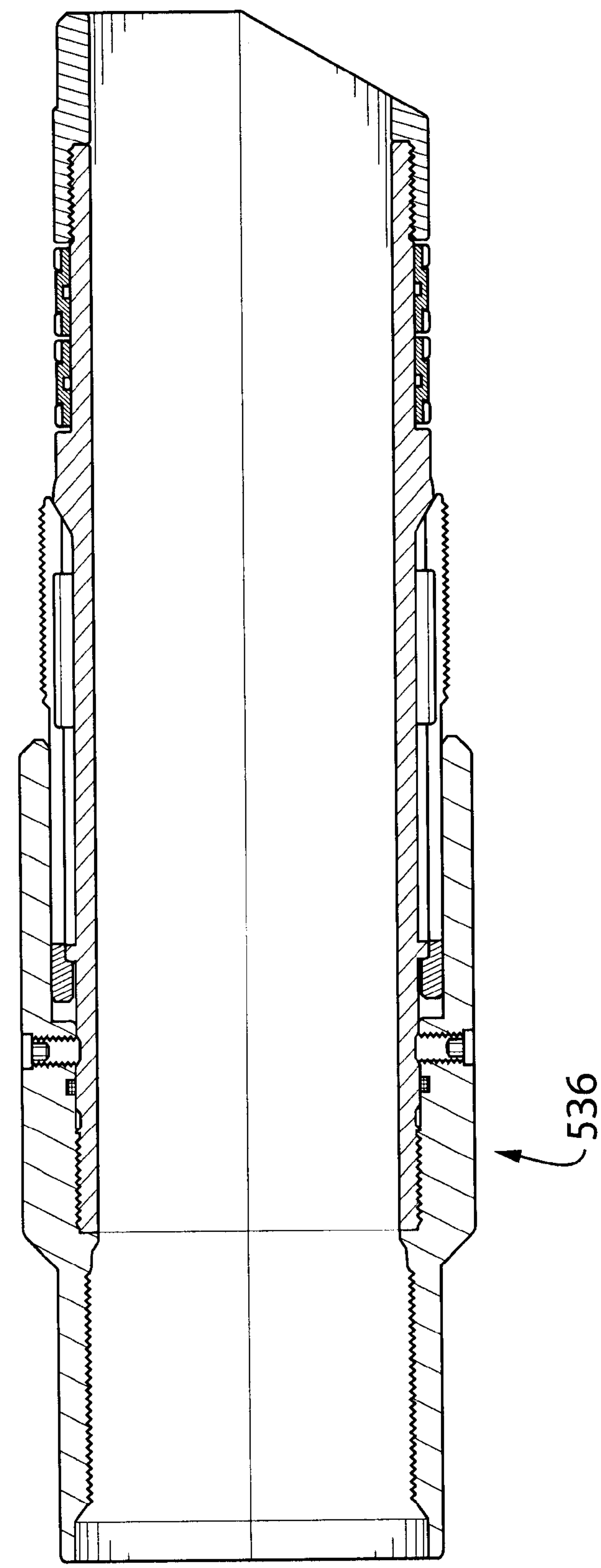

FIG. 6

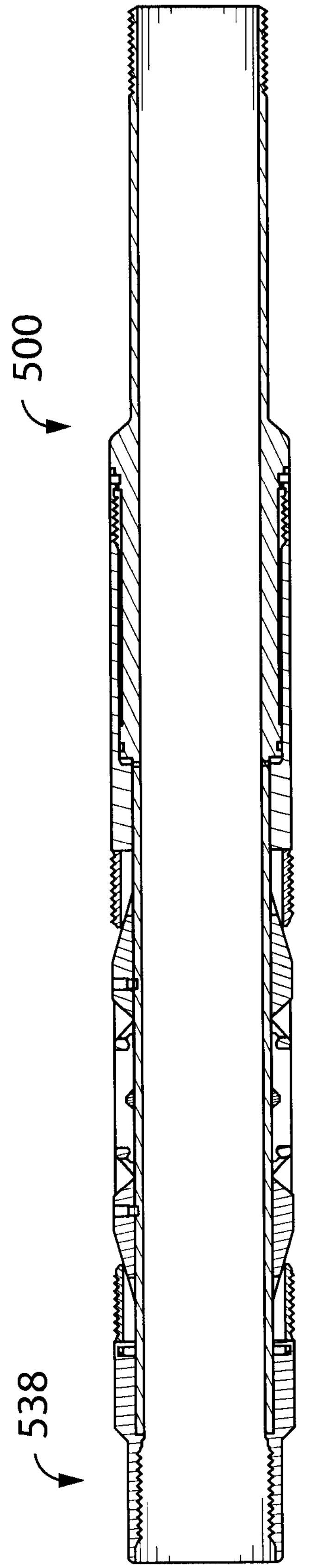

FIG. 7

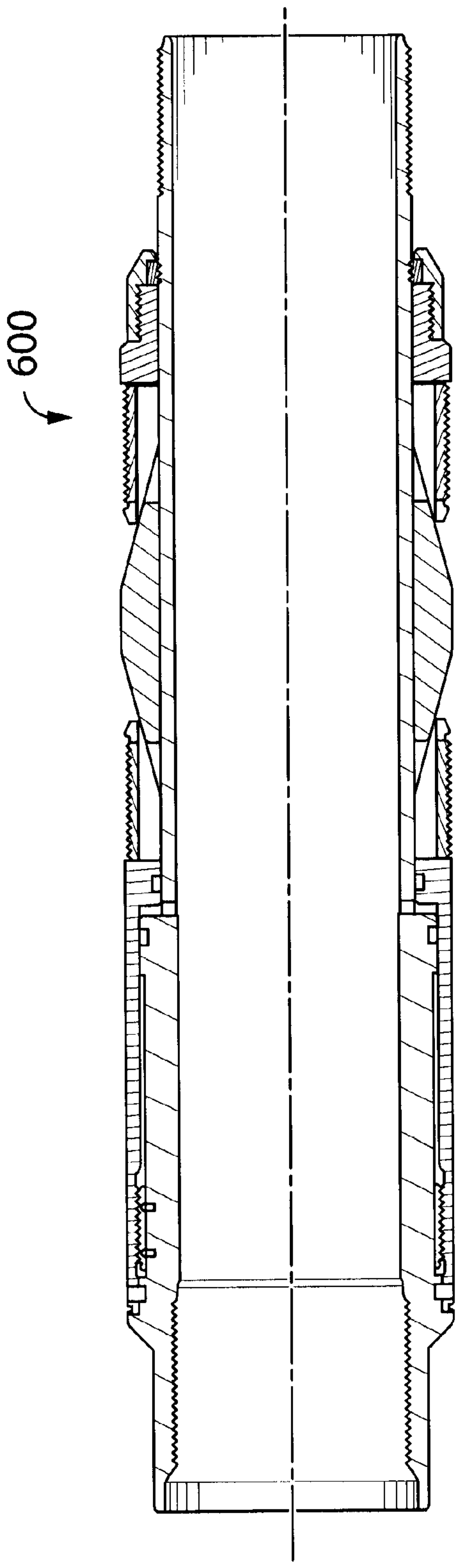

FIG. 8

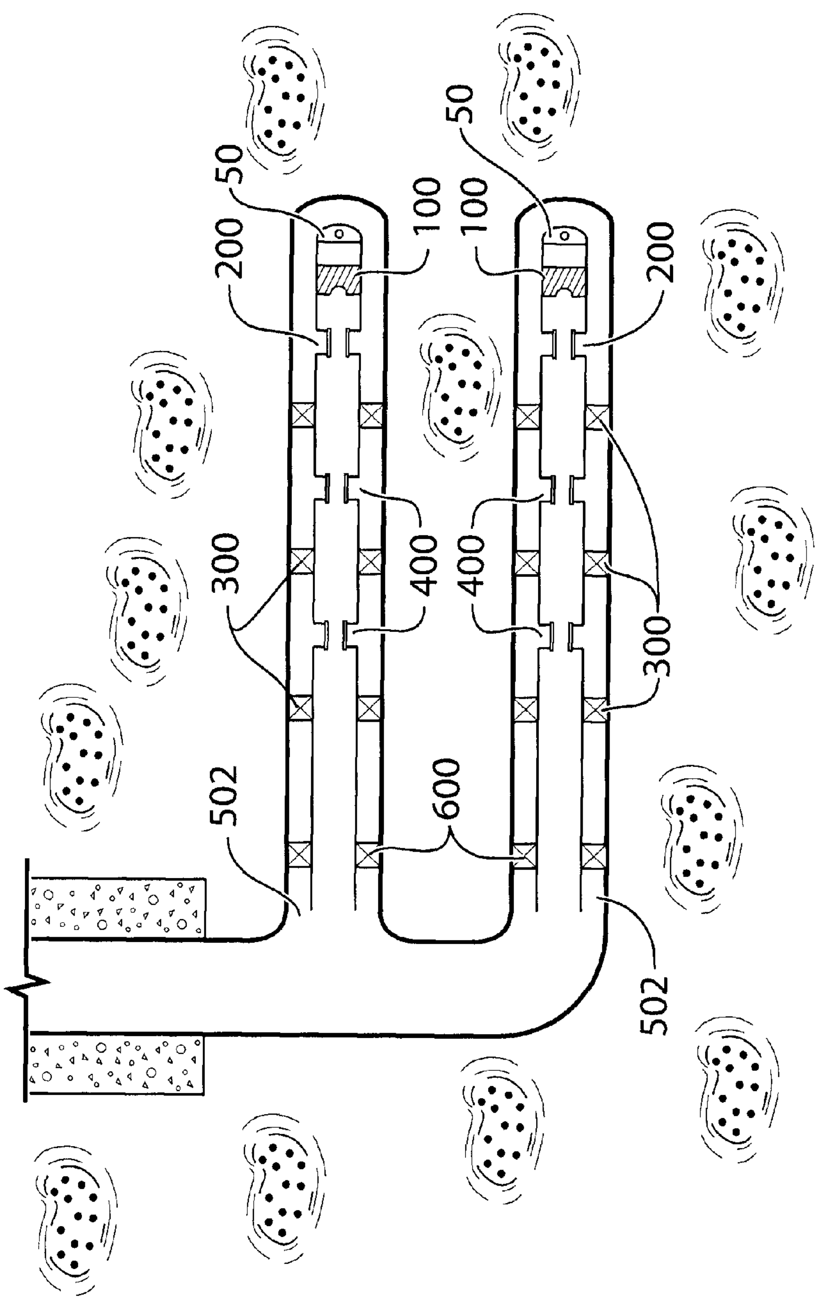

FIG. 9

MULTI-STAGE WELL ISOLATION AND FRACTURING

FIELD OF INVENTION

[0001] The present invention relates to devices for multi-stage, horizontal well isolation and fracturing.

BACKGROUND OF THE INVENTION

[0002] An important challenge faced in oil and gas well production is producing hydrocarbons that are locked into formations and not readily flowing. In such cases, treatment or stimulation of the formation is necessary to fracture the formation and provide passage of hydrocarbons to the wellbore, from which it can be brought to the surface and produced.

[0003] Fracturing of formations via horizontal wellbores traditionally involves pumping a stimulant fluid through either a cased or open hole section of the wellbore and into the formation to fracture the formation and produce hydrocarbons therefrom.

[0004] In many cases, multiple sections of the formation are desirably fractured either simultaneously or in stages. Tubular strings for the fracing of multiple stages of a formation typically include one or more fracing tools separated by one or more packers.

[0005] In some circumstances frac systems are deployed in cased wellbores, in which case perforations are provided in the cemented in system to allow stimulation fluids to travel through the fracing tool and the perforated cemented casing to stimulate the formation beyond. In other cases, fracing is conducted in uncased, open holes.

[0006] In the case of multistage fracing, multiple frac valve tools are used in a sequential order to frac sections of the formation, typically starting at a toe end of the wellbore and moving progressively towards a heel end of the wellbore.

[0007] Many configurations have been developed in the field to frac multiple stages of a formation. However, a need still exists for a fracing system that will ensure stimulation of the formation from a toe end to a heel end of the wellbore, while being simple in construction, small in size and effective at fracing formations in multiple stages

SUMMARY OF THE INVENTION

[0008] An activation tool is provided for use in a well isolation and stimulation string, said activation tool comprising a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat.

[0009] A first stage frac valve tool is also provided for use in a well stimulation string, said first stage frac valve tool comprising a stationary outer body and an internal piston movable between an closed and an open position.

[0010] A singular tool is further provided comprising a float shoe, an activation tool comprising a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner, stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat and integrally built with the float shoe and a first stage frac valve comprising a stationary outer body and an internal piston movable between an closed and an open position and integrally built with the activation tool.

[0011] A cased hole packer is further provided comprising an integral setting tool.

BRIEF DESCRIPTION OF DRAWINGS

[0012] FIG. **1** is a schematic diagram of a horizontal well fitted with the tools of the present invention;

[0013] FIG. **2** is a cross-sectional view of one example of the activation tool of the present invention, in various stages of use;

[0014] FIG. **3** is a cross sectional view of one example of the first stage frac valve tool of the present invention, in various stages of use;

[0015] FIG. **4** is a cross sectional view of one example of the cased hole packer of the present invention,

[0016] FIG. **5** is a cross sectional view of the cased hole packer of the present invention, showing a first means of deployment;

[0017] FIG. **6** is a cross sectional view of the cased hole packer of the present invention, showing a collet type latch seal assembly;

[0018] FIG. **7** is a cross-sectional view of a cased hole packer that may be deployed on the casing string;

[0019] FIG. **8** is a cross-sectional view of one example of a cased hole anchor of the present invention; and

[0020] FIG. **9** is a schematic diagram of dual horizontal liners drilled in one well.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

[0021] A series of tools is provided that improve on existing horizontal isolating and fracing tools, by providing increased safety during installation, reduced rig time and greater dependability of deploying the tools to the end of the horizontal section of the wellbore.

[0022] By combining both a slim outside diameter and short length, the present tools eliminate the need for handling pup joints, thereby reducing the rigidity of the liner. These features permit the more flexible, reduced outside diameter tool string to be deployed into the wellbore with greater ease.

[0023] The present invention consists of a series of tools strategically located along a liner and deployed into the open hole section of the wellbore. The tools provide a means of isolating various stages of the horizontal wellbore. After isolating various stages, stimulation fluid can be pumped from surface and through valve tools that are opened sequentially to thereby multi-stage frac the formation.

[0024] With reference to FIG. **1**, in a preferred method of deployment, the present system of tools comprises a cased hole packer **500** that anchors the liner and forms a seal between the casing string and the open hole. A float shoe or guide **50** is run at the toe of the liner. An activation tool **100** is placed a pre-determined distance from the guide shoe **50**. Next is a first stage frac valve tool **200**, and then an series comprising an open hole packer **300** alternated with one or more subsequent stage frac valve tools **400**. It would be well understood by a person of skill in the art that FIG. **1** merely represents one example of a tubular fracing string of tools and that additions, omissions and alterations to the illustrated string and its components can be made without departing from the scope of the present invention.

[0025] The float shoe **50** is preferably provided with an open end having a flap covering. The open end allows the liner pressure to be at least somewhat equalized with the formation pressure while the flap prevents ingress of formation fluids into the liner.

[0026] It would be understood by a person of skill in the art that any float shoe or similar device known in the art could be used with the tools of the present invention without departing from the scope thereof.

[0027] The activation tool **100**, as seen in FIG. **2** comprises an opening **102**. The one piece construction of the outer body **120** of the activation tool allows torque to be applied from the upper liner section, through the tool and into the liner to make up the liner string. The activation tool **100** can be lifted by hand and hand threaded onto the liner, which is typically gripped at the rig floor, and then a section of upper liner, typically gripped in an elevator or similar device, can be lowered onto the tool.

[0028] The opening **102** is open during deployment such that fluid can be circulated through the opening **102** when the liner is being run into the well, as seen in FIG. **2***a*. At a predetermined depth, a ball **104** is circulated down to the activation tool **100**, as seen in FIG. **2***b*, and prevents circulation through opening **102** and re-directs fluid into a chamber **106** formed between an activation tool inner body **118** and a sleeve **110**. The sleeve **110** comprises a first and a second diameter, D**1** and D**2** respectively. While D**1** is exposed to wellbore fluids and experiences wellbore pressures, D**2** is exposed to fluid pressure from within the liner. The product of the difference in these pressures and the difference in these diameters defines the force needed to displace sleeve **110** and move the activation tool **200** from an open (FIGS. **2***a*, **2***b*) to a closed position (FIG. **2***c*).

[0029] Pressure from the liner fluid serves to shears screws **108** that have been holding the sleeve **110** in the open position. The sleeve **110** then shifts and the opening **102** closes, blocking flow through the opening **102**. With fluid flow blocked in the liner, pressure increases to thereby trigger activation and setting of the open hole packers **300** and the cased hole packer **500**.

[0030] A number of seals **116** between the sleeve **110** and the activation tool inner body **118** guide this movement from open to closed.

[0031] Preferably, a collet **112** located on the sleeve **110** catches against an end of the activation tool inner body **118** when the sleeve **110** is in the closed position and prevents the sleeve **110** from shifting back to its original, open position. In its locked and set position, the activation tool **100** further advantageously serves as a redundant safety device to the float shoe **50**, ensuring that wellbore fluids do not enter the liner prior to fracing.

[0032] Advantageously, the opening **102** in the activation tool has been designed with minimum moving parts. The ball **104** and its corresponding seat **114** are entirely comprised of non-moving components, thereby eliminating the risk of creating a hydraulic lock, or locking of parts due to the presence of an incompressible fluid that has nowhere to be displaced to, below the opening **102**. Instead, the internal sleeve **110** shifts to close the opening **102** and is locked by means of the collet **112**, so that in the event that the ball **104** undesirably rolls off of the valve seat **114**, the opening **102** remains in the closed position.

[0033] The next tool in the present invention is the first stage frac valve tool **200**, depicted in FIGS. **3***a* and **3***b*. This is the frac valve through which the first stage of the stimulation is pumped to the toe of the wellbore. The present first stage frac valve tool **200** can be lifted by hand and hand threaded onto the liner, which is typically gripped at the rig floor, and then a section of upper liner, typically gripped in an elevator or similar device, can be lowered onto the tool.

[0034] Since the closing of the activation tool **100** prevents circulation of fluid, the first stage frac valve tool **200** relies solely on applied pressure to open. The opening pressure of the first stage frac valve tool **200** must be greater than the pack off pressure required to set the open hole packer **300** and cased hole packer **500**. Increasing liner fluid pressure acts on surface D**1** to apply pressure on piston **204**. The opening pressure of the first stage frac valve tool **200** is preferably controlled by the number of shear screws **202** installed into the piston **204**, although other known means of controlling opening pressure would also be understood by a person of skill in the art and encompassed by the present invention. At a pre-determined shear force, the shear screws **202** shear allowing the piston **204** to be shifted to the open position, as seen in FIG. **3***b*.

[0035] A pair of seals **206** between the piston **204** and the frac valve outer body **222** guide movement of the pistion **204** from closed to open. In the open position, ports **210** are opened to allow fluid to flow from inside the liner into the formation to thereby stimulate the adjacent formation.

[0036] A snap ring **208** preferably locks the piston **204** in the open position, although other known biasing means may also be used and would be well known to a person skilled in the art. Advantageously, the moving parts of the first stage frac valve tool **200** are all internal, meaning they do not have to overcome friction against the wellbore to shift from closed to open, allowing better control over the system.

[0037] A further advantage of the present first stage frac valve tool **200** is its ability to transmit torque. During installation torque can be transmitted through the first stage frac valve tool **200** from a joint above into the liner below in order to make up the threads. The internal body connection of the first stage frac valve tool **200** has been designed to handle torque greater than the make-up torque of the liner connections. The ability to transmit torque, combined with its short size, eliminate the need for handling joints that would need to be torqued on both ends of the first stage frac valve tool **200**.

[0038] Preferably, the geometry of the fracture ports **210** provides easy identification for the first stage frac valve tool **200**, thereby reducing the potential for incorrect placement in the liner string. The unique geometry of the fracture ports **210** differentiates the appearance of the first stage frac valve tool **200** from other similar looking valves installed on the liner. Ports **210** may also preferably be sized to reduce or prevent ingress of wellbore debris into the liner.

[0039] In a further preferred embodiment of the present invention a singular tool (not shown) comprising a float shoe **50** /activation tool **100** /first stage frac valve tool **200** can be used to replace individual float shoe **50**, activation tool **100** and first stage frac valve tool **200** with liner joints connecting them. Advantageously, the singular combination tool (not shown) requires less threaded connections, thereby reducing potential leak paths and decreases rig time since only one threaded connection needs to be torqued on the rig floor. The singular combination tool (not shown) also ensures that the fracture ports **210** of the first stage frac tool **200** are as close to the toe of the well as possible.

[0040] When the first stage frac valve tool **200** opens, the formation is immediately exposed to high pressure liner fluid. In an alternative embodiment, the first stage frac valve tool **200** may be configured such that a high fluid pressure is required to unlock the piston **204**, then a second surge of low pressure serves to open the fracture ports **210**. This embodiment of the first stage frac valve tool **100** can be used to protect sensitive formations from excessive pressures.

[0041] The next tools installed onto the liner are a series of one or more open hole packers **300** and a frac valve tools **400**. The open hole packers **300** are preferably single element open hole packers **300**.

[0042] The next element of the present invention is the cased hole packer **500**, which is run at the top of the liner, and is illustrated in FIG. **4**. The cased hole packer **500** is a hydraulically set, preferably permanent packer with a tie back receptacle **502** and is used to anchor the liner into the casing string and provide a seal between the top of the liner and the casing string.

[0043] Many prior art cased hole packers require a setting tool that is separate to the cased hole packer and used to set the packer against the casing string. To accommodate such cased hold packer and setting tool, the tool must be run on drill pipe, which is narrower than a typical frac string and therefore provides sufficient room between the drill pipe outer diameter (OD) and the casing string to accommodate the setting tool. Once deployed, the setting tool and drill pipe are then typically pulled out and a frac string is deployed to proceed with the fracing operating.

[0044] The present cased hole packer **500** advantageously incorporates an integral setting tool in the form of slips **504** to activate the cased hole packer **500**. The slips **504** do not extend beyond the OD of the cased hole packer **500** and require no additional space. Thus the present cased hole packer **500** and other present tools can be run on a frac string, without the need to run a drill string and then change out to a frac string, saving time during operation. It would be well understood by a person of skill in the art that the present cased hole packer **500** can also be deployed on drill string and any number of means can be used to accommodate this smaller diameter pipe.

[0045] The opposing slips **504** serve to anchor the cased hole packer **500** to the casing string in both tension and compression due to wickers formed on an outer surface thereof that act to engage the casing string inside diameter when the cased hole packer **500** is set.

[0046] After the liner has been deployed, the cased hole packer **500** is set by pressure buildup in the liner due to activation of the activation tool **100**. A setting piston **534** on the cased hole packer mandrel **530** comprises a first and a second diameter, D**1** and D**2** respectively. While D**1** is exposed to wellbore fluids and experiences wellbore pressures, D**2** is exposed to fluid pressure from within the liner. The product of the difference in these pressures and the difference in these diameters defines the force needed to displace setting piston **534** and move the cased hole packer **500** from an unset to a set position. A pair of seals **516** between the setting piston **534** and the mandrel body **530** guide this movement from unset to set. Upon movement of the setting piston **534** triggers movement of the opposing slips **504** against a pair of upper and lower cones **520**, that in turn presses against the packing element **522** causing packing element **522** to protrude into the wellbore until it comes in to sealing contact with the casing string inside diameter (ID). The cased hole packer **500** is held in place and prevented from unsetting by a ratchet ring **528**.

[0047] The packing element **522** is comprised of a solid band of flexible material having a thickness such that an outer surface of the packing element **522** in its unset position sits flush with an outer surface of the upper and lower cones **520**. Suitable materials for the packing element include any number of fluorocarbons and per-flourocarbons such as AFLAS™, HNBR, and Viton™, although it would be understood by a person of skill in the art that any flexible material showing resiliency and sufficient strength to maintain packing against wellbore fluid pressure would be suitable for the purposes of the present invention.

[0048] In a preferred embodiment, the packing element **522** is thinner at its axial midpoint than everywhere else. More preferably, the packing element **522** is formed with a circumferential groove **540** of predetermined width and depth around its inner surface at the axial midpoint, such groove **540** creating a thinner middle portion of the packing element **522**. The groove **540** ensures that the packing element **522** protrudes from its axial midpoint, thereby providing even contact with the wellbore and a positive seal. In a further preferred embodiment, a packing element ring **542** is provided on the mandrel **530** onto which the packing element groove **540** sits. The packing element ring **542** fills in the void of the groove **540** and ensures that the midpoint of the packing element **522** protrudes outwards upon actuation, and does not fold inwardly into itself.

[0049] One or more anti-extrusion expandable rings **524** hold the packing element **522** in place and press against the packing element **522** in actuation.

[0050] More preferably, the anti-extrusion rings **524** are positioned between backup rings **544** and the upper and lower cones **520** respectively.

[0051] The backup rings **544** are preferably shaped to allow an end of the upper and lower cones **520** to travel along and wedge into one contour of the backup ring **544** while allowing the anti-extrusion ring **524** to travel along and wedge between the upper and lower cones **520** and another contour of the backup ring **544** at each end of the packing element **522**. Such wedging prevents the packing element **522** from extruding internally and prevents packing element creep during high differential pressures and helps centralize the cased hole packer **500** while setting.

[0052] The use of the present anti-extrusion rings **524** creates a barrier around the packing element **522** after the cased hole packer **500** is set. Without this barrier the packing element **522** would not be able to maintain a seal at high differential pressures inside the casing.

[0053] A ratchet ring **528** is located between the mandrel body **530** and the setting piston **534** that serves to prevent the piston **534** from backing off from a set position, thus ensure that the packing element **522** remains in a set position once set.

[0054] In the present cased hole packer **500** the ratchet ring **528** is preferably comprised of a split ring with an inner surface ratchet profile and an outer surface ratchet profile. Preferably the inner surface ratchet profile is finer than the outer surface ratchet profile.

[0055] The ratchet ring **528** is first assembled onto the mandrel **530** of the cased hole packer **500**, at least a part of the outer surface of the mandrel **530** having a ratchet profile that mates with the inner surface ratchet profile of the ratchet ring **528**. Preferably the ratchet ring **528** is assembled over one or more spring pins **546** installed on the mandrel **530** to maintain the position and alignment of the ratchet ring **528**. A locking body thread **532** formed on an inner surface of at least part of the setting piston **534** is then installed over the ratchet ring **528**. Preferably, the locking body thread **532** mates with the outer surface ratchet profile of the ratchet ring **528**.

[0056] Orientation of the inner surface ratchet profiles of the ratchet ring **528** allow the setting piston **534** and ratchet ring **528** to travel from unset to set position along the mandrel body **530**, while preventing the setting piston **534** and ratchet ring **528** from sliding back to an unset direction from a set position. Orientation of the outer surface ratchet profile of the ratchet ring **528** allows the setting piston **534** to slide over the outer surface of the ratchet ring **528** when it is being installed onto the ratchet ring **528**. Once the locking body thread **532** and the outer surface ratchet profile of the ratchet ring **528** mate, these mating profiles lock the ratchet ring **528** to the setting piston **534** when the setting piston **534** moves from an unset to a set position.

[0057] The ratchet ring **528** and setting piston **534** have a larger ID than the mandrel body **530** OD, thereby being able to be installed on the mandrel **530** without having to split the locking body **532** from the setting piston **534**.

[0058] The tie back receptacle **502**, illustrated in more detail in FIG. **5**, acts as a sealing interface and latching mechanism between the liner and drill string, should a drill string be used in deployment, and as a sealing interface and latching mechanism between the liner and frac string during stimulation.

[0059] In a preferred embodiment, the cased hole packer **500** may also comprise one or more grooves (not shown) machined circumferentially around the O.D. of the cased hole packer **500**. The grooves can receive a clamp to permit shop pressure testing of the cased hole packer **500** to high pressures to verify correct assembly. The clamp prohibits the cased hole packer **500** from setting, while testing the integrity of the tool's internal seals.

[0060] The present cased hole packer can be deployed using three different deployment methods. In a first embodiment, the cased hole packer **500** can be attached to a jay type latch seal assembly **506**, illustrated in FIG. **5**. The latch seal assembly **506** is used to connect and seal the liner to the drill string, if a drill string is used, during deployment. The latch seal assembly **506** will have an upper thread **508** compatible with the thread on the drill string. It also has an anchoring mechanism **510** compatible with the tie back receptacle **502** that serves to anchor it to the packer. Seals **512** located on the latch seal assembly **506** engage matching seal bore located on the tie back receptacle **502** to prevent fluid leak between the tie back receptacle **502** and the latch seal assembly **506**. In a situation where the latch seal assembly **506** used directly with the frac string, and where no drill string need first be deployed, an upper thread **508** is sized to be compatible with the threads on the frac string.

[0061] The jay type latch seal assembly **506** is preferably full bore with an ID matching the liner I.D., and no restrictions in the mandrel **514** of the latch seal assembly **506**. Shear screws **518** installed prior to deployment ensure that the liner and cased hole packer **500** cannot disengage from the drill/frac string prematurely. The shear screws **518** are installed through the tie back receptacle **502** and engage a profile machined on the outer surface of the jay type latch seal assembly **506**. Torque is required to break these shear screws **518**. Although the current design of the jay type latch seal assembly is illustrated as having an anchoring mechanism in the form of three jay pins, it could instead have two or more jay pins, and such embodiments are encompassed by the scope of the present invention. Preferably the seals **512** are bonded seals, although other seal configurations could be used instead, including polypak type seals, o-rings or v-seals. The seal design on the latch seal assembly **506** allows the latch to be removed under differential pressure, thus eliminating seal damage.

[0062] A second deployment method that can be used with the cased hole packer **500** is depicted in FIG. **6**, which uses a collet type latch **536**, to deploy the liner and frac string. The collet type latch seal assembly **536** has flexible fingers that can deflect and allow the seal assembly to be stabbed into the receptacle. The flexible collet latch **536** can preferably comprise a tread profile machined on its external surface that matches a similar thread profile machined on the I.D. of the receptacle. The collet type latch seal assembly **536** can preferably be removed from the receptacle by rotating the work string clockwise while picking up, which serves to screw the collet type latch **536** out of the receptacle.

[0063] A third deployment method that can be used with the cased hole packer **500** is depicted in FIG. **7**, in the form of a casing string **538** screwed directly into top of cased hole packer **500**. In this case, the casing string is used for both deployment and fracturing and the casing string is not retrieved when the process is complete.

[0064] In one example of operation of the tools of the present invention, a liner is assembled with the following components, as illustrated in FIG. **1**: a float shoe **50**, the present activation tool **100**, a liner, the present first stage frac valve tool **200**, and then a series comprising a liner, an open hole packer **300**, a liner and a frac valve **400**. Optionally, an open hole anchor **600** may be used between the activation tool **100** and the first stage frac valve tool **200** to anchor the liner to the wellbore. Alternative to an open hole anchor **600** centralizers, stabilizers or other suitable means known in the art may also be used for this purpose.

[0065] Preferably up to 40 frac valves **400**, on a 4½" liner for example, separated with open hole packer **300***s* can be used in a string. A cased hole packer **500** is attached to the upper end of the casing. A latch seal assembly **506**, collet type latch **536** or other known means can be used to attach the cased hole packer **500** to the casing.

[0066] The liner is run into the conditioned bore hole by a drill string or on a frac string. At a predetermined depth, ball **104** is circulated down to the activation tool **100** to stop fluid flow. Pressure increase, thereby setting both the cased hole packer **500** and the open hole packers **300**. A pressure test may optionally be performed inside the casing to determine if the cased hole packer **500** has set properly. If the liner was run on a drill string, the latch seal assembly **506**, collet type latch **536** or other connection means can next be removed from the cased hole packer **500** and the drill string and connecting means are removed from the well and a frac string and associated connecting means are deployed. Otherwise, if the liner was run downhole on a frac string, no replacement has to be made.

[0067] Further pressure is applied to the frac string. At a pre-determined setting pressure that is higher than the pack off pressure of the open hole packers **300** and cased hole packer **500**, the first stage frac valve tool **200** shifts to the open position and stimulation fluid is pumped into the formation to stimulate the formation from the toe of the wellbore to the first stage frac valve tool **200**. Proppant is then pumped into the fracture. Next subsequent frac valve tools **400**, starting with that closest to the first stage frac valve tool **200**, are activated to thereby open communication between the inside of the liner and the isolated section of the formation between the two open hole packer **300** straddling the particular frac valve **400**.

[0068] The stimulation fluid pumped through the ports of the frac valve **400** fractures the exposed formation between the open hole packers **300** used to isolate that stage. Whenever this stage has been fractured, a next frac valve **400** is activated and the process is repeated. The process can be repeated up to 40 times in total in a 4½" liner, for example. Other sizes of liners can have a different number of frac valve tools **400** and open hole packers **300**. When all the desired stages have been fractured, the well is allowed to flow and formation pressure from formation fluid flow acts to deactivate the frac valves **400** and allows formation fluid flow into the liner. Afterwards the frac string and connecting means can be removed from the well.

[0069] In the case of ball drop activated frac valve tools **400**, if desired, the seats of the frac valves **400** can be drilled out at a later date.

[0070] In the event the operator needs to set the liner in an open hole, an open hole anchor **600**, illustrated in FIG. **8** can replace the cased hole packer **500**. This scenario can exist whenever dual horizontals are drilled in one well, as seen in FIG. **9**. The hydraulic set open hole anchor **600** is full bore. It is run in conjunction with an open hole packer **300** and tie back receptacle (not shown) to act as a means to seal and anchor the liner in the open hole. The tieback receptacle provides a means to deploy the liner then act as a means to seal and anchor the fracture string to the liner.

[0071] The open hole anchor **600** is preferably full bore with no mandrel restrictions and has the same I.D. as the liner. Preferably it is operated with slips **602** to anchor the liner to the formation. More preferably the open hole anchor **600** employs a similar setting piston and ratchet configurations of the cased hole packer **500**.

[0072] Preferably, after the bore hole has been drilled and before the liner is installed, a reamer trip is performed. The present reamer has a unique design to mimic the geometry of the stiffest components on the liner string. The present reamer has one set of blades instead of multiple sets and its reduced O.D. and short length enable it to be deployed and retrieved quickly while still ensuring the bore hole has no obstructions to impede running the liner with the present suite of fracturing tools. The reamer preferably has a small O.D. and a short length to mimic the geometry of the present tools of the frac string illustrated in FIG. **1**. The geometry of the reamer permit ease of deployment and in some circumstances allows the reamer to trave to the toe end of the frac string without needing to ream any tight spots in the wellbore. This reduces rig time while ensuring that the present frac tools can be deployed into the wellbore.

[0073] In the foregoing specification, the invention has been described with specific embodiments thereof; however, it will be evident that various modifications and changes may be made thereto without departing from the broader spirit and scope of the invention.

1. An activation tool for use in a well isolation and stimulation string, said activation tool comprising:

a. a stationary seat for receiving a ball deployed down the string;

b. a stationary inner body;

c. a stationary outer body; and

d. a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat.

2. The activation tool of claim **1**, wherein deployment of the ball onto the seat prevents circulation of liner fluid through the activation tool and re-directs fluid into a chamber formed between the stationary inner body and the moving sleeve, said fluid acting to move the sleeve.

3. The activation tool of claim **2**, further comprising one or more shears screws affixing the stationary inner body to the moving sleeve, said shear screws being shearable at a predetermined liner fluid accumulated in the tool when the ball lands on the seat, wherein shearing of said one or more shear screws allows the moving sleeve to shift to the closed position.

4. The activation tool of claim **1**, further comprising a collet connected to the moving sleeve to prevent retreat of the moving sleeve back to the open position from the set position.

5. A first stage frac valve tool for use in a well stimulation string, said first stage frac valve tool comprising:

a. a stationary outer body; and

b. an internal piston movable between an closed and an open position.

6. The first stage frac valve tool of claim **5**, wherein said tool is torqueable to torque values greater than those needed to make up the stimulation string.

7. The first stage frac valve tool of claim **5**, further comprising one or more ports formed on the stationary outer body, said ports openable when the piston moves to the open position, to allow fluid to flow from inside the liner into a formation to be stimulated.

8. The first stage frac valve tool of claim **7**, wherein the internal piston is moveable at a predetermined liner fluid pressure.

9. The first stage frac valve tool of claim **8**, wherein liner pressure required to move the internal piston is greater than pack off pressure of one or more packers on the stimulation string.

10. The first stage frac valve of claim **9**, further comprising one or more shear screws affixing the sleeve to the tool, said shear screws being shearable at the predetermined liner pressure to allow the internal piston to shift to the open position.

11. The first stage frac valve tool of claim **10**, wherein the one or more shear screws are shearable at a first liner fluid pressure and the internal piston is movable at a second liner fluid pressure, wherein the first liner fluid pressure is greater than the second liner fluid pressure.

12. The first stage frac valve tool of claim **5**, further comprising biasing means connected to the internal moveable piston to prevent retreat of the piston back to the closed position from the open position.

13. The first stage frac valve tool of claim **12**, wherein the biasing means comprises a snap ring.

14. The first stage frac valve tool of claim **7**, wherein the geometry of the one or more ports differentiates the appearance of the first stage frac valve tool from other valves installed on the liner.

15. The first stage frac valve tool of claim **7**, wherein the one or more ports are sized to reduce ingress of wellbore debris into the liner.

16. A singular tool comprising:

a. a float shoe;

b. an activation tool as described in claim **1** and integrally built with the float shoe; and

c. a first stage frac valve as described in claim **5** and integrally built with the activation tool.

17. A cased hole packer comprising an integral setting tool.

18. The cased hole packer of claim **17**, wherein the integral setting tool comprises one or more slips to activate the cased hole packer, wherein said slips are flush with an outside diameter of the cased hole packer.

19. The cased hole packer of claim **18**, wherein the slips further comprise wickers formed on an outer surface of the slips, said ratchets engagable to a casing string inside diameter when the cased hole packer is set.

20. The cased hole packer of claim **19**, further comprising a setting piston, moveable to set the cased hole packer from an unset to a set position.

21. The cased hole packer of claim **17**, comprising a ratchet ring assembled on a mandrel body of the cased hole packer.

22. The cased hole packer of claim **21**, wherein a piston is assembled overtop of the ratchet ring and mandrel body.

23. The cased hole packer of claim **22**, wherein the setting piston comprises an integral locking body thread formed on an inner surface of at least a portion of the setting piston.

24. The cased hole packer of claim **23**, wherein the ratchet ring comprises an inner surface ratchet profile that mates with a ratchet profile provided on at least part of the outer surface of the mandrel body and further comprises on outer surface ratchet profile that mates with the locking body thread.

25. The cased hole packer of claim **24**, wherein orientation of the inner surface ratchet profile allows movement of the setting piston and ratchet ring along the mandrel body from an unset to a set position.

26. The cased hole packer of claim **24**, wherein orientation of the outer surface ratchet profile allows assembly of the piston over the outer surface of the ratchet ring and serves to lock the ratchet ring to the setting piston during movement of the piston and ratchet ring from an unset to a set position.

27. The cased hole packer of claim **21**, wherein the ratchet ring is assembled onto the mandrel body over one or more spring pins installed on the mandrel.

28. The cased hole packer of claim **17**, comprising one or more anti-extrusion rings that remain flush with an outer surface of the open hole packer when the packer is unset.

29. The cased hole packer of claim **28**, wherein the one or more anti-extrusion rings comprises two anti-extrusion rings, one on either side of a packing element of the cased hole packer, that serve to abut against the packing element in actuation.

30. The cased hole packer of claim **29**, further comprising a backup rings positioned between each of the anti-extrusion rings and the packing element.

31. The cased hole packer of claim **30**, wherein interaction of the one or more anti-rotation rings with their corresponding backup rings serves to prevent the single packing element from extruding internally and creeping.

32. The cased hole packer of claim **31**, wherein the backup rings comprise a first contour into which upper and lower cones of the setting piston are engageable and comprise a second contour into which the anti-extrusion rings are engageable.

33. The cased hole packer of claim **17**, comprising a single hydraulic packing element.

34. The cased hole packer of claim **33**, wherein said single hydraulic packing element protrudes from an axial midpoint of said element when the packer is set.

35. The cased hole packer of claim **34**, wherein the single packing element is thinner at its axial midpoint than at any other axial point on the single packing element.

36. The cased hole packer of claim **35**, wherein the packing element is formed with a circumferential groove of predetermined width and depth around its inner surface at the axial midpoint.

37. The cased hole packer of claim **36**, further comprising a packing element ring on the mandrel body onto which the packing element groove sits.

38. The cased hole packer of claim **17**, wherein the cased hole packer is deployed in a work string by use of a tie back receptacle.

39. The cased hole packer of claim **38**, wherein the work string is selected from the group consisting of a drill string and a frac string.

40. The cased hole packer of claim **17**, further comprising one or more grooves formed circumferentially around the cased hole packer, to receive a pressure test clamp, said clamp allowing pressure testing of the cased hole packer while preventing setting of the cased hole packer.

41. The cased hole packer of claim **17**, wherein the cased hole packer is attached to a jay type latch seal assembly for deployment on a work string.

42. The cased hole packer of claim **17**, wherein the cased hole packer is attached to a collet type latch seal assembly for deployment on a work string.

43. The cased hole packer of claim **17**, wherein the cased hole packer is threaded directly to a work string.

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