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An agency of Industry Canada

CA 2787814 A1 2014/02/21

(21) 2 787 814

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2012/08/21

(41) Mise à la disp. pub./Open to Public Insp.: 2014/02/21

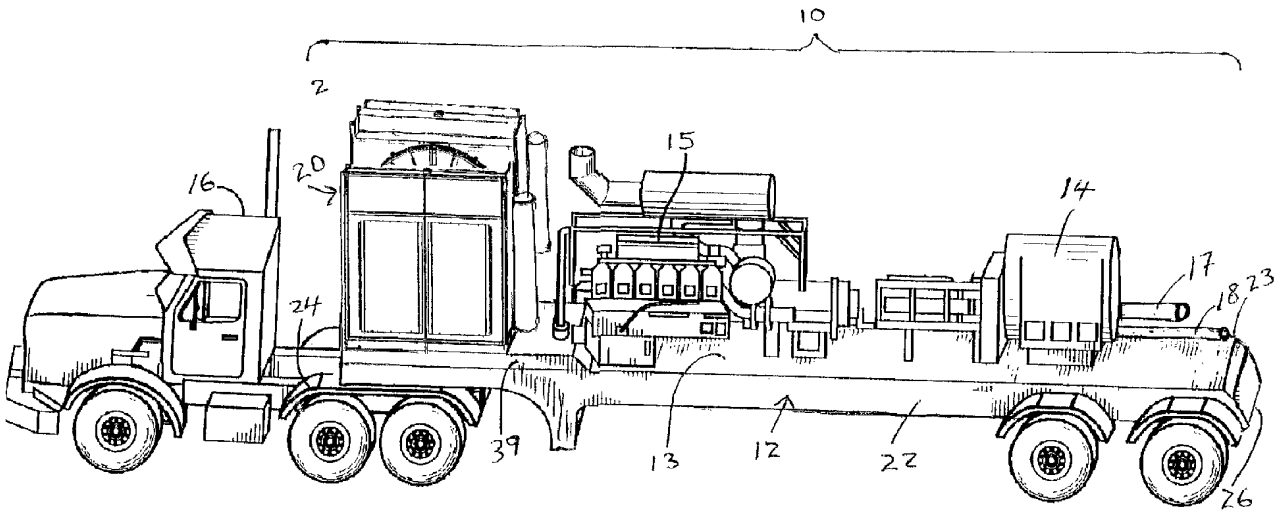
(51) Cl.Int./Int.Cl. *B60K 11/04* (2006.01),
E21B 43/26 (2006.01)

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(54) Titre : CONFIGURATION DE RADIATEUR
(54) Title: RADIATOR CONFIGURATION



(57) Abrégé/Abstract:
A modular mobile fract pump unit having for a radiator with a heat exchanger vertically for generally horizontal flow of air through the radiator and a duct provided on an air exit side of the heat exchanger to direct air exiting the heat exchanger upwardly. Preferably, the duct comprises a retractable duct for movement between an operative position for use in parked cooling operation and a storage position for transport of the unit as a road worthy vehicle, within the storage position the duct not increasing the overall width of the unit and in the operative position the duct extending laterally to the side of the unit beyond the storage position and increasing the overall width of the unit.

ABSTRACT

A modular mobile fract pump unit having for a radiator with a heat exchanger vertically for generally horizontal flow of air through the radiator and a duct provided on an air exit side of the heat exchanger to direct air exiting the heat exchanger upwardly. Preferably, the duct comprises a retractable duct for movement between an operative position for use in parked cooling operation and a storage position for transport of the unit as a road worthy vehicle, within the storage position the duct not increasing the overall width of the unit and in the operative position the duct extending laterally to the side of the unit beyond the storage position and increasing the overall width of the unit.

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Title

RADIATOR CONFIGURATION

Scope of the Invention

[0001] This invention relates to modular fractoring pump units each comprising a road vehicle carrying a pump, an engine to drive the pump and radiators to cool the engine; and more particularly to a radiator configuration and arrangement for mounting the radiator on the road vehicle to permit advantageous cooling of the engine when a plurality of these road vehicles are parked side to side closely together in an array.

Background of the Invention

[0002] Hydraulic fractoring is known as, for example, disclosed in U.S. Patent 7,063,147 to Siebrits et al, issued June 20, 2006 and U.S. Patent 7,788,037 to Soliman, issued August 31, 2010. U.S. Patent 7,845,413 to Shampine, issued December 7, 2010, the disclosure of which is incorporated herein by reference, teaches a typical manner of providing a plurality modular fract pumping units coupled together.

[0003] Hydraulic fractoring is a known process which requires heavy duty pumps known as fract or fractoring pumps which typically comprise high pressure pumps operating on typically diesel generators generating in the range of 2000 horsepower. A large number of such pumps are generally provided in an array to provide the necessary high pressure and large volume of fluids required for hydraulic fractoring at a remote location. The pumps are known to be provided as part of a modular mobile fract pump unit comprising a road compatible vehicle such as a customized flat bed trailer on which there is mounted the pump, an internal combustion engine to drive the pump and a radiator to cool the engine. The trailers of each unit are typically parked close together in an array side by side with the pump and a typically rigid discharge outlet for the pump at a rear end of the unit and the radiator at a front end of the unit. A central manifold can be provided for coupling of the rigid discharge outlet of each modular mobile fract pump unit at set spaced locations along a central manifold trunk moved towards or away from the manifold trunk. Each modular mobile fract pump unit when accurately located relative the manifold trunk can independently be coupled to the manifold or removed for replacement. The manifold trunk establishes a set spacing of the

trailers of the units in the array side by side as, for example, on 11.5 foot (138 inches) centers. For the modular mobile fract pump unit to be road worthy on Interstate highways in the USA, the unit preferably has a width not greater than 8.5 feet (102 inches.). With, for example, 11.5 foot centers for the pump discharge outlets, this provides for a 3 feet (36 inch) spacing between the sides of adjacent side by side units.

[0004] The internal combustion engine on each mobile fract pump unit typically is a diesel engine. Each diesel engine requires a large radiator to cool the engine. Known radiator structures often provide for two heat exchangers. Prior art devices such as the fractoring system shown in U.S. Patent 7,845,413 to Shampine illustrate horizontally disposed radiators for air flow vertically therethrough. The horizontally disposed radiators extend horizontally for air flow vertically therethrough with the air to pass firstly upwardly through a lower heat exchanger and then secondly upwardly through an upper heat exchanger above the lower heat exchanger. This stacked upper and lower heating exchanger configuration has been selected typically to provide the cooling requirements for the engine within the maximum width for the vehicle unit to be road worthy on Interstate highways in the USA. The stacked upper and lower heating exchanger configuration has the disadvantage that atmospheric air is heated by passing through the lower heat exchanger before the heated air flows upwardly through the second heat exchanger, thus reducing the cooling capacity of the second heat exchanger. As well, the stacked upper and lower heating exchanger arrangement renders it different to clean each heat exchanger after use.

Background of the Invention

[0005] To at least partially overcome these disadvantages of previously known devices, the present invention provides a modular mobile fract pump unit having for a radiator with a heat exchanger vertically for generally horizontal flow of air through the radiator and a duct provided on an air exit side of the heat exchanger to direct air exiting the heat exchanger upwardly. Preferably, the duct comprises a retractable duct for movement between an operative position for use in parked cooling operation and a storage position for transport of the unit as a road worthy vehicle, within the storage position the duct not increasing the overall width of the unit and in the operative position the duct extending laterally to the side

of the unit beyond the storage position and increasing the overall width of the unit. Preferably, the duct is provided with cleaning access doors opening therethrough which can be opened to access the radiator for cleaning. Preferably, a pair of radiators are provided, one along on each side of the vehicle, with the ducts opening outwardly.

[0006] Preferably, a roof member may be provided to bridge laterally between two radiators proximate the top of the radiators. A fan is provided on the interior of each radiator to direct flow laterally outwardly through each radiator. With the roof member in place, the roof member requires air to be passed through the radiators to be drawn laterally from the front or rear or below the radiators reducing the likelihood that heated air discharged vertically from each duct may be drawn down into the fan and passed again through the radiator.

[0007] Vehicles carrying radiators in accordance with the present invention can be parked relatively close together side by side as, for example, within three feet of each other in which the case the ducts would extend to one side, about eighteen inches so that the ducts effectively meet.

[0008] As the radiators preferably have a substantial height and size, to provide for manual closing of the ducts, an arrangement is provided which permits a person on the ground to open and close the radiators avoiding the need to climb the unit and dangers associated therewith. Access doors are provided laterally of the unit through each duct which, preferably when each duct is in a closed position, can be opened by a person on the ground to facilitate the radiators being cleaned as in a known manner by the passage of water through the heat exchangers.

[0009] In one aspect, the present invention provides a modular mobile pump unit comprising:

an elongate mobile trailer having a first side, a second side, a front and a rear,

the trailer having a longitudinal centerline between the first side and the second side,

the trailer having mounted thereon a pump to dispense a fluid, an internal combustion engine to power the pump, a first air cooled radiator to cool the engine and a second air cooled radiator to cool the engine,

the first radiator comprising a vertically extending first heat exchanger for passage of air horizontally therethrough to cool a fluid from the engine circulated within the first heat exchanger and a first fan to blow atmospheric air through the first heat exchanger,

the first radiator mounted to the trailer on the first side of the longitudinal center line proximate the first side with the first heat exchanger adjacent the first side and with the first fan laterally inwardly of the first heat exchanger, the first fan providing for passage of air through the first heat exchanger horizontally and laterally outwardly toward the first side of the trailer,

the first radiator having a first duct member carried on the first radiator at a location laterally outwardly of the first heat exchanger and in the flow path of air from the first fan exiting horizontally and laterally from the first heat exchanger,

the first duct member movable relative to the first radiator from a storage position in which the first duct member does not extend laterally outwardly beyond the first side of the trailer and an operative position in which the first duct member extends laterally outwardly beyond the first side of the trailer,

in the operative position the first duct member receiving air passing laterally from the first heat exchanger and directing this air to exit vertically upwardly from a first duct outlet disposed along an upper edge of the first duct member,

the second radiator comprising a vertically extending second heat exchanger for passage of air horizontally therethrough to cool a fluid from the engine circulated within the second heat exchanger and a second fan to blow atmospheric air through the second heat exchanger,

the second radiator mounted to the trailer directly opposite the first radiator on the second side of the longitudinal center line proximate the second side with the second heat exchanger adjacent the second side and with the second fan laterally inwardly of the second heat exchanger, the second fan providing for passage of air through the second heat exchanger horizontally and laterally outwardly toward the second side of the trailer,

the second radiator having a second duct member carried on the second radiator at a location laterally outwardly of the second heat exchanger and in the flow path of air from the second fan exiting horizontally and laterally from the second heat exchanger,

the second duct member movable relative to the second radiator from a storage position in which the second duct member does not extend laterally outwardly beyond the second side of the trailer and an operative position in which the second duct member extends laterally outwardly beyond the second side of the trailer,

in the operative position the second duct member receiving air passing laterally from the second heat exchanger and directing this air to exit vertically upwardly from a second duct outlet disposed along an upper edge of the second duct member. Preferably, the invention provides an array of such units wherein the units are arranged side by side with a spacing between adjacent units at least equal to a spacing distance represented by the sum of a distance that the first duct member in the operative position extends beyond the first side of the trailer and a distance that the second duct member in the operative position extends beyond the second side of the trailer.

Brief Description of the Drawings

[0010] Further aspects and advantages of the present invention will become apparent from the following description taken together with the accompanying drawings in which:

[0011] Figure 1 is a perspective rear view of a modular mobile pump unit in accordance with the present invention in conjunction with a tractor;

[0012] Figure 2 is a schematic front perspective view of a skid platform and the radiators shown in Figure 1 in a storage position;

[0013] Figure 3 is a front view of Figure 2;

[0014] Figure 4 is a schematic front perspective view the same as Figure 2 but showing the radiators in an operative position;

[0015] Figure 5 is a front view of Figure 4;

[0016] Figure 6 is a schematic cross-sectional front view along section line 6-6′ in Figure 4 showing the right hand side radiator;

[0017] Figure 7 is a schematic perspective view illustrating a mechanism for movement of the duct member between the storage position and the operative position;

[0018] Figure 8 is a perspective view the same as Figure 2 but showing access doors in an open position;

[0019] Figure 9 is a schematic top view showing a plurality of units in accordance with Figure 1 arranged in two rows, one on either side of a central manifold;

[0020] Figure 10 is an enlarged view of the front portions of three of the units shown in Figure 9 showing the units as being spaced an equal distance apart; and

[0021] Figure 11 is a perspective view the same as Figure 4 but additionally showing a roof baffle.

Detailed Description of the Drawings

[0022] Figure 1 shows a modular pump mobile unit 10 in accordance with the present invention. The mobile 10 comprises a standard trailer 12, a fluid pump 14, a diesel motor 15 that drives the pump 14 and a pair of radiators 20 and 21 for cooling the diesel motor 15. The trailer 12 is removably coupled to a tractor 16 for ease of transportation. The pump 14 has a intake pipe 17 for receiving fluid at a low pressure and a discharge pipe 18 for discharging fluid at a high pressure.

[0023] The unit 10 and the trailer 12 have a first side 22, a second parallel side 23, a front 24 and a rear 26. As seen in Figure 10, the unit 10 and the trailer 12 have a longitudinal center line 27 which extends longitudinally of the unit 10 and the trailer 12 between the first side 22 and the second side 23.

[0024] Referring to Figure 9, an array of mobile modular units 10 is arranged on opposite sides of a fluid manifold 30. The manifold 30 extends along a manifold longitudinal 31. The manifold includes a low pressure liquid line 32 and a high pressure discharge line 34. The intake pipe 17 from each unit 10 is adapted to be removably coupled to a corresponding outlet pipe 35 of the low pressure liquid line 32 and the discharge pipe 18 of each unit 10 is adapted to be removably coupled to a corresponding inlet pipe 36 of the high pressure discharge line 34. The low pressure liquid line 32 has the outlet pipe 35 located at equally spaced fixed distances along the longitudinal 31 of the manifold. The high pressure discharge

line 34 has the inlet pipes 36 located at correspondingly spaced fixed distances along the longitudinal 31 of the manifold 30. Each inlet pipe 36 includes a valve 37 and each outlet pipe includes a valve 38 to selectively independently permit or prevent flow. Each unit 10 is preferably located with its longitudinal center line 27 perpendicular to the longitudinal 31 of the manifold 30. Each mobile unit 10 may be disconnected from the manifold 30 and independently moved forwardly or rearwardly for replacement by another modular unit 10.

[0025] As can be seen in Figure 1, the trailer 12 has a deck 13 including a skid portion 39 upon which the radiators 20 and 21 are schematically shown as being mounted. For ease of illustration, in each of Figures 2 to 5, the radiators are shown as mounted on the skid 39 without illustrating other components of the unit 10.

[0026] Reference is made to Figure 6 which is a schematic cross-sectional view along section line 6-6′ of the first radiator 20. The first radiator 20 has a first heat exchanger 40. The first heat exchanger 40 includes a top header 41 and a bottom header 42 with a core 90 of vertically extending cooling tubes 43 extending vertically between the top header 41 and the bottom header 42. A fluid inlet 44 delivers fluid from the cooling system of the motor 15 to the bottom header 42. A fluid outlet 45 is connected to the top header 41 and delivers cooled fluid from the top header 41 back to the cooling system of the motor 15. Thus, cooling fluid from the motor 15 is to be circulated in a cooling circuit, only part of which is shown, to pass from the fluid inlet 44 into the bottom header 42 vertically through the cooling tubes 43 to the top header 41 and then out the fluid outlet 45 to return to the engine. As will be appreciated, a suitable circulating pump (not shown) is provided to circulate the cooling fluid through the first heat exchanger 40.

[0027] The first radiator 20 includes a system for passing atmospheric air through the core of the first heat exchanger past the cooling tubes 43 so as to reduce the temperature of the cooling fluid circulated through the cooling tubes 43. In this regard, as schematically shown in Figure 6, a fan 46 is rotatable about a horizontal fan axis 47 within a cylindrical fan casing 48 so as to draw atmospheric air inwardly through openings 49 in the fan casing and force the air horizontally and laterally outwardly through the core 90 and past the cooling tubes 43. As seen in Figure 6, the fan 46 directs air flow laterally outwardly in a direction

from the longitudinal center line 27 laterally outwardly toward the first side 22. In this regard, the first heat exchanger 40 may be considered to have an air inlet opening 50 on the laterally inward side of the cooling tubes 43 and an air outlet opening 51 on a radially outwardly side of the cooling tubes 43.

[0028] The first radiator 20 has a first duct member 52 which in Figure 6 is illustrated as being in an operative position permitting air flow from the fan 46 laterally outwardly through the air outlet opening 51 and then upwardly through the duct member 52 to exit upwardly through a first duct outlet 54 open to the atmosphere. As seen in Figure 6, the first duct outlet 54 is disposed along an upper edge 55 of the first duct member 52.

[0029] Each of the first radiator 20 and the second radiator 21 has identical components and each is located on a respective side of the longitudinal center line 27 of the trailer 12. The radiators 20 and 21 can be virtually identical but for arrangements so as to be suitably located adjacent either the first side 22 or the second side 23. For ease of discussion, each of the individual elements of the second radiator 21 will be referred to by the same reference numerals used to refer to the elements of the first radiator 20.

[0030] The duct member 52 of the radiators 20 and 21 are movable between operative positions as shown in Figures 4 and 5 which permit air flow upwardly from the duct outlets 54 and storage positions as shown in Figures 2 and 3 which substantially close the air outlets 51. As seen in end view in Figure 3, with the radiators 20 and 21 and the duct members 52 in the storage position, the radiators 20 and 21 do not extend outwardly beyond the trailer first side 22 or the second side 23. In contrast, as seen in end view in Figure 5, in the operative position, the duct members 52 extend laterally beyond the sides of the trailer, with the duct member 52 of the first radiator 20 extending beyond the trailer first side 22 and the duct member 52 of the second radiator 21 extending beyond the second side 23.

[0031] Reference is made to Figure 10 which is a schematic enlargement of front portions of three units 10 shown in Figure 9 arranged side to side and in which the left hand-most trailer is shown with its radiators 20 and 21 having their duct members 52 in the storage position, the middle unit 10 is shown as having its radiators 20 and 21 with its duct members 52 in the operative position and the right hand unit 10 is illustrated as having its second

radiator 21 with its first duct member 52 in an operative position and its first radiator 20 having its duct member 52 in a storage position. In Figure 10, the width of each unit 10 is illustrated as W with a width of each of the three units 10 being indicated as identical. The center line 27 for each unit 10 is shown and the distance between center lines, D_c is shown and is indicated as being identical. The units 10 are shown as arranged side by side with a spacing between units indicated as S and which such spacing S being represented as equal to two times the distance D_e that duct member 52 extends laterally from the respective side of its respective unit 10. In a preferred embodiment as illustrated in Figures 9 and 10, the inlet pipes 36 for the high pressure discharge line 34 and the outlet pipes 35 for the low pressure fluid line 32 may be spaced along the manifold longitudinal 31 a distance equal to D_c shown in Figure 10. Preferably, the distance D_c is equal to the width W of a trailer plus at least twice D_e the distance that each duct member 52 extends from a trailer. Such an arrangement provides for optimal usage of the spacing between units 10 for discharge of air upwardly. Preferably, the width of a trailer is a maximum width which permits the trailer to be roadworthy, for example, 102 inches. Preferably, the distance D_e is in the range of 12 to 24 inches, preferably 18 inches and the units 10 as well as the outlet pipes 35 and the inlet pipes 36 are spaced a distance of D_c of about 138 inches.

[0032] Reference is made to Figure 4 which illustrates a preferred configuration for each duct member 52. The duct member 52 has a side wall 70, a front wall 71 and a rear wall 72. The side wall 70 is mounted to a rectangular frame 73 of a casing 74 for each radiator that contains the heat exchanger 40 and provides the passageway for air flow. The frame 73 effectively defines the air outlet opening 51 for passage of air laterally outwardly through the core and its cooling tubes 43. The duct member 52 is pivotally mounted to the frame 73 for pivoting at its lower end about a horizontal axis generally indicated as 75. Each of the front wall 71 and the rear wall 72 is formed from two triangular gusset members 76 and 77, each mounted by hinge members extending along the edges of each gusset member such that with pivoting of the side wall 70 about the horizontal axis 75, the gusset members fold inwardly upon themselves in a manner not dissimilar to that of a pleat in an accordion.

[0033] An actuator member 79 is provided for moving each of the duct members 52 between the operative position and the storage position. As seen in Figures 4 and 6, a vertical strut 80 is mounted to the frame 73 and pivotably carries a first pivot arm 81 which is pivotably coupled to a second pivot arm 82 pivotably coupled to the center of the side wall 70. As illustrated in Figure 7, the actuator mechanism includes a rotatable rod 83 which is mounted to a lower portion of the frame 73 and extends upwardly to an actuator link 84 engaging the first pivot arm 81. With rotation of a crank handle 85, shown in Figure 7, the actuator link 84 is moved upwardly or downwardly and thus pivots the first and second pivot arms so as to move the duct member 52 toward the operative position by moving the pivot arms upwardly and to move the duct member 52 toward the storage position by moving the pivot arms downwardly.

[0034] The crank handle 85 is located at a height on the unit 10 to be accessible by a person standing on the ground without the need for the person to climb the unit 10 or its trailer 12. The crank handle 85 is to be provided so as to avoid interference in use with other portions of the unit 10 such as the trailer 12 or the skid 39 albeit, in the embodiments for ease of illustration, the crank handle 85 appears to be in interference with the skid 39. As can be seen in Figure 4, with the side wall 70 in the operative position, the duct outlet 54 is open upwardly to the atmosphere for discharge of air upwardly.

[0035] Reference is made to Figure 8 which illustrates the duct members 52 in a closed position, however, with access doors 88 on the duct member 52 shown as being in an open position. As seen in Figure 8, the side wall 70 of each duct member 52 is provided with two rectangular access openings 89 therethrough. An access door 90 is provided coupled by a vertically extending hinge 92 to an edge of each access opening 89. The access doors 88 are movable from a closed position as shown in Figure 2 which closes the side wall 70 to air flow therethrough and an open position as shown in Figure 8 in which the access doors provide access to the heat exchanger 40 therein and, more particularly, to the core of the heat exchanger and the cooling tubes 43. With the access doors 88 in the open position as shown in Figure 8, a person on the ground can access the core 90 and its cooling tubes 43 for cleaning as, for example, with a user to hold a hose to discharge a stream of air or water to engage the

core and its cooling tubes 43 to clean the outside of the cooling tubes from various matters such as dust, dirt, mud and the like which may have come to be engaged upon the cooling tubes during use and typically which impedes efficient heat transfer. Of course, the core and its cooling tubes 43 may have various cooling fins 70 which may be placed close together and from which debris such as dust, dirt and mud may preferably be removed in cleaning on a regular basis to maintain the efficiency of the heat exchanger. Figure 8 schematically shows four vertically extending cooling tubes 43 and two longitudinally extending cooling fins 70 although a large number typically are to be provided.

[0036] The access doors 88 are located on the radiators 20 and 21 at a location that a person standing on the ground can manually move the access doors between the open and closed positions and to latch the doors in the open and closed positions. Various latching arrangements may be used as they are accessible from the ground and are used, for example, to close the doors at the rear of box trailers and the like. A latching arrangement 72 is schematically illustrated in Figure 2 only. Vertically extending lock rod 73 rotatably supported on each door 88 and pivotable by a handle 74 between coupled and uncoupled conditions with cam latches 75 and 76 carried on the front wall 70 above and below each door 88 and are of the type disclosed in U.S. Patent 2,038,876 to Sonabend, issued April 28, 1936. The handle 74 is accessible to a person on the ground. Once unlatched, each door 88 is accessible to a person on the ground to pivot each door between open and closed positions.

[0037] In the preferred embodiments, the heat exchangers are shown with a core which has vertically extending cooling tubes 43. In accordance with the invention, it is not necessary that the cooling tubes 43 extend vertically. For example, in a similar heat exchanger, the cooling tubes may extend horizontally. Referring to Figure 6, in addition to the primary core 90 having vertically extending cooling tubes 43, a secondary core 91 is shown schematically to have horizontally extending cooling tubes 92.

[0038] In the preferred embodiment, the trailer first side 22 and the trailer second side 23 are shown as providing substantially in the same vertical plane, a laterally most extending surface of the unit 10, the trailer 12, the trailer deck 13, its skid 39 and each of the radiators 20 and 21. It is to be appreciated that a unit 10 with the duct members 52 in the storage

position, the unit 10 will have a width defined by a laterally outermost surface. The laterally outermost surface may comprise the side wall 70 of one of the radiators with, for example, the skid 39 or the trailer deck 13 or the portions of the trailer disposed laterally inwardly therefrom.

[0039] In the preferred embodiment, the duct member 52 is illustrated to assume an operative position in which the duct member 52 extends laterally from the unit 10 farther in the operative position than in a storage position. The particular configuration of the duct member 52 is not limited. The preferred duct member 52 illustrated hinges about the horizontal hinge axis 75 at the bottom of the duct member 52. This is not necessary. The duct member 52 could be provided to merely slide laterally to one side and, for example, to extend in the operative position farther laterally outwardly over its whole height than when in the storage position.

[0040] The duct member 52 is shown as having its front wall 71 and its rear wall 72 formed from gusset members which fold to collapse upon themselves when a duct member 52 is moved to the storage position. This is not necessary and each of the front wall 71 and the rear wall 72 could be rigid members which slide laterally into slots provided on the radiator of a casing 74. Similarly, rather than provide the front wall 71 and the rear wall 72 from rigid gusset members, each wall could be provided as from a flexible member as, for example, from a flexible elastomeric member or fabric.

[0041] Reference is made to Figure 11 which illustrates a second embodiment in accordance with the present invention and which is identical to the first embodiment with the first exception that a roof member 93 is provided bridging between the first radiator 20 and the second radiator 21 laterally inwardly of the duct outlet 54 on each side of the unit 10 and above the fans 46 and their fan casings 48. Between the casing 74 enclosing each heat exchanger 40, and beneath the roof member 93, a forward air inlet 94 and rear air inlet 95 is provided via which atmospheric air may be drawn into the fan as indicated by the arrows 96 and 98. Air drawn into the fans 46 is directed through the heat exchangers 40 to exit upwardly from the duct outlets 54 as indicated by the arrows 98 and 99. Providing the roof

member 93 assists in reducing the likelihood that heated air exhausted upwardly from the duct outlets is drawn back into the fans.

[0042] Figure 11 differs from the first embodiment in showing schematically a bottom air inlet 100 provided through the skid portion 39 and which permits air from below the deck 39 of the trailer 12 into the fan 46 as indicated by arrow 101. The bottom air inlet 100 can be accommodated with suitable ducting or apertures through the skid portion 39 and deck underneath the fans 46. Figure 11 further shows as also shown schematically in Figure 6 the deck 39 to be cut away under the fan 46 to provide the bottom air inlet 100 and permit air flow upwardly as indicated by arrow 100. Figures 11 and 6 also show one lower horizontal air inlet 102 shown to be formed internally within the deck 39 to permit air flow horizontally from the side as indicated by arrow 103 to the fan 46. The lower horizontal air inlet 102 may be provided, one on each side, whether or not a bottom air inlet 100 is provided.

[0043] While the invention has been described with reference to the preferred embodiments, many variations and modifications will now occur to a person skilled in the art. For a definition of the invention, reference is made to the accompanying claims.

I CLAIM:

1. A modular mobile pump unit comprising:

an elongate mobile trailer having a first side, a second side, a front and a rear,

the trailer having a longitudinal centerline between the first side and the second side,

the trailer having mounted thereon a pump to dispense a fluid, an internal combustion engine to power the pump, a first air cooled radiator to cool the engine and a second air cooled radiator to cool the engine,

the first radiator comprising a vertically extending first heat exchanger for passage of air horizontally therethrough to cool a fluid from the engine circulated within the first heat exchanger and a first fan to blow atmospheric air through the first heat exchanger,

the first radiator mounted to the trailer on the first side of the longitudinal center line proximate the first side with the first heat exchanger adjacent the first side and with the first fan laterally inwardly of the first heat exchanger, the first fan providing for passage of air through the first heat exchanger horizontally and laterally outwardly toward the first side of the trailer,

the first radiator having a first duct member carried on the first radiator at a location laterally outwardly of the first heat exchanger and in the flow path of air from the first fan exiting horizontally and laterally from the first heat exchanger,

the first duct member movable relative to the first radiator from a storage position in which the first duct member does not extend laterally outwardly beyond the first side of the trailer and an operative position in which the first duct member extends laterally outwardly beyond the first side of the trailer,

in the operative position the first duct member receiving air passing laterally from the first heat exchanger and directing this air to exit vertically upwardly from a first duct outlet disposed along an upper edge of the first duct member,

the second radiator comprising a vertically extending second heat exchanger for passage of air horizontally therethrough to cool a fluid from the engine circulated within the

second heat exchanger and a second fan to blow atmospheric air through the second heat exchanger,

the second radiator mounted to the trailer directly opposite the first radiator on the second side of the longitudinal center line proximate the second side with the second heat exchanger adjacent the second side and with the second fan laterally inwardly of the second heat exchanger, the second fan providing for passage of air through the second heat exchanger horizontally and laterally outwardly toward the second side of the trailer,

the second radiator having a second duct member carried on the second radiator at a location laterally outwardly of the second heat exchanger and in the flow path of air from the second fan exiting horizontally and laterally from the second heat exchanger,

the second duct member movable relative to the second radiator from a storage position in which the second duct member does not extend laterally outwardly beyond the second side of the trailer and an operative position in which the second duct member extends laterally outwardly beyond the second side of the trailer,

in the operative position the second duct member receiving air passing laterally from the second heat exchanger and directing this air to exit vertically upwardly from a second duct outlet disposed along an upper edge of the second duct member.

2. A unit as claimed in claim 1 wherein:

the first duct member extends vertically throughout the height of the first heat exchanger locating the first duct outlet at a height substantially the same as uppermost portions of the first heat exchanger, and

the second duct member extends vertically throughout the height of the second heat exchanger locating the second duct outlet at a height substantially the same as uppermost portions of the second heat exchanger.

3. A unit as claimed in claim 2 including:

a roof baffle member bridging laterally between the first radiator and the second radiator above the first fan and the second fan at a height below the first duct outlet and the second duct outlet,

the baffle member limiting the direct flow of air discharged upwardly from the first duct outlet and the second duct outlet downwardly into the first fan and the second fan.

4. A unit as claimed in claim 3 wherein:

a front air entrance way is defined between the first radiator and the second radiator below the roof baffle member for passage of atmospheric air rearwardly to the first fan and the second fan,

a rear air entrance way is defined between the first radiator and the second radiator below the roof baffle member for passage of atmospheric air forwardly to the first fan and the second fan.

5. A unit as claimed in claim 2 including:

at least one first access door through the first duct member movable between a closed position and an open position, wherein with the first duct member in the storage position and the first access door in the open position the first access door providing access from the first side of the trailer to the first heat exchanger for cleaning, and

at least one second access door through the second duct member movable between a closed position and an open position, wherein with the second duct member in the storage position and the second access door in the open position the second access door providing access from the second side of the trailer to the second heat exchanger for cleaning.

6. A unit as claimed in claim 5 wherein:

the first heat exchanger having an air flow passageway for air flow therethrough from a laterally inwardly located first air inlet opening to a laterally outwardly located first air outlet opening,

in the operative position the first duct member receiving air from the first air outlet opening of the first heat exchanger and directing the air to exit vertically upwardly from the first duct outlet,

the first duct member in the storage position with the first access door closed extends across the first air outlet opening of the first heat exchanger closing the first air outlet opening,

the second heat exchanger having an air flow passageway for air flow therethrough from a laterally inwardly located second air inlet opening to a laterally outwardly located second air outlet opening,

in the operative position the second duct member receiving air from the second air outlet opening of the second heat exchanger and directing the air to exit vertically upwardly from the second duct outlet,

the second duct member in the storage position with the second access door closed extends across the second air outlet opening of the second heat exchanger closing the second air outlet opening.

7. An array of units as claimed in claim 1 wherein the units are arranged side by side with a spacing between adjacent units at least equal to a spacing distance represented by the sum of a distance that the first duct member in the operative position extends beyond the first side of the trailer and a distance that the second duct member in the operative position extends beyond the second side of the trailer.

8. An array of units as claimed in claim 7 wherein the spacing between adjacent units is substantially equal to the spacing distance.

9. An array of units as claimed in claim 2 including a first mechanism operative by a person on the ground to move the first duct member between the storage position and the operative position; and

a second mechanism operative by a person on the ground to move the second duct member between the storage position and the operative position.

10. An array of units as claimed in claim 5 including a first latching mechanism accessible by a person on the ground to latch and unlatch the first access door; and

a second latching mechanism accessible by a person on the ground to latch and unlatch the second access door

11. An array of units as claimed in claim 7 in combination with a manifold having a plurality of inlet pipes, located longitudinally along the manifold an equal distance equal to at least the width of each trailer between the first side and the second side plus the spacing between adjacent units,

the pump of each unit having a discharge pipe adapted to be removably coupled to the inlet pipes of the manifold,

each mobile unit having its rear located proximate the manifold and its front remote from the manifold,

each unit being independently removably coupled to the manifold and independently movable forwardly away from the manifold for replacement by another similar modular unit.

12. A unit as claimed in claim 3 including at least one of:

a front air entrance way is defined between the first radiator and the second radiator below the roof baffle member for passage of atmospheric air rearwardly to the first fan and the second fan,

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a rear air entrance way is defined between the first radiator and the second radiator below the roof baffle member for passage of atmospheric air forwardly to the first fan and the second fan,

a bottom air entranceway is defined for passage of atmospheric air from below the trailer upwardly through the trailer to the first fan and the second fan,

a first lower air entranceway is defined for passage of atmospheric air from below the first radiator from the first side laterally inwardly and underneath the first radiator to the first fan, and

a second lower air entranceway is defined for passage of atmospheric air from below the second radiator from the second side laterally inwardly and underneath the second radiator to the second fan.

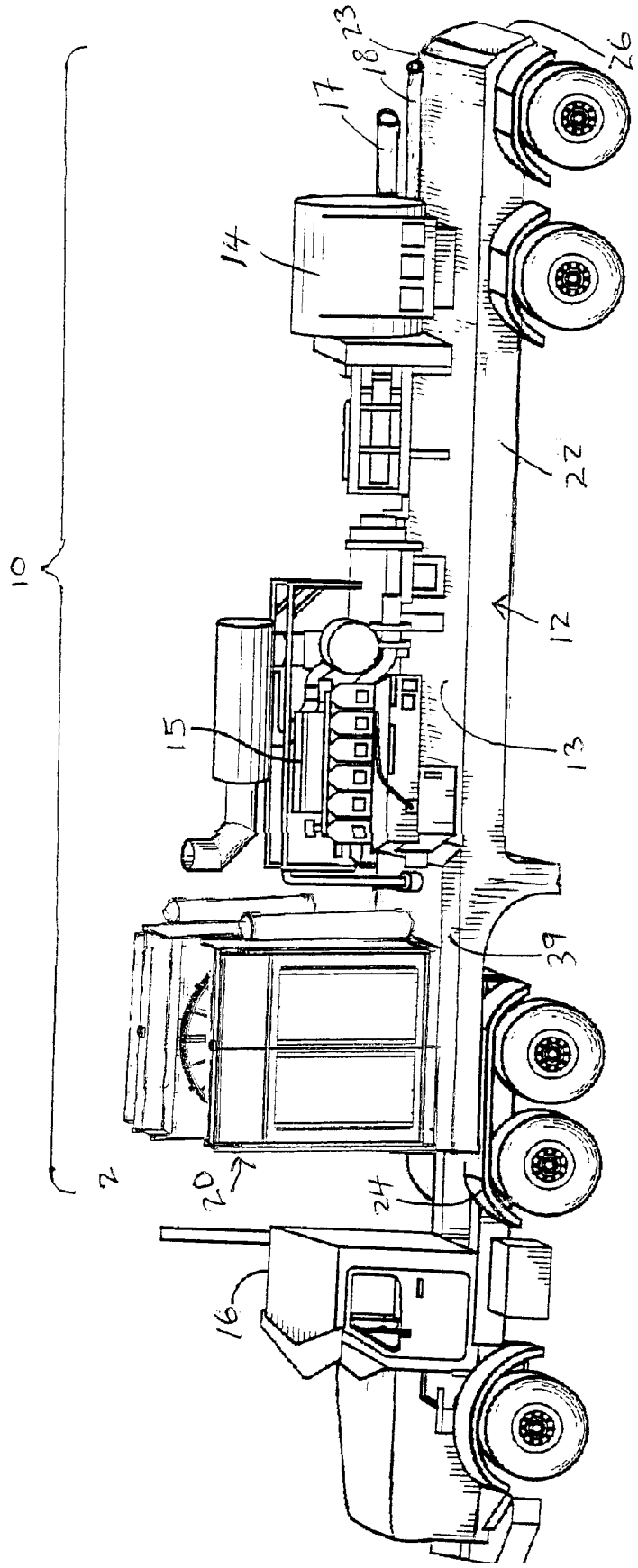


FIG. 1

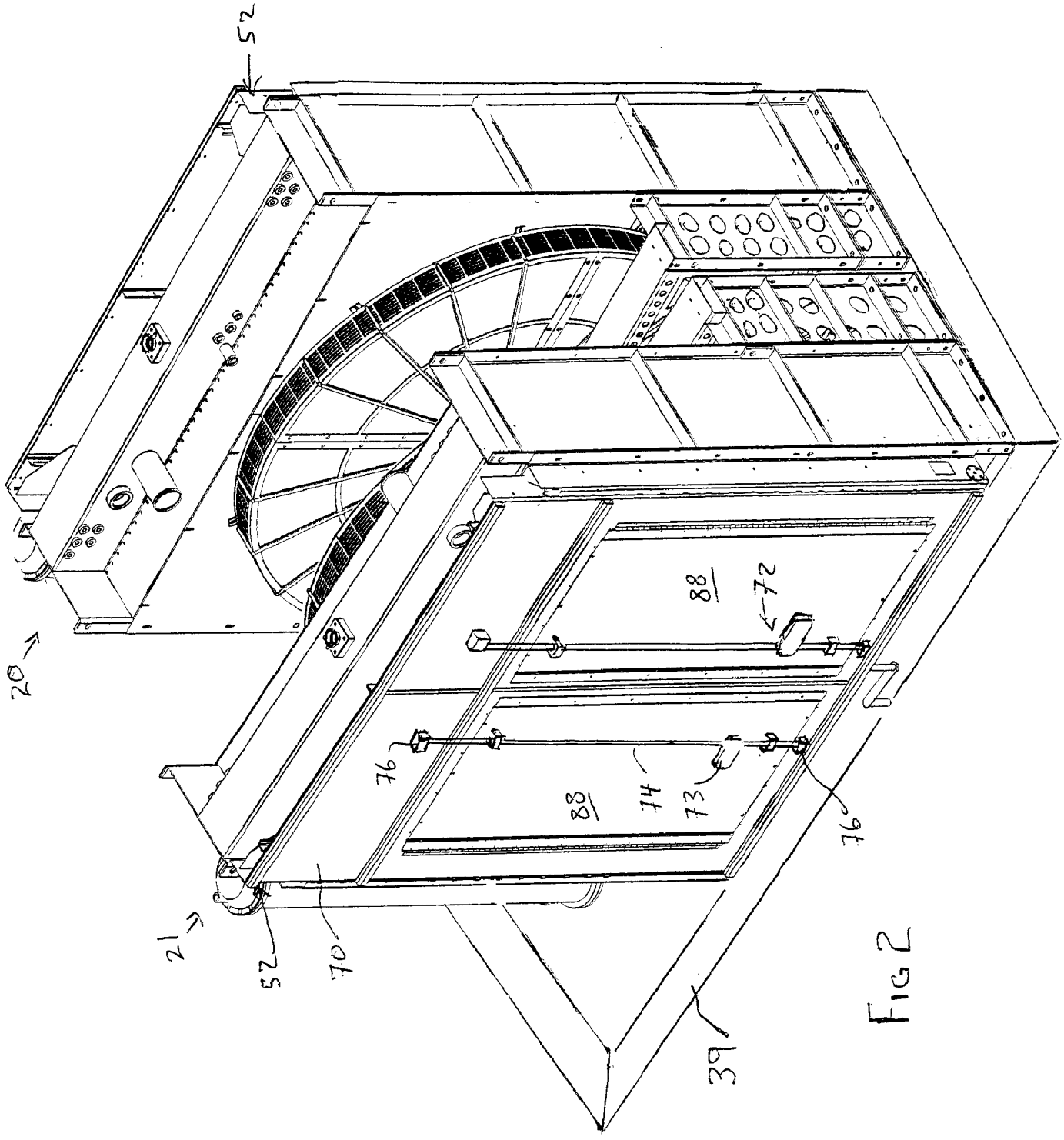


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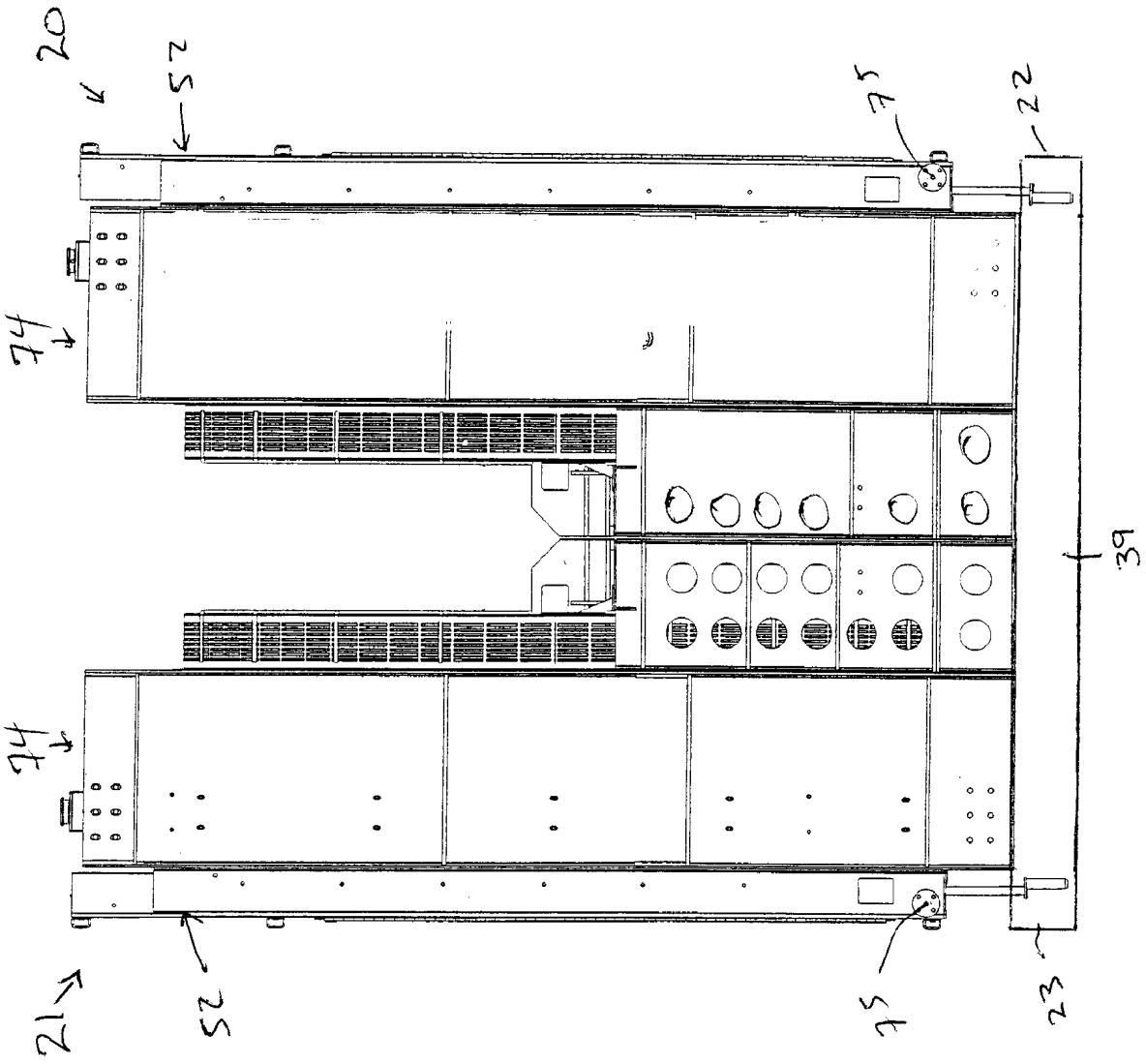


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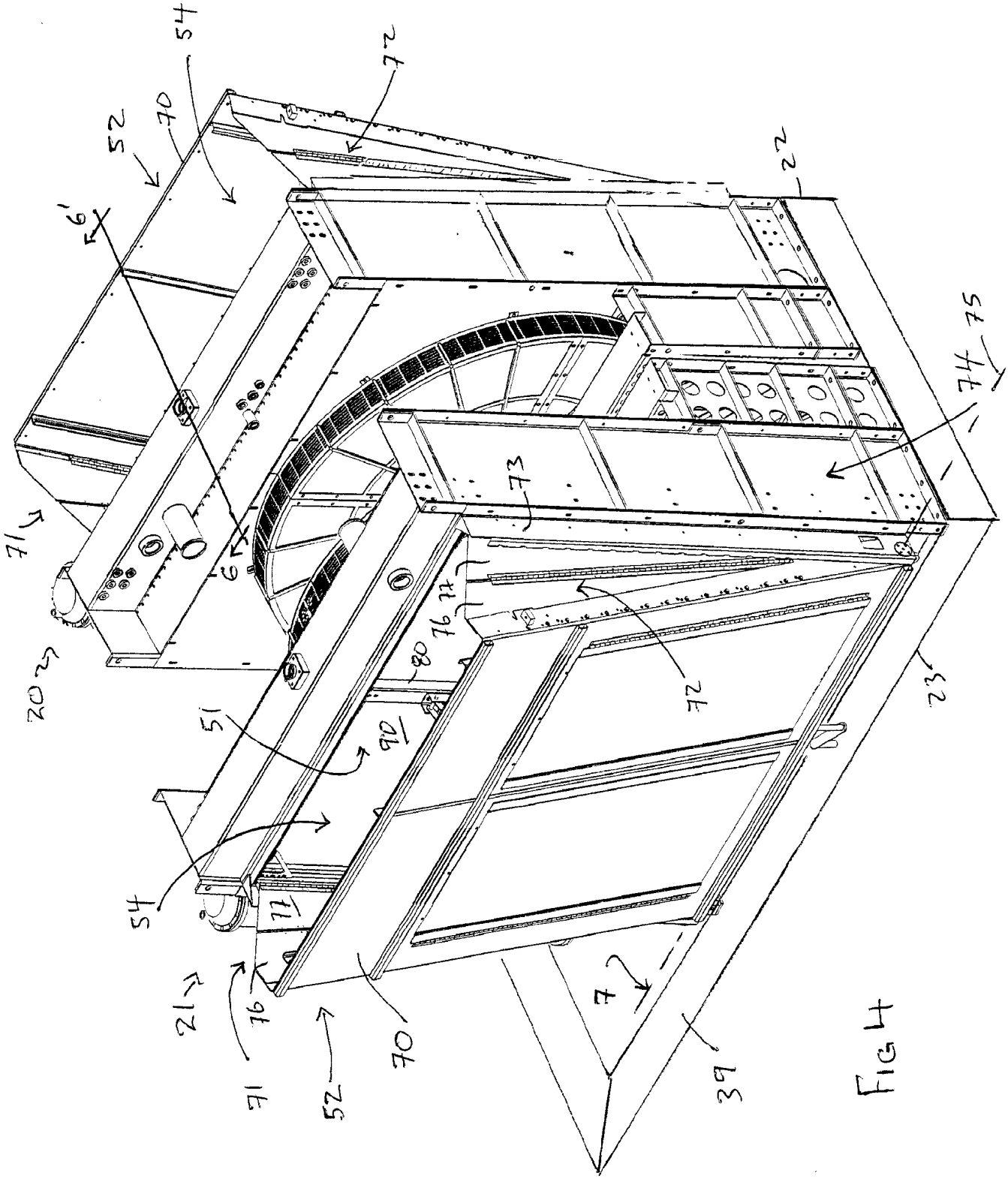

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Fig 4

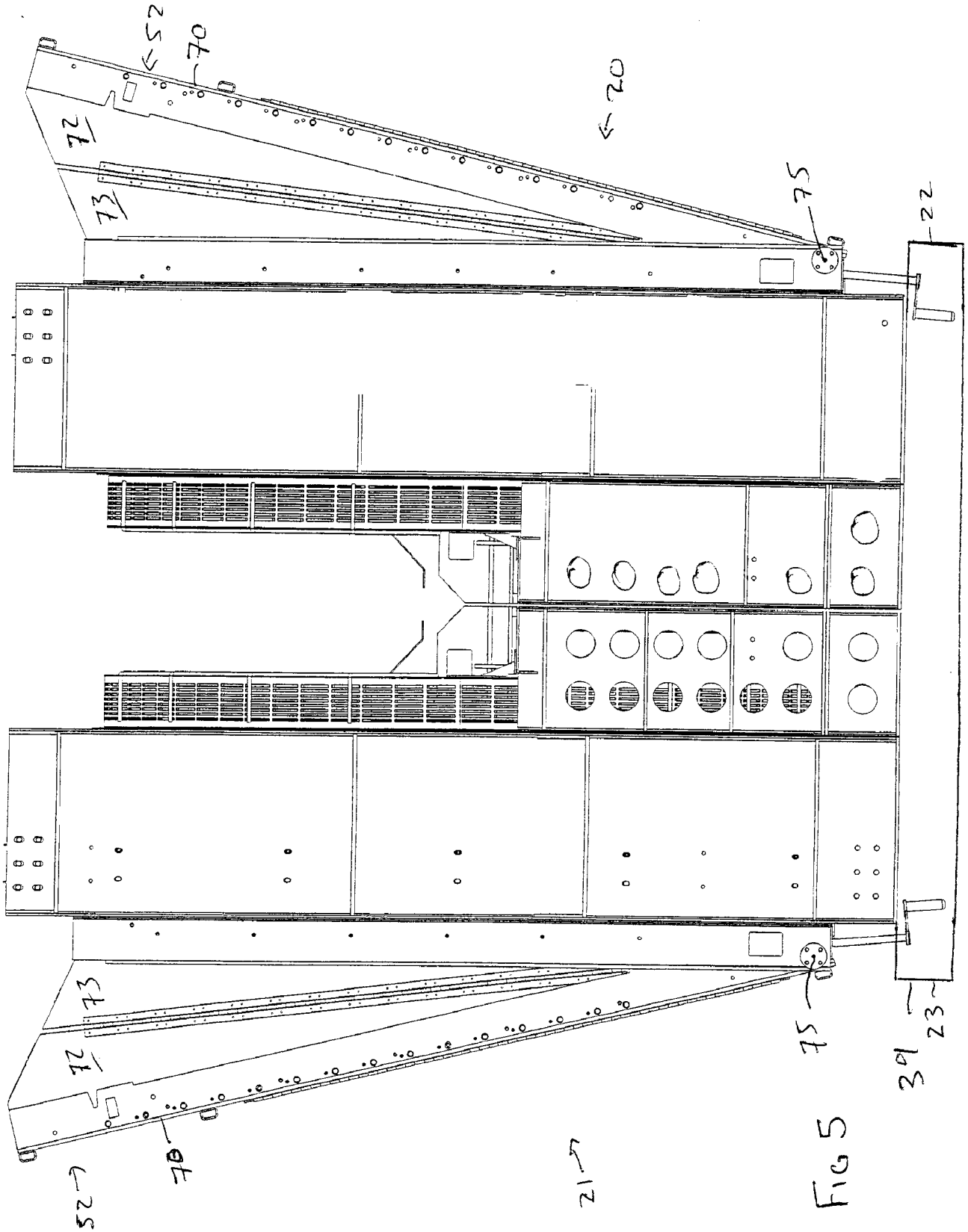


Fig 5

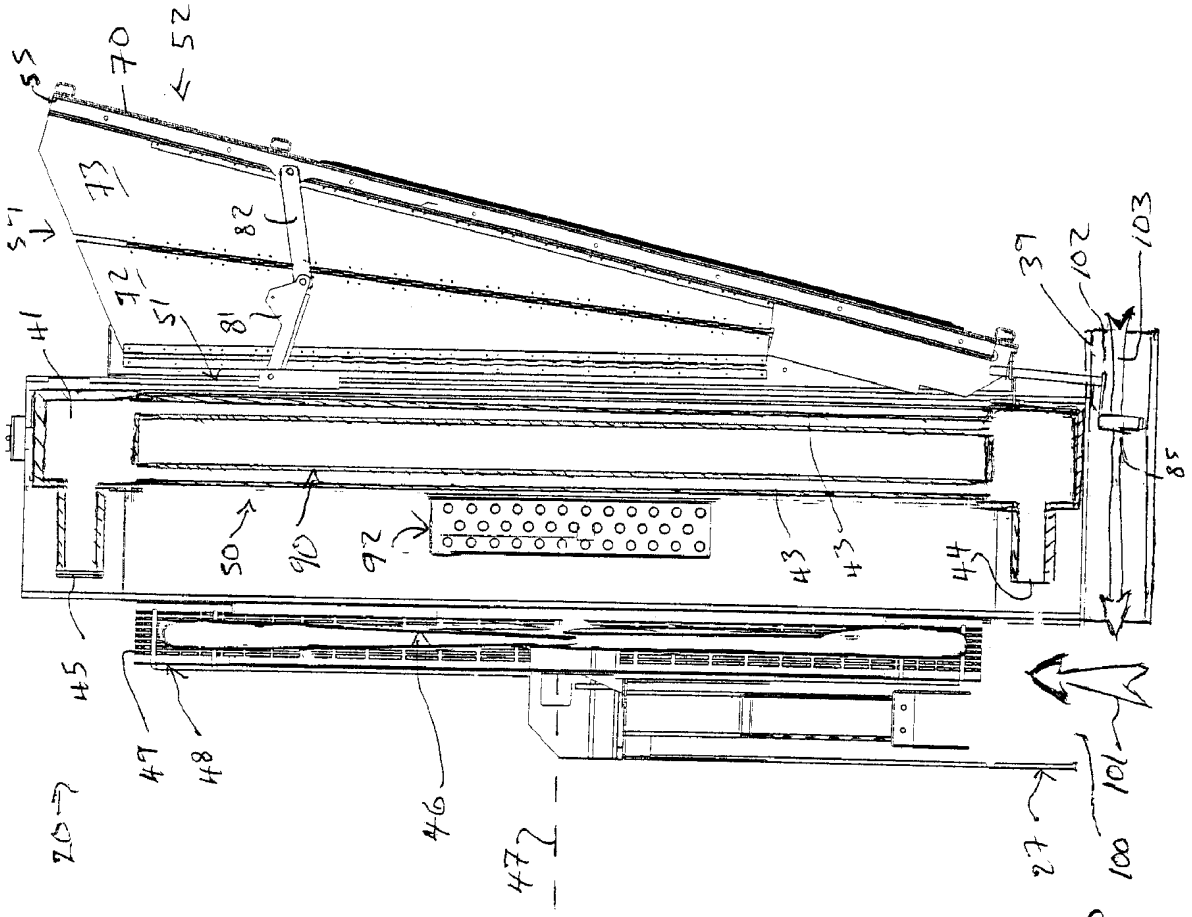

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Fig 9

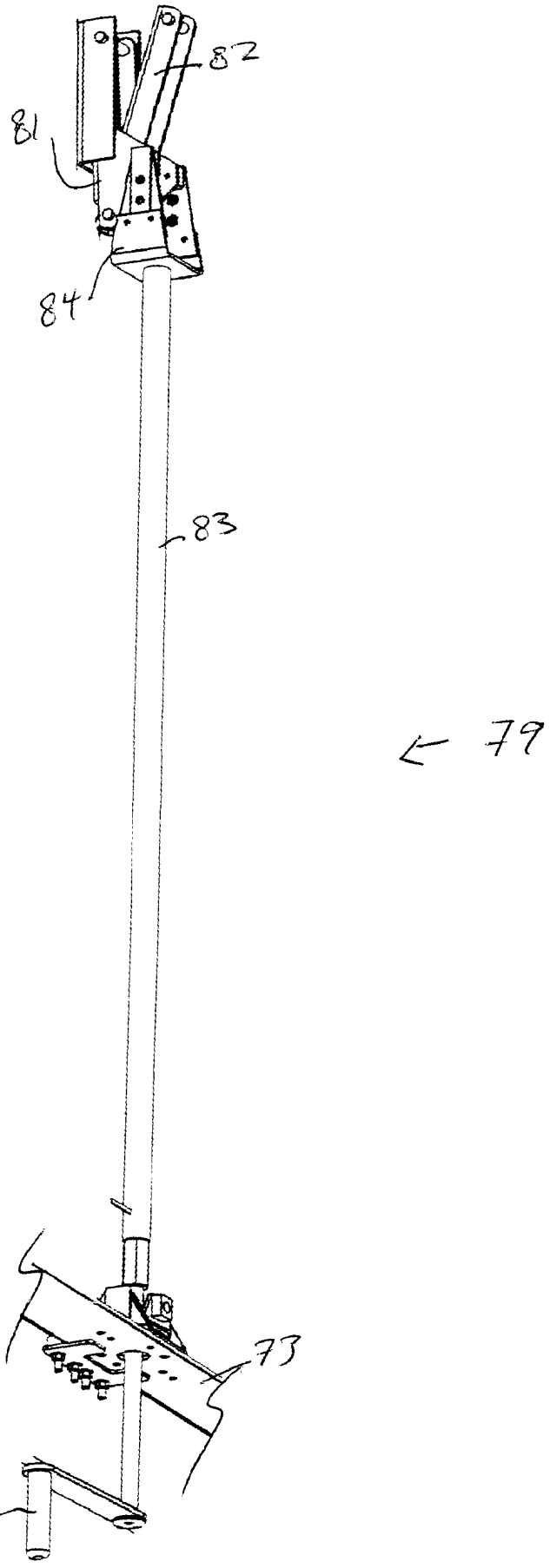


FIG 7

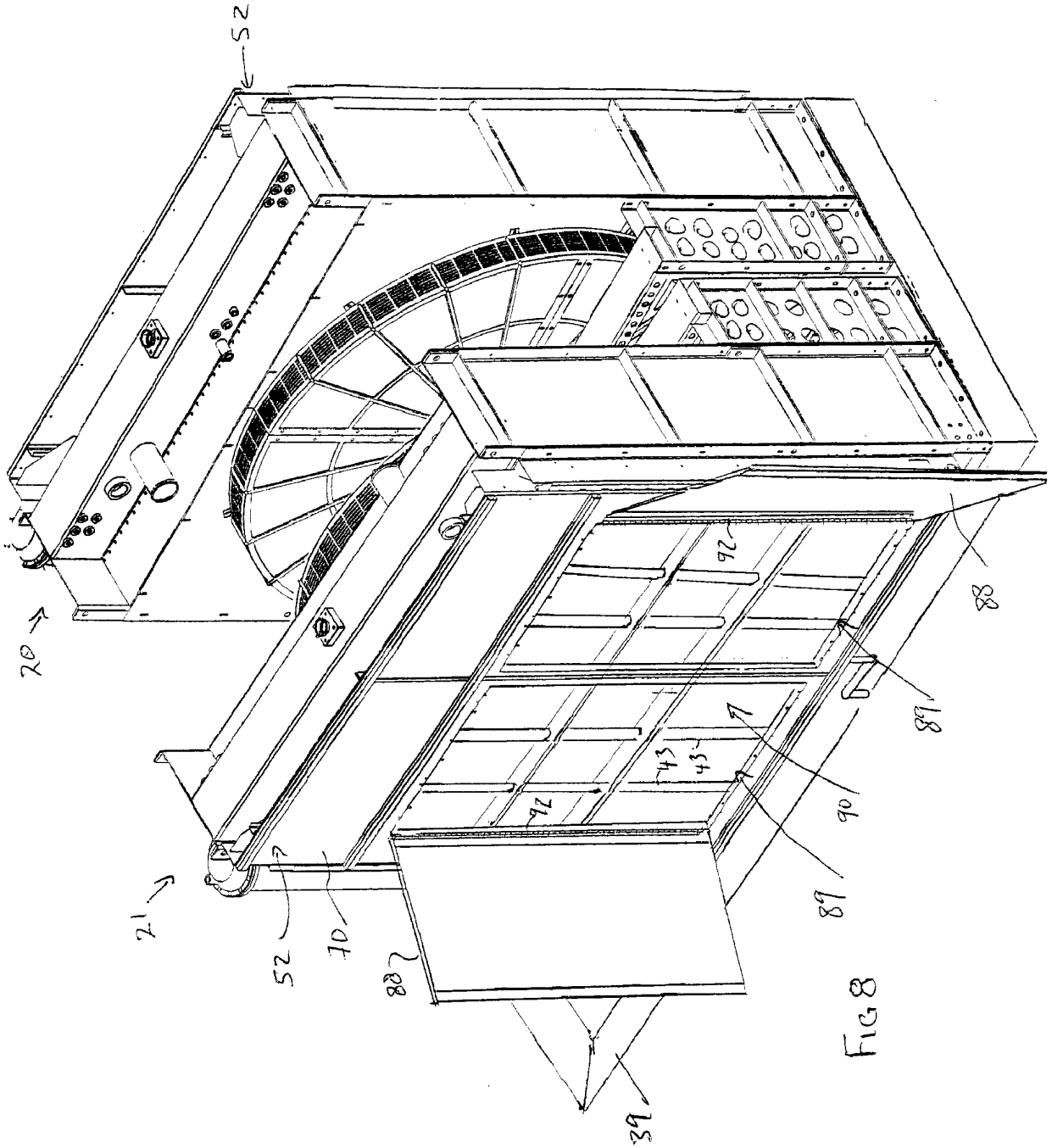


Fig 8

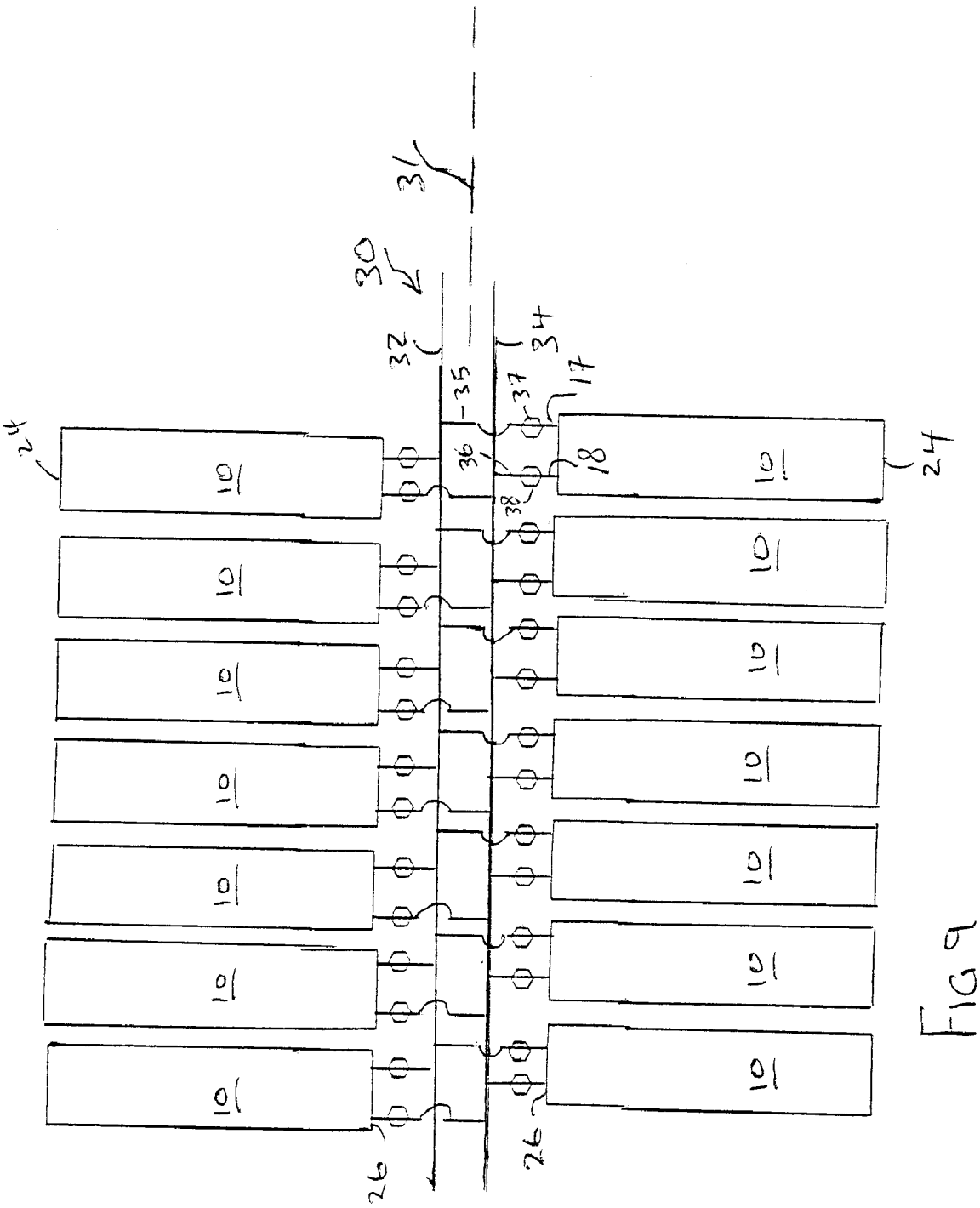


FIG 9

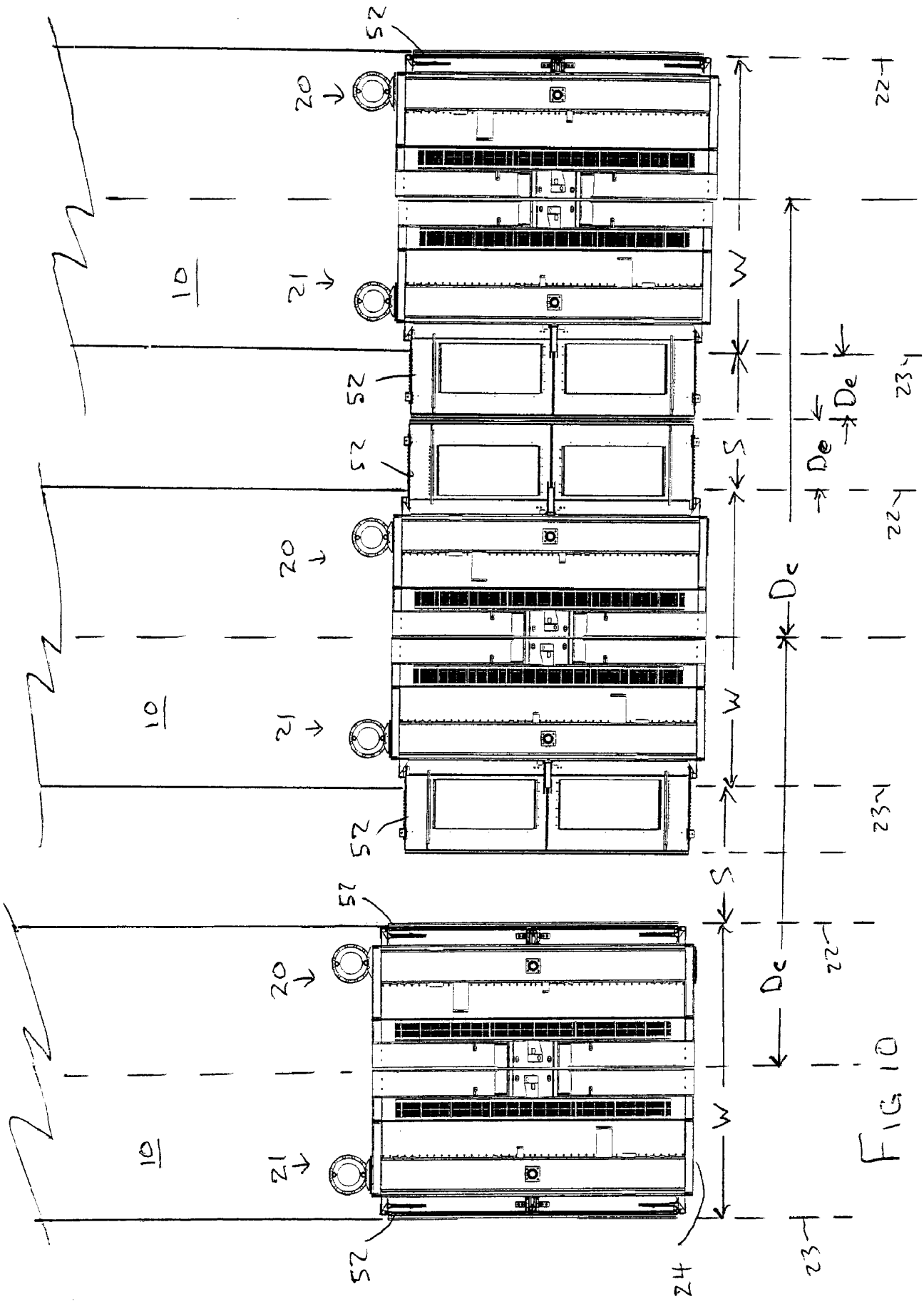


FIG 10

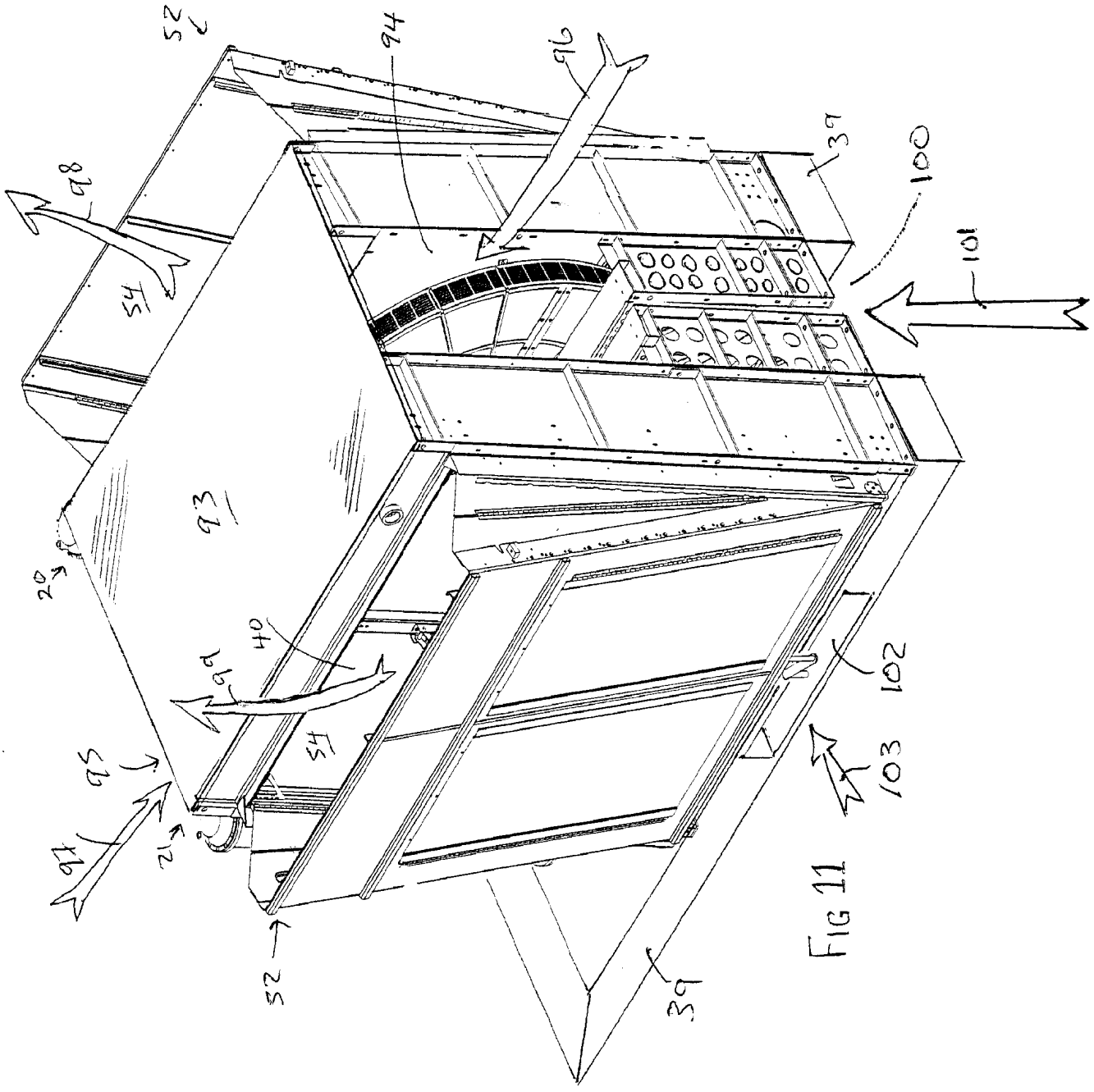
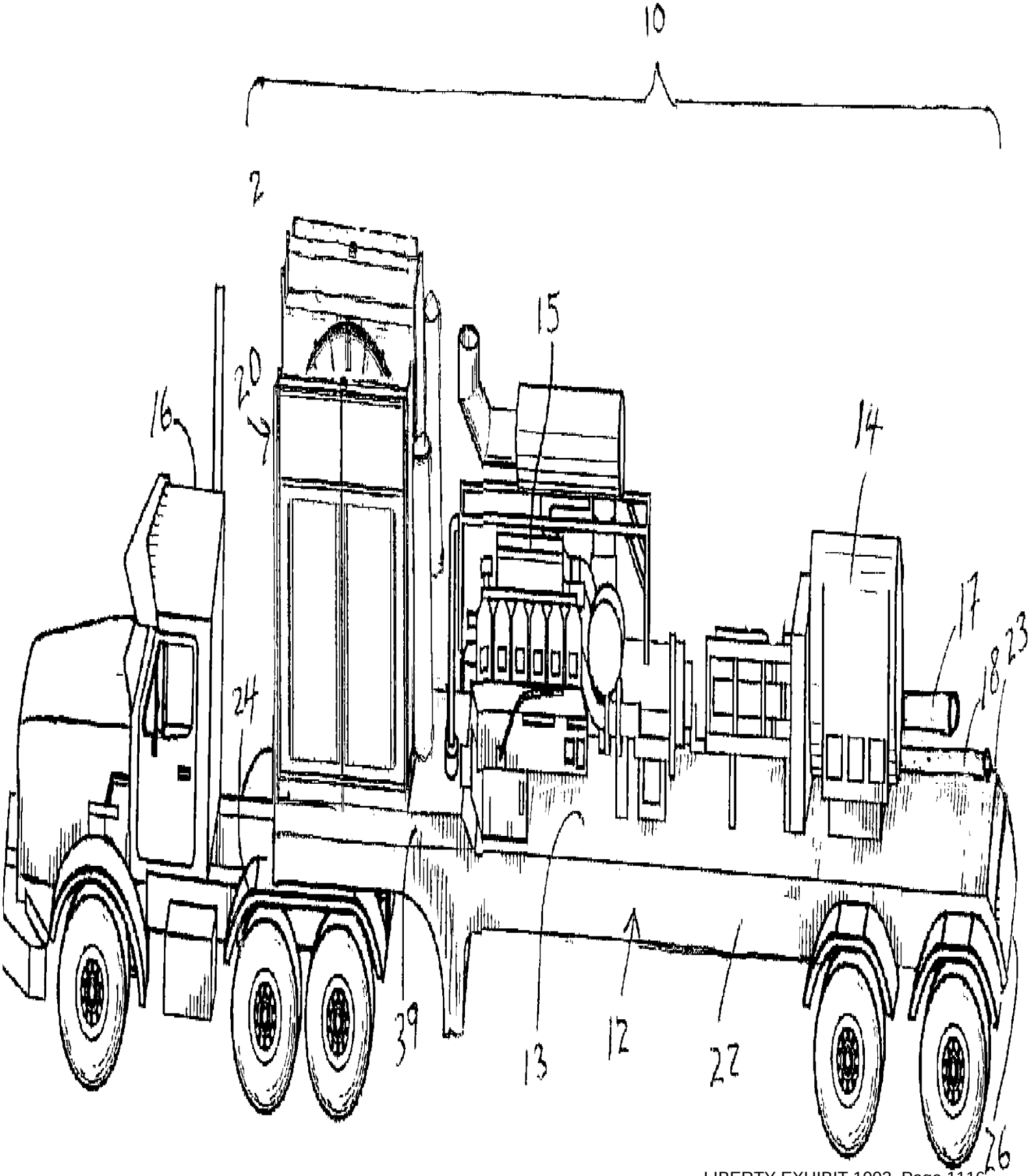


FIG 11


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CA 2797081 A1 2011/11/03

(21) 2 797 081

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2011/05/02
(87) Date publication PCT/PCT Publication Date: 2011/11/03
(85) Entrée phase nationale/National Entry: 2012/10/19
(86) N° demande PCT/PCT Application No.: US 2011/034863
(87) N° publication PCT/PCT Publication No.: 2011/137460
(30) Priorité/Priority: 2010/04/30 (US61/330,248)

(51) Cl.Int./Int.Cl. *G06F 19/00* (2011.01), *E21B 43/00* (2006.01), *G06Q 50/00* (2012.01)

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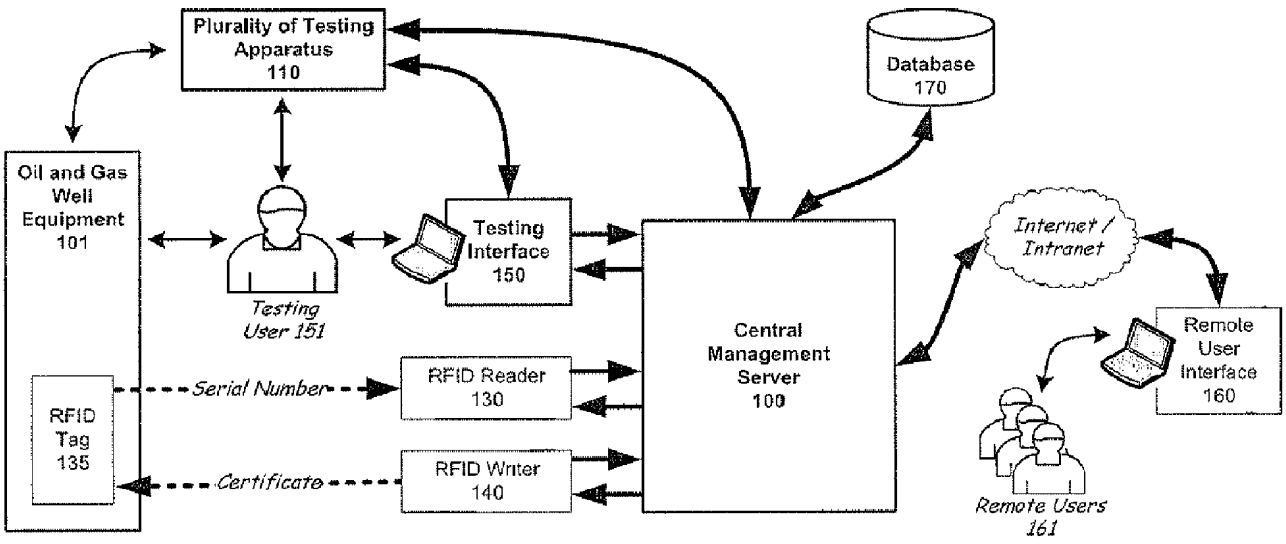
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HUNTER, SCOTT, US

(74) Agent: GOWLING LAFLEUR HENDERSON LLP

(54) Titre : MACHINES, SYSTEMES, PROCEDES MIS EN OEUVRE PAR ORDINATEUR ET PRODUITS DE PROGRAMME INFORMATIQUE POUR TESTER ET CERTIFIER UN MATERIEL PETROLIER ET GAZIER

(54) Title: MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT

FIG. 1



(57) Abrégé/Abstract:
Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
3 November 2011 (03.11.2011)

PCT

(10) International Publication Number
WO 2011/137460 A3

(51) International Patent Classification:
G06F 19/00 (2011.01) *G06Q 50/00* (2006.01)
E21B 43/00 (2006.01)

(21) International Application Number:
PCT/US2011/034863

(22) International Filing Date:
2 May 2011 (02.05.2011)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
61/330,248 30 April 2010 (30.04.2010) US

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(74) Agent: **BRADLEY, James**; Bracewell & Giuliani LLP, P.O. Box 61389, Houston, TX 77208-1389 (US).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, RO, RS, RU, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

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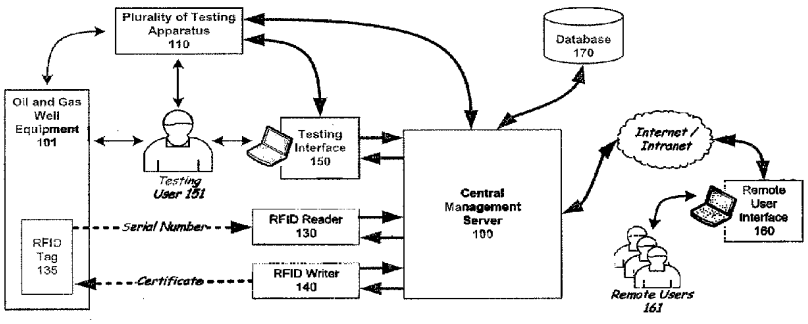
— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

(88) Date of publication of the international search report:
12 January 2012

(54) Title: MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT

FIG. 1



(57) Abstract: Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

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MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT

Related Applications

[0001] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "**Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment,**" which is incorporated by reference in its entirety herein.

Field of the Invention

[0002] The present invention relates to oil and gas production. In more particular aspects, the present invention relates to testing and certification of equipment used in oil and gas production.

Background of the Invention

[0003] The production of oil and gas requires specialized well equipment, such as pipes, valves, joints, and fittings that operate in extreme conditions, including, for example, high pressure, temperature, volatility, and corrosivity. Such conditions promote the rapid wear of well equipment and increase the potential for failure. Moreover, when well equipment does fail, the impact of the failure is typically catastrophic. For example, the failure of well equipment can result in massive explosions that hurt workers, destroy property, and halt operations for a significant time—potentially costing millions of dollars in liabilities, repairs, and lost revenue.

[0004] Well equipment particularly susceptible to catastrophic failure includes, for example, the equipment used in the process of hydraulic fracturing known as "fracing" or "fracking." The process of fracing creates or extends fractures in subterranean rock formations by pumping fluid into the formation at high pressure. For example, fluid-driven fractures can be formed at the borehole in a drilling operation and then "grown" or extended into the rock formations. The injected fluid may contain "proppant" particles, such as grains of sand or ceramic, to lodge in the

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fractures thereby keeping them open. Fracing is used to improve the rate at which oil and gas can be produced from a reservoir, and fracing is especially useful for extracting oil and gas from formations having low porosity and permeability, such as shale rock and other formations deep below the earth's surface. The equipment used in hydraulic fracturing for oil and gas wells can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings, which are known as "frac iron" or, simply, "iron." For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves.

[0005] To mitigate the likelihood and impact of their failure, frac iron must be periodically inspected and recertified according to certain specifications, which can be provided by, for example, a manufacturer or operator of the frac iron. Because of the likelihood and impact of failure, inspections can be performed as frequently as every 90 days. Inspections and recertifications typically require several different test procedures, which may include, for example, a visual check of bores, connections, seal surfaces; wall thickness measurements to check for erosion or corrosion, for example, using ultrasonic measurement; crack tests, for example, using magnetic particle measurement; and pressure tests, for example, of over 20,000 pounds per square inch (PSI).

[0006] Previously known methods to certify frac iron were lengthy and laborious, often lasting one to three weeks and requiring a human tester to control all testing, to record the results manually, and later to enter the results into a database—costing valuable production capacity due to downtime.

[0007] Also, previously known methods to certify frac iron were susceptible to inconsistencies due to the manually intensive nature of the certification, such as inconsistent performance of testing operations and inconsistent adherence to prescribed test specifications. Also, for example, certification records were created by manual input, introducing human error and recording and measurement variances into the certification records.

[0008] Also, previously known methods to certify frac iron were susceptible to operational inefficiencies. For example, certification records were kept in hard copy, which did not allow on-site operators to readily access certifications while in the field, which may be a remote

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location such as an offshore rig. Furthermore, certification records and the test results associated therewith could not be tracked, updated, or reported on from a central control center.

Summary of the Invention

[0009] Embodiments of the present invention provide systems, methods, and machines for testing and certifying well equipment that enhance testing management, certification management, field operations management, and asset management. For example, embodiments of the present invention increase efficiency in testing and certifying well equipment by providing a systematic solution to control testing operations. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by seamlessly generating, storing, and processing testing data immediately upon performance of the testing operations, allowing a user to view the testing data in real time. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by dynamically generating certificates and reports responsive to the testing data according to multiple formats or user criteria.

[0010] Furthermore, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensuring that testers use the proper test specifications and perform all test operations according to defined test sequences. Also, well equipment tested according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensure that equipment that fail any test sequence according to defined testing specifications are scrapped in the system and are unable to proceed in further testing or operation. Also, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because operational crews can more readily access certificates, including comprehensive testing and certification data, on-demand and on-site. Furthermore, manufacturers and suppliers of well equipment can benefit from embodiments of the present invention by enhancing research and development efforts with greater knowledge of real-world wear patterns and wear rates for well equipment devices.

[0011] In view of the foregoing, applicant has provided a machine to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a

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plurality of testing apparatus performing one or more testing operations upon the well equipment devices. The machine comprises a processor, a non-transitory memory, an input/output unit to communicate with the plurality of testing apparatus, a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences. The machine also comprises a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform operations. The operations of the testing module include identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations.

[0012] The operations of the testing module further include selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device.

[0013] The operations of the testing module further include controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations of the testing module further include generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations.

[0014] The operations of the testing module further include linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

[0015] The machine also comprises a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module

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being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform certain operations.

[0016] The operations of the certification module include identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device.

[0017] The operations of the certification module further include generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification.

[0018] The operations of the certification module further include linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

[0019] Also in view of the foregoing, applicant has provided a system to certify oil and gas well equipment. The system comprises a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith. The system further comprises a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test specification and the plurality of testing sequences defining certification criteria for the well equipment device. The system further comprises a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence upon the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification. The system further comprises a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification. The system

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further comprises a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

[0020] Also in view of the foregoing, applicant has also provided a computer-implemented method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices. The computer-implemented method comprises receiving a device identifier for a selected well equipment device of the plurality of well equipment devices. The computer-implemented method further comprises identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The computer-implemented method further comprises selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The computer-implemented method further comprises calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification. The computer-implemented method further comprises controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The computer-implemented method further comprises generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The computer-implemented method further comprises linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

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[0021] Also in view of the foregoing, applicant has also provided a computer program product to manage periodic testing of a plurality of well equipment devices. The computer program product can be stored in a memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the computer program product being operable by a processor. The computer program product comprises a set of instructions that, when executed by the processor, cause the testing module to perform certain operations. The operations performed by the computer program product includes identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The operations performed by the computer program product further includes selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The operations performed by the computer program product further includes controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations performed by the computer program product further includes generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The operations performed by the computer program product further includes linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto. The operations performed by the computer program product further includes identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device. The operations performed by the computer program product further includes generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been

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performed upon the selected well equipment device responsive to the device test specification. The operations performed by the computer program product further includes linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

Brief Description of the Drawings

[0022] So that the manner in which the features and benefits of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is also to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[0023] FIG. 1 is a schematic diagram illustrating exemplary data flows and interactions among components of a system to certify well equipment according to an embodiment of the present invention;

[0024] FIG. 2 is a schematic illustrating exemplary components and connections of a central management server to certify well equipment according to an embodiment of the present invention;

[0025] FIG. 3 is a flowchart illustrating exemplary program product logic and computer-implemented methods for certifying well equipment according to an embodiment of the present invention;

[0026] FIG. 4 is a database diagram illustrating exemplary data structures according to an embodiment of the present invention;

[0027] FIG. 5 is an exemplary certificate according to an embodiment of the present invention;

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[0028] FIGs. 6-8 are flowcharts illustrating exemplary process flow according to embodiments of the present invention;

[0029] FIGs. 9-23 are exemplary testing interface displays according to embodiments of the present invention; and

[0030] FIGs. 24-25 are exemplary reporting interface displays according to embodiments of the present invention.

Detailed Description

[0031] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate various embodiments of the invention. This invention, however, may be embodied in many different forms and should not be construed as limited to the embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. It is to be fully recognized that the different teachings of the various embodiments discussed below may be employed separately or in any suitable combination to produce desired results. The various characteristics mentioned above, as well as other features and characteristics described in more detail below, will be readily apparent to those skilled in the art upon reading the following detailed description of the various embodiments, and by referring to the accompanying drawings. In the drawings and description that follow, like parts are marked throughout the specification and drawings with the same reference numerals, respectively. The prime notation, if used, indicates similar elements in alternative embodiments. The drawings are not necessarily to scale. Certain features of the disclosure may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness.

[0032] Accordingly, embodiments of the present invention improve safety, effectiveness, and efficiency of operating well equipment by meeting the foregoing objectives to mitigate the likelihood and impact of the failure of such equipment. In embodiments of the present invention, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron."

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Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. Those skilled in the art will appreciate that embodiments of the present invention are not limited to uses related to in oil and gas wells, but, rather, embodiments of the present invention are applicable to processes for testing or certifying any industrial equipment or device, and at any stage in the lifespan of the equipment, including during or after manufacturing and before, during, or after use or ongoing operations.

[0033] FIG. 1 illustrates a central management server 100 for performing operations of a testing module 220 and a certification module 210. The central management server 100 is positioned to be in communication with a plurality of testing apparatus 110. The plurality of testing apparatus 110 is capable of performing testing operations on a selected well equipment device 101. The central management server 100 is positioned to systematically control the performing of testing operations upon the well equipment device 101, systematically record and process the results of such testing operations, and systematically generate a certificate responsive to such recording and processing. Embodiments of the present invention providing systems, methods, and machines to certify of well equipment and are further described herein with specific reference to the drawings.

Central Management Server 100

[0034] An embodiment of a central management server 100, as illustrated in FIG. 2, can be configured as a computer, a server, or a machine of distributed computers or servers that at least include non-transitory memory 240, program products 210, 220, and 230, a processor or processors 251, an input/output device or devices ("I/O") 252.

[0035] I/O 252 connects the central management server 100 to a database 170, a testing interface 150, and one or more testing apparatus 110 (although represented as one block, those of skill in the art will appreciate that a plurality of testing apparatus 110 may include one or more

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links to the I/O) to thereby allow central management server 100 to send and receive commands and data. I/O 252 can be any I/O including, but not limited to a network card/controller connected by a PCI (Peripheral Component Interconnect) bus to the motherboard, or hardware built into the motherboard of the central management server 100 to connect same to the forgoing database, interface, and apparatus.

[0036] As those of skill in the art will appreciate, I/O 252 can connect the central management server 100 with any other compatible machine, server, system, device, or equipment having a suitable physical interface and that I/O 252 and/or computer program products 210, 220, and 230 on non-transitory memory 240 may be positioned to understand, convert, or translate application or communication protocols of such machines, servers, systems, devices, or equipment irrespective of native protocols. Also, one of skill in the art will understand that I/O 252 can include or otherwise incorporate any logical or physical technology necessary to effect a connection with any of the aforementioned devices, including, for example, hubs, switches, routers, converters, amplifiers, and wireless transceivers. For example, as is further described herein, I/O 252 can also connect the central management server 100 to devices for interacting with radio frequency identification (RFID) devices, such as an RFID reader or interrogator 130 and an RFID writer 140. The central management server 100 can further connect to a remote user interface 160 for interacting with a remote user 161, as is also discussed further herein. Also, the plurality of testing apparatus 110, RFID reader 130, and the RFID writer 140 may be configured as peripherals to the testing interface 150. Also, there a testing apparatus 110 interface 253, such as a programmable logic controller (PLC), an interface between the I/O 252 and the plurality of testing apparatus 110 to control the plurality of testing apparatus 110.

[0037] As can be seen in FIG. 2, the I/O 252 is connected to a processor 251. The processor 251 is the "brains" of the central management server, and as such executes program products 210, 220, and 230 and works in conjunction with the I/O 252 to direct data to the non-transitory memory 240 and to send data from the non-transitory memory 240 to the database 170, the testing interface 150, and one or more testing apparatus 110. The processor 251 can be any commercially available processor, or plurality of processors, adapted for use in or with the central management server 100, *e.g.*, Intel® Xeon® multicore processors, Intel® micro-

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architecture Nehalem, and AMD Opteron™ multicore processors. As one skilled in the art will appreciate, processor 251 may also include components that allow the central management server 100 to be connected to a display, as will be understood by those skilled in the art, and keyboard or other peripherals that would allow a user to directly or indirectly access the processor 251 and non-transitory memory 240.

[0038] Non-transitory memory 240 stores computer program products 210, 220, and 230 having instructions for execution on the processor 251, and consists of both non-volatile memory, *e.g.*, hard disks, flash memory, optical disks, and the like, and volatile memory, *e.g.*, SRAM, DRAM, and SDRAM as required to support embodiments of the instant invention. As one skilled in the art will appreciate, though the non-transitory memory 240 is depicted on, *e.g.*, a motherboard, of the central management server 100, the non-transitory memory 240 may also be a separate component or device, *e.g.*, FLASH memory, connected to the central management server 100 through the I/O 252. The non-transitory memory 240 may also store applications that various workstations or remote units can access and run on the central management server 100. For example, a testing user 151 may access applications and computer program products stored on the non-transitory memory 240 and run on the processor 251 using the testing interface 150. Importantly, non-transitory memory 240 stores the program products 210, 220, and 230 of the instant invention. As one skilled in the art will understand, the program products 210, 220, and 230, along with one or more databases/tables/fields/records for data associated with the selected well equipment device 101 can be stored either in non-transitory memory 240 or in separate non-transitory memory associated, for example, with a storage medium such as database 170, positioned in communication with the central management server 100.

Database 170

[0039] As seen in FIG. 1 and FIG. 2, the database 170 is in communication with the central management server 100. Although the database 170 is illustrated according to an embodiment in which the database 170 is separate and distinct from the central management server 100, for example, as a database server, the present invention may also include any arrangement of the database 170 in communication with the central management server 100, including the database 170 being incorporated into the same computer, server, machine, or system constituting the

central management server 100, as one physical unit, for example, as an application or partition in the central management server 100 or as an installed component of the central management server 100 communicating with the processor 251 through the use of the I/O and having, for example, a database memory separate and distinct from memory 240, such as a hard drive, optical storage, or the like. Database 170, as is understood in the art, can include a processor directing data from a bus into the database memory, which can be, for example, a hard drive, optical storage or the like, and computer software that provides computers, including the central management server, access the data therein.

[0040] The database 170 can store therein a data structure or data structures relating to the well equipment devices 101 to be tested and all data generated during the execution of the testing module 211 and certification module 210, as is further discussed herein. In embodiments, database 170 is a relational database positioned to match data by using common data found between data sets, the data sets being organized according to tables 400, 410, 420, 430, 440, and 450 as seen in FIG. 4. As will be understood by those skilled in the art, FIG. 4 illustrates an exemplary set of data structures only, and there may be other unique table structures positioned to relate and match the data in manners commensurate with the embodiments of the present invention. Data stored in the database 170 may be updated as needed, for example, by a user with administrative access to the database to add new well equipment devices to the database as they become supported. As is described further herein with relation to the computer program products, database 170 can be positioned to store data in tables relating to the unique device tested 400, parts in a parts library 410, test specifications in a test specification library 420, test sequences in a test sequence library 430, test data in a test data repository 440, and certificate data in a certificate data repository 450. And as is described further herein, the database 170 is positioned to match common data appearing in the foregoing tables.

Testing Apparatus 110

[0041] As shown in FIG. 1 and FIG. 2, the plurality of testing apparatus 110 are in communication with the central management server 100. The plurality of testing apparatus 110 perform testing operations under the control of the central management server 110 and provide tools or devices to gather testing data 440 as shown in FIG. 4, *i.e.,* the data that serves as the

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basis for the certification. In embodiments, the plurality of testing apparatus 110 at least includes an ultrasonic wall thickness meter ("UT meter") and a pressure test pump having a transducer. The plurality of testing apparatus 110 can include any other device or unit capable of being employed either manually or under automated control by the central management server 100 to interact with the well equipment device 101. Other testing apparatus 110 can include, for example, digital calipers. A local user may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test performed, and by manually configuring the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test.

[0042] Although shown as separate blocks in FIG. 1, the testing interface 150, which can be a personal computer (PC), can be connected to a peripheral testing apparatus 110 to control or collect data from a testing apparatus 110 connected as a peripheral to an input/output unit of the PC. The combination of the testing apparatus 110 and a PC may be referred to, collectively, as a testing apparatus 110. PC or testing interface 150 can connect to a peripheral testing apparatus 110 via any connection type known to those in the art, such as a Universal Serial Bus connection (USB), and such connection may include analog inputs and digital inputs, wired and wireless, and including analog-to-digital converters and amplifiers for digital inputs.

[0043] The plurality of testing apparatus 110 and a PC incorporated with a peripheral testing apparatus 110 can be a mobile unit or units having remote or wireless connectivity to central management server 100 using any protocols or standards known in the art, including Wi-Fi, GSM, and WIMAX, for example. Mobile units may also be synchronized with central management server through periodic wired or wireless connections when returning from field use. The PC can be, for example, any suitable PC known in the art and is preferably a Panasonic® Toughbook® or other portable, notebook, laptop, or tablet computer preferably designed to withstand vibration, drops, spills, extreme temperature, and other rough handling and conditions common to industrial use.

[0044] The UT meter can be, for example, an Olympus® MG2DL, or any similar UT meter known in the art. The UT meter can include, for example, features such as B-scan, gain adjust, auto sensitivity optimizations, echo-to-echo, differential mode, hi-low alarm, and live A-scan.

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The UT meter can also include a file-based alphanumeric data logger and an interface program for transferring data bi-directionally to and from a PC. The testing apparatus 110 can include a PC, such as described above, for enabling data and control functions of a peripheral testing apparatus 110 such as a UT meter.

[0045] The pressure test pump and transducer can be any suitable pressure test pump known in the art. Preferably, embodiments of the invention employ an X45 series model 345 Viatran® test and control pressure sensor, which can, for example, operate in the range of 0-100,000 psi with output in the range of 4-20 mA. As is known in the art, the testing apparatus 110 can include a control interface such as a programmable logic controller (PLC) for communication with and control of the pressure test pump and transducer.

Testing User 151 and Testing Interface 150

[0046] As described above, a testing user 151 may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test to be performed, and will manually configure the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test. In other embodiments, the testing user may perform testing operations according to instructions provided by the central management server 110 and displayed, for example, on the testing interface 150. The testing user 151 may provide the means of manually gathering testing data 440 as shown in FIG. 4, *i.e.*, the data that serves as the basis for the certification. Testing operations, as described above with reference to the testing apparatus 110, may be systematic, manual, or hybrid systematic/manual. For example, a sequence of testing operations for testing wall thickness of the frac iron may include systematic test operations to be performed by a testing apparatus 110, such as a UT meter, and manual operations to be performed by a testing user 151, such as using digital calipers to measure wall thickness or other dimensions of the frac iron, as can be seen in FIGS. 15-16, for example. Likewise, other sequences of testing operations may be fully manual, such as the mag particle test discussed further herein.

[0047] Also as described above, the testing interface 150 may be a PC, which may be any desktop, laptop, notebook, tablet, or portable computer known to those in the art. As is known the art, the testing interface 150 can include any number of peripheral devices to interact with the

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testing user 151, including a keyboard, mouse, control stick/joystick, and memory reader for receiving data input and a display screen, printer, and local storage device for outputting or storing data. Furthermore, embodiments of invention have a testing interface with a touch-sensitive screen (*e.g.,* using a stylus) for interactive display/input so that users can select parts responsive to viewing them on the display of the testing interface 150 and thereafter performing testing operations responsive to the selection, in communication with the testing module 210. The testing interface 150 may connect with the central management server 100 via any communications interface known to those of skill in the art, wired or wireless, and is preferably a secure local Intranet or other authenticated and encrypted communications network, including a VPN over the Internet.

Certificate 500

[0048] FIG. 5 sets forth an exemplary certificate 500 generated responsive to embodiments of the present invention. The certificate 500 relates to data stored in the database 170, for example, the certificate data 450 as shown in FIG. 4. The certificate 500, as is appreciated by those skilled in the art, can be a paper document printout or an electronic document in a format such as Adobe® Portable Document Format (.PDF), Microsoft® Word (.DOC or .DOCX), or a similar format. The certificate 500, for example, can be a paper document printout, as it is the custom in drilling and fracing operations for a paper document printout of a certificate to be presented to company personnel when well equipment is brought on-site in field operations. The company personnel takes possession of the physical document and reviews the testing parameters and testing results documented thereon to verify the quality of the equipment brought on site.

[0049] The certificate 500 can reference the well equipment device 101 by a unique device identifier, such as the serial number 501, which can relate to data stored in database 170 in the device information table 400. The certificate 500 can contain a summary indication as to whether certain test sequences were graded as a "PASS" or a "FAIL" 502. The grading operation, for example, can be performed by a certification module 220 computer program product operating on the central management server 100. The PASS or FAIL grading 502 can relate to data stored in the database 170, for example, the certificate data 450 and the testing data 440 shown in FIG. 4. The certificate 500 can also contain a summary or other rendering of

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testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. Graphical representation 503 can relate to data stored in the database 170 in the certificate data table 450 and the testing data table 440.

[0050] The certificate 500 can also contain a summary indication as to measured qualities of the selected well equipment device 101 and their relation to the qualities demanded by the test specification. For example, measured wall thickness value 505 appears adjacent to demanded wall thickness value 506. Additionally, drawing 504 shows a graphical representation of the parameters measured according to the test specification, as referenced by letter key (*e.g.*, "A," "B," and "C".).

[0051] In certain embodiments of the present invention, a certificate can be stored in a proprietary data table format so that a lightweight electronic copy of the certificate, and an "RFID certificate" can be stored directly onto RFID tag 135 attached to the selected well equipment 101. For example, as understood by those skilled in the art, the RFID certificate can be written to an RFID tag 135 attached to the well equipment so that the certificate can be readily accessed in the field using an RFID reader device 130 capable of recognizing the proprietary data table format. The RFID certificate can include all fields available on the paper certificate 500, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded, for example, using lightweight vector-based primitive formats. Also, RFID certificate will allow new schemes for protecting certificate data heretofore unavailable for field use, for example, by having individual cells in the table that are protected according to user access schemes such as read-only, read-write, or no access. For example, the serial number and the certification may be read-only to all; the certificate data may be read-only to many and read-write to few; and custom fields may be user-configurable.

Testing Module 210

[0052] As is shown in FIG. 2, the testing module 210 may be a computer program product stored in the memory 240 on the central management server 100 and operable on the processor

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251 thereof. Computer program product 210 contains instructions that are operable on the processor 251 that cause the testing module 210 and the central management server 100 to perform the operations discussed further herein.

[0053] The testing module 210 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In embodiments discussed below, the testing module 210 at least interacts with the testing interface 150, testing apparatus 110, RFID reader 130, and database 170. Although testing interface 150 has been described to be a personal computer (PC), testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, or using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality. Testing interface 150, for example, can receive user-selected identifiers or other user-selected values or parameters from a testing user as will be described in further detail below and can display identifiers, values, parameters, and other specification data, for example, as can be shown with reference to the selection, input, or display fields 900, 1000, 1100-1101, and 1200-1205 in FIGS. 9-12. Other user selection, input, or display fields are also shown elsewhere in FIGS. 13-25, as will be apparent to those having skill in the art.

[0054] The testing module 210 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device positioned to undergo testing and certification, *i.e.,* in the testing warehouse, on a testing trailer, or otherwise positioned at a testing station. In the embodiment of the present invention, only one well equipment device is tested at any given time using any particular testing apparatus 110. It is possible, however, that multiple instances or threads of the testing module 210 can run on the processor 251 concurrently, with each instance being directed to the testing of a different piece of well equipment positioned for testing. It is also possible that multiple testing apparatus 110 of the same type may be employed to perform the same test sequence in simultaneous testing operations performed on multiple well equipment devices 101.

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[0055] The testing module 210 can receive a serial number as a device identifier as shown in FIG. 6. The testing module 210 can receive a serial number as a device identifier, for example, by receiving input from the testing interface 150 as entered therein by a testing user 151. The testing module 210 can also receive a device identifier, such as a serial number, from a peripheral device, such as an RFID reader 130, as is discussed further herein.

[0056] The testing module 210 can identify the selected well equipment device responsive to the device identifier as shown in and match the selected well equipment to: (i) device library information as shown in FIG. 4 at table 400, the device library information including a part number, and (ii) a part library information at table 410 including type, test specification, and test profile, as shown in FIG. 7. If the testing module 210 is unable to identify the foregoing information as shown in FIG. 8 (*i.e.*, the device has not yet been tested), then the testing module 210 can prompt the testing user 151 to enter information to identify the device as shown in FIG. 9. Once the testing module 210 has matched the device 101 to a part number, the testing module 210 can match the device to a test specification and a test profile as shown in FIG. 4 at tables 420 and 430. The test specification can be criteria to which the testing operations will be performed, for example, as specified by the manufacturer or the customer. Test specifications can include, for example, a series of benchmark parameters as shown in FIG. 5 at 506. Test specifications can also include, for example, a schematic associated with the series of parameters as shown in FIG. 5 at 504.

[0057] The test profile as shown in FIG. 4 at table 430 may be a plurality of test sequences that are to be performed upon the well equipment device. A test profile may indicate that certain test sequences shall be run on certain parts, but not on others. For example, test profiles may be defined by "levels" as set forth by the logical process flows shown in FIGS. 6-9.

[0058] Level 1, as set forth in FIG. 6, can include, for example, making an inventory of all iron and entering al serial numbers or parts and specifications into the system. Then a testing user can visually examine and record any defects, damage, worn bodies, threads, and wing nuts on the iron. If the visual examine is acceptable, the tester can proceed with a wall thickness test, as discussed further herein. If the visual examination is unsuccessful, the user can scrap the iron in the database, mark the part with orange paint, and return or destroy the iron so that it becomes

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unusable. If the wall thickness is acceptable, the customer can be contacted if the wall thickness is within 5% of the minimum value set forth in the testing specification. If not, the testing user can proceed to the pressure test. If the pressure test is acceptable, the final inspection to be signed off by leading supervisor. If continued testing is desired, the tester can proceed to Level 2 before performing the pressure test.

[0059] Level 2, as set forth in FIG. 7, can include, for example, dismantling and stripping down and discarding all rubber seals and worn or corroded parts, then cleaning and removing grease from affected parts with solvent. Also, the testing user can perform a surface preparation in caustic solution tank, de-scale surfaces area to remove dirt scale, rust, and paint, and pressure rinse to remove caustic solution. The testing user then performs the visual examination as specified for Level 1, and may scrap the part also as specified for Level 1. If proceeding to Level 3 is acceptable, the testing user goes to Level 3 before performing the pressure test. Otherwise, the pressure test can be performed as specified for Level 1.

[0060] Level 3, as set forth in FIG. 8, can include, for example, inspecting the part to make sure its free from all oil, grease, paint, scale, rust, and all contaminates that might degrade the result of this inspection. The testing user then coats area to be inspected with wet fluorescent bath and puts a yoke on the part to create magnetic field. The user can pass the part for the magnetic particle test if, using a black light to check for indications of cracks and rechecking at right angles, the user finds no indications of cracks. If the magnetic particle test fails, the user can scrap the iron in the database as set forth for Level 1. After cleaning the part and completing the inspection buyoff, the testing user can reassemble and fit with news seals and any spare parts required. Thereafter the testing user can perform the pressure test as specified for Level 1 and proceed to paint per the customer's specifications or according to standardized paint schemes as set forth in FIG. 8. After painting, the supervising leader must sign off on the final inspection.

[0061] Test sequences 1300 can include, for example, visual inspection, wall thickness inspection, disassembly/assembly, magnetic ("mag") particle inspection, pressure test, paint, and final inspection. As shown in FIG. 13, test sequences available for the device 101, (*i.e.*, available according to the test profile 430) can be displayed to the testing user 151 using the

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testing interface 150 so that the testing user 151 may select one of the available test sequences to be performed.

[0062] Test sequences as shown in FIG. 13 may correspond to one of a plurality of testing apparatus 110. For example, the test sequence "wall thickness inspection" corresponds to the UT meter testing apparatus 110 and the test sequence "pressure test" corresponds to the pressure test pump and transducer. Other test sequences shown in FIG. 13 may correspond to manual procedures; for example, the test sequence "visual inspection" corresponds only to operations to be performed by the testing user 151. Each test sequence, as shown in table 440 of FIG. 4, corresponds to a sequence of testing operations to be performed upon the well equipment device 101.

[0063] Once the testing interface 150 displays the plurality of test sequences 440 available for the well equipment device, the testing user 151 can select a test sequence to be performed. The test sequence should correspond to the testing user positioning the selected well equipment device so that the testing apparatus 110 can perform the testing operations. For example, if the testing user 151 has selected the pressure test sequence, the testing user must also ensure that the appropriate testing apparatus 110 (*e.g.*, the pressure pump and transducer) is positioned upon the selected well equipment device so that the test can be properly performed.

[0064] If the testing user 151 has selected the pressure test sequence or the wall thickness inspection sequence, the testing module 210 will calibrate the testing apparatus 110 as shown in FIG. 14 and FIG. 15. In certain embodiments, the calibration 1400, 1500 can be performed responsive to the tolerances as specified in the test specification 420. Calibration can be performed, for example, by shoring a transducer of the testing apparatus 110 to return a rated pressure value or a baseline calibration setting by the manufacturer, as will be understood by those skilled in the art. Embodiments of the present invention can receive the baseline calibration setting returned and configure a calibration setting responsive thereto.

[0065] According to certain embodiments of the present invention, the testing module 210 systematically controls the performance of testing operations in certain test sequences. For such testing modules having full systematic control of performing the testing operations, *e.g.*, the pressure test sequence, the testing user 151 can initiate the performance of the testing operations

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to be controlled by the central management server 100, as shown at control deck 1600 in FIG. 16. The testing module 210 can control the corresponding testing apparatus 110 for the selected testing sequence so that the corresponding testing apparatus 110 performs the sequence of testing operations upon the selected well equipment device 101. For example, the pressure test sequence can be performed responsive to the pressure criteria set forth in the test specification. As shown in FIG. 17, the pressure test proceeds systematically as shown in test chart 1700 and the test module controls the performance of a pressurization of the selected well equipment device 101 for a preselected period of time, for example, as specified in the test specification.

[0066] In further embodiments of the present invention, the testing module 210 systematically controls the performance of some testing operations and requires manual performance of other testing operations ("hybrid systematic/manual"). For testing modules having hybrid systematic/manual performance of testing operations, such as for wall thickness inspection, the testing user 151 can initiate the performance of the testing operations to be controlled by the central management server 100, and the central management server 100 can control the testing apparatus 110 as discussed above with respect to fully systematic testing. Also, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIG. 18 and FIG. 19, the thickness at "Location A" can be measured and input 1800, 1900 either by the UT Meter or by the testing user 151 manually measuring Location A with a digital caliper. The testing module 210 transmits the schematic from the test specification to the testing interface 150 so that it may be displayed 1901 to the testing user 151 and instructs the testing user 151 how to perform the test operations with respect to the information set forth in the schematic and test specification.

[0067] In further embodiments of the present invention, the testing module 210 requires full manual performance of the testing operations for certain test sequences. For testing modules having full manual performance of testing operations, such as for the visual inspection sequence, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIGs. 20-21, band information 2000 and paint parameters 2100 can be input by the testing user 151 responsive to instructions provided by the testing module 210 to the test interface 150, the testing module 210 providing such instructions responsive to the sequence of testing operations and the test

specification. As can be seen in FIG. 17, for example, the testing interface 150 can display the schematic 2001 from the test specification to the testing user 151 and instructs the user how to perform the test operations with respect to information set forth in the schematic and the test specification.

[0068] Responsive to systematic, manual, or hybrid systematic/manual performance of the test operation described above, the testing module 210 receives testing data either as captured by the testing apparatus 110 for the corresponding testing sequence or as captured by the testing user 151 and entered into the testing interface 150 according to specific instructions provided by the testing module 210, e.g., at banding menu 2000. As shown in FIG. 4, the testing data is stored in the table 440 and linked to the device library 400 for the selected well equipment device 101. Also as shown in FIG. 4, an exemplary embodiment of the testing data in table 440 can have individual cells for each testing sequence (*e.g.*, wall thickness, pressure test, visual inspection, etc.). The testing data in table 440 can be used, as is discussed further herein, to generate certification data by execution of the certification module 220 on the processor 251.

[0069] Additionally, further embodiments of the present invention include certain test sequences as described in FIGS. 6-9. These test sequences, for example, can include disassembly/assembly, magnetic particle ("mag particle") inspection, paint, and final inspection. Although an embodiment of the invention includes manual performance of the test operations for these sequences, each of these test sequences may be implemented either by systematic, manual, or hybrid systematic/manual performance of the testing operations. Regardless of whether the performance of the testing operations are performed systematically or manually, those skilled in the art will realize that all testing operations are performed responsive to a command or instruction being systematically issued by the testing module 210 when executed on the central management server 100. As such, any test operation described herein as manual can be performed systematically provided there exists a testing apparatus 110 that can receive an instruction from the central management server 100 to perform the operation. For example, the performance of test operations using a digital caliper may be performed either manually or systematically, although an embodiment employs manual performance of such operations. Those skilled in the art will understand that it is within the scope of the invention to employ a testing apparatus 110 having a digital caliper, actuator, and an control device to systematically

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perform a wall thickness measurement using a digital caliper in addition to the embodiment employing manual performance. Likewise, it will be understood by those in the art that any manual operation described herein may also be performed systematically under the architecture of the central management server as set forth in FIG. 2.

Certification Module 220

[0070] As is shown in FIG. 2, the certification module 220 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 220 contains instructions that are operable on the processor 251 that cause the certification module 220 and the central management server 100 to perform the operations discussed further herein.

[0071] The certification module 220 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition both the certification module 220 and the testing module 210 are in communication with the processor 251 and the non-transitory memory 240 so that modules can pass or return variables between modules according to a shared API or access global variables being stored on the non-transitory memory 240 to ensure interoperability and open communication between computer program products in communication with the processor 251. Likewise, those skilled in the art will understand that computer program products 220 and 210 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251, but that a common API will allow interoperability and open communications. In embodiments discussed below, the certification module 220 at least interacts with the testing interface 150, RFID reader 130, RFID writer 140, and database 170. Although testing interface 150 has been described to be a PC, testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. The testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

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[0072] The certification module 220 can receive a device identifier for a selected well equipment device 101. As described above, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron." Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. The selected well equipment device is a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The certification module 220 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The certification module 220 can also receive a device identifier, for example, responsive to receiving input from a remote user interface as entered therein by a remote user 161. Furthermore, the certification module 220 can receive a device identifier from the testing module 210 responsive to the testing module 210 having completed execution of the testing operations and the generation and linking of the testing data in the database 170. The certification module 220 can identify a selected well equipment device responsive to the device identifier and generate and link certification data in database 170, for example, in certification table 450, responsive to the testing data. For example, the certification data 450 can include all data as can be entered onto certificate 500 as a summary or other rendering of testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. The certification module 220 can include logic to generate charts and data modeling based upon testing data, which is raw data stored, for example, in table 440. Further examples of summaries or renderings of raw testing data responsive to the testing operations appear on the face of certificate 500. As a result of the linking operation, the certification data 440 can be readily accessed or queried according to a serial number for a well equipment device.

[0073] The certification module 220 can also generate certification data in a format responsive the proprietary data table format for the exemplary RFID certificate. For example,

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certification module 220 may generate certificate data according to specific standards or protocols employed in the proprietary standard, for example, cell size, packet size, header length, payload length, etc. The RFID certificate can be generated so that it is ready to be stored to the media attached to the well equipment without further processing. The certification module 220 may also include logic for rendering graphics stored as certification data, such as the schematics and charts, into a lightweight graphics formats such as vector graphics formats. The RFID certificate, for example, can include all fields available on the paper document, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded in lightweight vector graphics formats, for example.

Reporting Module 230 and Enterprise Resource Planning Interface

[0074] As is shown in FIG. 2, the reporting module 230 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 230 contains instructions that are operable on the processor 251 that cause reporting module 230 and the central management server 100 to perform the operations discussed further herein.

[0075] The reporting module 230 can interact with the processor 251 to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition, both the reporting module 230 and the testing module 210 are in communication with the processor 251 and non-transitory memory 240 so that these two modules can pass or return variables between each other according to a common application programming interface (API) or shared global variables being stored on the non-transitory memory 240, thereby enhancing interoperability and open communication between the modules. Likewise, those skilled in the art will understand that computer program products 230 and 220 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251 and that a common API will allow interoperability and open communications as described above. In embodiments discussed below, the reporting module 230 at least interacts with the testing module 210, certification module 220, and database 170. Although remote user interface 160 may be a PC as has been described for testing interface 150,

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remote user interface 160 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Remote user interface 160 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

[0076] The reporting module 230 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The reporting module 230 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The reporting module 230 can also receive a device identifier from any other module, as discussed above. In response to receiving the device identifier, the reporting module 230 can match the device identifier to any desired data in the database 170, for example, testing data in the database at testing data table 440, certification data in the certification data table 450, device library data from the device library table 410, and test specification data from the specification library 420. The reporting module, responsive to the device identifier, can return any of the test specification for the selected well equipment device 101, testing data for a plurality of testing sequences performed on the selected well equipment device 101, and certificate data for the selected well equipment device 101, for example, according to the database structure provided in FIG. 4.

[0077] The reporting module 230 may also receive an indication or selection of additional variables for reporting purposes, for example, a part number, work order number, etc. In the event that the reporting module 230 receives an additional variable, the reporting module 230 can or expand or refine the matched data with respect to the additional variable. For example, the reporting module 230 may receive a device identifier, a work order number, and the reporting module 230 will return a list of all certifications, tests, or specifications for that device identifier according to the tests performed under the received work order number. On the other hand, a reporting module 230 may receive a device identifier and a part number, and the reporting module 213 will return a list of all certifications, tests, or specifications for either the selected well device 101 or all well devices tested having the selected the part number.

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[0078] Embodiments of the present invention employing the reporting module 230 are beneficial in that they transform the task of testing and certification—once a costly operational hurdle—into a robust data-point in business and operational management decisions. For example, manufacturers may use embodiments of the reporting module in research and development to better understand wear patterns and rates in real-world applications, to build a better product, and to manage customer relations. As those skilled in the art will appreciate, the reporting module 230 can be a powerful tool in achieving management-level value from systematic testing and certifications, which provides a comprehensive and reliable (*i.e.*, consistent) pool of data pertaining to asset management, inventory management, purchasing, risk management, and other business analytics. Exemplary reports generated by the reporting module 13 are shown in FIGS. 24-25.

[0079] Furthermore, embodiments of the present invention can employ an ERP (Enterprise Resource Planning) interface (not pictured) connected to the I/O of the central management server 100 to provide the foregoing benefits realized by the reporting module, but in a manner that is more fully integrated into enterprise-wide information systems and providing high levels of cross-functional integration, network scalability, and real-time data synchronization. In particular, embodiments of the present invention employ an ERP interface for the purposes of invoicing the testing and certification operations, for example, responsive to work order information entered by a testing user 151 to the testing interface 150 as shown in FIG. 6.

RFID 130, 135, 140

[0080] Furthermore, embodiments of the present invention can achieve some or all of the foregoing objectives by providing a central management server 200 that can communicate with one or more well equipment devices 101. For example, the central management server 200 can be in communication with the one or more well equipment devices using wireless communication technologies, for example, radio frequency identification (RFID) technologies. The one or more well equipment devices 101 can include an RFID tag 135, and the central management server 200 can communicate with the RFID tag 135 on the one or more well equipment devices using an RFID reader 130 in communication with the central management server 200 through the I/O 252. In an embodiment, the RFID tag is a UHF Gen-2 RFID tag that

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is attached to the frac iron using a clamp designed to be sufficiently robust so that the RFID tag is not affected by the harsh operating conditions of the downhole environment.

[0081] In an embodiment, the RFID reader 130 and RFID 140 are peripherals to the testing interface 150, attaching thereto by known connection means in the art, such as a USB cable or cables. In certain embodiments, the RFID reader and RFID writer may be one unit, such as an RFID reader/writer device.

[0082] The RFID reader 130 can read a device identifier from the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The central management server is positioned to receive the device identifier from the RFID reader 130. Any of the computer program products discussed herein, such as the testing module 210, can receive a device identifier responsive to the central management server 200 receiving a device identifier from the RFID reader 130. An embodiment of a computer-implemented method for using the RFID reader 130 includes the testing user 151 having a handheld and/or remote RFID reader 130 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can interrogate the RFID tag 135 and so that the RFID tag can transmit the device identifier to the RFID reader 130.

[0083] The RFID writer 140 can write an RFID certificate to the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The RFID certificate can have the qualities and properties as described herein, preferably including at least a serial number. The central management server is positioned to transmit the RFID certificate or any data included therein to the RFID writer 140 responsive to any of the computer program products discussed herein, such as the certification module 220. An embodiment of a computer-implemented method for using the RFID writer 140 includes the testing user 151 having a handheld or remote RFID writer 140 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can establish a communication link with the RFID tag 135 and so that the RFID writer can transmit and store the RFID certificate or the information therein to the RFID tag 135.

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[0084] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment," which is incorporated by reference in its entirety herein.

[0085] The foregoing has broadly outlined certain features, and technical advantages of the present invention and a detailed description of the invention so that embodiments of the invention may be better understood in light of features and advantages of the invention as described herein, which form the subject of certain claims of the invention. It should be appreciated that the conception and specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the present invention. It should also be realized that such equivalent constructions do not depart from the invention as set forth in the appended claims. The novel features which are believed to be characteristic of the invention, both as to its organization and method of operation, together with further advantages are better understood from the description when considered in connection with the accompanying figures. It is to be expressly understood, however, that such description and figures are provided for the purpose of illustration and description only and are not intended as a definition of the limits of the present invention. For example, although the example embodiments discussed herein are directed to oil and gas hydraulic fracturing operations, it should be specifically noted that the systems, machines, methods, and computer program products to test and certify well equipment devices may be employed to carry out similar functions for other equipment or devices requiring routine testing and certification, including without limitation, aircraft maintenance and construction, ship maintenance and construction, facilities maintenance and construction, and so on.

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That Claimed Is:

1. A central management server to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a plurality of testing apparatus performing one or more testing operations upon the well equipment devices, the machine comprising:

a processor;

a non-transitory memory;

an input/output unit to communicate with the plurality of testing apparatus;

a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences;

a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform the following operations:

identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations,

selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device,

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification,

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations, and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform the following operations:

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device,

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification, and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

2. A central management server as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a testing interface, the testing module further performing the following operation:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

3. A central management server as defined in Claim 1 or Claim 2, the testing module further performing the following operations:

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

4. A central management server as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a remote user interface, the central management server further comprising:

a reporting module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the reporting module being operable by the processor, the reporting module comprising a set of instructions that, when executed by the processor, cause the reporting module to perform the following operations:

identifying a selected well equipment device, a device test specification, testing data for a plurality of testing sequences, and a certificate, the identifying operation

responsive to receiving a device identifier for the selected well equipment device from the remote user interface,

delivering to the remote user interface at least one of the testing data, the device test specification, and the certificate responsive to the identifying operation.

5. A central management server as defined in Claim 1, wherein:

the input/output unit is further positioned to communicate with an RFID reader; and

the receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using the RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

6. A central management server as defined in Claim 5, wherein the input/output unit is further positioned to communicate with an RFID writer, the certification module further performing the following operations:

generating an RFID certificate responsive to the certificate, the RFID certificate being formatted so that the RFID certificate is recognizable by a remote interrogation device having an RFID reader; and

delivering an RFID certificate to the device RFID tag using the RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device.

7. A system to certify oil and gas well equipment, the system comprising:

a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith;

a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test

specification and the plurality of testing sequences defining certification criteria for the well equipment device;

a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence to test physical characteristics of the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification;

a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification; and

a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

8. A system as defined in Claim 7, the system further comprising:

a plurality of device RFID tags, each device RFID tag of the plurality of device RFID tags being attached to a well equipment device of the plurality of well equipment devices and having a device identifier for the well equipment device encoded thereon; and

an RFID reader in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to receive the device identifier for a well equipment device having a device RFID tag attached thereto responsive to the RFID reader interrogating the device RFID tag.

9. A system as defined in Claim 8, the system further comprising an RFID writer in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to generate an RFID certificate responsive to the certificate and deliver the RFID certificate to a device RFID tag using the RFID writer.

10. A system as defined in any one of Claims 7 to 9, the system further comprising database positioned to match a device identifier to a well equipment device, a device test specification, and a plurality of testing sequences, wherein the central management server identifies a device test specification and a plurality of testing sequences for a selected well equipment device responsive to matching the device identifier in the database.

11. A system as defined in any one of Claims 7 to 10, the system further comprising a testing interface in communication with the central management server, wherein:

each testing apparatus of the plurality of testing apparatus is positioned to perform a testing sequence responsive to receiving a selection of the testing sequence from the testing interface; and

the certificate is also generated responsive to user data received from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification.

12. A method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices, the method comprising:

receiving by a computer a device identifier for a selected well equipment device of the plurality of well equipment devices;

identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations;

selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device

being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device;

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification;

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations; and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

13. A method as defined in Claim 12 wherein selecting a testing sequence is responsive to receiving a selection of the test sequence from a testing interface.

14. A method as defined in Claim 12 or Claim 13, further comprising:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

15. A method as defined in any one of Claims 12 to 14, further comprising

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

16. A method as defined in any one of Claims 12 to 15 wherein receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using a RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

17. A method as defined in any one of Claims 12 to 16, further comprising: generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

18. A computer program comprising computer program code means adapted to perform all the steps of any one of Claims 12 to 17 when said computer program is run on a computer.

19. A computer program comprising computer program code means adapted to perform all the steps of any one of Claims 12 to 17 when said program is run on a computer, the computer program embodied on a computer readable medium.

20. A method to manage periodic certification of a plurality of well equipment devices, the certification based upon testing data generated responsive to a plurality of testing apparatus

performing one or more testing operations to test physical characteristics of the plurality of well equipment devices, the method comprising:

identifying by a computer a selected well equipment device and a device test specification responsive to receipt of physical testing data for a plurality of physical testing sequences, the selected well equipment device corresponding to a device identifier for the selected well equipment device;

generating a certificate for the selected well equipment device responsive to receipt of the physical testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in a database so that the certificate can be readily recalled from the database responsive to the device identifier.

21. A method as defined in Claim 20, the method further comprising:

delivering an RFID certificate to a device RFID tag using an RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

FIG. 1

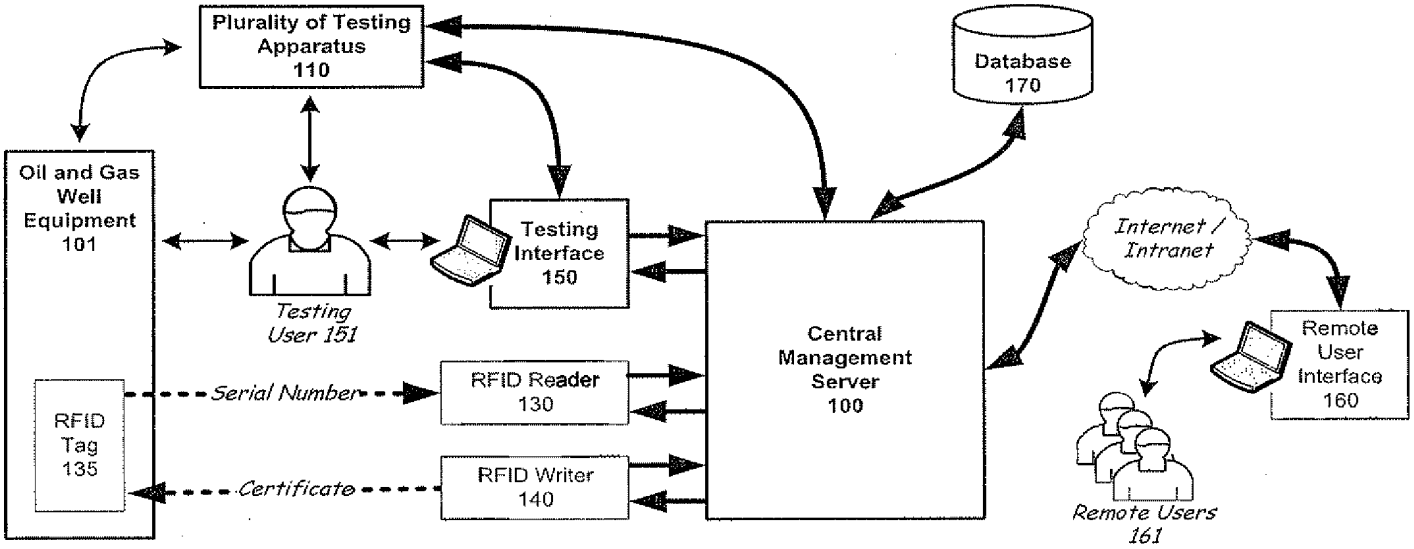

Plurality of Testing Apparatus 110
Database 170
Oil and Gas Well Equipment 101
Testing Interface 150
Testing User 151
Central Management Server 100
Internet / Intranet
Remote User Interface 160
RFID Tag 135
Serial Number
RFID Reader 130
RFID Writer 140
Certificate
Remote Users 161

FIG. 2

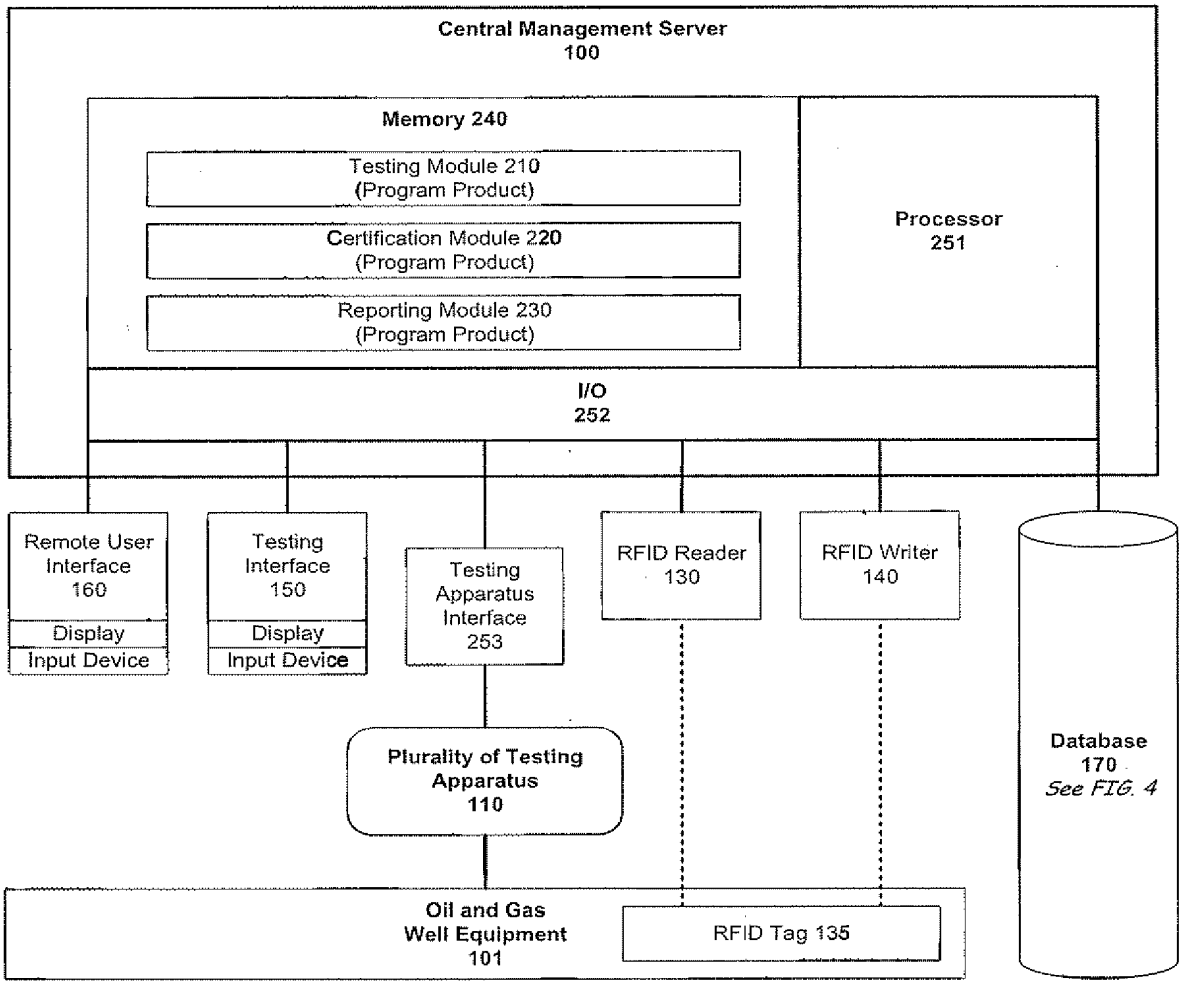

Central Management Server 100
Memory 240
Testing Module 210 (Program Product)
Certification Module 220 (Program Product)
Reporting Module 230 (Program Product)
Processor 251
I/O 252
Remote User Interface 160
Display
Input Device
Testing Interface 150
Display
Input Device
Testing Apparatus Interface 253
RFID Reader 130
RFID Writer 140
Database 170 See FIG. 4
Plurality of Testing Apparatus 110
Oil and Gas Well Equipment 101
RFID Tag 135

FIG. 3

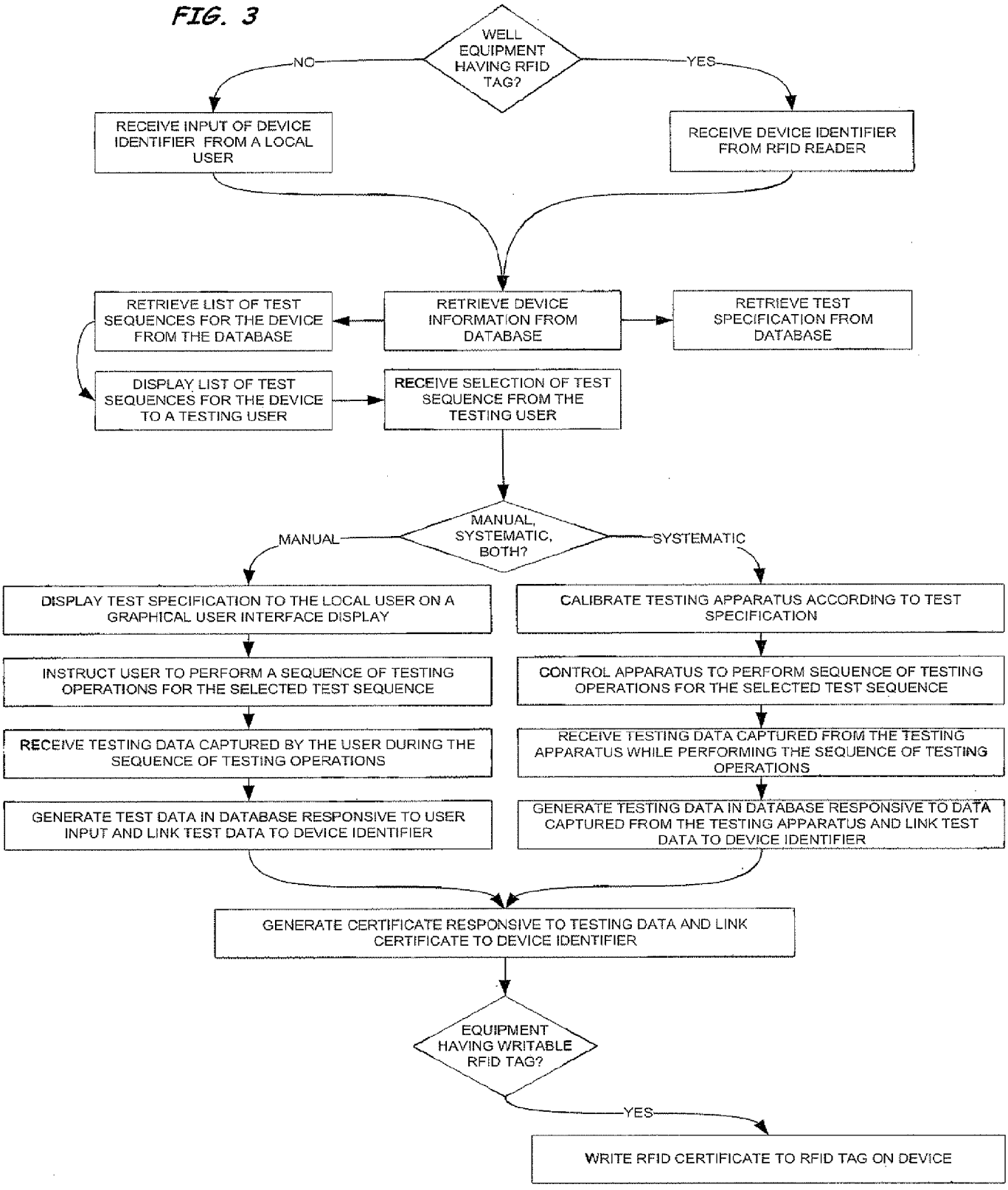
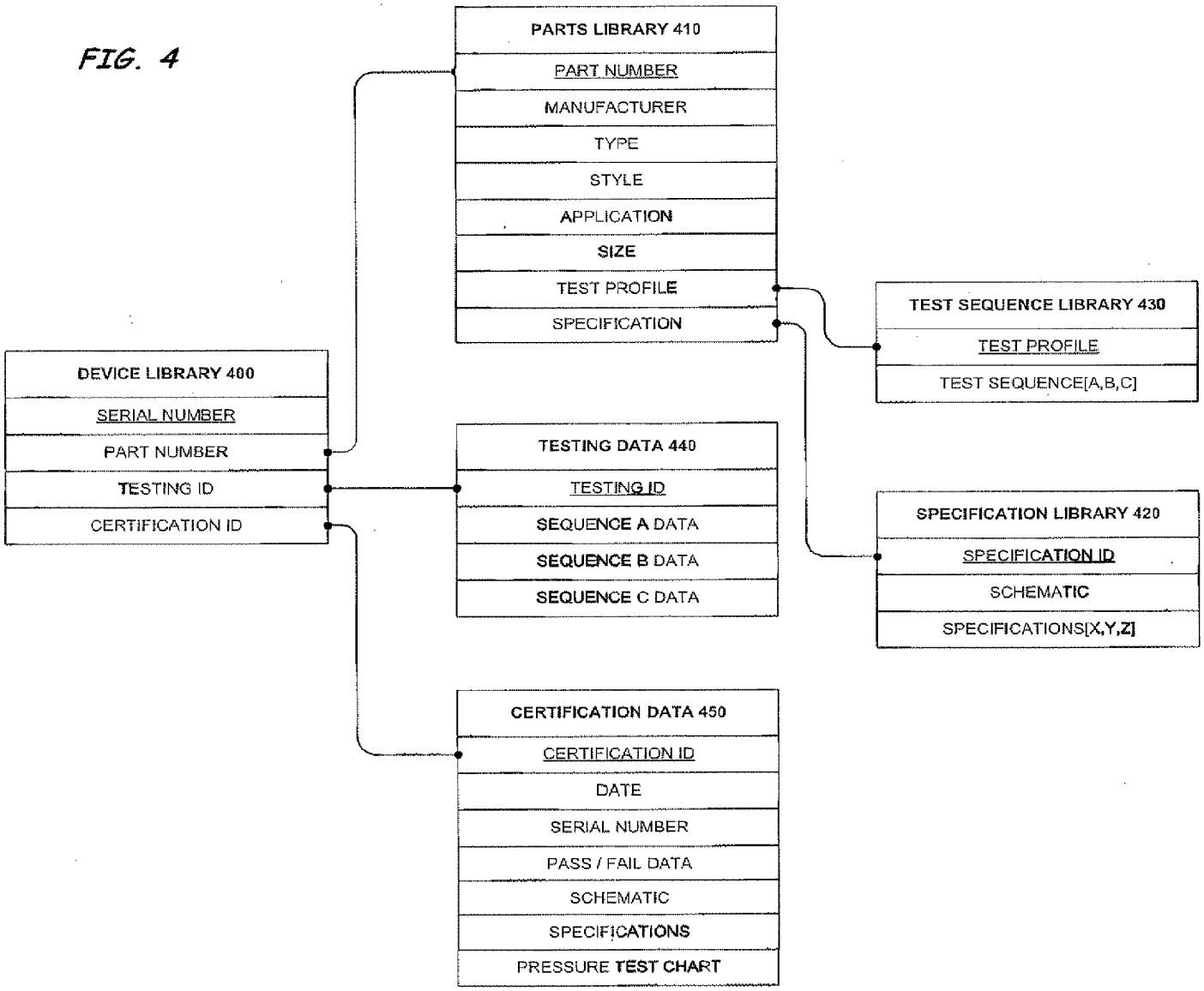

WELL EQUIPMENT HAVING RFID TAG?
NO
YES
RECEIVE INPUT OF DEVICE IDENTIFIER FROM A LOCAL USER
RECEIVE DEVICE IDENTIFIER FROM RFID READER
RETRIEVE LIST OF TEST SEQUENCES FOR THE DEVICE FROM THE DATABASE
RETRIEVE DEVICE INFORMATION FROM DATABASE
RETRIEVE TEST SPECIFICATION FROM DATABASE
DISPLAY LIST OF TEST SEQUENCES FOR THE DEVICE TO A TESTING USER
RECEIVE SELECTION OF TEST SEQUENCE FROM THE TESTING USER
MANUAL, SYSTEMATIC, BOTH?
MANUAL
SYSTEMATIC
DISPLAY TEST SPECIFICATION TO THE LOCAL USER ON A GRAPHICAL USER INTERFACE DISPLAY
INSTRUCT USER TO PERFORM A SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED BY THE USER DURING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TEST DATA IN DATABASE RESPONSIVE TO USER INPUT AND LINK TEST DATA TO DEVICE IDENTIFIER
CALIBRATE TESTING APPARATUS ACCORDING TO TEST SPECIFICATION
CONTROL APPARATUS TO PERFORM SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED FROM THE TESTING APPARATUS WHILE PERFORMING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TESTING DATA IN DATABASE RESPONSIVE TO DATA CAPTURED FROM THE TESTING APPARATUS AND LINK TEST DATA TO DEVICE IDENTIFIER
GENERATE CERTIFICATE RESPONSIVE TO TESTING DATA AND LINK CERTIFICATE TO DEVICE IDENTIFIER
EQUIPMENT HAVING WRITABLE RFID TAG?
YES
WRITE RFID CERTIFICATE TO RFID TAG ON DEVICE

FIG. 4


PARTS LIBRARY 410
PART NUMBER
MANUFACTURER
TYPE
STYLE
APPLICATION
SIZE
TEST PROFILE
SPECIFICATION
TEST SEQUENCE LIBRARY 430
TEST PROFILE
TEST SEQUENCE[A,B,C]
DEVICE LIBRARY 400
SERIAL NUMBER
PART NUMBER
TESTING ID
CERTIFICATION ID
TESTING DATA 440
TESTING ID
SEQUENCE A DATA
SEQUENCE B DATA
SEQUENCE C DATA
SPECIFICATION LIBRARY 420
SPECIFICATION ID
SCHEMATIC
SPECIFICATIONS[X,Y,Z]
CERTIFICATION DATA 450
CERTIFICATION ID
DATE
SERIAL NUMBER
PASS / FAIL DATA
SCHEMATIC
SPECIFICATIONS
PRESSURE TEST CHART

500

501

CERTIFICATION

SERIAL NUMBER:

Customer: **Cust Num:** **Plant:**
Work Order: **Part Num:** 2A1 **Mfr:**
Description: MXF/INT/4 LR10 WR
District

Visual Inspection - PASS 502

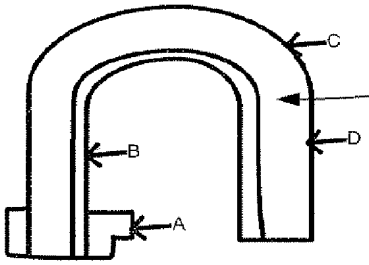
Comments:
Inspected By: SCOTT H **Test Date:** March 18, 2010

Wall Thickness Inspection - PASS 502

504

Comments:
Thickness Gauge: VERSION: 1.13 /1.01s
Gauge Cal Date: March 18, 2010
Wall Thickness Values (minimum in parenthesis):
A: 0.60"(0.40"), B: 0.60"(0.44"), C: 0.88"(0.36"), D: 0.89"(0.39"),

505
506



Inspected By:
Test Date:

Disassembly/Assembly - PASS 502

Comments:
Inspected By: **Test Date:** March 18, 2010

Magnetic Particle Inspection - N/A 502

Comments: THIS TEST WAS NOT PERFORMED FOR THIS IRON.
Mag Part **Gauge Cal Date:**
Inspected By: **Test Date:**

Pressure Test - PASS 502

Comments: good
Required Test Pres: 10000 PSI
Rated Working Pres: 10000 PSI
Test Duration: minutes
Tested By:
Approved By:
Test Date: March 18, 2010
Pres Gauge: 357808
Gauge Cal Date: March 16, 2010
Pres Recorder:
Recorder Cal Date:

503

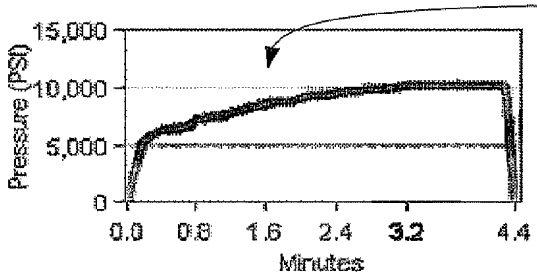


FIG. 5

FIG. 6

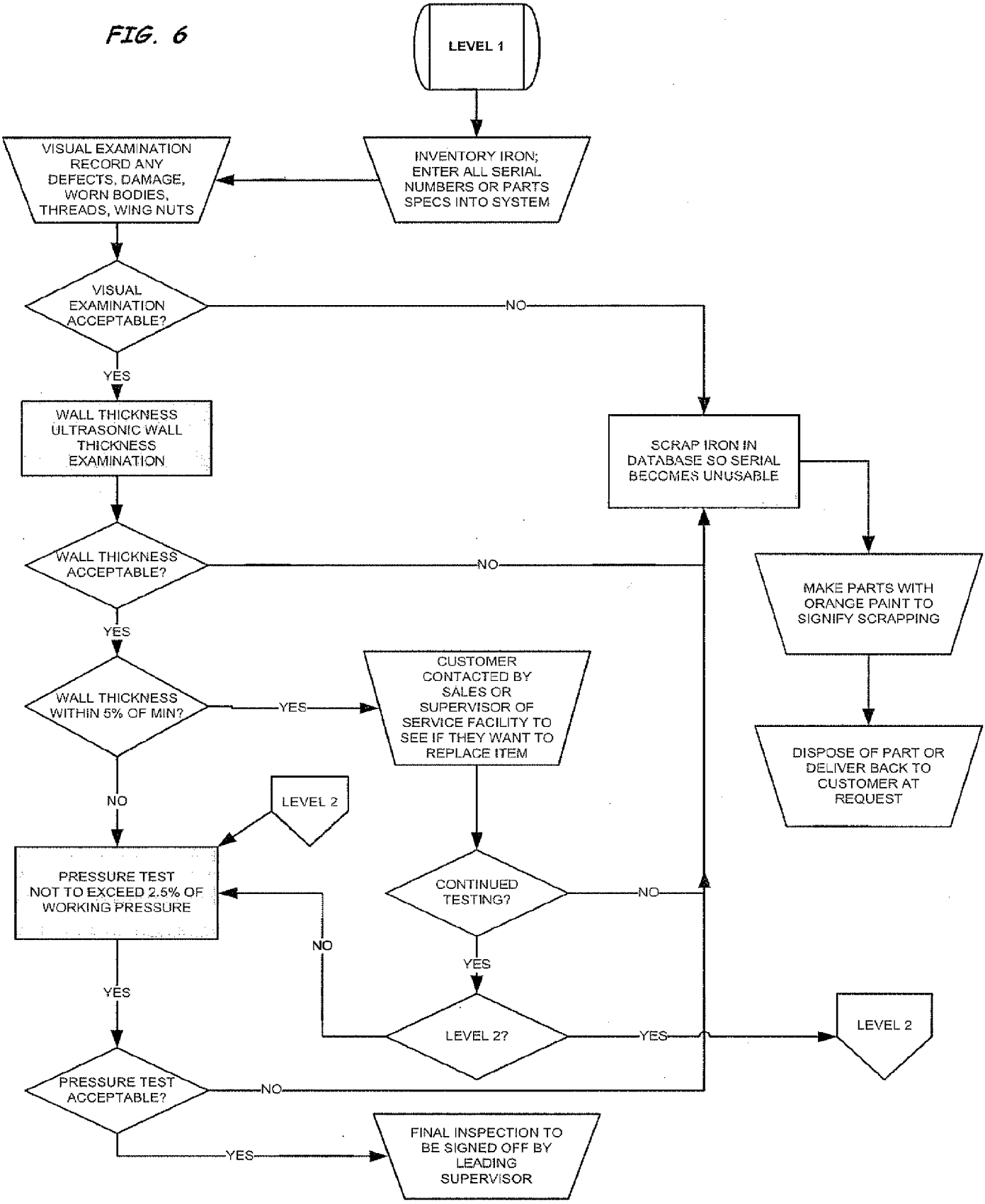
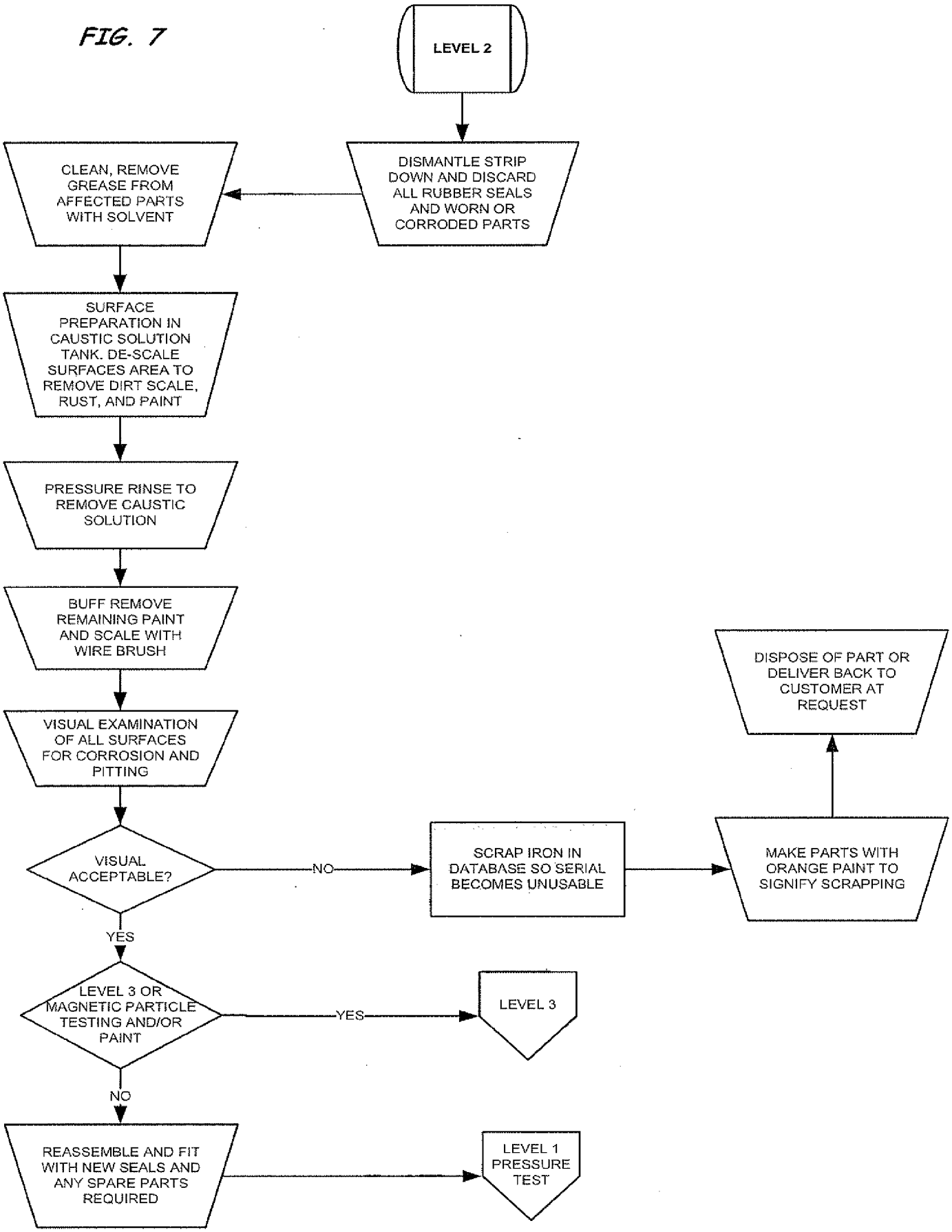

LEVEL 1
INVENTORY IRON; ENTER ALL SERIAL NUMBERS OR PARTS SPECS INTO SYSTEM
VISUAL EXAMINATION RECORD ANY DEFECTS, DAMAGE, WORN BODIES, THREADS, WING NUTS
VISUAL EXAMINATION ACCEPTABLE?
NO
YES
WALL THICKNESS ULTRASONIC WALL THICKNESS EXAMINATION
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
WALL THICKNESS ACCEPTABLE?
NO
YES
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
WALL THICKNESS WITHIN 5% OF MIN?
YES
CUSTOMER CONTACTED BY SALES OR SUPERVISOR OF SERVICE FACILITY TO SEE IF THEY WANT TO REPLACE ITEM
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
NO
LEVEL 2
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
CONTINUED TESTING?
NO
NO
YES
YES
LEVEL 2?
YES
LEVEL 2
PRESSURE TEST ACCEPTABLE?
NO
YES
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR

FIG. 7


LEVEL 2
DISMANTLE STRIP DOWN AND DISCARD ALL RUBBER SEALS AND WORN OR CORRODED PARTS
CLEAN, REMOVE GREASE FROM AFFECTED PARTS WITH SOLVENT
SURFACE PREPARATION IN CAUSTIC SOLUTION TANK. DE-SCALE SURFACES AREA TO REMOVE DIRT SCALE, RUST, AND PAINT
PRESSURE RINSE TO REMOVE CAUSTIC SOLUTION
BUFF REMOVE REMAINING PAINT AND SCALE WITH WIRE BRUSH
VISUAL EXAMINATION OF ALL SURFACES FOR CORROSION AND PITTING
VISUAL ACCEPTABLE?
NO
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
YES
LEVEL 3 OR MAGNETIC PARTICLE TESTING AND/OR PAINT
YES
LEVEL 3
NO
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
LEVEL 1 PRESSURE TEST

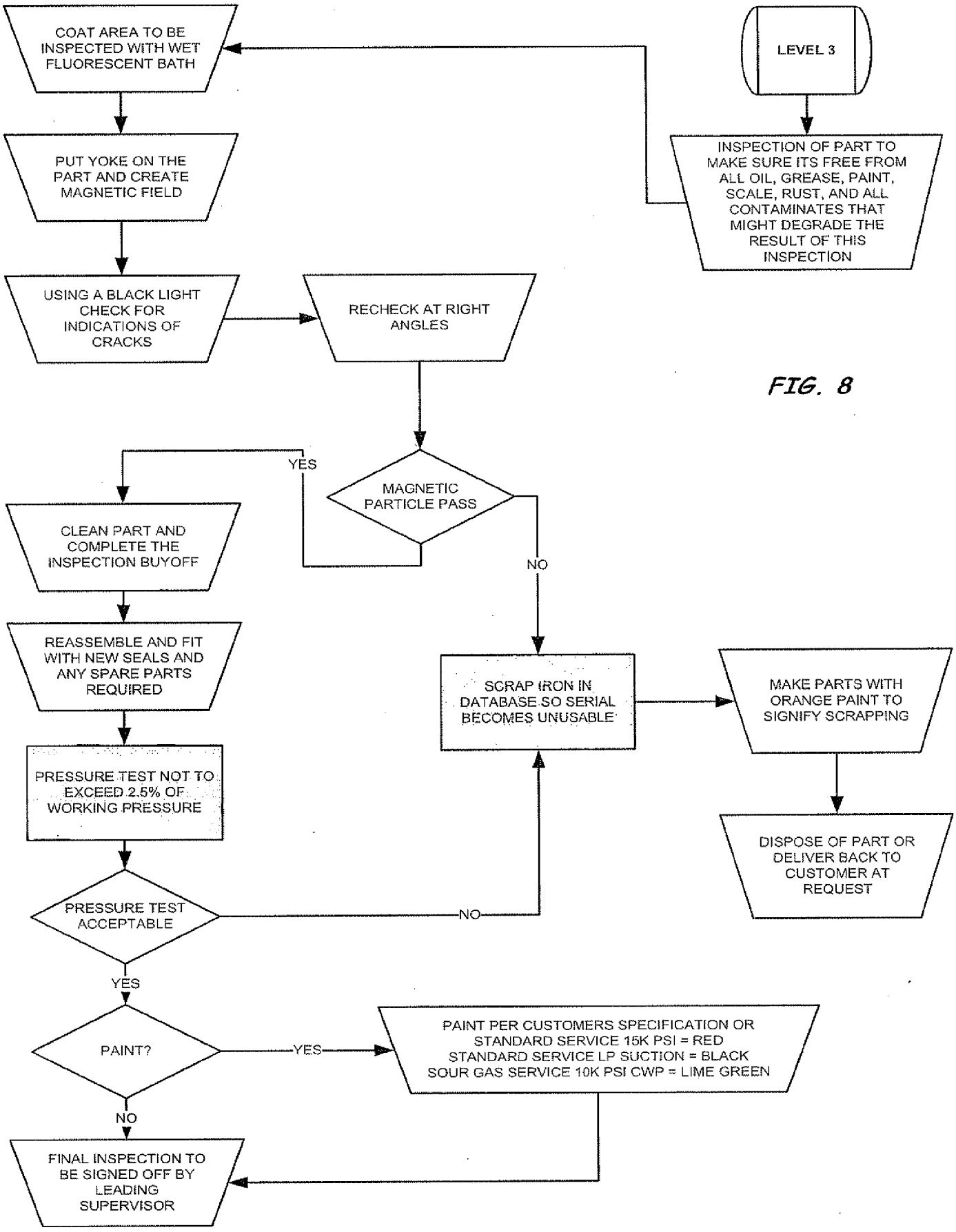

COAT AREA TO BE INSPECTED WITH WET FLUORESCENT BATH
PUT YOKE ON THE PART AND CREATE MAGNETIC FIELD
USING A BLACK LIGHT CHECK FOR INDICATIONS OF CRACKS
RECHECK AT RIGHT ANGLES
MAGNETIC PARTICLE PASS
YES
NO
CLEAN PART AND COMPLETE THE INSPECTION BUYOFF
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
PRESSURE TEST ACCEPTABLE
NO
YES
PAINT?
YES
NO
PAINT PER CUSTOMERS SPECIFICATION OR
STANDARD SERVICE 15K PSI = RED
STANDARD SERVICE LP SUCTION = BLACK
SOUR GAS SERVICE 10K PSI CWP = LIME GREEN
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
LEVEL 3
INSPECTION OF PART TO MAKE SURE ITS FREE FROM ALL OIL, GREASE, PAINT, SCALE, RUST, AND ALL CONTAMINATES THAT MIGHT DEGRADE THE RESULT OF THIS INSPECTION

FIG. 8

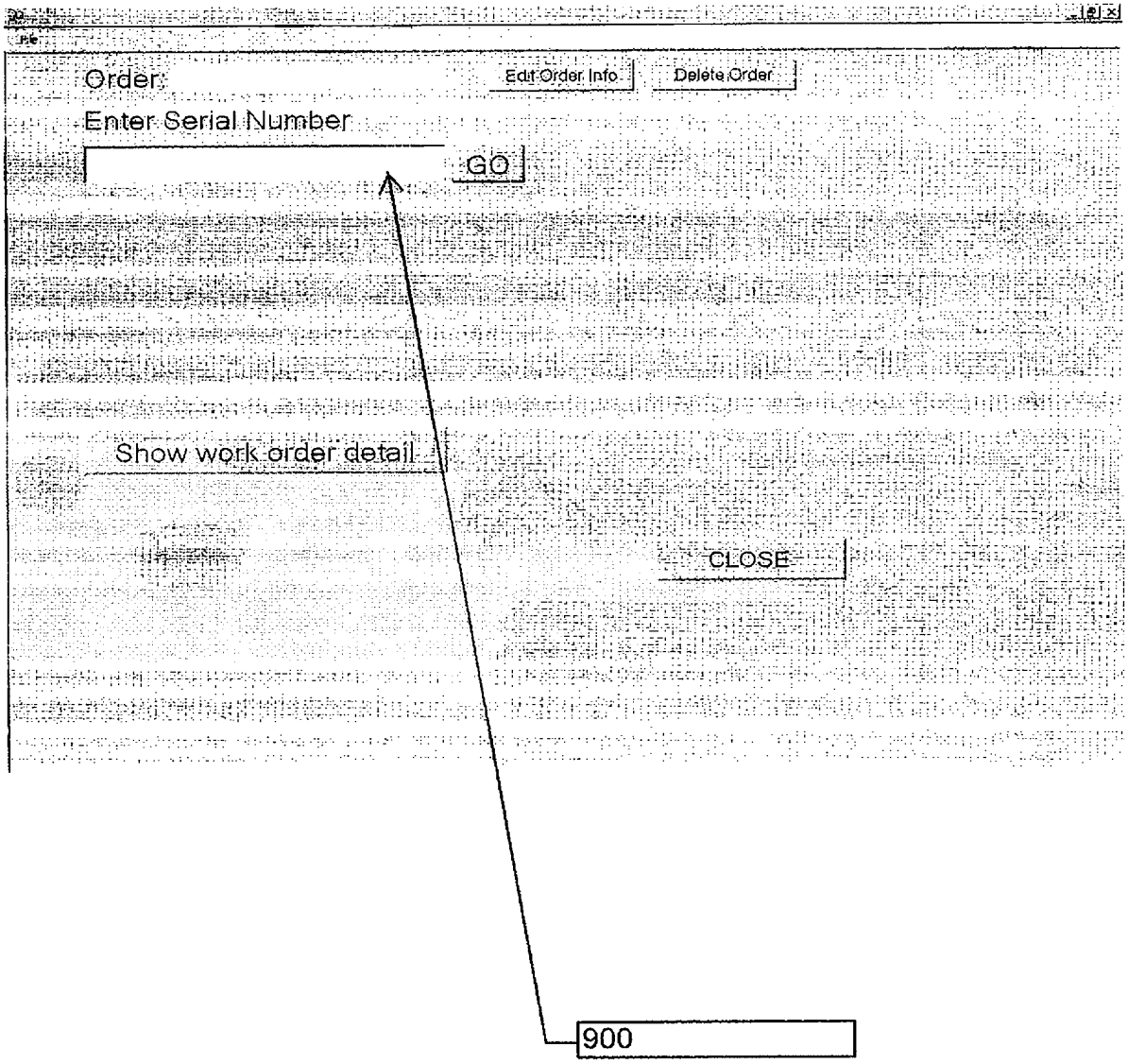

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Show work order detail
CLOSE
900

FIG. 9

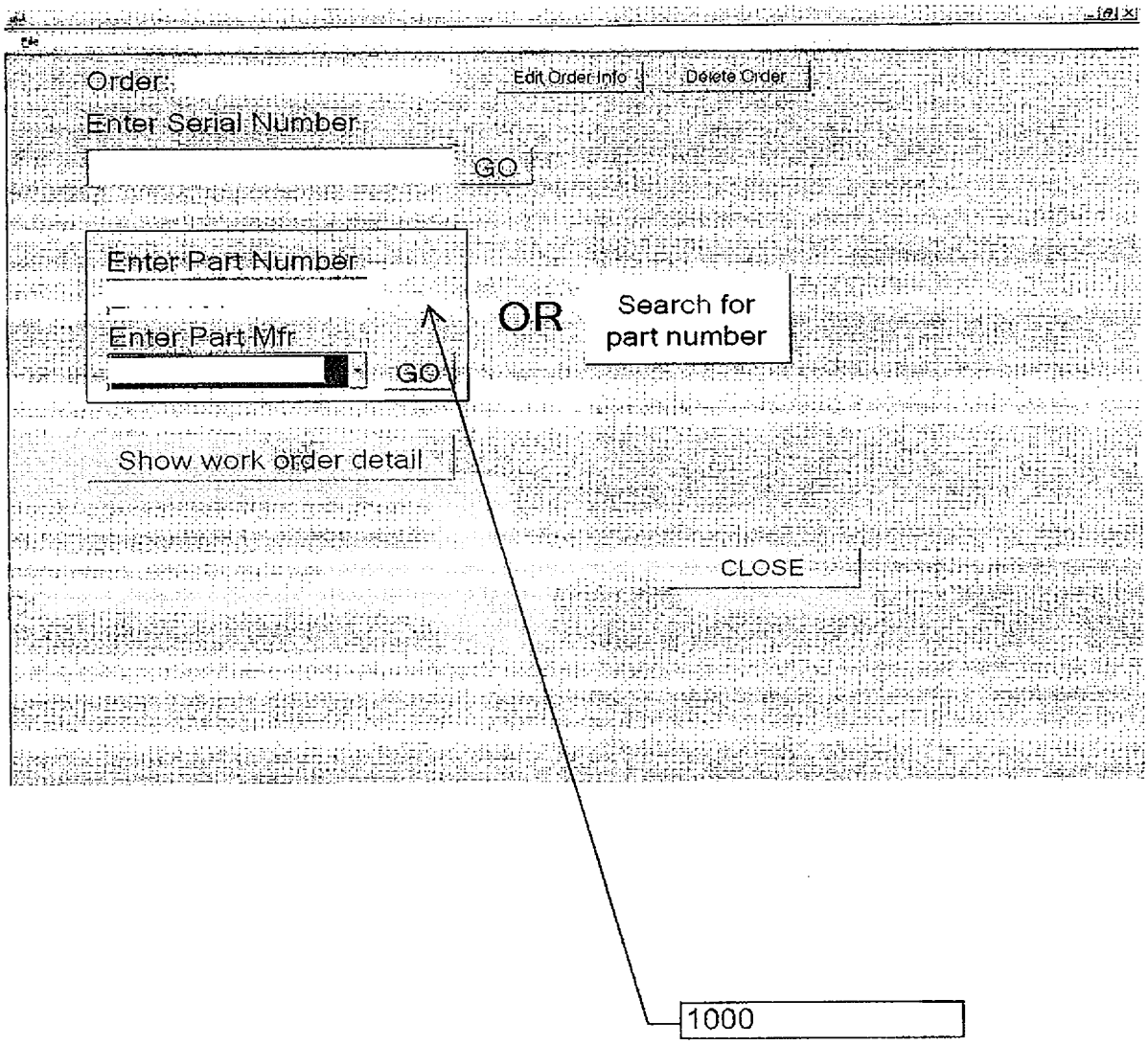

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Enter Part Number
Enter Part Mfr
GO
OR
Search for part number
Show work order detail
CLOSE
1000

FIG. 10

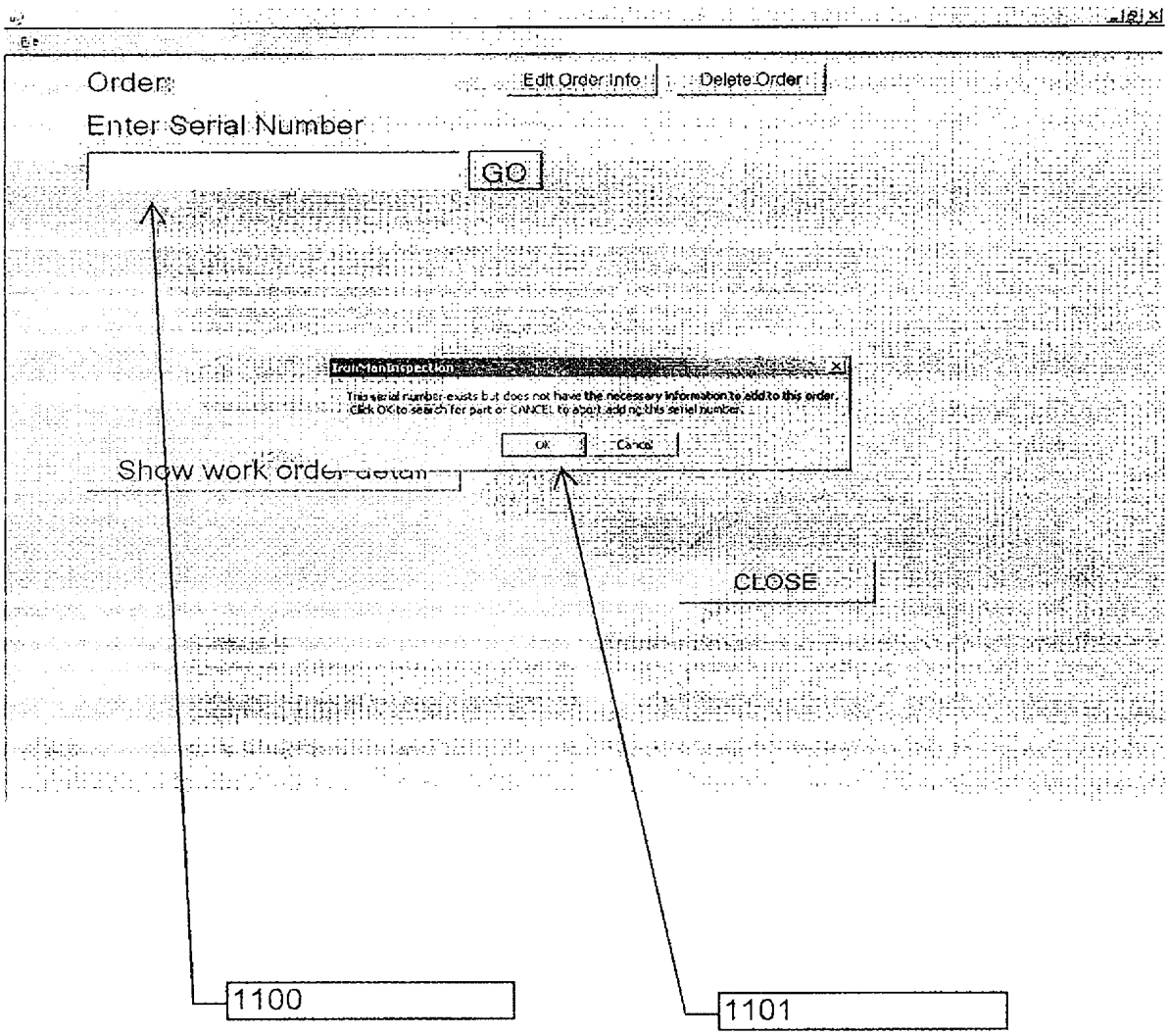

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Show work order detail
CLOSE
1100
1101

FIG. 11

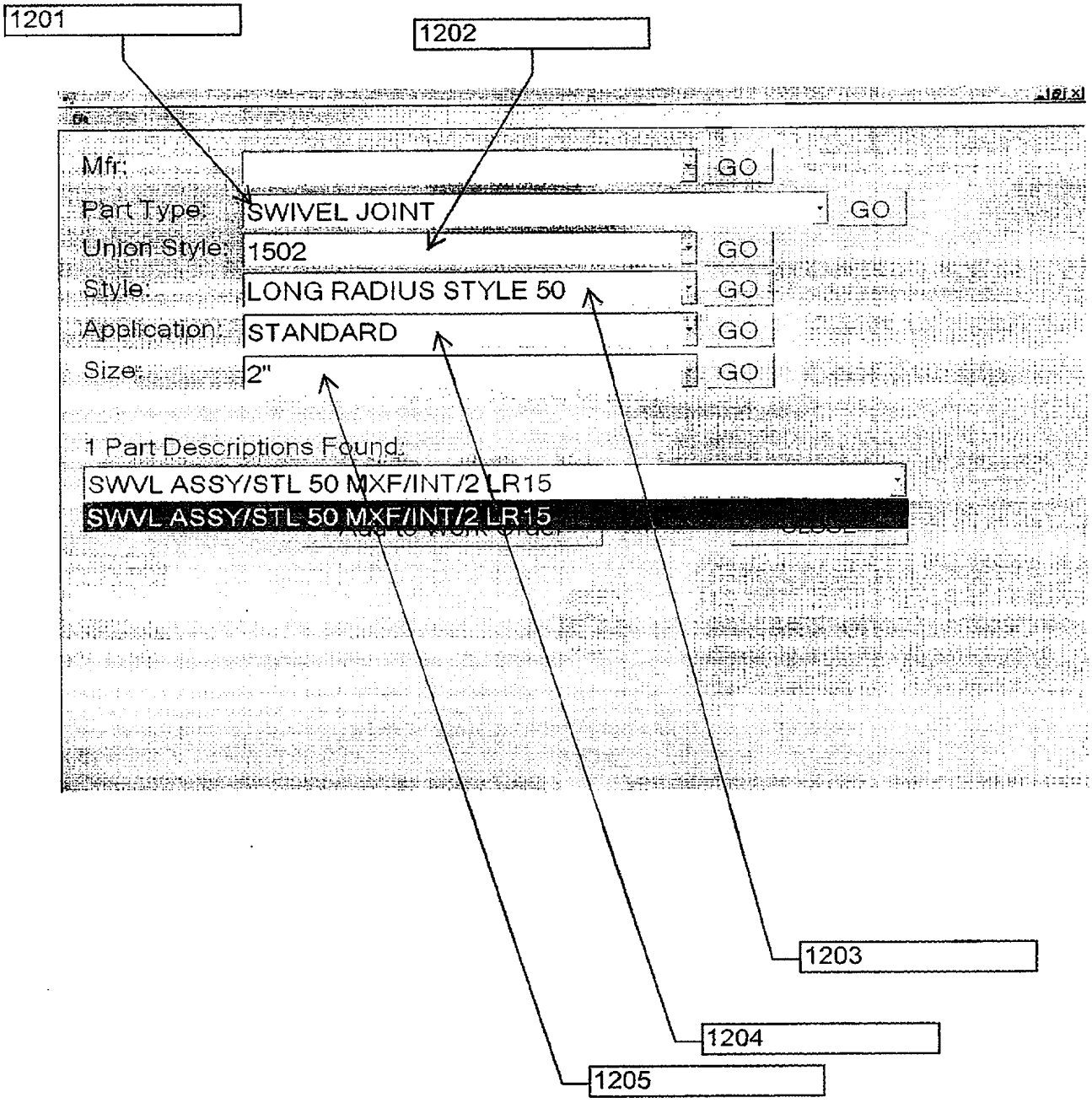

1201
1202
Mfr:
GO
Part Type:
SWIVEL JOINT
GO
Union Style:
1502
GO
Style:
LONG RADIUS STYLE 50
GO
Application:
STANDARD
GO
Size:
2"
GO
1 Part Descriptions Found:
SWVL ASSY/STL 50 MXF/INT/2 LR15
SWVL ASSY/STL 50 MXF/INT/2 LR15
1203
1204
1205

FIG. 12

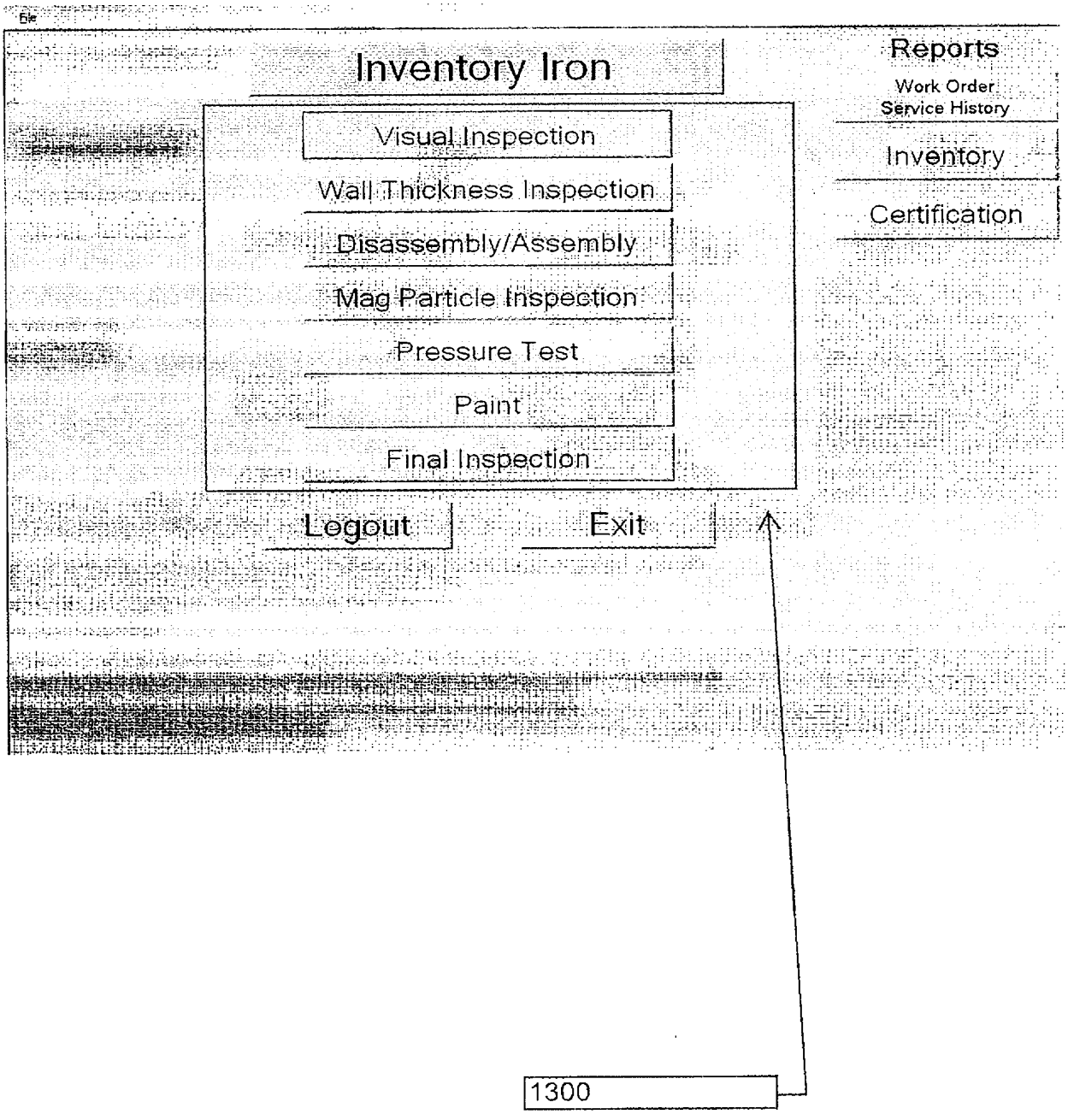

File
Inventory Iron
Visual Inspection
Wall Thickness Inspection
Disassembly/Assembly
Mag Particle Inspection
Pressure Test
Paint
Final Inspection
Logout
Exit
Reports
Work Order
Service History
Inventory
Certification
1300

FIG. 13

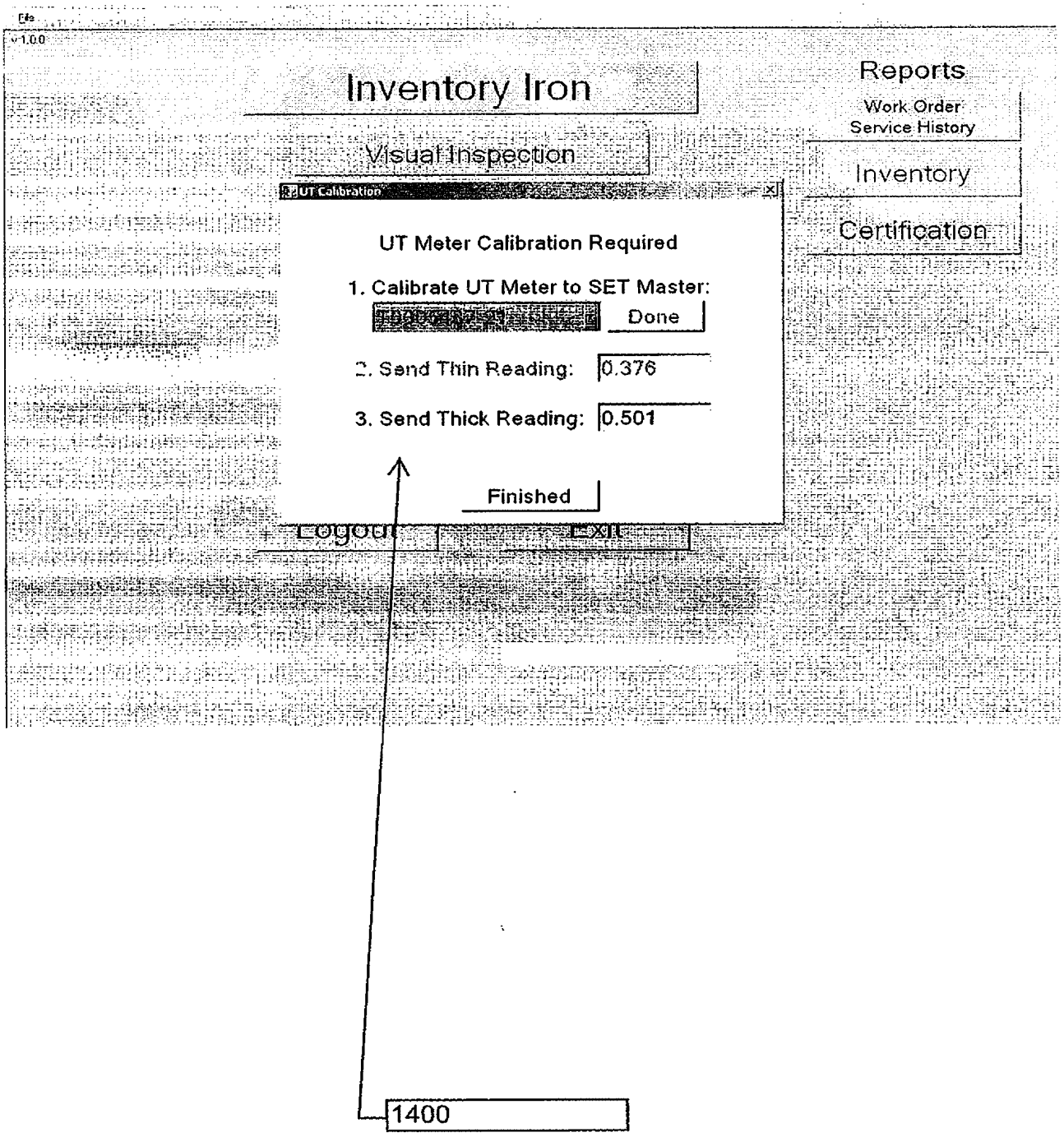

File
v 1.0.0
Inventory Iron
Reports
Work Order
Service History
Visual Inspection
Inventory
Certification
UT Calibration
UT Meter Calibration Required
1. Calibrate UT Meter to SET Master:
Done
2. Send Thin Reading: 0.376
3. Send Thick Reading: 0.501
Finished
Logout
Exit
1400

FIG. 14

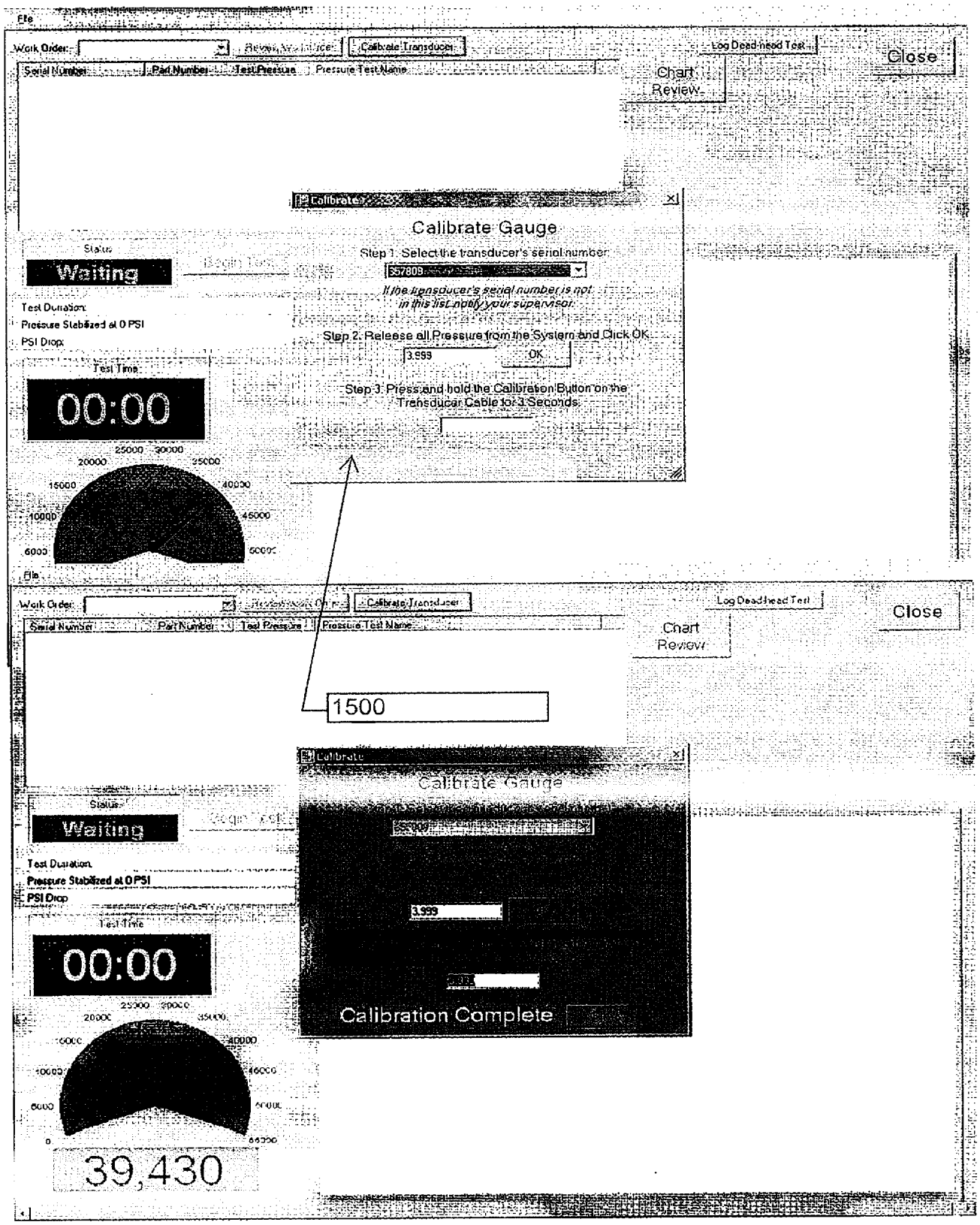

File
Work Order:
Calibrate Transducer
Log Deadhead Test
Close
Serial Number
Part Number
Test Pressure
Pressure Test Name
Chart Review
Calibrate Gauge
Step 1: Select the transducer's serial number
If the transducer's serial number is not in this list, notify your supervisor.
Step 2: Release all Pressure from the System and Click OK
OK
Step 3: Press and hold the Calibration Button on the Transducer Cable for 3 Seconds
Status
Waiting
Test Duration:
Pressure Stabilized at 0 PSI
PSI Drop:
Test Time:
00:00
1500
3.999
Calibration Complete
39,430

FIG. 15

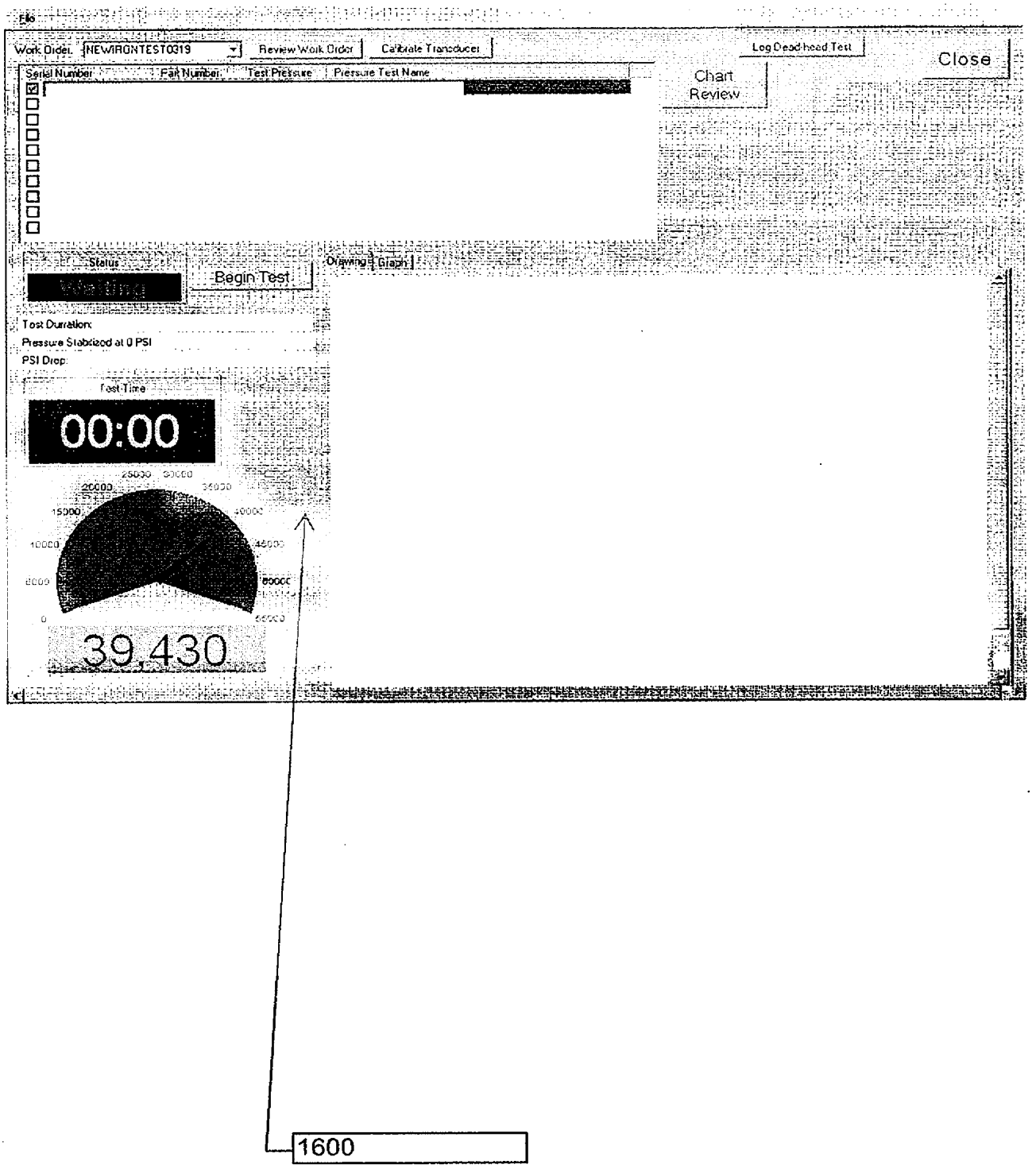

File
Work Order: NEWIRONTEST0319
Review Work Order
Calibrate Transducer
Log Deadhead Test
Close
Serial Number
Part Number
Test Pressure
Pressure Test Name
Chart Review
Status
Begin Test
Drawing
Graph
Test Duration:
Pressure Stabilized at 0 PSI
PSI Drop
Test Time
00:00
39.430
1600

FIG. 16

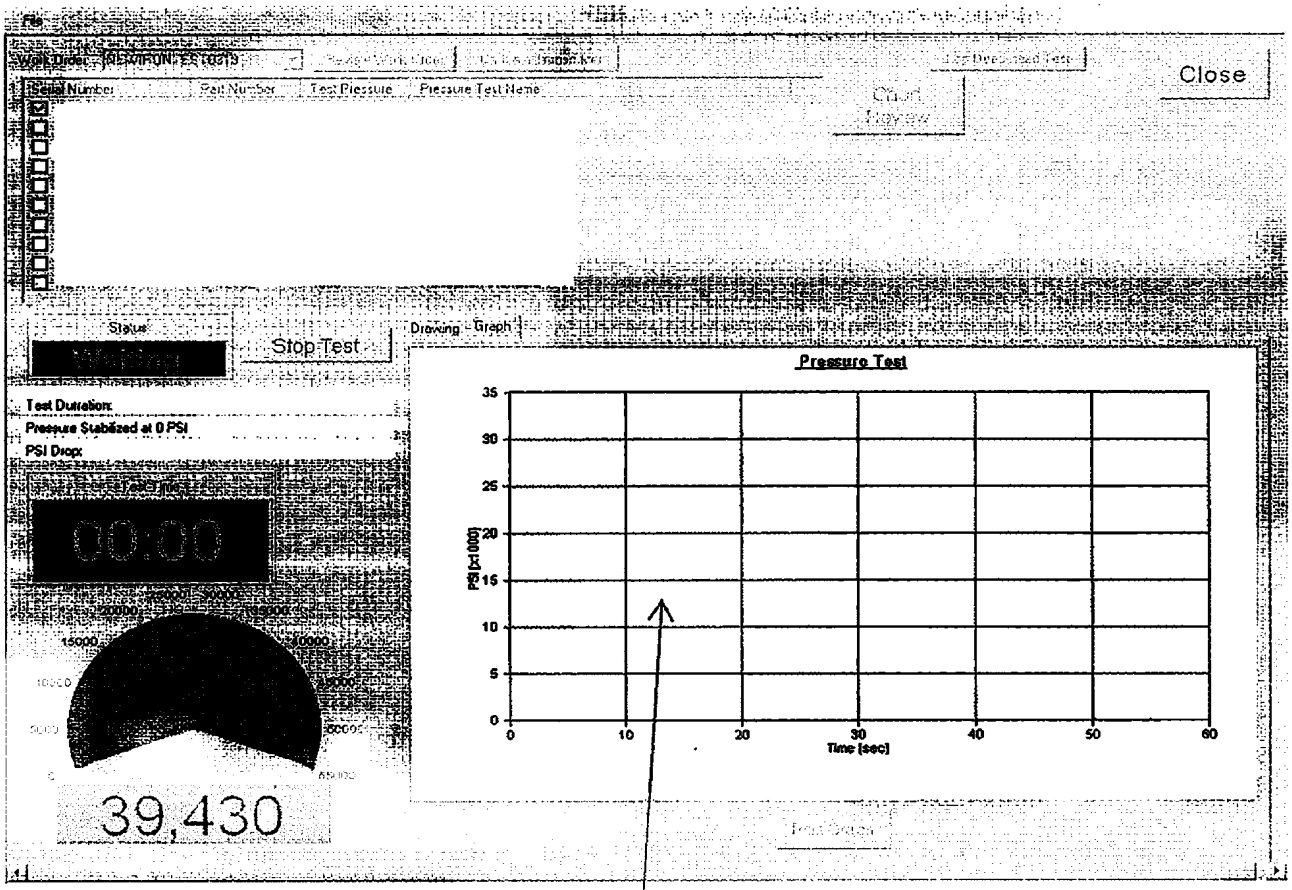

Close
Stop Test
Drawing - Graph
Pressure Test
PSI [x1 000]
Time [sec]
Test Duration
Pressure Stabilized at 0 PSI
PSI Drop
00:00
39,430
1700

FIG. 17

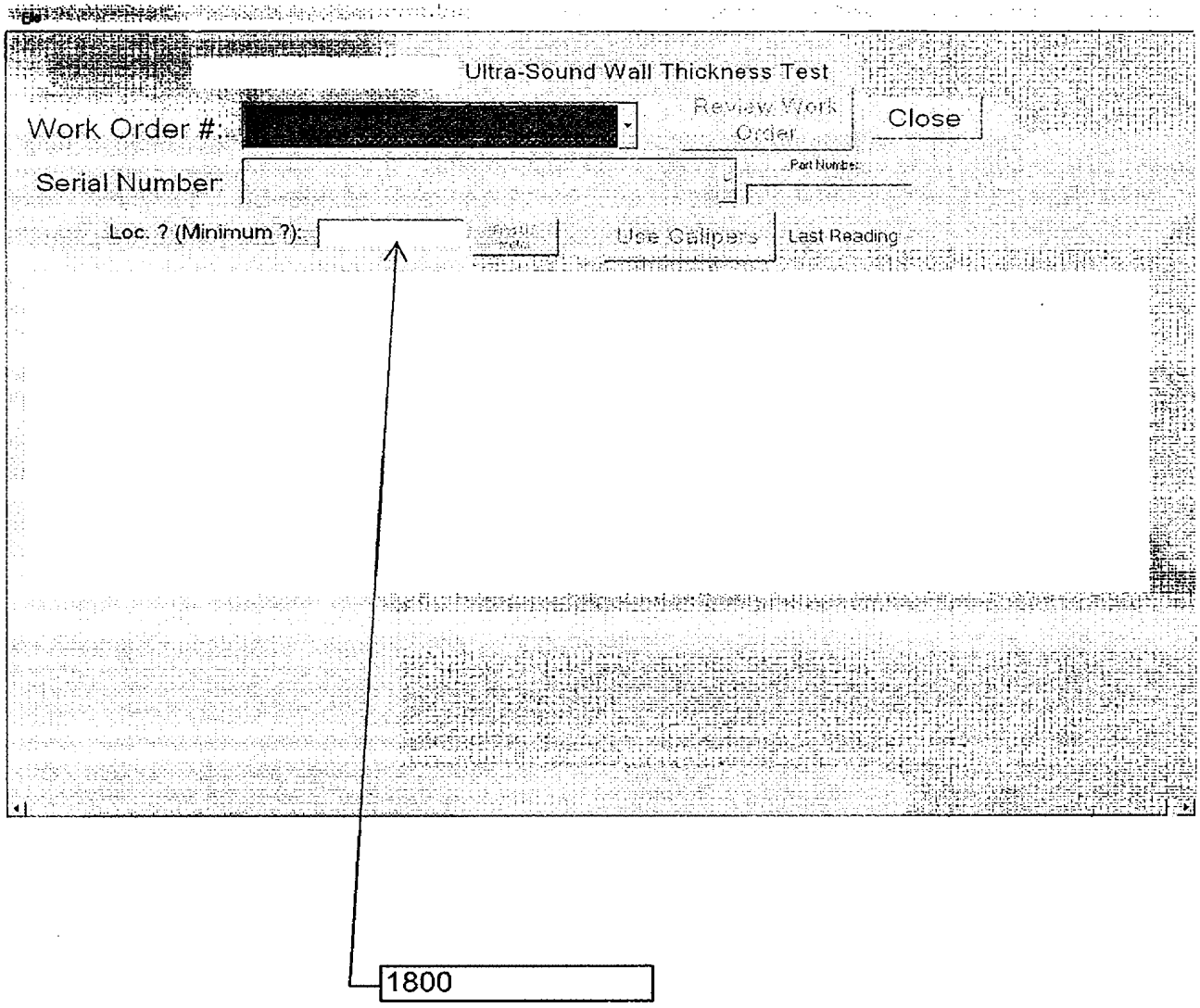

Ultra-Sound Wall Thickness Test
Work Order #:
Review Work Order
Close
Serial Number:
Part Number:
Loc. ? (Minimum ?):
Use Calipers
Last Reading
1800

FIG. 18

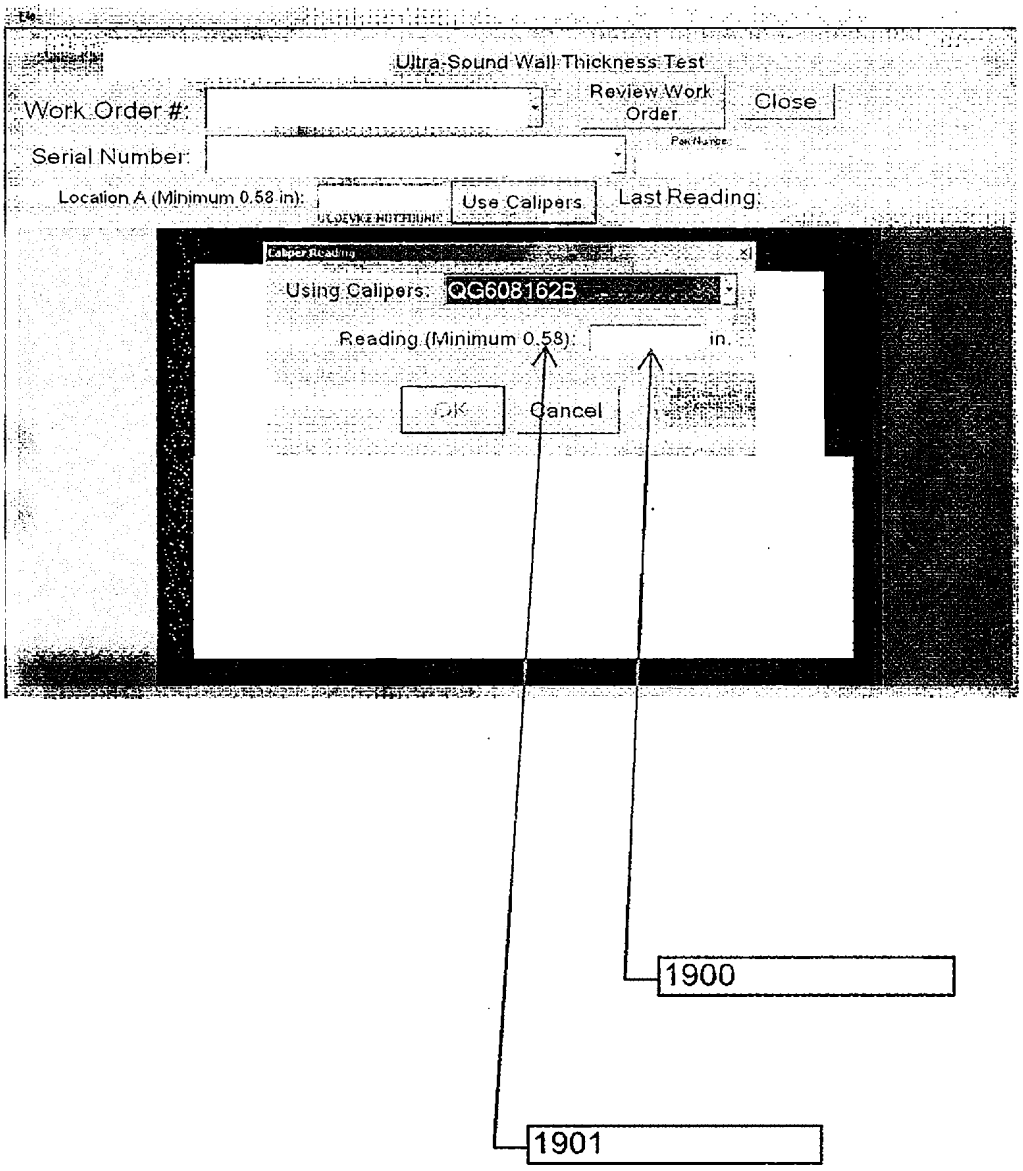

Ultra-Sound Wall Thickness Test
Work Order #:
Review Work Order
Close
Serial Number:
Location A (Minimum 0.58 in):
Use Calipers
Last Reading:
Caliper Reading
Using Calipers:
QG608162B
Reading (Minimum 0.58):
in.
OK
Cancel
1900
1901

FIG. 19

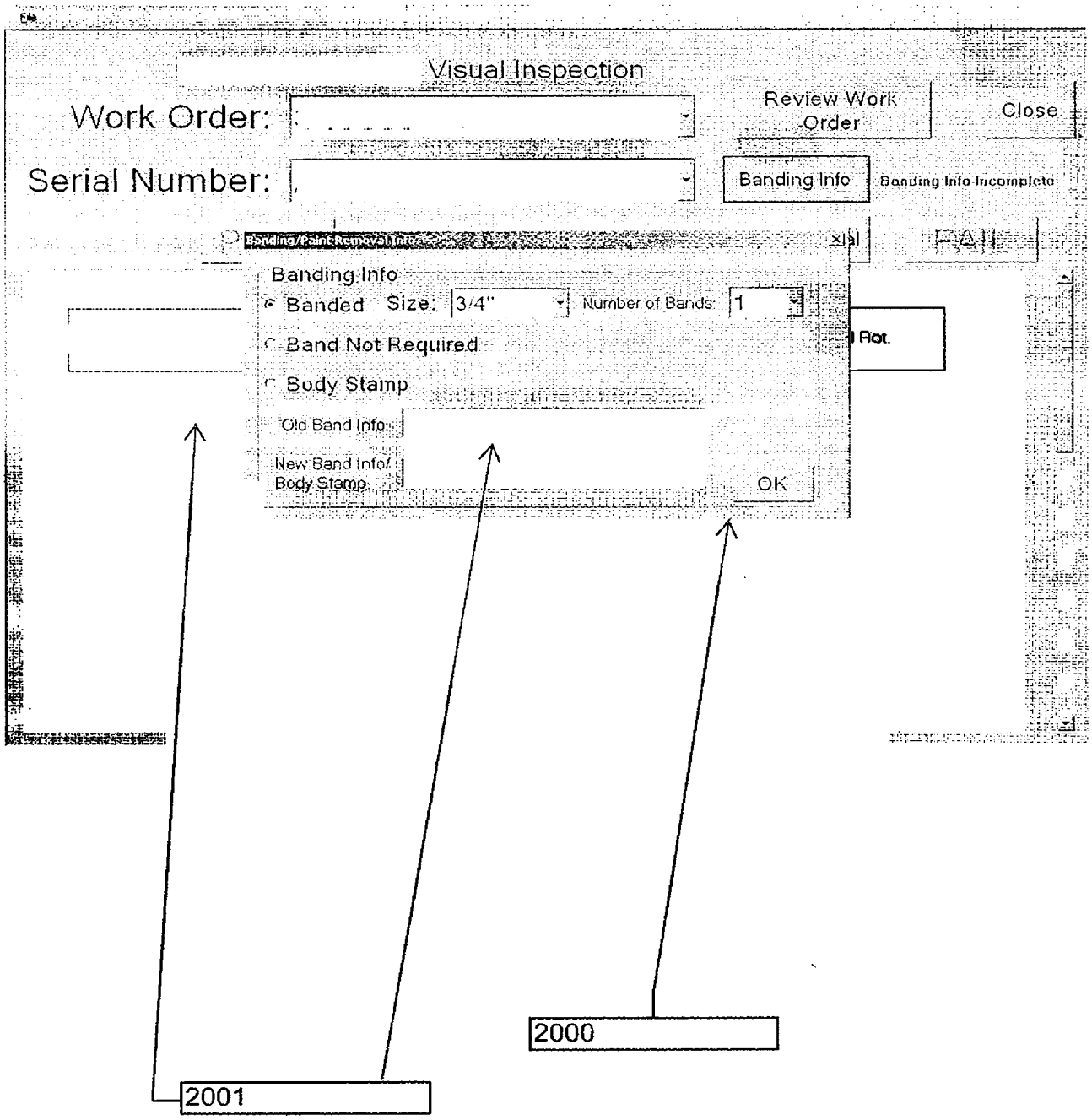

Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
Banding Info Incomplete
Banding Info
Banded
Size:
3/4"
Number of Bands:
1
Band Not Required
Body Stamp
Old Band Info
New Band Info/ Body Stamp
OK
2000
2001

FIG. 20

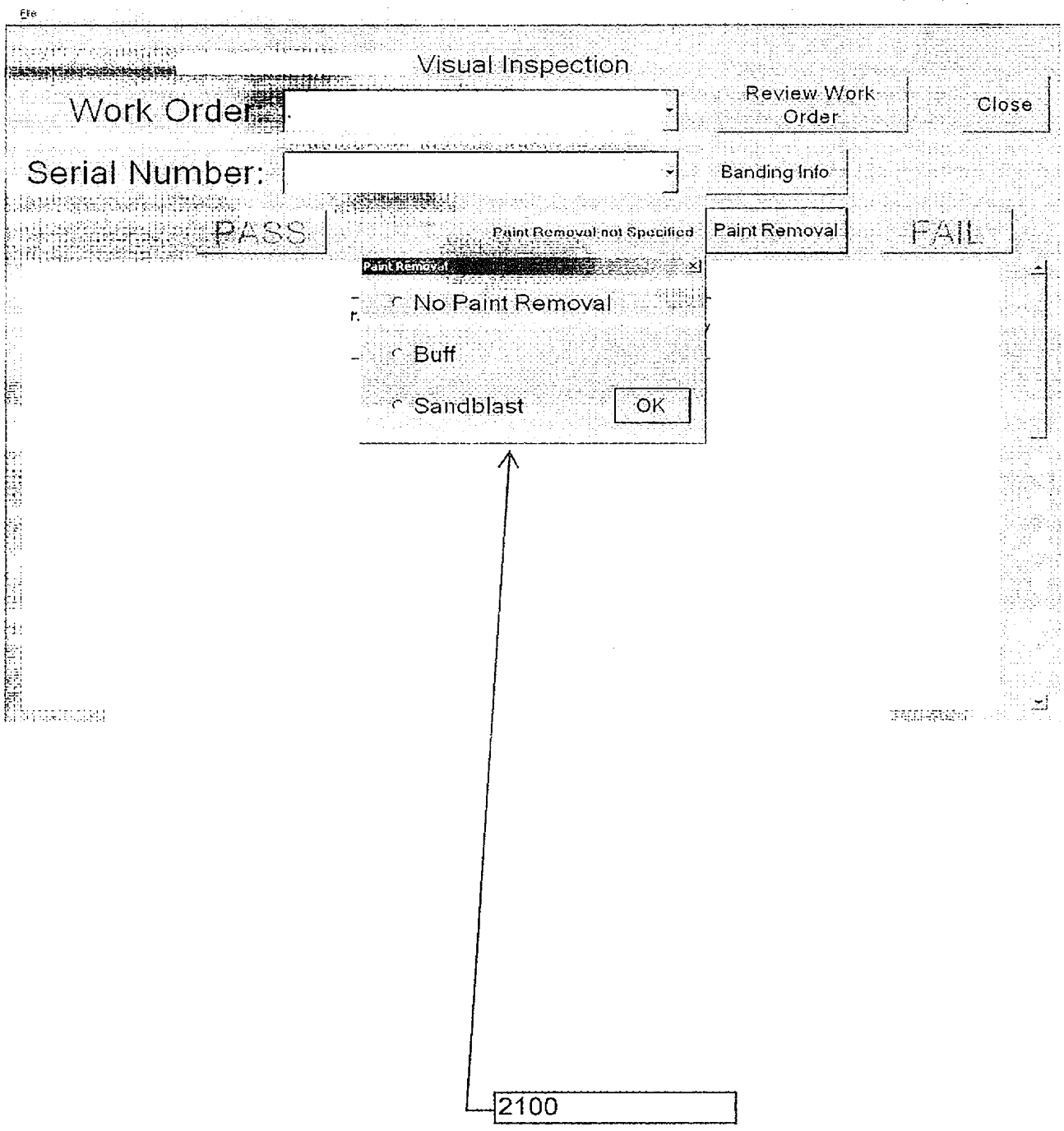

File
Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
PASS
Paint Removal not Specified
Paint Removal
FAIL
Paint Removal
No Paint Removal
Buff
Sandblast
OK
2100

FIG. 21

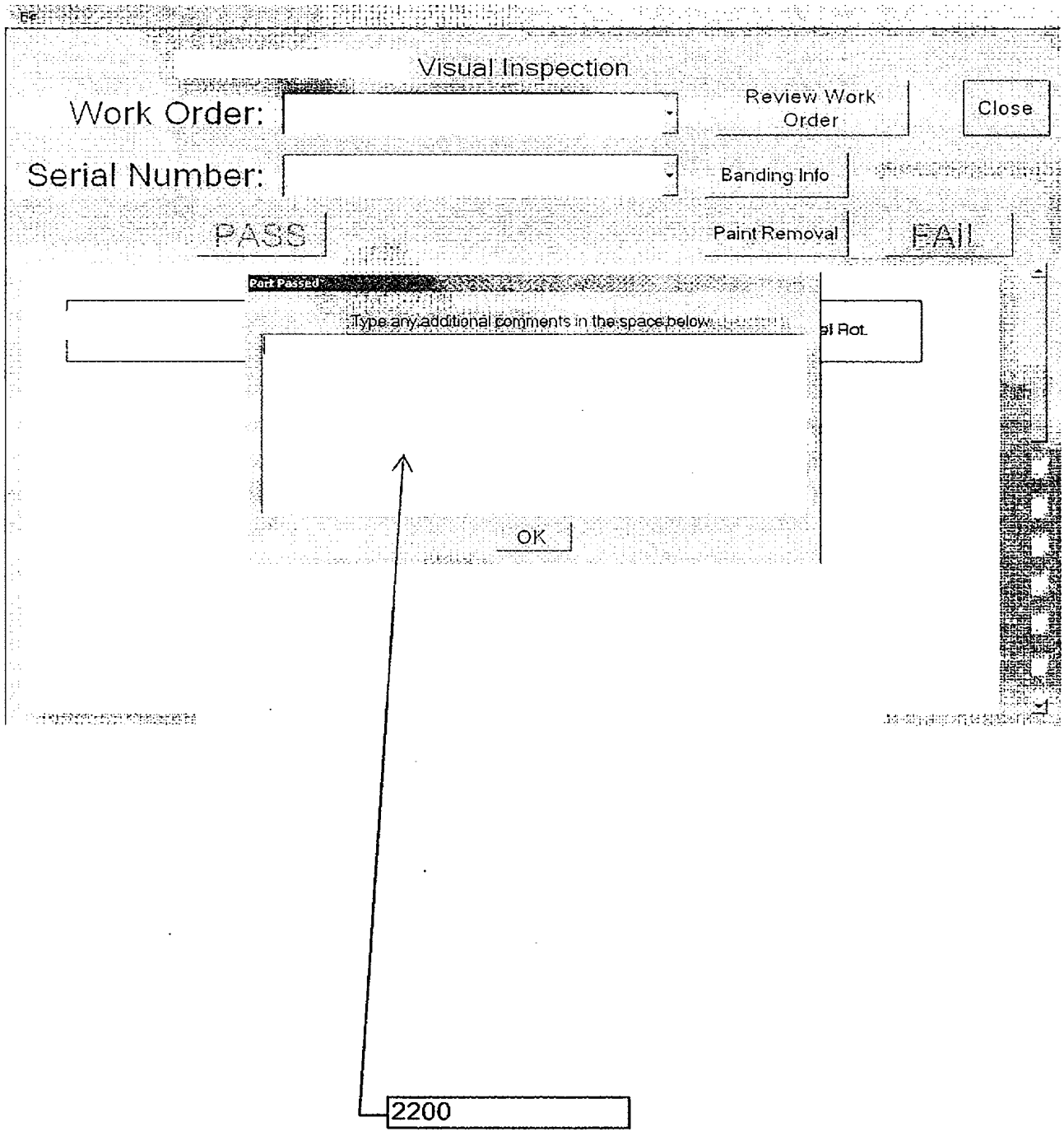

Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
PASS
Paint Removal
FAIL
Part Passed
Type any additional comments in the space below
OK
2200

FIG. 22

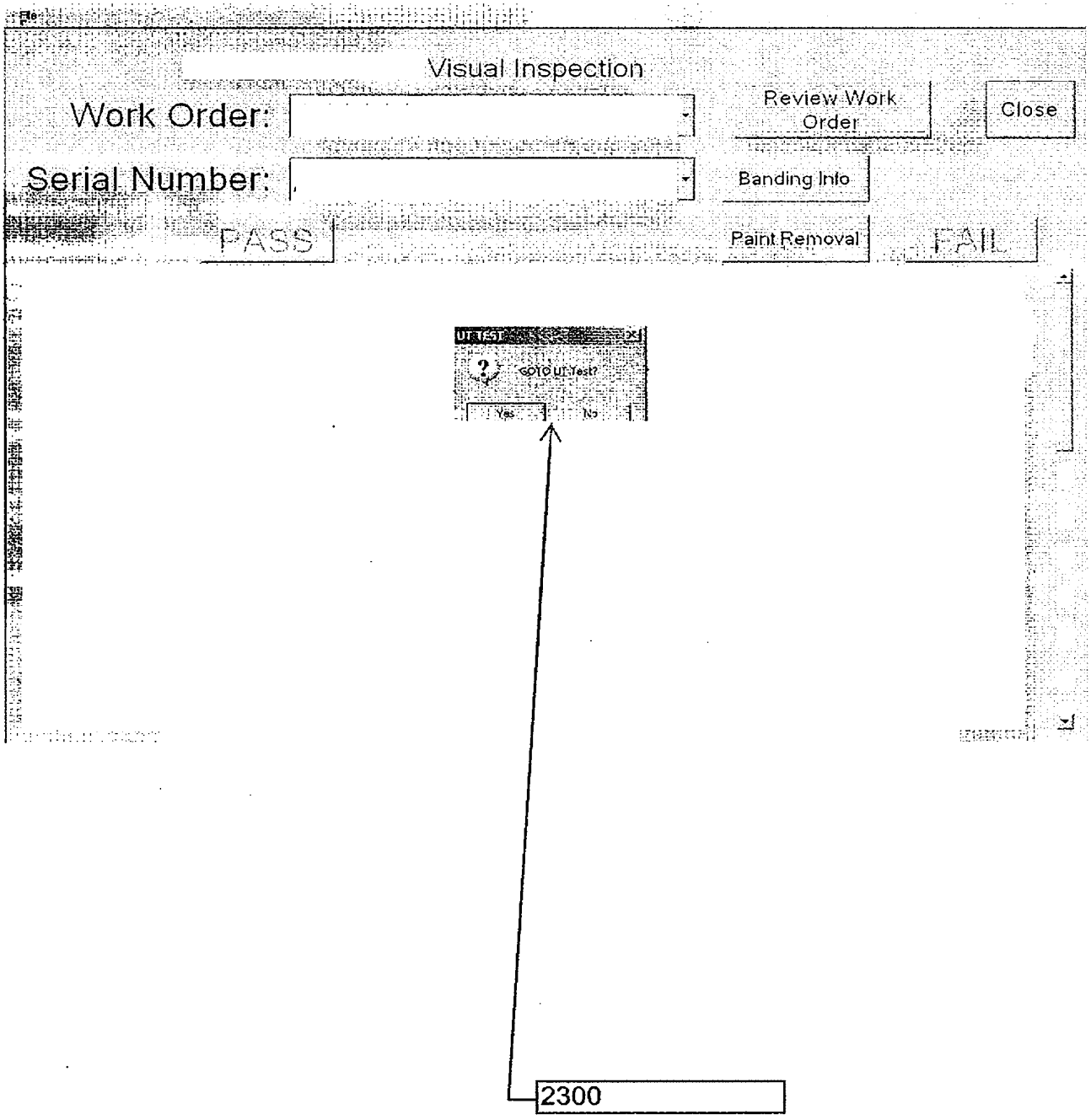

File
Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
PASS
Paint Removal
FAIL
UT Test
Goto UT Test?
Yes
No
2300

FIG. 23

Service Center Service History

Date: 02/24/2010	Customer:
Location:	Group ID / Unit #:
Description: 5 piece Rental	Quantity: 6
Inspection: Rental	Start Date: 02/24/2010
	Finish Date:
Wo / Sro #:	Approved By:

Specifications to be followed: SERVICE COMPANY

Product Description

Cust P/N: 100011214 Cust S/N: TEST003 Size: 1.5" Svc:
Mfr P/N: Style: DART Pressure Rating: 15,000.00
Connections: UNION CONNECTIONS Test Pressure: 15,000.00
Mfr: Product Type: CHECK VALVE Configuration: F X M Test Duration: min

Inspections Performed

	Pass/Fail	Inspector	Date
Visual			
UT Wall Thickness:			
Disembly/Asmbly:	N/A		
Magnetic Particle:	N/A		
Pressure:			
Paint:			
Final			

Gauges Used

	Serial Number		Serial Number
Calipers:		No Go Gauge Kit:	
UT Meter:			
MPI Equip:			
Pres Gauge:		Pres Recorder:	

Wall Thickness Information

Inspection Point:	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
New Wall Thickness (if reqd):	1.01	0.64	1.19	0.47											
Min Allowable Wall Thick (Spec:	0.72	0.80	1.05	0.33											
Actual Measurement:															

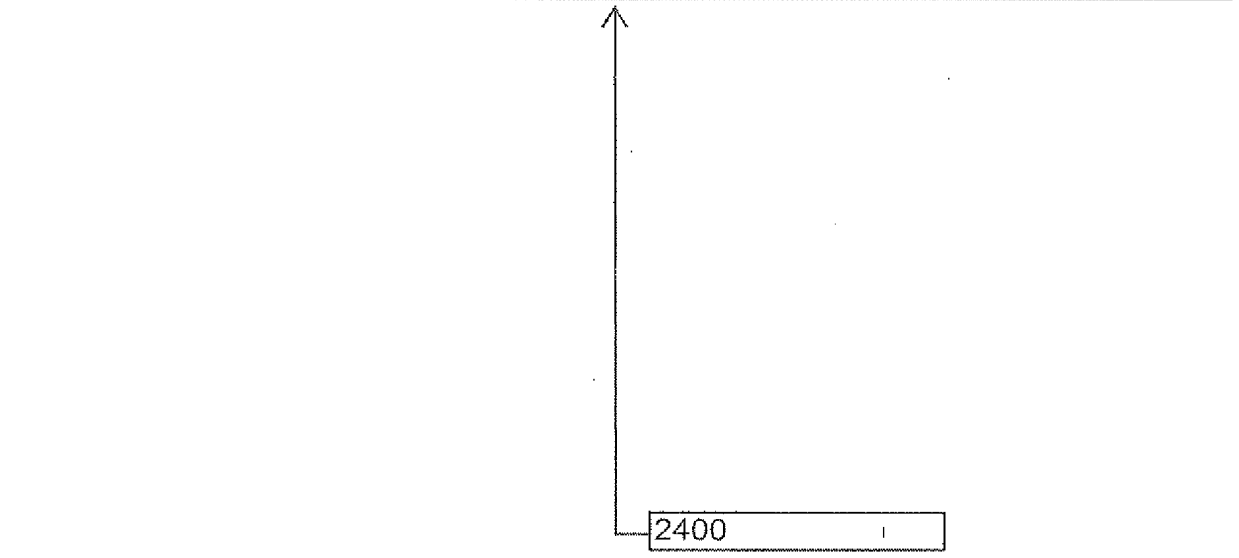


FIG. 24

Iron Inventory

Date:	02/24/2010	Customer:	
Location:		Group ID / Unit #:	
Description:	6 piece Rental	Quantity:	6
Inspection:	Rental	Start Date:	02/24/2010
		Finish Date:	
WO / SRO #:		Approved By:	

Specifications to be followed: SERVICE COMPANY

Serial Number	Part Number	Status	Description
		Visual Inspection (PENDING)	**1.5** X 1.5-1502 DART STYLE CHECK VALVE UNION CONNECTIONS
		Visual **Inspection (PENDIN**G)	PPG **ASSY/2-1502 PS 240**.00
		Wall Thickness (PENDING)	SWVL ASSY/STL 10 MXF/INT/2 LR15
		Wall Thickness (PENDING)	SWVL **ASS**Y/STL 50 MXF/INT/2 LR15
		Wall Thickness (PENDING)	SWVL **ASS**Y/STL 50 MXF/INT/2 LR15

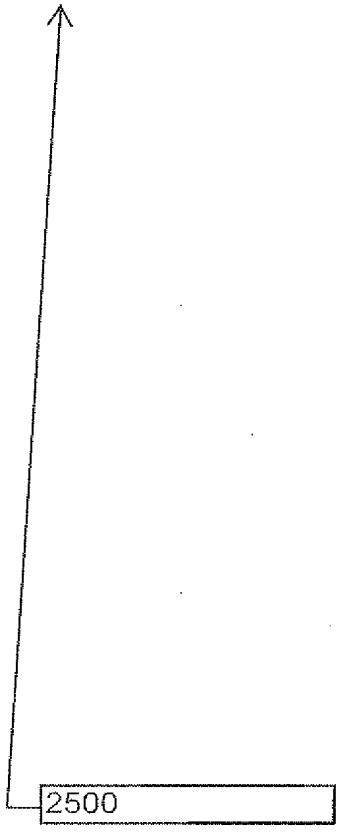
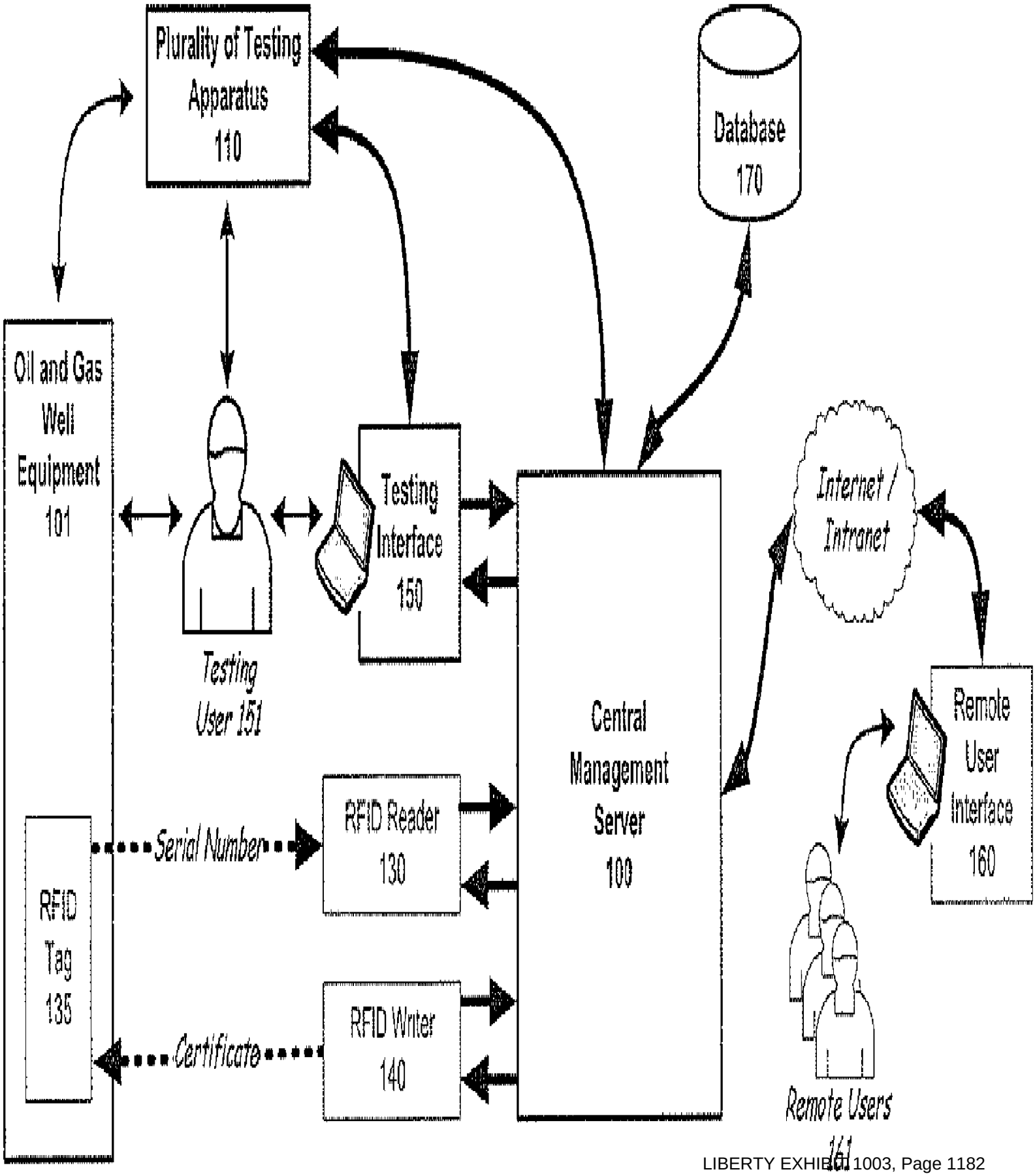


FIG. 25

FIG. 1


Plurality of Testing Apparatus 110
Database 170
Oil and Gas Well Equipment 101
Testing Interface 150
Testing User 151
Internet / Intranet
Central Management Server 100
Remote User Interface 160
RFID Reader 130
Serial Number
RFID Tag 135
RFID Writer 140
Certificate
Remote Users 161

Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2833711 A1 2014/05/16

(21) 2 833 711

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2013/11/15

(41) Mise à la disp. pub./Open to Public Insp.: 2014/05/16

(30) Priorité/Priority: 2012/11/16 (US13/679,689)

(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01),
E21B 43/12 (2006.01)

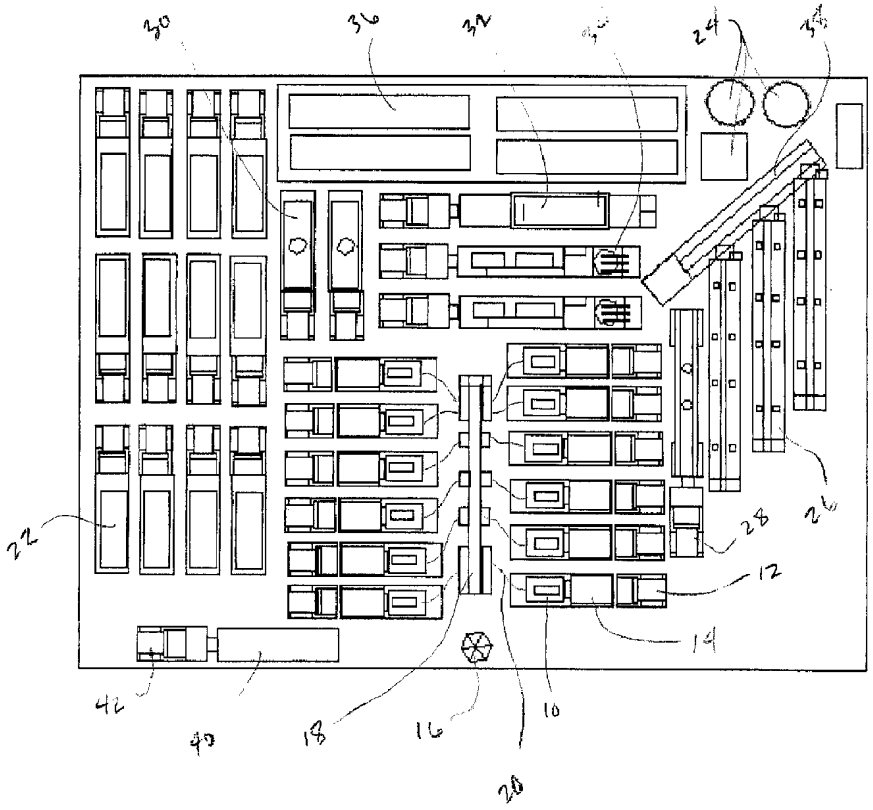
(71) Demandeur/Applicant:
US WELL SERVICES LLC, US

(72) Inventeurs/Inventors:
BROUSSARD, JOEL N., US;
MCPHERSON, JEFF, US;
KURTZ, ROBERT, US

(74) Agent: FINLAYSON & SINGLEHURST

(54) Titre : SYSTEME POUR POMPAGE DE FLUIDE DE FRACTIONNEMENT HYDRAULIQUE AU MOYEN DE POMPES ELECTRIQUES

(54) Title: SYSTEM FOR PUMPING HYDRAULIC FRACTURING FLUID USING ELECTRIC PUMPS



(57) Abrégé/Abstract:
A system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation. The system includes a plurality of

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(21) 2 833 711

(13) A1

(57) Abrégé(suite)/Abstract(continued):
electric pumps fluidly connected to the well, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the, and fractures the formation. The system can also include a plurality of natural gas powered generators electrically connected to the plurality of electric pumps to provide electrical power to the pumps.

ABSTRACT

A system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation. The system includes a plurality of electric pumps fluidly connected to the well, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the, and fractures the formation. The system can also include a plurality of natural gas powered generators electrically connected to the plurality of electric pumps to provide electrical power to the pumps.

SYSTEM FOR PUMPING HYDRAULIC FRACTURING FLUID USING ELECTRIC PUMPS

BACKGROUND OF THE INVENTION

1. Field of the Invention

[0001] This technology relates to hydraulic fracturing in oil and gas wells. In particular, this technology relates to pumping fracturing fluid into an oil or gas well using pumps powered by electric motors.

2. Brief Description of Related Art

[0002] Hydraulic fracturing has been used for decades to stimulate production from conventional oil and gas wells. The practice consists of pumping fluid into a wellbore at high pressure. Inside the wellbore, the fluid is forced into the formation being produced. When the fluid enters the formation, it fractures, or creates fissures, in the formation. Water, as well as other fluids, and some solid proppants, are then pumped into the fissures to stimulate the release of oil and gas from the formation.

[0003] Fracturing rock in a formation requires that the fracture fluid be pumped into the wellbore at very high pressure. This pumping is typically performed by large diesel-powered pumps. Such pumps are able to pump fracturing fluid into a wellbore at a high enough pressure to crack the formation, but they also have drawbacks. For example, the diesel pumps are very heavy, and thus must be moved on heavy duty trailers, making transport of the pumps between oilfield sites expensive and inefficient. In addition, the diesel engines required to drive the pumps require a relatively high level of expensive maintenance. Furthermore, the cost of diesel fuel is much higher than in the past, meaning that the cost of running the pumps has increased.

[0004] What is needed therefore, is a pump system for hydraulic fracturing fluid that overcomes the problems associated with diesel pumps.

SUMMARY OF THE INVENTION

[0005] Disclosed herein is a system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation. The system includes a plurality of electric pumps fluidly connected to the well, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation. The system also includes a plurality of generators electrically connected to the plurality of electric pumps to provide electrical power to the pumps. At least some of the plurality of generators can be powered by natural gas. In addition, at least some of the plurality of generators can be turbine generators.

[0006] In one embodiment, the system further includes an A/C console and a variable frequency drive that controls the speed of the pumps. Furthermore, the electric pumps, as well as the electric generators, can be mounted on vehicles, and can be ported from one well to another. The vehicles can be trucks and can have at least five axles.

[0007] Further disclosed herein is a system for fracturing a rock formation in an oil or gas well by pumping hydraulic fracturing fluid into the well that includes a pump, an electric motor, a variable frequency drive, and a natural gas powered electric generator. The pump is configured for pumping the hydraulic fracturing fluid into the well, and then from the well into the formation, and is capable of pumping the hydraulic fracturing fluid at high pressure to crack the formation. The electric motor can have a high-strength steel or steel alloy shaft attached to the pump and configured to drive the pump. The variable frequency drive can be connected to the electric motor to control the speed of the motor. In addition, the natural gas powered generator,

which can be a turbine generator, can be connected to the electric motor and provide electric power to the electric motor.

[0008] In one embodiment, the pump can be a triplex or a quinteplex pump, optionally rated at about 2250 hydraulic horsepower or more. In addition, the pump can also have 4.5 inch diameter plungers with an eight inch stroke. In another embodiment, the electric motor can have a maximum continuous power output of about 1500 brake horsepower, 1750 brake horsepower, or more, and a maximum continuous torque of about 8750 lb-ft or more. Furthermore, the electric motor can have a high temperature rating of about 1100 degrees C or more, and a shaft composed of 4340 alloy steel.

[0009] In another embodiment, variable frequency drive can frequently perform electric motor diagnostics to prevent damage to the electric motor if it becomes grounded or shorted. In addition, the variable frequency drive can include power semiconductor heat sinks having one or more thermal sensors monitored by a microprocessor to prevent semiconductor damage caused by excessive heat.

[0010] Also disclosed herein is a system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation. The system includes a trailer for attachment to a truck. Two or more electric pumps can be attached to the trailer and are fluidly connected to the well, the electric pumps configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation. One or more electric motors are attached to the electric pumps to drive the pumps. The electric motors can also be attached to the trailer. A natural gas powered generator is provided for connection to the electric motor to provide electric power to the electric motor. The

system of claim can further include a variable frequency drive attached to the trailer and connected to the electric motor to control the speed of the motor. In addition, the system can include a skid to which at least one of the electric pumps, the one or more electric motors, and the variable frequency drives are attached.

[0011] Also disclosed herein is a process for stimulating an oil or gas well by hydraulically fracturing a formation in the well. The process includes the steps of pumping fracturing fluid into the well with an electrically powered pump at a high pressure so that the fracturing fluid enters and cracks the formation, the fracturing fluid having at least a liquid component and a solid proppant, and inserting the solid proppant into the cracks to maintain the cracks open, thereby allowing passage of oil and gas through the cracks. The process can further include powering the electrically powered pump with a natural gas generator, such as, for example, a turbine generator.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] The present technology will be better understood on reading the following detailed description of nonlimiting embodiments thereof, and on examining the accompanying drawing, in which:

[0013] Fig. 1 is a schematic plan view of equipment used in a hydraulic fracturing operation, according to an embodiment of the present technology; and

[0014] Fig. 2 is a schematic plan view of equipment used in a hydraulic fracturing operation, according to an alternate embodiment of the present technology.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0015] The foregoing aspects, features, and advantages of the present technology will be further appreciated when considered with reference to the following description of preferred embodiments and accompanying drawing, wherein like reference numerals represent like elements. In describing the preferred embodiments of the technology illustrated in the appended drawing, specific terminology will be used for the sake of clarity. However, the technology is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0016] Fig. 1 shows a plan view of equipment used in a hydraulic fracturing operation. Specifically, there is shown a plurality of pumps 10 mounted to pump vehicles 12. The pump vehicles 12 can be trucks having at least five axles. In the embodiment shown, the pumps 10 are powered by electric motors 14, which can also be mounted to the pump vehicles 12. The pumps 10 are fluidly connected to the wellhead 16 via the missile 18. As shown, the pump vehicles 12 can be positioned near enough to the missile 18 to connect fracturing fluid lines 20 between the pumps 10 and the missile 18. The missile 18 is then connected to the wellhead 16 and configured to deliver fracturing fluid provided by the pumps 10 to the wellhead 16.

[0017] In some embodiments, each electric motor 14 can be capable of delivering about 1500 brake horsepower (BHP), 1750 BHP, or more, and each pump 10 can optionally be rated for about 2250 hydraulic horsepower (HHP) or more. In addition, the components of the system, including the pumps 10 and the electric motors 14, can be capable of operating during prolonged pumping operations, and in temperature in a range of about 0 degrees C or less to about 55 degrees C or more. In addition, each electric motor 14 can be equipped with a variable

frequency drive (VFD), and an A/C console, that controls the speed of the electric motor 14, and hence the speed of the pump 10.

[0018] The electric motors 14 of the present technology can be designed to withstand an oilfield environment. Specifically, some pumps 10 can have a maximum continuous power output of about 1500 BHP, 1750 BHP, or more, and a maximum continuous torque of about 8750 lb-ft or more. Furthermore, electric motors 14 of the present technology can include class H insulation and high temperature ratings, such as about 1100 degrees C or more. In some embodiments, the electric motor 14 can include a single shaft extension and hub for high tension radial loads, and a high strength 4340 alloy steel shaft, although other suitable materials can also be used.

[0019] The VFD can be designed to maximize the flexibility, robustness, serviceability, and reliability required by oilfield applications, such as hydraulic fracturing. For example, as far as hardware is concerned, the VFD can include packaging receiving a high rating by the National Electrical Manufacturers Association (such as nema 1 packaging), and power semiconductor heat sinks having one or more thermal sensors monitored by a microprocessor to prevent semiconductor damage caused by excessive heat. Furthermore, with respect to control capabilities, the VFD can provide complete monitoring and protection of drive internal operations while communicating with an operator via one or more user interfaces. For example, motor diagnostics can be performed frequently (e.g., on the application of power, or with each start), to prevent damage to a grounded or shorted electric motor 14. The electric motor diagnostics can be disabled, if desired, when using, for example, a low impedance or high-speed electric motor.

[0020] In some embodiments, the pump 10 can optionally be a 2250 HHP triplex or quinteplex pump. The pump 10 can optionally be equipped with 4.5 inch diameter plungers that have an

eight (8) inch stroke, although other size plungers can be used, depending on the preference of the operator. The pump 10 can further include additional features to increase its capacity, durability, and robustness, including, for example, a 6.353 to 1 gear reduction, autuofrettaged steel or steel alloy fluid end, wing guided slush type valves, and rubber spring loaded packing.

[0021] In addition to the above, certain embodiments of the present technology can include a skid (not shown) for supporting some or all of the above-described equipment. For example, the skid can support the electric motor 14 and the pump 10. In addition, the skid can support the VFD. Structurally, the skid can be constructed of heavy-duty longitudinal beams and cross-members made of an appropriate material, such as, for example, steel. The skid can further include heavy-duty lifting lugs, or eyes, that can optionally be of sufficient strength to allow the skid to be lifted at a single lift point.

[0022] Referring back to Fig. 1, also included in the equipment is a plurality of electric generators 22 that are connected to, and provide power to, the electric motors 14 on the pump vehicles 12. To accomplish this, the electric generators 22 can be connected to the electric motors 14 by power lines (not shown). The electric generators 22 can be connected to the electric motors 14 via power distribution panels (not shown). In certain embodiments, the electric generators 22 can be powered by natural gas. For example, the generators can be powered by liquefied natural gas. The liquefied natural gas can be converted into a gaseous form in a vaporizer prior to use in the generators. The use of natural gas to power the electric generators 22 can be advantageous because, where the well is a natural gas well, above ground natural gas vessels 24 can already be placed on site to collect natural gas produced from the well. Thus, a portion of this natural gas can be used to power the electric generators 22, thereby reducing or eliminating the need to import fuel from offsite. If desired by an operator, the

electric generators 22 can optionally be natural gas turbine generators, such as those shown in Fig. 2.

[0023] Fig. 1 also shows equipment for transporting and combining the components of the hydraulic fracturing fluid used in the system of the present technology. In many wells, the fracturing fluid contains a mixture of water, sand or other proppant, acid, and other chemicals. Examples of fracturing fluid components include acid, anti-bacterial agents, clay stabilizers, corrosion inhibitors, friction reducers, gelling agents, iron control agents, pH adjusting agents, scale inhibitors, and surfactants. Historically, diesel has at times been used as a substitute for water in cold environments, or where a formation to be fractured is water sensitive, such as, for example, clay. The use of diesel, however, has been phased out over time because of price, and the development of newer, better technologies.

[0024] In Fig. 1, there are specifically shown sand transporting vehicles 26, an acid transporting vehicle 28, vehicles for transporting other chemicals 30, and a vehicle carrying a hydration unit 32, such as, for example, a water pump. Also shown are fracturing fluid blenders 34, which can be configured to mix and blend the components of the hydraulic fracturing fluid, and to supply the hydraulic fracturing fluid to the pumps 10. In the case of liquid components, such as water, acids, and at least some chemicals, the components can be supplied to the blenders 34 via fluid lines (not shown) from the respective component vehicles, or from the hydration unit 32. In the case of solid components, such as sand, the component can be delivered to the blender 34 by a conveyor belt 38. The water can be supplied to the hydraulic unit 32 from, for example, water tanks 36 onsite. Alternately, the water can be provided by water trucks. Furthermore, water can be provided directly from the water tanks 36 or water trucks to the blender 34, without first passing through the hydration unit 32.

[0025] Pump control and data monitoring equipment 40 can be mounted on a control vehicle 42, and connected to the pumps 10, electric motors 14, blenders 34, and other downhole sensors and tools (not shown) to provide information to an operator, and to allow the operator to control different parameters of the fracturing operation. For example, the pump control and data monitoring equipment 40 can include an A/C console that controls the VFD, and thus the speed of the electric motor 14 and the pump 10. Other pump control and data monitoring equipment can include pump throttles, a pump VFD fault indicator with a reset, a general fault indicator with a reset, a main estop, a programmable logic controller for local control, and a graphics panel. The graphics panel can include, for example, a touchscreen interface.

[0026] Referring now to Fig. 2, there is shown an alternate embodiment of the present technology. Specifically, there is shown a plurality of pumps 110 which, in this embodiment, are mounted to pump trailers 112. As shown, the pumps 110 can optionally be loaded two to a trailer 112, thereby minimizing the number of trailers needed to place the requisite number of pumps at a site. The ability to load two pumps 110 on one trailer 112 is possible because of the relatively light weight of the electric pumps 110 compared to other known pumps, such as diesel pumps. In the embodiment shown, the pumps 110 are powered by electric motors 114, which can also be mounted to the pump trailers 112. Furthermore, each electric motor 114 can be equipped with a VFD, and an A/C console, that controls the speed of the motor 114, and hence the speed of the pumps 110.

[0027] In addition to the above, the embodiment of Fig. 2 can include a skid (not shown) for supporting some or all of the above-described equipment. For example, the skid can support the electric motors 114 and the pumps 110. In addition, the skid can support the VFD. Structurally, the skid can be constructed of heavy-duty longitudinal beams and cross-members made of an

appropriate material, such as, for example, steel. The skid can further include heavy-duty lifting lugs, or eyes, that can optionally be of sufficient strength to allow the skid to be lifted at a single lift point.

[0028] The pumps 110 are fluidly connected to a wellhead 116 via a missile 118. As shown, the pump trailers 112 can be positioned near enough to the missile 118 to connect fracturing fluid lines 120 between the pumps 110 and the missile 118. The missile 118 is then connected to the wellhead 116 and configured to deliver fracturing fluid provided by the pumps 110 to the wellhead 116.

[0029] Still referring to Fig. 2, this embodiment also includes a plurality of turbine generators 122 that are connected to, and provide power to, the electric motors 114 on the pump trailers 112. To accomplish this, the turbine generators 122 can be connected to the electric motors 114 by power lines (not shown). The turbine generators 122 can be connected to the electric motors 114 via power distribution panels (not shown). In certain embodiments, the turbine generators 122 can be powered by natural gas, similar to the electric generators 22 discussed above in reference to the embodiment of Fig. 1. Also included are control units 144 for the turbine generators 122.

[0030] The embodiment of Fig. 2 can include other equipment similar to that discussed above. For example, Fig. 2 shows sand transporting vehicles 126, acid transporting vehicles 128, other chemical transporting vehicles 130, hydration units 132, blenders 134, water tanks 136, conveyor belts 138, and pump control and data monitoring equipment 140 mounted on a control vehicle 142. The function and specifications of each of these is similar to corresponding elements shown in Fig. 1.

[0031] Use of pumps 10, 110 powered by electric motors 14, 114 and natural gas powered electric generators 22 (or turbine generators 122) to pump fracturing fluid into a well is advantageous over known systems for many different reasons. For example, the equipment (e.g. pumps, electric motors, and generators) is lighter than the diesel pumps commonly used in the industry. The lighter weight of the equipment allows loading of the equipment directly onto a truck body. In fact, where the equipment is attached to a skid, as described above, the skid itself can be lifted on the truck body, along with all the equipment attached to the skid, in one simple action. Alternatively, and as shown in Fig. 2, trailers 112 can be used to transport the pumps 110 and electric motors 114, with two or more pumps 110 carried on a single trailer 112. Thus, the same number of pumps 110 can be transported on fewer trailers 112. Known diesel pumps, in contrast, cannot be transported directly on a truck body or two on a trailer, but must be transported individually on trailers because of the great weight of the pumps.

[0032] The ability to transfer the equipment of the present technology directly on a truck body or two to a trailer increases efficiency and lowers cost. In addition, by eliminating or reducing the number of trailers to carry the equipment, the equipment can be delivered to sites having a restricted amount of space, and can be carried to and away from worksites with less damage to the surrounding environment. Another reason that the electric pump system of the present technology is advantageous is that it runs on natural gas. Thus, the fuel is lower cost, the components of the system require less maintenance, and emissions are lower, so that potentially negative impacts on the environment are reduced.

[0033] In practice, a hydraulic fracturing operation can be carried out according to the following process. First, the water, sand, and other components are blended to form a fracturing fluid, which is pumped down the well by the electric-powered pumps. Typically, the well is designed

so that the fracturing fluid can exit the wellbore at a desired location and pass into the surrounding formation. For example, in some embodiments the wellbore can have perforations that allow the fluid to pass from the wellbore into the formation. In other embodiments, the wellbore can include an openable sleeve, or the well can be open hole. The fracturing fluid can be pumped into the wellbore at a high enough pressure that the fracturing fluid cracks the formation, and enters into the cracks. Once inside the cracks, the sand, or other proppants in the mixture, wedges in the cracks, and holds the cracks open.

[0034] Using the pump control and data monitoring equipment 40, the operator can monitor, gauge, and manipulate parameters of the operation, such as pressures, and volumes of fluids and proppants entering and exiting the well. For example, the operator can increase or decrease the ratio of sand to water as the fracturing process progresses and circumstances change.

[0035] This process of injecting fracturing fluid into the wellbore can be carried out continuously, or repeated multiple times in stages, until the fracturing of the formation is optimized. Optionally, the wellbore can be temporarily plugged between each stage to maintain pressure, and increase fracturing in the formation. Generally, the proppant is inserted into the cracks formed in the formation by the fracturing, and left in place in the formation to prop open the cracks and allow oil or gas to flow into the wellbore.

[0036] While the technology has been shown or described in only some of its forms, it should be apparent to those skilled in the art that it is not so limited, but is susceptible to various changes without departing from the scope of the technology. Furthermore, it is to be understood that the above disclosed embodiments are merely illustrative of the principles and applications of the present technology. Accordingly, numerous modifications can be made to the illustrative

embodiments and other arrangements can be devised without departing from the spirit and scope of the present technology as defined by the appended claims.

What is claimed is:

1. A system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation, the system comprising:

a plurality of electric pumps fluidly connected to the well, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation; and

a plurality of generators electrically connected to the plurality of electric pumps to provide electrical power to the pumps.

2. The system of claim 1, wherein at least some of the plurality of generators are powered by natural gas.

3. The system of claim 1, wherein at least some of the plurality of generators are turbine generators.

4. The system of claim 1, further comprising:

an A/C console and a variable frequency drive that controls the speed of the pumps.

5. The system of claim 1, wherein the electric pumps are mounted on vehicles, and can be ported from one well to another.

6. The system of claim 5, wherein the generators are mounted on vehicles, and can be ported from one well to another.

7. The system of claim 6, wherein the vehicles are trucks having at least five axles.

8. A system for fracturing a rock formation in an oil or gas well by pumping hydraulic fracturing fluid into the well, the system comprising:

a pump for pumping the hydraulic fracturing fluid into the well, and then from the well into the formation, the pump capable of pumping the hydraulic fracturing fluid at high pressure to crack the formation;

an electric motor having a high-strength steel or steel alloy shaft attached to the pump and configured to drive the pump;

a variable frequency drive connected to the electric motor to control the speed of the motor; and

a natural gas powered generator connected to the electric motor that provides electric power to the electric motor.

9. The system of claim 8, wherein the pump is a triplex or a quinteplex pump rated at about 2250 hydraulic horsepower or more.

10. The system of claim 9, wherein the pump has 4.5 inch diameter plungers with an eight inch stroke.

11. The system of claim 8, wherein the electric motor has a maximum continuous power output of about 1750 brake horsepower or more.

12. The system of claim 11, wherein the electric motor has a maximum continuous torque of about 8750 lb-ft or more.

13. The system of 12, wherein the electric motor has a high temperature rating of about 1100 degrees C or more.

14. The system of 13, wherein the shaft of the electric motor is composed of 4340 alloy steel.

15. The system of 8, wherein the variable frequency drive frequently performs electric motor diagnostics to prevent damage to the electric motor if it becomes grounded or shorted.

16. The system of 15, wherein the natural gas powered generator is a turbine generator.

17. The system of 8, wherein the variable frequency drive includes power semiconductor heat sinks having one or more thermal sensors monitored by a microprocessor to prevent semiconductor damage caused by excessive heat.

18. A system for hydraulically fracturing an underground formation in an oil or gas well to extract oil or gas from the formation, the oil or gas well having a wellbore that permits passage of fluid from the wellbore into the formation, the system comprising:

a trailer for attachment to a truck;

two or more electric pumps attached to the trailer and fluidly connected to the well, the electric pumps configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation;

one or more electric motors attached to the electric pumps to drive the pumps, the electric motors attached to the trailer; and

a natural gas powered generator for connection to the electric motor that provides electric power to the electric motor.

19. The system of claim 18, further comprising:

a variable frequency drive attached to the trailer and connected to the electric motor to control the speed of the motor.

20. The system of claim 18, further comprising:

a skid to which at least one of the electric pumps, the one or more electric motors, and the variable frequency drives are attached.

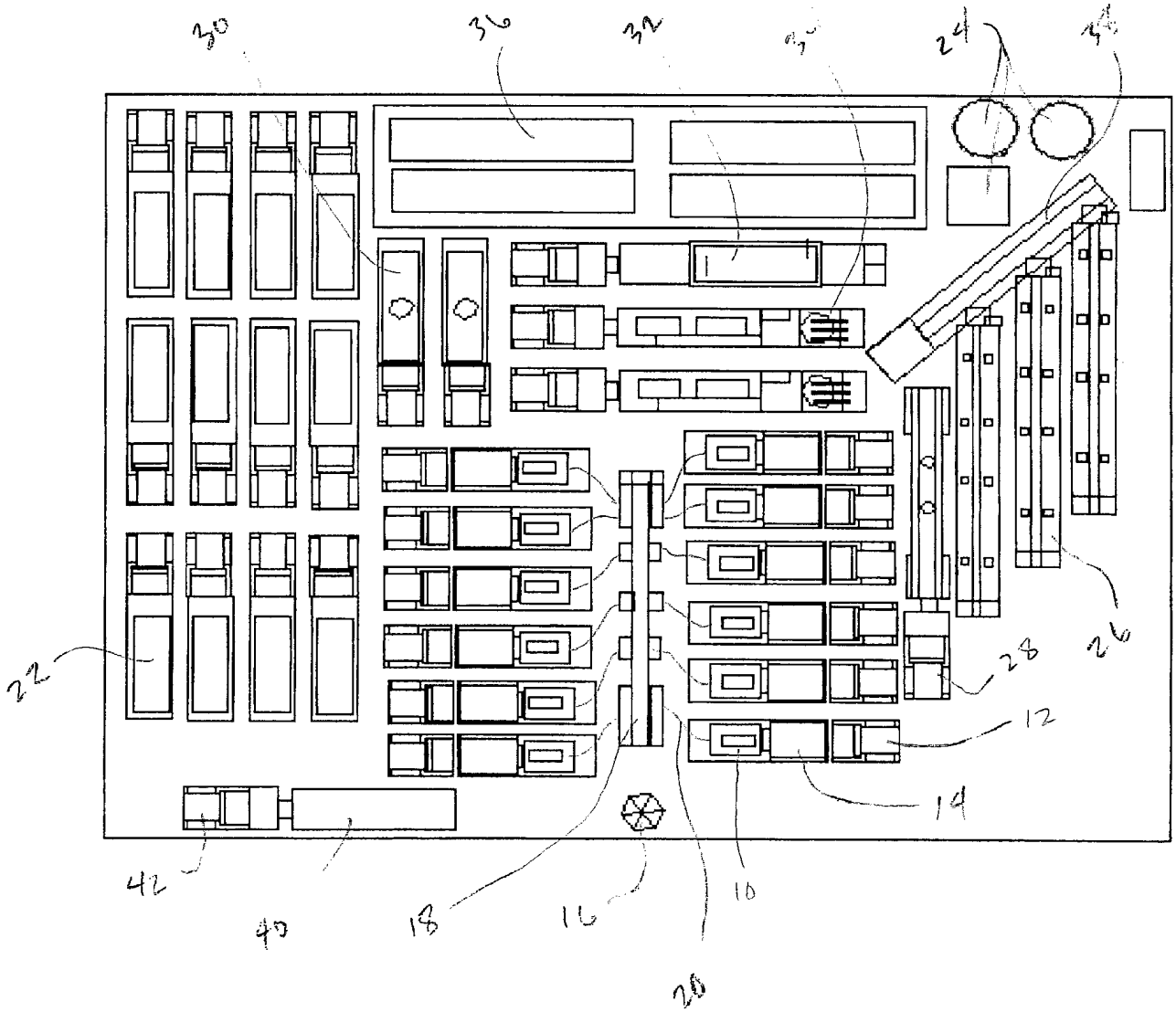


FIG. 1

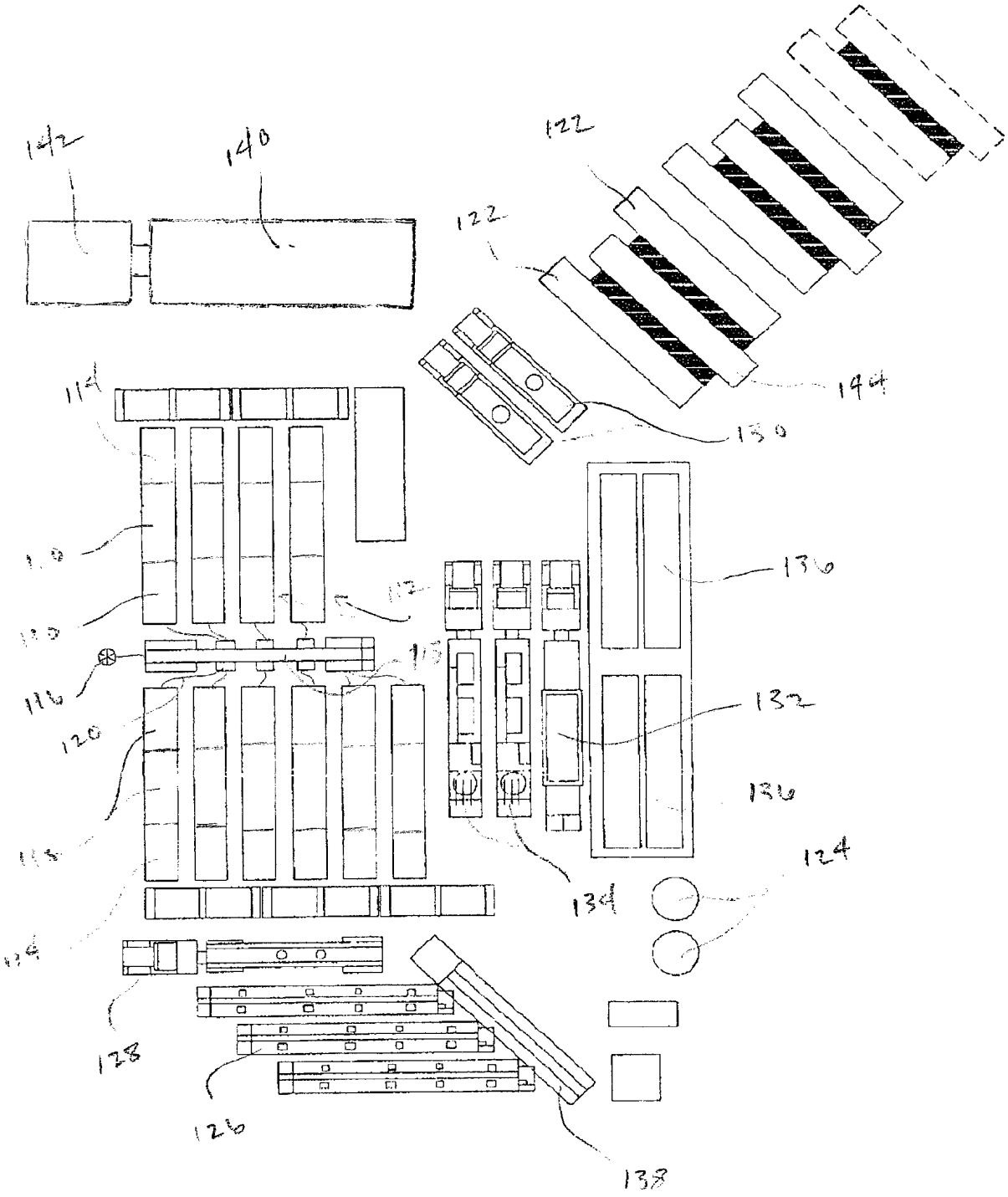

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FIG. 2

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CA 2849825 A1 2013/04/18

(21) 2 849 825

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2012/10/09
(87) Date publication PCT/PCT Publication Date: 2013/04/18
(85) Entrée phase nationale/National Entry: 2014/03/21
(86) N° demande PCT/PCT Application No.: US 2012/059361
(87) N° publication PCT/PCT Publication No.: 2013/055691
(30) Priorité/Priority: 2011/10/09 (US13/269,596)

(51) Cl.Int./Int.Cl. *E21B 41/00* (2006.01), *E21B 17/02* (2006.01), *E21B 43/30* (2006.01)

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(54) Titre : PROCEDE DE CONTROLE ET DE TRANSMISSION EN TEMPS REEL VERS LA SURFACE D'EVENEMENTS SISMIQUES DANS UNE FRACTURE HYDRAULIQUE PAR L'AVANT-TROU DU PUITS DE TRAITEMENT UTILISE COMME PUITS DE SURVEILLANCE

(54) Title: METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

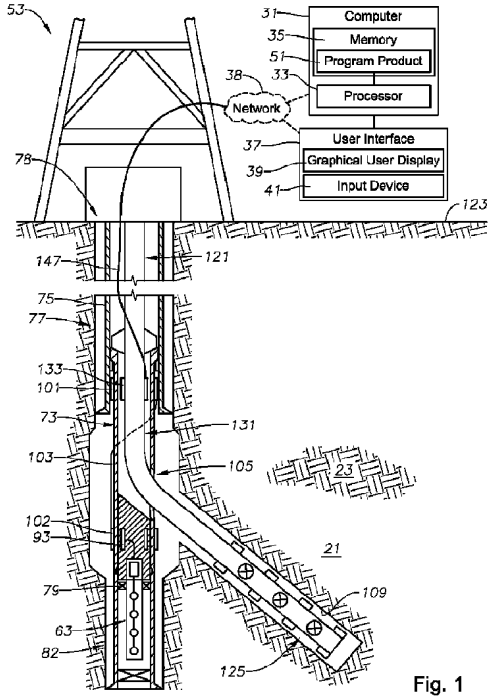


Fig. 1

(57) Abrégé/Abstract:
Methods for determining hydraulic fracture geometry and/or areal extent of an area of interest (21) in a reservoir (23), are provided. An exemplary method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
18 April 2013 (18.04.2013)

WIPO | PCT

(10) International Publication Number
WO 2013/055691 A3

(51) **International Patent Classification**:
E21B 41/00 (2006.01) *E21B 17/02* (2006.01)
E21B 43/30 (2006.01)

(21) **International Application Number**:
PCT/US2012/059361

(22) **International Filing Date**:
9 October 2012 (09.10.2012)

(25) **Filing Language**: English

(26) **Publication Language**: English

(30) **Priority Data**:
13/269,596 9 October 2011 (09.10.2011) US

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(81) **Designated States** *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) **Designated States** *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ,

[Continued on next page]

(54) **Title**: METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

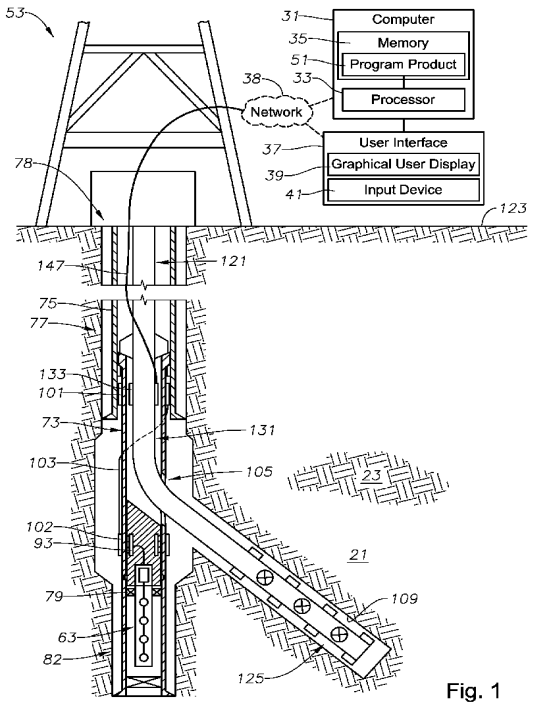


Fig. 1

(57) **Abstract**: Methods for determining hydraulic fracture geometry and/or area! extent of an area of interest (21) in a reservoir (23), are provided. An exemplar}' method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

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TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

(88) Date of publication of the international search report:
27 February 2014

METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

BACKGROUND OF THE INVENTION

1 Field of the Invention

[0001] The present invention relates in general to the field of hydraulic fracturing, monitoring, and data transmission of microseismic information from a zone of interest within a reservoir, and more particularly, to the utilization and employment of electrically and physically isolated downhole acoustic monitoring equipment within a fracturing treatment well to detect microseismic events during fracturing operations.

2. Description of the Related Art

[0002] Hydraulic fracturing has been used for over 60 years in more than one million wells to improve the productivity of a hydrocarbon bearing formation, particularly those drilled in low permeability reservoirs. An estimated 90% of the natural gas wells in the United States alone use hydraulic fracturing to produce gas at economic rates. Successful hydraulic fracturing is generally considered vital for economic production of natural gas from shale beds and other 'tight gas' plays.

[0003] Fracturing treatment operations are typically employed in vertical, deviated, and horizontal wells. In a typical well development operation, the wellbore of the treatment well is drilled through the desired formation where the fracture treatment will take place.

[0004] The hydraulic fracture is formed by pumping a fluid into the wellbore at a rate sufficient to increase the pressure downhole to a value in excess of the fracture gradient of the formation rock in the area of interest. The pressure causes the formation to crack, allowing the fracturing fluid to enter and extend the crack further into the formation. One method to keep this fracture open after the injection stops is to add a solid proppant to the fracture fluid. The

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proppant, which is commonly sieved round sand or other nonporous material, is carried into the fracture. This sand is chosen to be higher in permeability than the surrounding formation, and the propped hydraulic fracture then becomes a high permeability conduit through which the formation fluids can flow to the well.

[0005] Determining the size and orientation of completed hydraulic fractures is quite difficult and expensive, and in less expensive alternatives, highly inaccurate. It is well known that hydraulic fractures create a series of small "earthquakes" that can be mapped to show the position of the fracture event. The technology currently in use deploys a series of microseismic detectors typically in the form of geophones inside a separate monitoring well to measure fracturing events while pumping a hydraulic fracture treatment. Deployment of geophones or tilt meters on the surface can also be used, but the resolution is significantly less as you go deeper in the well.

[0006] Tiltmeter arrays, deployed on the surface or in a nearby monitoring well, measure the horizontal gradient of the vertical displacement. Microseismic detector arrays, deployed in a nearby monitoring well or on the surface adjacent the zone of interest if it is not too deep and/or environmental noise is not too excessive, can detect individual microseismic events associated with discrete fracture opening events. The microseismic event can be located in three dimensions by a triangulation methodology based on comparing acoustic arrival times at various sensors in a receiver array. By mapping the location of small seismic events that are associated with the growing hydraulic fracture during the fracturing process, the approximate geometry of the fracture can be inferred.

[0007] Although the use of a monitoring well located separate from the treatment well is often preferred as it provides improved accuracy, particularly in areas with high environmental noise and/or relatively inaccessible surface conditions, the cost of drilling a monitor well is typically in the area of $10 million and requires 30-50 days of drilling rig time. Further, availability of surface real estate or other factors can prevent the monitoring well from being drilled sufficiently close to the area of interest, and thus, results in a degraded performance.

[0008] In order to try to reduce capital costs and deployment time, some progressive operators have, with minimal success, attempted to build a combination monitoring and

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treatment well by placing the acoustical sensors in the annulus of the treatment well. Some other operators, have instead chosen to deploy the acoustic sensors directly in the treatment flow path.

[0009] Recognized by the inventors, however, is that as a result of the pumping of the fracturing fluid, such acoustic sensors located along the annulus of the treatment well or within the flow path encounter substantial noise during the hydraulic fracturing events, which in turn, results in the collection of acoustic data having an excessively low signal-to-noise ratio. Accordingly, also recognized by the inventors is that this type of monitoring can generally only provide usable data when the fracture is closing, and thus, causes the operator to miss the fracturing events occurring while pumping the fracturing slurry.

[00010] Further recognized by the inventors is that due to the exposure limitations of the electrical data/power conduit (e.g., run with the acoustic sensors to transmit data to the surface), the operator is limited to certain slurry concentrations and is limited by the amount of total pressure that can be applied while fracturing due to the pressure limitation of the electric line cable heads. Still further, recognized by the inventors is that the deployment of acoustic sensors within the treatment flow or in the annulus adjacent current or potential future sidetracking operations can impede such operations.

[00011] Recognized, therefore, by the inventors is that there is a need for systems and processes that requires only a single treatment well to reduce capital costs and deployment time, that includes provisions for isolating the acoustic sensors to provide for gathering during pumping of the fracturing slurry downhole, acoustic data having an acceptable signal-to-noise ratio. Also recognized by the inventors is that there is a need for systems and processes that allow for high slurry concentrations and that allow for a total pressure necessary for optimal fracturing without concern for the pressure limitations of electric conduit/line cable heads in the communication pathway of the acoustic sensors, and/or that does not impede current or future sidetracking operations.

SUMMARY OF THE INVENTION

[00012] In view of the foregoing, various embodiments of the present invention advantageously provide systems and methods of/processes for determining hydraulic fracture geometry and areal extent of a zone of interest, that require utilization of only portions of a single

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treatment well to reduce capital costs and deployment time, that includes provisions for isolating acoustic monitoring sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping of the fracturing slurry, that allows for high slurry concentrations, that allows for a total pressure necessary for optimal fracturing, without concern for the pressure limitations of the electric line cable heads, and/or that does not impede current or future sidetracking operations, and that can be employed for seismic monitoring in all types of hydraulic fracture operations, including fracturing unconventional or shale gas reservoirs.

[00013] More specifically, an example of an embodiment of a method to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include various steps including those to establish the well and to deploy the acoustic and communications equipment. According to an embodiment of the present invention, a well is drilled through a zone of interest and is either cased and cemented or left in an openhole environment. A kickover or other deflection-type tool is then deployed with the geophones or other acoustic receivers hung below at predetermined intervals to capture fracture events below, above and within the zone of interest. The geophones or other acoustic receivers are coupled to the casing or open hole section. Coupling of the geophones or other acoustic receivers can be accomplished by cementing them in place or hanging the geophones or other acoustic receivers in the cased or open hole with centralizers. A packer can also be used to isolate pressure from the fracturing operations and to isolate the geophones. If left un-cemented the deployed kickover/deflecting tool and geophones or other acoustic receivers can be retrieved at a later date.

[00014] During fracturing operations, data is transmitted up hole using, for example, a down hole electrical coupler to make an electrical connection down hole in well test operations. Utilization of coupling device can advantageously remove any physical contact between electrical connections and wellbore fluids. According to an exemplary configuration, power and/or communication signals are transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. As such, an advantage of this system is the positive power and communication provided across the coupling device.

[00015] Upon completion of the fracturing operation, a surface computer having received the acoustic data describing each microseismic fracture and then producing and graphically displaying a map of the hydraulic fracture geometry and extent of such fracturing.

[00016] According to another embodiment of a method, the method can include the steps of positioning an acoustic assembly within a first wellbore adjacent the zone of interest in the reservoir and drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining the zone of interest. The acoustic assembly can include an acoustic receiver controller, e.g., seismic brain, and a set of one or more acoustic sensors, e.g., geophones, tilt meters, etc., to capture fracture events within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest. Such isolization can advantageously serve to minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00017] The steps can also include inserting a drilling deflector into the first wellbore, drilling a second wellbore to receive a fracturing fluid, and typically before drilling the second wellbore if not pre-drilled, positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore.

[00018] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing by employing the set of acoustic sensors, and communicating to a surface unit the real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore. In order to provide for such communication, the steps can further include coupling the acoustic receiver controller to a first coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, and coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location, for example, above the lateral aperture.

[00019] According to another embodiment of a method, the method can include the steps of positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest, and positioning an acoustic assembly within the production liner in the first wellbore below major portions of the

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kickover tool and adjacent the zone of interest in the reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00020] The steps can further include opening a lateral aperture in the production liner to form an entrance to a second wellbore to receive a fracturing fluid, and positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture. The positioning of the communication conduit bypass is normally accomplished during deployment of the production liner in conjunction with the deployment of the acoustic assembly, and is later completed upon deployment of a tubing string.

[00021] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing through employment of the set of acoustic sensors, and communicating to a surface unit, real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest. The communications can be enabled by inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, inductively coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location above the lateral aperture.

[00022] According to another embodiment of a method, the method can include the steps of running a lower completion including wellbore sensors attached to a first connector within a tubular, running a communication conduit (lower umbilical) extending from a position outside the tubular adjacent the first connector to a position adjacent an operable position of a second connector, drilling a lateral wellbore oriented at least partially lateral to an orientation of the

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tubular and positioned at a location above the first connector and below the second connector, while avoiding intersection with the lower umbilical, and running an upper completion with a communication conduit (upper umbilical) attached to the second connector. The method can also include running a lateral completion attached below the upper completion, and/or providing a reservoir monitoring sensor or sensors with the lateral completion and connecting a lateral umbilical cord to extend from the sensor to a tee connection in the upper umbilical cord. The lateral completion can also carry a plurality of flow management components including inflow control valves, inflow control devices, and/or isolation packers.

[00023] According to an embodiment of the method, the steps can include sensing an acoustic event resulting from hydraulic fracturing of the formation adjacent the producing well and associated with the fracturing operations conducted through the lateral completion. Wellbore sensors, for example, in the form of acoustic sensors are positioned to detect the acoustic event at different times to facilitate locating the acoustic event. The steps can also or alternatively include the plurality of acoustic sensors sensing an acoustic event resulting from hydraulic fracturing associated with a lateral completion of an adjacent well. The steps can also or alternatively include positioning a packer below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors to enhance data quality.

[00024] According to another embodiment of a method, the method can include the steps of providing a plurality of producing wells each producing well including an upper completion, a lower completion, and a lateral completion extending into a lateral wellbore, combining the functions of a subterranean observation well and a subterranean producing well into each separate one of the plurality of producing wells for each of the producing wells, and sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion of one of the plurality of producing wells. The combining the functions is performed, for example, by positioning a plurality of acoustic sensors in the lower completion, and hydraulically isolating the plurality of acoustic sensors from fracturing fluid flowing through the upper completion and the lateral completion. The isolation is provided via an isolation device such as a packer positioned below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of the fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors. Additionally, the sensing is advantageously

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performed by one or more of the plurality of acoustic sensors in at least two of the plurality of producing wells to enhance data accuracy.

[00025] According to an example of an embodiment of the present invention, a system to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include a main casing string extending within a first portion of a first wellbore, and a production liner connected to an inner surface of a portion of the casing string and extending into a second portion of the first wellbore and having a lateral aperture adjacent an opening into a lateral branch wellbore. The system can also include a kickover or other deflection tool positioned within the production liner at a location below major portions of the lateral aperture to facilitate the performance of drilling operations associated with the lateral branch wellbore and to isolate an acoustic assembly positioned within the production liner below the kickover tool adjacent a zone of interest from fracturing operations. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest.

[00026] The system can also include a packer positioned within a bore of the production liner below major portions of the kickover tool and at a location above the set of one or more acoustic sensors to isolate the set of one or more acoustic sensors from acoustic interference associated with delivery of the fracturing fluid and/or can include a packer positioned within the bore of the production liner at a location below the set of acoustic sensors to hydraulically isolate the acoustic sensors within the bore of the production liner and/or to reduce acoustic interference from the fracturing components of the system.

[00027] The system also includes a tubing string extending through the first portion of the first wellbore, an upper portion of the second portion of the first wellbore, the lateral aperture, and portions of the lateral branch wellbore to deliver a fracturing fluid, and an inductive communication assembly positioned to receive data signals from the acoustic receiver controller and/or to provide power thereto and positioned to provide electrical isolation between lower completion equipment and upper completion equipment. According to a preferred configuration, the inductive communication assembly includes a communication conduit bypass positioned within the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to prevent interference with the fracturing equipment or deployment

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thereof. Advantageously, the inductive communications assembly includes two sets of inductive couplings to isolate up hole communication components from the communication components adjacent the lateral branch wellbore and to isolate such communication components from the acoustic assembly components located below the kickover tool. Notably, desired electrical and physical isolations can be achieved by using such inductive coupling technology to connect surface equipment with the downhole acoustic monitoring equipment.

[00028] A system according to another embodiment of the present invention can include a first wellbore including a first portion containing fluid delivery conduits and a second portion containing an acoustic assembly positioned adjacent a zone of interest within a reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors in communication therewith to capture fracture events below, above, and within the zone of interest. The system also include a second wellbore connected to the first wellbore at a lateral aperture in the first wellbore located above the acoustic assembly and containing a fracture treatment system, whereby the second wellbore and fracturing treatment system is hydraulically isolated from the second portion of the first wellbore containing the acoustic assembly. The system can further include an inductively coupled communication conduit bypass positioned within the first and the second portions of the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to provide well operations in the second wellbore devoid of any acoustic monitoring equipment and associated interfering communication conduits.

[00029] A system according to another embodiment of the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular, a lower umbilical extending from a position outside the tubular to a position adjacent an operable position of a first connector, a lateral wellbore positioned to avoid intersection with the lower umbilical and oriented at least partially lateral to an orientation of the tubular, and an upper completion run with an upper umbilical attached to the first connector. According to an exemplary configuration, the lower umbilical and tubular containing the wellbore sensors are configured to be run together. According to an exemplary configuration, the first connector connects to the upper umbilical. A second connector within a bore of the tubular connects to the wellbore sensors. An entranceway to the lateral wellbore is positioned at a location above the

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second connector and below the first connector. According to an exemplary configuration, the first and the second connectors are configured to inductively couple to the lower umbilical.

[00030] According to an exemplary configuration, a packer is positioned below an entranceway to the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors and to isolate pressure encountered by the acoustic sensors. According to another exemplary configuration, the plurality of acoustic sensors are cemented in place to minimize noise encountered by the plurality of acoustic sensors and to isolate pressure.

[00031] A system according to another embodiment the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular and positioned within a formation layer of interest, a lower umbilical extending from a position outside a portion of the tubular containing the well sensors to a position adjacent an operable position of a first connector, a lateral wellbore oriented at least partially lateral to an orientation of the tubular and positioned at least substantially within the formation layer of interest to thereby provide fracturing within the formation layer of interest. An upper completion run with an upper umbilical attached to the connector, whereby the connector operably coupled to the lower umbilical. According to an exemplary configuration, the connector is a first connector connecting to the upper umbilical, and the wellbore sensors are connected to at least portions of a second connector having at least portions positioned within a bore of the tubular. According to an exemplary configuration, the entranceway to the lateral wellbore is positioned at a location above the second connector and below the first connector.

[00032] According to an exemplary configuration, a lateral completion is horizontally aligned at least substantially between upper and lower boundaries of the formation layer of interest to provide fracturing within the formation layer of interest. According to such configuration, the portion of the tubular containing the acoustic sensors is positioned between upper and lower boundaries of the formation layer of interest. According to an exemplary configuration, a portion of the formation layer of interest is fractured above and below the lateral completion. According to such exemplary configuration, the acoustic sensors are positioned to receive fracturing data for portions of the formation layer of interest located above the lateral completion

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and receive fracturing data from portions of the formation layer of interest located below the lateral completion.

[00033] Various embodiments of the present invention advantageously allow real time data transmission of seismic event data from the treatment well while pumping a hydraulic fracture treatment. Conventional practice is to drill an observation/monitoring well and to deploy geophones to monitor fracture seismic events during the fracture treatment or to deploy geophones at the surface. Often observation/monitoring wells or the surface is too far from the fracture treatment to allow collection of good quality monitoring data, and there substantial costs associated with establishing an observation/monitoring well. Accordingly, to solve such problems, various embodiments of the present invention advantageously provide for utilization of a single treatment well to perform fracture seismic mapping without a need for a separate monitoring well or surface equipment deployment. This can be accomplished by deploying the acoustic sensors downhole in a portion of the treatment well, below the sidetrack well used for delivering the fracturing fluid. This portion of the treatment well can be, for example, a portion of the pilot hole for the treatment well extending beyond the desired entrance location of the sidetrack well. Advantageously, use of, for example, the original pilot hole in a sidetrack provides a significant reduction in the cost of fracture wrapping by eliminating the drilling and completion of a separate monitoring well, which may typically cost $10.0 MM and 30-50 days of drilling rig time.

[00034] Various embodiments of the present invention also advantageously provide for isolating the acoustic sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping, and/or provide for use of slurry concentrations greater than 4 PPA, by running the sensors below the kickover tool and/or installing a packer below the kickover tool to contain the acoustic sensors within the extended section of the main portion of the treatment well (e.g., the pilot hole)--separating the slurry carrying components and acoustic communications components so that they do not contact or otherwise communicate with each other. Advantageously, by placing the geophones below the kickover tool, the noise issue is reduced or eliminated with the use of simple filtering technology. Additionally, slurry limitations are eliminated, treating pressure is not limited to the tool deployed, and the geophones can be pre-positioned below, directly across the zone of interest and above the treatment interval.

[00035] Further, various embodiments of the present invention utilize an inductive coupler technology to provide for transmission of data to surface with real time measurements, which allows the acoustic sensors and acoustic receiver controller (e.g., seismic brain), to not only remain physically/hydraulically isolated, but also, electrically isolated--i.e., no electrical passageways or conduits providing communications between the acoustic receiver controller (e.g., seismic brain) and surface computer, need to be extended through the kickover tool or packer. The inductive coupler removes any physical contact between electrical connections and wellbore fluids. Power is transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. An additional advantage of this system is the positive power and communication provided across the coupling device.

[00036] Various embodiments of the present invention further advantageously provide for the use of a total pressure necessary for optimal fracturing, without concern for the pressure limitations of electric line cable heads providing communications between an acoustic assembly and a surface unit, and/or provide for employment of a monitoring system within the treatment well that does not impede current or future sidetracking operations. By employing the inductive coupling technology, electrical telemetry is transferred from inside the well to external of the production liner at a location above an anticipated or existing aperture in the production liner by a first inductive coupling and is returned to be inside the well and at location below the anticipated or existing location of the kickover tool by a second inductive coupling, with the cabling between the two couplings routed external to the production liner away from the location of the anticipated or existing aperture in the production liner.

BRIEF DESCRIPTION OF THE DRAWINGS

[00037] So that the manner in which the features and advantages of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[00038] FIG. 1 is a schematic diagram of a general system architecture of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00039] FIG. 2 is a schematic diagram of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00040] FIGS. 3-11 provide a series of schematic diagrams illustrating the development of a main wellbore, a wellbore for performing fracturing operations, and deployment of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to embodiments of the present invention;

[00041] FIG. 12 is a schematic diagram illustrating operational employment of downhole portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00042] FIG. 13 is a schematic diagram of an inductive circuit according to an embodiment of the present invention;

[00043] FIG. 14 is a schematic diagram illustrating duplicate portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest employed in a pair of adjacent producing wells, commonly receiving, processing, and providing complementary data for each other according to an embodiment of the present invention;

[00044] FIG. 15 is a schematic diagram illustrating a plurality of taps in a primary umbilical cord illustrating use of the umbilical cord as a primary communications link between both downhole acoustic sensors and reservoir monitoring sensors according to an embodiment of the present invention;

[00045] FIG. 16 is a schematic diagram illustrating application of a plurality of flow control devices according to an embodiment of the present invention; and

[00046] FIG. 17 is a schematic diagram illustrating a communication line connection configuration between surface components and downhole acoustic sensors according to an embodiment of the present invention.

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DETAILED DESCRIPTION

[00047] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate embodiments of the invention. This invention may, however, be embodied in many different forms and should not be construed as limited to the illustrated embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. Like numbers refer to like elements throughout. Prime notation, if used, indicates similar elements in alternative embodiments.

[00048] Various embodiments of the present invention advantageously provide systems and methods for real-time monitoring of hydraulic fractures using the treatment well pilot hole. According to an exemplary embodiment of the present invention, the well is drilled through the desired formation where the fracture treatment will take place. A kickover or other deflecting tool is then lowered into the wellbore and oriented to the preferred fractured orientation. Below the kick-over tool are acoustical sensors. At least one sensor is run, but preferably a series of sensors are run below the kickover tool. With the kickover tool in place, a sidetrack is drilled either as a vertical or horizontal wellbore. Advantageously, multiple sidetracks can be placed if required by stacking the kickover tools. Noise while pumping the fracturing fluid will be further minimized by placing a packer located below the kickover tool. The following provides additional details according to an exemplary embodiments of the present invention.

[00049] As shown in FIG. 1, a system 30 to determine hydraulic fracture geometry and areal extent of an area of interest 21 of a reservoir 23 can include a fracture mapping computer 31 having a processor 33, memory 35 coupled to the processor 33 to store software and database records therein, and a user interface 37 which can include a graphical display 39 for displaying graphical images, and a user input device 41 as known to those skilled in the art, to provide a user access to manipulate the software and database records. Note, the computer 31 can be in the form of a personal computer or in the form of a server or server farm serving multiple user interfaces 37 or other configuration known to those skilled in the art. Accordingly, the user interface 37 can be either directly connected to the computer 31 or through a network 38 as known to those skilled in the art.

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[00050] The system 30 can also include a database (not shown) stored in the memory 35 (internal or external) of the fracture mapping computer 31 and having data indicating position points of detected seismic events, and can include fracture mapping program product 51 stored in memory 35 of the fracture mapping computer 31 and adapted to receive signals from an acoustic receiver controller 61. Note, the fracture mapping program product 51 can be in the form of microcode, programs, routines, and symbolic languages that provide a specific set for sets of ordered operations that control the functioning of the hardware and direct its operation, as known and understood by those skilled in the art. Note also, the fracture mapping program product 51, according to an embodiment of the present invention, need not reside in its entirety in volatile memory, but can be selectively loaded, as necessary, according to various methodologies as known and understood by those skilled in the art. Still further, at least portions of the fracture mapping program product 51 can be stored in memory of the acoustic receiver controller 61 and/or executed by acoustic receiver controller 61.

[00051] As shown in FIGS. 1 and 2, the system 30 also includes an acoustic assembly 63 including the acoustic receiver controller (e.g., seismic brain) 61 and a set of at least one, but more typically a plurality of acoustic sensors (e.g., geophones, hydrophones, etc.) 65 hung below a kickover or other drilling deflection-type tool 71 positioned within a production or other liner 73, itself hung within a casing 75 itself positioned within a main portion 77 of a typically vertical wellbore 78. In a cased hole configuration, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art.

[00052] According to the illustrated embodiment of the system 30, the set of acoustic sensors 65 include multiple spaced apart sensors spaced at a predetermined distance or distances capture the same set of fracturing events, but at different travel times, to allow for triangulation of the received acoustic signals emanating from each separate fracture event. Note, as shown in FIG. 2, a packer or packers 79, 84 as known and understood by those of ordinary skill in the art can optionally be installed within the bore 76 of the production liner 73 prior to the installation of kickover tool 71. According to one embodiment, the packer 79 is positioned below the kickover tool 71 at a location above the acoustic assembly 63 to isolate the sensors 65 from acoustic interference. In such embodiment, a centralizer (not shown) or other connection device can be used to stabilize the sensors 65 within the bore 76 of the liner 73. According to an alternative embodiment, the packer 84 as installed below the acoustic assembly 63 to hydraulically seal

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chamber 80 within liner 73 to contain the acoustic assembly 63, and in conjunction with the kickover tool 71 (or other whipstock-type tool) and/or another packer 79 adjacent thereto, to thereby prevent hydraulic incursions.

[00053] According to the illustrated embodiment of the system 30, wellbore 78 includes the main or "upper formation" portion 77 and a "lower formation" portion 81 primarily comprising the pilot hole 82 drilled to guide drilling of the main portion 77 of the wellbore 78. As shown in the figures, according to such configuration, the acoustic assembly 63 and at least portions of the kickover tool 71 are landed within the lower portion 81 of the wellbore 78 (e.g., within chamber 80), and/or physically connected to hang from the kickover tool 71.

[00054] A locator key 83 comprising a recess-protuberance combination, illustrated as a recess 85 in the liner 73 and an annular protuberance 87 or set of one or more individual protuberances extending radially from the lower portion of the kickover tool 71, can be utilized to properly orient the kickover tool 71 and/or the set of acoustic sensors 65. Note, other means including a protuberance-recess combination or utilization of a centralizer (not shown) supporting or landing the set of acoustic sensors 65 and/or the kickover tool 71, or other means known to one of ordinary skill in the art, however, is/are within the scope of the present invention.

[00055] According to the illustrated embodiment of the system 30, the kickover tool 71 includes a recess 89 containing at least portions of the acoustic receiver controller 61 or associated connection hardware (not shown) as understood by one of ordinary skill in the art. The kickover tool 71 also includes an annular recess 91 housing a male inductive coupler 93 (individual or assembly) connected to an electrical conduit 95 connected to or otherwise in communication with the acoustic receiver controller 61. Note, the locator key 83 provides both positioning of the kickover tool 71 and positioning of the male inductive coupler 93. Note also, as described is being electrical conduit, conduit 91 can take other forms including optical, RF, etc. or combination thereof.

[00056] Further, according to the illustrated embodiments of the system 30, the liner 73 is landed within a lower end of the casing 75, preferably at least partially within a portion 97 of the wellbore 78 extended out, for example, by an "undee" ream bit (not shown), using means as known and understood by one of ordinary skill in the art. According to a preferred configuration, the external surface 99 of the liner 73 carries a set of female inductive couplers

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101, 102 connected via a communication conduit, e.g., electrical cable 103 routed along the external surface 99 of the liner 73, above and below a radial aperture 105, respectively. The radial aperture 105 is pre-formed prior to landing of the liner 73 or later cut through the exterior wall 99 of the liner 73 to provide a pathway for a "sidekick" drilled as a horizontal or vertical wellbore (e.g., lateral wellbore 109) carrying the various fracturing equipment 111. As such, beneficially, the female inductive couplers 101, 102 and the cable 103 do not impede fracturing operations or formation of the lateral wellbore 109.

[00057] The system 30 also includes a string of tubing 121 extending from a surface 123 (FIG. 1), through the main portion 77 of the wellbore 78 and casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and can include multiple fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127, to thereby provide for multi-stage fracturing.

[00058] A portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry a male inductive coupler 133 on its exterior surface 99. The male inductive coupler 133 is sized to be deployed within the inner diameter 137 of liner 73. When properly deployed with portion 131 of tubing string 121, male inductive coupler 133 is positioned to complement the female inductive coupler 101 connected to the exterior surface 99 of liner 73. Correspondingly, the portion 131 can include a tubing locator 141 sized to extend through casing 75 and to land upon an upper portion 143 of the casing hangar 74 hanging liner 73 (defining a landing point or surface 143). The male inductive coupler 133 is spaced apart at a predetermined longitudinal distance from the tubing locator 141 so that when the tubing locator 141 is landed upon landing point/surface 143, the male inductive coupler 133 is in a proper juxtaposition with female inductive coupler 101. The locator key 83, described previously, locates the male inductive coupler 93 in the proper juxtaposition with female inductive coupler 102, to thereby form a properly matched inductive circuit 145 (see, e.g., FIG. 13).

[00059] A communication conduit, e.g. electrical cable 147 is physically connected to outer surface portions of the exterior surface 135 of the tubing string 121 and electrically connected to male inductive coupler 133, e.g., via a wet connector, to provide data to computer 31.

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Beneficially, the electrical and physical isolations can be achieved by using inductive coupler pairs 101, 133, and 102, 93, to connect the surface equipment (e.g., computer 31) with the downhole acoustic monitoring assembly 63. Note, although described as being electrical conductors, it should be understood that conduits/cables 103, 147 can take various forms including electrical, optical, electro-optical, wireless, hydraulic or a combination thereof and are often collectively referred to as umbilicals. Note also, as shown in FIG. 17, although illustrated in the form of an inductive coupling, conduit/cable 103 can be hard-line connected to the acoustic assembly 63 via a connection with/through kickover tool 71' and can be connected to conduit/cable 147 via connector 133' illustrated as being positioned adjacent landing point 143.

[00060] FIGS. 1 and 2 illustrate a "cased hole" configuration of the wellbores 78, 109. One of ordinary skill in the art, however, would recognize that one or more embodiments of the present invention fall within the scope of the system 30 employed in non-cased wellbores. Additionally, in the exemplary illustration, the casing 75 is 9 5/8 inch casing, the tubing liner is 7 inch, and the tubing string 121 is 4 1/2 tubing, and the lateral wellbore 109 is 6 1/8 inch. Various other sizes as known to those of ordinary skill in the art, however, are within the scope of the present invention.

[00061] FIGS. 3-12 illustrate examples of embodiments of a method of determining hydraulic fracture geometry and areal extent of an area/zone of interest 21 in a reservoir 23 by combining functions of a subterranean observation well and a subterranean producing well into a single producing well 53. Referring to FIG. 3, according to an example of an embodiment of the method, a wellbore 78 is drilled through the area/zone of interest 21 and is either cased and cemented or left in an openhole state. According to the illustrated method, a pilot hole 82 is first drilled followed by the main portion 77.

[00062] As illustrated in FIG. 3, an undee reaming bit (not shown) can be used to widen the portion of the wellbore 78 at a location where a sidekick (e.g., wellbore 109, FIG. 2) is to be drilled. As shown in FIG. 4, in the illustrated cased-hole configuration, casing 75 is run within the upper portion 77 of the wellbore 78 above the undee 97.

[00063] As illustrated in FIG. 5, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art. According to the illustrated configuration, liner 73 extends from above undee 97, through undee 97, and through significant

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portions of the pilot hole 82 preferably having an inner diameter similar to that of the liner 73. As further illustrated in FIG. 5, liner 73 includes female inductive couplers 101, 102, connected to or embedded within an outer/exterior surface 99.

[00064] As illustrated in FIGS. 6 and 7, in order to acoustically isolate the set of acoustic sensors 65, a packer 79 can be positioned at a location below the kickover tool or other deflection-type tool 71 but above at least the acoustic sensors 65. In order to acoustically isolate further hydraulically isolate acoustic assembly 63, a packer 84 can also or alternatively be inserted within the bore 76 of the liner 73 at a location below the lowest (most downhole) expected point of the acoustic assembly 63.

[00065] As illustrated in FIG. 7, regardless of whether or not packer 79 is run, the method includes running a kickover or other deflection-type tool 71 to isolate the acoustic assembly 63 from the fracturing operations, described below. According to an exemplary configuration, the kickover tool 71 is deployed with geophones or other acoustic receivers 65 hung below at predetermined intervals to capture fracture events below, above and within the area/zone of interest 21. The geophones or other acoustic receivers 65 can be coupled to the inner surface of the tubing liner 73 or alternatively, directly to the open hole section of the pilot hole 82. Coupling of the geophones or other acoustic receivers 65 can be accomplished by cementing them in place in either the open hole or cased hole or hanging the geophones or other acoustic receivers 65 in the cased hole or the open hole using centralizers (not shown). Note, if left un-cemented, the kickover tool 71 and acoustic receivers 65 can be retrieved at a later date.

[00066] As illustrated in FIG. 8, according to another configuration, the casing 75, liner 73, kick over tool 71', packer 79, acoustic assembly 63, upper and lower communication conduits 103, 147, and the upper inductive coupler 101 can be run together. Although inductive coupler pair 102, 93 can also be run, according to such configuration, as shown in the figure, conduit 103 can instead be hardwired to acoustic controller 61 through passageway 72. FIG. 9 illustrates an embodiment whereby the acoustic sensors 65 of the acoustic assembly 63 are instead cemented to reduce noise and/or isolate pressure that would otherwise be encountered by the acoustic sensors 65.

[00067] Regardless of the running methodology, as illustrated in FIG. 10, having the kickover tool 71 positioned within liner 73 (or directly within the pilot hole 82 if no liner 73 was utilized), wellbore 109 is drilled through aperture 105 at a desired length and distance and depth.

[00068] As illustrated in FIG. 11, a tubing string 121 is run from surface 123 (FIG. 1), through the casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127. The portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry the male inductive coupler 133 on its exterior surface 135. In order to place male inductive coupler 133 in a proper juxtaposition with female inductive coupler 101, the deployment of tubing string 121 includes landing a tubing locator 141 in contact with a landing point/surface 143.

[00069] As illustrated in FIG. 12, during pumping operations, microfractures begin generating acoustic signals which are received at different times by the separated acoustic receivers 65. As illustrated in FIG. 13, in the illustrated embodiment whereby communications are established between the surface 123 (e.g., computer 31) and the acoustic sensors 65 utilizing inductive coupling, an inductive circuit is formed as illustrated, which can provide a reliable means to make an electrical connection down hole in well test operations. Processed acoustic data, processed by acoustic controller 61, is transmitted uphole via the illustrated circuit through the illustrated series of conductor connections and inductive couplings.

[00070] Beneficially, the utilization of the inductive coupling, particularly in conjunction with the establishment of separate electrical connections which do not across boundaries, can function to remove any physical contact between electrical connections and wellbore fluids. An advantage of this system/process is the positive communication provided across the coupling devices. The inductive couplings function so that communication signals emanating from acoustic controller 61 are transmitted through an A/C current created in male coupler 93, which creates an electromagnetic (EM) field transmitted to the female the coupler 102.

[00071] Similarly, FIG. 14 illustrates acoustic sensors 65 receiving acoustic signals from microfracture sources resulting from fracturing operations adjacent separate lateral wellbores

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109, 109'. In this embodiment, however, the other lateral wellbore 109' is associated with an adjacent producing well 53'. Further, data from the respective acoustic controllers 61 associated with each respective producing well 53, 53' can be gathered by computer 31 via network 38 and compared. Alternatively, each producing well 53, 53' can have a separate computer 31 associated therewith in communication with each other through network 38 and/or another network as known to one of ordinary skill in the art.

[00072] According to another embodiment of the present invention, the system/process also includes an advantage whereby power can be delivered across the coupling devices to provide power to the acoustic assembly 63. In yet another embodiment of the present invention, an additional coupling can be made with inductive coupler 133, inductive coupler 101, and/or a Tee-type connection 151 or other form of tap or series of taps in cable 147 (FIG. 15) to provide power and/or communications to the fracturing equipment 111 from the surface 123 and/or provide support to reservoir monitoring sensors 128 such as, for example, pressure, temperature, flow, DTS sensors, etc.. According to an embodiment, a plurality of reservoir monitoring sensors 128 can provide various reservoir condition sensing functions to include providing or providing for determining conductivity for waterfront observation, along with others known to those of ordinary skill in the art.

[00073] FIG. 16 illustrates another embodiment of the present invention whereby improved production control is achieved through application of one or more flow management components 153 such as, for example, inflow control valves, inflow control devices, and/or isolation packers.

[00074] This application claims priority to U.S. Non-Provisional Patent Application number 13/269,596 titled "Method for Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events to Surface using the Pilot Hole of the Treatment Well as the Monitoring Well", filed October 9, 2011, and is related to U.S. Non-Provisional Patent Application Number 13/269,599, titled "System For Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events To Surface Using The Pilot Hole Of The Treatment Well As the Monitoring Well," filed on October 9, 2011, incorporated herein by reference in it's entirety.

[00075] In the drawings and specification, there have been disclosed a typical preferred embodiment of the invention, and although specific terms are employed, the terms are used in a descriptive sense only and not for purposes of limitation. The invention has been described in

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considerable detail with specific reference to these illustrated embodiments. It will be apparent, however, that various modifications and changes can be made within the spirit and scope of the invention as described in the foregoing specification. For example, in place of the inductive coupling portions of inductive coupling circuit 145, connectors such as, e.g., wet mate connectors can be employed as a substitute for the sets of inductive coupling, albeit with some degradation to the advantages of the above described embodiments of the featured system that employ inductive coupling.

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THAT CLAIMED IS:

1. A method of determining hydraulic fracture geometry in a reservoir (23) by combining functions of a first subterranean well and a second subterranean well into a single well (53), the method being characterized by the steps of:

running a lower completion (at 81) comprising wellbore sensors (65) positioned within a tubular (73);

running a communication conduit (103) defining a lower umbilical (103), the lower umbilical (103) extending from a position outside the tubular (73) to a position adjacent an operable position of a connector (133);

drilling a lateral wellbore (109), avoiding intersection with the lower umbilical (103), the lateral wellbore (109) oriented at least partially lateral to an orientation of the tubular (73); and

running an upper completion (at 77) with a communication conduit (147) defining an upper umbilical (147), the upper umbilical (147) attached to the connector (133).

2. A method as defined in claim 1, wherein the step of running the lower completion (at 81) and the step of running a communication conduit (103) are performed simultaneously, the communication conduit (103) defining the lower umbilical (103) and tubular (73) containing the wellbore sensors (65) being run together.

3. A method as defined in either of claims 1 or 2, wherein the first subterranean well comprises a subterranean observation well, wherein the second subterranean well comprises a subterranean producing well, and wherein the single well (53) comprises a single producing well (53).

4. A method as defined in claim 3, wherein the connector (133) is a first connector (133) connecting to the upper umbilical (147), and wherein the wellbore sensors (65) are connected to at least portions of a second connector (93) within a bore (76) of the tubular (73).

5. A method as defined in claim 4, wherein the step of drilling the lateral wellbore (109) comprises positioning an entranceway (105) to the lateral wellbore (109) at a location above the second connector (93) and below the first connector (133).

6. A method as defined in any of claims 1-5, being further characterized by the step of:

running a lateral completion (at 109) attached below the upper completion (at 77).

7. A method as defined in any of claims 1-6, being further characterized by the step of:

running a lateral completion (at 109) below the upper completion (at 77),

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wherein at least one reservoir monitoring sensor (128) is connected to the lateral completion (at 109),

wherein a lateral umbilical is positioned to extend from the at least one reservoir monitoring sensor (128) to a tee connection (151) in the upper umbilical (147).

8. A method as defined in claim 7, being further characterized by the step of:

positioning one or more monitoring sensors (128) in the lateral completion (at 109), the one or more monitoring sensors (128) comprising one or more of the following: a pressure sensor, a temperature sensor, a flow sensor, and a fluid sensor.

9. A method as defined in either of claims 7 or 8, wherein the lateral completion (at 109) includes a plurality of flow management components (129) comprising one or more of the following: inflow control valves (129), inflow control devices, and isolation packers (79, 84).

10. A method as defined in any of claims 1-9, wherein the first subterranean well comprises a subterranean observation well, wherein the second subterranean well comprises a subterranean producing well, wherein the single well (53) comprises a single producing well (53), and wherein a portion of the formation layer of interest (21) associated with the producing well is fractured, and wherein the wellbore sensors (65) within the tubular (73) comprise a plurality of acoustic sensors (65).

11. A method as defined in claim 10, being further characterized by the step of:

sensing an acoustic event by the plurality of acoustic sensors (65), the acoustic event resulting from hydraulic fracturing associated with the lateral completion (at 109).

12. A method as defined in either of claims 10 or 111, being further characterized by the step of:

sensing an acoustic event by the plurality of acoustic sensors (65), the acoustic event resulting from hydraulic fracturing associated with a lateral completion (at 109) of an adjacent well (53').

13. A method as defined in any of claims 10-12, being further characterized by the step of:

positioning a packer (79) below an entranceway (105) to the lateral wellbore (109) and above the plurality of acoustic sensors (65) to minimize noise associated with movement of fracturing fluid through the lateral completion (at 109) and encountered by the plurality of acoustic sensors (65).

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14. A method as defined in any of claims 1-13, being further characterized by the step of:

running a plurality of lateral completions (at 109) below the upper completion (at 77), each lateral completion (at 109) having at least one reservoir monitoring sensor (128) connected thereto and operably coupled to a lateral umbilical positioned to connect to the upper umbilical (147).

15. A method as defined in any of claims 1-14, wherein the first subterranean well comprises a subterranean observation well, wherein the second subterranean well comprises a subterranean producing well, wherein the single well (53) comprises a single producing well (53), wherein a portion of the formation layer of interest (21) associated with the producing well is fractured, wherein the wellbore sensors (65) within the tubular (73) comprise a plurality of acoustic sensors (65), and wherein the plurality of acoustic sensors (65) are connected to an acoustic sensor controller (61), the acoustic sensor controller (61) configured to monitor reservoir monitoring events including conductivity for waterflood front observation.

16. A method as defined in any of claims 1-15,

wherein the connector (133) is a first connector (133) connecting to the upper umbilical (147);

wherein the wellbore sensors (65) are attached to a second connector (93) within the tubular (73); and

wherein the first and the second connectors (133, 93) are configured to inductively couple to the lower umbilical (103).

17. A method as defined in claim 16, wherein the first connector (133) further comprises a wet connector coupled to the upper umbilical (147).

18. A method as defined in either of claims 16 or 17, wherein the second connector (93) further comprises a wet connector coupled to the wellbore sensors (65).

19. A method as defined in any of claims 1-18, wherein the first subterranean well comprises a subterranean observation well, wherein the second subterranean well comprises a subterranean producing well, wherein the single well (53) comprises a single producing well (53), wherein the formation (21) associated with the producing well is fractured, wherein the wellbore sensors (65) within the tubular (73) comprise a plurality of acoustic sensors (65), and wherein the method further comprises the step of:

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cementing the plurality of acoustic sensors (65) in place to minimize noise encountered by the plurality of acoustic sensors (65).

20. A method of determining hydraulic fracture geometry in a reservoir (23) by combining functions of a first subterranean well and a second subterranean well into a single well (53), the method being characterized by the steps of:

running a lower completion (at 81) comprising wellbore sensors (65) positioned within a tubular (73), the wellbore sensors (65) positioned within a formation layer of interest (21);

running a communication conduit (103) defining a lower umbilical (103), the lower umbilical (103) extending from a position outside a portion of the tubular (73) containing the wellbore sensors (65) to a position adjacent an operable position of a connector (133);

drilling a lateral wellbore (109), the lateral wellbore (109) oriented at least partially lateral to an orientation of the tubular (73) and positioned at least substantially within the formation layer of interest (21) to thereby provide fracturing within the formation layer of interest (21); and

running an upper completion (at 77) with a communication conduit (147) defining an upper umbilical (147), the upper umbilical (147) attached to the connector (133), the connector (133) operably coupled to the lower umbilical (103).

21. A method as defined in claim 20, wherein the step of running the lower completion (at 81) and the step of running a communication conduit (103) are performed simultaneously, the communication conduit (103) and at least a portion of the tubular (73) containing the wellbore sensors (65) being connected and run together.

22. A method as defined in either of claims 20, wherein the first subterranean well comprises a subterranean observation well, wherein the second subterranean well comprises a subterranean producing well, and wherein the method further comprises the step of:

combining functions of the first subterranean observation well and the second subterranean producing well into a single producing well (53).

23. A method as defined in claim 22, wherein the connector (133) is a first connector (133) connecting to the upper umbilical (147), and wherein the wellbore sensors (65) are connected to at least portions of a second connector (93) having at least portions positioned within a bore (76) of the tubular (73).

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24. A method as defined in claim 23, wherein the step of drilling the lateral wellbore (109) comprises positioning an entranceway (105) to the lateral wellbore (109) at a location above the second connector (93) and below the first connector (133).

25. A method as defined in claim 24, wherein the step of running the upper completion (at 77) is performed prior to drilling the lateral wellbore (109).

26. A method as defined in either of claims 24 or 25, being further characterized by the step of:

running a lateral completion (at 109), the step of running the lateral completion (at 109) comprising horizontally aligning the lateral completion (at 109) at least substantially between upper and lower boundaries of the formation layer of interest (21) to provide fracturing within the formation layer of interest (21).

27. A method as defined in claim 26, wherein the wellbore sensors (65) are acoustic sensors (65), and wherein the step of running the lower completion (at 81) comprises the step of:

positioning the portion of the tubular (73) containing the acoustic sensors (65) between upper and lower boundaries of the formation layer of interest (21).

28. A method as defined in either of claims 26 or 27, wherein a portion of the formation layer of interest (21) is fractured above and below the lateral completion (at 109), wherein the wellbore sensors (65) within the tubular (73) comprise a plurality of acoustic sensors (65) located within the formation layer of interest (21), and wherein the acoustic sensors (65) receive fracturing data for portions of the formation layer of interest (21) located above the lateral completion (at 109) and receive fracturing data from portions of the formation layer of interest (21) located below the lateral completion (at 109).

29. A method as defined in any of claims 26-28, wherein the wellbore sensors (65) are acoustic sensors (65), the method being further characterized by the step of:

sensing an acoustic event by the plurality of acoustic sensors (65), the acoustic event resulting from hydraulic fracturing associated with the lateral completion (at 109).

30. A method as defined in any of claims 20-29, wherein the step of drilling the lateral wellbore (109) comprises positioning an entranceway (105) to the lateral wellbore (109) at a location above the second connector (93) and below the first connector (133), and wherein the wellbore sensors (65) are acoustic sensors (65), the method being further characterized by the step of:

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sensing an acoustic event by the plurality of acoustic sensors (65), the acoustic event resulting from hydraulic fracturing associated with a lateral completion (at 109) of an adjacent well (53').

31. A method as defined in any of claims 20-30, wherein the step of drilling the lateral wellbore (109) comprises positioning an entranceway (105) to the lateral wellbore (109) at a location above the second connector (93) and below the first connector (133), the method being further characterized by the step of:

positioning a packer (79) below the entranceway (105) to the lateral wellbore (109) and above the plurality of acoustic sensors (65) to minimize noise associated with movement of fracturing fluid through the lateral completion (at 109) and encountered by the plurality of acoustic sensors (65).

32. A method as defined in any of claims 20-31,

wherein the connector (133) is a first connector (101, 133) connecting to the upper umbilical (147);

wherein the wellbore sensors (65) are attached to a second connector (93) within the tubular (73); and

wherein the first and the second connectors (133, 93) are configured to inductively couple to the lower umbilical (103).

33. A method as defined in claim 32, wherein the first connector (133) further comprises a wet connector coupled to the upper umbilical (147).

34. A method as defined in either of claims 32 or 33, wherein the second connector (93) further comprises a wet connector coupled to the wellbore sensors (65).

35. A method as defined in any of claims 32-34, wherein the formation (21) associated with the producing well is fractured, wherein the wellbore sensors (65) within the tubular (73) comprise a plurality of acoustic sensors (65), and wherein the method further comprises:

cementing the plurality of acoustic sensors (65) in place within the tubular (73) to minimize noise encountered by the plurality of acoustic sensors (65).

36. A method of determining hydraulic fracture geometry of a zone of interest (21) in a reservoir (23), the method being characterized by the steps of:

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providing a plurality of wells (53, 53'), each well (53, 53') comprising an upper completion (at 77), a lower completion (at 81), and a lateral completion (at 109) extending into a lateral wellbore (109);

combining functions of a first subterranean well and a second subterranean well into each separate one of the plurality of wells (53, 53') by performing the following for each of the plurality of wells (53, 53'):

positioning a plurality of acoustic sensors (65) in the lower completion (at 81), and

hydraulically isolating the plurality of acoustic sensors (65) from fracturing fluid flowing through the upper completion (at 77) and the lateral completion (at 109), the isolation provided via an isolation device (71, 79, 87) positioned below the lateral wellbore (109) and above the plurality of acoustic sensors (65) to minimize noise associated with movement of the fracturing fluid through the lateral completion (at 109) and encountered by the plurality of acoustic sensors (65); and

sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion (at 109) of one of the plurality of wells, the sensing performed by one or more of the plurality of acoustic sensors (65) in at least two of the plurality of wells (53, 53').

37. A method as defined in claim 36, wherein the plurality of wells (53, 53') comprise a plurality of producing wells (53, 53'), wherein the first subterranean well comprises a first subterranean observation well, and wherein the second subterranean well comprises a subterranean producing well.

38. A method as defined in either of claims 36 or 37, wherein the isolation device (71, 79, 87) comprises a packer (79).

39. A method as defined in any of claims 36-38, wherein the isolation device (71, 79, 87) comprises cement.

40. A method of determining hydraulic fracture geometry of a zone of interest (21) in a reservoir (23), the method being characterized by the steps of:

positioning an acoustic assembly (63) within a first wellbore (78) adjacent the zone of interest (21) in a reservoir (23), the first wellbore (78) drilled within a portion of the reservoir (23) to receive a hydraulic fracturing treatment defining the zone of interest (21), the acoustic

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assembly (63) including an acoustic receiver controller (61) and a set of one or more acoustic sensors (65) to capture fracture events within the zone of interest (21);

inserting a drilling deflector (71) into the first wellbore (78);

drilling a second wellbore (109) to receive a fracturing fluid;

positioning a communication conduit bypass (101, 133; 103; 102, 93) within the first wellbore (78) to extend from a first location above an interface with the second wellbore (109) to a second location below the interface with the second wellbore (109);

inductively coupling the acoustic receiver controller (61) to a first inductive coupler (102) connected to a first end of the communication conduit bypass (101, 133; 103; 102, 93), the first inductive coupler (102) positioned adjacent the second location below the lateral aperture (105);

inductively coupling surface equipment (31, 38) to a second inductive coupler (101) connected to a second opposite end of the communication conduit bypass (101, 133; 103; 102, 93), the second inductive coupler (101) positioned adjacent the first location above the lateral aperture (105); and

communicating real-time microseismic event data to a surface unit (31), the microseismic event data describing microseismic events detected by the acoustic assembly (63) when performing hydraulic fracturing of the reservoir (23) in the zone of interest (21) through the second wellbore (109).

41. A method as defined in claim 40, being further characterized by the steps of:

isolating the set of one or more acoustic sensors (65) from acoustic interference associated with delivery of fracturing fluid through a conduit string (121) extending through portions of the first wellbore (78) and into the second wellbore (109) when performing the hydraulic fracturing of the reservoir (23) in the zone of interest (21) to thereby minimize noise encountered by the set of one or more acoustic sensors (65) and associated with movement of fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of acoustic sensors (65).

42. A method as defined in claim 41, wherein the step of isolating the set of one or more acoustic sensors (65) from acoustic interference includes the step of:

positioning a packer (79) within a production liner (73) containing the one or more acoustic sensors (65) below major portions of the first wellbore (78) containing the conduit string

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(121) and above the set of one or more acoustic sensors (65) to thereby minimize the noise encountered by the set of one or more acoustic sensors (65) and associated with movement of the fracturing fluid.

43. A method as defined in claim 42, wherein the steps of inserting a drilling deflector (71) and positioning an acoustic assembly (63) within a first wellbore (78) are performed simultaneously, the method being further characterized by the step of:

connecting the set of one or more acoustic sensors (65) to a down-hole facing portion of the drilling deflector (71) prior to performing the step of inserting the drilling defector (71) into the first wellbore (78).

44. A method as defined in any of claims 40-43, wherein the step of positioning a communication conduit bypass (101, 133; 103; 102, 93) within the first wellbore (78) includes the steps of:

determining an expected location of the lateral aperture (105) through a production liner (73);

connecting the second inductive coupler (101) to an outer facing surface of the production liner (73) at a location above the expected location of the lateral aperture (105);

connecting first inductive coupler (102) to an outer facing surface of the production liner (73) at a location below the expected location of the lateral aperture (105);

connecting an electrical conduit (103) along an outer surface of the production liner (73) between the first and the second inductive couplers (102, 101) away from the expected location of the lateral aperture (105); and

running the production liner (73) within the first wellbore (78).

45. A method as defined in claim 44, wherein the steps of inductively coupling the acoustic receiver controller (61) to the first inductive coupler (102) and inductively coupling surface equipment (31, 38) to the second inductive coupler (101) comprises the steps of:

connecting a third inductive coupler (133) to an outward facing surface of a portion of a tubing segment (121) at a predetermined longitudinal distance from a reference point associated with a tubing locator (141) extending from an outer surface portion of the tubing segment (121), the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the first inductive coupler (102) when the tubing locator (141) is landed upon a portion of the production liner (73); and

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connecting a fourth inductive coupler (93) to an outward facing surface of the drilling deflector (71) at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the drilling deflector (71) reference point to the second inductive coupler (101) when the drilling deflector (71) is landed at a preselected location within the production liner (73).

46. A method as defined in any of claims 40-45, wherein the second wellbore (109) is devoid of any acoustic monitoring equipment (63) and associated interfering communication conduits (95, 103, 147).

47. A method of determining hydraulic fracture geometry of a zone of interest (21) in a reservoir (23), the method being characterized by the steps of:

positioning a kickover tool (71) within a production liner (73) in a first wellbore (78) drilled within a portion of a reservoir (23) to receive a hydraulic fracturing treatment defining a zone of interest (21);

positioning an acoustic assembly (63) within the production liner (73) in the first wellbore (78) below major portions of the kickover tool (71) and adjacent the zone of interest (21) in the reservoir (23), the acoustic assembly (63) including an acoustic receiver controller (61) and a set of one or more acoustic sensors (65) to capture fracture events within the zone of interest (21);

opening a lateral aperture (105) in the production liner (73), the lateral aperture (105) forming an entrance to a second wellbore (109) to receive a fracturing fluid;

positioning a communication conduit bypass (101, 133; 103; 102, 93) within the first wellbore (78) to extend from a first location above the lateral aperture (105) to a second location below the lateral aperture (105);

inductively coupling the acoustic receiver controller (61) to a first inductive coupler (102) connected to a first end of the communication conduit bypass (101, 133; 103; 102, 93), the first inductive coupler (102) positioned adjacent the second location below the lateral aperture (105);

inductively coupling surface equipment (31, 38) to a second inductive coupler (101) connected to a second opposite end of the communication conduit bypass (101, 133; 103; 102, 93), the second inductive coupler (101) positioned adjacent the first location above the lateral aperture (105); and

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communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly (63) when performing hydraulic fracturing of the reservoir (23) in the zone of interest (21).

48. A method as defined in claim 47, being further characterized by the steps of:

isolating the set of one or more acoustic sensors (65) from acoustic interference associated with delivery of fracturing fluid through a conduit string (121) extending through portions of the first wellbore (78) and into the second wellbore (109) when performing the hydraulic fracturing of the reservoir (23) in the zone of interest (21) to thereby minimize noise encountered by the set of one or more acoustic sensors (65) and associated with movement of fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of acoustic sensors (65).

49. A method as defined in claim 48, wherein the step of isolating the set of one or more acoustic sensors (65) from acoustic interference includes the step of:

positioning a packer (79) within the production liner (73) below major portions of the kickover tool (71) and above the set of one or more acoustic sensors (65) to thereby minimize the noise encountered by the set of one or more acoustic sensors (65) and associated with movement of the fracturing fluid.

50. A method as defined in either of claims 47-49, wherein the steps of positioning a kickover tool (71) within a production liner (73) and positioning an acoustic assembly (63) within the production liner (73) are performed simultaneously, the method being further characterized by the step of:

connecting the set of one or more acoustic receivers (65) to a down-hole facing portion of the kickover tool (71) prior to performing the step of positioning the kickover tool (71) in the production liner (73).

51. A method as defined in any of claims 47-50, wherein the step of positioning a communication conduit bypass (101, 133; 103; 102, 93) within the first wellbore (78) includes the steps of:

determining an expected location of the lateral aperture (105) through the production liner (73);

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connecting the first inductive coupler (102) to an outer facing surface of the production liner (73) at a location above the expected location of the lateral aperture (105);

connecting second inductive coupler (101) to an outer facing surface of the production liner (73) at a location below the expected location of the lateral aperture (105);

connecting an electrical conduit along an outer surface of the production liner (73) between the first and the second inductive couplers (102, 101) away from the expected location of the lateral aperture (105); and

running the production liner (73) within the first wellbore (78).

52. A method as defined in claim 51, wherein the steps of inductively coupling the acoustic receiver controller (61) to the first inductive coupler (102) and inductively coupling surface equipment (31, 38) to the second inductive coupler (101) comprises the steps of:

connecting a third inductive coupler (133) to an outward facing surface of a portion of a tubing segment (121) at a predetermined longitudinal distance from a reference point associated with a tubing locator (141) extending from an outer surface portion of the tubing segment (121), the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the first inductive coupler (102) when the tubing locator (141) is landed upon a portion of the production liner (73); and

connecting a fourth inductive coupler (93) to an outward facing surface of the kickover tool (71) at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the kickover tool reference point to the second inductive coupler (101) when the kickover tool (71) is landed at a preselected location within the production liner (73).

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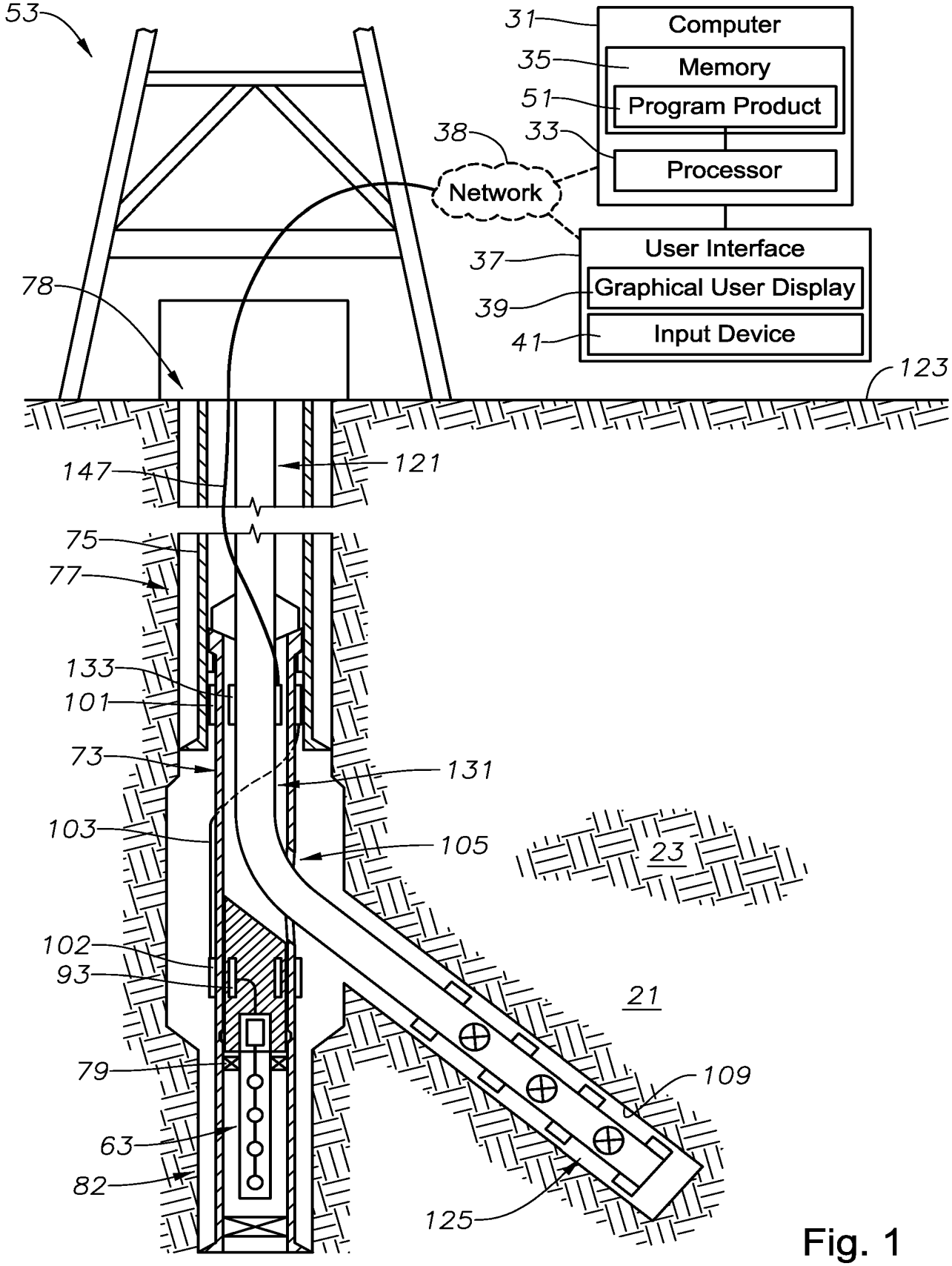

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Computer
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Memory
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Program Product
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33
Processor
Network
User Interface
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Graphical User Display
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Input Device
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Fig. 1

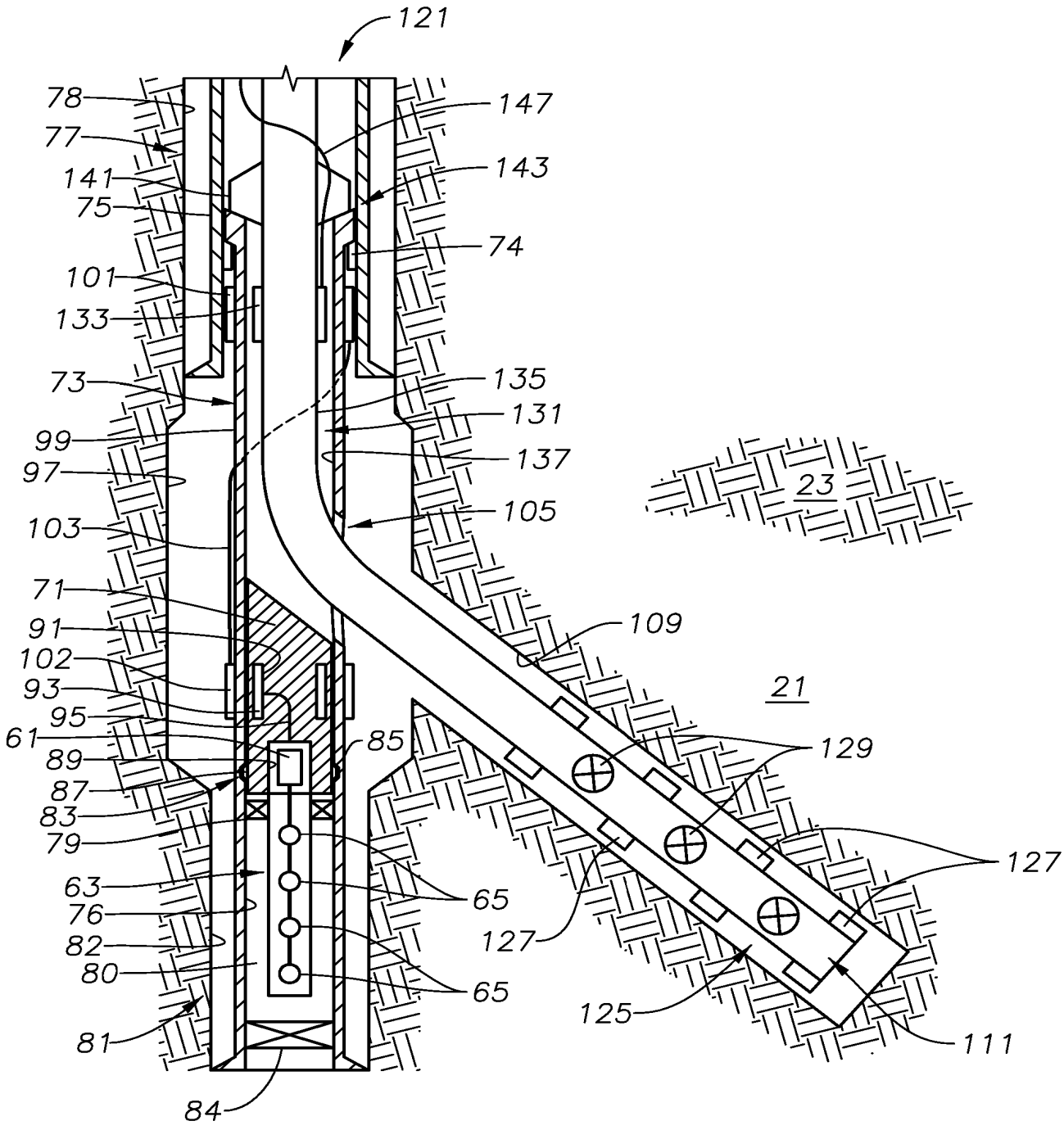

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Fig. 2

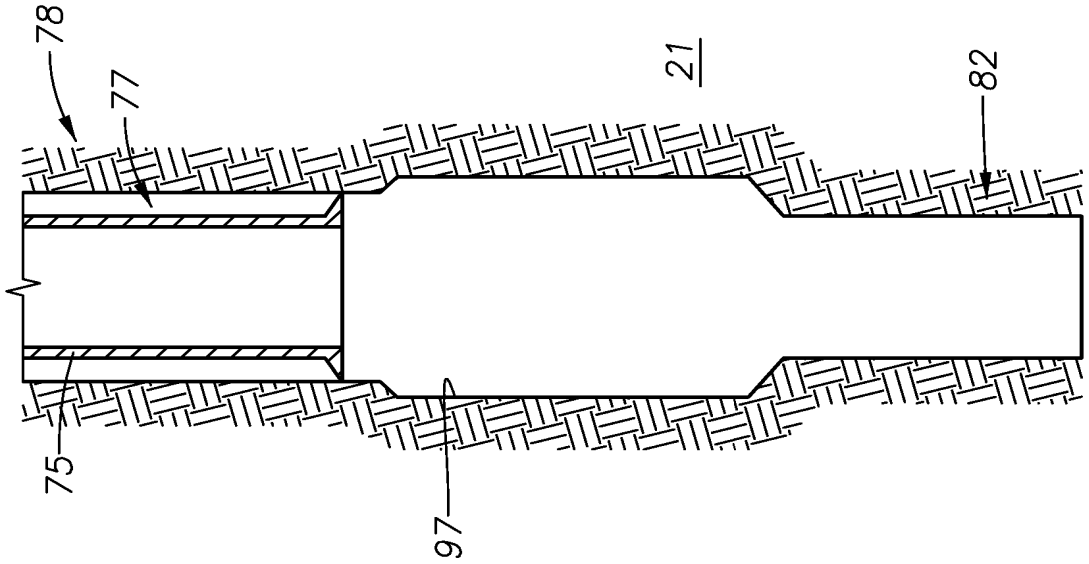


Fig. 4

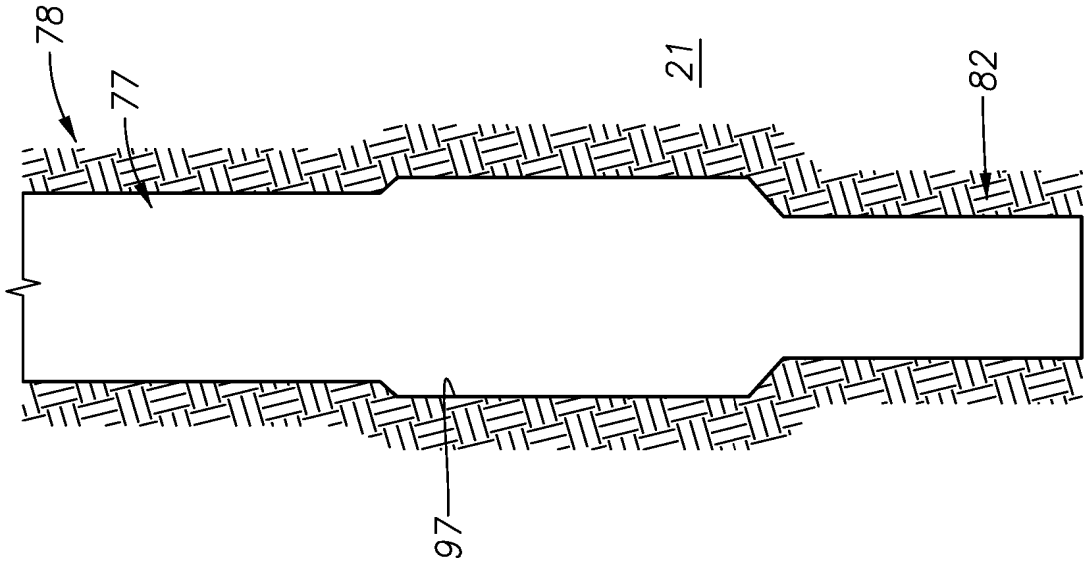


Fig. 3

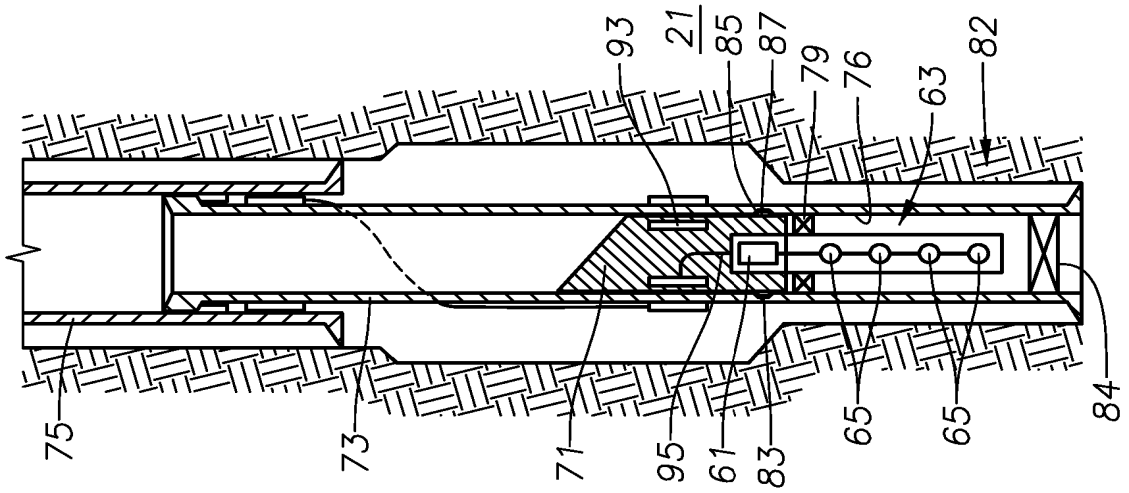


Fig. 7

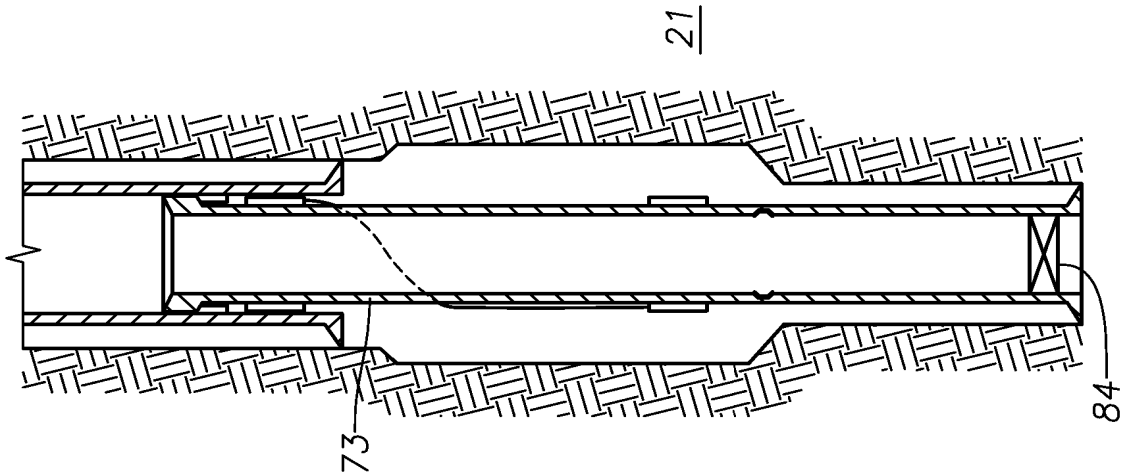


Fig. 6

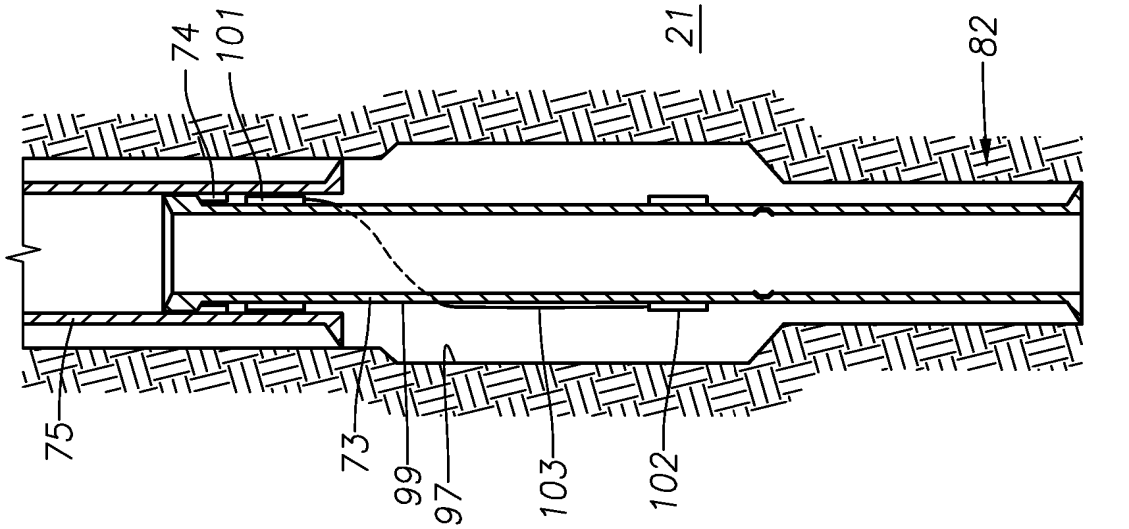


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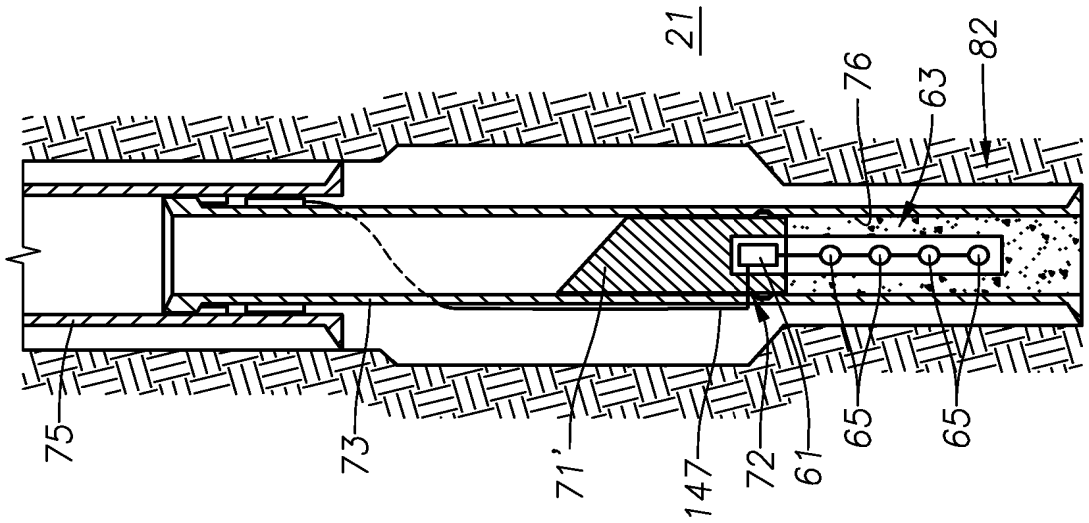

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Fig. 9

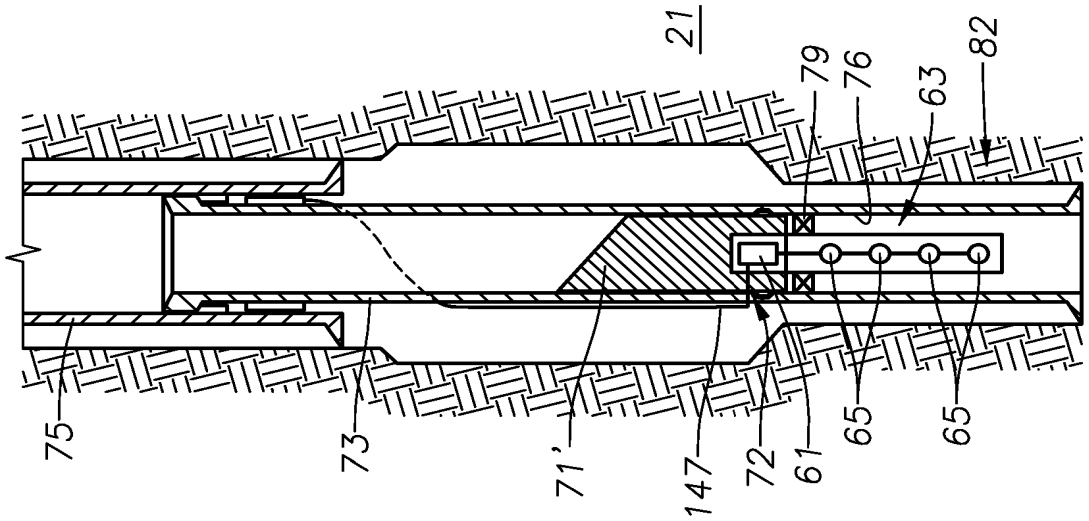

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Fig. 8

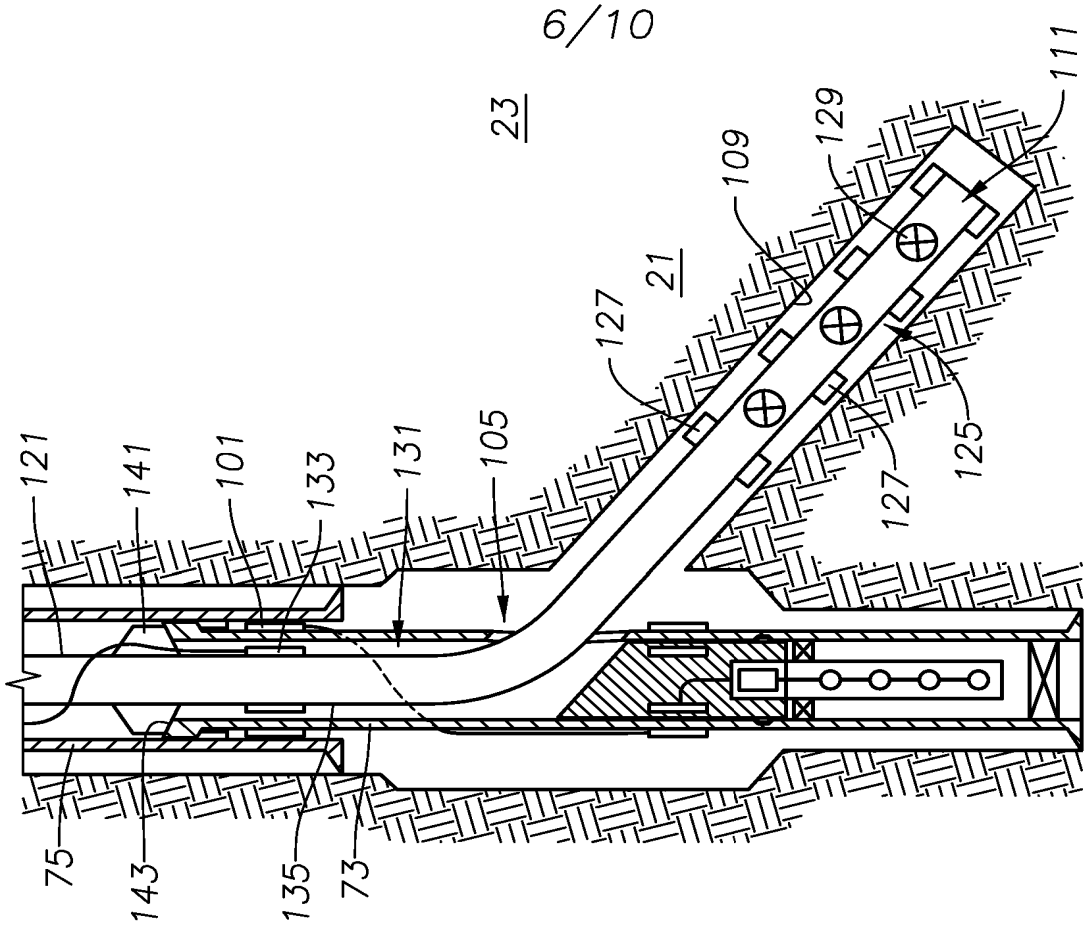

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Fig. 11

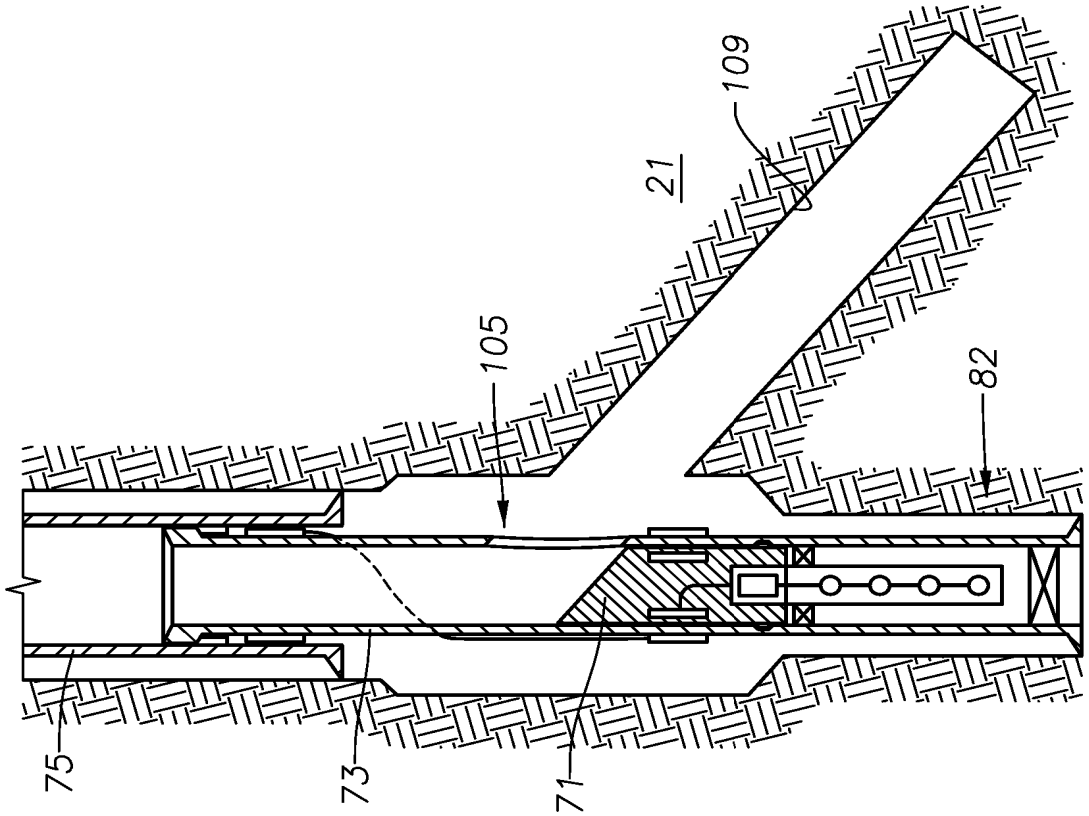

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Fig. 10

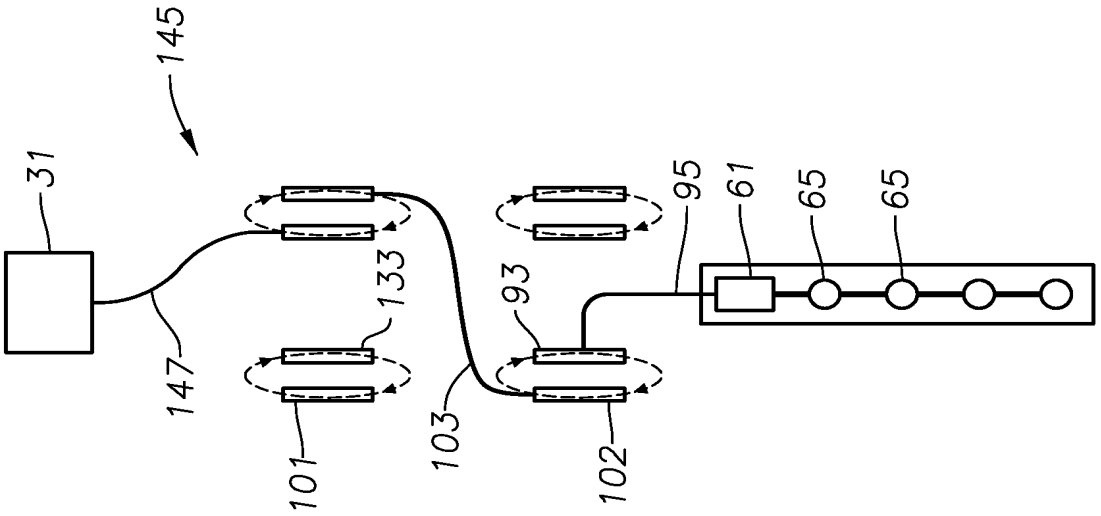


Fig. 13

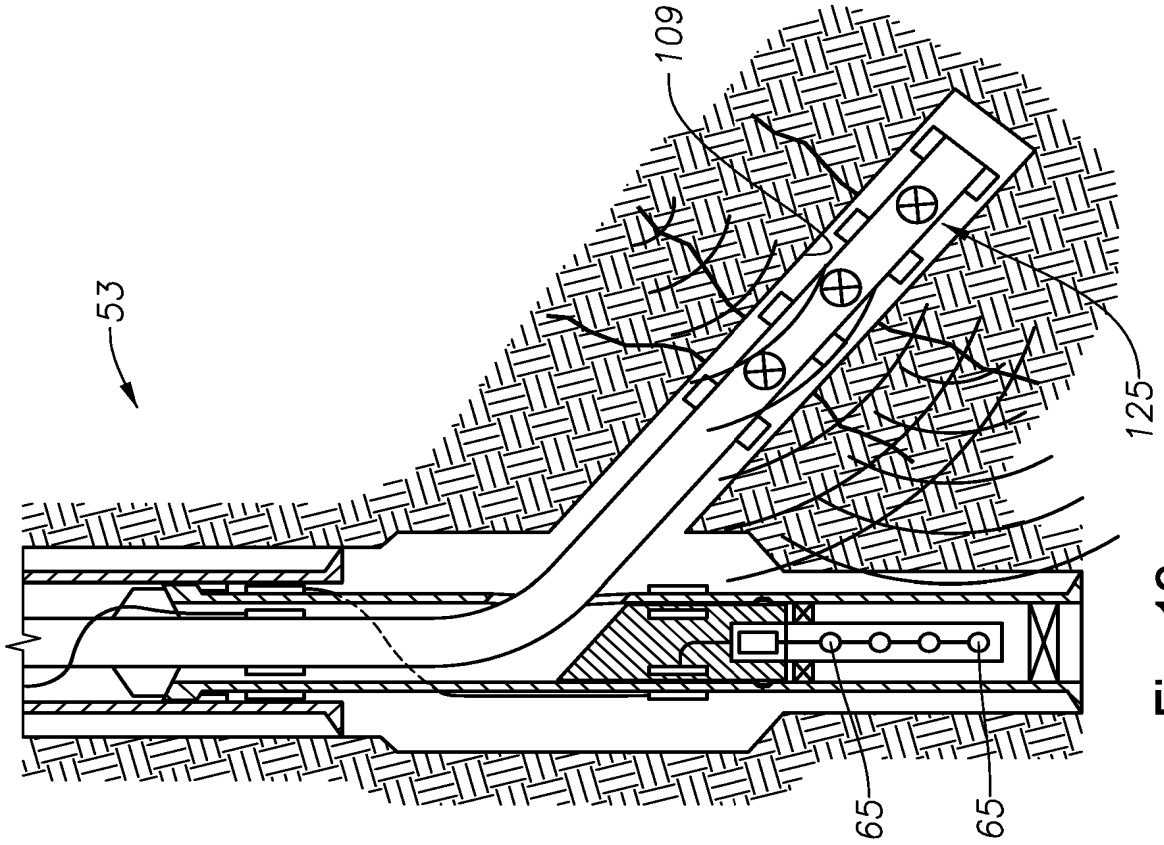


Fig. 12

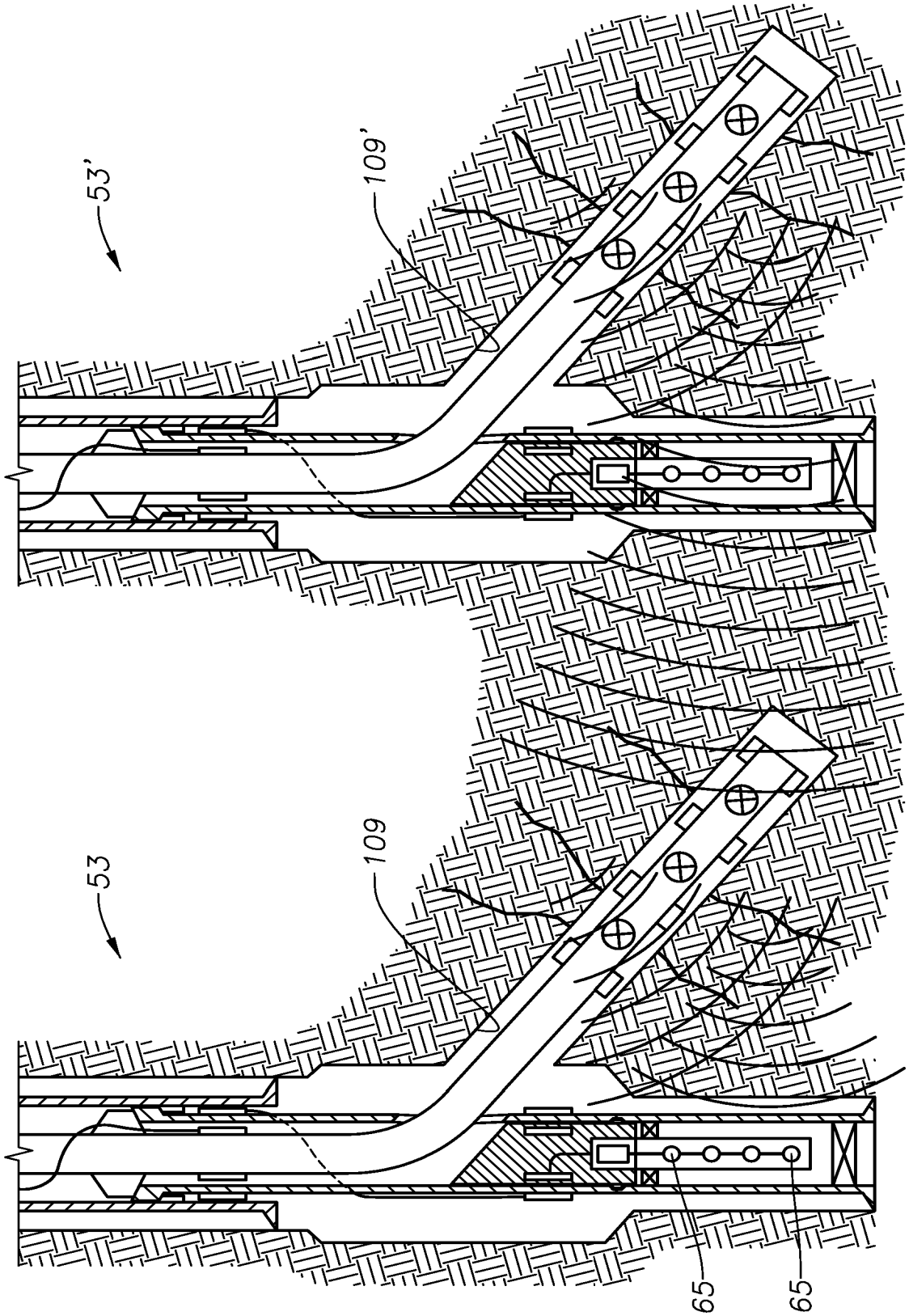


Fig. 14

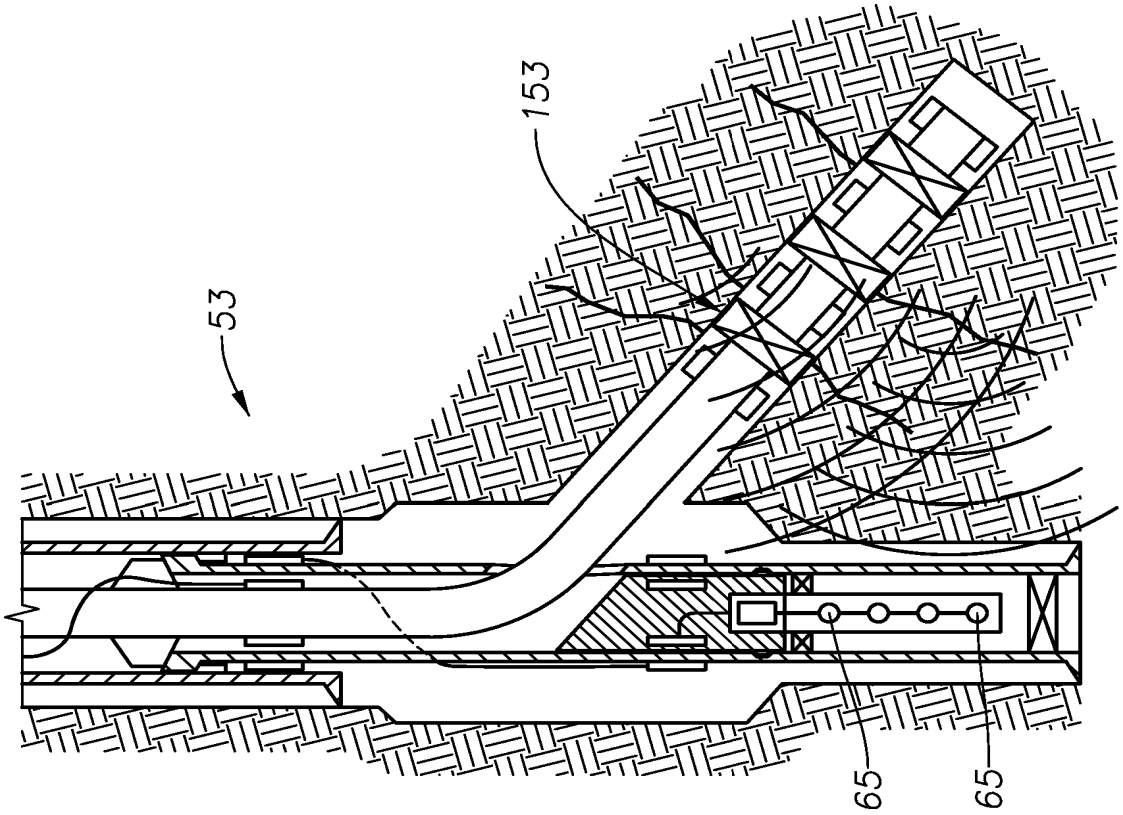


Fig. 16

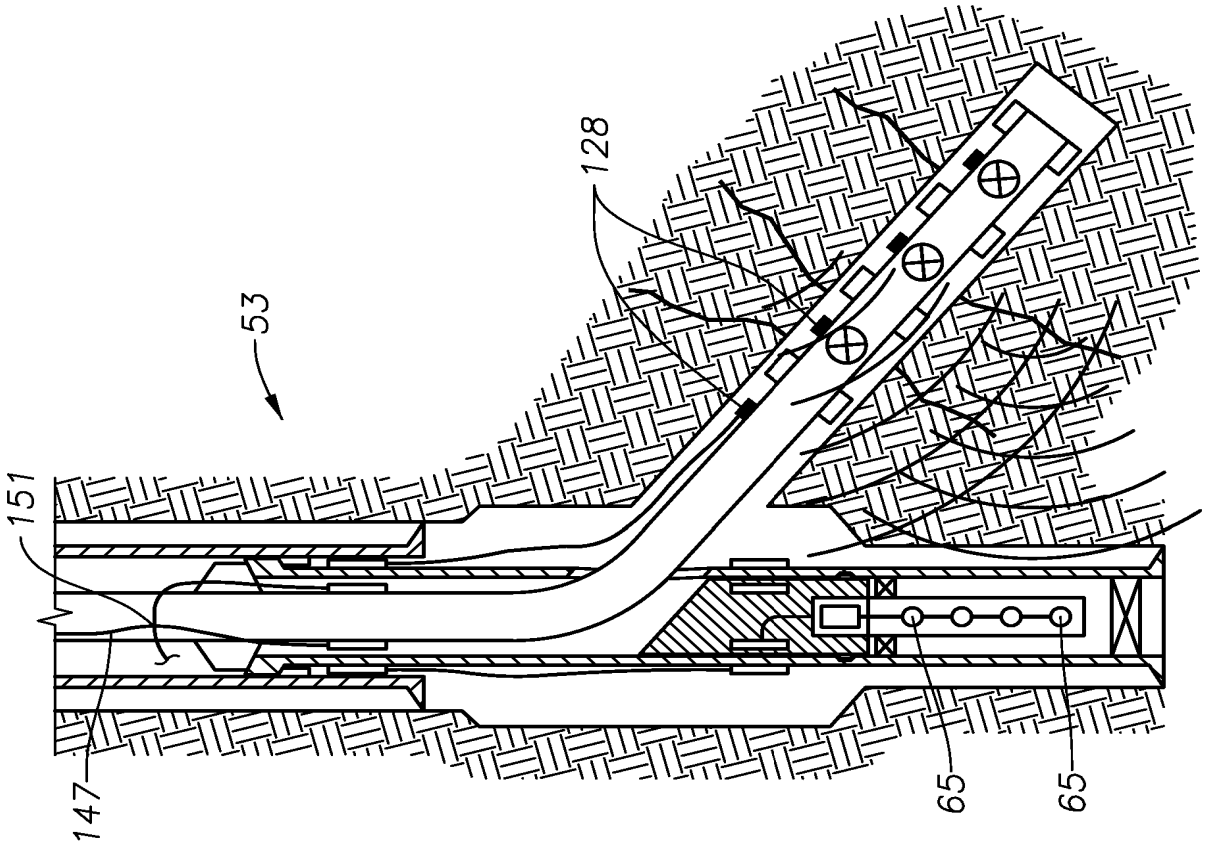


Fig. 15

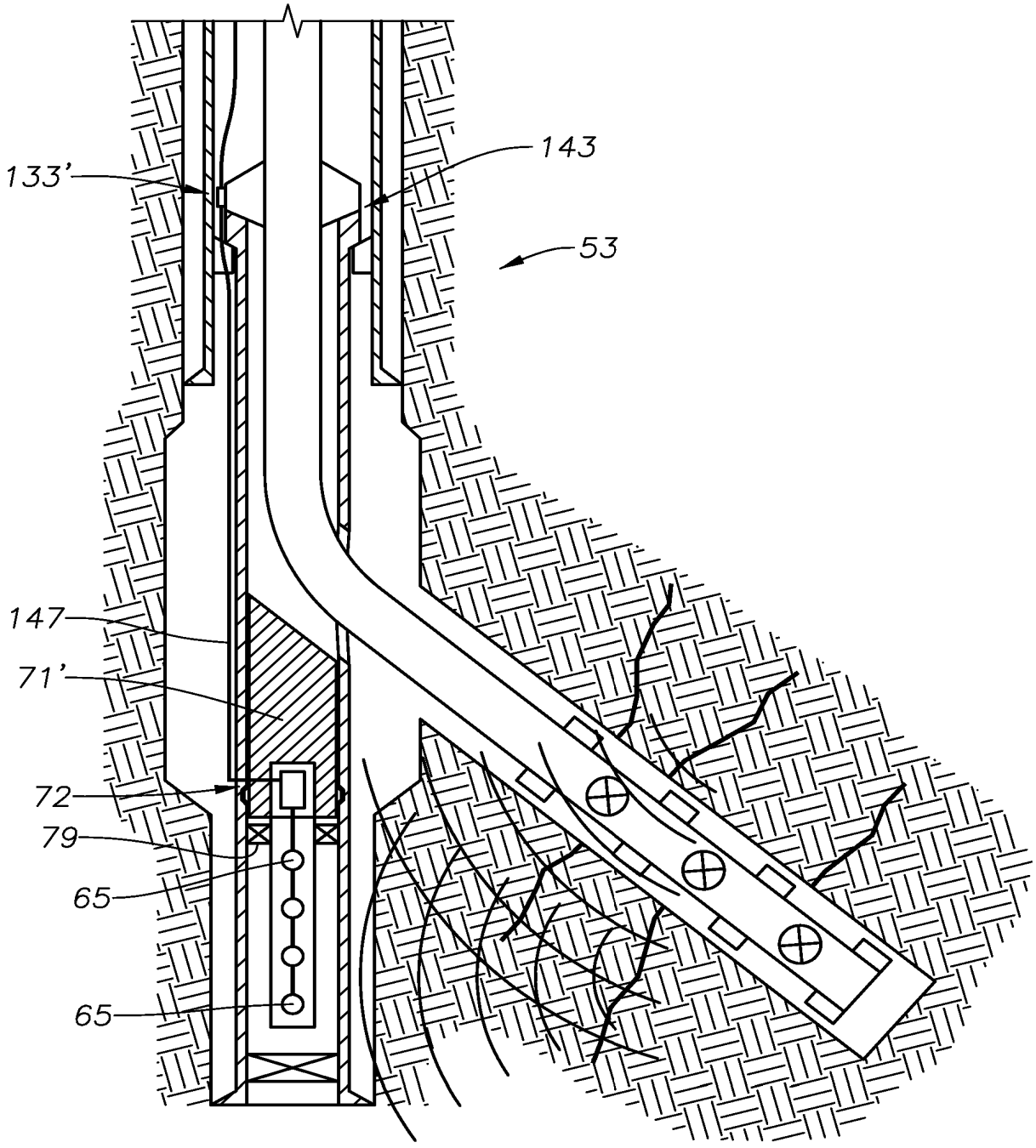


Fig. 17

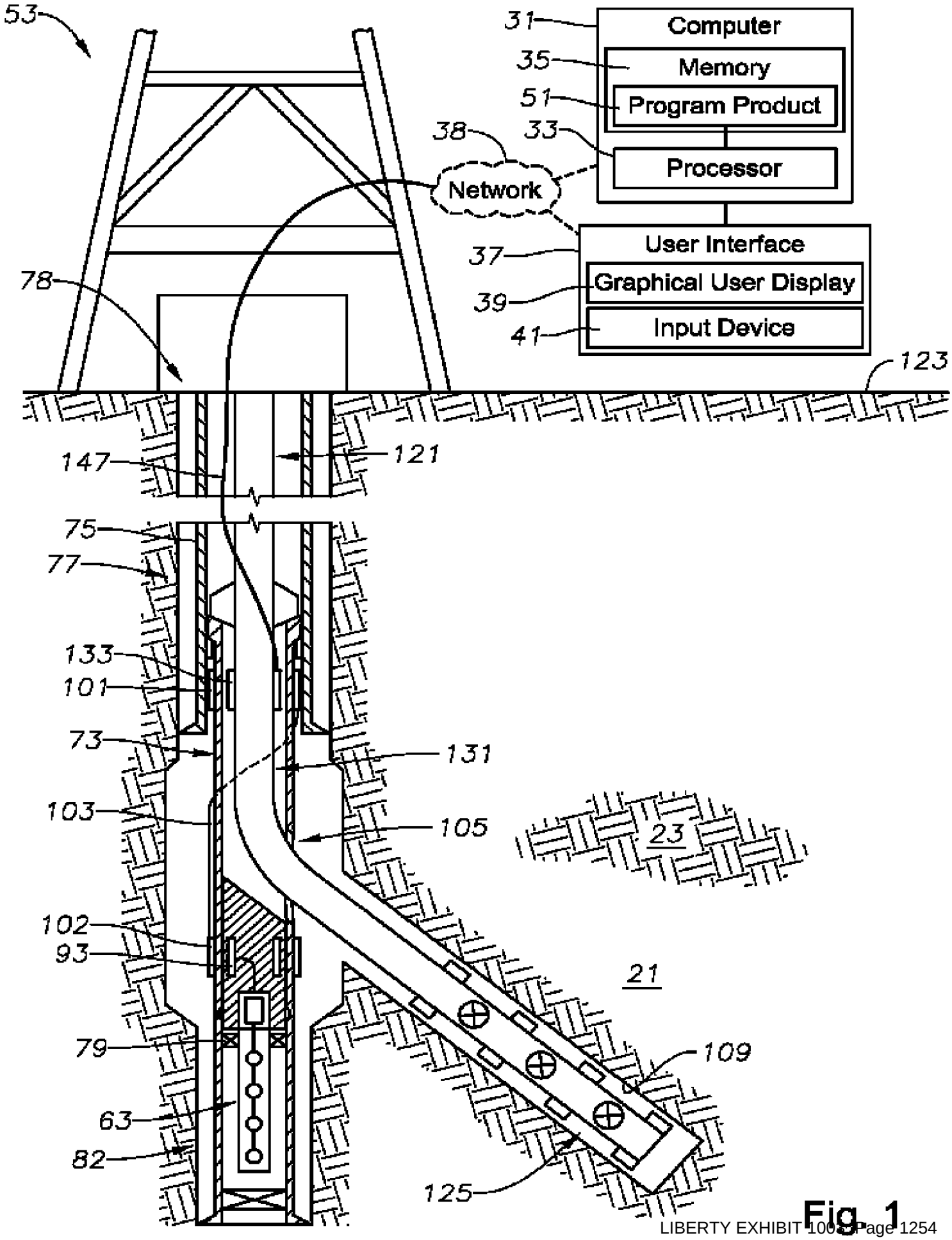

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Fig. 1

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CA 2919649 A1 2016/08/24

(21) 2 919 649

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) **Date de dépôt/Filing Date:** 2016/02/02

(41) **Mise à la disp. pub./Open to Public Insp.:** 2016/08/24

(30) **Priorités/Priorities:** 2015/02/24 (US62/120,212); 2015/07/29 (US62/198,575); 2016/01/28 (US15/009,572)

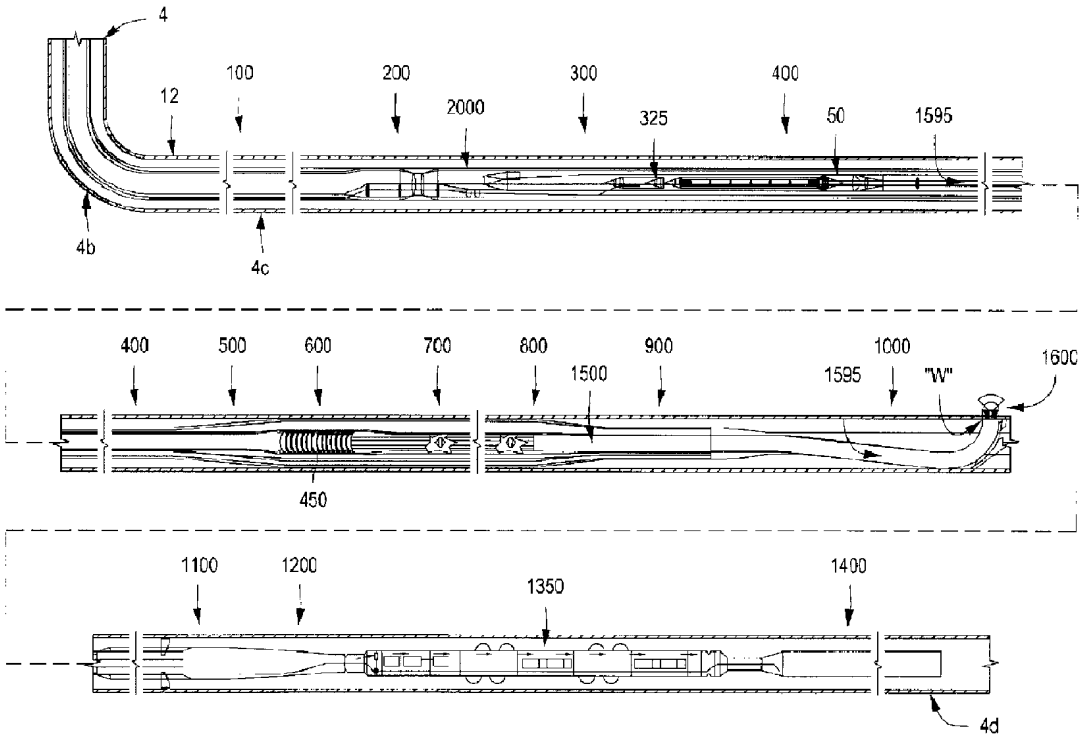
(51) **Cl.Int./Int.Cl.** ***E21B 7/18*** (2006.01), ***E21B 7/04*** (2006.01), ***E21B 7/08*** (2006.01)

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(54) **Titre : MECANISME DE LANCAGE DE JETS HYDRAULIQUES EN FOND DE TROU**
(54) **Title: DOWNHOLE HYDRAULIC JETTING ASSEMBLY**



(57) **Abrégé/Abstract:**
A downhole hydraulic jetting assembly is provided herein. The assembly is useful for steerably jetting multiple lateral boreholes into a subsurface formation from an existing parent wellbore of any inclination. The assembly is useful for single trip completions or recompletion through the placement of multiple lateral boreholes. The assembly includes an external system wherein coiled tubing and a whipstock member are run into a wellbore. The assembly further includes an internal system that is run into the wellbore housed within the external system, but which allows a nozzle at the end of the hose to be directed against a wellbore exit location after the whipstock member is located and set. A window may be formed through casing using the jetting hose and nozzle, followed by the formation of a lateral bore hole. The whipstock may be re-located and/or re-oriented for the jetting of additional casing exits and lateral boreholes in the same trip.

ABSTRACT

A downhole hydraulic jetting assembly is provided herein. The assembly is useful for steerably jetting multiple lateral boreholes into a subsurface formation from an existing parent wellbore of any inclination. The assembly is useful for single trip completions or recompletion through the placement of multiple lateral boreholes. The assembly includes an external system wherein coiled tubing and a whipstock member are run into a wellbore. The assembly further includes an internal system that is run into the wellbore housed within the external system, but which allows a nozzle at the end of the hose to be directed against a wellbore exit location after the whipstock member is located and set. A window may be formed through casing using the jetting hose and nozzle, followed by the formation of a lateral bore hole. The whipstock may be re-located and/or re-oriented for the jetting of additional casing exits and lateral boreholes in the same trip.

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DOWNHOLE HYDRAULIC JETTING ASSEMBLY

BACKGROUND OF THE INVENTION

[1] This section is intended to introduce selected aspects of the art, which may be associated with various embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Field of the Invention

[2] The present disclosure relates to the field of well completion. More specifically, the present disclosure relates to the completion and stimulation of a hydrocarbon-producing formation by the generation of small-diameter boreholes from an existing wellbore using a hydraulic jetting assembly. The present disclosure further relates to the controlled generation of multiple lateral boreholes that extend many feet into a subsurface formation, in one trip, thereby creating a designed "cluster" of boreholes.

Discussion of Technology

[3] In the drilling of an oil and gas well, a near-vertical wellbore is formed through the earth using a drill bit urged downwardly at a lower end of a drill string. After drilling to a predetermined bottomhole location, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the formation penetrated by the wellbore. Particularly in a vertical wellbore, or the vertical section of a horizontal well, a cementing operation is conducted in order to fill or "squeeze" the entire annular volume with cement along part or all of the length of the wellbore. The combination of cement and casing strengthens the wellbore and facilitates the zonal isolation, and subsequent completion, of certain sections of potentially hydrocarbon-producing pay zones behind the casing.

[4] Within the last two decades, advances in drilling technology have enabled oil and gas operators to economically "kick-off" and steer wellbore trajectories from a generally vertical orientation to a generally horizontal orientation. The horizontal "leg" of each of these wellbores now often exceeds a length of one mile. This significantly multiplies the wellbore exposure to a target hydrocarbon-bearing formation (or "pay zone"). For example, for a given target pay zone having a (vertical) thickness of 100 feet, a one mile horizontal leg exposes 52.8 times as much pay zone to a horizontal wellbore as compared to the 100-foot exposure of a conventional vertical wellbore.

[5] **Figure 1A** provides a cross-sectional view of a wellbore **4** having been completed in a horizontal orientation. It can be seen that a wellbore **4** has been formed from the earth surface **1**, through numerous earth strata **2a**, **2b**, . . . **2h** and down to a hydrocarbon-producing formation **3**. The subsurface formation **3** represents a "pay zone" for the oil and gas operator. The wellbore **4** includes a vertical section **4a** above the pay zone, and a horizontal section **4c**. The horizontal section **4c** defines a heel **4b** and a toe **4d** and an elongated leg there between that extends through the pay zone **3**.

[6] In connection with the completion of the wellbore **4**, several strings of casing having progressively smaller outer diameters have been cemented into the wellbore **4**. These include a string of surface casing **6**, and may include one or more strings of intermediate casing **9**, and finally, a production casing **12**. (Not shown is the shallowest and largest diameter casing referred to as conductor pipe, which is a short section of pipe separate from and immediately above the surface casing.) One of the main functions of the surface casing **6** is to isolate and protect the shallower, fresh water bearing aquifers from contamination by any wellbore fluids. Accordingly, the conductor pipe and the surface casing **6** are almost always cemented **7** entirely back to the surface **1**.

[7] The process of drilling and then cementing progressively smaller strings of casing is repeated several times until the well has reached total depth. In some instances, the final string of casing **12** is a liner, that is, a string of casing that is not tied back to the surface **1**. The final string of casing **12**, referred to as a production casing, is also typically cemented **13** into place. In the case of a horizontal completion, the production casing **12** may be cemented, or may

provide zonal isolation using external casing packers ("ECP's), swell packers, or some combination thereof.

[8] Additional tubular bodies may be included in a well completion. These include one or more strings of production tubing placed within the production casing or liner (not shown in **Figure 1A**). In a vertical well completion, each tubing string extends from the surface **1** to a designated depth proximate the production interval **3**, and may be attached to a packer (not shown). The packer serves to seal off the annular space between the production tubing string and the surrounding casing **12**. In a horizontal well completion, the production tubing is typically landed (with or without a packer) at or near the heel **4b** of the wellbore **4**.

[9] In some instances, the pay zone **3** is incapable of flowing fluids to the surface **1** efficiently. When this occurs, the operator may install artificial lift equipment (not shown in **Figure 1A**) as part of the wellbore completion. Artificial lift equipment may include a downhole pump connected to a surface pumping unit via a string of sucker rods run within the tubing. Alternatively, an electrically-driven submersible pump may be placed at the bottom end of the production tubing. Gas lift valves, hydraulic jet pumps, plunger lift systems, or various other types of artificial lift equipment and techniques may also be employed to assist fluid flow to the surface **1**.

[10] As part of the completion process, a wellhead **5** is installed at the surface **1**. The wellhead **5** serves to contain wellbore pressures and direct the flow of production fluids at the surface **1**. Fluid gathering and processing equipment (not shown in **Figure 1A**) such as pipes, valves, separators, dehydrators, gas sweetening units, and oil and water stock tanks may also be provided. Subsequent to completion of the pay zone(s) followed by installation of any requisite downhole tubulars, artificial lift equipment, and the wellhead **5**, production operations may commence. Wellbore pressures are held under control, and produced wellbore fluids are segregated and distributed appropriately.

[11] Within the United States, many wells are now drilled principally to recover oil and/or natural gas, and potentially natural gas liquids, from pay zones previously thought to be too impermeable to produce hydrocarbons in economically viable quantities. Such "tight" or "unconventional" formations may be sandstone, siltstone, or even shale formations.

Alternatively, such unconventional formations may include coalbed methane. In any instance, "low permeability" typically refers to a rock interval having permeability less than 0.1 millidarcies.

[12] In order to enhance the recovery of hydrocarbons, particularly in low-permeability formations, subsequent (i.e., after perforating the production casing or liner) stimulation techniques may be employed in the completion of pay zones. Such techniques include hydraulic fracturing and/or acidizing. In addition, "kick-off" wellbores may be formed from a primary wellbore in order to create one or more new directionally or horizontally completed boreholes. This allows a well to penetrate along the plane of a subsurface formation to increase exposure to the pay zone. Where the natural or hydraulically-induced fracture plane(s) of a formation is vertical, a horizontally completed wellbore allows the production casing to intersect, or "source," multiple fracture planes. Accordingly, whereas vertically oriented wellbores are typically constrained to a single hydraulically-induced fracture plane per pay zone, horizontal wellbores may be perforated and hydraulically fractured in multiple locations, or "stages," along the horizontal leg **4c**.

[13] **Figure 1A** demonstrates a series of fracture half-planes **16** along the horizontal section **4c** of the wellbore **4**. The fracture half-planes **16** represent the orientation of fractures that will form in connection with a perforating/fracturing operation. According to principles of geo-mechanics, fracture planes will generally form in a direction that is perpendicular to the plane of least principal stress in a rock matrix. Stated more simply, in most wellbores, the rock matrix will part along vertical lines when the horizontal section of a wellbore resides below 3,000 feet, and sometimes as shallow as 1,500 feet, below the surface. In this instance, hydraulic fractures will tend to propagate from the wellbore's perforations **15** in a vertical, elliptical plane perpendicular to the plane of least principle stress. If the orientation of the least principle stress plane is known, the longitudinal axis of the leg **4c** of a horizontal wellbore **4** is ideally oriented parallel to it such that the multiple fracture planes **16** will intersect the wellbore at-or-near orthogonal to the horizontal leg **4c** of the wellbore, as depicted in **Figure 1A**.

[14] The desired density of perforated and fractured intervals within the pay zone **3** along the horizontal leg **4c** is optimized by calculating:

- the estimated ultimate recovery ("EUR") of hydrocarbons each fracture will drain, which requires a computation of the Stimulated Reservoir Volume ("SRV") that each fracture treatment will connect to the wellbore via its respective perforations; less
- any overlap with the respective SRV's of bounding fracture intervals; coupled with
- the anticipated time-distribution of hydrocarbon recovery from each fracture; versus
- the incremental cost of adding another perforated/fractured interval.

The ability to replicate multiple vertical completions along a single horizontal wellbore is what has made the pursuit of hydrocarbon reserves from unconventional reservoirs, and particularly shales, economically viable within relatively recent times. This revolutionary technology has had such a profound impact that currently Baker Hughes Rig Count information for the United States indicates only about one-fourth (26%) of wells being drilled in the U.S. are classified as "Vertical", whereas the other three-fourths are classified as either "Horizontal" or "Directional" (62% and 12%, respectively). That is, horizontal wells currently comprise approximately two out of every three wells being drilled in the United States.

[15] The additional costs in drilling and completing horizontal wells as opposed to vertical wells is not insignificant. In fact, it is not at all uncommon to see horizontal well drilling and completion ("D&C") costs top multiples (double, triple, or greater) of their vertical counterparts. Depending on the geologic basin, and particularly the geologic characteristics that govern such criteria as drilling penetration rates, required drilling mud rheology, casings design and cementation, etc., significant additional costs for drilling and completing horizontal wells include those involved in controlling the radius of curvature of the kick-off, and guidance of the bit and drilling assembly (including MWD and LWD technologies) in initially obtaining, then maintaining the preferred at-or-near horizontal trajectory of the wellbore **4** within the pay

zone **3**, and the overall length of the horizontal section **4c**. The critical process of obtaining wellbore isolation between frac stages, as with additional cementing and/or ECP's, are often significant additions to the increased completion expenses, as are costs for "plug-and-perf" or sleeve or port (typically ball-drop actuated) completion systems.

[16] In many cases, however, the greatest single cost in drilling and completing horizontal wells is the cost associated with pumping the multiple hydraulic fracture treatments themselves. It is not uncommon for the sum of the costs of a given horizontal well's hydraulic fracturing treatments to approach, or even exceed, 50% of its total drilling and completion cost.

[17] Crucial to the economic success of any horizontal well is the achievement of satisfactory hydraulic fracture geometries within the pay zone being completed. Many factors can contribute to the success or failure in achieving the desired geometries. These include the rock properties of the pay zone, pumping constraints imposed by the wellbore's construction and/or surface pumping equipment, and characteristics of the fracturing fluids. In addition, proppants of various mesh (sieve) sizes are typically added to the fracturing mixture to maintain the hydraulic pressure-induced fracture width in a "propped open" state, thereby increasing the fracture's conductive capacity for producing hydrocarbon fluids.

[18] Often, in order to achieve desired fracture characteristics (fracture width, fracture conductivity, and particularly, fracture half-length) within the pay zone, an overall fracture height must be created that considerably exceeds the boundaries of the pay zone. Fortunately, vertical out-of-zone fracture height growth is usually confined to a few multiples of the overall pay formation's thickness (i.e., ten's or hundreds' of feet), and thereby cannot pose a threat to contamination of much shallower fresh water sources, almost always separated from the pay zone by multiple thousands of feet of rock formations. See K. Fisher and N. Warpinski, "*Hydraulic Fracture-Height Growth: Real Data*," SPE Paper No. 145,949, SPE Annual Technical Conference and Exhibit, Denver Colorado (Oct. 30 - Nov. 2, 2012).

[19] Nevertheless, this increases the amount of fracturing fluid and proppant needed at the various "frac" stages, and further increases the required pumping horsepower. It is known that for a typical fracturing job, significant volumes of fracturing fluids, fluid additives, proppants, hydraulic ("pumping") horsepower (or, "HHP"), and their correlative costs are

expended on non-productive portions of the fractures. This represents a multi-billion dollar problem each year within the U.S. alone.

[20] Further complicating the planning of a horizontal wellbore are the uncertainties associated with fracture geometries within unconventional reservoirs. Many experts believe, based on analyses of real-time data from both tilt meter and micro-seismic surveys, that fracture geometries in less permeable, and particularly, more brittle, unconventional reservoirs can yield highly complex fracture geometries. That is, as opposed to the relatively simplistic bi-wing elliptical model perceived to fit most conventional reservoirs (and as shown in the idealistic rendition in **Figure 1A**), fracture geometries in unconventional reservoirs can be frustratingly unpredictable.

[21] In most cases, far-field fracture length and complexity is deemed detrimental (rather than beneficial) due to excessive fluid leak-off and/or reduced fracture width that can cause early screen-outs. Hence, whether fracture complexity (or, the lack thereof) enhances or reduces the SRV that the fracture network will enable the wellbore to drain is typically determined on a case-by-case (e.g., reservoir-by-reservoir) basis.

[22] Thus, it is desirable, particularly in horizontal wellbore completions for tight reservoirs, to obtain greater control over the geometric growth of the primary fracture network extending perpendicularly outward from the horizontal leg **4c**. It is further desirable to extend the length of the fracture network azimuth without significantly trespassing the horizontal pay zone **3** boundaries. Further, it is desirable to decrease the well density required to drain a given reservoir volume by increasing the effectiveness of the fracture network between wellbores through the use of two or more hydraulically-jetted mini-laterals along a horizontal leg. Still further, it is desirable to provide this guidance, constraint, and enhancement of SRV's by the creation of one or more mini-lateral boreholes as a replacement of conventional casing portals provided by the use of conventional completion procedures requiring perforations, sliding sleeves, and the like.

[23] Accordingly, a need exists for a downhole assembly having a jetting hose and a whipstock, whereby the assembly can be conveyed into any wellbore interval of any inclination, including an extended horizontal leg. A need further exists for a hydraulic jetting system that provides for substantially a 90° turn of the jetting hose opposite the point of a

casing exit, preferably utilizing the entire casing inner diameter as the bend radius for the jetting hose, thereby providing for the maximum possible inner diameter of jetting hose, and thus providing the maximum possible hydraulic horsepower to the jetting nozzle. A need further exists for a system that includes a whipstock deployable on a string of coiled tubing, wherein the whipstock can be reoriented in discreet, known increments, and not depend upon pipe rotation at the surface translating downhole.

[24] Additional needs exist that, in certain embodiments, are addressed herein. A need exists for improved methods of forming lateral wellbores using hydraulically directed forces, wherein the desired length of jetting hose can be conveyed even from a horizontal wellbore. Further, a need exists for a method of forming mini-lateral boreholes off of a horizontal leg that assist in confining subsequent SRV's up to, but not significantly beyond, pay zone boundaries. Still further, a need exists for a method by which a whipstock and jetting hose can be conveyed and operated with hydraulic and/or mechanical push forces that enable movement of the jetting nozzle and connected hose into the formation, retrieved, re-oriented and re-deployed and re-operated multiple times at as many parent wellbore depths and lateral azimuth orientations as desired, to generate multiple mini-lateral bore holes within not only vertical, but highly directional and even horizontal portions of wellbores in a single trip. A need further exists to be able to convey the jetting hose in an uncoiled state, such that the bend radius within the production casing and along the whipstock is the tightest bending constraint the hose must satisfy.

[25] A need further exists for a method of hydraulically fracturing mini-lateral boreholes jetted off of the horizontal leg of a wellbore immediately following mini-lateral(s) formation, and without the need of pulling the jetting hose, whipstock, and conveyance system out of the parent wellbore. Finally, a need exists for a method of remotely controlling the erosional excavation path of the jetting nozzle and connected hydraulic hose, such that a mini-lateral borehole, or multiple mini-lateral borehole "clusters" can be contoured to best control the SRV geometry resulting from a subsequent stimulation treatment.

SUMMARY OF THE INVENTION

[26] The systems and methods described herein have various benefits in the conducting of oil and gas well completion activities. A downhole hydraulic jetting assembly is provided herein. The assembly is useful for jetting multiple lateral boreholes from an existing parent wellbore into a subsurface formation. The assembly is basically comprised of two synergetic systems:

(1) an internal hose system ("the internal system"), which defines an elongated jetting hose having at its proximal end a jetting fluid inlet, and at its terminal end a jetting nozzle configured to be directed to and through a parent wellbore exit location; and

(2) an external hose conveyance, deployment and retrieval system ("the external system") that is run on a working string to provide a defined path of travel (including a whipstock) within a wellbore, with the external system being configured to carry the elongated jetting hose into a wellbore and "push" it against a whipstock set in the wellbore to urge the jetting nozzle forward into the surrounding formation.

[27] In the case of a cased wellbore, a window is formed through the casing using the jetting hose and connected nozzle, followed by the formation of a lateral borehole out into a hydrocarbon-bearing pay zone. The configuration and operation of these two synergetic systems provide that the whipstock may be re-oriented and/or re-located, and the jetting hose re-deployed into the casing and re-retrieved, for the jetting of multiple casing exits and lateral boreholes in the same trip.

[28] As noted, the internal system comprises a jetting hose having a proximal end and a distal end. A fluid inlet resides at the proximal end, while a jetting nozzle is disposed at the distal end. Preferably, a power supply such as a battery pack resides at the proximal end for providing power to electrical components of the jetting assembly.

[29] The external system comprises a pair of tubular bodies. These represent an outer conduit and an inner conduit. The outer conduit has an upper end configured to be operatively

attached to the working string, or the "tubing conveyance medium," for running the jetting hose assembly into the production casing, a lower end, and an internal bore there between. The inner conduit resides within the bore of the outer conduit and serves as a jetting hose carrier. The jetting hose carrier slidably receives the jetting hose during operation.

[30] A micro-annulus is formed between the jetting hose and the surrounding jetting hose carrier. The micro-annulus is sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly. The micro-annulus is further configured to allow the operator to control the amount and flow direction of hydraulic fluid between the jetting hose and the surrounding inner conduit, which then converts to a fluid force that can either: (1) maintain the jetting hose in a taught configuration as it is urged downstream; or (2) urge the jetting hose in an upstream direction as it is retrieved back into the inner conduit (or jetting hose carrier).

[31] The jetting hose assembly also includes a whipstock member. The whipstock member is disposed below the lower end of the outer conduit. The whipstock member includes a concave face for receiving and directing the jetting nozzle and connected hose during operation of the assembly.

[32] The jetting hose assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting along an operator's designed geo-trajectory forming a lateral borehole into the rock matrix within the pay zone, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed to allow the location of the whipstock device within the wellbore to be optionally adjusted.

[33] In one aspect, the whipstock is configured so that a face of the whipstock provides a bend radius for the jetting hose across the entire wellbore. In the case of a cased hole, the jetting hose will bend across the entire inner diameter of the production casing. Thus, the hose contacts the production casing on one side, bends along the face of the whipstock, and then extends to a casing exit on an opposite side of the production casing. This jetting hose bend

radius spanning the entire I.D. of the production casing provides for utilization of the greatest possible diameter of jetting hose, which in turn provides for maximum delivery of hydraulic horsepower through the jetting hose to the jetting nozzle.

[34] The external system is configured to be run in on a string of standard coiled tubing, or in the preferred embodiments, on a bundled coiled tubing product that includes wiring. Further, the external system is configured such that it contains, conveys, deploys, and retrieves the jetting hose of the internal system in such a way as to maintain the hose in an uncoiled state. Thus, the minimum bend radius that the hose must satisfy is that of the bend radius within the production casing, along the whipstock face, at the point of a desired casing exit. In addition, the coiled tubing-based conveyance of these synergetic internal/external systems provides for simultaneous running of other conventional coiled tubing tools in the same tool string. These may include a packer, a mud motor, a downhole (external) tractor, logging tools, and/or a retrievable bridge plug residing below the whipstock member.

[35] A unique electric-driven, rotatable jetting nozzle is optionally provided for the external system. The nozzle can emulate the hydraulics of conventional hydraulic perforators, thereby precluding the need for a separate run with a milling tool to form a casing exit. The nozzle optionally includes rearward thrusting jets about the body to enhance forward thrust and borehole cleaning during mini-lateral formation, and to provide clean-out and, possibly, borehole expansion, during pull-out.

[36] Within the external system, regulation of the hydraulic forces of both: (a) the jetting fluid's hydraulic force that urges the internal hose system downstream; and, (b) the hydraulic fluid's hydraulic force that urges the hose system back upstream, are both controlled with valves at the top and base of the carrier system, and seal assemblies both at the top of the jetting hose and at the base of the carrier system. In addition, the external system may include an internal tractor system that provides a mechanical force for selectively urging the jetting hose upstream or downstream.

[37] It is observed that known jetting systems generally rely only on "slack-off" weight of a continuous coiled tubing and/or jetting hose string for "push" force. However, this source of propulsion would be quickly dissipated by helical buckling (e.g., due to friction forces

between the jetting hose and wellbore tubulars) in a highly directional or horizontal wellbore. Once the point of helical buckling is reached, supplemental push force from additional slack-off of the string tied to the surface is no longer attainable. The "can't-push-a-rope" limitation of other systems is uniquely overcome herein by the combination of hydraulic and mechanical (tractor) forces, enabling the formation of mini-laterals off of an extended-reach horizontal wellbore.

[38] The hydraulic jetting assembly also includes wiring chambers along components of the external system. The wiring chambers provide electric wires that supply power to charge batteries for the jetting nozzle and, optionally, other conventional tools (such as logging tools) downhole. The wiring chambers also optionally provide data cables so that the servo/transmitter/receiver systems, logging tools, etc. may return data to the surface. In this way, real time control of power and data are provided.

[39] The hydraulic jetting assembly herein is able to generate lateral bore holes in excess of 10 feet, or in excess of 25 feet, and even in excess of 300 feet, depending on the length of the jetting hose and its jetting hose carrier, and the hydraulic jetting-resistance qualities of the host rock. These jetting-resistance qualities may include compressive strength, pore pressure, or other features inherent to the lithology of the host rock matrix, such as cementation. The boreholes generated by the hydraulic jetting assembly may have a diameter of about 1.0" or greater. These lateral boreholes may be formed at penetration rates much higher than any of the systems that have preceded it that have in common completing a 90° turn of the jetting hose within the production casing. This is because the hydraulic jetting assembly presented herein, in certain embodiments, utilizes the entire casing I.D. as the bend radius for the jetting hose, thus enabling utilization of larger diameter hoses, resulting in delivery of higher hydraulic horsepower to the jetting nozzle.

[40] The present system will have the capacity to generate lateral boreholes from portions of horizontal and highly directional parent wellbores heretofore thought unreachable. Anywhere to which conventional coiled tubing can be tractored within a cased wellbore, lateral boreholes can now be hydraulically jetted. Similarly, superior efficiencies will be captured as multiple intervals of lateral bore holes are formed from a single trip. Wherever satisfactory

fracturing hydraulics (pump rates and pressures) are attainable via the coiled tubing-casing annulus, the entire horizontal leg of a newly drilled well may be "perforated and fractured" without need of frac plugs, sliding sleeves or dropped balls.

[41] In one embodiment, multiple lateral boreholes and, optionally, side mini-lateral boreholes, together form a network or cluster of ultra-deep perforations in the rock matrix. Such a network may be designed by the operator to optimally drain a pay zone. Preferably, the lateral boreholes extend away from the parent wellbore at a normal, or right, angle, and extend to an upper or lower boundary of the pay zone. Other angles may be used as well to take advantage of the richest portions of a pay zone. In any respect, the method may then include producing hydrocarbons. Where multiple boreholes are formed at different orientations from the wellbore and at different depth, hydrocarbons may be produced from a network of lateral boreholes. Moreover, the operation may choose to conduct subsequent formation fracturing operations from the lateral boreholes, thereby further extending the SRV.

[42] Given the system's ability to controllably "steer" a jetting nozzle and thereby contour the path of a mini-lateral borehole (or, "clusters" of mini-lateral boreholes), subsequent stimulation treatments can be more optimally "guided" and constrained within a pay zone. Coupled with real-time feedback of actual stimulation (particularly, frac) stage geometry and resultant SRV (as from micro-seismic, tiltmeter, and/or ambient micro-seismic surveys), subsequent mini-lateral boreholes can be custom contoured to better direct each stimulation stage prior to pumping.

Brief Description of the Drawings

[43] So that the manner in which the present inventions can be better understood, certain illustrations, charts and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[44] Figure 1A is a cross-sectional view of an illustrative horizontal wellbore. Half-fracture planes are shown in 3-D along a horizontal leg of the wellbore to illustrate fracture stages and fracture orientation relative to a subsurface formation.

[45] Figure 1B is an enlarged view of the horizontal portion of the wellbore of Figure 1A. Conventional perforations are replaced by ultra-deep perforations, or mini-lateral boreholes, to create fracture wings.

[46] Figure 2 is a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly of the present invention, in one embodiment. The assembly is shown within a horizontal section of a production casing. The jetting assembly has an external system and an internal system.

[47] Figure 3 is a longitudinal, cross-sectional view of the internal system of the hydraulic jetting assembly of Figure 2. The internal system extends from an upstream battery pack end cap (that mates with the external system's docking station) at its proximal end to an elongated hose having a jetting nozzle at its distal end.

[48] Figure 3A is a cut-away perspective view of the battery pack section of the internal system of Figure 3.

[49] Figure 3B-1 is a cut-away perspective view of a jetting fluid inlet located between the base of the battery pack section and the jetting hose. A jetting fluid receiving funnel is shown for receiving fluids into the jetting hose of the internal system of Figure 3.

[50] Figure 3B-1.a is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the bottom end cap of the battery pack section.

[51] Figure 3B-1.b is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the jetting fluid inlet.

[52] Figure 3C is a cut-away perspective view of an upper portion of the internal system of Figure 3, from the base of the jetting hose's fluid receiving funnel through the jetting hose's upper seal assembly.

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[53] Figure 3D-1 presents a cross-sectional view of a bundled jetting hose, with electrical wiring and data cabling, as may be used in the internal system of Figure 3.

[54] Figure 3D-1a is an axial, cross-sectional view of the bundled jetting hose of Figure 3D-1. Both electrical wires and fiber optical (or data) cables are seen.

[55] Figure 3E is an expanded cross-sectional view of the terminal end of the jetting hose of Figure 3D-1, showing the jetting nozzle of the internal system of Figure 3. The bend radius of the jetting hose is shown within a cut-away section of the whipstock of the external system of Figure 3.

[56] Figures 3F-1a through 3G-1c present enlarged, cross-sectional views of the jetting nozzle of Figure 3E, in various embodiments.

[57] Figure 3F-1a is an axial, cross-sectional view showing a basic nozzle body. The nozzle body includes a rotor and a surrounding stator.

[58] Figure 3F-1b is a longitudinal, cross-sectional view of a jetting nozzle, taken across line C-C′ of Figure 3F-1a. Here, the nozzle uses a single discharge slot at the tip of the rotor. The nozzle also includes bearings between the rotor and the surrounding stator.

[59] Figure 3F-1c is a longitudinal cross-sectional view of the jetting nozzle of Figure 3F-1b, in a modified embodiment. Here, the jetting nozzle includes a geo-spatial chip, and is shown connected to a jetting hose via welding.

[60] Figure 3F-1d is an axial, cross-sectional view of the jetting hose of Figure 3F-1c, taken across line c-c′.

[61] Figures 3F-2a and 3F-2b present longitudinal, cross-sectional views of the nozzle of Figure 3E, in an alternate embodiment. Along with a single discharge slot at the tip of the rotor, five rearward thrust jets are placed in the body of the stator, actuated by forward displacement of a slideable nozzle throat insert against a slideable collar and biasing mechanism.

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[62] In Figure 3F-2a, the insert and collar are in their closed position. In Figure 3F-2b, the insert and collar are in their open position allowing fluid to flow through the rearward thrust jets. The jets are opened when a sufficient pumping pressure overcomes the resistance of a spring.

[63] Figure 3F-2c is an axial, cross-sectional view of the nozzle of Figure 3F-2a. Five rearward thrust jets are shown for generating a rearward thrust force.

[64] Figures 3F-3a and 3F-3c provide longitudinal, cross-sectional views of the jetting nozzle of Figure 3E, in another alternate embodiment. Here, multiple rearward thrust jets residing in both the stator body and the rotor body are used. In this arrangement, an electromagnetic force pulling on a magnetic collar, biased by a spring, is used for opening/closing the rearward thrust jets.

[65] In Figure 3F-3a, the collar of the jetting nozzle is in its closed position. In Figure 3F-2b, the collar is in its open position allowing fluid to flow through the rearward thrust jets.

[66] Figures 3F-3b and 3F-3d show axial, cross-sectional views of the jetting nozzle correlative to Figures 3F-3a and 3F-3c, respectively. Eight rearward thrust jets are seen. This embodiment provides for intermittent alignment of the four jetting ports in the rotor with either of the two sets of four jetting ports in the stator to produce a pulsating rearward thrust flow.

[67] Figure 3G-1a is an axial, cross-sectional view showing a basic collar body for a jetting collar that can be placed within a length of jetting hose. The collar body again includes a rotor and a surrounding stator. The view is taken across line D-D' of Figure 3G-1b.

[68] Figure 3G-1b is a longitudinal, cross-sectional view of the jetting collar of Figure 3G-1a. As with the jetting nozzle of Figures 3F-3a through 3F-3d, two sets of four jetting ports in the stator intermittently align with the four jetting ports in the rotor to produce pulsating rearward thrust flow.

[69] Figure 3G-1c is an axial, cross-sectional view of the jetting nozzle of Figure 3G-1b, taken across line d-d'.

[70] Figure 4 is a longitudinal, cross-sectional view of the external system of the downhole hydraulic jetting assembly of Figure 2, in one embodiment. The external system resides within production casing of the horizontal leg of the wellbore of Figure 2.

[71] Figure 4A-1. is an enlarged, longitudinal cross-sectional view of a portion of a bundled coiled tubing conveyance medium which conveys the external system of Figure 4 into and out of the wellbore.

[72] Figure 4A-1a is an axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1. In this embodiment, an inner coiled tubing is "bundled" concentrically with both electrical wires and data cables within a protective outer layer.

[73] Figures 4A-2 is another axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1a, but in a different embodiment. Here, the inner coiled tubing is "bundled" eccentrically within the protective outer layer to provide more evenly-spaced protection of the electrical wires and data cables.

[74] Figure 4B-1 is a longitudinal, cross-sectional view of a crossover connection, which is the upper-most member of the external system of Figure 4. The crossover section is configured to join the coiled tubing conveyance medium of Figure 4A-1 to a main control valve.

[75] Figure 4B-1a is an enlarged, perspective view of the crossover connection of Figure 4B-1, seen between cross-sections E-E′ and F-F′. This view highlights the wiring chamber's general transition in cross-sectional shape from circular to elliptical.

[76] Figure 4C-1 is a longitudinal, cross-sectional view of the main control valve of the external system of Figure 4.

[77] Figure 4C-1a is a cross-sectional view of the main control valve, taken across line G-G′ of Figure 4C-1.

[78] Figure 4C-1b is a perspective view of a sealing passage cover of the main control valve, shown exploded away from Figure 4C-1a.

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[79] Figure 4D-1 is a longitudinal, cross-sectional view of a jetting hose carrier section of the external system of Figure 4. The jetting hose carrier section is attached downstream of the main control valve.

[80] Figure 4D-1a shows an axial, cross-sectional view of the main body of the jetting hose carrier section, taken along line H-H′ of Figure 4D-1.

[81] Figure 4D-1b is an enlarged view of a portion of the jetting hose carrier section of Figure 4D.1. A docking station of the external system is more clearly seen.

[82] Figure 4D-2 is an enlarged, longitudinal, cross-sectional view of the external system's jetting hose carrier section of Figure 4D-1, with inclusion of the jetting hose of the internal system from Figure 3.

[83] Figure 4D-2a provides an axial, cross-sectional view of the jetting hose carrier section of Figure 4D-1, with the jetting hose residing therein.

[84] Figure 4E-1 is a longitudinal, cross-sectional view of selected portions of the external system of Figure 4. Visible are a jetting hose pack-off section, and an outer body transition from the preceding circular body (I-I′) of the jetting hose carrier section to a star-shaped body (J-J′) of the jetting hose pack-off section

[85] Figure 4E-1a is an enlarged, perspective view of the transition between lines I-I' and J-J' of Figure 4E-1.

[86] Figure 4E-2 shows an enlarged view of a portion of the jetting hose pack-off section. Internal seals of the pack-off section conform to the outer circumference of the jetting hose (Figure 3) residing therein. A pressure regulator valve is shown schematically adjacent the pack-off section.

[87] Figure 4F-1 is a further downstream longitudinal, cross-sectional view of the external system of Figure 4. The jetting hose pack-off section and the outer body transition from Figure 4E-1 are again shown. Also visible here is an internal tractor system. Note each

of the aforementioned components are shown with a longitudinal cross-sectional view of the jetting hose of Figure 3 residing therein.

[88] Figure 4F-2 is an enlarged, longitudinal, cross-sectional view of a portion of the internal tractor system of Figure 4-F1, again with a cross-section of the jetting hose residing therein. An internal motor, gear and gripper assembly is also shown.

[89] Figure 4F-2a is an axial, cross-sectional view of the internal tractor system of Figure 4F-2, taken across line K-K′ of Figures 4F-1 and 4F-2.

[90] Figure 4F-2b is an enlarged half-view of a portion of the internal tractor system of Figure 4F-2a.

[91] Figure 4G-1 is still a further downstream longitudinal, cross-sectional view of the external system of Figure 4. This view shows a transition from the internal tractor to an upper swivel, followed by the upper swivel of the external system.

[92] Figure 4G-1a depicts a perspective view of the outer body transition between the internal tractor system to the upper swivel. This is a star-shape (L-L') to a circle-shape (M-M') transition of the outer body.

[93] Figure 4G-1b provides an axial, cross-sectional view of the upper swivel of Figure 4-G1, taken across line N-N′.

[94] Figure 4H-1 is a cross-sectional view of a whipstock member of the external system of Figure 4, but shown vertically instead of horizontally. The jetting hose of the internal system (Figure 3) is shown bending across the whipstock, and extending through a window in the production casing. The jetting nozzle of the internal system is shown affixed to the distal end of the jetting hose.

[95] Figure 4H-1a is an axial, cross-sectional view of the whipstock member, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member at line O-O′ to the start of the jetting hose's bend radius as it approaches line P-P′.

[96] Figure 4H-1b depicts an axial, cross-sectional view of the whipstock member at line P-P'.

[97] Figure 4I-1 is a longitudinal, cross-sectional view of a bottom swivel within the external system of Figure 4, residing just downstream of slips (shown engaging the surrounding production casing) near the base of the preceding whipstock member.

[98] Figure 4I-1a provides an axial, cross-sectional view of a portion of the bottom swivel of Figure 4I-1, taken across line Q-Q'.

[99] Figure 4J is another longitudinal view of the bottom swivel of Figure 4I-1. Here, the bottom swivel is connected to a transition section, which in turn is connected to a conventional mud motor, an external tractor, and a logging sonde, thus completing the entire downhole tool string. For simplification, neither a packer nor a retrievable bridge plug has been included in this configuration.

Detailed Description of Certain Embodiments

Definitions

[100] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[101] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient conditions. Hydrocarbon fluids may include, for example, oil, natural gas, condensate, coal bed methane, shale oil, shale gas, and other hydrocarbons that are in a gaseous or liquid state.

[102] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

[103] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[104] The term "subsurface interval" refers to a formation or a portion of a formation wherein formation fluids may reside. The fluids may be, for example, hydrocarbon liquids, hydrocarbon gases, aqueous fluids, or combinations thereof.

[105] The terms "zone" or "zone of interest" refer to a portion of a formation containing hydrocarbons. Sometimes, the terms "target zone," "pay zone," or "interval" may be used.

[106] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shape. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

[107] The term "jetting fluid" refers to any fluid pumped through a jetting hose and nozzle assembly for the purpose of erosionally boring a lateral borehole from an existing parent wellbore. The jetting fluid may or may not contain an abrasive material.

[108] The term "abrasive material" or "abrasives" refers to small, solid particles mixed with or suspended in the jetting fluid to enhance erosional penetration of: (1) the pay zone; and/or (2) the cement sheath between the production casing and pay zone; and/or (3) the wall of the production casing at the point of desired casing exit.

[109] The terms "tubular" or "tubular member" refer to any pipe, such as a joint of casing, a portion of a liner, a joint of tubing, a pup joint, or coiled tubing.

[110] The terms "lateral borehole" or "mini-lateral" or "ultra-deep perforation" ("UDP") refer to the resultant borehole in a subsurface formation, typically upon exiting a production

casing and its surrounding cement sheath in a parent wellbore, with said borehole formed in a known or prospective pay zone. For the purposes herein, a UDP is formed as a result of hydraulic jetting forces erosionally boring through the pay zone with a jetting fluid directed through a jetting hose and out a jetting nozzle affixed to the terminal end of the jetting hose. Preferably, each UDP will have a substantially normal trajectory relative to the parent wellbore.

[111] The terms "steerable" or "guidable", as applied to a hydraulic jetting assembly, refers to a portion of the jetting assembly (typically, the jetting nozzle and/or the portion of jetting hose immediately proximal the nozzle) for which an operator can direct and control its geo-spatial orientation while the jetting assembly is in operation. This ability to direct, and subsequently re-direct the orientation of the jetting assembly during the course of erosional excavation can yield UDP's with directional components in one, two, or three dimensions, as desired.

[112] The terms "perforation cluster" or "UDP cluster" refer to a designed grouping of lateral boreholes off a parent well casing. These groupings are ideally designed to receive and transmit a specific "stage" of a stimulation treatment, usually in the course of completing or recompleting a horizontal well by hydraulic fracturing (or "fracking"). As an alternative, the term "network" may be used.

[113] The term "stage" references a discreet portion of a stimulation treatment applied in completing or recompleting a specific pay zone, or specific portion of a pay zone. In the case of a cased horizontal parent wellbore, up to 10, 20, 50 or more stages may be applied to their respective perforation (or UDP) clusters. Typically, this requires some form of zonal isolation prior to pumping each stage.

[114] The terms "contour" or "contouring" as applied to individual UDP's, or groupings of UDP's in a "cluster", refers to steerably excavating the lateral boreholes so as to optimally receive, direct, and control stimulation fluids, or fluids and proppants, of a given stimulation (typically, fracking) stage. This ability to '...optimally receive, direct, and control...' a given stage's stimulation fluids is designed to retain the resultant stimulation geometry "in zone",

and/or concentrate the stimulation effects where desired. The result is to optimize, and typically maximize, the Stimulated Reservoir Volume ("SRV").

[115] The terms "real time" or "real time analysis" of geophysical data (such as micro-seismic, tiltmeter or ambient micro-seismic data) that is obtained during the course of pumping a stage of a stimulation (such as fracking) treatment means that results of said data analysis can be applied to: (1) altering the remaining portion of the stimulation treatment (yet to be pumped) in its pump rates, treating pressures, fluid rheology, and proppant concentration in order to optimize the benefits therefrom; and, (2) optimizing the placement of perforations, or contouring the trajectories of UDP's, within the subsequent "cluster(s)" to optimize the SRV obtained from the subsequent stimulation stages.

Description of Specific Embodiments

[116] A downhole hydraulic jetting assembly is provided herein. The jetting assembly is designed to direct a jetting nozzle and connected hydraulic hose through a window formed along a string of production casing, and then "jet" one or more boreholes outwardly into a subsurface formation. The lateral boreholes essentially represent ultra-deep perforations that are formed by using hydraulic forces directed through a flexible, high pressure jetting hose, having affixed to its distal end a high pressure jetting nozzle. The subject assembly capitalizes on a single hose and nozzle apparatus to continuously jet, optionally, both a casing exit and the subsequent lateral borehole.

[117] **Figure 1A** is a schematic depiction of a horizontal well **4**, with wellhead **5** located above the earth's surface **1**, and penetrating several series of subsurface strata **2a** through **2h** before reaching a pay zone **3**. The horizontal section **4c** of the wellbore **4** is depicted between a "heel" **4b** and a "toe" **4d**. Surface casing **6** is shown as cemented **7** fully from the surface casing shoe **8** back to surface **1**, while the intermediate casing string **9** is only partially cemented **10** from its shoe **11**. Similarly, production casing string **12** is only partially cemented **13** from its casing shoe **14**, though sufficiently isolating the pay zone **3**. Note how in the **Figure 1A** depiction of a typical horizontal wellbore, conventional perforations **15** within

the production casing **12** are shown in up-and-down pairs, and are depicted with subsequent hydraulic fracture half-planes (or, "frac wings") **16**.

[118] **Figure 1B** is an enlarged view of the lower portion of the wellbore **4** of **Figure 1A**. Here, the horizontal section **4c** between the heel **4b** and the toe **4d** is more clearly seen. In this depiction, application of the subject apparati and methods herein replaces the conventional perforations (**15** in **Figure 1A**) with pairs of opposing horizontal UDP's **15** as depicted in **Figure 1B**, again with subsequently generated fracture half-planes **16**. Specifically depicted in **Figure 1B** is how the frac wings **16** are now better confined within the pay zone **3**, while reaching much further out from the horizontal wellbore **4c** into the pay zone **3**. Stated another way, in-zone fracture propagation is significantly enhanced by the pre-existence of the UDP's **15** as generated by the assembly and methods disclosed herein.

[119] **Figure 2** provides a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly **50** of the present invention, in one embodiment. The jetting assembly **50** is shown residing within a string of production casing **12**. The production casing **12** may have, for example, a 4.5-inch O.D. (4.0-inch I.D.). The production casing **12** is presented along a horizontal portion **4c** of the wellbore **4**. As noted in connection with **Figures 1A** and **1B**, the horizontal portion **4c** defines a heel **4b** and a toe **4d**.

[120] The jetting assembly **50** generally includes an internal system **1500** and an external system **2000**. The jetting assembly **50** is designed to be run into a wellbore **4** at the end of a working string, sometimes referred to herein as a "conveyance medium." Preferably, the working string is a string of coiled tubing **100**. The conveyance medium **100** may be conventional coiled tubing. Alternatively, a "bundled" product that incorporates electrically conductive wiring and data conductive cables (such as fiber optic cables) around the coiled tubing core, protected by an erosion/abrasion resistant outer layer(s), such as PFE and/or Kevlar, or even another (outer) string of coiled tubing may be used. It is observed that fiber optic cables have a practically negligible diameter, and are oilfield-proven to be efficient in providing direct, real-time data transmission and communications with downhole tools. Other emerging transmission media such as carbon nanotube fibers may also be employed.

[121] Other conveyance media may be used for the jetting assembly **50**. These include, for example, a standard e-coil system, a customized FlatPAK® assembly, PUMPTEK's® Flexible Steel Polymer Tubing ("FSPT") or Flexible Tubing Cable ("FTC") tubing. Alternatively, tubing have PTFE (Polytetrafluorethylene) and Kevlar®-based materials, or Draka Cableteq USA, Inc.'s® Tubing Encapsulated Cable ("TEC") system may be used. In any instance, it is desirable that the conveyance medium **100** be flexible, somewhat malleable, non-conductive, pressure resistant (to withstand high pressure fracturing fluids optionally being pumped down the annulus), temperature resistant (to withstand bottom hole wellbore operating temperatures, often in excess of 200° F, and sometimes exceeding 300° F), chemical resistant (at least in resistance to the additives included in the frac fluids), friction resistant (to minimize the downhole pressure loss due to friction while pumping the frac treatment), erosion resistant (to withstand the erosive effects of afore-mentioned annular fracturing fluids) and abrasion resistant (to withstand the abrasive effects of proppants suspended in the aforementioned annular fracturing fluids).

[122] If a standard coiled tubing string is employed, communications and data transmission may be accomplished by hydro-pulse technology (or so-called mud-pulse telemetry), acoustic telemetry, EM telemetry, or some other remote transmission/reception system. Similarly, electricity for operating the apparatus may be generated downhole by a conventional mud motor(s), which would allow the electrical circuitry for the system to be confined below the end of the coiled tubing. The present hydraulic jetting assembly **50** is not limited by the data transmission system or the power transmission or the conveyance medium employed unless expressly so stated in the claims.

[123] It is preferred to maintain an outer diameter of the coiled tubing **100** that leaves an annular area within the approximate 4.0" I.D. of the casing **12** that is greater than or equal to the cross-sectional area open to flow for a 3.5" O.D. frac (tubing) string. This is because, in the preferred method (after jetting one or more, preferably two opposing mini-laterals, or even specially contoured "clusters" of small-diameter lateral boreholes), fracture stimulation can immediately (after repositioning the tool string slightly uphole) take place down the annulus between the coiled tubing conveyance medium **100** plus the external system **2000**, and the well casing **12**. For 9.2#, 3.5" O.D. tubing (i.e., frac string equivalent), the I.D. is 2.992 inches, and

the cross-sectional area open to flow is 7.0309 square inches. Back-calculating from this same 7.0309 in^2 equivalency yields a maximum O.D. available for both the coiled tubing conveyance medium **100** and the external system **2000** (having generally circular cross-sections) of 2.655". Of course, a smaller O.D. for either may be used provided such accommodate a jetting hose **1595**.

[124] In the view of **Figure 2**, the assembly **50** is in an operating position, with a jetting hose **1595** being run through a whipstock **1000**, and a jetting nozzle **1600** passing through a first window "**W**" of the production casing **12**. At the end of the jetting assembly **50**, and below the whipstock **1000**, are several optional components. These include a conventional mud motor **1300**, an external (conventional) tractor **1350** and a logging sonde **1400**. These components are shown and described more fully below in connection with **Figure 4**.

[125] **Figure 3** is a longitudinal, cross-sectional view of the internal system **1500** of the hydraulic jetting assembly **50** of **Figure 2**. The internal system **1500** is a steerable system that, when in operation, is able to move within and extend out of the external system **2000**. The internal system **1500** is comprised primarily of:

(1) power and geo-control components;

(2) a jetting fluid intake;

(3) the jetting hose **1595**; and

(4) the jetting nozzle **1600**.

[126] The internal system **1500** is designed to be housed within the external system **2000** while being conveyed by the coiled tubing conveyance medium **100** and the attached external system **2000** in to and out of the parent wellbore **4**. Extension of the internal system **1500** from and retraction back into the external system **2000** is accomplished by the application of: (a) hydraulic forces; (b) mechanical forces; or (c) a combination of hydraulic and mechanical forces. Beneficial to the design of the internal **1500** and external **2000** systems comprising the hydraulic jetting apparatus **50** is that transport, deployment, or retraction of the jetting hose **1595** never requires the jetting hose to be coiled. Specifically, the jetting hose **1595** is never subjected to a bend radius smaller than the I.D. of production casing **12**, and that only

incrementally while being advanced along the whipstock **1050** of the jetting hose whipstock member **1000** of the external system **2000**. Note the jetting hose **1595** is typically ¼th" to $^{5}/_{8}$ths" I.D., and up to approximately 1" O.D., flexible tubing that is capable of withstanding high internal pressures.

[127] The internal system **1500** first includes a battery pack **1510**. **Figure 3A** provides a cut-away perspective view of the battery pack **1510** of the internal system **1500** of **Figure 3**. Note this section **1510** has been rotated 90° from the horizontal view of **Figure 3** to a vertical orientation for presentation purposes. An individual AA battery **1551** is shown in a sequence of end-to-end like batteries forming the battery pack **1550**. Protection of the batteries **1551** is primarily via a battery pack casing **1540** which is sealed by an upstream battery pack end cap **1520** and a downstream battery pack end cap **1530**. These components (**1540**, **1520**, and **1530**) present exterior faces exposed to the high pressure jetting fluid stream. Accordingly, they are preferably constructed of or are coated with a non-conductive, highly abrasion/erosion/corrosion resistant material.

[128] The upstream battery pack end cap **1520** has a conductive ring about a portion of its circumference. When the internal system **1500** is "docked" (i.e., matingly received into a docking station **325** of the external system **2000**) the battery pack end cap **1520** can receive and transmit current and, thus, re-charge the battery pack **1550**. Note also that the end caps **1520** and **1530** can be sized so as to house and protect any servo, microchip, circuitry, geospatial or transmitter/receiver components within them.

[129] The battery pack end-caps **1520**, **1530** may be threadedly attached to the battery pack casing **1540**. The battery pack end-caps **1520**, **1530** may be constructed of a highly erosive- and abrasive-resistant, high pressure material, such as titanium, perhaps even further protected by a thin, highly erosive- or abrasive-resistant coating, such as polycrystalline diamond. The shape and construction of the end-caps **1520**, **1530** are preferably such that they can deflect the flow of high pressure jetting fluid without incurring significant wear. The upstream end cap **1520** must deflect flow to an annular space (not shown in **Figure 3**) between the battery casing **1540** and a surrounding jetting hose conduit **420** (seen in **Figure 3C**) of a jetting hose carrier system (shown at **400** in **Figure 4D-1**). The downstream end-cap **1530**

bounds part of the flow path of the jetting fluid from this annular space down into the I.D. of the jetting hose **1595** itself through a jetting fluid receiving (or, "intake") funnel (shown at **1570** in **Figure 3B-1**).

[130] Thus, the path of the high pressure hydraulic jetting fluid (with or without abrasives) is as follows:

(1) Jetting fluid is discharged from a high pressure pump at the surface **1** down the I.D. of the coiled tubing conveyance medium **100**, at the end of which it enters the external system **2000**;

(2) Jetting fluid enters the external system **2000** through a coiled tubing transition connection **200**;

(3) Jetting fluid enters the main control valve **300** through a jetting fluid passage **345**;

(4) Because the main control valve **300** is positioned to receive jetting fluid (as opposed to hydraulic fluid), a sealing passage cover **320** will be positioned to seal a hydraulic fluid passage **340**, leaving the only available fluid path through the jetting fluid passage **345**, the discharge of which is sealingly connected to the jetting hose conduit **420** of the jetting hose carrier system **400**;

(5) Upon entering the jetting hose conduit **420**, the jetting fluid will first pass by a docking station **325** (which is affixed within the jetting hose conduit **420**) through the annulus between the docking station **325** and the jetting hose conduit **420**;

(6) Because the jetting hose **1595** itself resides in the jetting hose conduit **420**, the high pressure jetting fluid must now either go through or around the jetting hose **1595**; and

(7) Because of the internal system's **1500** seal **1580U**, which seals the annulus between the jetting hose **1595** and the jetting hose conduit **420**, jetting fluid cannot go around the jetting hose **1595** (note this hydraulic pressure on the

seal assembly **1580** is the force that tends to pump the internal system **1500**, and hence the jetting hose **1595**, "down the hole") and thus jetting fluid is forced to go through the jetting hose **1595** according to the following path:

(a) jetting fluid first passes the top of the internal system **1500** at the upstream battery pack end cap **1520**,

(b) jetting fluid then passes through the annulus between the battery pack casing **1540** and the jetting hose conduit **420** of the jetting hose carrier system **400**;

(c) after jetting fluid passes the downstream battery pack end cap **1530**, it is forced to flow between battery pack support conduits **1560**, and into a jetting fluid receiving funnel **1570**; and

(d) because the jetting fluid receiving funnel **1570** is rigidly and sealingly connected to the jetting hose **1595**, jetting fluid is forced into the I.D. of jetting hose **1595**.

[131] Worthy of note in the above-described jetting fluid flow sequence are the following initiation conditions:

(i) an internal tractor system **700** is first engaged to translate a discreet length of jetting hose **1595** in a downstream direction, such that the jetting nozzle **1600** and jetting hose **1595** enter the jetting hose whipstock **1000** and specifically, after traveling a fixed distance within the inner wall (shown at **1020** in **Figure 4H-1**), are forced radially outward to engage first the interior wall of production casing **12** and then engage the upper curved face **1050.1** of whipstock member **1050**, at which point,

(ii) the jetting hose **1595** is curvedly 'bent' approximately 90°, assuming its pre-defined bend radius (shown at **1599** in **Figure 4H-1**) and directing the jetting nozzle **1600** attached to its terminal end to engage the precise point of desired casing exit **"W"** within the I.D. of the production casing **12**; at which point

(iii) increased torque within the internal tractor system's **700** gripper assemblies **750** is then realized, a signal for which is immediately conveyed electronically to the surface, signaling the operator to shut down rotation of the grippers (illustrative griper seen at **756** in **Figure 4F-2b**).

(Practically, such shut-down could be pre-programmed into the operating system at a certain torque level.) Note that during stages (i) through (iii), a pressure regulator valve (seen at **610** in **Figure 4E-2**) is in an "open" position This allows hydraulic fluid in the annulus between the jetting hose **1595** and the surrounding jetting hose conduit **420** to bleed-off. Once the tip of jetting nozzle **1600** engages the I.D. (casing wall) of production casing **12**, then the operator may:

(iv) reverse the direction of rotation of the grippers **756** to translate the jetting hose **1595** back into the jetting hose (or inner) conduit **420**; and

(v) switch a main control valve **300** to begin pumping hydraulic fluid though the hydraulic fluid passage **340**, down the conduit-carrier annulus **440**, through the pressure regulator valve **610**, and into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** to both: (1) pump upwards against lower seals **1580L** of the jetting hose's seal assembly **1580** to re-extend the jetting hose **1595** in a taught position; and, (2) assist the (now reversed) gripper assemblies **750** in positioning the internal system **1500** such that the jetting nozzle **1600** has the desired stand-off distance (preferably less than 1 inch) between itself and the I.D. of the production casing **12** to begin jetting the casing exit.

Upon reaching this desired stand-off distance, rotation of grippers **756** ceases, and pressure regulator valve **610** is closed to lock down the internal system at the desired, fixed position for jetting the casing exit **"W"**.

[132] Referring back to **Figure 3A**, in one embodiment the interior of the downstream end-cap **1530** houses a micro-geo-steering system. The system may include a micro-transmitter, a micro-receiver, a micro-processor, and a current regulator. This geo-steering system is electrically or fiber-optically connected to a small geo-spatial IC chip (shown at **1670** in **Figure 3F-1c** and discussed more fully below) located in the body of the jetting nozzle

1600. In this way, geo-spatial data may be sent from the jetting nozzle **1600** to the micro-processor (or appropriate control system) which, coupled with the values of dispensed hose length, can be used to calculate the precise geo-location of the nozzle at any point, and thus the contour of the UDP's path. Conversely, geo-steering signals may be sent from the control system (such as a micro-processor in the docking station or at the surface) to modify, through one or more electrical current regulators, individualized current strengths down to each of the (at least three) actuator wires (shown at **1590A** in **Figure 3F-1c**), thus redirecting the nozzle as desired.

[133] The geo-steering system can also be utilized to control the rotational speed of a rotor body within the jetting nozzle **1600**. As will be described more fully below, the rotating nozzle configuration utilizes the rotor portion **1620** of a miniature direct drive electric motor assembly to also form a throat and end discharge slot **1640** of the rotating nozzle itself. Rotation is induced via electromagnetic forces of a rotor/stator configuration. In this way, rotational speeds can be governed in direct proportion to the current supplied to the stators.

[134] As depicted in **Figures 3F-1** through **3F-3**, the upstream portion of the rotor (in this depiction, a four-pole rotor) **1620** includes a near-cylindrical inner diameter (the I.D. actually reduces slightly from the fluid inlet to the discharge slot to further accelerate the fluid before it enters the discharge slot) that provides a flow channel for the jetting fluid through the center of the rotor **1620**. This near-cylindrical flow channel then transitions to the shape of the nozzle's **1600** discharge slot **1640** at its far downstream end. This is possible because, instead of the typical shaft and bearing assembly inserted longitudinally through the center diameter of the rotor **1620**, the rotor **1620** is stabilized and positioned for balanced rotation about the longitudinal axis of the rotor **1620** by a single set of bearings **1630** positioned about the interior of the upstream butt end, and outside the outer diameter of the flow channel ("nozzle throat") **1650**, such that the bearings **1630** stabilize the rotor body **1620** both longitudinally and axially.

[135] Referring now to **Figure 3B-1a**, and again discussing the internal system **1500**, a cross-sectional view of the battery pack section **1510**, taken across line **A-A'** of **Figure 3B-1** is shown. The view is taken at the top of the bottom end cap **1530** of the battery pack **1510** looking down into a jetting fluid receiving funnel **1570**. Visible in this figure are three wires

1590 extending away from the battery pack **1510**. Using the wires **1590**, power is sent from the "AA"-size lithium batteries **1551** to the geo-steering system for controlling the rotating jet nozzle **1600**. By adjusting current through the wires **1590**, the geo-steering system controls the rate of rotation of the rotor **1620** along with its orientation.

[136] Note that because the longitudinal axis of the nozzle's discharge stream is designed to be continuous to and aligned with that of the nozzle throat, there is virtually no axial moment acting on the nozzle from thrust of the exiting jetting fluid. That is, as the nozzle is designed to operate in an axially "balanced" condition, the torque moment required to actually rotate the nozzle about its longitudinal axis is relatively small. Similarly, in that relatively low rotational speeds (RPM's) are required for rotational excavation, the electromagnetic force required from the nozzle's rotor/stator interaction is relatively small as well.

[137] Note from **Figure 3** that the jetting nozzle **1600** is located at the far downstream end of the jetting hose **1595**. Though the diameters of the components of the internal system **1500** must meet some rather stringent diameter constraints, the respective lengths of each component (with the exception of the jetting nozzle **1600** and, if desired, one or more jetting collars) are typically far less restricted. This is because the jetting nozzle **1600** and collars (not shown) are the only components affixed to the jetting hose **1595** that will ever have to make the approximate 90° bend as directed by the whipstock face **1050.1**. All other components of the internal system **1500** will always reside at some position within the jetting hose carrier system **400**, and above the jetting hose pack-off section **600** (discussed below).

[138] The length of many of the components can also be adjusted. For example, though the battery pack **1510** in **Figure 3A** is depicted to house six AA batteries **1551**, a much greater number could be easily accommodated by simply constructing a longer battery pack casing **1540**. Similarly, the battery pack end-caps **1520**, **1530**, the support columns **1560**, and the fluid intake funnel **1570** may be substantially elongated as well to accommodate fluid flow and power needs.

[139] Referring again to the docking station **325**, the docking station **325** serves as a physical "stop" beyond which the internal system **1500** can no longer travel upstream. Specifically, the upstream limit of travel of the internal system **1500** (comprised primarily of

the jetting hose **1595**) is at that point where the upstream battery pack end cap **1520** lodges (or, "docks") within a bottom, conically-shaped receptacle **328** of the docking station **325**. The receptacle **328** serves as a lower end cap. The receptacle **328** provides matingly conductive contacts which line up with the upstream battery pack end cap **1520** to form a docking point. In this way, a transfer of data and/or electrical power (specifically, to recharge batteries **1551**) can occur while "docked."

[140] The docking station **325** also has a conically-shaped end-cap **323** at the upstream (proximal) end of the docking station **325**. The conical shape serves to minimizing erosive effects by diverting the flow of jetting fluid around the body thereof, thereby aiding in the protection of the system components housed within the docking station **325**. Depending on the guidance, steering, and communications capabilities desired, an upper portion **323** of the docking station **325** can house the servo, transmission, and reception circuitry and electronics systems designed to communicate directly (either in continuous real time, or only discretely while docked) with counterpart systems in the internal system **1500**. Note, as shown in **Figure 3**, the O.D. of the cylindrical docking station **325** is approximately equal to that of the jetting hose **1595**.

[141] The internal system **1500** next includes a jetting fluid receiving funnel **1570**. **Figure 3B-1** includes a cut-away perspective view of the jetting fluid receiving funnel **1570**, with an axial cross-sectional view along **B-B'** shown as **Figure 3B-1b**. The jetting fluid receiving funnel **1570** is located below the base of the battery pack section **1510**, shown and described above in connection with **Figure 3A**. As the name implies, the jetting fluid receiving funnel **1570** serves to guide the jetting fluid into the interior of the jetting hose **1595** during the casing exit and mini-lateral formation process. Specifically, the annular flow of jetting fluid (e.g., passing along the outside of battery pack casing **1540** and subsequently the battery pack end cap **1530**, and inside the I.D. of jetting hose conduit **420**) is forced to transition to flow between the three battery pack support conduits **1560**, because an upper seal (seen in **Figure 3** at **1580U**) precludes any fluid flow along a path exterior to the jetting hose **1595**. Thus, all flow of jetting fluid (as opposed to hydraulic fluid) is forced between conduits **1560** and into fluid receiving funnel **1570**.

[142] In the design of **Figure 3B-1**, three columnar supports **1560** are used to house the wires **1590**. The columnar supports **1560** also provide an area open to fluid flow. The spacing between the supports **1560** is designed to be significantly greater than that provided by the I.D. of the jetting hose **1595**. At the same time, the supports **1560** have I.D.'s large enough to house and protect up to an AWG #5 gauge wire **1590**. The columnar supports **1560** also support the battery pack **1510** at a specific distance above the jetting fluid intake funnel **1570** and the jetting hose seal assembly **1580**. The supports **1560** may be sealed with sealing end caps **1562**, such that removal of the end caps **1562** provides access to the wiring **1590**.

[143] **Figure 3B-1b** provides a second axial, cross-sectional view of the fluid intake funnel **1570**. This view is taken across line **B-B'** of **Figure 3B-1**. The three columnar supports **1560** are again seen. The view is taken at the top of the jetting fluid inlet, or receiving funnel **1570**.

[144] Downstream from the jetting fluid receiving funnel **1570** is a jetting hose seal assembly **1580**. **Figure 3C** is a cut-away perspective view of the seal assembly **1580**. In the view of **Figure 3C**, columnar support members **1560** and electrical wiring **1590** have been removed for the sake of clarity. However, the receiving funnel **1570** is again seen at the upper end of the seal assembly **1580**.

[145] Also visible in **Figure 3C** is an upper end of the jetting hose **1595**. The jetting hose **1595** has an outermost jetting hose wrap O.D. **1595.3** (also seen in **Figure 3D-1a**) that, at points, may engage the jetting hose conduit **420**. A micro-annulus **1595.420** (shown in **Figures 3D-1** and **3D-1a**) is formed between the jetting hose **1595** and the surrounding conduit **420**. The jetting hose **1595** also has a core (O.D. **1595.2,** I.D. **1595.1**) that transmits jetting fluid during the jetting operation. The jetting hose **1595** is fixedly connected to the seal assembly **1580**, meaning that the seal assembly **1580** moves with the jetting hose **1595** as the jetting hose advances into a mini-lateral.

[146] As previously described, the upper seal **1580U** of the jetting hose's seal assembly **1580** (shown as a solid portion with a slightly concave upwards upper face) precludes any continued downstream flow of jetting fluid outside of the jetting hose **1595**. Similarly, the lower seal **1580L** of this seal assembly **1580** (shown as a series of concave-downwards cup

faces) precludes any upstream flow of hydraulic fluid from below. Note how any upstream-to-downstream hydraulic pressure from the jetting fluid will tend to expand the jetting fluid intake funnel **1570** and, thus, urge the upper seal **1580U** of the seal assembly **1580** radially outwards to sealingly engage the I.D. **420.1** of the jetting hose carrier's (inner) jetting hose conduit **420**. Similarly, any downstream-to-upstream hydraulic pressure from the hydraulic fluid radially expands bottom cup-like faces making up the lower seal **1580L** to sealingly engage the I.D. **420.1** of the jetting hose carrier's inner conduit **420**. Thus, when jetting fluid pressure is greater than the trapped hydraulic fluid pressure, the overbalance will tend to "pump" the entire assembly "down-the-hole". Conversely, when the pressure overbalance is reversed, hydraulic fluid pressure will tend to "pump" the entire seal assembly **1580** and connected hose **1595** back "up-the-hole".

[147] Returning to **Figures 2** and **3**, the upper seal **1580U** provides an upstream pressure and fluid-sealed connection for the internal system **1500** to the external system **2000**. (Similarly, as will be discussed further below, a pack-off seal assembly **650** within a pack-off section **600** provides a downstream pressure and fluid-sealed connection between the internal system **1500** and the external system **2000**.) The seal assembly **1580** includes seals **1580U**, **1580L** that hold incompressible fluid between the hose **1595** and the surrounding conduit **420**. In this way, the jetting hose **1595** is operatively connected to the coiled tubing string **100** and sealingly connected to the external system **2000**.

[148] **Figure 3C** illustrates utility of the sealing mechanisms involved in this upstream seal **1580**. During operation, jetting fluid passes:

(1) through an annulus **420.2** between the battery pack casing **1540** and the jetting hose carrier inner conduit **420**;

(2) between the battery pack support conduits **1560**;

(3) into the fluid receiving funnel **1570**;

(4) down the core **1595.1** (I.D.) of the jetting hose **1595**; and

(5) then exits the jetting nozzle **1600**.

[149] As noted, the downward hydraulic pressure of the jetting fluid acting upon the axial cross-sectional area of the jetting hose's fluid receiving funnel **1570** creates an upstream-to-downstream force that tends to "pump" the seal assembly **1580** and connected jetting hose **1595** "down the hole." In addition, because the components of the fluid receiving funnel **1570** and the supporting upper seal **1580U** of the seal assembly **1580** are slightly flexible, the net pressure drop described above serves to swell and flare the outer diameters of upper seal **1580U** radially outwards, thus producing a fluid seal that precludes fluid flow behind the hose **1595**.

[150] **Figure 3D-1** provides a longitudinal, cross-sectional view of the "bundled" jetting hose **1595** of the internal system **1500** as it resides in the jetting hose carrier's inner conduit **420**. Also included in the longitudinal cross section are perspective views (dashed lines) of electrical wires **1590** and data cables **1591**. Note from the axial cross-sectional view of **Figure 3D-1a**, that all of the electrical wires **1590** and data cables **1591** in the "bundled" jetting hose **1595** safely reside within the outermost jetting hose wrap **1595.3**.

[151] In the preferred embodiment, the jetting hose **1595** is a "bundled" product. The hose **1595** may be obtained from such manufacturers as Parker Hannifin Corporation. The bundled hose includes at least three electrically conductive wires **1590**, and at least one, but preferably two dedicated data cables **1591** (such as fiber optic cables), as depicted in **Figures 3B-1b** and **3D-1a**. Note these wires **1590** and fiber optic strands **1591** are located on the outer perimeter of the core **1595.2** of the jetting hose **1595**, and surrounded by a thin outer layer of a flexible, high strength material or "wrap" (such as Kevlar®) **1595.3** for protection. Accordingly, the wires **1590** and fiber optic strands **1591** are protected from any erosive effects of the high-pressure jetting fluid.

[152] Moving now down the hose **1595** to the distal end, **Figure 3E** provides an enlarged, cross-sectional view of the end of the jetting hose **1595**. Here, the jetting hose **1595** is passing through the whipstock member **1000**, and ultimately along the whipstock face **1050.1** to casing exit "**W**". A jetting nozzle **1600** is attached to the distal end of the jetting hose **1595**. The jetting nozzle **1600** is shown in a position immediately subsequent to forming an exit opening,

or window "**W**" in the production casing **12**. Of course, it is understood that the present assembly **50** may be reconfigured for deployment in an uncased wellbore.

[153] As described in the related applications, the jetting hose **1595** immediately preceding this point of casing exit "**W**" spans the entire I.D. of the production casing **12**. In this way, a bend radius "**R**" of the jetting hose **1595** is provided that is always equal to the I.D. of the production casing **12**. This is significant as the subject assembly **50** will always be able to utilize the entire casing (or wellbore) I.D. as the bend radius "**R**" for the jetting hose **1595**, thereby providing for utilization of the maximum I.D./O.D hose. This, in turn, provides for placement of maximum hydraulic horsepower ("HHP") at the jetting nozzle **1600**, which further translates in the capacity to maximize formation jetting results such as penetration rate, or the lateral borehole diameter, or some optimization of the two.

[154] It is observed here that there is a consistency of three "touch points" for the bend radius "**R**" of the jetting hose **1595**. First, there is a touch point where the hose **1595** contacts the I.D. of the casing **12**. This occurs at a point directly opposite and slightly (approximately one casing I.D. width) above the point of casing exit "**W**." Second, there is a touch point along a whipstock curved face **1050.1** of the whipstock member **1000** itself. Finally, there is a touch point against the I.D. of the casing **12** at the point of casing exit "**W**," at least until the window "**W**" is formed.

[155] As depicted in **Figure 3E** (and in **Figure 4H-1**), the jetting hose whipstock member **1000** is in its set and operating position within the casing **12**. (U.S. Patent No. 8,991,522, also demonstrates the whipstock member **1050** in its run-in position.) The actual whipstock **1050** within the whipstock member **1000** is supported by a lower whipstock rod **1060**. When the whipstock member **1000** is in its set-and-operating position, the upper curved face **1050.1** of the whipstock member **1050** itself spans substantially the entire I.D. of the casing **12**. If, for example, the casing I.D. were to vary slightly larger, this would obviously not be the case. The three aforementioned "touch points" of the jetting hose **1595** would remain the same, however, albeit while forming a slightly larger bend radius "**R**" precisely equal to the (new) enlarged I.D. of casing **12**.

[156] As described in greater detail in the co-owned U.S. Patent No. 8,991,522, the whipstock rod is part of a tool assembly that also includes an orienting mechanism, and an anchoring section that includes slips. Once the slips are set, the orienting mechanism utilizes a ratchet-like action that can rotate the upstream portion of the whipstock member **1000** in discreet 10° increments. Thus, the angular orientation of the whipstock member **1000** within the wellbore may be incrementally changed downhole.

[157] In one embodiment, the whipstock **1050** is a single body having an integral curved face configured to receive the jetting hose and redirect the hose about 90 degrees. Note the whipstock **1050** is configured such that, at the point of casing exit when in set and operating position, it forms a bend radius for the jetting hose that spans the entire ID of the parent wellbore's production casing **12**.

[158] **Figure 4H-1** is a cross-sectional view of the whipstock member **1000** of the external system of **Figure 4**, but shown vertically instead of horizontally. The jetting hose of the internal system (**Figure 3**) is shown bending across the whipstock face **1050**, and extending through a window "**W**" in the production casing **12**. The jetting nozzle of the internal system **1500** is shown affixed to the distal end of the jetting hose **1595**.

[159] **Figure 4H-1a** is an axial, cross-sectional view of the whipstock member **1000**, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member **1000** at line **O-O′** to the start of the jetting hose's bend radius as it approaches line **P-P′**.

[160] **Figure 4H-1b** depicts an axial, cross-sectional view of the whipstock member **1000** at line **P-P′**. Note the adjustments in location and configuration of both the whipstock member's wiring chamber and hydraulic fluid chamber from line **O-O′** to line **P-P′**.

[161] As noted above, the present assembly **50** is preferably used in connection with a nozzle having a unique design. **Figures 3F-1a** and **3F-1b** provide enlarged, cross-sectional views of the nozzle **1600** of **Figure 3**, in a first embodiment. The nozzle **1600** takes advantage of a rotor/stator design, wherein the forward portion **1620** of the nozzle **1600**, and hence the forward jetting slot (or "port") **1640**, is rotated. Conversely, the rearward portion of the nozzle

1600, which itself is directly connected to jetting hose **1595**, remains stationary relative to the jetting hose **1595**. Note in this arrangement, the jetting nozzle **1600** has a single forward discharge slot **1640**.

[162] First, **Figure 3F-1a** presents a basic nozzle body having a stator **1610**. The stator **1610** defines an annular body having a series of inwardly facing shoulders **1615** equi-distantly spaced therein. The nozzle **1600** also includes a rotor **1620**. The rotor **1620** also defines a body and has a series of outwardly facing shoulders **1625** equi-distantly spaced therearound. In the arrangement of **Figure 3F-1a**, the stator body **1610** has six inwardly-facing shoulders **1615**, while the rotor body **1620** has four outwardly-facing shoulders **1625**.

[163] Residing along each of the shoulders **1615** is a small diameter, electrically conductive wire **1616** wrapping the stator's inwardly facing shoulders (or "stator poles") **1615** with multiple wraps. Movement of electrical current through the wires **1616** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** (or battery pack **1550**) of **Figure 3A**.

[164] As noted above, the stator **1610** and rotor **1620** bodies are analogous to a direct drive motor. The stator **1610** (in this depiction, a six-pole stator) of this direct drive electric motor analog is included within the outer body of the nozzle **1600** itself, with each pole protruding directly from the body **610**, and commensurately wrapped in electric wire **1616**. The current source for the wire **1616** wrapping the stator poles is derived through the 'bundled' electrical wires**1590** of the jetting hose **1595**, and is thereby manipulated by the current regulator and micro-servo mechanism housed in the conically-shaped battery pack's (downstream) end-cap **1530**. Rotation of the rotor **1620** of the nozzle **1600**, and particularly the speed of rotation (RPM's), is controlled via induced electro-magnetic forces of a DC rotor/stator system.

[165] Note that **Figure 3F-1a** could serve as a representative axial cross section of essentially any basic direct current electromagnetic motor, with the central shaft/bearing assembly removed. By eliminating a central shaft and bearings, the nozzle **1600** can now accommodate a nozzle throat **1650** placed longitudinally through its center. The throat **1650** is suitable for conducting high pressure fluid flow.

[166] **Figure 3F-1b** provides a longitudinal, cross-sectional view of the nozzle **1600** of **Figure 3F-1a**, taken across line **C-C'** of **Figure 3F-1b**. The rotor **1620** and surrounding stator **1610** are again seen. Bearings **1630** are provided to facilitate relative rotation between the stator body **1610** and the rotor body **1620**.

[167] It is observed in **Figure 3F-1b** that the nozzle throat **1650** has a conically-shaped narrowing portion before terminating in the single fan-shaped discharge slot **1640**. This profile provides two benefits. First, additional non-magnetic, high-strength material may be placed between the throat **1650** and the magnetized rotor portion **1625** of the forward portion of the nozzle body **1620**. Second, final acceleration of the jetting fluid through the throat **1650** is accommodated before entering the discharge slot **1640**. The size, placement, load capacity, and freedom of movement of the bearings **1630** are considerations as well. The forward slot **1640** begins with a relatively semi-hemispherically shaped opening, and terminates at the forward portion of the nozzle **1600** in a curved, relatively elliptical shape (or, optionally, a curved rectangle with curved small ends.)

[168] Simulations were conducted with the single planar slot slightly twisted such that the discharge angle(s) of the fluid generated sufficient thrust so as to rotate the nozzle **1600**. The observed problem was that nozzle rotation rates were hypersensitive to changes in fluid flow rates, leaving the concern of instantaneous and frequent overloading (with resultant failure) of the bearings **1630**. The solution was to design, as nearly as possible, a balanced single slot system, such that there is no appreciable axial thrust generated by fluid discharge. In other words, the nozzle **1600** is no longer sensitive to injection rate.

[169] At this point it is important to note the basic nozzle design criteria for the flow capacity of the combined flow path comprised of the throat **1650** and slot **1640** elements. That is, that these inner throat **1650** and slot **1640** elements of the nozzle **1600** retain dimensions that can approximate the dimensions, and resultant hydraulics, of conventional hydraulic jet casing perforators. Specifically, the nozzle **1600** depicted in **Figures 3F-1a** and **3F-1b** throat **1650** and slot **1640** dimensions that can approximate the perforating hydraulics obtained by a perforator's 1/8th-inch orifice. Note that the terminal width of slot **1640** can not only accommodate 100 mesh sand as an abrasive, but the larger sizes such as 80 mesh sand as well.

[170] Angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown in **Figure 3F-1b**. (These angles are also shown in **Figures 3F-2b** and **3F-3b**, discussed below.) Angle Θ_{SLOT} **1641** represents the actual angle of the outer edges of the slot **1640**, and angle Θ_{MAX} **1642** represents the maximum Θ_{SLOT} **1641** achievable within the existing geometric and construction constraints of the nozzle **1600**. In **Figures 3F-1b, 3F-2b** and **3F-3b**, both angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown at 90 degrees. This geometry, coupled with rotation of the rotor body **1620** (and, consequently, rotation of the jetting slot **1640**) provides for the erosion of a hole diameter that is at least equal to the nozzle's outer diameter even at a stand-off (e.g., the distance from the very tip of the nozzle **1600** at the longitudinal center line to the target rock along the same centerline) of zero.

[171] **Figures 3F-2a** and **3F-2b** provide longitudinal, cross-sectional views of the jetting nozzle of **Figure 3E**, in an alternate embodiment. In this embodiment, multiple ports are used, including both a forward discharge port **1640** and a plurality of rearward thrust jets **1613**, for a modified nozzle **1601**.

[172] The nozzle configuration of **Figures 3F-2a** and **3F-2b** is identical to the nozzle configuration **1600** of **Figure 3F-1a**, with the exception of three additional components:

(1) the use of rearward thrusting jets **1613**;

(2) the use of a slideable collar **1633** biased by a biasing mechanism (spring) **1635**; and

(3) the use of a slideable nozzle throat insert **1631**.

The first of these three additional components, rearward thrusting jets **1613**, provide a rearward thrust that effectively drags the jetting hose **1595** along the lateral borehole, or mini-lateral, as it is formed. Preferably, five rearward thrust jets **1613** are used along the body **1610**, although variations of the number and/or exit angles **1614** of the jets **1613** may be utilized.

[173] **Figure 3F-2c** is an axial, cross-sectional view of the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**. This demonstrates the star-shaped jet pattern created by the multiple rearward thrust jets **1613**. Five points are seen in the star, indicating five illustrative rearward thrust jets **1613**.

[174] Note particularly in a homogeneous host pay zone, the forward (jetting) hydraulic horsepower requirement necessary to excavate fresh rock at a given rate of penetration would be essentially constant. The rearward thrust hydraulic horsepower requirement, however, is constantly increasing in proportion to the growth in length of the mini-lateral. As continued extension of the mini-lateral requires dragging an ever-increasing length of jetting hose **1595** along an ever-increasing distance, the rearward thrusting hydraulic horsepower requirement to maintain forward propulsion of the jetting nozzle **1601** and hose **1595** increases commensurately.

[175] It may be required to consume upwards of two-thirds of available horsepower through the rearward thrust jets **1613** in order to extend the jetting hose **1595** and connected nozzles **1601**, **1602** to the furthest lateral extent. If this maximum requirement is utilized constantly throughout the borehole jetting process, much of the available horsepower will be wasted in the early stages in jetting the bore. This is particularly detrimental when the same jetting nozzle and assembly utilized in rock excavation is also utilized to form the initial casing exit "**W**." Further, if the same rearwards jetting forces cutting the 'points' of the star-shaped rock excavation are active in the wellbore tubulars (particularly, while jetting the casing exit "**W**") significant damage to the nearby tool string (particularly, the whipstock member **1000**) and the well casing **12** could result. Hence, the optimum design would provide for the activation/deactivation of the rearward thrust jets **1613** when desired, particularly, after the casing exit is formed and after the first 5 or 10 feet of lateral borehole is formed.

[176] There are several possible mechanisms by which jet activation/deactivation may be enabled to help conserve HHP and protect the tool string and tubulars. One approach is mechanical, whereby the opening and closing of flow to the jets **1613** is actuated by overcoming the force of a biasing mechanism. This is shown in connection with the spring **1635** of **Figures 3F-2a** and **3F-2b**, where a throat insert **1631** and a slideable collar **1633** are moved together to open rearward thrust jets **1613**. Another approach is electromagnetic, wherein a magnetic port seal is pulled against a biasing mechanism (spring **1635**) by electromagnetic forces. This is shown in connection with **Figures 3F-3a** and **3F-3c**, discussed below.

[177] The second of the three additions incorporated into the nozzle design of **Figures 3F-2a** and **3F-2b** is that of a slideable collar **1633**. The collar **1633** is biased by a biasing mechanism (spring) **1635**. The function of this collar **1633**, whether directly or indirectly (by exerting a force on the slideable nozzle throat insert **1631**), is to temporarily seal the fluid inlets of the thrust jets **1613**. Note that this sealing function by the slideable collar **1633** is "temporary"; that is, unless a specific condition determined by the biasing mechanism **1635** is satisfied. As shown in the embodiment presented in **Figures 3F-2a** and **3F-2b**, the biasing mechanism **1635** is a simple spring.

[178] In **Figure 3F-2a**, the collar **1633** is in its closed position, while in **Figure 3F-2b** the collar **1633** is in its open position. Thus, a specific differential pressure exerted on the cross-sectional area of the slideable nozzle throat insert **1631** has overcome the pre-set compressive force of the spring **1635**.

[179] The third of the three additions incorporated into the nozzle **1601** design of **Figures 3F-2a** and **3F-2b** is that of a slideable nozzle throat insert **1631**. The slideable throat insert **1631** has two basic functions. First, the insert **1631** provides an intentional and pre-defined protrusion into the flow path within the nozzle throat **1650**. Second, the insert **1631** provides an erosion- and abrasion-resistant surface within the highest fluid velocity portion of the internal system **1500**. For the first of these functions, the degree of protrusion to be designed into the slideable nozzle throat insert **1631** is a function of at what point in mini-lateral formation the operator anticipates actuating the thrust jets **1613**.

[180] To illustrate, suppose that system hydraulics provide for a suitable pump rate of 0.5 BPM through the nozzle **1601** at the point of casing exit "**W**," and that this can be sustained at a surface pumping pressure of 8,000 psi. Suppose further that actuation of the thrust jets **1613** in the nozzle **1601** is not required until the nozzle **1601** achieves a lateral distance of 50 feet from the parent wellbore. That is, particularly while jetting the casing exit **"W"** itself and an abrasive mixture (say, of 1.0 ppg of 100 mesh sand in a 1 pound guar-based fresh water gel system) is being pumped, none of the jets**1613** have been opened (which could risk clogging by the abrasive in the jetting fluid mixture.) Consequently, no abrasives are included in the jetting fluid after it is sure that the nozzle **1600** has sufficiently cleared the casing exit "**W**".

Accordingly, while jetting the hole in production casing **12** to form casing exit "**W**", no rearwards jetting forces from fluids expelled through thrust jets **1613** can pose a threat to unintentionally damage either the jetting hose **1595**, the whipstock member **1000**, or the production casing **12**.

[181] Later, after generating the casing exit "**W**" plus a mini-lateral length of, say, approximately 50 feet, the pump pressure is increased to 9,000 psi, the incremental 1,000 psi increase in surface pumping pressure being sufficient to overcome the force of the biasing mechanism **1635** and act against the cross-sectional area of the protrusion of the insert **1631** to actuate the jets **1613**. Thus, at mini-lateral length of 50 feet from the parent wellbore **4**, the thrust jets **1613** are actuated, and high pressure rearwards thrust flow is generated through the jets **1613**.

[182] Suppose these conditions are sufficient to continue jetting a mini-lateral out to a lateral length of 300 feet. At 300 feet, the length of jetting hose laying against the floor of the mini-lateral is causing a commensurate frictional resistance such that it and the thrust forces generated through the thrust jets **1613** are in approximate equilibrium. (Instrumentation such as tensiometers, for example, would indicate this.) At this point, the pump rate is increased to, say, 10,000 psi, and the rearward thrust jets **1613** remain actuated, but at higher differential pressures and flow rates, thus generating higher pull force on the jetting hose **1595**.

[183] **Figures 3F-3a and 3F-3c** provide longitudinal, cross-sectional views of a jetting nozzle **1602**, in yet another alternate embodiment. Here, multiple rearward thrust jets **1613,** and a single forward jetting slot **1640**, are again used. A collar **1633** and spring **1635** are again used for providing selective fluid flow through rearward thrust jets **1613**.

[184] **Figures 3F-3b** and **3F-3d** provide axial, cross-sectional views of the jetting nozzle **1602** of **Figures 3F-3a** and **3F-3c**, respectively. These demonstrate the star-shaped jet pattern created by the multiple jets **1613**. Eight points are seen in the star, indicating two sets of four (alternating) illustrative thrust jets **1613**. In **Figures 3F-3a** and **3F-3b**, the collar **1633** is in its closed position, while in **Figures 3F-3c** and **3F-3d** the collar **1633** is in its open position permitting fluid flow through the jets **1613**. The biasing force provided by the spring **1635** has been overcome.

[185] The nozzle **1602** of **Figures 3F-3a** and **3F-3c** is similar to the nozzle **1601** of **Figures 3F-2a** and **3F-2b**; however, in the arrangement of **Figures 3F-3a** and **3F-3c**, an electro-magnetic force generating a downstream magnetic pull against the slideable collar **1633**, sufficient to overcome the biasing force of the biasing mechanism (spring) **1635**, replaces the hydraulic pressure force against the slideable throat insert **1631** in the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**.

[186] The nozzle **1602** of **Figures 3F-3a and 3F-3c** presents yet another preferred embodiment of a rotating nozzle **1602**, also suitable for forming casing exits and continued excavation through a cement sheath and host rock formation. In **Figures 3F-3a** and **3F-3c** (and in Figure **3G-1**, described in more detail below), it is the electromagnetic force generated by the rotor/stator system that must overcome the spring **1635** force to open hydraulic access to the rearward thrust jets **1613** (and **1713**). (Note that in **Figure 3G-1**, depicting an in-line hydraulic jetting collar, discussed more fully below, direct mechanical connection of internal turbine fins **740** to the slideable collar **733** change the biasing criteria to one of differential pressure, as with the jetting nozzle depicted in **Figure 3F-2a**). The key here is the ability to keep the fluid inlets to the rearward thrust jets **1613** (and **1713**) closed until the operator initiates opening them, specifically by increasing the pump rate, such that either (or both) the differential pressure through the nozzle and/or the nozzle rotation speed's proportional increase of electromagnetic pull on the slideable collars **1633 / 1733** opens access to the fluid inlets of the thrust jets **1613 / 1713**.

[187] It is also observed that in the nozzle **1602**, the number of rearward thrust jets **1613**, though also symmetrically placed about the circumference of the rotor **1610**, has been increased from a single set of five to two sets of four. Note that each of the four jets **1613** within each of the two sets are also symmetrically placed about the rotor **1610** circumference, orthogonally relative to each other; hence, the two sets of jets **1613** must overlap. Additionally, the path of each jet now not only travels through the rearward (stator) portion **1610** of the nozzle **1602**, but now also through the forward (rotor) section **1620** of the nozzle **1602**. Note, however, as depicted in **Figures 3F-3b** and **3F-3d**, whereas there are eight individual jet passages through the rearward (stator) portion **1610** of the nozzle **1602**, there are only four passing through the forward (rotor) section **1620** of the nozzle **1600**. Hence, rotation

of the forward (rotor) section **1620** of the nozzle **1602** will only provide for the alignment of, and subsequent fluid flow through, only one set of four jets **1613** at a time. In fact, for most of a single rotation's duration, the flow channels of the rotor **1620** will have no access to those of the stator **1610**, and are thereby effectively sealed. The result will be an oscillating (or, "pulsating") jetting flow through the rearward thrust jets **1613**.

[188] The commensurate subtraction of jetting fluid volumes going through the nozzle port **1640** produces a commensurate pulsating forward jetting flow for excavation, as well. The benefits of pulsating flow over and against continuous flow for excavation systems are well documented, and will not be repeated here. Note, however, the subject nozzle design not only captures the rock excavation benefits of a rotating jet, but also the benefits of a pulsating jet.

[189] Another embodiment of a thrust collar that employs an electromagnetic force is provided in **Figures 3G-1a** and **3G-1b**. **Figures 3G-1a** presents an axial, cross-sectional view of a basic body for a thrust jetting collar **1700** of the internal system **1500** of **Figure 3**. The view is taken through line **D-D'** of **Figure 3G-1b**. Here, as with the jetting nozzle **1602**, two layers of rearward thrust jets **1713** are again offered.

[190] The collar **1700** has a rear stator **1710** and an inner (rotating) rotor **1720**. The stator **1710** defines an annular body having a series of inwardly facing shoulders **1715** equi-distantly spaced therein, while the rotor **1720** defines a body having a series of outwardly facing shoulders **1725** equi-distantly spaced therearound. In the arrangement of **Figure 3G.1.a**, the stator body **1710** has six inwardly-facing shoulders **1715**, while the rotor body **1720** has four outwardly-facing shoulders **1725**.

[191] Residing along each of the shoulders **1715** is a small diameter, electrically conductive wire **1716** wrapping the stator's **1710** inwardly facing shoulders (or, "stator poles") **1715** with multiple wraps. Movement of electrical current through the wires **1716** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** of **Figure 3A**.

[192] **Figure 3G-1b** is a longitudinal, cross-sectional view of the nozzle **1700**. **Figure 3G-1c** is an axial cross section intersecting the thrust jets **1713** along line **d-d'** of **Figure 3G-1b**.

[193] **Figures 3G-1a** thru **3G-1c** show the embodiment of similar concepts for the rotating nozzles **1600**, **1601**, and **1602**, but with modifications adapting the apparatus for use as an in-line thrust jetting collar **1700**. Note particularly the retention of a flow-through rotor **1725** providing a collar throat **1750**, coupled with a stator **1715** and bearings **1730**. However, the stationary flow channels for the rearward thrusting jets **1713** penetrating the stator **1710** are staggered, being in two sets of four. The single set of four orthogonal jets penetrating the rotor **1725** will, for each full rotation, "match-up" four times each with the jets penetrating the stator **1710**, each match-up providing a four-pronged instantaneous pulsed flow spaced equi-distant about the outer circumference of the collar **1700**. Similar to the rotating nozzle **1602**, the slideable collar **1733** is moved electromagnetically against a biasing mechanism (spring) **1735** to actuate flow through the rearward thrust jets **1713**.

[194] **Figure 3G-1c** is another cross-sectional view, showing the star pattern of the rearward thrust jets **1713**. Eight points are seen.

[195] A unique opportunity exists to configure the collar **1733** as either a net power consumer or a net power provider. The former would rely on the battery pack-provided power, just as the jetting nozzle **1600** does, to fire the stator, rotate the rotor, and generate the requisite electromagnetic field. The latter is accomplished by incorporating interior, slightly angled turbine fins **1740** within the I.D. of the rotor **1720**, hence harnessing the hydraulic force of the jetting fluid as it is pumped through the collar **1700**. Such force would be dependent only on the pump rate and the configuration of the turbine fins **1740**.

[196] In one aspect, internal turbine fins **1740** are placed equi-distant about the collar throat **1750**, such that hydraulic forces are harnessed both to rotate the rotor **1720** and to supply a net surplus of electrical current to be fed back into the internal system's circuitry. This may be done by sending excess current back up wires **1590**. The ability to incorporate a rotor/stator configuration into construction of the rearward thrust jet collar enables a full-opening I.D. equal to that of the jetting hose. More than ample hydroelectric power could be obtained to

generate the electromagnetic field needed to operate the slideable port collar **1733**, the surplus being available to be fed into the now "closed" electrical system incurred once the internal system **1500** disengages from the docking station **325**. Hence, this surplus hydroelectric power generated by the collar **1700** may beneficially be used to maintain charges of the batteries **1551** in the battery pack **1550**.

[197] It is observed that the various nozzle designs **1600**, **1601**, **1602** discussed above are designed to jet not only through a rock matrix, but also through the steel casing and the surrounding cement sheath of the wellbore **4c** in order to reach the rock. The nozzle designs incorporate the ability to handle relatively large mesh-size abrasives through the forward nozzle jetting port **1640** prior to engaging the RTJ's **1613**. It is understood though that other nozzle designs may be used that accomplish the purpose of forming mini-laterals but which are not so robust as to cut through steel.

[198] In the various nozzle designs **1600**, **1601**, **1602** discussed above, a single forward port in a hemispherically-shaped nozzle is used. The forward port **1640** is defined by the angles θ_{MAX} (whereby the width of the jet is equal to the width of the nozzle when the outermost edge of the jet reaches a point forward equivalent to the nozzle tip) and θ_{SLOT} (the actual slot angle). Note $\theta_{SLOT} \leq \theta_{MAX}$. For presentation purposes herein, $\theta_{SLOT} = \theta_{MAX}$, such that even if the tip of the rotating nozzle was against the host rock (or casing I.D.) face while jetting, it would still excavate a tunnel diameter equal to the outer (maximum) nozzle diameter. It is this single-plane, rotating slot configuration that will provide a maximum width in order to accommodate ample pass-through capacity for any abrasives that may be incorporated in the jetting fluid.

[199] The preferred rearward orifice jet orientation is from 30° to 60° from the longitudinal axis. The rearward thrust jets **1613/1713** are designed to be symmetrical about the circumference of the nozzle's/collar's stator body **1610/1710**. This maintains a purely forwards orientation of the jetting assembly **1600**, **1601**, **1602** along the longitudinal axis. Accordingly, there should be at least three jets **1613/1713** spaced equi-distant about the circumference, and preferably at least five equi-distant jets **1613/1713**.

[200] As noted above, the nozzle in any of its embodiments may be deployed as part of a guidance, or geo-steering, system. In this instance, the nozzle will include at least one geo-spatial chip, and will employ at least three actuator wires. The actuator wires are spaced equi-distant about the nozzle, and receive electrical current, or excitation, from the electrical wires **1590** already provided in the jetting hose **1595**.

[201] **Figure 3F-1c** is a longitudinal cross-sectional view of the jetting nozzle **1600** of **Figure 3F-1b**, in a modified embodiment. Here, the jetting nozzle **1600** is shown connected to a jetting hose **1595**. The connection may be a threaded connection; alternatively, the connection may be by means of welding. In **Figure 3F-1c**, an illustrative weld connection is shown at **1660**.

[202] In the arrangement of **Figure 3F-1c**, the jetting nozzle **1600** includes a geo-spatial integrated circuit ("IC") chip **1670**. The geo-spatial chip **1670** resides within an IC chip port seal **1675**. The geo-spatial chip **1670** may comprise a two-axial or a three-axial accelerometer, a bi-axial or a tri-axial gyroscope, a magnetometer, or combinations thereof. The present inventions are not limited by the type or number of geo-spatial chips used, or their respective locations within the assembly, unless expressly so stated in the claims. Preferably, the chip **1670** will be associated with a micro-electro-mechanical system residing on or near the nozzle body such as shown and described in connection with the nozzle embodiments (**1600**, **1601**, **1602**) described above.

[203] **Figure 3F-1d** is an axial-cross-sectional view of the jetting hose **1590** of **Figure 3F-1c**, taken across line **c-c'**. Visible in this view are power wires **1590** and actuator wires **1590A**. Also visible are optional fiber optic data cables **1591**. The wires **1590**, **1590A**, **1591** may be used to transmit geo-location data from the chip **1670** up to a micro-processor in the battery pack section **1550**, and then wirelessly to a receiver located in the docking station (shown best at **325** in **Figure 4D-1b**), wherein the receiver communicates with the micro-processor in the docking station **325**. Preferably, the micro-processor in the docking station **325** processes the geo-location data, and makes adjustments to electrical current in the actuator wires **1590A** (using one or more current regulators), in order to ensure that the nozzle is oriented to hydraulically bore the lateral boreholes in a pre-programmed direction.

[204] The micro-transmitter in the battery pack is preferably housed in the battery pack's downstream end cap **1530**, while the docking station **325** is preferably affixed to the interior of a jetting hose carrier system **400** (described below in connection with **Figures 3A, 3B-1,** and **4D-1**). The receiver housed in the docking station **325** may be in electrical or optical connection with a micro-processor at the surface **1**. For example, a fiber optic cable **107** may run along the coiled tubing conveyance system **100**, to the surface **1**, where the geo-location data is processed as part of a control system.

[205] The reverse (surface-to-downhole instrumentation) communication is likewise facilitated by hard-wired (again, preferably fiber optic) connection of surface instrumentation, through fiber optic cable **107** within coiled tubing conveyance medium **100** and external system **2000**, to a specific terminus receiver (not shown) housed within the docking station **325**. An adjoining wireless transmitter within the docking station **325** then transmits the operator's desired commands to a wireless receiver housed within the end cap **1530** of the internal system **1500**. This communication system allows an operator to execute commands setting both the rotational speed and/or the trajectory of the jetting nozzle **1600**.

[206] When the nozzle **1600** exits the casing, the operator knows the location and orientation of the nozzle **1600**. By monitoring the length of jetting hose **1590** that is translated out of the jetting hose carrier, integrated with any changes in orientation, the operator knows the geo-location of the nozzle **1600** in the reservoir.

[207] In one option, a desired geo-trajectory is first sent as geo-steering command from the surface **1**, down the coiled tubing **100**, and to the micro-processor associated with the docking station **325**. Upon receiving a geo-steering command from the surface **1**, such as from an operator or a surface control system, the micro-processor will forward the signals on wirelessly to a corresponding micro-receiver associated with the battery pack section **1550**. That signal, in turn, will engage one or more current regulators to alter the current conducted down one, two, or all three of the at least three electric wires **1590**, connected directly to the jetting nozzle **1600**. Note that at least part of these electrical wire connections, preferably segments closest to the jetting nozzle **1600**, are comprised of actuator wires **1590A**, such as the Flexinol® actuator wires manufactured by Dynalloy, Inc. These small diameter, nickel-

titanium wires contract when electrically excited. This ability to flex or shorten is characteristic of certain alloys that dynamically change their internal structure at certain temperatures. The contraction of actuator wires is opposite to ordinary thermal expansion, is larger by a hundredfold, and exerts tremendous force for its small size. Given close temperature control under a constant stress, one can get precise position control, i.e., control in microns or less. Accordingly, given (at least) three separate actuator wires **1590A** positioned at-or-near equidistant around the perimeter and within the body of the jetting hose (toward its end, adjacent to the jetting nozzle **1600**), a small increase in current in any given wire will cause it to contract more than the other two, thereby steering the jetting nozzle **1600** along a desired trajectory. Given an initial depth and azimuth via the geo-spatial chip in the nozzle **1600**, a determined path for a lateral borehole **15** may be pre-programmed and executed automatically.

[208] Of interest, the actuator wires **1590A** have a distal segment residing along a chamber or sheath, or even interwoven with the matrix of the distal segment of the jetting hose **1595**. Further, the distal end of the actuator wires **1590A** may continue partially into the nozzle body, wrapping the stator poles **1615** to connect to, or even form the electro-magnetic coils **1616**. This is also demonstrated in **Figure 3F-1c**. In this way, electrical power is provided from the battery pack section **1550** to induce the relative rotational movement between the rotor body and the stator body.

[209] As can be seen from the above discussion, an internal system **1500** for a hose jetting assembly **50** is provided. The system **1500** enables a powerful hydraulic nozzle (**1600**, **1601**, **1602**) to jet away subsurface rock in a controlled (or steerable) manner, thereby forming a mini-lateral borehole that may extend many feet out into a formation. The unique combination of the internal system's **1500** jetting fluid receiving funnel **1570**, the upper seal **1580U**, the jetting hose **1595**, in connection with the external system's **2000** pressure regulator valve **610** and pack-off section **600** (discussed below) provide for a system by which advancement and retraction of the jetting hose **1595**, regardless of the orientation of the wellbore **4**, can be accomplished entirely by hydraulic means. Alternatively, mechanical means may be added through use of an internal tractor system **700**, described more fully below.

[210] Not only can the above-listed components be controlled to determine the direction of the jetting hose **1595** propulsion (e.g., either advancement or retraction), but also the rate of propulsion. The rate of advancement or retraction of the internal system **1500** may be directly proportional to the rate of fluid (and pressure) bleed-off and/or pump-in, respectively. Specifically, "pumping the hose **1595** down-the-hole" would have the following sequence:

(1) the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose carrier's inner conduit **420** is filled by pumping hydraulic fluid through the main control valve **310**, and then through the pressure regulator valve **610**; then

(2) the main control valve **310** is switched electronically using surface controls to begin directing jetting fluid to the internal system **1500**; which

(3) initiates a hydraulic force against the internal system **1500** directing jetting fluid through the intake funnel **1570**, into the jetting hose **1595**, and "down-the-hole"; such force being resisted by

(4) compressing hydraulic fluid in the micro-annulus **1595.420**; which is

(5) bled-off, as desired, from surface control of the pressure regulator valve **610**, thereby regulating the rate of "down-the-hole" decent of the internal system **1500**.

[211] Similarly, the internal system **1500** can be pumped back "up-the-hole" by directing the pumping of hydraulic fluid through (first) the main control valve **310** and (secondly) through the pressure regulator valve **610**, thereby forcing an ever-increasing (expanding) volume of hydraulic fluid into the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose conduit **420**, which pushes upwardly against the bottom seals **1580L** of the jetting hose seal assembly **1580**, thereby driving the internal system **1500** back "up-the-hole". The direction and rate of propulsion of the internal system **1500** by hydraulic means can be either augmented or replaced by propulsion of the internal system **1500** via the mechanical means of the internal tractor system **700**, also described below.

[212] Beneficially, once the jetting hose assembly **50** is deployed to a downhole location adjacent a desired point of casing exit "**W**" within a parent wellbore **4** of any inclination (including at-or-near horizontal), the entire length of jetting hose **1595** can be deployed and

retrieved without any assistance from gravitational forces. This is because the propulsion forces used to both deploy and retrieve the jetting hose **1595**, and to maintain its proper alignment while doing so, are either hydraulic or mechanical, as described more fully, below. Note also these propelling hydraulic and mechanical forces are available in more than sufficient quantities as to overcome any frictional forces from movement of the internal system **1500** (including, specifically, the jetting hose **1595**) within the external system **2000** (including, specifically, the jetting hose conduit **420)** induced by any non-vertical alignment, and to maintain the hose **1595** in a substantially taught state along the hose length within the external system **2000**. Hence, these hydraulic and mechanical propulsion forces overcome the "can't-push-a-rope" limitation in its entirety.

[213] Hydraulic force to advance the jetting hose **1595** within and subsequently out of the external system **2000** will be observed any time jetting fluid is being pumped; specifically, force in a plane parallel to the longitudinal axis of the jetting hose **1595**, in an upstream-to-downstream direction, as hydraulic force is exerted against the upstream end-cap of the battery pack **1520**, the fluid intake funnel **1570**, the interior face of the jetting nozzle **1600**, e.g., any internal system **1500** surface that is both: (a) exposed to the flow of jetting fluid; and, (b) having a directional component not parallel to the longitudinal axis of the parent wellbore. As these surfaces are rigidly attached to the jetting hose **1595** itself, this upstream-to-downstream force is conveyed directly to the jetting hose **1595** whenever jetting fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100** (seen in **Figure 2)**, and through the jetting fluid passage **345** within the main control valve **300** (described below in connection with **Figure 4C-1**). Note the function of the only other valve in this system, the pressure regulator valve **610** located just upstream of the pack-off seal assembly **650** of pack-off section **600** (seen and described in connection with **Figures 4E-1** and **4E-2),** is simply to release pressure from the compression of hydraulic fluid within the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** (seen in **Figures 3D-1a** and **4D-2**) commensurate with the operator's desired rate of decent of the internal system **1500**.

[214] Conversely, hydraulic forces are operational in propelling the internal system **1500** in a downstream-to-upstream direction whenever hydraulic fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100**, and through the hydraulic fluid

passage **340** within the main control valve **300**. In this configuration, the pressure regulator valve **610** allows the operator to direct injected fluids into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** commensurate with the operator's desired rate of ascent of the internal system **1500**. Thus, hydraulic forces are available to assist in both conveyance and retrieval of the jetting hose **1595**.

[215] Similarly, mechanical forces applied by the internal tractor system **700** assist in conveyance, retrieval, and maintaining alignment of the jetting hose **1595**. The close tolerance between the O.D. of the jetting hose **1595** and the I.D. of the jetting hose conduit **420** of jetting hose carrier system **400**, thus defining annulus **1595.420** , serves to provide confining axial forces that assist in maintaining the alignment of the hose **1595**, such that the portion of the hose **1595** within the jetting hose carrier system **400** can never experience significant buckling forces. Direct mechanical (tensile) force for both deployment and retrieval of the jetting hose **1595** is applied by direct frictional attachment of grippers **756** of specially-designed gripper assemblies **750** of the internal tractor system **700** to the jetting hose **1595** , discussed below in connection with **Figures 4F-1** and **4F-2**.

[216] As described above, jetting hose conveyance is also assisted by the hydraulic forces emanating from the rearward thrusting jets **1613** of the jetting nozzle **1601, 1602** itself; and, if included, from the rearward thrust jets **1713** of any added jetting collar(s) **1700**. These furthest downstream hydraulic forces serve to advance the jetting hose **1595** forward into the pay zone **3** simultaneously with the creation of the UDP **15** (**Figure 1B**), maintaining the forward-aimed jetting fluid proximally to the rock face being excavated. The balance between deploying hydraulic energy forward proximate to the nozzle (for excavating new hole) versus rearward (for propulsion) requires balance. Too much rearward propulsion, and there is not enough residual hydraulic horsepower focused forward to excavate new hole. If there is too much forward expulsion of jetting fluid, there is insufficient fluid available for the rearward thrust jets **1613** / **1713** to generate the requisite horsepower to drag the jetting hose along the lateral borehole. Hence, the ability to redirect either rearward or forward focused hydraulic horsepower through the nozzle *in situ* as described herein is a major enhancement.

[217] For presentation purposes, two configurations of rearward thrust jets **1613/1713** have been included herein – one for pulsating flow wherein eight rearward thrust jets, each inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are grouped into two sets of four, with rearwards flow alternating (or 'pulsing') between the two sets; and one for continuous flow, wherein a single set of five jets, each inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are shown. However, other jet numbers and angles may be employed.

[218] The **Figure 3** series of drawings, and the preceding paragraphs discussing those drawings, are directed to the internal system **1500** for the hydraulic jetting assembly **50**. The internal system **1500** provides a novel system for conveying the jetting hose **1595** into and out of a parent wellbore **4** for the subsequent steerable generation of multiple mini-lateral boreholes **15** in a single trip. The jetting hose **1595** may be as short as 10 feet or as long as 300 feet or even 500 feet or longer, depending on the thickness and compressive strength of the formation or the desired geo-trajectory of each lateral borehole.

[219] As noted, the hydraulic jetting assembly **50** also provides an external system **2000**, uniquely designed to convey, deploy, and retrieve the internal system **1500** previously described. The external system **2000** is conveyable on conventional coiled tubing **100**; but, more preferably, is deployed on a "bundled" coiled tubing product (**Figures 3D-1a**, **4A-1** and **4A-1a**) providing for real-time power and data transmission.

[220] Consistent with the related and co-owned patent documents cited herein, the external system **2000** includes a jetting hose whipstock member **1000** including a whipstock **1050** having a curved face **1050.1** that preferably forms the bend radius for the jetting hose **1595** across the entire I.D. of the production casing **12**. The external system **2000** may also include a conventional tool assembly comprised of mud motor(s) **1300**, (external) coiled tubing tractor(s) **1350**, logging tools **1400** and/or a packer or a bridge plug (preferably, retrievable) that facilitate well completion. In addition, the external system **2000** provides for power and data transmission throughout, so that real time control may be provided over the downhole assembly **50**.

[221] **Figure 4** is a longitudinal, cross-sectional view of an external system **2000** of the downhole hydraulic jetting assembly **50** of **Figure 2**, in one embodiment. The external system **2000** is presented within the string of production casing **12**. For clarification, **Figure 4** presents the external system **2000** as "empty"; that is, without containing the components of the internal system **1500** described in connection with the **Figure 3** series of drawings. For example, the jetting hose **1595** is not shown. However, it is understood that the jetting hose **1595** is largely contained in the external system during run-in and pull-out.

[222] In presenting the components of the external system **2000**, it is assumed that the system **2000** is run into production casing **12** having a standard 4.50" O.D. and approximate 4.0" I.D. In one embodiment, the external system **2000** has a maximum outer diameter constraint of 2.655" and a preferred maximum outer diameter of 2.500". This O.D. constraint provides for an annular (i.e., between the system **2000** O.D. and the surrounding production casing **12** I.D.) area open to flow equal to or greater than 7.0309 in^2, which is the equivalent of a 9.2#, 3.5" frac (tubing) string.

[223] The external system **2000** is configured to allow the operator to optionally "frac" down the annulus between the coiled tubing conveyance medium **100** (with attached apparatus) and the surrounding production casing **12**. Preserving a substantive annular region between the O.D. of the external system **2000** and the I.D. of the production casing **12** allows the operator to pump a fracturing (or other treatment) fluid down the subject annulus immediately after jetting the desired number of lateral bores and without having to trip the coiled tubing **100** with attached apparatus **2000** out of the parent wellbore **4**. Thus, multiple stimulation treatments may be performed with only one trip of the assembly **50** in to and out of the parent wellbore **4**. Of course, the operator may choose to trip out of the wellbore for each frac job, in which case the operator would utilize standard (mechanical) bridge plugs, frac plugs and/or sliding sleeves. However, this would impose a much greater time requirement (with commensurate expense), as well as much greater wear and fatigue of the coiled tubing-based conveyance medium **100**.

[224] In actuality, rigorous adherence to the (O.D.) constraint is perhaps only essential for the coiled tubing conveyance medium **100**, which may comprise over 90% of the length of the

system **50**. Slight violations of the O.D. constraint over the comparatively minute lengths of the other components of the external system **2000** should not impose significant annular hydraulic pressure drops as to be prohibitive. If these outer diameter constraints can be satisfied, while maintaining sufficient inner diameters so as to accommodate the design functionality of each of the components (particularly of the external system **2000**), and this can be accomplished for a system **50** that operates in the smaller of standard oilfield production casing **4** sizes of 4.5" O.D., then there should be no significant barriers to adapting the system **50** to any of the larger standard oilfield production casing sizes (5.5", 7.0", etc.).

[225] Presentation of each of the major components of the external system **2000**, which follows below, will be in an upstream-to-downstream direction. Note in **Figure 4** the demarcation of the major components of the external system **2000**, with the corresponding Figure(s) herein:

a. the coiled tubing conveyance medium **100**, presented in **Figures 4A-1** and **4A-2**;

b. the first crossover connection (the coiled tubing transition) **200**, presented in **Figure 4B-1**;

c. the main control valve **300**, presented in **Figure 4C.1**;

d. the jetting hose carrier system, **400** with its docking station **325**, presented in **Figures 4D-1** and **4D-2**;

e. the second crossover connection **500** (transitioning the outer body from circular to star-shaped) and the jetting hose pack-off section **600**, presented in **Figures 4E-1** and **4E-2**;

f. the internal tractor system **700** and the third crossover connection **800**, presented in **Figures 4F-1** and **4F-2**;

g. the third crossover connection **800** and the upper swivel **900**, presented in **Figure 4G-1**;

h. the whipstock member **1000**, presented in **Figure 4H-1**;

i. the lower swivel **1100**, presented in **Figure 4I-1**; and, lastly,

j. the transitional connection **1200** to the conventional coiled tubing mud motor **1300** and a conventional coiled tubing tractor **1350**, coupled to a conventional logging sonde **1400**, presented in **Figure 4J**.

[226] **Figure 4A-1** is a longitudinal, cross-sectional view of a "bundled" coiled tubing conveyance medium **100**. The conveyance medium **100** serves as a conveyance system for the downhole hydraulic jetting assembly **50** of **Figure 2**. The conveyance medium **100** is shown residing within the production casing **12** of a parent wellbore **4**, and extending through a heel **4b** and into the horizontal leg **4c**.

[227] **Figure 4A-1a** is an axial, cross-sectional view of the coiled tubing conveyance medium **100** of **Figure 4A-1**. It is seen that the conveyance medium **100** includes a core **105**. In one aspect, the coiled tubing core **105** is comprised of a standard 2.000" O.D. (**105.2**) and 1.620" I.D. (**105.1**), 3.68 lbm/ft. HSt110 coiled tubing string, having a Minimum Yield Strength of 116,700 lbm and an Internal Minimum Yield Pressure of 19,000 psi. This standard sized coiled tubing provides for an inner cross-sectional area open to flow of 2.06 in^2. As shown, this "bundled" product **100** includes three electrical wire ports **106** of up to .20" in diameter, which can accommodate up to AWG #5 gauge wire, and 2 data cable ports **107** of up to .10" in diameter.

[228] The coiled tubing conveyance medium **100** also has an outermost, or "wrap," layer **110**. In one aspect, the outer layer **110** has an outer diameter of 2.500", and an inner diameter bonded to and exactly equal to that of the O.D. **105.2** of the core coiled tubing string **105** of 2.000".

[229] Both the axial and longitudinal cross-sections presented in **Figures 4A-1** and **4A-1a** presume bundling the product **100** concentrically, when in actuality, an eccentric bundling may be preferred. An eccentric bundling provides more wrap layer protection for the electrical wiring **106** and data cables **107**. Such a depiction is included as **Figure 4A-2** for an eccentrically bundled coiled tubing conveyance medium **101**. Fortunately, eccentric bundling

would have no practical ramifications on sizing pack-off rubbers or wellhead injector components for lubrication into and out of the parent wellbore, since the O.D. **105.2** and circularity of the outer wrap layer **110** of an eccentric conveyance medium **101** remain unaffected.

[230] The conveyance medium **101** may have, for example, an internal flow area of 2.0612 in^2, a core wall thickness **105** of 0.190 in^2, and an average outer wall thickness of 0.25 in^2. The outer wall **110** may have a minimum thickness of 0.10 in^2.

[231] Note the main design criteria of the conveyance medium, whether concentrically **100** or eccentrically **101** bundled, is to provide real-time power (via electrical wiring **106**) and data (via data cabling **107**) transmission capacities to an operator located at the surface **1** while deploying, operating, and retrieving apparatus **50** in the wellbore **4**. For example, in a standard e-coil system, components **106** and **107** would be run within the coiled tubing core **105**, thereby exposing them to any fluids being pumped via the I.D. **105.1** of the core **105**. Given the subject method provides for pumping abrasives within a high-pressure jetting fluid (particularly, while eroding casing exit "**W**" from within production casing **12**), it is preferred instead to locate components **106** and **107** at the O.D. **105.2** of the core **105**.

[232] Similarly, the subject method provides for pumping proppants within high pressure hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and production casing **12**. Hence, the protective coiled tubing wrap layer **110** is preferably of sufficient thickness, strength, and erosive resistance to isolate and protect components **106** and **107** during fracturing operations.

[233] The present conveyance medium **100** (or **101**) also maintains a sufficiently large inner diameter **105.1** of the core wall **105** such as to avoid appreciable friction losses (as compared to the losses incurred in the internal system **1500** and external system **2000**) while pumping jetting and/or hydraulic fluids. At the same time, the system maintains a sufficiently small outer diameter **110.2** so as to avoid prohibitively large pressure losses while pumping hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and the production casing **12**. Further, the system **50** maintains a sufficient wall thickness for the outer wrap layer **110**, whether it is concentrically or eccentrically wrapped

about the inner coiled tubing core **105**, so as to provide adequate insular protection and spacing for the electrical transmission wiring **106** and the data transmission cabling **107**. It is understood that other dimensions and other tubular bodies may be used as the conveyance medium for the external system **2000**.

[234] Moving further down the external system **2000**, **Figure 4B-1** presents a longitudinal, cross-sectional view of the first crossover connection, the coiled tubing crossover connection **200**. **Figure 4B-1**a shows a portion of the coiled tubing crossover connection **200** in perspective view. Specifically, the transition between lines **E-E'** and line **F-F'** is shown. In this arrangement, an outer profile transitions from circular to oval to bypass the main control valve **300**.

[235] The main functions of this crossover connection **200** are as follows:

(1) To connect the coiled tubing conveyance medium **100** (or **101**) to the jetting assembly **50** and, specifically, to the main control valve **300**. In **Figure 4B-1**, this connection is depicted by the steel coiled tubing core **105** connected to the main control valve's outer wall **290** at connection point **210**.

(2) To transition the electrical cables **106** and data cables **107** from the outside of the core **105** of the coiled tubing conveyance medium **100** (or **101**) to the inside of the main control valve **300**. This is accomplished with wiring port **220** facilitating the transition of wires/cables **106/107** inside outer wall **290**.

(3) To provide an ease-of-access point, such as the threaded and coupled collars **235** and **250**, for the splicing/connection of electrical cables **106** and data cables **107.**

and

(4) To provide separate, non-intersecting and non-interfering pathways for electrical cables **106** and data cables **107** through a pressure- and fluid-protected conduit, that is, a wiring chamber **230**.

[236] The next component in the external system **2000** is a main control valve **300**. **Figure 4C-1** provides a longitudinal, cross-sectional view of the main control valve **300**.

Figure 4C-1a provides an axial, cross-sectional view of the main control valve **300**, taken across line **G-G'** of **Figure 4C-1**. The main control valve **300** will be discussed in connection with both **Figures 4C-1** and **4C-1a** together.

[237] The function of the main control valve **300** is to receive high pressure fluids pumped from within the coiled tubing **100**, and to selectively direct them either to the internal system **1500** or to the external system **2000**. The operator sends control signals to the main control valve **300** by means of the wires **106** and/or data cable ports **107**.

[238] The main control valve **300** includes two fluid passages. These comprise a hydraulic fluid passage **340** and a jetting fluid passage **345**. Visible in **Figures 4C-1, 4C-1a** and **4C-1b** (longitudinal cross-sectional, axial cross-sectional, and perspective view, respectively) is a sealing passage cover **320**. The sealing passage cover **320** is fitted to form a fluid-tight seal against inlets of both the hydraulic fluid passage **340** and the jetting fluid passage **345**. Of interest, **Figure 4C-1b** presents a three dimensional depiction of the passage cover **320**. This view illustrates how the cover **320** can be shaped to help minimize frictional and erosional effects.

[239] The main control valve **300** also includes a cover pivot **350**. The passage cover **320** rotates with rotation of the passage cover pivot **350**. The cover pivot **350** is driven by a passage cover pivot motor **360**. The sealing passage cover **320** is positioned by the passage cover pivot **350** (as driven by the passage cover pivot motor **360**) to either: (1) seal the hydraulic fluid passage **340**, thereby directing all of the fluid flow from the coiled tubing **100** into the jetting fluid passage **345**, or (2) seal the jetting fluid passage **345**, thereby directing all of the fluid flow from the coiled tubing **100** into the hydraulic fluid passage **340**.

[240] The main control valve **300** also includes a wiring conduit **310**. The wiring conduit **310** carries the electrical wires **106** and data cables **107**. The wiring conduit **310** is optionally elliptically shaped at the point of receipt (from the coiled tubing transition connection **200**, and gradually transforms to a bent rectangular shape at the point of discharging the wires **106** and cables **107** into the jetting hose carrier system **400**. Beneficially, this bent rectangular shape serves to cradle the jetting hose conduit **420** throughout the length of the jetting hose carrier system **400**.

[241] The next component of the external system **2000** is a jetting hose carrier system **400**. **Figure 4D-1** is a longitudinal, cross-sectional view of the jetting hose carrier system **400**. The jetting hose carrier system **400** is attached downstream of the main control valve **300**. The jetting hose carrier system **400** is essentially an elongated tubular body that houses the docking station **325**, the internal system's battery pack section **1550**, the jetting fluid receiving funnel **1570**, the seal assembly **1580** and connected jetting hose **1595**. In the view of **Figure 4D-1**, only the docking station **325** is visible so that the profile of the jetting hose carrier system **400** itself is more clearly seen.

[242] **Figure 4D-1a** is an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D.1**, taken across line **H-H'** of **Figure 4D-1**. **Figure 4D-1b** is an enlarged view of a portion of the jetting hose carrier system **400** of **Figure 4D-1**. Here, the docking station **325** is visible. The jetting hose carrier system **400** will be discussed with reference to each of **Figures 4D-1**, **4D-1a** and **4D-1b**, together.

[243] The jetting hose carrier system **400** defines a pair of tubular bodies. The first tubular body is a jetting hose conduit **420**. The jetting hose conduit **420** houses, protects, and stabilizes the internal system **1500** and, particularly, the jetting hose **1595**. As previously presented in the discussion of the internal system **1500**, it is the size (specifically, the I.D.), strength, and rigidity of this fluid-tight and pressure-sealing conduit **420** that provides the pathway and particularly, the micro-annulus (shown at **1595.420** in **Figure 3D-1a**, **Figure 4D-2** and **Figure 4D-2a**) for the jetting hose **1595** of internal system **1500** to be "pumped down" and reversibly "pumped up" the longitudinal axis of the external system **2000** as it operates within the production casing **12**.

[244] The jetting hose carrier section **400** also has an outer conduit **490**. The outer conduit **490** resides along and circumscribes the inner conduit **420**. In one aspect, the outer conduit **490** and the jetting hose conduit **420** are simply concentric strings of 2.500" O.D. and 1.500" O.D. HSt100 coiled tubing, respectively. The inner conduit, or jetting hose conduit **420**, is sealed to and contiguous with the jetting fluid passage **345** of the main control valve **300**. When high pressure jetting fluid is directed by the valve **300** into the jetting fluid passage

345, the fluid flows directly and only into the jetting hose conduit **420** and then into the jetting hose **1595**.

[245] An annular area **440** exists between the inner (jetting hose) conduit **420** and the surrounding outer conduit **490**). The annular area **440** is also fluid tight, directly sealed to and contiguous with the hydraulic fluid passage **340** of the control valve **300**. When high pressure hydraulic fluid is directed by the main control valve **300** into the hydraulic fluid passage **340**, the fluid flows directly into the conduit-carrier annulus **440**.

[246] The jetting hose carrier section **400** also includes a wiring chamber **430**. The wiring chamber **430** has an axial cross-section of an upwardly-bent rectangular shape, and receives the electrical wires **106** and data cables **107** from the main control valve's **300** wiring conduit **310**. This fluid-tight chamber **430** not only separates, insulates, houses, and protects the electrical wires **106** and data cables **107** throughout the entire length of the jetting hose carrier section **400**, but its cradle shape serves to support and stabilize the jetting hose conduit **420**. Note the jetting hose carrier section **400** wiring chamber **430** and inner (jetting hose) conduit **420** may or may not be attached either to each other, and/or to the outer conduit **490**.

[247] In addition to housing and protecting wires **106** and data transmission cables **107**, the wiring conduit **430** within the jetting hose carrier system **400** supports the jetting hose conduit's **420** horizontal axis at a position slightly above a horizontal axis that would bifurcate the outer conduit **490**. Different types of materials may be utilized in its construction, given its design constraints are significantly less stringent than those for the outer layer(s) of the CT-based conveyance medium, particularly in regard to chemical and abrasion resistance, as the exterior of the wiring conduit **430** will only be exposed to hydraulic fluid – never jetting or fracturing fluids.

[248] Additional design criteria for the wiring conduit **430** may be invoked if it is desired for it to be rigidly attached to either the jetting hose conduit **420**, the outer conduit **490**, or both. In one aspect, the wiring conduit **430** has a width of approximately 1.34", and provides three 0.20" diameter circular channels for electrical wiring, and two 0.10" diameter circular channels for data transmission cables. It is understood that other diameters and configurations for the

wiring conduit **430** may vary, depending on design objectives, so long as an annular area **440** open to flow of hydraulic fluid is preserved.

[249] Also visible in **Figure 4D-1** is the docking station **325**. The docking station **325** resides immediately downstream of the connection between the main control valve **300** and the jetting hose carrier system **400**. The docking station **325** is rigidly attached within the interior of the jetting hose conduit **420**. The docking station **325** is held in the jetting hose conduit **420** by diagonal supports. The diagonal supports are hollow, the interior(s) of which serving as a fluid- and pressure-tight conduit(s) of leads of electrical wires **106** and data cables **107** into the communications/control/electronics systems of the docking station **325**. This is similar to functions of the battery pack support conduits **1560** of the internal system **1500**. Whether connected to a servo device, a transmitter, a receiver, or other device housed within the docking station **325**, these devices are thereby "hard-wired" via electrical wires **106** and data cables **107** to an operator's control system (not shown) at the surface **1**.

[250] **Figure 4D-2** provides an enlarged, longitudinal cross-sectional view of a portion of the jetting hose carrier system **400** of external system **2000**, depicting its operational hosting of a commensurate length of jetting hose **1595**. **Figure 4D-2a** provides an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D-2**, taken across line **H-H'**. Note that the cross-sectional view of **Figure 4D-2a** matches the cross-sectional view of **Figure 4D-1a**, except that the conduit **420** in **Figure 4D-1a** is "empty," meaning that the jetting hose **1595** is not shown.

[251] The length of the jetting hose conduit **420** is quite long, and should be approximately equivalent to the desired length of jetting hose **1595**, and thereby defines the maximum reach of the jetting nozzle **1600** orthogonal to the wellbore **4**, and the corresponding length of the mini-lateral **15**. The inner diameter specification defines the size of the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. The I.D. should be close enough to the O.D. of the jetting hose **1595** so as to preclude the jetting hose **1595** from ever becoming buckled or kinked, yet it must be large enough to provide sufficient annular area for a robust set of seals **1580L** by which hydraulic fluid can be

pumped into the sealed micro-annulus **1595.420** to assist in controlling the rate of deployment of the jetting hose **1595**, or assisting in hose retrieval.

[252] It is the hydraulic forces within the sealed micro-annulus **1595.420** that keep the segment of jetting hose (above the internal tractor system **700**) straight, and slightly in tension. The I.D. of jetting hose conduit **420** can likewise not be too close to the O.D. of the jetting hose **1595** so as to place unnecessarily high frictional forces between the two. The O.D. of the jetting hose conduit **420** (in conjunction with the I.D. of the outer conduit **490**, less the external dimensions of the jetting hose carrier's wiring chamber **430**) define the annular area **440** through which hydraulic fluid is pumped. Certainly, if the jetting hose carrier system's inner conduit **420** O.D. is too large, it thereby invokes undue frictional losses in pumping hydraulic fluid. However, if not large enough, then the inner conduit **420** will not have sufficient wall thickness to support either the inner or outer operating pressures required. Note, for the subject apparatus designed to be deployed in 4.5" wellbore casing, the inner string is comprised of 1.5" O.D. and 1.25" I.D. (i.e., .125" wall thickness) coiled tubing. If this were 1.84#/ft., HSt110, for example, it would provide for an Internal Minimum Yield Pressure rating of 16,700 psi. Similarly, the outer conduit **490** can be constructed of standard coiled tubing. In one aspect, the outer conduit **490** is comprised of 2.50" O.D. and 2.10" I.D., thereby providing for a wall thickness of 0.20".

[253] Progressing again uphole-to-downhole, the external system **2000** next includes the second crossover connection **500,** transitioning to the jetting hose pack-off section **600**. **Figure 4E-1** provides an elongated, cross-sectional view of both the crossover connection (or transition) **500** and the jetting hose pack-off section **600**. Figure **4E-1a** is an enlarged perspective view highlighting the transition's **500** outer body shape, transitioning from circular- to star-shaped. Axial cross-sectional lines **I-I'** and **J-J'** illustrate the profile of the transition **500** fittingly matching the dimensions of the outer wall **490** of jetting hose carrier system **400** at its beginning, and an outer wall **690** of the pack-off section **600** at its end.

[254] **Figure 4E-2** shows an enlarged portion of the jetting hose pack-off section **600** of **Figure 4E-1**, and particularly sealing assembly **650**. The transition **500** and the jetting hose pack-off section **600** will be discussed with reference to each of these views together.

[255] As its name implies, the main function of the jetting hose pack-off section **600** is to "pack-off", or seal, an annular space between the jetting hose **1595** and a surrounding inner conduit **620**. The jetting hose pack-off section **600** is a stationary component of the external system **2000.** Through transition **500**, and partially through pack-off section **600**, there is a direct extension of the micro-annulus **1595.420**. This extension terminates at the pressure/fluid seal of the jetting hose **1595** against the inner faces of seal cups making up the pack-off seal assembly **650**. Immediately prior to this terminus point is the location of the pressure regulator valve, shown schematically as component **610** in **Figures 4E-1** and **4E-2**. It is this valve **610** that serves to either communicate or segregate the annulus **1595.420** from the hydraulic fluid running throughout the external system **2000**. The hydraulic fluid takes its feed from the inner diameter of the coiled tubing conveyance medium **100** (specifically, from the I.D. **105.1** of coiled tubing core **105**) and proceeds through the continuum of hydraulic fluid passages **240**, **340**, **440**, **540**, **640**, **740**, **840**, **940**, **1040**, and **1140**, then through the transitional connection **1200** to the coiled tubing mud motor **1300**, and eventually terminating at the tractor **1350**. (Or, terminating at the operation of some other conventional downhole application, such as a hydraulically set retrievable bridge plug.)

[256] The crossover connection **500** from the jetting hose carrier system **400** to the pack off section **600** is notable for several reasons:

[257] First, within this transition **500**, the free flow of hydraulic fluid from the conduit-carrier annulus **440** of the jetting hose carrier section **400** will be re-directed and re-compartmentalized within the upper (triangular-shaped) quadrant of the star-shaped outer conduit **690**. Toward the upstream end of the inner conduit **620** is the pressure regulator valve **610**. The pressure regulator valve **610** provides for increasing or decreasing the hydraulic fluid (and commensurately, the hydraulic pressure) in the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. It is the operation of this valve **610** that provides for the internal system **1500** (and specifically, the jetting hose **1595**) to be "pumped down," and then reversibly "pumped up" the longitudinal axis of the production casing **12**.

[258] The upwardly bent, rectangular-shaped fluid-tight chamber **430** that separates, insulates, houses, and protects the electrical wires **106** and data cables **107** along the length of the jetting hose carrier body **400** is transitioned via wiring chamber **530** into a lower (triangular-shaped) quadrant **630** of the star-shaped outer body **690** of the pack-off section **600**. This preserves the separation, insulation, housing, and protection of the electrical wires **106** and the data cables **107** in the jetting hose pack-off section **600**. The star-shaped outer body **690** forms an annulus between itself and the I.D. of the surrounding production casing **12**.

[259] Given the prong-tip-to-opposite-prong-tip distances of the four-pronged star-shaped outer conduit **690** are just slightly less than the I.D. of the production casing **12**, the pack-off section **600** also serves to nearly centralize the jetting hose **1595** in the parent wellbores production casing **12**. As will be explained later, this near-centralization will translate through the internal tractor system **700** so as to beneficially centralize the upstream end of the whipstock member **1000**.

[260] Recall the outer diameter of the upstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the inner conduit **420** of the jetting hose carrier system **400** by virtue of the jetting hose's upper **1580U** and lower **1580L** seals, forming a single seal assembly **1580**. The seals **1580U** and **1580L**, being formably affixed to the jetting hose **1595**, travel up and down the inner conduit **420**. Similarly, the outer diameter of the downstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the pack-off section's **600** inner conduit **620** by virtue of the seal assembly **650** of the pack-off section **600**. Thus, when the internal system **1500** is "docked" (i.e., when the upstream battery pack end cap **1520** is in contact with the external system's docking station **325**) then the distance between the two seal assemblies **1580**, **620** approximates the full length of the jetting hose **1595**. Conversely, when the jetting hose **1595** and jetting nozzle **1600** have been fully extended into the maximum length lateral borehole (or UDP) **15** attainable by the jetting assembly **50**, then the distance between the two seal assemblies **1580**, **620** is negligible. This is because, though the internal system's jetting hose seal assembly **1580** essentially travels the entire length of the external system's **2000** jetting hose carrier system **400**, the seal assembly **650** (of the pack-off section **600** in the external system **2000**) is relatively stationary, as the seal cups comprising seal assembly **650** must reside between opposing seal cup stops **615**.

[261] Note further how the alignment of the two opposing sets of seal cups comprising seal assembly **650** (e.g., an upstream set facing upstream, placed back-to-back with a downstream set facing downstream) thereby provides a pressure/fluid seal against differential pressure from either the upstream direction or the downstream direction. These opposing sets of seal cups comprising seal assembly **650** are shown with a longitudinal cross section of jetting hose **1595** running concentrically through them, in the enlarged view of **Figure 4E-2**.

[262] As noted, the pressure maintained in the micro-annulus **1595.420** by the pressure regulator valve **610** provides for the hydraulic actions of "pumping the hose down the hole" or, reversibly, "pumping the hose up the hole". These annular hydraulic forces also serve to mitigate other, potentially harmful forces that could be imposed on the jetting hose **1595**, such as buckling forces when advancing the hose **1595** downstream, or internal burst forces while jetting. Hence, combined with the upper hose seal assembly **1580** and the jetting hose conduit **420**, the jetting hose pack-off section **600** serves to maintain the jetting hose **1595** in an essentially taut condition. Hence, the diameter of the hose **1595** that can be utilized will be limited only by the bend radius constraint imposed by the I.D. of the wellbore's production casing **12**, and the commensurate pressure ratings of the hose **1595**. At the same time, the length of the hose **1595** that may be utilized is certainly well into the hundreds of feet.

[263] Note the most likely limiting constraint of hose **1595** length will not be anything imposed by the external system **2000**, but instead will be the hydraulic horsepower distributable to the rearward thrust jets **1613/1713**, such that sufficient horsepower can remain forward-focused for excavating rock. As one might expect, the length (and commensurate volume) of mini-laterals that can be jetted will ultimately be a function of rock strength in the subsurface formation. This length limitation is quite unlike the system posited in U.S. Patent No. 6,915,853 (Bakke, *et al.*) that attempts to convey the entirety of the jetting hose downhole in a coiled state within the apparatus itself. That is, in Bakke, *et al.*, the hose is stored and transported while in horizontally stacked, 360° coils contained within the interior of the device. In this case, the bend radius/pressure hose limitations are imposed by (among other constraints), not the I.D. of the casing, but by the I.D. of the device itself. This results in a much smaller hose I.D./O.D., and hence, geometrically less horsepower deliverable to Bakke's jetting nozzle.

[264] In operation, after a UDP **15** has been formed and the main control valve **300** has been shifted to shut-off the flow of hydraulic jetting fluid to the internal system **1500** and is then providing flow of hydraulic fluid to the external system **2000**, the pressure regulator valve **610** can feed flow into the micro-annulus **1595.420** in the opposite direction. This downstream-to-upstream force will "pump" the assembly back into the wellbore **4** and "up the hole," as the bottom, downwards facing cups **1580L** of the seal assembly **1580** will trap flow (and pressure) below them.

[265] The next component within the external system **2000** (again, progressing uphole-to-downhole) is an optional internal tractor system **700**. **Figure 4F-1** provides an elongated, cross-sectional view of the tractor system **700**, downstream from the jetting hose pack-off section **600**. **Figure 4F-2** shows an enlarged portion of the tractor system **700** of **Figure 4F-1**. **Figure 4F-2a** is an axial, cross-sectional view of the internal tractor system **700**, taken across line **K-K'** of **Figures 4F-1** and **4F-2**. Finally, **Figure 4F-2b** is an enlarged half-view of a portion of the internal tractor system **700** of **Figure 4F-2a**. The internal tractor system **700** will be discussed with reference to each of these four views together.

[266] It is first observed that two types of tractor systems are known. These are the wheeled tractor systems and the so-called inch-worm tractor systems. Both of these tractor systems are "external" systems, meaning that they have grippers designed to engage the inner wall of the surrounding casing (or, if in an open hole, to engage the borehole wall). Tractor systems are used in the oil and gas industry primarily to advance either a wireline or a string of coiled tubing (and connected downhole tools) along a horizontal (or highly deviated) wellbore – either uphole or downhole.

[267] In the present assembly **50**, a unique tractor system has been developed which employs "internal," grippers. This means that gripper assemblies **750** are aimed inwardly, for the purpose of either advancing or retracting the jetting hose **1595** relative to the external system **2000**. The result of this inversion is that the coiled tubing string **100** and attached external system **2000** can now be stationary while the somewhat flexible hose **1595** is being translated in the wellbore **4c**. The outwardly-aimed electrically driven wheels of a conventional ("external") tractor are replaced with inwardly-aimed concave grippers **756**. The

result is the inwardly-aimed concave grippers **756** frictionally attach to the jetting hose **1595**, with subsequent rotation of the grippers **756** propelling the jetting hose **1595** in a direction that corresponds with the direction of rotation.

[268] Note specifically the following consequence of this inversion: In a conventional system, the relative movement that occurs is that of the rigidly gripper-attached body (i.e., the coiled tubing) relative to the stationary, frictionally attached body (i.e., the borehole wall). Conversely, the subject internal tractor system is rigidly attached to the stationary body (i.e., the external system **2000**) and the grippers **756** rotate to move the jetting hose **1595**. Accordingly, when the internal tractor system **700** is actuated, the whipstock member **1000** will already be in its set and operating position; e.g., the slips of the whipstock member **1000** will be engaged with the inner wall of the casing **12**. Hence, all advancement/retraction of the jetting hose **1595** by the tractor system **700** takes place when the external system **2000** itself is set and is stationary within the production casing **12**.

[269] It is next observed that the internal tractor system **700** preferably maintains the star-shape profile of the jetting hose pack-off system **600**. The star shape profile of the internal tractor system **700**, with its four points, helps centralizes the tractor system **700** within the production casing **12**. This is beneficial inasmuch as the slips of the whipstock member **1000** (located relatively close to tractor system **700**, due to the short lengths of the third crossover connection (or transition) **800** and upper swivel **900** between them, discussed below) will be engaged when operating the tractor system **700**, meaning that centralization of the tractor system **700** serves to align the defined path of the jetting hose **1595** and precludes any undo torque at the connection with the jetting hose whipstock device **1000**. It is observed in **Figures 4F-1** and **4F-2a** that the position of the jetting hose **1595** is approximately centered, both within the tractor system **700** and, therefore, within the production casing **12**. This places the hose **1595** in optimum position to be either fed into or retracted from the jetting hose whipstock device **1000**.

[270] In addition to centralizing the hose **1595**, another function served by the star-shape profile of the tractor system **700** is that it accommodates interior room for placement of two opposing sets of gripper assemblies **750**. Specifically, the gripper assemblies **750** reside inside

the 'dry' working room of the two side chambers, while simultaneously providing for separate chambers for the electrical wires **106** and data cabling **107** (shown in lower chamber **730**) and the hydraulic fluid (in upper chamber **740**). At the same time, ample cross-sectional flow area is preserved between the tractor system **700** and the I.D. of the production casing **12** within their respective annular area **700.12** for conducting fracturing fluids.

[271] As shown within the 4.5" production casing **12**, the annular area **700.12** open to flow is approximately 10.74 in^2, equating to an equivalent pipe diameter (I.D.) of 3.69 in. Recall the design objective is to maintain an annular flow area greater than or equal to the interior area of a typical 3.5" O.D. (2.922" I.D., 10.2#/ft.) frac string, i.e. 6.706 in^2. Note then, if the tip-to-tip dimension of opposing prongs of the "star" is, for example, 3.95 in, and (to gain additional internal volume within the four chambers of the tractor system **700**) the star shape were changed to a perfect square, then the external area of the square would be 7.801 in^2, and the remaining annular area (open to flow of frac fluid) inside the 4.00" I.D. production casing would be 4.765 in^2, which is equivalent to a 2.463" pipe I.D. Hence, though the base of each triangular chamber within the star shape could be somewhat expanded to provide additional internal volumes or wall thickness, the outer perimeter cannot be completely squared-off and still satisfy the preferred 3.5" frac string criteria. Note, however, there is no reason the triangular dimensions of each chamber must remain symmetrical; e.g., the dimensions could be varied individually in order to accommodate each chamber's internal volume requirements, just as long as the 3.5" frac string requirement is still preferably satisfied.

[272] Each of the gripper assemblies **750** is comprised of a miniature electric motor **754**, and a motor mount **755** securing the motor **754** to the outer wall **790**. In addition, each of the gripper assemblies **750** includes a pair of axles. These represent a gripper axle **751** and a gripper motor axle **753**. Finally, each of the gripper assemblies **750** includes gripper gears **752**.

[273] The tractor system **700** also includes bearing systems **760**. The bearing systems **760** are placed along the length of inner walls **720**. These bearing systems **760** isolate frictional forces against the jetting hose **1595** at the contact points of the grippers **756**, and eliminate unwanted frictional drag against the inner walls **720**.

[274] Rearward rotation of the grippers **756** serve to advance the hose **1595**, while forward rotation of the grippers **756** serves to retract the hose **1595**. Propulsion forces provided by the grippers **756** help advance the jetting hose **1595** by pulling it through the jetting hose carrier system **400**, transition **500**, and pack-off section **600**, and assist in advancing the jetting hose **1595** by pushing it into the lateral borehole **15** itself.

[275] The view of **Figure 4F-1** depicts only two sets of opposing gripper assemblies **750**. However, gripper assemblies **750** may be added to accommodate virtually any length and construction of jetting hose **1595**, depending on compressional, torsional and horsepower constraints. Additional gripper assemblies **750** should add tractor force, which may be desirable for extended length lateral boreholes **15**. Though it is presumed maximum grip force will be obtained when pairs of gripper assemblies **750** are placed axially opposing one another in the same plane (as shown in **Figure 4F-2.a**), that is, maximizing a "pinch" force on the jetting hose **1595**, other arrangements/placements of gripper systems **750** are within the scope of this aspect of the inventions.

[276] Optionally, the internal tractor system **700** also includes a tensiometer. The tensiometer is used to provide real-time measurement of the pulling tension of the upstream section of hose **1595** and the pushing compression on the downstream section of hose **1595**. Similarly, mechanisms could be included to individualize the applied compressional force of each set of grippers **756** upon the jetting hose **1595**, so as to compensate for uneven wear of the grippers **756**.

[277] Again proceeding in presentation of the external system's **2000** main components from upstream-to-downstream, **Figure 4G-1** shows a longitudinal, cross-sectional view of the internal tractor-to-upper swivel (or third) crossover connection **800**, and the upper swivel **900** itself. Figure **4G-1a** depicts a perspective view of the crossover connection **800** between its upstream and downstream ends, denoted by lines **L-L′** and **M-M′**, respectively. **Figure 4G-1b** presents an axial, cross-sectional view within the upper swivel **900** along line **N-N′**. The third transition **800** and upper swivel **900** are discussed in connection with **Figures 4G-1**, **4G-1a** and **4G-1b** together.

[278] The transition **800** functions similarly to previous transitional sections (**200**, **500**) of the external system **2000** discussed herein. Suffice it to say the main function of the transition **800** is to convert the axial profile of the star-shaped internal tractor system **700** back to a concentric circular profile as used for the swivel **900**, and to do so within I.D. restrictions that meet the 3.5" frac string test.

[279] The upper swivel **900** simultaneously accomplishes three important functions:

(1) First, it allows the indexing mechanism to rotate the connected whipstock member **1000** without torqueing any upstream components of the system **50**.

(2) Second, it provides for rotation of the whipstock **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107** through wiring chamber **930** between the transition **800** and the whipstock member **1000**.

(3) Third, it provides a horseshoe-shaped hydraulic fluid chamber **940** that accommodates rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path between the transition **800** and the whipstock member **1000**.

[280] Desirable for the simultaneous satisfaction of the above design criteria are the double sets of bearings **960** (the inner bearings) and **965** (the outer bearings). In one aspect, the upper swivel **900** has an O.D. of 2.6 in.

[281] The outer wall **990** of the upper swivel **900** maintains the circular profile achieved by an outer wall **890** of transition **800**. Similarly, concentric circular profiles are obtained in the upper swivel's **900** middle body **950** and inner wall **920**. These three sequentially and concentrically smaller cylindrical bodies (**990**, **950**, and **920**) provide for placement of an inner set of circumferential bearings **960** (between the inner wall **920** and the middle body **950**) and an outer set of circumferential bearings **965** (between the middle body **950** and the outer wall **990**). The larger cross-sectional area of the middle body **950** allows it to host a horseshoe-shaped hydraulic fluid chamber **940**, and an arc-shaped wiring chamber **930**. The bearings **960**, **965** facilitate relative rotation of the three sequentially and concentrically smaller cylindrical bodies **990**, **950**, and **920**. The bearings **960**, **965** also provide for rotatable

translation of the whipstock member **1000** below the upper swivel **900** (also shown in **Figure 4G-1**) while in its set and operating position. This, in turn, provides for a change in orientation of subsequent lateral boreholes jetted from a given setting depth in the parent wellbore **4**. Stated another way, the upper swivel **900** allows an indexing mechanism (described in the related U.S. Patent No. 8,991,522 and incorporated herein in its entirety) to rotate the whipstock member **1000** without torqueing any upstream components of the external system **2000**.

[282] It is also observed that the upper swivel **900** provides for rotation of the whipstock member **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107**. The upper swivel **900** also permits the horseshoe-shaped hydraulic fluid chamber **940** to provide for rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path down to the whipstock member **1000** and beyond.

[283] Returning to **Figure 4**, and as noted above, the external system **2000** includes a whipstock member **1000**. The jetting hose whipstock member **1000** is a fully reorienting, resettable, and retrievable whipstock means similar to those described in the precedent works of U.S. Provisional Patent Application No. 61/308,060 filed February 25, 2010, U.S. Patent No. 8,752,651 filed February 23, 2011, and U.S. Patent No. 8,991,522 filed August 5, 2011. Those applications are again referred to and incorporated herein for their discussions of setting, actuating and indexing the whipstock. Accordingly, detailed discussion of the jetting hose whipstock device **1000** will not be repeated herein.

[284] **Figure 4H.1** provides a longitudinal cross-sectional view of a portion of the wellbore **4** from **Figure 2**. Specifically, the jetting hose whipstock member **1000** is seen. The jetting hose whipstock member **1000** is in its set position, with the upper curved face **1050.1** of the whipstock **1050** receiving a jetting hose **1595**. The jetting hose **1595** is bending across the hemispherically-shaped channel that defines the face **1050.1**. The face **1050.1**, combined with the inner wall of the production casing **12**, forms the only possible pathway within which the jetting hose **1595** can be advanced through and later retracted from the casing exit "**W**" and lateral borehole **15**.

[285] A nozzle **1600** is also shown in **Figure 4H.1**. The nozzle **1600** is disposed at the end of the jetting hose **1595**. Jetting fluids are being dispersed through the nozzle **1600** to initiate formation of a mini-lateral borehole into the formation. The jetting hose **1595** extends down from the inner wall **1020** of the jetting hose whipstock member **1000** in order to deliver the nozzle **1600** to the whipstock member **1050**.

[286] As discussed in U.S. Patent No. 8,991,522, the jetting hose whipstock member **1000** is set utilizing hydraulically controlled manipulations. In one aspect, hydraulic pulse technology is used for hydraulic control. Release of the slips is achieved by pulling tension on the tool. These manipulations were designed into the whipstock member **1000** to accommodate the general limitations of the conveyance medium (conventional coiled tubing) **100**, which can only convey forces hydraulically (e.g., by manipulating surface and hence, downhole hydraulic pressure) and mechanically (i.e., tensile force by pulling on the coiled tubing, or compressive force by utilizing the coiled tubing's own set-down weight).

[287] The jetting hose whipstock member **1000** is herein designed to accommodate the delivery of wires **106** and data cables **107** further downhole. To this end, a wiring chamber **1030** (conducting electrical wires **106** and data cables **107**) is provided. Power and data are provided from the external system **2000** to conventional logging equipment **1400**, such as a Gamma Ray – Casing Collar Locator logging tool, in conjunction with a gyroscopic tool. This would be attached immediately below a conventional mud motor **1300** and coiled tubing tractor **1350**. Hence, for this embodiment, hydraulic conductance through the whipstock **1000** is desirable to operate a conventional ("external") hydraulic-over-electric coiled tubing tractor **1350** immediately below, and electrical (and preferably, fiber optic) conductance to operate the logging sonde **1400** below the coiled tubing tractor **1350**. The wiring chamber **1030** is shown in the cross-sectional views of **Figures 4H-1a** and **4H-1b**, along lines **O-O'** and **P-P'**, respectively, of **Figure 4H-1**.

[288] Note that this tractor **1350** is placed below the point of operation of the jetting nozzle **1600**, and therefore will never need to conduct either the jetting hose **1595** or high pressure jetting fluids to generate either the casing exit "**W**" or subsequent lateral borehole. Hence, there are no I.D. constraints for this (bottom) coiled tubing tractor **1350** other than the

wellbore itself. The coiled tubing tractor **1350** may be either of the conventional wheel ("external roller") type, or the gripper (inch worm) type.

[289] A hydraulic fluid chamber **1040** is also provided along the jetting hose whipstock member **1000**. The wiring chamber **1030** and the fluid chamber **1040** become bifurcated while transitioning from semi-circular profiles (approximately matching their respective counterparts **930** and **940** of the upper swivel **900**) to a profile whereby each chamber occupies separate end sections of a rounded rectangle (straddling the whipstock member **1050**). Once sufficiently downstream of the whipstock member **1050**, the chambers can be recombined into their original circular pattern, in preparation to mirror their respective dimensions and alignments in a lower swivel **1100**. This enables the transport of power, data, and high pressure hydraulic fluid through the whipstock member **1000** (via their respective wiring chamber **1030** and hydraulic fluid chamber **1040**) down to the mud motor **1300**.

[290] Below the whipstock member **1000** and the nozzle **1600** but above the tractor **1350** is an optional lower swivel **1100**. **Figure 4I-1** is a longitudinal cross-sectional view of the lower swivel **1100**, as it resides between the jetting hose whipstock member **1000** and crossover connection **1200**, and within the production casing **12**. A slip **1080** is shown set within the casing **12**. **Figure 4I-1a** is an axial cross-sectional view of the lower swivel **1100**, taken across **line Q-Q'** of **Figure 4I.1**. The lower swivel **1100** will be discussed with reference to **Figures 4I-1** and **4I-1a** together.

[291] The lower swivel **1100** is essentially a mirror-image of the upper swivel **900**. As with the upper swivel **900**, the lower swivel **1100** includes an inner wall **1120**, a middle body **1150**, and an outer wall **1190**. In a preferred embodiment, the outer conduit has an O.D. of 2.60", or slightly less. The constraint of the O.D. outer conduit **1190** is the self-imposed 3.5" frac string equivalency test.

[292] The middle body **1150** further houses wiring chamber **1130** and a hydraulic fluid chamber **1140**. The fluid chamber **1140** transports hydraulic fluid to crossover connection **1200** and eventually to the mud motor **1300**.

[293] The lower swivel **1100** also includes a wiring chamber **1130** that houses electrical wires **106** and data cables **107**. Continuous electrical and/or fiber optic conductance may be desired when real time conveyance of logging data (gamma ray and casing collar locator, "CCL" data, for example) or orientation data (gyroscopic data, for example) is desired. Additionally, continuous electrical and/or fiber optic conductance capacity enables direct downhole assembly manipulation from the surface **1** in response to the real time data received.

[294] It is noted that while the inner conduit **920** of the upper swivel **900** defines a hollow core of sufficient dimensions to receive and conduct the jetting hose **1595**, the lower swivel **1100** has no such requirement. This is because in the design of the assembly **50** and the methods of usage thereof, the jetting hose **1595** is never intended to proceed downstream to a point beyond the whipstock member **1050**. Accordingly, the innermost diameter of the lower swivel **1100** may in fact be comprised of a solid core, as depicted in **Figure 4I-1a**, thereby adding additional strength qualities.

[295] The lower swivel **1100** resides between the jetting hose whipstock member **1000** and any necessary crossover connections **1200** and downhole tools, such as a mud motor **1300** and the coiled tubing tractor **1350**. Logging tools **1400**, a packer, or a bridge plug (preferably retrievable, not shown) may also be provided. Note that, depending on the length of the horizontal portion **4c** of the wellbore **4**, the respective sizes of the conveyance medium **100** and production casing **12**, and hence the frictional forces to be encountered, more than one mud motor **1300** and/or CT tractor **1350** may be needed.

[296] The final figure presented is **Figure 4J**. **Figure 4J** depicts the final transitional component **1200**, the conventional mud motor **1300**, and the (external) coiled tubing tractor **1350**. Along with the tools listed above, the operator may also choose to use a logging sonde **1400** comprised of, for example, a Gamma Ray – Casing Collar Locator and gyroscopic logging tools. The gyroscopic logging tools provide real-time data describing not only the precise downhole location, but the initial alignment of the whipstock face **1050.1** of the preceding jetting hose whipstock member **1000**. This data is useful in determining:

(1) how many degrees of re-alignment, via the whipstock face **1050.1** alignment, are desired to direct the initial lateral borehole along its preferred azimuth; and

(2) subsequent to jetting the first lateral borehole, how many degrees of re-alignment are required to direct subsequent lateral borehole(s) along their respective preferred azimuth(s).

[297] It is anticipated that, in preparation for a subsequent hydraulic fracturing treatment in a horizontal parent wellbore **4c**, an initial borehole **15** will be jetted substantially perpendicular to and at or near the same horizontal plane as the parent wellbore **4c**, and a second lateral borehole will be jetted at an azimuth of 180° rotation from the first (again, perpendicular to and at or near the same horizontal plane as the parent wellbore). In thicker formations, however, and particularly given the ability to steer the jetting nozzle **1600** in a desired direction, more complex lateral bores may be desired. Similarly, multiple lateral boreholes (from multiple setting points typically close together) may be desired within a given "perforation cluster" that is designed to receive a single hydraulic fracturing treatment stage. The complexity of design for each of the lateral boreholes will typically be a reflection of the hydraulic fracturing characteristics of the host reservoir rock for the pay zone **3**. For example, an operator may design individually contoured lateral boreholes within a given "cluster" to help retain a hydraulic fracture treatment predominantly "in zone."

[298] It can be seen that an improved downhole hydraulic jetting assembly **50** is provided herein. The assembly **50** includes an internal system **1500** comprised of a guidable jetting hose and rotating jetting nozzle that can jet both a casing exit and a subsequent lateral borehole in a single step. The assembly **50** further includes an external system **2000** containing, among other components, a carrier apparatus that can house, transport, deploy, and retract the internal system to repeatably construct the requisite lateral boreholes during a single trip into and out of a parent wellbore **4**, and regardless of its inclination. The external system **2000** provides for annular frac treatments (that is, pumping fracturing fluids down the annulus between the coiled tubing deployment string and the production casing **12**) to treat newly jetted lateral boreholes. When combined with stage isolation provided by a packer and/or spotting temporary or retrievable plugs, thus providing for repetitive sequences of plug-and-UDP-and-frac, completion of the entire horizontal section **4c** can be accomplished in a single trip.

[299] In one aspect, the assembly **50** is able to utilize the full I.D. of the production casing **12** in forming the bend radius **1599** of the jetting hose **1595**, thereby allowing the operator to use a jetting hose **1595** having a maximum diameter. This, in turn, allows the operator to pump jetting fluid at higher pump rates, thereby generating higher hydraulic horsepower at the jetting nozzle **1600** at a given pump pressure. This will provide for substantially more power output at the jetting nozzle, which will enable:

(1) optionally, jetting larger diameter lateral boreholes within the target formation;

(2) optionally, achieving longer lateral lengths;

(3) optionally, achieving greater erosional penetration rates; and

(4) achieving erosional penetration of higher strength and threshold pressure (σ_M and P_{Th}) oil/gas formations heretofore considered impenetrable by existing hydraulic jetting technology.

[300] Also of significance, the internal system **1500** allows the jetting hose **1595** and connected jetting nozzle **1600** to be propelled independently of a mechanical downhole conveyance medium. The jetting hose **1595** is not attached to a rigid working string that "pushes" the hose and connected nozzle **1600**, but instead uses a hydraulic system that allows the hose and nozzle to travel longitudinally (in both upstream and downstream directions) within the external system **2000**. It is this transformation that enables the subject system **1500** to overcome the "can't-push-a-rope" limitation inherent to all other hydraulic jetting systems to date. Further, because the subject system does not rely on gravitational force for either propulsion or alignment of the jetting hose/nozzle, system deployment and hydraulic jetting can occur at any angle and at any point within the host parent wellbore **4** to which the assembly **50** can be "tractored" in.

[301] The downhole hydraulic jetting assembly allows for the formation of multiple mini-laterals, or bore holes, of an extended length and controlled direction, from a single parent wellbore. Each mini-lateral may extend from 10 to 500 feet, or greater, from the parent wellbore. As applied to horizontal wellbore completions in preparation for subsequent

hydraulic fracturing ("frac") treatments in certain geologic formations, these small lateral wellbores may yield significant benefits to optimization and enhancement of fracture (or fracture network) geometry and subsequent hydrocarbon production rates and reserves recovery. By enabling: (1) better extension of the propped fracture length; (2) better confinement of the fracture height within the pay zone; (3) better placement of proppant within the pay zone; and (4) further extension of a fracture network prior to cross-stage breakthrough, the lateral boreholes may yield significant reductions of the requisite fracturing fluids, fluid additives, proppants, hydraulic horsepower , and hence related fracturing costs previously required to obtain a desired fracture geometry, if it was even attainable at all. Further, for a fixed input of fracturing fluids, additives, proppants, and horsepower, preparation of the pay zone with lateral boreholes prior to fracturing could yield significantly greater Stimulated Reservoir Volume, to the degree that well spacing within a given field may be increased. Stated another way, fewer wells may be needed in a given field, providing a significance of cost savings. Further, in conventional reservoirs, the drainage enhancement obtained from the lateral boreholes themselves may be sufficient as to preclude the need for subsequent hydraulic fracturing altogether.

[302] As an additional benefit, the downhole hydraulic jetting assembly **50** and the methods herein permit the operator to apply radial hydraulic jetting technology without "killing" the parent wellbore. In addition, the operator may jet radial lateral boreholes from a horizontal parent wellbore as part of a new well completion. Still further, the jetting hose may take advantage of the entire I.D. of the production casing. Further yet, the reservoir engineer or field operator may analyze geo-mechanical properties of a subject reservoir, and then design a fracture network emanating from a customized configuration of directionally-drilled lateral boreholes.

[303] The hydraulic jetting of lateral boreholes may be conducted to enhance fracture and acidization operations during completion. As noted, in a fracturing operation, fluid is injected into the formation at pressures sufficient to separate or part the rock matrix. In contrast, in an acidization treatment, an acid solution is pumped at bottom-hole pressures less than the pressure required to break down, or fracture, a given pay zone. (In an acid frac, however,

pump pressure intentionally exceeds formation parting pressure.) Examples where the pre-stimulation jetting of lateral boreholes may be beneficial include:

(a) prior to hydraulic fracturing (or prior to acid fracturing) in order to help confine fracture (or fracture network) propagation within a pay zone and to develop fracture (network) lengths a significant distance from the parent wellbore before any boundary beds are ruptured, or before any cross-stage fracturing can occur; and

(b) using lateral boreholes to place stimulation from a matrix acid treatment far beyond the near-wellbore area before the acid can be "spent," and before pumping pressures approach the formation parting pressure.

[304] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to pre-determine a path for the jetting of lateral boreholes. Such boreholes may be controlled in terms of length, direction or even shape. For example, a curved borehole or each "cluster" of curved boreholes may be intentionally formed to further increase SRV exposure of the formation **3** to the wellbore **4c**. Wellbores may optionally be formed in corkscrew patterns to further expose the formation **3** to the wellbore **4c**.

[305] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to re-enter an existing wellbore that has been completed in an unconventional formation, and "re-frac" the wellbore by forming one or more lateral boreholes using hydraulic jetting technology. The hydraulic jetting process would use the hydraulic jetting assembly **50** of the present invention in any of its embodiments. There will be no need for a workover rig, a ball dropper / ball catcher, drillable seats or sliding sleeve assemblies.

CLAIMS

What is claimed is:

1. A downhole hydraulic jetting assembly for forming lateral bore holes within a subsurface formation from a parent wellbore, the parent wellbore having an inner diameter, and the jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to a tubing conveyance medium for running the assembly into the wellbore, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier being dimensioned to slidably receive the jetting hose;

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly; and

a whipstock member disposed proximate the lower end of the outer conduit, the whipstock member having an arcuate face;

wherein the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force, and then (ii) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed.

2. The downhole hydraulic jetting assembly of claim 1, wherein:

the translation force comprises a mechanical force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

3. The hydraulic jetting assembly of claim 2, wherein:

each prong of the outer conduit portion provides an inner chamber around the inner conduit portion;

a first of the inner chambers is configured to conduct the jetting fluid down the assembly;

a second of the inner chambers is configured to house the electrical wires, data cables, or both; and

at least third and fourth opposing inner chambers house each of the grippers.

4. The hydraulic jetting assembly of claim 3, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers as the grippers engage and translate the jetting hose.

5. The hydraulic jetting assembly of claim 4, wherein:

the outer conduit portion has a star-shaped profile; and

each of the inner chambers has a near-triangular shaped profile.

6. The hydraulic jetting assembly of claim 4, wherein:

an external distance from end-to-end of opposing inner chambers is dimensioned to substantially centralize the internal tractor system in the parent wellbore; and

the jetting hose is at least 25 feet in length.

7. The downhole hydraulic jetting assembly of claim 1, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises:

a main control valve residing between the tubing conveyance medium and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit.

8. The downhole hydraulic jetting assembly of claim 7, further comprising:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slideably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus;

wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the tubing conveyance medium, through the main control valve, and against the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the tubing conveyance medium, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer

conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

9. The downhole hydraulic jetting assembly of claim 8, wherein:

the micro-annulus defines an elongated pressure chamber formed between the movable upper seal assembly and the jetting hose pack-off section;

the main control valve resides proximate an upper end of the outer conduit; and

the jetting hose carrier is dimensioned to hold the jetting hose from the upper sealing assembly down proximate to the jetting nozzle when the assembly is in a run-in position.

10. The hydraulic jetting assembly of claim 9, wherein the pressure regulator valve is configured such that:

(i) when pressure is released from the micro-annulus and fluids are injected through the main control valve in its first position, the upper seal assembly glides down an inner bore of the jetting hose carrier while still sealing, thereby pushing the jetting hose forward through the jetting hose carrier without buckling; and

(ii) when pressure is increased in the micro-annulus by the injection of fluids through the main control valve in its second position, increased fluid pressure against the upper seal assembly urges the jetting hose to glide back up the jetting hose carrier.

11. The hydraulic jetting assembly of claim 10, wherein:

the jetting hose is at least 25 feet in length;

a controlled release of fluids from the micro-annulus and through the pressure regulator valve regulates the jetting hose's rate of descent down-the-hole; and

a controlled intake of fluids through the regulator valve and into the micro-annulus regulates the jetting hose's rate of ascent up-the-hole.

12. The downhole hydraulic jetting assembly of claim 11, wherein:

the translation force comprises both the hydraulic force and a mechanical force; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

13. The hydraulic jetting assembly of claim 12, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers and translate the jetting hose into and out of the inner conduit portion as the grippers engage the jetting hose.

14. The hydraulic jetting assembly of claim 1, wherein the whipstock member is movable from a first run-in position to a second set and operating position, with the face of the whipstock member being configured to receive the nozzle and connected jetting hose in its set position as the jetting hose is advanced along the jetting hose carrier, and then direct the nozzle against the surrounding wellbore inner diameter to form a window.

15. The hydraulic jetting assembly of claim 14, wherein:

the wellbore is completed with a string of production casing;

the window is a casing exit;

the inner diameter is an inner diameter of the production casing; and

the face of the whipstock member generates a minimum bend radius for the jetting hose that is less than or equal to the inner diameter of the wellbore.

16. The hydraulic jetting assembly of claim 15, wherein the face of the whipstock member generates a bend radius for the jetting hose across the entire inner diameter of the production casing.

17. The hydraulic jetting assembly of claim 16, wherein:

the tubing conveyance medium comprises a string of coiled tubing;

the coiled tubing carries electrical wires, data cables, or combinations thereof along its length;

the internal system further comprises a battery pack for providing power to electrical components within the assembly, the battery pack residing at the proximal end of the jetting hose; and

the assembly further comprises a docking station located at an upper end of the external system configured to mate with the battery pack, the docking station having a processor and being in communication with an operator at the surface by means of the electrical wires, the data cables or both of the string of coiled tubing.

18. The hydraulic jetting assembly of claim 17, wherein the string of coiled tubing comprises a wall or a sheath that houses the electrical wires, the data cables, or both along its length, extending down to the docking station.

19. The hydraulic jetting assembly of claim 17, wherein the battery pack comprises:

a series of batteries located in an elongated, fluid-sealed housing; and

an end cap located at each of opposing ends of the battery pack, wherein the end caps are shaped to deflect jetting fluid during operation of the assembly.

20. The hydraulic jetting assembly of claim 19, wherein the docking station houses a micro-processor, a micro-transmitter, a micro-receiver, electrical current regulators, or combinations thereof.

21. The hydraulic jetting assembly of claim 20, wherein the docking station is configured to transfer: (1) power to the battery pack, said power either originating from generation at the

surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between an at least one geo-spatial chip housed at or near the nozzle and the operator at the surface.

22. The hydraulic jetting assembly of claim 21, further comprising:

at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle, the actuator wires being equi-distantly spaced about the circumference of the jetting hose at its distal end, and further being configured to contract in response to electrical current sent through the actuator wires, whereby differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle; and

wherein the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires, and thus control a geo-orientation of the nozzle for directional hydraulic boring.

23. The hydraulic jetting assembly of claim 22, wherein:

the geo-location signals of the at least one geo-spatial chip are indicative of both the location and orientation of the jetting nozzle, such signals being transmitted as data from the geo-spatial chip to the micro-receiver in the battery pack via the electrical wiring, the data cables, or both, bundled in the jetting hose;

contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives, thereby enabling geo-steering of the nozzle; and

wherein the actuator wires are fabricated from a material comprising nickel, titanium or a combination thereof.

24. The hydraulic jetting assembly of claim 23, wherein

the micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station; and

the docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

25. The hydraulic jetting assembly of claim 24, wherein the bending moment applied to the distal end of the jetting hose is configured to be controlled by an operator at the surface through the delivery of geo-location signals sent to a micro-transmitter in the docking station through (i) wireless signals sent downhole, (ii) the electrical wires bundled in the coiled tubing, or (iii) the data cables bundled in the coiled tubing, such geo-location signals adjusting the current being transmitted through the actuator wires.

26. The hydraulic jetting assembly of claim 24, wherein:

the electrical wiring along the jetting hose originates within housing or the end caps of the battery pack, and is conducted by elongated columnar supports connecting the battery pack to the jetting hose;

the columnar supports have a length tuned to separate the batteries from a fluid inlet at an upper end of the jetting hose; and

the columnar supports are spaced apart to provide an inlet flow area for the jetting fluid, after the jetting fluid is pumped down an annular region between the battery pack and the inner conduit.

27. The hydraulic jetting assembly of claim 16, wherein:

the upper seal assembly resides downstream of the battery pack; and

the jetting hose carrier comprises a continuous wiring chamber providing electrical connection from the docking station to electrical components below the whipstock member.

28. The hydraulic jetting assembly of claim 16, further comprising:

a tractor disposed below the whipstock member configured to convey the assembly along a horizontal or highly deviated portion of the wellbore;

a mud motor also disposed below the whipstock member for receiving hydraulic fluid from the string of coiled tubing, and converting it to electrical power; and

a logging tool also disposed below the whipstock member powered by electricity sourced from the mud motor, a power generation source located at the surface, or both.

29. The hydraulic jetting assembly of claim 28, further comprising:
a packer or a retrievable bridge plug located below the whipstock member.

30. The hydraulic jetting assembly of claim 28,wherein:
the translation force comprises a hydraulic force;
the jetting hose is at least 25 feet in length; and
the assembly further comprises:
a main control valve residing between the tubing conveyance system and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit.

31. The hydraulic jetting assembly of claim 30, wherein the logging tool comprises a gamma ray log, a casing collar locator, a gyroscopic orientation tool, or combinations thereof.

32. The hydraulic jetting assembly of claim 30, wherein the coiled tubing itself is a component of a bundled product that comprises continuous strands of electrical wire, data cables, or both, residing within a sheath.

33. The hydraulic jetting assembly of claim 32, wherein the string of coiled tubing comprises:
a coiled tubing crossover connection member connecting the coiled tubing to the main control valve, whereby electrical wiring and data cables within the sheath are sealed and transferred into a wiring chamber within the main control valve.

34. The hydraulic jetting assembly of claim 30, wherein the main control valve comprises:

a jetting fluid passage for receiving the jetting fluid in the first position, and a hydraulic fluid passage for receiving the hydraulic fluid in the second position, wherein each of the jetting fluid passage and the hydraulic fluid passage run longitudinally along the main control valve and parallel to each other;

a wiring conduit for housing the electrical wires, the data cables, or both;

a motor;

a passage cover pivot powered by the motor; and

a sealing passage cover moved by the passage cover pivot in order to selectively direct the jetting fluid and the hydraulic fluid into the appropriate passage in response to signals from the operator at the surface.

35. The downhole hydraulic jetting assembly of claim 34, wherein the passage cover pivot comprises a biasing mechanism responsive to fluid pressure, wherein fluids flow through the hydraulic fluid passage at a first fluid pressure, and the biasing mechanism is overcome to move the sealing passage cover to the hydraulic fluid passage at a second greater pressure, thereby causing jetting fluids to flow into the jetting fluid passage.

36. The downhole hydraulic jetting assembly of claim 34, further comprising:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slidably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus;

wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the tubing conveyance system, through the main control valve, and against the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the tubing conveyance system, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the outer conduit in its uncoiled state.

37. The downhole hydraulic jetting assembly of claim 36, wherein the jetting hose pack-off section comprises:

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a plurality of prongs forming a star-shaped profile;

an inner conduit portion defining a part of the jetting hose carrier for slidably receiving the jetting hose; and

a series of seals residing within the inner conduit portion of the jetting hose pack-off section, sealing the jetting hose from pressure from an upstream direction, followed by an adjacent series of seals sealing the jetting hose from pressure from a downstream direction, both sets of seals resting between an upstream seal stop and a downstream seal stop, thereby limiting travel of the seals via attachment to the exterior of the jetting hose, with the seals serving as a downstream seal of the micro-annulus.

38. The downhole hydraulic jetting assembly of claim 37, wherein:

each of the plurality of prongs of the outer conduit portion of the jetting hose pack-off section provides for an inner chamber, the inner chambers being spaced equi-distant around the inner conduit portion of the jetting hose pack-off section;

the external distance from end-to-end of the prongs is dimensioned to substantially centralize the jetting hose pack-off section within the surrounding production casing;

one of the inner chambers is used to conduct hydraulic fluid down to the pressure regulator valve; and

another of the inner chambers houses a wiring chamber.

39. The downhole hydraulic jetting assembly of claim 36, further comprising:

an upper swivel residing between the jetting hose pack-off section and the whipstock member, the upper swivel having an upper transition section that transitions from a star-shaped profile to a circular profile, and a lower bearing section having bearings configured to permit relative rotational movement between the transition section and the whipstock member, and having a centralized passage configured to receive and guide the jetting hose into the whipstock member; and

a lower swivel residing below the whipstock member, the lower swivel having an upper bearing section also having bearings that permit relative rotational movement between the whipstock member and any tools connected below the lower swivel; and

wherein:

the bearings sections of the upper and lower swivels permit incremental rotational re-orienting of the whipstock member while precluding the transmission of torque upstream of the upper swivel and downstream of the lower swivel; and

each of the upper and lower swivels comprises a sheath residing between the jetting hose carrier and the surrounding outer conduit, the sheath housing (1) the electrical wiring chamber; and (2) a hydraulic chamber that transports hydraulic fluid.

40. The downhole hydraulic jetting assembly of claim 39, wherein the upper section of the upper swivel comprises a through-opening through which the jetting hose exits to encounter the face of the whipstock.

41. The downhole hydraulic jetting assembly of claim 40, wherein each of the upper and lower swivels comprises:

an outer tubular body;

a middle tubular body;

an inner tubular body; and

inner and outer bearings making up the bearing sections.

42. The hydraulic jetting assembly of claim 1, further comprising:

a retrievable bridge plug or a packer disposed below the whipstock member.

43. A jetting hose carrier system, comprising:

an elongated inner conduit dimensioned to slidably receive a jetting hose and serving as a jetting hose carrier, wherein a micro-annulus is formed between the jetting hose and the surrounding inner conduit, with the micro-annulus being dimensioned to prevent the jetting hose from buckling;

an elongated outer conduit encompassing the inner conduit, wherein an annular region is formed between the inner conduit and the surrounding outer conduit, the outer conduit being dimensioned to be run into a string of production casing within a wellbore while accommodating stimulation treatments through the annular region;

a wiring chamber housing electrical wires, data cables, or both within the annular region between the inner and outer conduits and running the length of the outer conduit;

a fluid chamber formed within the annular region, the fluid chamber having a flow area equivalence of at least 0.75 in^2 pipe diameter; and

a fluid pressure regulator valve residing proximate a distal end of the inner conduit, the pressure regulator valve being configured to move fluids between the fluid chamber and the micro-annulus to effectuate movement of the jetting hose within the inner conduit.

44. The jetting hose carrier system of claim 43, further comprising:

an upper seal assembly residing at an upstream end of the jetting hose, the upper seal assembly comprising one or more seals fixedly attached to an outer diameter of the jetting hose, and with the upper seal assembly being slidably movable within the inner conduit and forming an upstream boundary of the micro-annulus;

a jetting hose pack-off system comprising a series of stationary seals at a downstream end of the inner conduit, the stationary seals forming a downstream boundary of the micro-annulus;

and whereby the fluid pressure regulator valve is arranged so that hydraulic fluid can be injected into the micro-annulus above the jet hose pack-off system to propel the jetting hose in an upstream direction, and the hydraulic fluid can then be released from the micro-annulus through the pressure regulator valve, thereby controlling advancement of the jetting hose in a downstream direction.

45. A downhole hydraulic jetting assembly for forming lateral bore holes within a subsurface formation from an existing wellbore, the existing wellbore having an inner diameter, and the jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to a tubing conveyance system for running the assembly into the production casing, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier slidably receiving the jetting hose;

a micro-annulus formed between the jetting house and the surrounding jetting hose carrier, the micro-annulus being sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly; and

a whipstock member disposed below the lower end of the outer conduit, the whipstock member having an arcuate face;

wherein:

the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting forming a lateral borehole into the subsurface formation, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed by applying the translation force in a second opposite direction; and

the jetting nozzle comprises:

a rotor body having one or more fluid discharge ports for delivering jetting fluid from the jetting hose;

a stator body; and

wire-wrapped stator poles configured to induce an electromagnetic field about the rotor body upon receipt of electrical current, which thereby induces rotation of the rotor body at a rotational speed corresponding to an electrical current feed.

46. The downhole hydraulic jetting assembly of claim 45, wherein the electrical current feed is delivered through at least three longitudinally oriented electrically conductive power wires disposed equi-distantly about the jetting hose.

47. The downhole hydraulic jetting assembly of claim 46, wherein at least a distal portion of the electrically conductive power wires are fabricated from a material that, upon electrical excitement, will contract in proportion to the respective current feeds received therein such that differentiation of current feeds through the three power wires will cause a proportional contraction of the respective power wires, thus inducing a bending moment at the distal end of the jetting hose.

48. The downhole hydraulic jetting assembly of claim 47, wherein the electrically conductive power wires are fabricated from a conductive material comprising nickel, titanium or a combination thereof.

49. The downhole hydraulic jetting assembly of claim 47, wherein the jetting nozzle further comprises:

one or more geo-spatial chips located proximate the stator body; and

wherein the one or more geo-spatial chips is configured to determine orientation of the nozzle, and transmit real-time geo-location data through electrical wires or data cables to a wireless micro-transmitter upstream of the micro-annulus.

50. The downhole hydraulic jetting assembly of claim 49, further comprising:

a coiled tubing string for conveying the external system and the connected internal system from a surface into the wellbore; and

a battery pack associated with the internal system configured to provide the electrical feed;

and wherein:

the micro-transmitter resides proximate the battery pack;

the external system further comprises a docking station configured to dock with the battery pack and to communicate with the micro-transmitter; and

the geo-location data is transmitted wirelessly by the micro-transmitter to a micro-receiver within the docking station, then relayed to the surface through electrical wires or through data cables provided along the coiled tubing string, or to the surface wirelessly.

51. The downhole hydraulic jetting assembly of claim 50, wherein the geo-location data is processed (i) through a micro-processor located in the internal system's battery pack, (ii) through a microprocessor located in the external system's docking station, or (iii) in a surface control system.

52. The downhole hydraulic jetting assembly of claim 51, wherein, in response to receipt of geo-location data at the surface, the assembly is configured to permit the operator or surface control system to send instructions to the docking station downhole to send new rates of electrical current feed to the power wires to induce bending moments toward the distal end of the jetting hose hosting the jetting nozzle, thereby permitting the operator to:

vary the orientation and inclination of the jetting nozzle, in real time, as it is discharges jetting fluid and generates a path of a lateral borehole; and

vary rotational speed of the jetting nozzle;

thereby achieving a desired lateral borehole path and penetration rate within a host pay zone.

53. The downhole hydraulic jetting assembly of claim 49, wherein the geo-location data is sent to a control system at the surface that is configured to process the geo-location data and, in response, generate signals to adjust the electrical current feed to the power wires according to a pre-programmed geo-trajectory of a lateral borehole.

54. The downhole hydraulic jetting assembly of claim 51, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 25 feet in length;

the assembly further comprises:

a main control valve residing between the tubing conveyance system and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit;

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slidably receiving the jetting hose; and

a fluid intake funnel located at an upstream end of the jetting hose, the fluid intake funnel being configured to receive jetting fluids into the jetting hose when the main control valve is in its first position; and

wherein the micro-annulus is bounded at its upstream end by an interface of seals of the upper seal assembly, these upstream seals being movable within the inner conduit, and at its downstream end by seals of the jetting hose pack-off section, these downstream seals remaining generally stationary relative to the wellbore during operation.

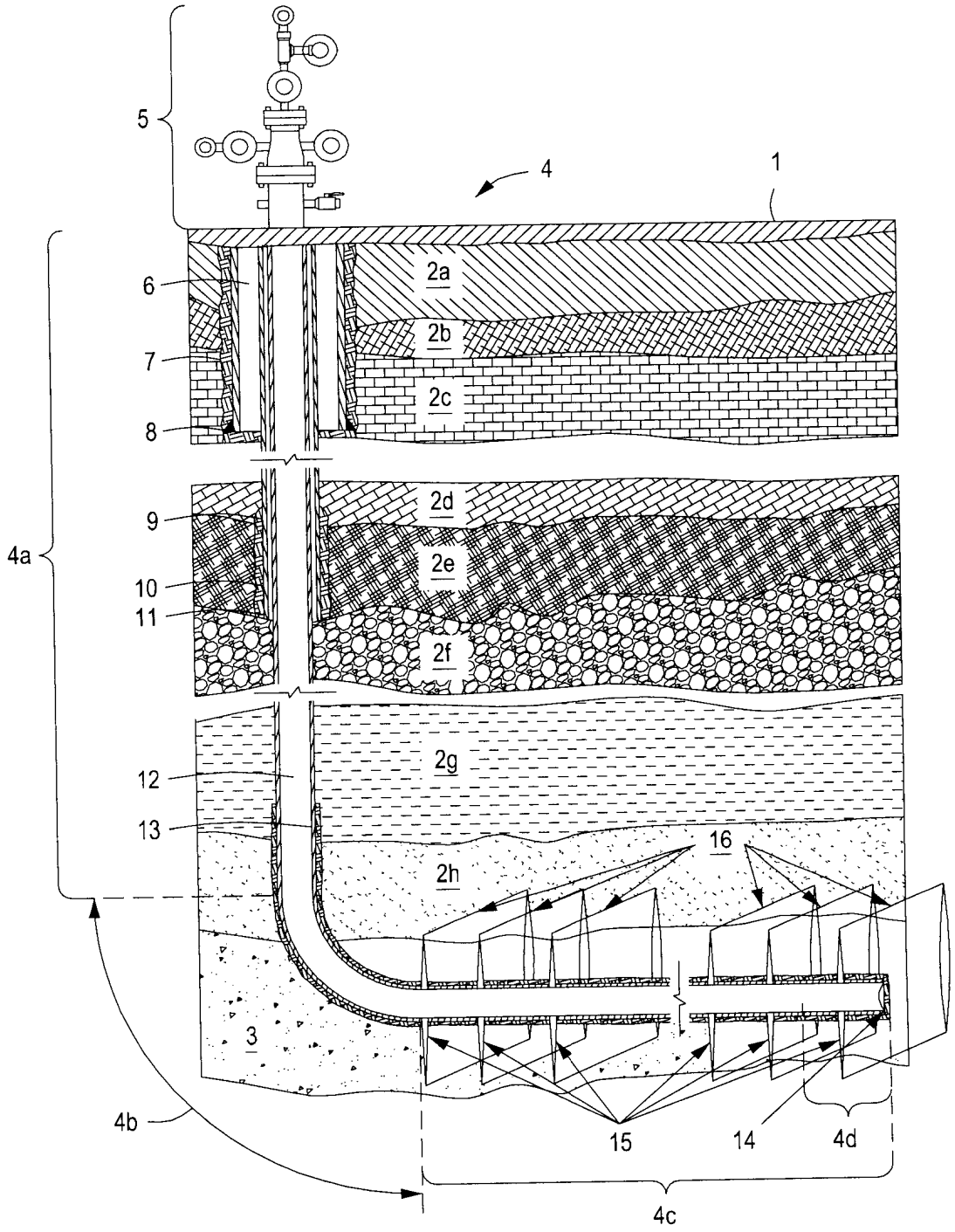


FIG. 1A

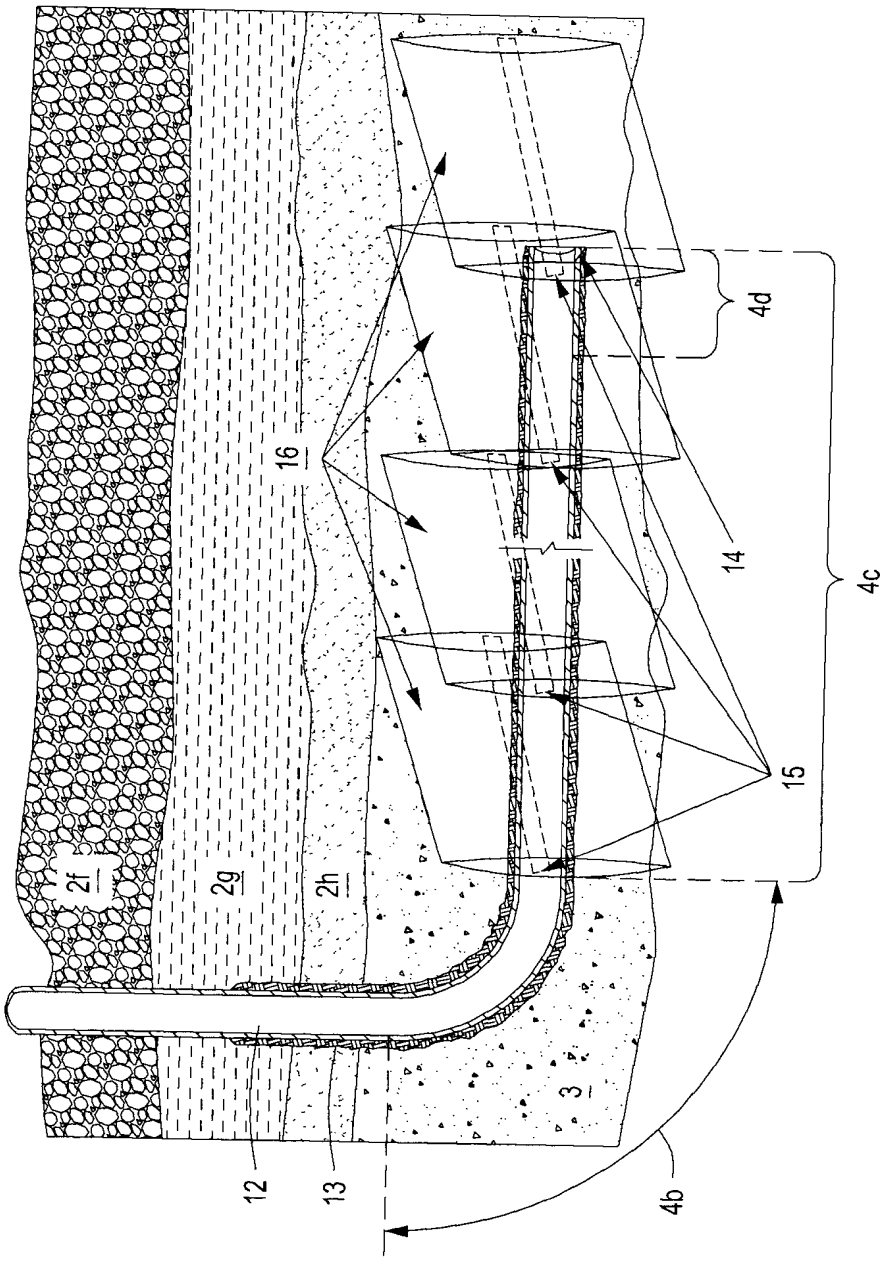


FIG. 1B

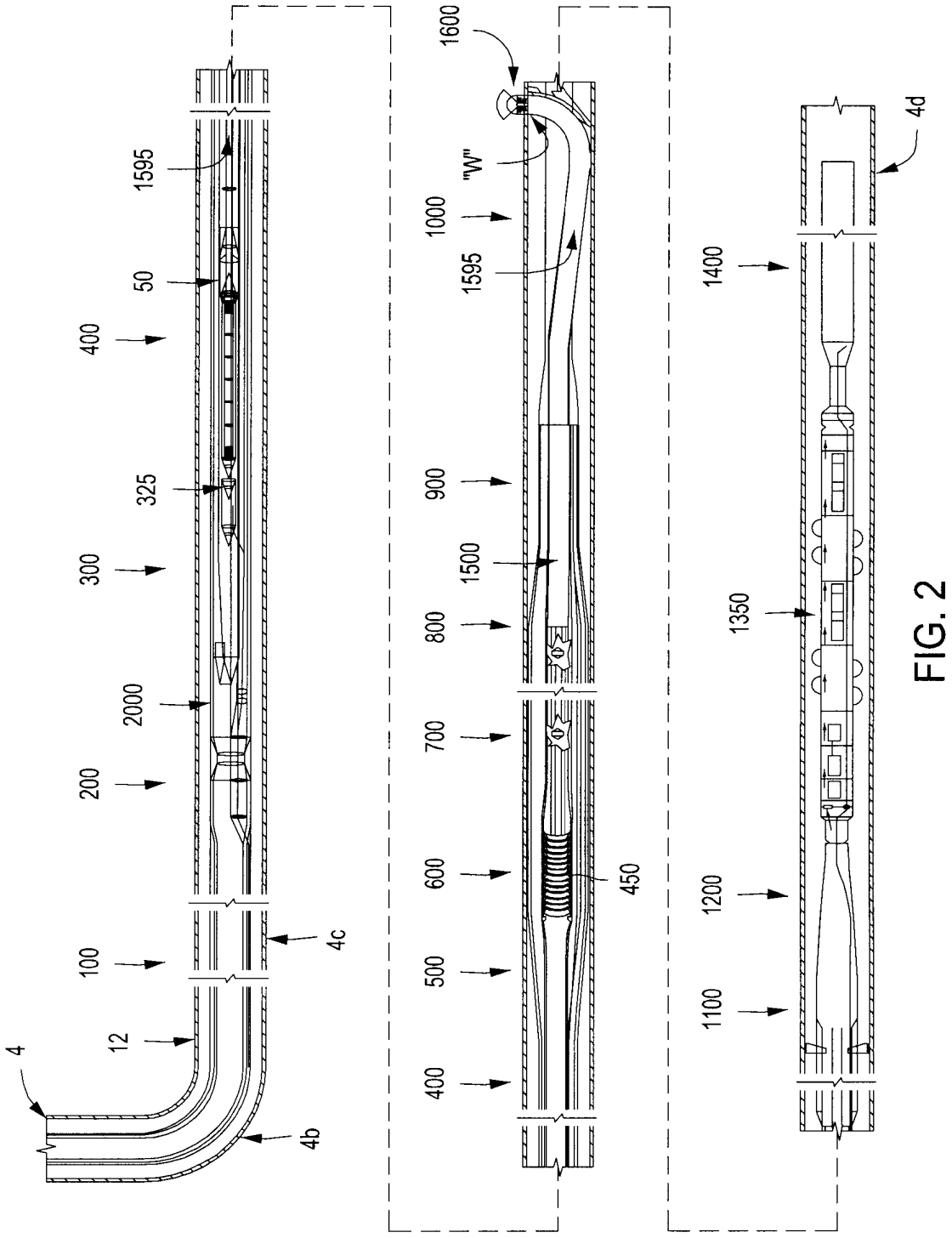

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FIG. 2

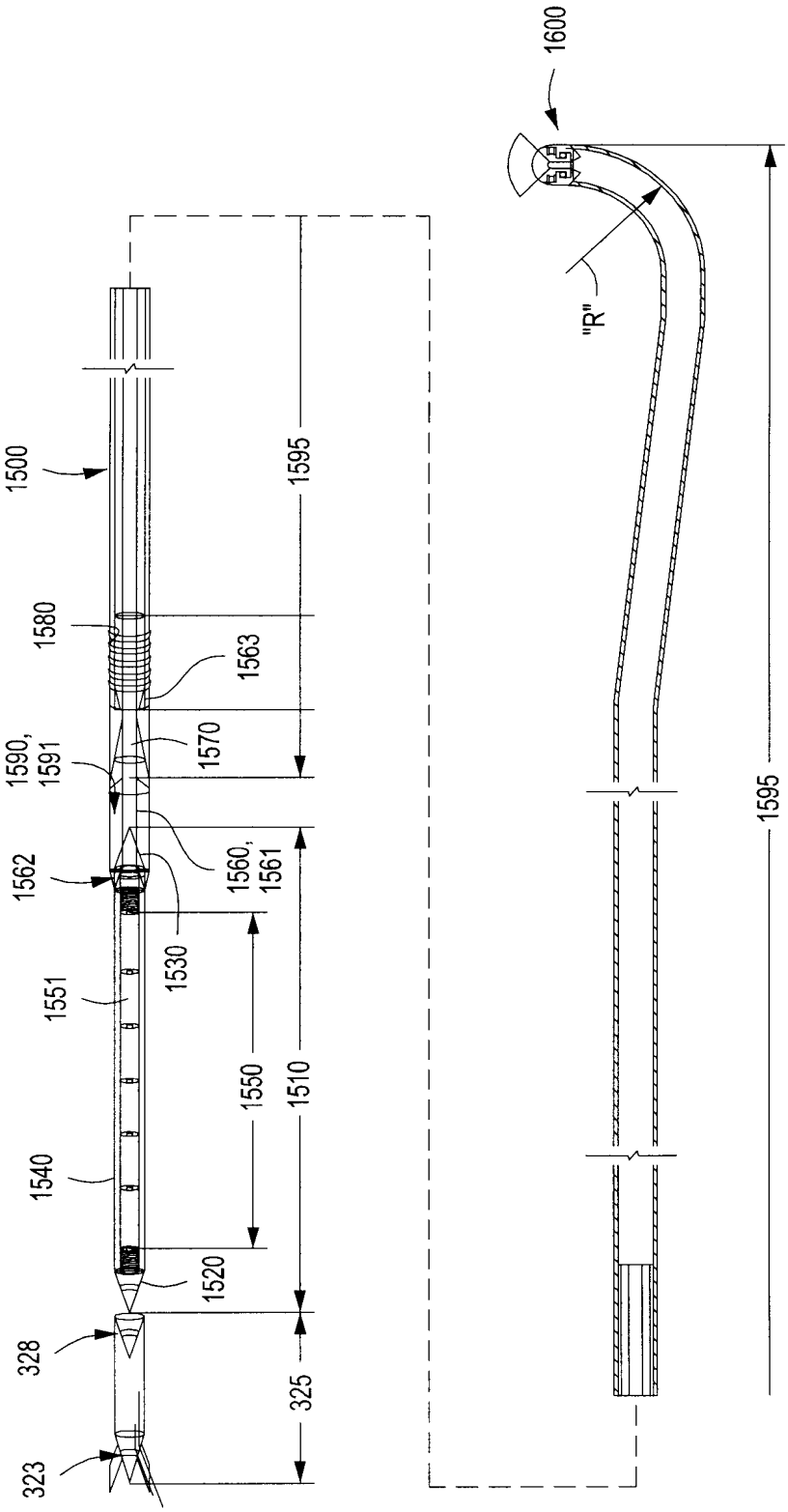

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FIG. 3

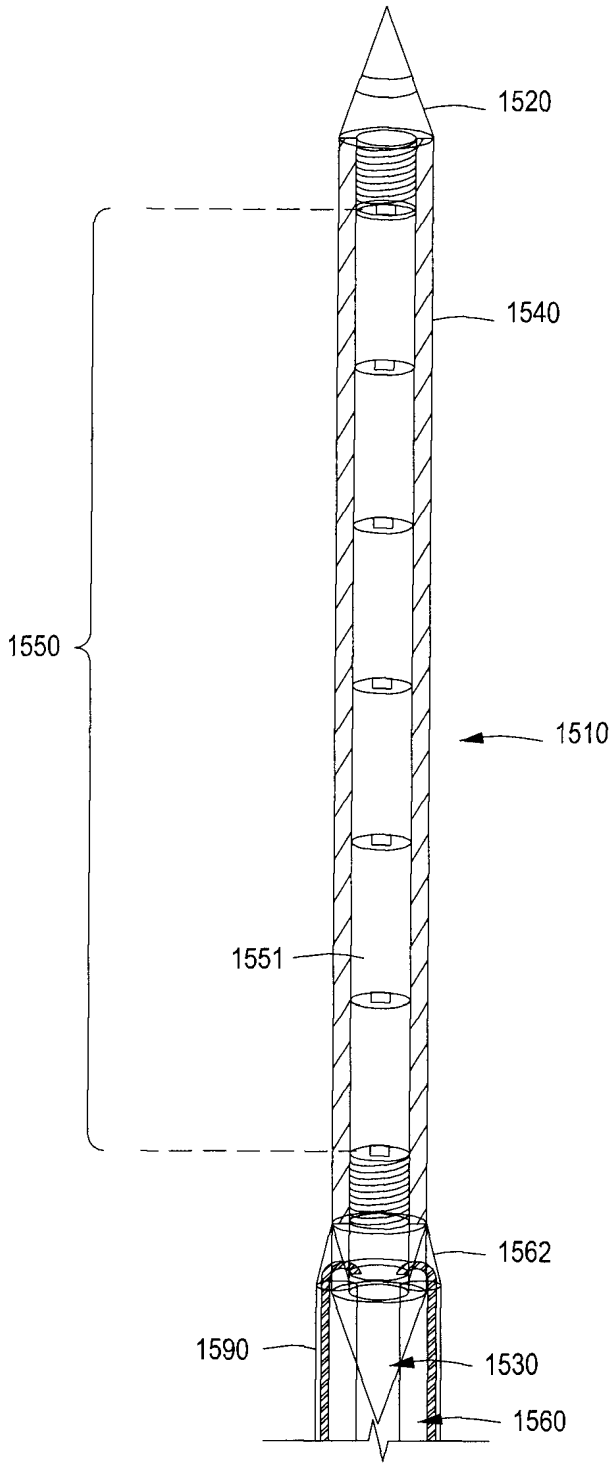


FIG. 3A

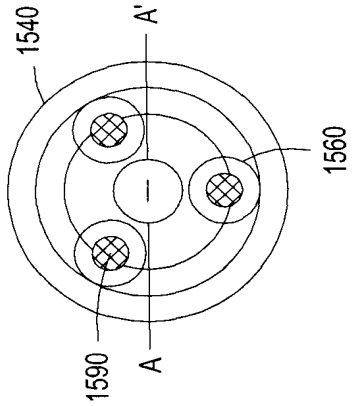


FIG. 3B-1a

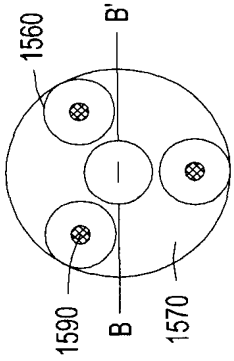


FIG. 3B-1b

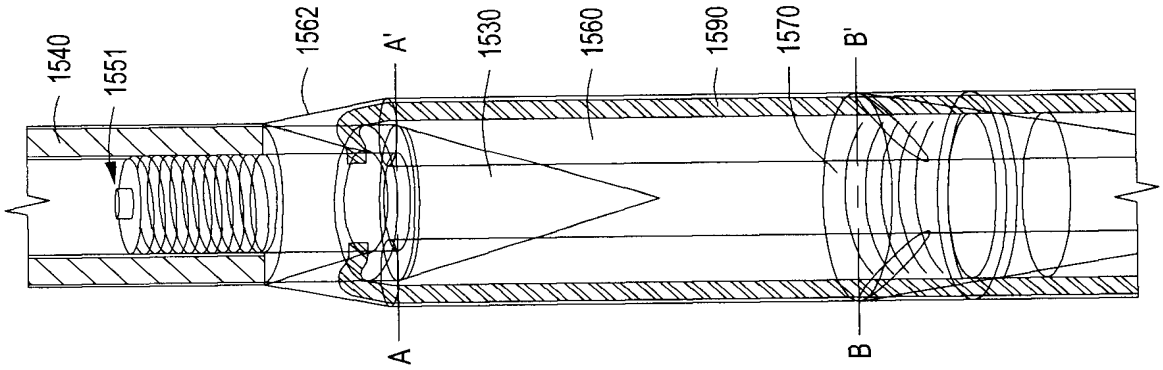


FIG. 3B-1

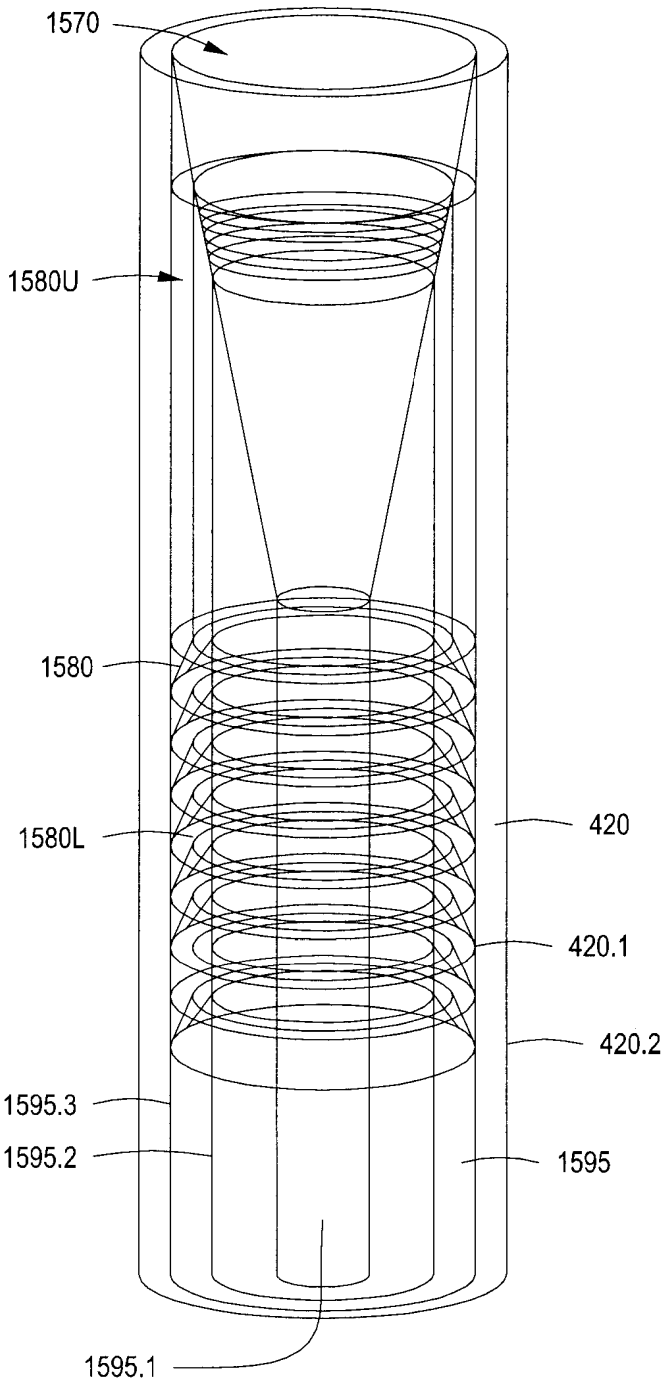


FIG. 3C

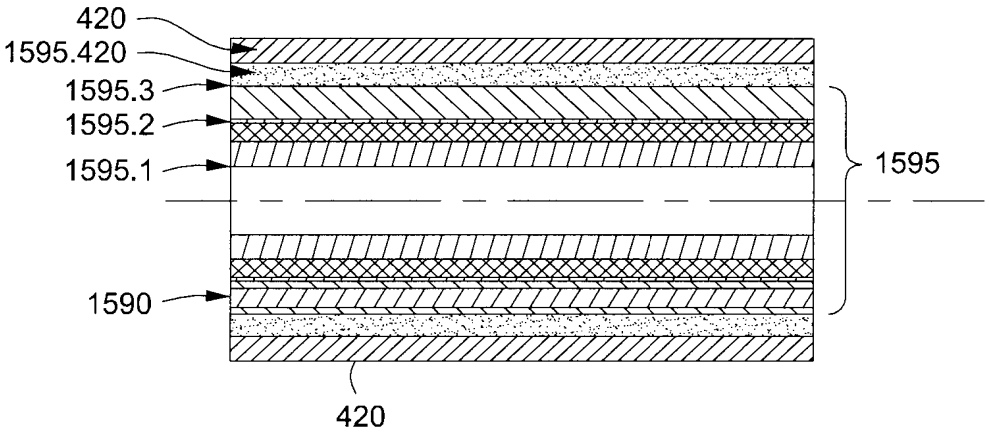


FIG. 3D-1

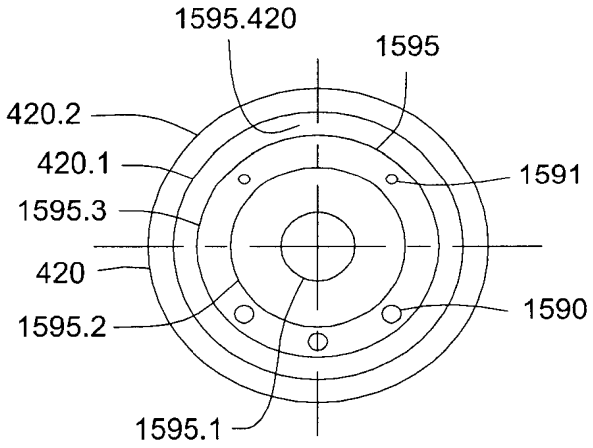


FIG. 3D-1a

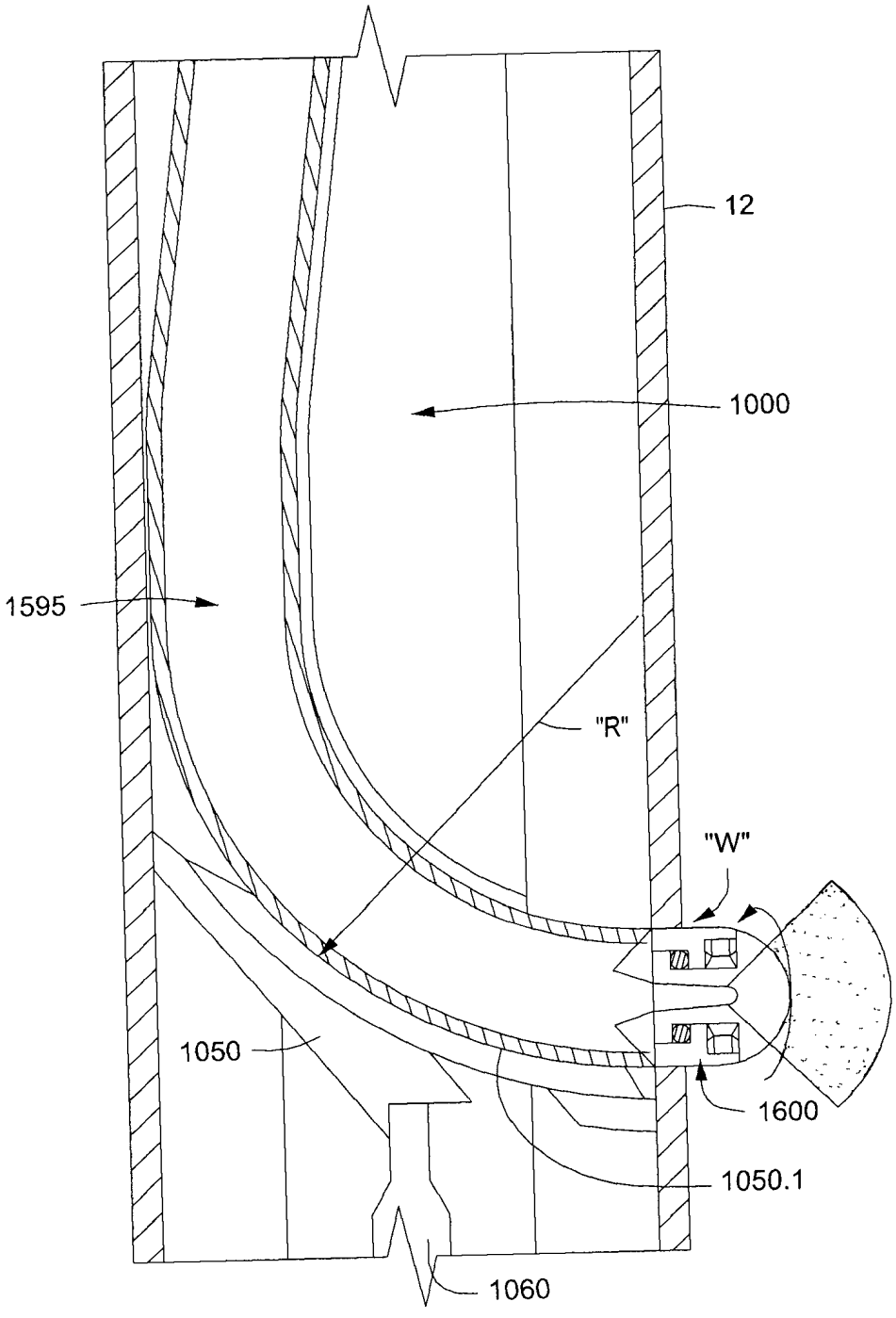


FIG. 3E

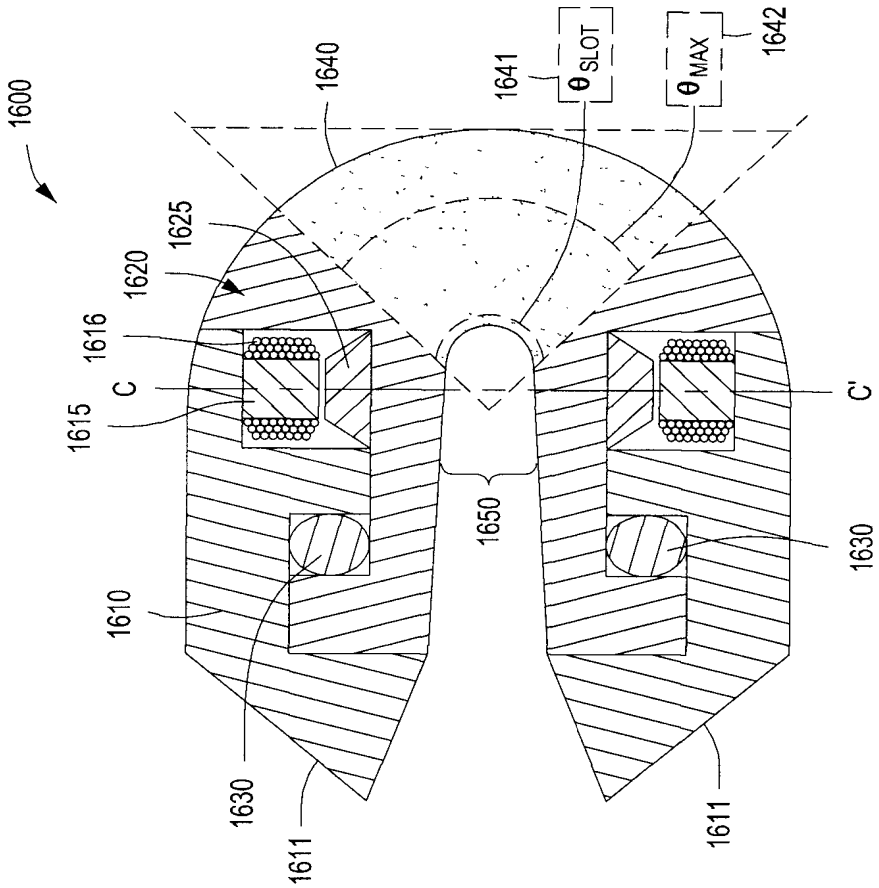


FIG. 3F-1b

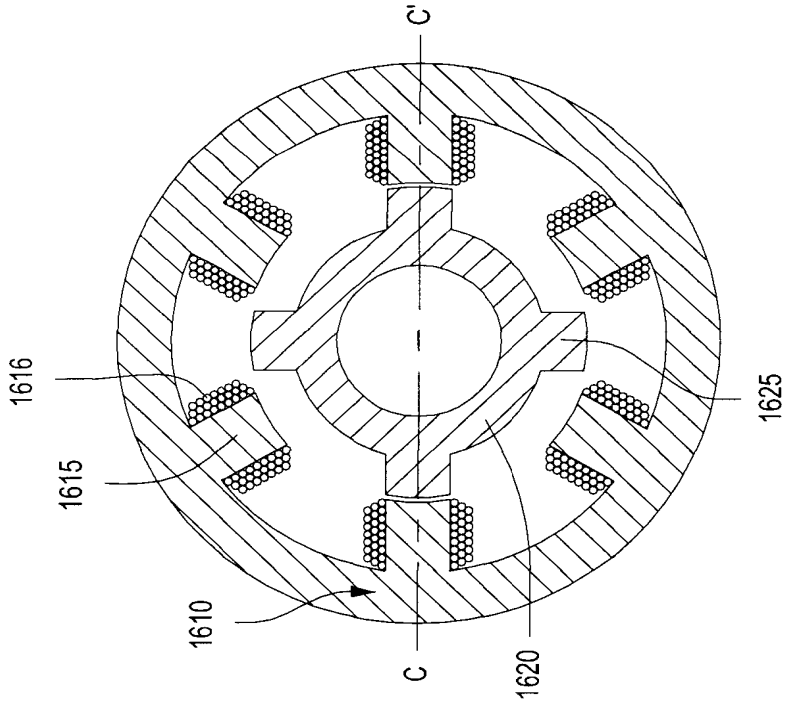


FIG. 3F-1a

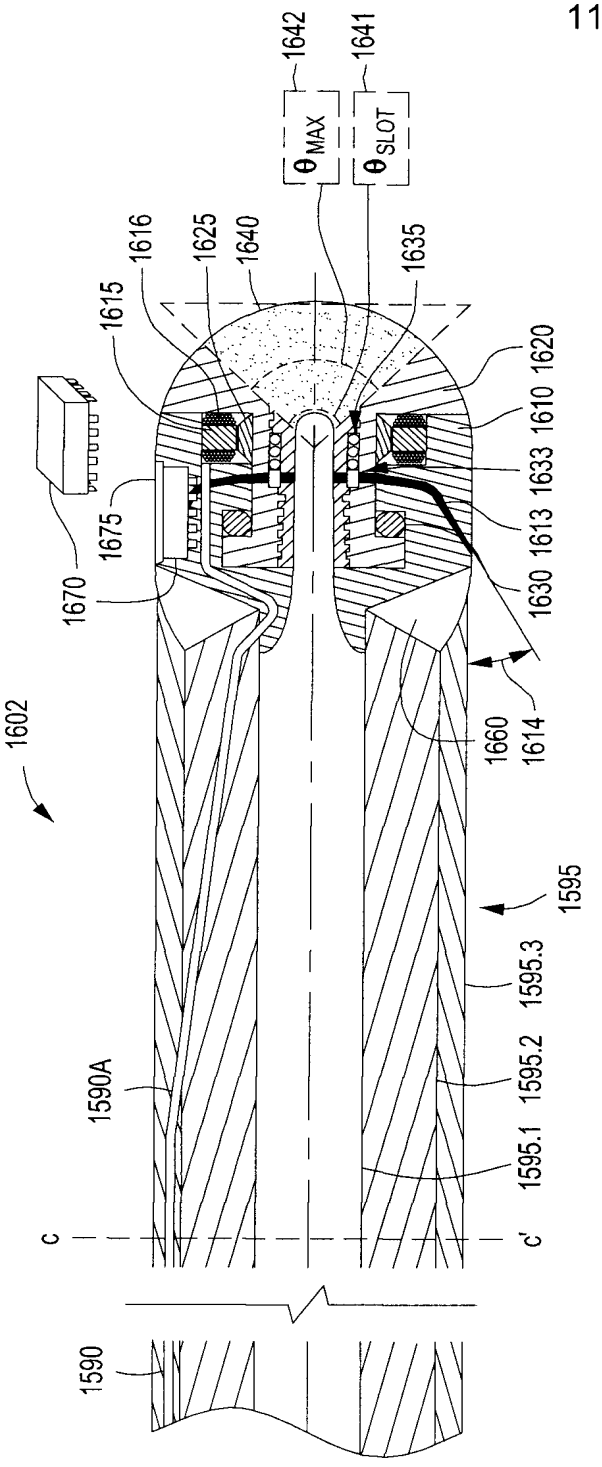


FIG. 3F-1c

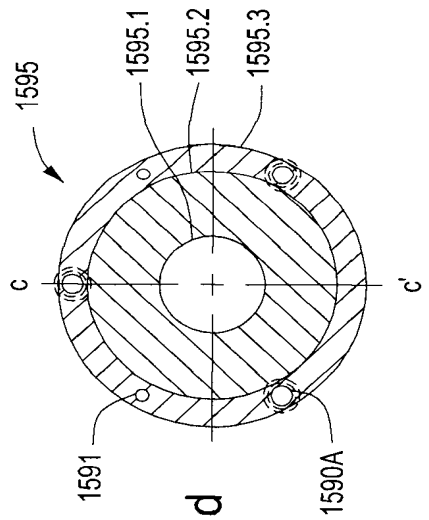


FIG. 3F-1d

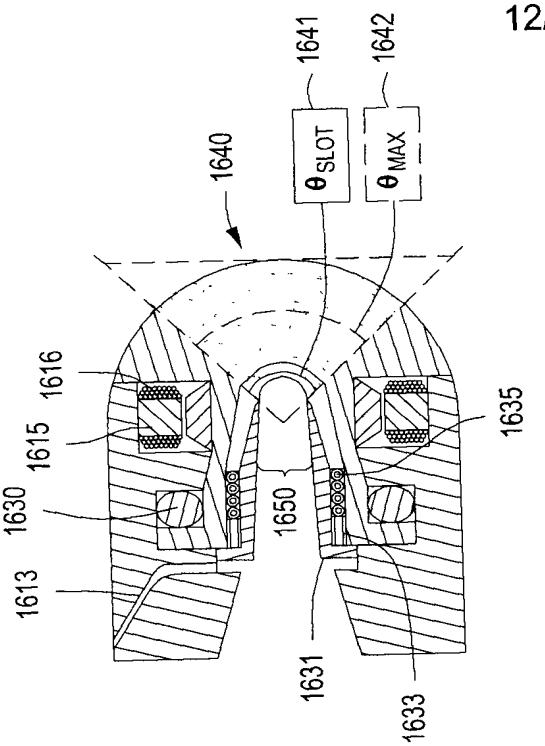


FIG. 3F-2b

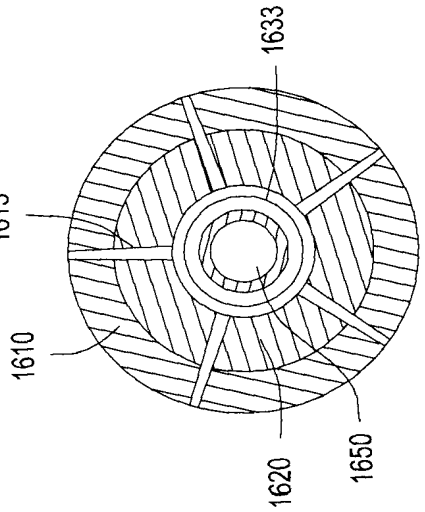


FIG. 3F-2c

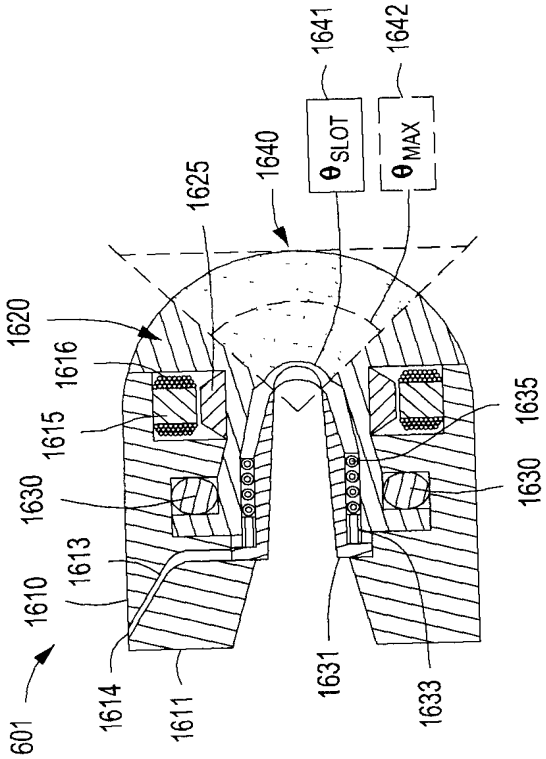


FIG. 3F-2a

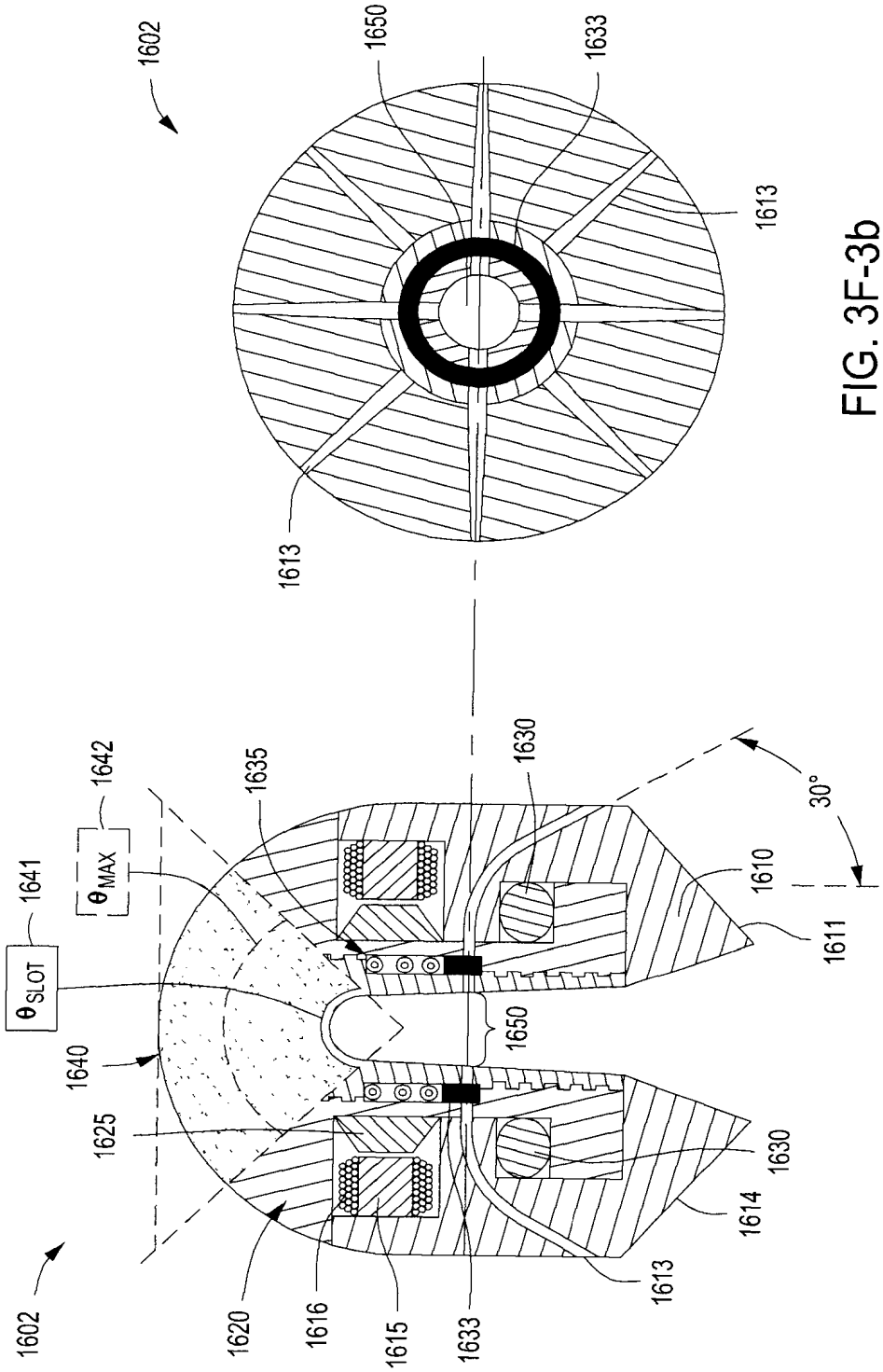


FIG. 3F-3b

FIG. 3F-3a

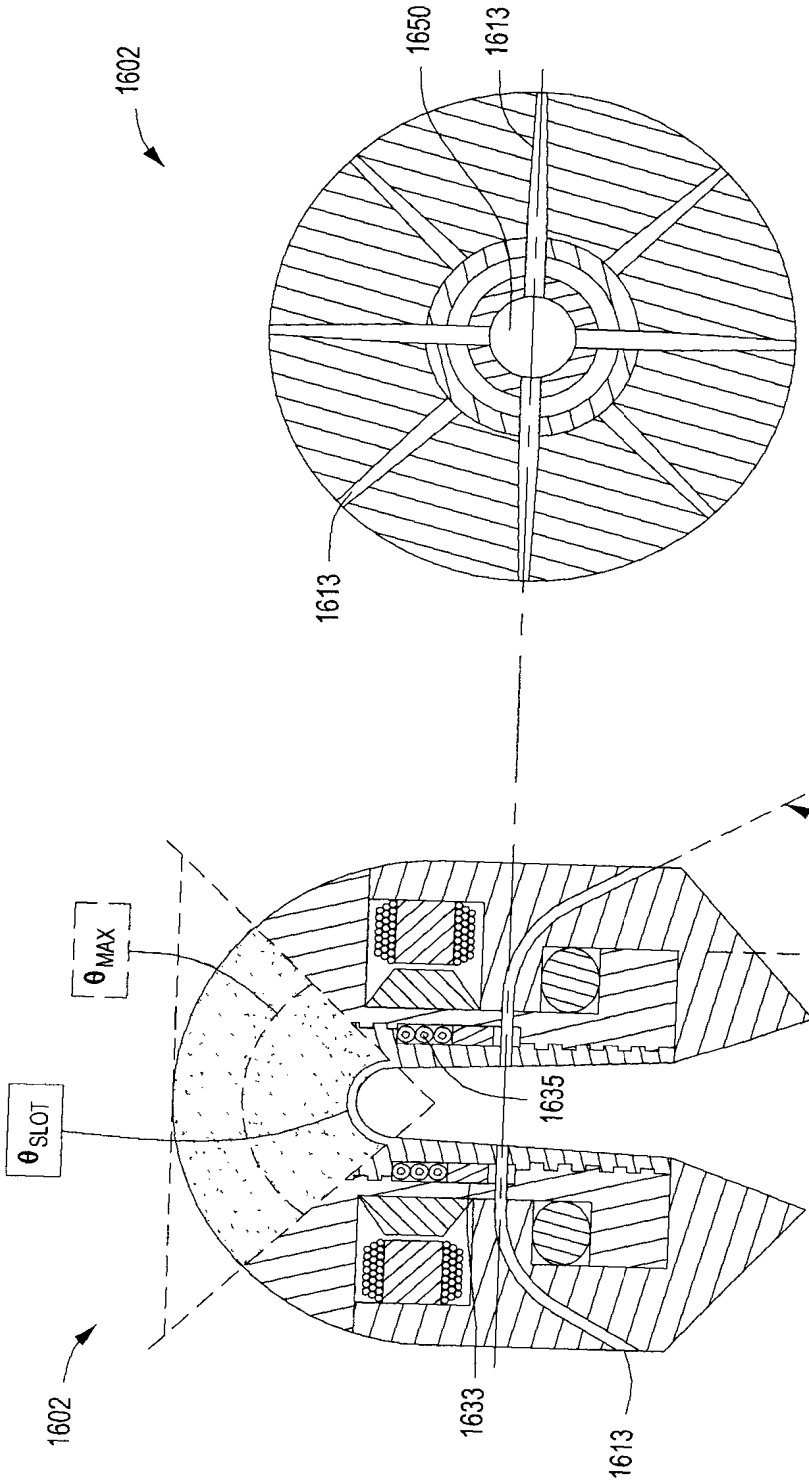


FIG. 3F-3d

FIG. 3F-3c

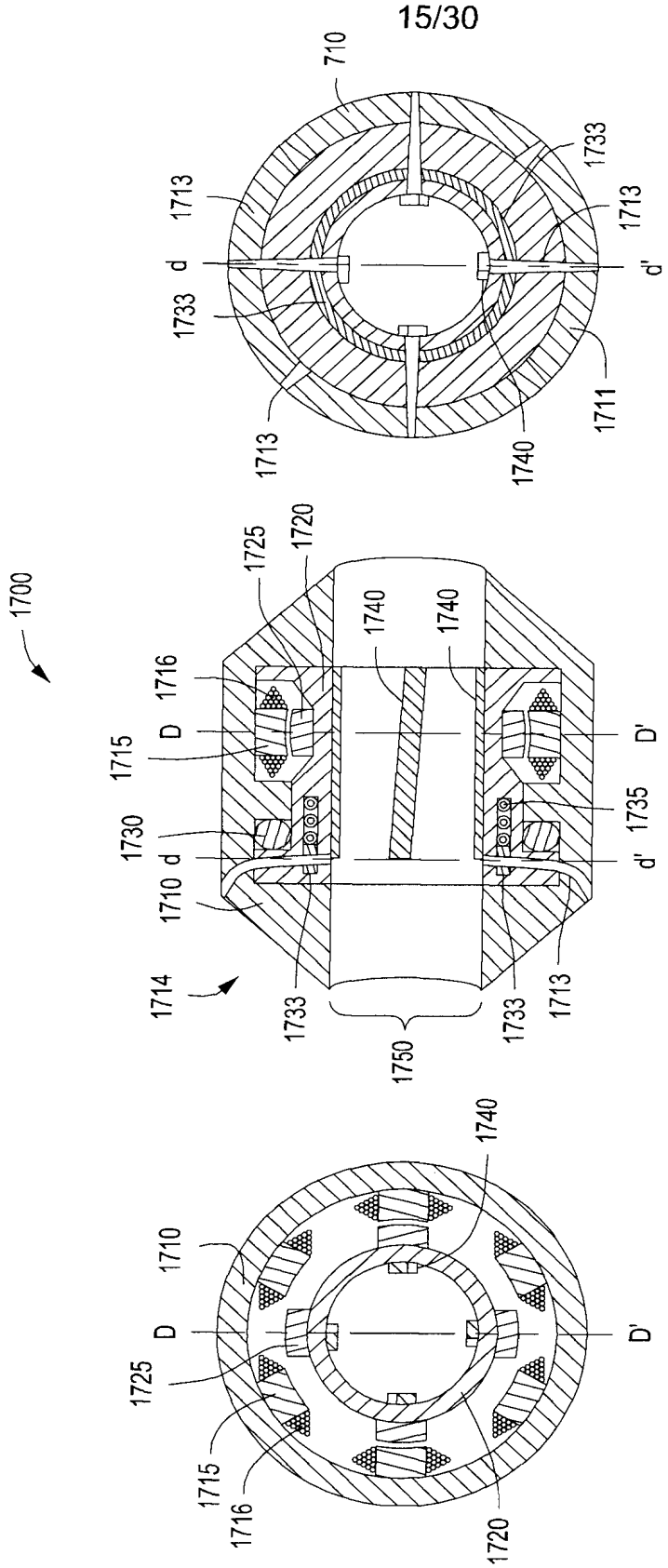


FIG. 3G-1c

FIG. 3G-1b

FIG. 3G-1a

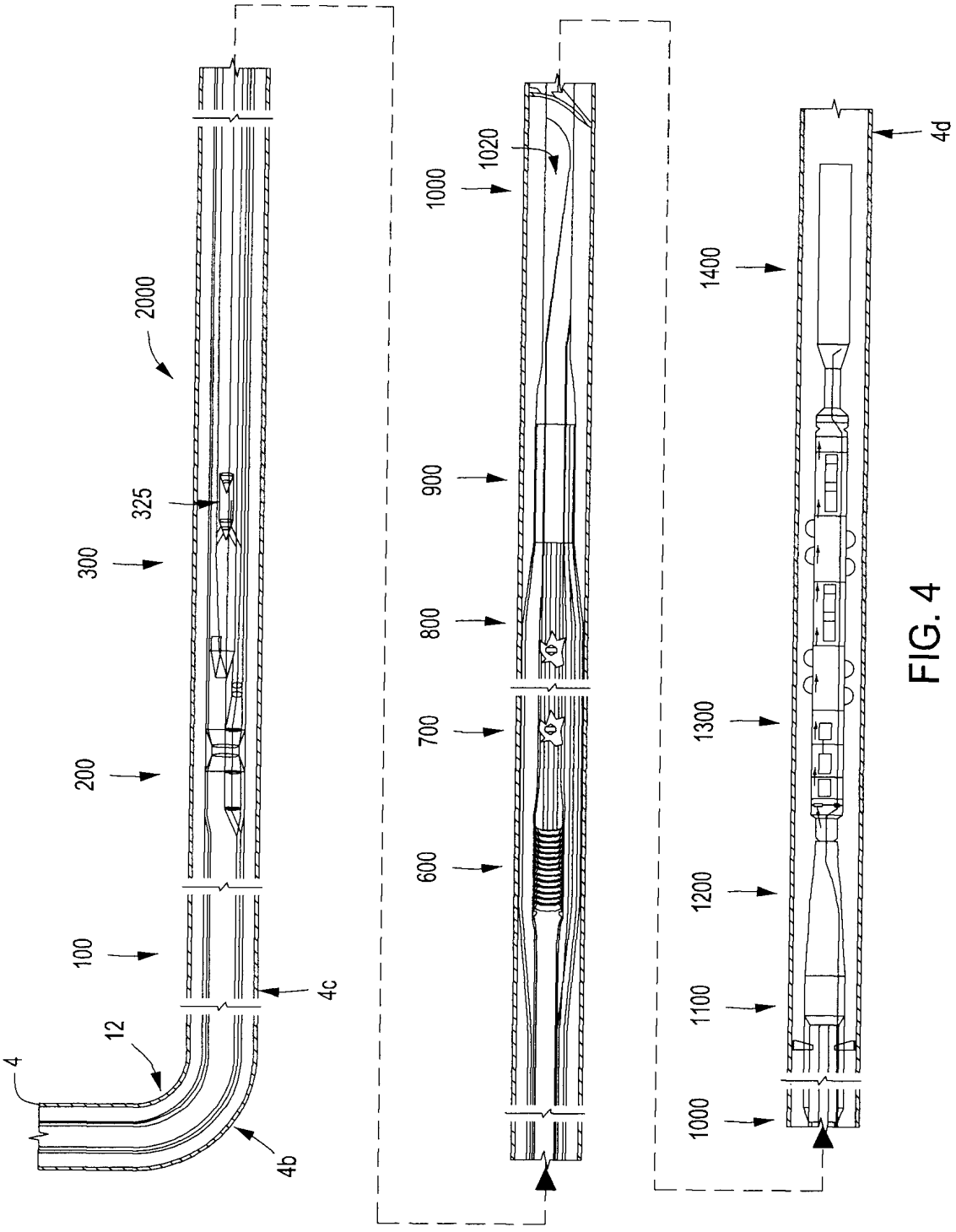

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FIG. 4

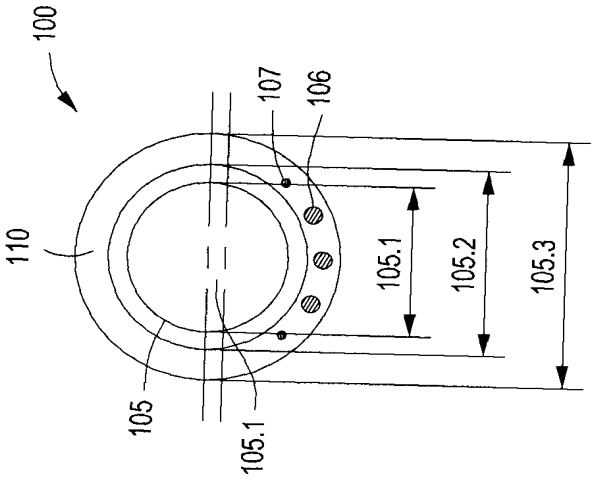


FIG. 4A-1a

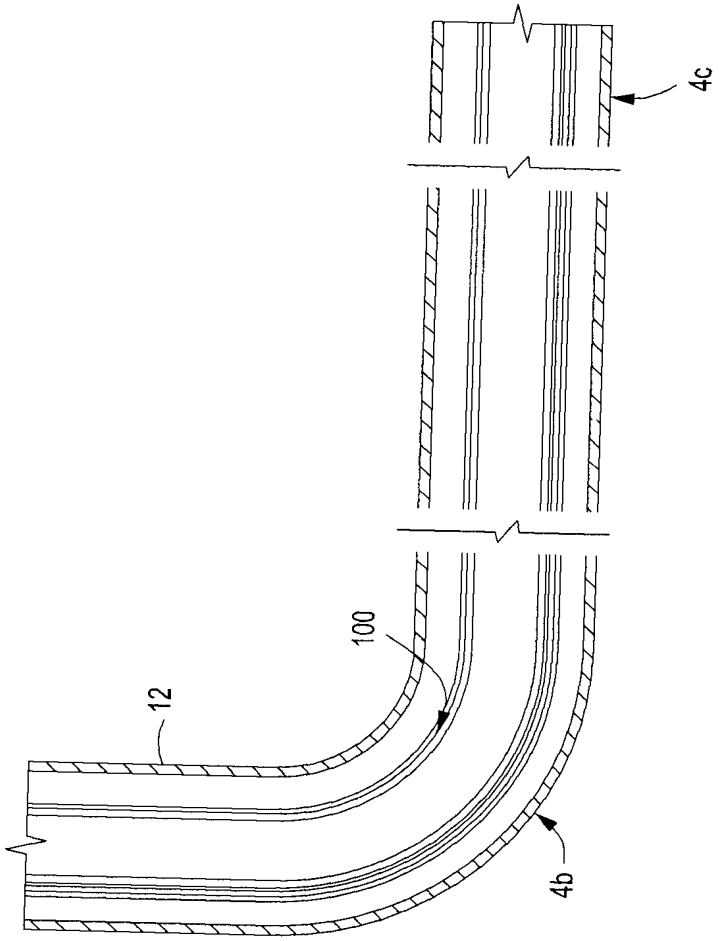


FIG. 4A-1

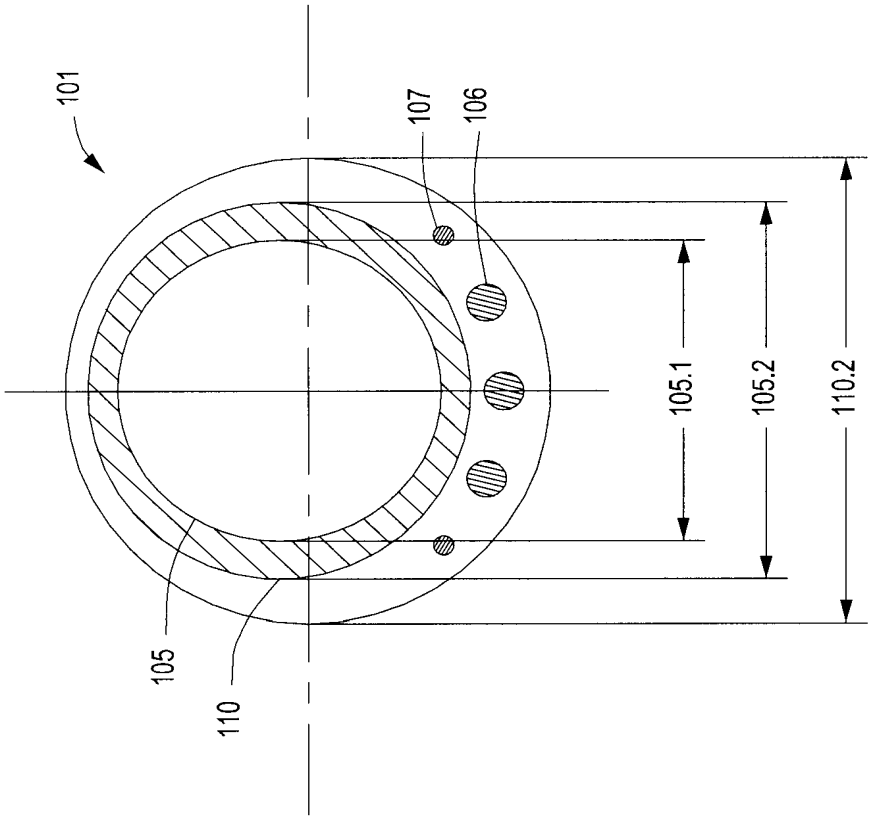


FIG. 4A-2

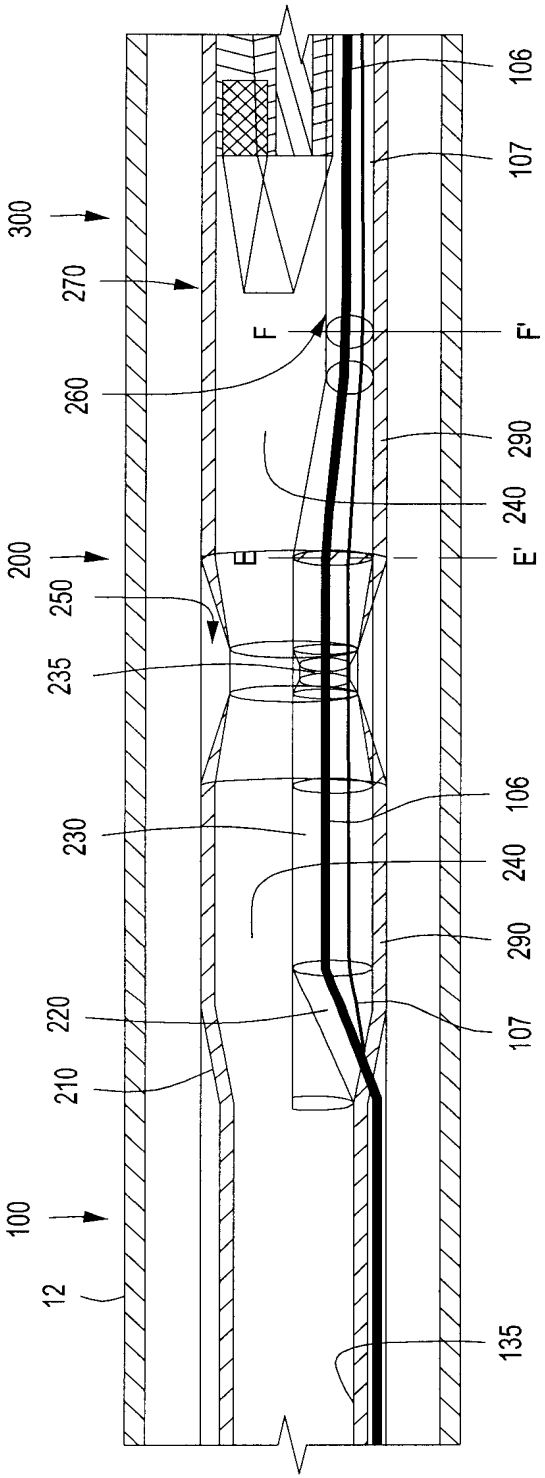


FIG. 4B-1

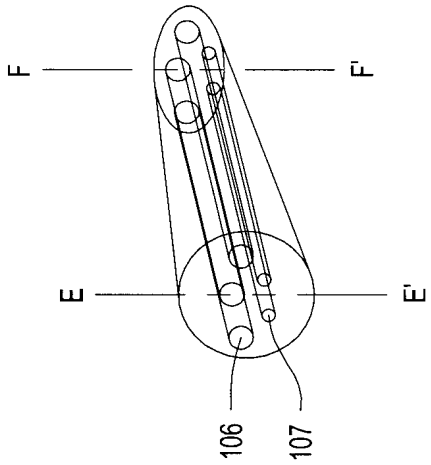


FIG. 4B-1a

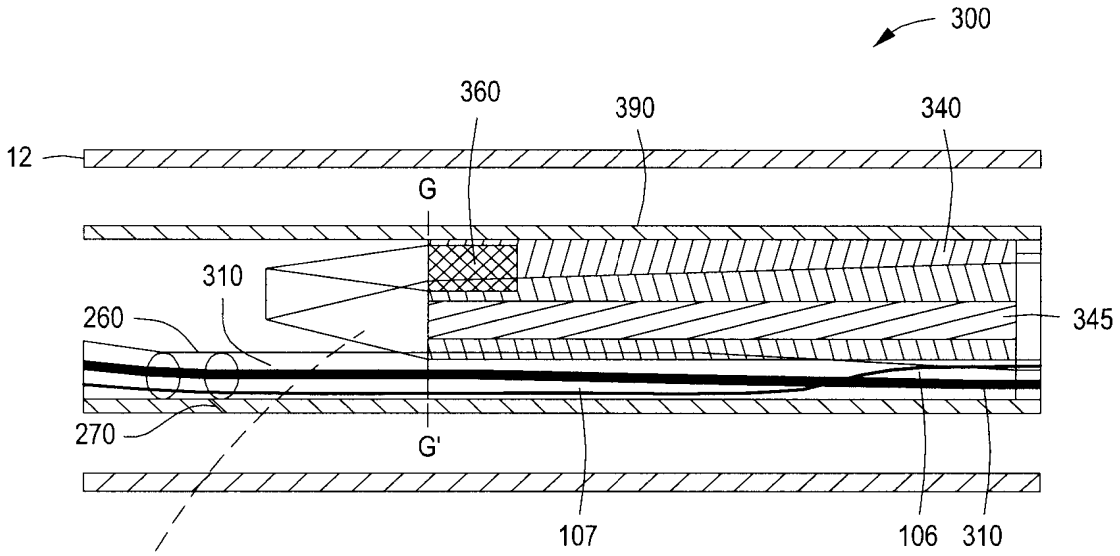


FIG. 4C-1

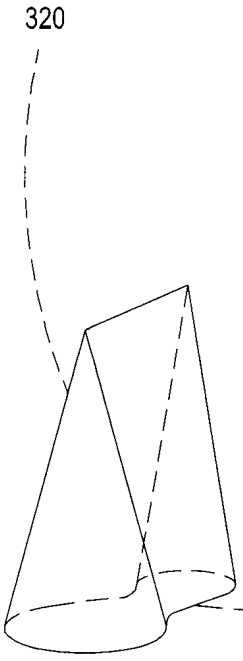


FIG. 4C-1b

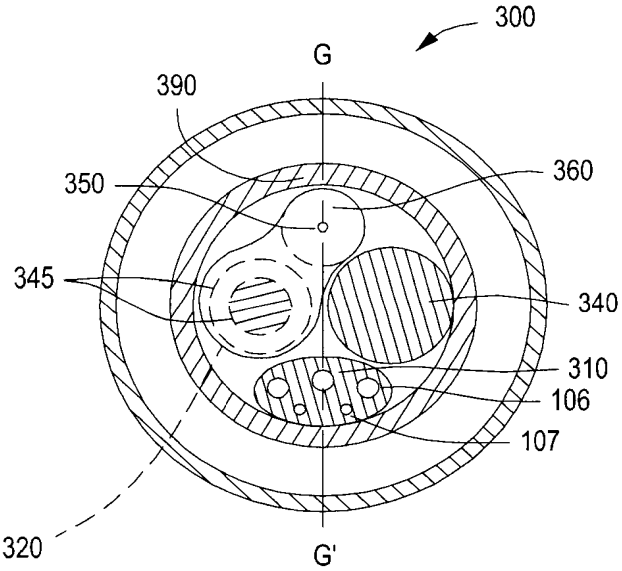


FIG. 4C-1a

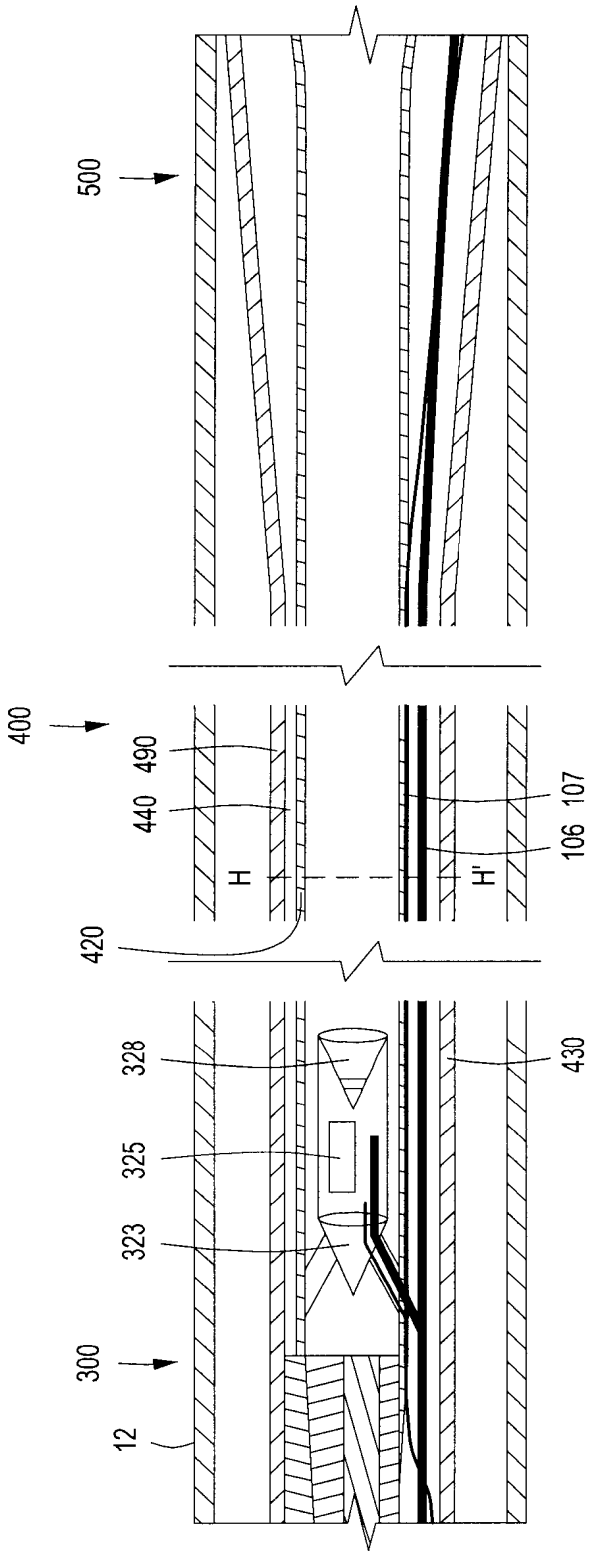


FIG. 4D-1

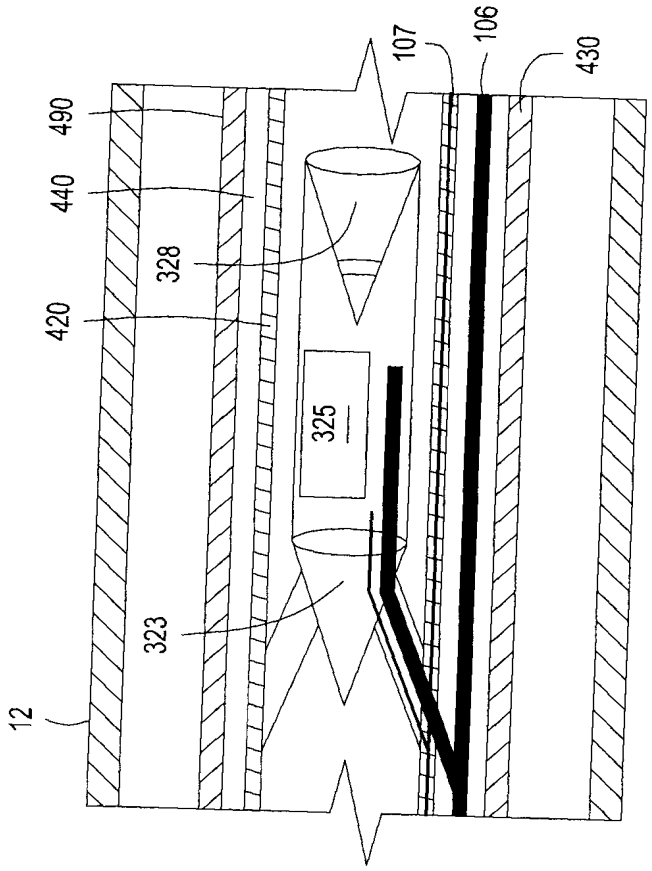


FIG. 4D-1b

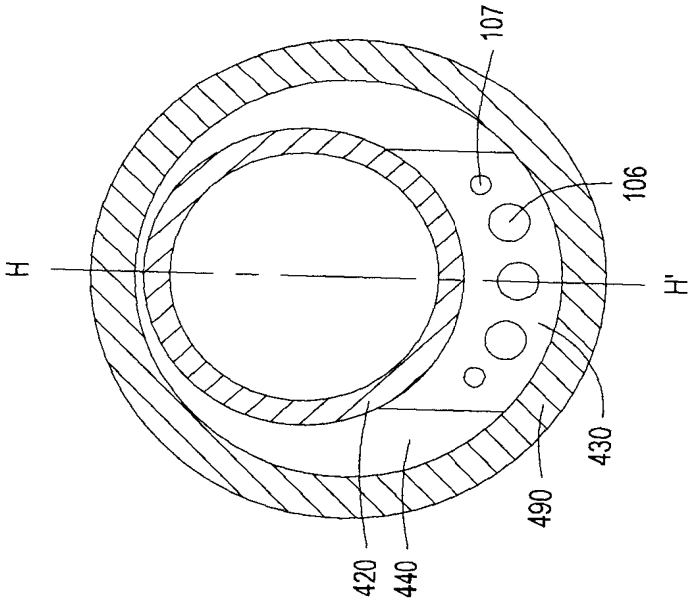


FIG. 4D-1a

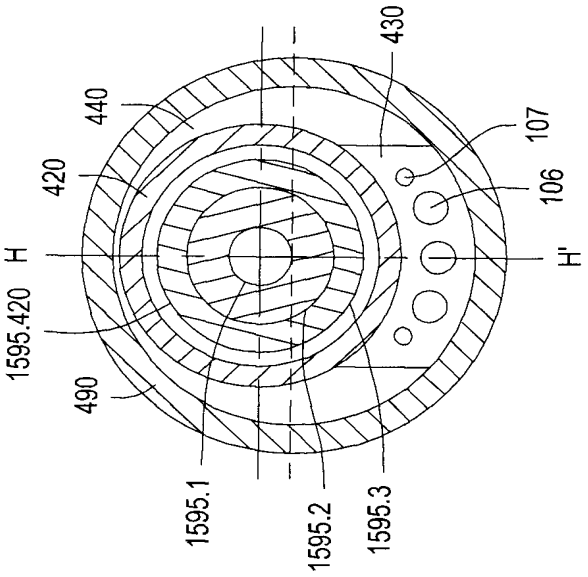


FIG. 4D-2a

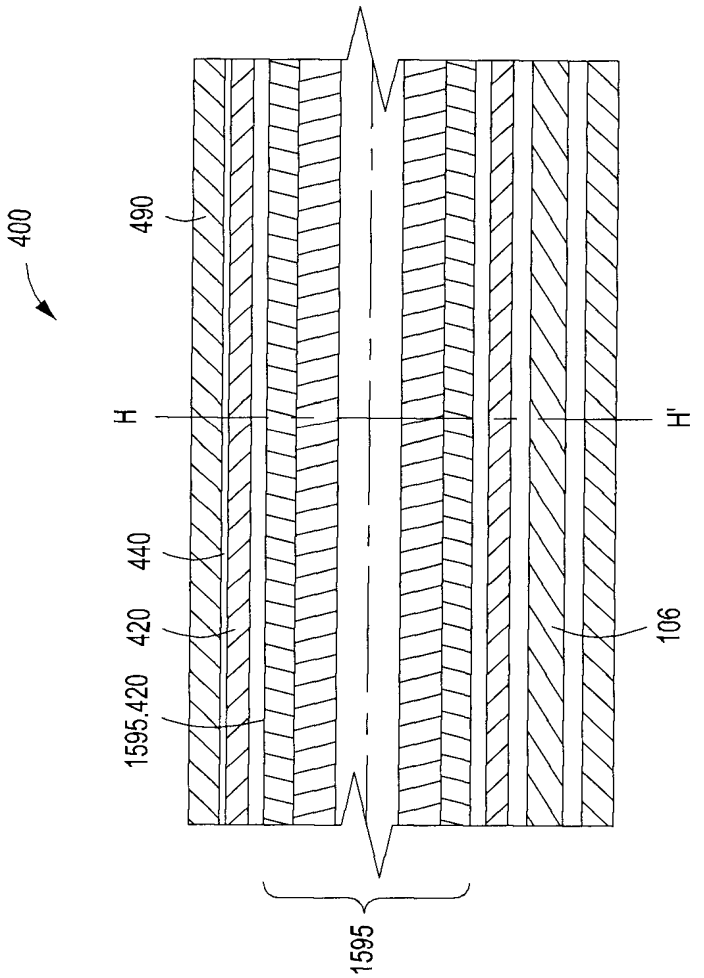


FIG. 4D-2

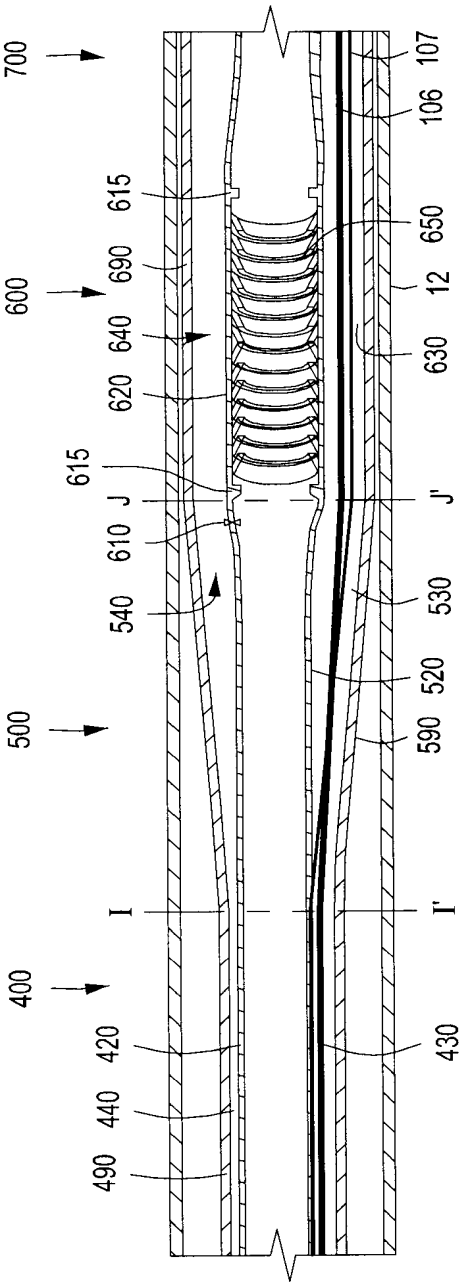


FIG. 4E-1

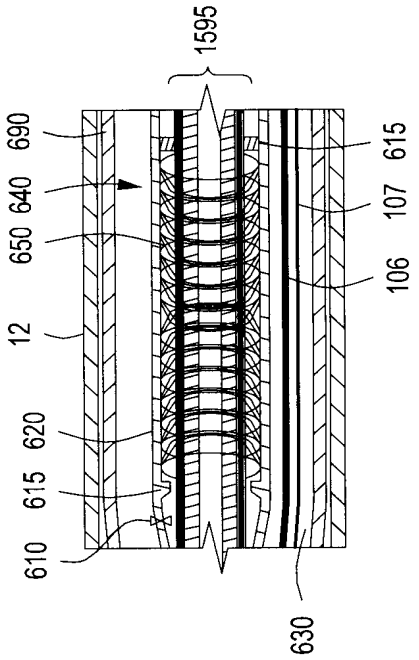


FIG. 4E-2

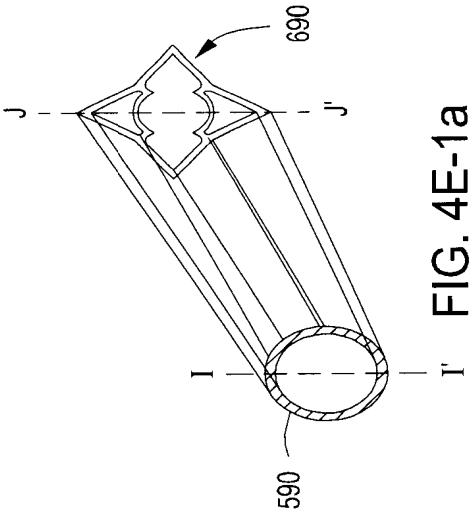


FIG. 4E-1a

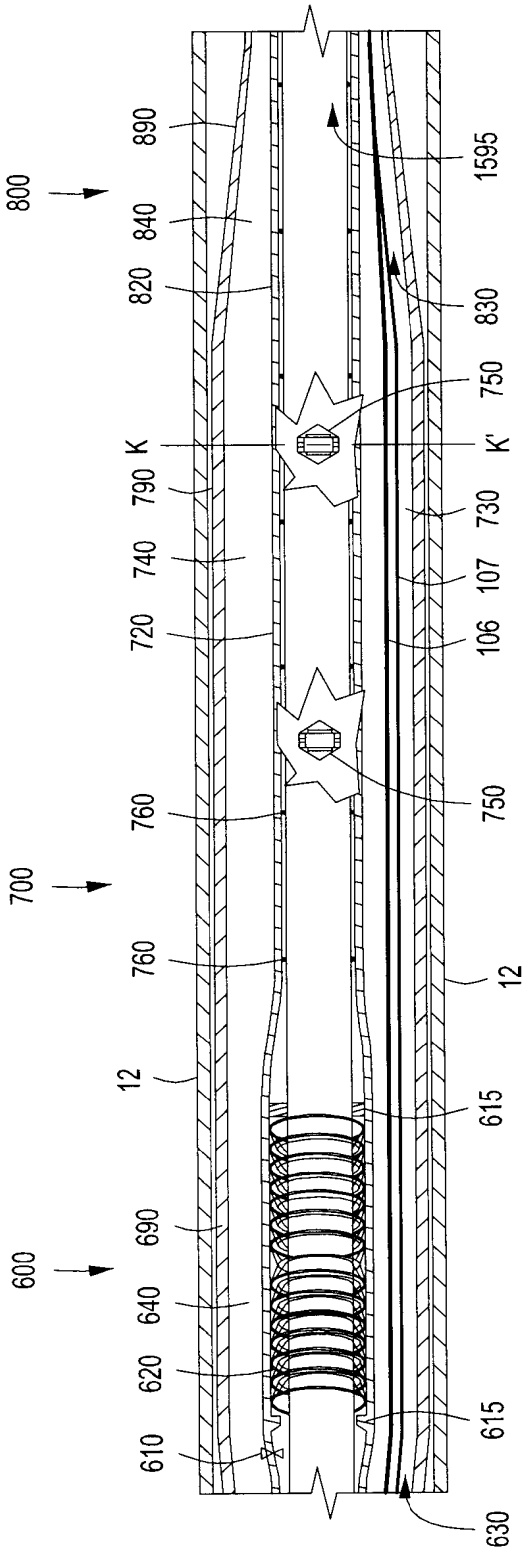

800
890
840
820
K
790
740
720
760
700
760
12
690
600
640
620
610
1595
830
750
K'
730
107
106
750
12
615
615
630

FIG. 4F-1

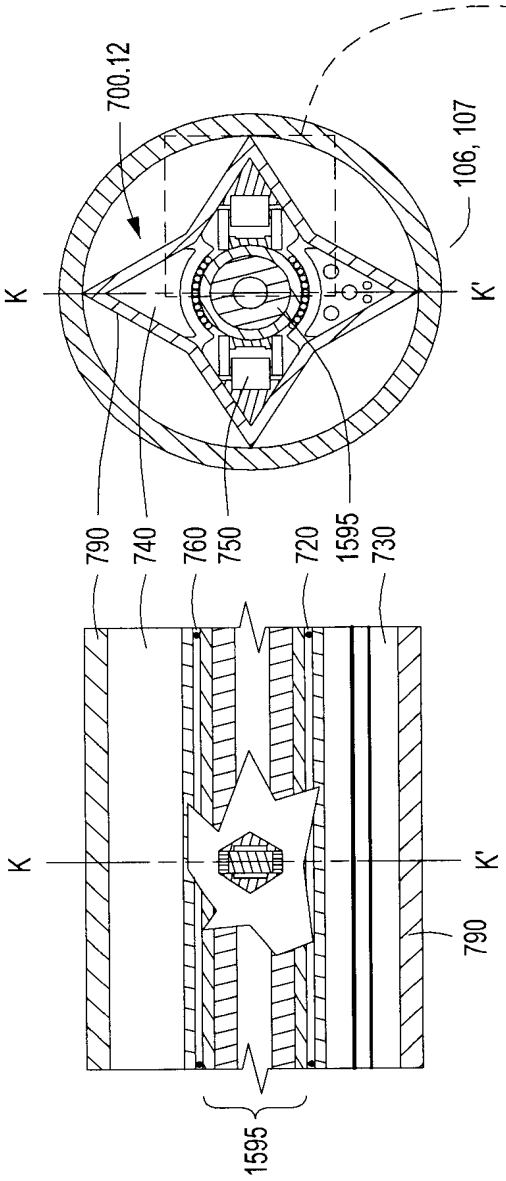


FIG. 4F-2

FIG. 4F-2a

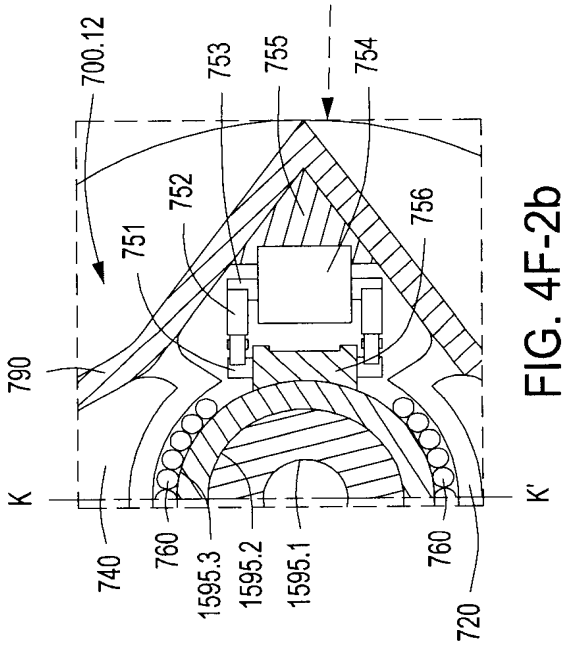


FIG. 4F-2b

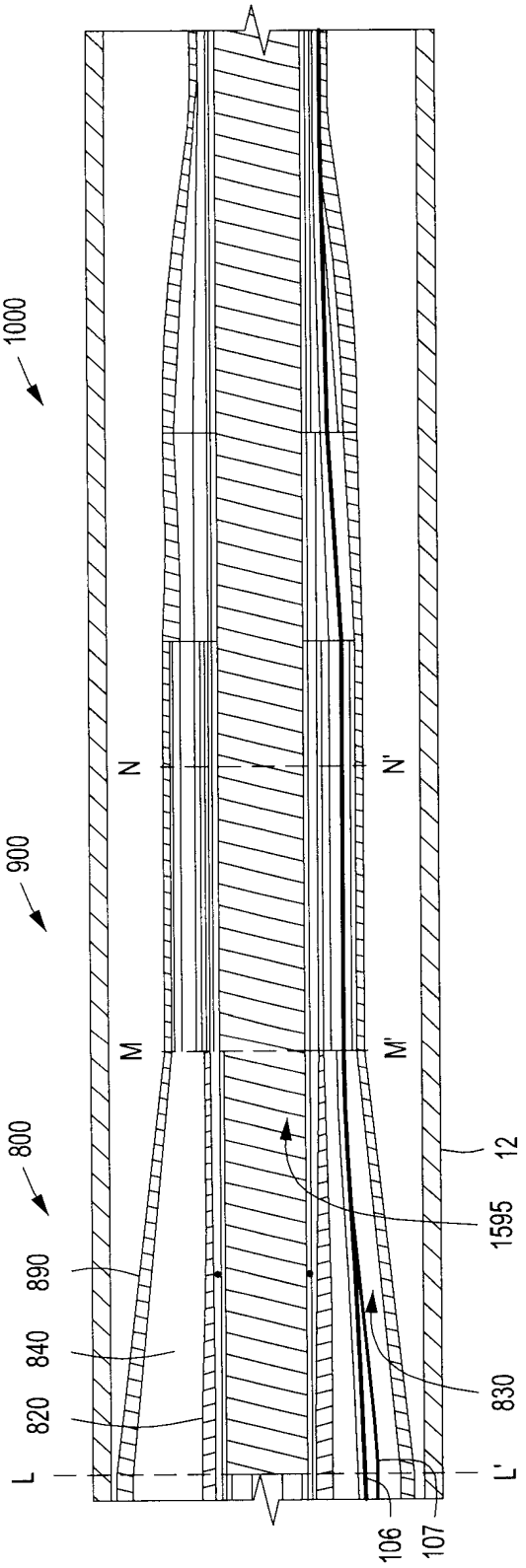


FIG. 4G-1

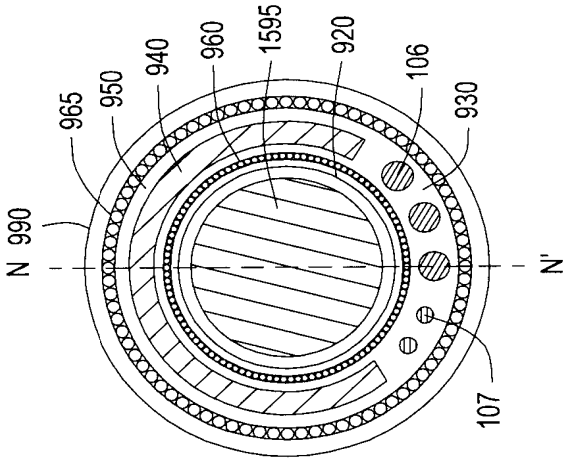


FIG. 4G-1b

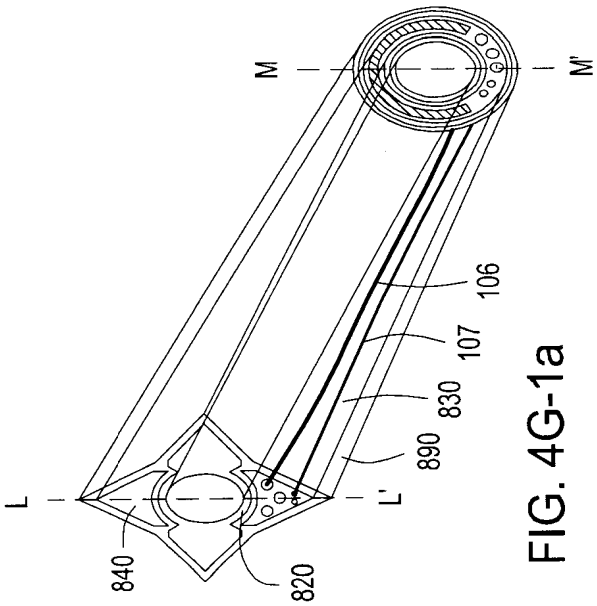


FIG. 4G-1a

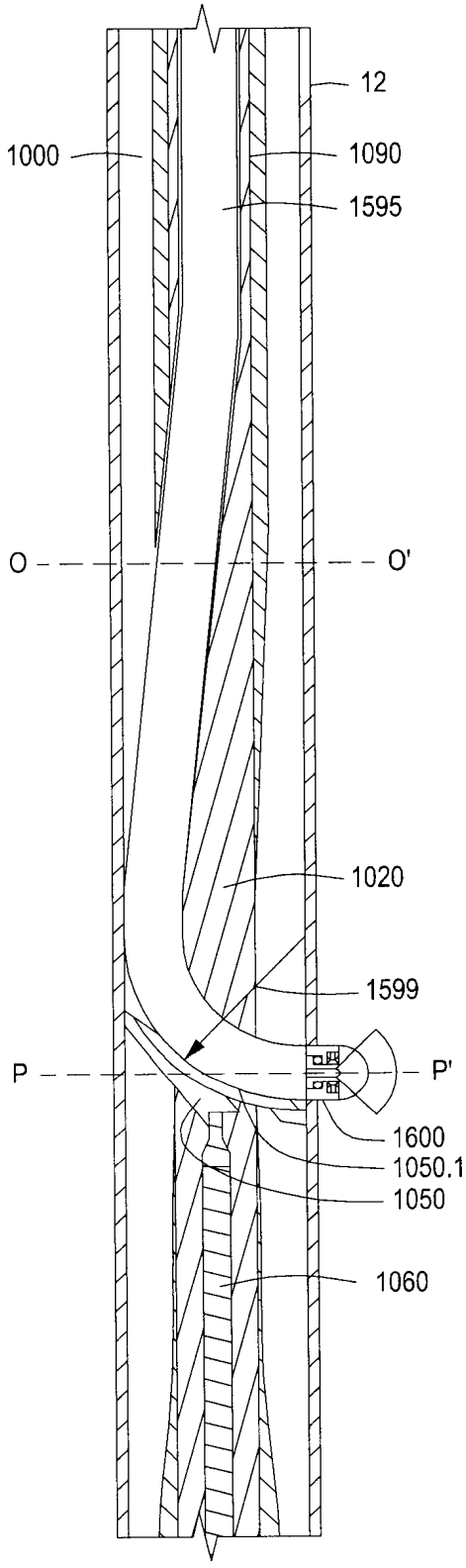


FIG. 4H-1

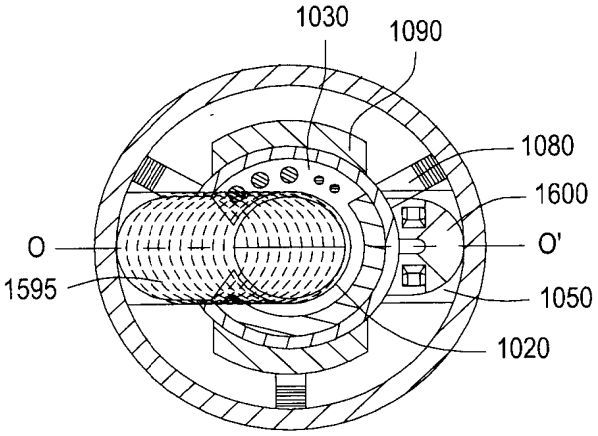


FIG. 4H-1a

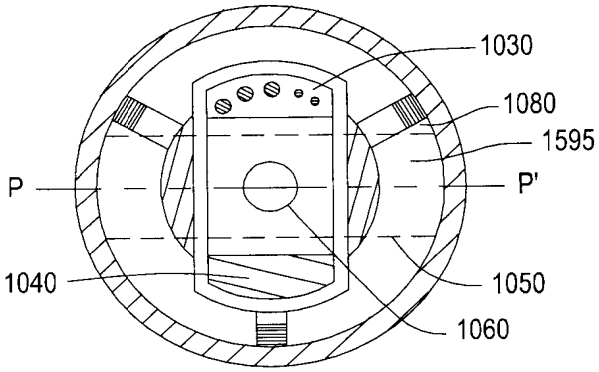


FIG. 4H-1b

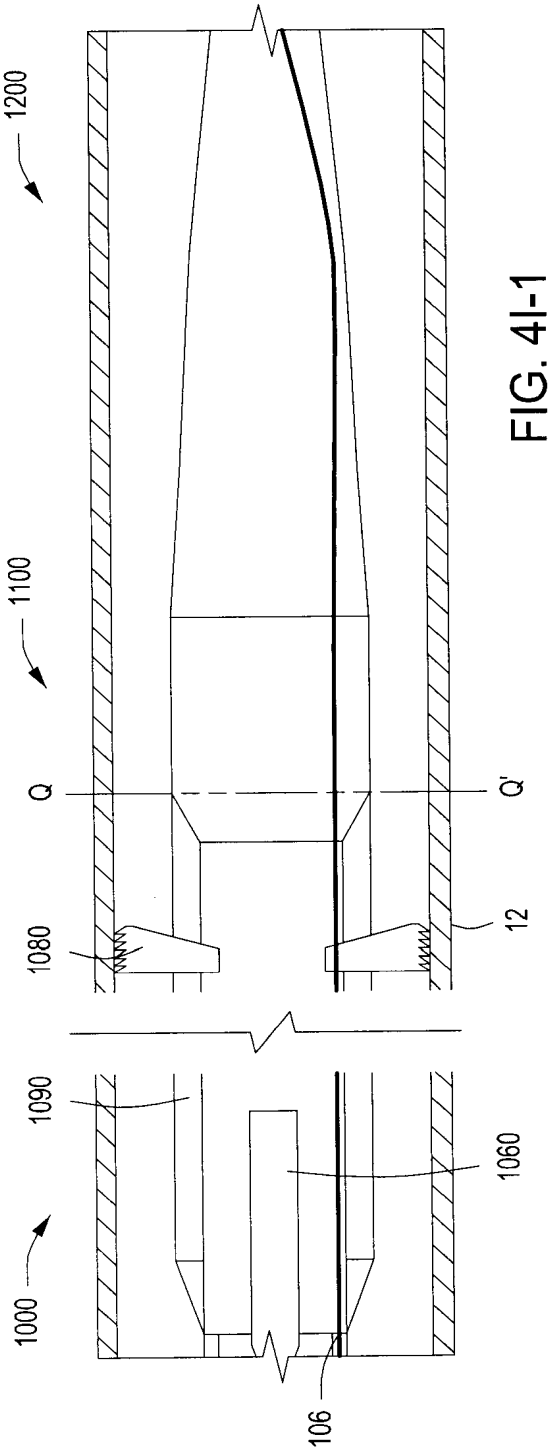


FIG. 4I-1

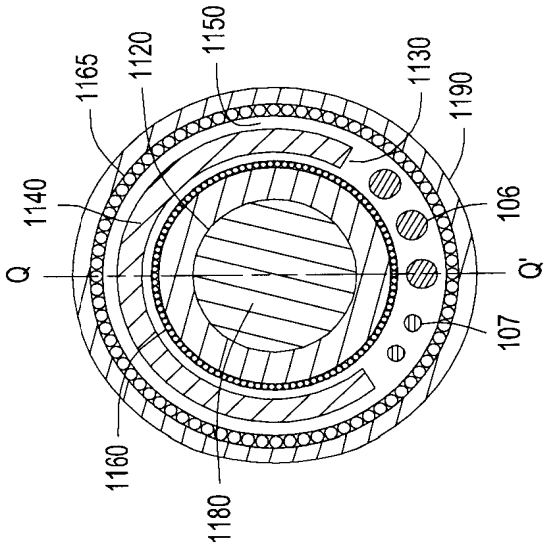


FIG. 4I-1a

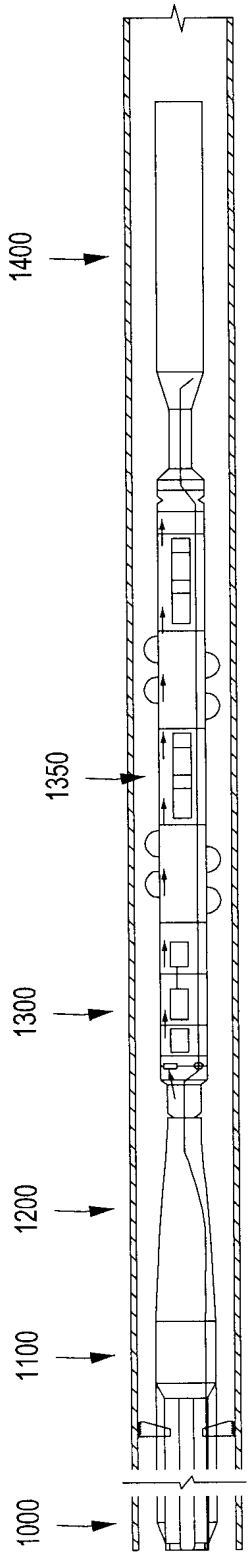
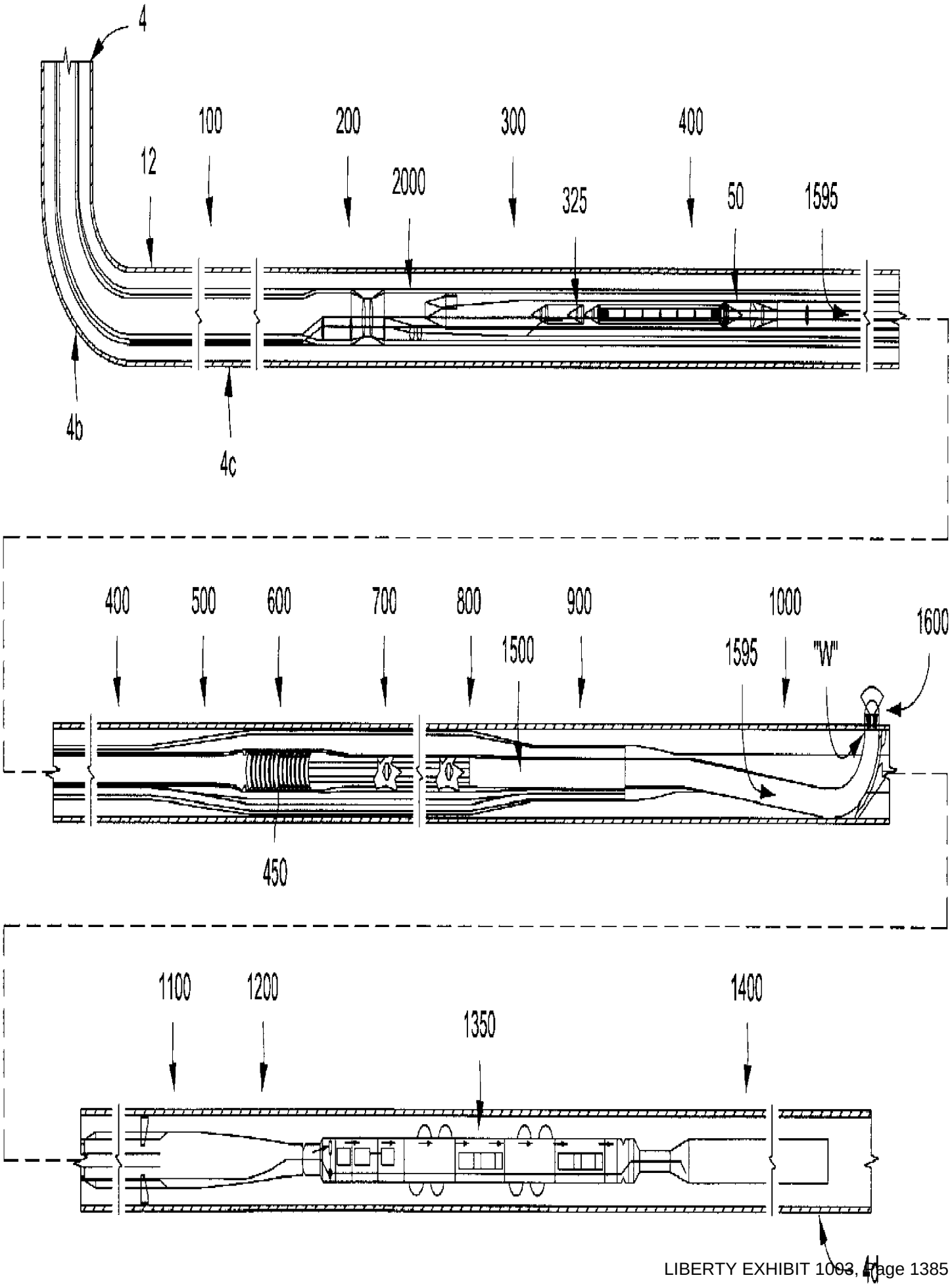


FIG. 4J


4
100
200
300
400
12
2000
325
50
1595
4b
4c
400
500
600
700
800
900
1000
1600
1500
1595
"W"
450
1100
1200
1400
1350
10

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CA 2919666 A1 2016/08/24

(21) 2 919 666

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) **Date de dépôt/Filing Date:** 2016/02/02

(41) **Mise à la disp. pub./Open to Public Insp.:** 2016/08/24

(30) **Priorités/Priorities:** 2015/02/24 (US62/120,212); 2015/07/29 (US62/198,575); 2016/01/28 (US15/009,623)

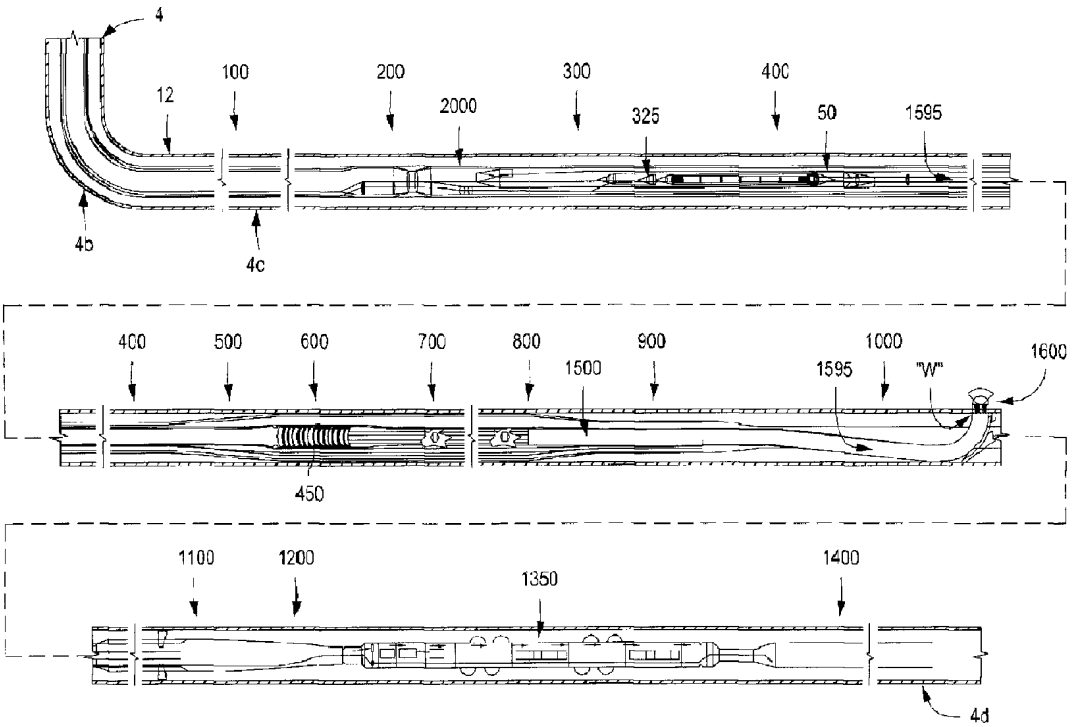
(51) **Cl.Int./Int.Cl.** ***E21B 7/18*** (2006.01), ***E21B 43/11*** (2006.01), ***E21B 43/26*** (2006.01), ***E21B 47/04*** (2012.01), ***E21B 47/12*** (2012.01), ***E21B 7/06*** (2006.01)

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(54) **Titre : METHODE DE FORMAGE DE TROUS DE FORAGE LATERAUX**
(54) **Title: METHOD OF FORMING LATERAL BOREHOLES**



(57) **Abrégé/Abstract:**
A method of forming a lateral borehole in a pay zone located within an earth subsurface is provided. The method includes determining a depth of a pay zone in the earth subsurface, and then forming a wellbore within the pay zone. The method also includes conveying a hydraulic jetting assembly into the wellbore on a working string. The assembly includes a jetting hose carrier, and a jetting hose within the jetting hose carrier having a nozzle connected at a distal end. The method additionally includes setting a whipstock in the wellbore along the pay zone, and translating the jetting hose out of the jetting hose carrier to advance the nozzle along the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix, and further injecting the fluid while further translating the jetting hose and connected nozzle along the face of the whipstock without coiling or uncoiling the hose, thereby forming a lateral borehole that extends at least feet from the wellbore.

ABSTRACT

A method of forming a lateral borehole in a pay zone located within an earth subsurface is provided. The method includes determining a depth of a pay zone in the earth subsurface, and then forming a wellbore within the pay zone. The method also includes conveying a hydraulic jetting assembly into the wellbore on a working string. The assembly includes a jetting hose carrier, and a jetting hose within the jetting hose carrier having a nozzle connected at a distal end. The method additionally includes setting a whipstock in the wellbore along the pay zone, and translating the jetting hose out of the jetting hose carrier to advance the nozzle along the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix, and further injecting the fluid while further translating the jetting hose and connected nozzle along the face of the whipstock without coiling or uncoiling the hose, thereby forming a lateral borehole that extends at least 5 feet from the wellbore.

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METHOD OF FORMING LATERAL BOREHOLES

BACKGROUND OF THE INVENTION

[1] This section is intended to introduce selected aspects of the art, which may be associated with various embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Field of the Invention

[2] The present disclosure relates to the field of well completion. More specifically, the present disclosure relates to the completion and stimulation of a hydrocarbon-producing formation by the generation of small diameter boreholes from an existing wellbore using a hydraulic jetting assembly. The present disclosure further relates to the controlled generation of multiple lateral boreholes that extend many feet into a subsurface formation, in one trip.

Discussion of Technology

[3] In the drilling of an oil and gas well, a near-vertical wellbore is formed through the earth using a drill bit urged downwardly at a lower end of a drill string. After drilling to a predetermined bottomhole location, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the formation penetrated by the wellbore. Particularly in a vertical wellbore, or the vertical section of a horizontal well, a cementing operation is conducted in order to fill or "squeeze" the entire annular volume with cement along part or all of the length of the wellbore. The combination of cement and casing strengthens the wellbore and facilitates the zonal isolation, and subsequent completion, of certain sections of potentially hydrocarbon-producing pay zones behind the casing.

[4] Within the last two decades, advances in drilling technology have enabled oil and gas operators to economically "kick-off" and steer wellbore trajectories from a generally vertical orientation to a generally horizontal orientation. The horizontal "leg" of each of these wellbores now often exceeds a length of one mile. This significantly multiplies the wellbore exposure to a target hydrocarbon-bearing formation (or "pay zone"). For example, for a given target pay zone having a (vertical) thickness of 100 feet, a one mile horizontal leg exposes 52.8 times as much pay zone to a horizontal wellbore as compared to the 100-foot exposure of a conventional vertical wellbore.

[5] **Figure 1A** provides a cross-sectional view of a wellbore **4** having been completed in a horizontal orientation. It can be seen that a wellbore **4** has been formed from the earth surface **1**, through numerous earth strata **2a**, **2b**, . . . **2h** and down to a hydrocarbon-producing formation **3**. The subsurface formation **3** represents a "pay zone" for the oil and gas operator. The wellbore **4** includes a vertical section **4a** above the pay zone, and a horizontal section **4c**. The horizontal section **4c** defines a heel **4b** and a toe **4d** and an elongated leg there between that extends through the pay zone **3**.

[6] In connection with the completion of the wellbore **4**, several strings of casing having progressively smaller outer diameters have been cemented into the wellbore **4**. These include a string of surface casing **6**, and may include one or more strings of intermediate casing **9**, and finally, a production casing **12**. (Not shown is the shallowest and largest diameter casing referred to as conductor pipe, which is a short section of pipe separate from and immediately above the surface casing.) One of the main functions of the surface casing **6** is to isolate and protect the shallower, fresh water bearing aquifers from contamination by any wellbore fluids. Accordingly, the conductor pipe and the surface casing **6** are almost always cemented **7** entirely back to the surface **1**.

[7] The process of drilling and then cementing progressively smaller strings of casing is repeated several times until the well has reached total depth. In some instances, the final string of casing **12** is a liner, that is, a string of casing that is not tied back to the surface **1**. The final string of casing **12**, referred to as a production casing, is also typically cemented **13** into place. In the case of a horizontal completion, the production casing **12** may be cemented, or may

provide zonal isolation using external casing packers ("ECP's), swell packers, or some combination thereof.

[8] Additional tubular bodies may be included in a well completion. These include one or more strings of production tubing placed within the production casing or liner (not shown in **Figure 1A**). In a vertical well completion, each tubing string extends from the surface **1** to a designated depth proximate the production interval **3**, and may be attached to a packer (not shown). The packer serves to seal off the annular space between the production tubing string and the surrounding casing **12**. In a horizontal well completion, the production tubing is typically landed (with or without a packer) at or near the heel **4b** of the wellbore **4**.

[9] In some instances, the pay zone **3** is incapable of flowing fluids to the surface **1** efficiently. When this occurs, the operator may install artificial lift equipment (not shown in **Figure 1A**) as part of the wellbore completion. Artificial lift equipment may include a downhole pump connected to a surface pumping unit via a string of sucker rods run within the tubing. Alternatively, an electrically-driven submersible pump may be placed at the bottom end of the production tubing. Gas lift valves, hydraulic jet pumps, plunger lift systems, or various other types of artificial lift equipment and techniques may also be employed to assist fluid flow to the surface **1**.

[10] As part of the completion process, a wellhead **5** is installed at the surface **1**. The wellhead **5** serves to contain wellbore pressures and direct the flow of production fluids at the surface **1**. Fluid gathering and processing equipment (not shown in **Figure 1A**) such as pipes, valves, separators, dehydrators, gas sweetening units, and oil and water stock tanks may also be provided. Subsequent to completion of the pay zone(s) followed by installation of any requisite downhole tubulars, artificial lift equipment, and the wellhead **5**, production operations may commence. Wellbore pressures are held under control, and produced wellbore fluids are segregated and distributed appropriately.

[11] Within the United States, many wells are now drilled principally to recover oil and/or natural gas, and potentially natural gas liquids, from pay zones previously thought to be too impermeable to produce hydrocarbons in economically viable quantities. Such "tight" or "unconventional" formations may be sandstone, siltstone, or even shale formations.

Alternatively, such unconventional formations may include coalbed methane. In any instance, "low permeability" typically refers to a rock interval having permeability less than 0.1 millidarcies.

[12] In order to enhance the recovery of hydrocarbons, particularly in low-permeability formations, subsequent (i.e., after perforating the production casing or liner) stimulation techniques may be employed in the completion of pay zones. Such techniques include hydraulic fracturing and/or acidizing. In addition, "kick-off" wellbores may be formed from a primary wellbore in order to create one or more new directionally or horizontally completed boreholes. This allows a well to penetrate along the plane of a subsurface formation to increase exposure to the pay zone. Where the natural or hydraulically-induced fracture plane(s) of a formation is vertical, a horizontally completed wellbore allows the production casing to intersect, or "source," multiple fracture planes. Accordingly, whereas vertically oriented wellbores are typically constrained to a single hydraulically-induced fracture plane per pay zone, horizontal wellbores may be perforated and hydraulically fractured in multiple locations, or "stages," along the horizontal leg **4c**.

[13] **Figure 1A** demonstrates a series of fracture half-planes **16** along the horizontal section **4c** of the wellbore **4**. The fracture half-planes **16** represent the orientation of fractures that will form in connection with a perforating/fracturing operation. According to principles of geo-mechanics, fracture planes will generally form in a direction that is perpendicular to the plane of least principal stress in a rock matrix. Stated more simply, in most wellbores, the rock matrix will part along vertical lines when the horizontal section of a wellbore resides below 3,000 feet, and sometimes as shallow as 1,500 feet, below the surface. In this instance, hydraulic fractures will tend to propagate from the wellbore's perforations **15** in a vertical, elliptical plane perpendicular to the plane of least principle stress. If the orientation of the least principle stress plane is known, the longitudinal axis of the leg **4c** of a horizontal wellbore **4** is ideally oriented parallel to it such that the multiple fracture planes **16** will intersect the wellbore at-or-near orthogonal to the horizontal leg **4c** of the wellbore, as depicted in **Figure 1A**.

[14] The desired density of perforated and fractured intervals within the pay zone **3** along the horizontal leg **4c** is optimized by calculating:

- the estimated ultimate recovery ("EUR") of hydrocarbons each fracture will drain, which requires a computation of the Stimulated Reservoir Volume ("SRV") that each fracture treatment will connect to the wellbore via its respective perforations; less
- any overlap with the respective SRV's of bounding fracture intervals; coupled with
- the anticipated time-distribution of hydrocarbon recovery from each fracture; versus
- the incremental cost of adding another perforated/fractured interval.

The ability to replicate multiple vertical completions along a single horizontal wellbore is what has made the pursuit of hydrocarbon reserves from unconventional reservoirs, and particularly shales, economically viable within relatively recent times. This revolutionary technology has had such a profound impact that currently Baker Hughes Rig Count information for the United States indicates only about one-fourth (26%) of wells being drilled in the U.S. are classified as "Vertical", whereas the other three-fourths are classified as either "Horizontal" or "Directional" (62% and 12%, respectively). That is, horizontal wells currently comprise approximately two out of every three wells being drilled in the United States.

[15] The additional costs in drilling and completing horizontal wells as opposed to vertical wells is not insignificant. In fact, it is not at all uncommon to see horizontal well drilling and completion ("D & C") costs top multiples (double, triple, or greater) of their vertical counterparts. Depending on the geologic basin, and particularly the geologic characteristics that govern such criteria as drilling penetration rates, required drilling mud rheology, casings design and cementation, etc., significant additional costs for drilling and completing horizontal wells include those involved in controlling the radius of curvature of the kick-off, and guidance of the bit and drilling assembly (including MWD and LWD technologies) in initially obtaining, then maintaining the preferred at-or-near horizontal trajectory of the wellbore **4** within the pay zone **3**, and the overall length of the horizontal

section **4c**. The critical process of obtaining wellbore isolation between frac stages, as with additional cementing and/or ECP's, are often significant additions to the increased completion expenses, as are costs for "plug-and-perf" or sleeve or port (typically ball-drop actuated) completion systems.

[16] In many cases, however, the greatest single cost in drilling and completing horizontal wells is the cost associated with pumping the multiple hydraulic fracture treatments themselves. It is not uncommon for the sum of the costs of a given horizontal well's hydraulic fracturing treatments to approach, or even exceed, 50% of its total drilling and completion cost.

[17] Crucial to the economic success of any horizontal well is the achievement of satisfactory hydraulic fracture geometries within the pay zone being completed. Many factors can contribute to the success or failure in achieving the desired geometries. These include the rock properties of the pay zone, pumping constraints imposed by the wellbore's construction and/or surface pumping equipment, and characteristics of the fracturing fluids. In addition, proppants of various mesh (sieve) sizes are typically added to the fracturing mixture to maintain the hydraulic pressure-induced fracture width in a "propped open" state, thereby increasing the fracture's conductive capacity for producing hydrocarbon fluids.

[18] Often, in order to achieve desired fracture characteristics (fracture width, fracture conductivity, and particularly, fracture half-length) within the pay zone, an overall fracture height must be created that considerably exceeds the boundaries of the pay zone. Fortunately, vertical out-of-zone fracture height growth is usually confined to a few multiples of the overall pay formation's thickness (i.e., ten's or hundreds' of feet), and thereby cannot pose a threat to contamination of much shallower fresh water sources, almost always separated from the pay zone by multiple thousands of feet of rock formations. See K. Fisher and N. Warpinski, "*Hydraulic Fracture-Height Growth: Real Data*," SPE Paper No. 145,949, SPE Annual Technical Conference and Exhibit, Denver Colorado (Oct. 30 - Nov. 2, 2012).

[19] Nevertheless, this increases the amount of fracturing fluid and proppant needed at the various "frac" stages, and further increases the required pumping horsepower. It is known that for a typical fracturing job, significant volumes of fracturing fluids, fluid additives, proppants, hydraulic ("pumping") horsepower (or, "HHP"), and their correlative costs are

expended on non-productive portions of the fractures. This represents a multi-billion dollar problem each year within the U.S. alone.

[20] Further complicating the planning of a horizontal wellbore are the uncertainties associated with fracture geometries within unconventional reservoirs. Many experts believe, based on analyses of real-time data from both tilt meter and micro-seismic surveys, that fracture geometries in less permeable, and particularly, more brittle, unconventional reservoirs can yield highly complex fracture geometries. That is, as opposed to the relatively simplistic bi-wing elliptical model perceived to fit most conventional reservoirs (and as shown in the idealistic rendition in **Figure 1A**), fracture geometries in unconventional reservoirs can be frustratingly unpredictable.

[21] In most cases, far-field fracture length and complexity is deemed detrimental (rather than beneficial) due to excessive fluid leak-off and/or reduced fracture width that can cause early screen-outs. Hence, whether fracture complexity (or, the lack thereof) enhances or reduces the SRV that the fracture network will enable the wellbore to drain is typically determined on a case-by-case (e.g., reservoir-by-reservoir) basis.

[22] Thus, it is desirable, particularly in horizontal wellbore completions for tight reservoirs, to obtain greater control over the geometric growth of the primary fracture network extending perpendicularly outward from the horizontal leg **4c**. It is further desirable to extend the length of the fracture network azimuth without significantly trespassing the horizontal pay zone **3** boundaries. Further, it is desirable to decrease the well density required to drain a given reservoir volume by increasing the effectiveness of the fracture network between wellbores through the use of two or more hydraulically-jetted mini-laterals along a horizontal leg. Still further, it is desirable to provide this guidance, constraint, and enhancement of SRV's by the creation of one or more mini-lateral boreholes as a replacement of conventional casing portals provided by the use of conventional completion procedures requiring perforations, sliding sleeves, and the like.

[23] Accordingly, a need exists for a downhole assembly having a jetting hose and a whipstock, whereby the assembly can be conveyed into any wellbore interval of any inclination, including an extended horizontal leg. A need further exists for a hydraulic jetting system that provides for substantially a 90° turn of the jetting hose opposite the point of a

casing exit, preferably utilizing the entire casing inner diameter as the bend radius for the jetting hose, thereby providing for the maximum possible inner diameter of jetting hose, and thus providing the maximum possible hydraulic horsepower to the jetting nozzle. A need further exists for a system that includes a whipstock deployable on a string of coiled tubing, wherein the whipstock can be reoriented in discreet, known increments, and not depend upon pipe rotation at the surface translating downhole.

[24] Additional needs exist that, in certain embodiments, are addressed herein. A need exists for improved methods of forming lateral wellbores using hydraulically directed forces, wherein the desired length of jetting hose can be conveyed even from a horizontal wellbore. Further, a need exists for a method of forming mini-lateral boreholes off of a horizontal leg that assist in confining subsequent SRV's up to, but not significantly beyond, pay zone boundaries. Still further, a need exists for a method by which a whipstock and jetting hose can be conveyed and operated with hydraulic and/or mechanical push forces that enable movement of the jetting nozzle and connected hose into the formation, retrieved, re-oriented and re-deployed and re-operated multiple times at as many parent wellbore depths and mini-lateral azimuth orientations as desired, to generate multiple mini-lateral bore holes within not only vertical, but highly directional and even horizontal portions of wellbores in a single trip. A need further exists to be able to convey the jetting hose in an uncoiled state, such that the bend radius within the production casing and along the whipstock is the tightest bending constraint the hose must satisfy.

[25] A need further exists for a method of hydraulically fracturing mini-lateral boreholes jetted off of the horizontal leg of a wellbore immediately following lateral borehole formation, and without the need of pulling the jetting hose, whipstock, and conveyance system out of the parent wellbore. A need further exists for a method of contouring clusters of lateral boreholes' paths based upon real-time analysis of geophysical (micro-seismic and/or tiltmeter and/or ambient micro-seismic) descriptions of resultant SRV development (or lack thereof) from pumping a given stimulation (frac) stage. Additionally, a need exists for a method of optimizing the recompletion of an existing horizontal well by optimizing the placement and contouring of new lateral borehole clusters / stimulation stages based upon the performance (or, more specifically, non-performance such as observed by production logging or permanent

ambient micro-seismic installations) of existing conventional perforation clusters and their respective stimulation stage's SRV. Stated another way, a need exists for a method of remotely controlling the erosional excavation path of the jetting nozzle and connected hydraulic hose, such that a lateral borehole, or multiple lateral borehole "clusters," can be contoured to best control the SRV geometry resulting from a subsequent stimulation treatment stage.

SUMMARY OF THE INVENTION

[26] The systems and methods described herein have various benefits in the conducting of oil and gas well completion activities. In the present disclosure, a method of forming a lateral borehole in a pay zone is first claimed. The pay zone exists within an earth subsurface. In one embodiment, the method first comprises determining a depth of the pay zone in a subsurface formation. The pay zone defines a rock matrix that has been identified as holding, or at least potentially holding, hydrocarbon fluids or organic-rich rock. In one aspect, the method also includes determining a thickness of the pay zone.

[27] The method additionally includes forming a wellbore within the pay zone. In a preferred embodiment, the wellbore has deviated section or, more preferably, is completed horizontally. In these instances, forming the wellbore means forming a parent wellbore at an angle offset from vertical, or even forming a wellbore along a generally horizontal plane.

[28] The method further includes conveying a hydraulic jetting assembly into the wellbore on a working string. Preferably, the working string is a string of coiled tubing having a sheath for holding electrical wires and, optionally, fiber optic data cables.

[29] The downhole hydraulic jetting assembly is useful for jetting multiple lateral boreholes from an existing parent wellbore into the subsurface formation. The assembly is basically comprised of two synergetic systems:

(1) an internal hose system ("the internal system"), which defines an elongated jetting hose having at its proximal end a jetting fluid inlet, and at its terminal end a jetting nozzle configured to be directed to and through a parent wellbore exit location; and

(2) an external hose conveyance, deployment and retrieval system ("the external system") that is run on the working string to provide the defined path of travel (including a whipstock) within a wellbore, with the external system being configured to carry the elongated jetting hose into a wellbore and "push" it against a whipstock set in the wellbore to urge the jetting nozzle forward into the surrounding formation.

[30] In the case of a cased wellbore, a window is formed through the casing using the jetting hose and connected nozzle, followed by the formation of a lateral borehole out into a hydrocarbon-bearing pay zone. The configuration and operation of these two synergetic systems provide that the whipstock may be re-oriented and/or re-located, and the jetting hose re-deployed into the casing and re-retrieved, for the jetting of multiple casing exits and lateral boreholes in the same trip.

[31] As noted, the internal system comprises a jetting hose having a proximal end and a distal end. A fluid inlet resides at the proximal end, while a jetting nozzle is disposed at the distal end. Preferably, a power supply such as a battery pack resides at the proximal end for providing power to electrical components of the jetting assembly.

[32] The external system comprises a pair of tubular bodies. These represent an outer conduit and an inner conduit. The outer conduit has an upper end configured to be operatively attached to the working string, or "tubing conveyance medium," for running the jetting hose assembly into the production casing, a lower end, and an internal bore there between. The inner conduit resides within the bore of the outer conduit and serves as a jetting hose carrier. The jetting hose carrier slidably receives the jetting hose during operation.

[33] A micro-annulus is formed between the jetting hose and the surrounding jetting hose carrier. The micro-annulus is sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly. The micro-annulus is further configured to allow the operator to control the amount and flow direction of hydraulic fluid between the jetting hose and the surrounding inner conduit, which then converts to a fluid force that can either: (1) maintain the jetting hose in a taught configuration as it is urged

downstream; or (2) urge the jetting hose in an upstream direction as it is retrieved back into the inner conduit.

[34] The jetting hose assembly also includes a whipstock member. The whipstock member is disposed below the lower end of the outer conduit. The whipstock member includes a concave face for receiving and directing the jetting nozzle and connected hose during operation of the assembly.

[35] The jetting hose assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the arcuate whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting along an operator's designed geo-trajectory forming a lateral borehole into the rock matrix within the pay zone, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed to allow the location of the whipstock device within the wellbore to be adjusted.

[36] In one aspect, the whipstock is configured so that a face of the whipstock provides a bend radius for the jetting hose across the entire wellbore. In the case of a cased hole, the jetting hose will bend across the entire inner diameter of the production casing. Thus, the hose contacts the production casing on one side, bends along the face of the whipstock, and then extends to a casing exit on an opposite side of the production casing. This jetting hose bend radius spanning the entire I.D. of the production casing provides for utilization of the greatest possible diameter of jetting hose, which in turn provides for maximum delivery of hydraulic horsepower through the jetting hose to the jetting nozzle.

[37] The external system is configured such that it contains, conveys, deploys, and retrieves the jetting hose of the internal system in such a way as to maintain the hose in an uncoiled state. Thus, the minimum bend radius that the hose must satisfy is that of the bend radius within the production casing, along the whipstock face, at the point of a desired casing exit. In addition, the coiled tubing-based conveyance of these synergetic internal/external systems provides for simultaneous running of other conventional coiled tubing tools in the

same tool string. These may include a packer, a mud motor, a downhole (external) tractor, logging tools, and/or a retrievable bridge plug residing below the whipstock member.

[38] Returning to the method at hand, the method also comprises setting the whipstock at a desired first casing exit location along the wellbore. The face of the whipstock bends the jetting hose substantially across the entire inner diameter of the wellbore while the jetting hose is translated out of the jetting hose carrier. The method additionally includes translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix in the pay zone.

[39] The method also includes further injecting the jetting fluid while further translating the jetting hose and connected jetting nozzle through the jetting hose carrier and along the face of the whipstock. In this way, a first lateral borehole that extends at least 5 feet from the horizontal wellbore is formed.

[40] In the present disclosure, a unique electric-driven, rotatable jetting nozzle is optionally provided for the external system. The nozzle can emulate the hydraulics of conventional hydraulic perforators, thereby precluding the need for a separate run with a milling tool to form a casing exit. The nozzle optionally includes rearward thrusting jets about the body to enhance forward thrust and borehole cleaning during mini-lateral formation, and to provide clean-out and, possibly, borehole expansion, during pull-out.

[41] Within the external system, regulation of the hydraulic forces of both: (a) the jetting fluid's hydraulic force that urges the internal hose system downstream; and, (b) the hydraulic fluid's hydraulic force that urges the hose system back upstream, are both controlled with valves at the top and base of the carrier system, and seal assemblies both at the top of the jetting hose and at the base of the carrier system. In addition, the external system may include an internal tractor system that provides a mechanical force for selectively urging the jetting hose upstream or downstream.

[42] It is observed that known jetting systems generally rely only on "slack-off" weight of a continuous coiled tubing and/or jetting hose string for "push" force. However, this source of propulsion would be quickly dissipated by helical buckling (e.g., due to friction forces between the jetting hose and wellbore tubulars) in a highly directional or horizontal wellbore. Once the point of helical buckling is reached, supplemental push force from additional slack-off of the string tied to the surface is no longer attainable. The "can't-push-a-rope" limitation of other systems is uniquely overcome herein by the combination of hydraulic and mechanical (tractor) forces, enabling the formation of mini-laterals off of an extended-reach horizontal wellbore.

[43] The hydraulic jetting assembly herein is able to generate lateral bore holes in excess of 10 feet, or in excess of 25 feet, and even in excess of 300 feet, depending on the length of the jetting hose and its jetting hose carrier. Length of penetration and penetration rate itself may also be influenced by the hydraulic jetting-resistance qualities of the host rock. These jetting-resistance qualities may include compressive strength, pore pressure, cementation, and other features inherent to the lithology of the host rock matrix. In any instance, the lateral boreholes may have a diameter of about 1.0" or greater and may be formed at penetration rates much higher than any of the systems that have preceded it that have in common completing a 90° turn of the jetting hose within the production casing.

[44] The present system will have the capacity to generate lateral boreholes from portions of horizontal and highly directional parent wellbores heretofore thought unreachable. Anywhere to which conventional coiled tubing can be tractored within a cased wellbore, lateral boreholes can now be hydraulically jetted. Similarly, superior efficiencies will be captured as multiple intervals of lateral boreholes are formed from a single trip. Wherever satisfactory fracturing hydraulics (pump rates and pressures) are attainable via the coiled tubing-casing annulus, the entire horizontal leg of a newly drilled well may be "perforated and fractured" in stages without need of frac plugs, sliding sleeves or dropped balls.

[45] In one embodiment, multiple lateral boreholes and, optionally, side mini-lateral boreholes, together form a network or cluster of ultra-deep perforations in the rock matrix. Such a network may be designed by the operator to optimally drain a pay zone. Preferably, the

lateral boreholes extend away from the parent wellbore at a normal, or right, angle, and extend to an upper or lower boundary of the pay zone. Other angles may be used as well to take advantage of the richest portions of a pay zone. In any respect, the method may then include producing hydrocarbons. Where multiple boreholes are formed at different orientations from the wellbore and at different depths, hydrocarbons may be produced from a network of lateral boreholes. Moreover, the operation may choose to conduct subsequent formation fracturing operations from the lateral boreholes, thereby further extending the SRV.

[46] In one aspect, geometries of lateral boreholes and side min-lateral boreholes are customized within the host pay zone. The boreholes can then optimally receive a subsequent stimulation (particularly, hydraulic fracturing) treatments. This, in turn, enables optimization of the resultant Stimulated Reservoir Volume ("SRV") to be obtained from each pumping stage. During fracturing, the operator may receive real-time geophysical data, such as micro-seismic, tiltmeter, and/or ambient micro-seismic data, indicative of the effectiveness of formation treatments and SRV development. In one aspect, during a horizontal wellbore's completion or re-completion, real-time customization of the next cluster's lateral borehole geometries may be conducted prior to pumping a next stage.

[47] In one embodiment, hydrocarbons are produced from the wellbore for a period of time before the lateral borehole is formed. Thus, a novel "re-fracturing" method is provided.

[48] In a variation, the method comprises:

- forming perforations along the horizontal wellbore in sequential stages using one or more perforating guns;
- hydraulically fracturing the rock matrix along the horizontal wellbore through the perforations in sequential stages;
- conducting a flowback operation to at least partially remove hydraulic fluids injected in connection with the hydraulic fracturing; and
- optionally, producing hydrocarbon fluids for a period of time before forming the lateral borehole.

[49] In another alternate embodiment, the method further comprises:

- retracting the jetting hose and connected nozzle from the first casing exit after forming the first lateral borehole;
- re-orienting the whipstock at the desired first location;
- injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit;
- further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone; and;
- still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore from the second casing exit.

[50] In this embodiment, each of the first and second lateral boreholes may have an internal diameter of between about 0.4 and 2.5 inches. In one aspect, the second lateral borehole is offset from the first lateral borehole by between 10-degrees and 180-degrees. The method may then further include producing hydrocarbon fluids from the first and second lateral boreholes together.

[51] In another alternate embodiment, the method further comprises:

- retracting the jetting hose and connected nozzle from the first casing exit after forming the first lateral borehole;
- retracting the jetting hose and connected nozzle from the first casing exit;
- moving the whipstock to a desired second location, preferably further uphole;
- injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit at the second location;
- further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone at the second location; and

- still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore along the second desired location.

[52] In this embodiment, the first and second lateral boreholes may be separated by about 5 to 200 feet. Preferably, each of the first and second lateral boreholes is at least 25 feet in length and, more preferably, at least 100 feet in length.

[53] In any of the above embodiments, the method may further comprise injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing, and injecting the fracturing fluids into one or more lateral boreholes at an injection pressure sufficient to part the rock matrix in the pay zone. The hydraulic jetting assembly may further comprise a packer or a retrievable bridge plug disposed below the whipstock member, and the method may further comprise setting the packer or bridge plug before injecting a fracturing fluid. Alternatively or in addition, an acid treatment may be washed down through the annular region and into the lateral boreholes, preferably prior to fracturing. Given the system's ability to controllably "steer" a jetting nozzle and thereby contour the path of a lateral borehole (or, "clusters" of boreholes), fracturing fluids can be more optimally "guided" and constrained within a pay zone.

[54] In any of the above methods, the translation force used in moving the jetting hose out of the jetting hose carrier may be a hydraulic force. The jetting hose and associated jetting hose carrier are preferably each at least 10 feet in length and, more preferably, at least 50 feet in length.

[55] In one embodiment, the jetting hose assembly further comprises a main control valve. The main control valve is disposed proximate the upper end of the outer conduit, and is movable between a first position and a second position. In the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, while in the second position the main control valve directs hydraulic fluid pumped into the wellbore into the annular region formed between the jetting hose carrier and the surrounding outer conduit. Placement of the main control valve in its first position allows an operator to pump jetting fluids into the working string, through the main control valve, and against the upper seal

assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle. Placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the working string, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

[56] In one preferred embodiment, the translation force comprises both the hydraulic force and a separate mechanical force. In this instance, the jetting hose assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit. The internal tractor system comprises an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose, an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs, a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs, and at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

[57] In one embodiment, the hydraulic jetting assembly further comprises a docking station located at an upper end of the external system. The docking station is configured to mate with the battery pack. The docking station having a micro-processor and is in communication with an operator at the surface by means of the electrical wires, the data cables or both of the coiled tubing. In this arrangement, the method may further comprise:

- sending commands from the surface to the docking station;
- sending data from a logging tool downstream from the whipstock to the docking station; and
- sending data from the docking station to the surface.

[58] The docking station preferably also houses a micro-processor along with a micro-transmitter, a micro-receiver, an electrical current regulator, or combinations thereof. The

docking station may be configured to transfer: (1) power to the battery pack, said power either originating from generation at the surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between one or more geo-spatial chips housed at or near the nozzle and the operator at the surface. The micro-transmitter housed in the battery pack is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station. The docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

[59] In one arrangement, the method further comprises

- obtaining geo-mechanical data for the pay zone, the data comprising porosity, permeability, Poisson ratio, modulus of elasticity, shear modulus, Lame' constant, Vp/Vs, or combinations thereof;
- conducting a geo-mechanical analysis of the rock matrix in the pay zone to determine a direction of least minimum principle stress; and
- forming at least two lateral boreholes in the pay zone using the downhole hydraulic jetting assembly by steering the nozzle (i) in a direction perpendicular to the direction of least minimum principle stress, or (ii) in a direction parallel to the direction of least minimum principle stress.

[60] In one arrangement, a longitudinal axis of the horizontal wellbore is oriented parallel to the plane of least principle stress of the rock matrix comprising the pay zone. In addition, the first lateral borehole is formed in a direction perpendicular to the plane of least principle stress of the rock matrix. Conducting a geo-mechanical analysis of the rock matrix may comprise creating a finite element mesh representing the pay zone, wherein the mesh defines a plurality of nodes representing points in space. Each point has potential displacement in more than one direction. The analysis may further involve predicting changes in the stress profile within the rock matrix as a result of the formation of the lateral boreholes.

[61] In another arrangement, the downhole hydraulic jetting assembly and the methods herein operate in conjunction with a guidance system. The guidance system includes the use of at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle. The actuator wires are equi-distantly spaced about the circumference of the jetting hose at its distal end, and are fabricated from a conductive material that contracts in response to electrical current. Differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle in a desired direction. In this arrangement, the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires. This, in turn, controls a geo-orientation of the nozzle for directional hydraulic boring.

[62] In one aspect of the guidance system, geo-location signals are sent by one or more geo-spatial chips residing along or near the nozzle. The geo-location signals are indicative of the location of the nozzle, its orientation, or both. The geo-location signals are transmitted as data from the geo-spatial chips to the micro-receiver in the battery pack. Signals may be sent via electrical wiring or data cables bundled in the jetting hose. The micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a corresponding micro-receiver housed in the docking station. In addition, the docking station may be configured to further transmit the data to a processor at the surface. This geo-date may be sent wirelessly, via electrical wires bundled in the coiled tubing, or via data cables bundled in the coiled tubing.

[63] Geo-trajectory instructions may likewise be sent from a control system residing either at the surface, or in the micro-processor residing in the docking station, downhole. The control system sends signals to one or more current regulators for regulating an amount of current to be sent to each individual actuator wire downhole. Contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives. The contraction, in turn, creates a bending moment, thereby enabling geo-steering of the nozzle according to a desired trajectory. In a preferred embodiment, the bending moment applied to the distal end of the jetting hose is controlled by an operator at the surface through the delivery of geo-trajectory signals sent to a micro-transmitter in the docking station.

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Brief Description of the Drawings

[64] So that the manner in which the present inventions can be better understood, certain illustrations, charts and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[65] Figure 1A is a cross-sectional view of an illustrative horizontal wellbore. Half-fracture planes are shown in 3-D along a horizontal leg of the wellbore to illustrate fracture stages and fracture orientation relative to a subsurface formation.

[66] Figure 1B is an enlarged view of the horizontal portion of the wellbore of Figure 1A. Conventional perforations are replaced by ultra-deep perforations, or mini-lateral boreholes, to create fracture wings.

[67] Figure 2 is a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly of the present invention, in one embodiment. The assembly is shown within a horizontal section of a production casing. The jetting assembly has an external system and an internal system.

[68] Figure 3 is a longitudinal, cross-sectional view of the internal system of the hydraulic jetting assembly of Figure 2. The internal system extends from an upstream battery pack end cap (that mates with the external system's docking station) at its proximal end to an elongated hose having a jetting nozzle at its distal end.

[69] Figure 3A is a cut-away perspective view of the battery pack section of the internal system of Figure 3.

[70] Figure 3B-1 is a cut-away perspective view of a jetting fluid inlet located between the base of the battery pack section and the jetting hose. A jetting fluid receiving funnel is shown for receiving fluids into the jetting hose of the internal system of Figure 3.

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[71] Figure 3B-1.a is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the bottom end cap of the battery pack section.

[72] Figure 3B-1.b is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the jetting fluid inlet.

[73] Figure 3C is a cut-away perspective view of an upper portion of the internal system of Figure 3, from the base of the jetting hose's fluid receiving funnel through the jetting hose's upper seal assembly.

[74] Figure 3D-1 presents a cross-sectional view of a bundled jetting hose, with electrical wiring and data cabling, as may be used in the internal system of Figure 3.

[75] Figure 3D-1a is an axial, cross-sectional view of the bundled jetting hose of Figure 3D-1. Both electrical wires and fiber optical (or data) cables are seen.

[76] Figure 3E is an expanded cross-sectional view of the terminal end of the jetting hose of Figure 3D-1, showing the jetting nozzle of the internal system of Figure 3. The bend radius of the jetting hose is shown within a cut-away section of the whipstock of the external system of Figure 3.

[77] Figures 3F-1a through 3G-1c present enlarged, cross-sectional views of the jetting nozzle of Figure 3E, in various embodiments.

[78] Figure 3F-1a is an axial, cross-sectional view showing a basic nozzle body. The nozzle body includes a rotor and a surrounding stator.

[79] Figure 3F-1b is a longitudinal, cross-sectional view of a jetting nozzle, taken across line C-C′ of Figure 3F-1a. Here, the nozzle uses a single discharge slot at the tip of the rotor. The nozzle also includes bearings between the rotor and the surrounding stator.

[80] Figure 3F-1c is a longitudinal cross-sectional view of the jetting nozzle of Figure 3F-1b, in a modified embodiment. Here, the jetting nozzle includes a geo-spatial chip, and is shown connected to a jetting hose via welding.

[81] Figure 3F-1d is an axial, cross-sectional view of the jetting hose of Figure 3F-1c, taken across line c-c'.

[82] Figures 3F-2a and 3F-2b present longitudinal, cross-sectional views of the nozzle of Figure 3E, in an alternate embodiment. Along with a single discharge slot at the tip of the rotor, five rearward thrust jets are placed in the body of the stator, actuated by forward displacement of a slideable nozzle throat insert against a slideable collar and biasing mechanism.

[83] In Figure 3F-2a, the insert and collar are in their closed position. In Figure 3F-2b, the insert and collar are in their open position allowing fluid to flow through the rearward thrust jets. The jets are opened when a sufficient pumping pressure overcomes the resistance of a spring.

[84] Figure 3F-2c is an axial, cross-sectional view of the nozzle of Figure 3F-2a. Five rearward thrust jets are shown for generating a rearward thrust force.

[85] Figures 3F-3a and 3F-3c provide longitudinal, cross-sectional views of the jetting nozzle of Figure 3E, in another alternate embodiment. Here, multiple rearward thrust jets residing in both the stator body and the rotor body are used. In this arrangement, an electromagnetic force pulling on a magnetic collar, biased by a spring, is used for opening/closing the rearward thrust jets.

[86] In Figure 3F-3a, the collar of the jetting nozzle is in its closed position. In Figure 3F-2b, the collar is in its open position allowing fluid to flow through the rearward thrust jets.

[87] Figures 3F-3b and 3F-3d show axial, cross-sectional views of the jetting nozzle correlative to Figures 3F-3a and 3F-3c, respectively. Eight rearward thrust jets are seen. This embodiment provides for intermittent alignment of the four jetting ports in the rotor with either of the two sets of four jetting ports in the stator to produce a pulsating rearward thrust flow.

[88] Figure 3G-1a is an axial, cross-sectional view showing a basic collar body for a jetting collar that can be placed within a length of jetting hose. The collar body again includes a rotor and a surrounding stator. The view is taken across line D-D' of Figure 3G-1b.

[89] Figure 3G-1b is a longitudinal, cross-sectional view of the jetting collar of Figure 3G-1a. As with the jetting nozzle of Figures 3F-3a through 3F-3d, two sets of four jetting ports in the stator intermittently align with the four jetting ports in the rotor to produce pulsating rearward thrust flow.

[90] Figure 3G-1c is an axial, cross-sectional view of the jetting nozzle of Figure 3G-1b, taken across line d-d'.

[91] Figure 4 is a longitudinal, cross-sectional view of the external system of the downhole hydraulic jetting assembly of Figure 2, in one embodiment. The external system resides within production casing of the horizontal leg of the wellbore of Figure 2.

[92] Figure 4A-1. is an enlarged, longitudinal cross-sectional view of a portion of a bundled coiled tubing conveyance medium which conveys the external system of Figure 4 into and out of the wellbore.

[93] Figure 4A-1a is an axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1. In this embodiment, an inner coiled tubing is "bundled" concentrically with both electrical wires and data cables within a protective outer layer.

[94] Figures 4A-2 is another axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1a, but in a different embodiment. Here, the inner coiled tubing is "bundled" eccentrically within the protective outer layer to provide more evenly-spaced protection of the electrical wires and data cables.

[95] Figure 4B-1 is a longitudinal, cross-sectional view of a crossover connection, which is the upper-most member of the external system of Figure 4. The crossover section is configured to join the coiled tubing conveyance medium of Figure 4A-1 to a main control valve.

[96] Figure 4B-1a is an enlarged, perspective view of the crossover connection of Figure 4B-1, seen between cross-sections E-E′ and F-F′. This view highlights the wiring chamber's general transition in cross-sectional shape from circular to elliptical.

[97] Figure 4C-1 is a longitudinal, cross-sectional view of the main control valve of the external system of Figure 4.

[98] Figure 4C-1a is a cross-sectional view of the main control valve, taken across line G-G′ of Figure 4C-1.

[99] Figure 4C-1b is a perspective view of a sealing passage cover of the main control valve, shown exploded away from Figure 4C-1a.

[100] Figure 4D-1 is a longitudinal, cross-sectional view of a jetting hose carrier section of the external system of Figure 4. The jetting hose carrier section is attached downstream of the main control valve.

[101] Figure 4D-1a shows an axial, cross-sectional view of the main body of the jetting hose carrier section, taken along line H-H′ of Figure 4D-1.

[102] Figure 4D-1b is an enlarged view of a portion of the jetting hose carrier section of Figure 4D.1. A docking station of the external system is more clearly seen.

[103] Figure 4D-2 is an enlarged, longitudinal, cross-sectional view of the external system's jetting hose carrier section of Figure 4D-1, with inclusion of the jetting hose of the internal system from Figure 3.

[104] Figure 4D-2a provides an axial, cross-sectional view of the jetting hose carrier section of Figure 4D-1, with the jetting hose residing therein.

[105] Figure 4E-1 is a longitudinal, cross-sectional view of selected portions of the external system of Figure 4. Visible are a jetting hose pack-off section, and an outer body transition from the preceding circular body (I-I′) of the jetting hose carrier section to a star-shaped body (J-J′) of the jetting hose pack-off section

[106] Figure 4E-1a is an enlarged, perspective view of the transition between lines I-I' and J-J' of Figure 4E-1.

[107] Figure 4E-2 shows an enlarged view of a portion of the jetting hose pack-off section. Internal seals of the pack-off section conform to the outer circumference of the jetting hose (Figure 3) residing therein. A pressure regulator valve is shown schematically adjacent the pack-off section.

[108] Figure 4F-1 is a further downstream longitudinal, cross-sectional view of the external system of Figure 4. The jetting hose pack-off section and the outer body transition from Figure 4E-1 are again shown. Also visible here is an internal tractor system. Note each of the aforementioned components are shown with a longitudinal cross-sectional view of the jetting hose of Figure 3 residing therein.

[109] Figure 4F-2 is an enlarged, longitudinal, cross-sectional view of a portion of the internal tractor system of Figure 4-F1, again with a cross-section of the jetting hose residing therein. An internal motor, gear and gripper assembly is also shown.

[110] Figure 4F-2a is an axial, cross-sectional view of the internal tractor system of Figure 4F-2, taken across line K-K′ of Figures 4F-1 and 4F-2.

[111] Figure 4F-2b is an enlarged half-view of a portion of the internal tractor system of Figure 4F-2a.

[112] Figure 4G-1 is still a further downstream longitudinal, cross-sectional view of the external system of Figure 4. This view shows a transition from the internal tractor to an upper swivel, followed by the upper swivel of the external system.

[113] Figure 4G-1a depicts a perspective view of the outer body transition between the internal tractor system to the upper swivel. This is a star-shape (L-L') to a circle-shape (M-M') transition of the outer body.

[114] Figure 4G-1b provides an axial, cross-sectional view of the upper swivel of Figure 4-G1, taken across line N-N′.

[115] Figure 4H-1 is a cross-sectional view of a whipstock member of the external system of Figure 4, but shown vertically instead of horizontally. The jetting hose of the internal system (Figure 3) is shown bending across the whipstock, and extending through a window in

the production casing. The jetting nozzle of the internal system is shown affixed to the distal end of the jetting hose.

[116] Figure 4H-1a is an axial, cross-sectional view of the whipstock member, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member at line O-O′ to the start of the jetting hose's bend radius as it approaches line P-P′.

[117] Figure 4H-1b depicts an axial, cross-sectional view of the whipstock member at line P-P′.

[118] Figure 4I-1 is a longitudinal, cross-sectional view of a bottom swivel within the external system of Figure 4, residing just downstream of slips (shown engaging the surrounding production casing) near the base of the preceding whipstock member.

[119] Figure 4I-1a provides an axial, cross-sectional view of a portion of the bottom swivel of Figure 4I-1, taken across line Q-Q′.

[120] Figure 4J is another longitudinal view of the bottom swivel of Figure 4I-1. Here, the bottom swivel is connected to a transition section, which in turn is connected to a conventional mud motor, an external tractor, and a logging sonde, thus completing the entire downhole tool string. For simplification, neither a packer nor a retrievable bridge plug has been included in this configuration.

Detailed Description of Certain Embodiments

Definitions

[121] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[122] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient conditions. Hydrocarbon fluids may include, for example, oil, natural gas, condensate, coal bed methane, shale oil, shale gas, and other hydrocarbons that are in a gaseous or liquid state.

[123] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

[124] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[125] The term "subsurface interval" refers to a formation or a portion of a formation wherein formation fluids may reside. The fluids may be, for example, hydrocarbon liquids, hydrocarbon gases, aqueous fluids, or combinations thereof.

[126] The terms "zone" or "zone of interest" refer to a portion of a formation containing hydrocarbons. Sometimes, the terms "target zone," "pay zone," or "interval" may be used.

[127] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shape. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

[128] The term "jetting fluid" refers to any fluid pumped through a jetting hose and nozzle assembly for the purpose of erosionally boring a lateral borehole from an existing parent wellbore. The jetting fluid may or may not contain an abrasive material.

[129] The term "abrasive material" or "abrasives" refers to small, solid particles mixed with or suspended in the jetting fluid to enhance erosional penetration of: (1) the pay zone;

and/or (2) the cement sheath between the production casing and pay zone; and/or (3) the wall of the production casing at the point of desired casing exit.

[130] The terms "tubular" or "tubular member" refer to any pipe, such as a joint of casing, a portion of a liner, a joint of tubing, a pup joint, or coiled tubing.

[131] The terms "lateral borehole" or "mini-lateral" or "ultra-deep perforation" ("UDP") refer to the resultant borehole in a subsurface formation, typically upon exiting a production casing and its surrounding cement sheath in a parent wellbore, with said borehole formed in a known or prospective pay zone. For the purposes herein, a UDP is formed as a result of hydraulic jetting forces erosionally boring through the pay zone with a jetting fluid directed through a jetting hose and out a jetting nozzle affixed to the terminal end of the jetting hose. Preferably, each UDP will have a substantially normal trajectory relative to the parent wellbore.

[132] The terms "steerable" or "guidable", as applied to a hydraulic jetting assembly, refers to a portion of the jetting assembly (typically, the jetting nozzle and/or the portion of jetting hose immediately proximal the nozzle) for which an operator can direct and control its geo-spatial orientation while the jetting assembly is in operation. This ability to direct, and subsequently re-direct the orientation of the jetting assembly during the course of erosional excavation can yield UDP's with directional components in one, two, or three dimensions, as desired.

[133] The terms "perforation cluster" or "UDP cluster" refer to a designed grouping of lateral boreholes off a parent well casing. These groupings are ideally designed to receive and transmit a specific "stage" of a stimulation treatment, usually in the course of completing or recompleting a horizontal well by hydraulic fracturing (or "fracking").

[134] The term "stage" references a discreet portion of a stimulation treatment applied in completing or recompleting a specific pay zone, or specific portion of a pay zone. In the case of a cased horizontal parent wellbore, up to 10, 20, 50 or more stages may be applied to their respective perforation (or UDP) clusters. Typically, this requires some form of zonal isolation prior to pumping each stage.

[135] The terms "contour" or "contouring" as applied to individual UDP's, or groupings of UDP's in a "cluster", refers to steerably excavating the UDP (or lateral borehole) so as to optimally receive, direct, and control stimulation fluids, or fluids and proppants, of a given stimulation (typically, fracking) stage. This ability to '...optimally receive, direct, and control...' a given stage's stimulation fluids is designed to retain the resultant stimulation geometry "in zone", and/or concentrate the stimulation effects where desired. The result is to optimize, and typically maximize, the Stimulated Reservoir Volume ("SRV").

[136] The terms "real time" or "real time analysis" of geophysical data (such as micro-seismic, tiltmeter, and or ambient micro-seismic data) that is obtained during the course of pumping a stage of a stimulation (such as fracking) treatment means that results of said data analysis can be applied to: (1) altering the remaining portion of the stimulation treatment (yet to be pumped) in its pump rates, treating pressures, fluid rheology, and proppant concentration in order to optimize the benefits therefrom; and, (2) optimizing the placement of perforations, or contouring the trajectories of UDP's, within the subsequent "cluster(s)" to optimize the SRV obtained from the subsequent stimulation stages.

Description of Specific Embodiments

[137] A downhole hydraulic jetting assembly is provided herein. The jetting assembly is designed to direct a jetting nozzle and connected hydraulic hose through a window formed along a string of production casing, and then "jet" one or more boreholes outwardly into a subsurface formation. The lateral boreholes essentially represent ultra-deep perforations that are formed by using hydraulic forces directed through a flexible, high pressure jetting hose, having affixed to its distal end a high pressure jetting nozzle. The subject assembly capitalizes on a single hose and nozzle apparatus to continuously jet, optionally, both a casing exit and the subsequent lateral borehole.

[138] **Figure 1A** is a schematic depiction of a horizontal well **4**, with wellhead **5** located above the earth's surface **1**, and penetrating several series of subsurface strata **2a** through **2h** before reaching a pay zone **3**. The horizontal section **4c** of the wellbore **4** is depicted between a "heel" **4b** and a "toe" **4d**. Surface casing **6** is shown as cemented **7** fully from the surface

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casing shoe **8** back to surface **1**, while the intermediate casing string **9** is only partially cemented **10** from its shoe **11**. Similarly, production casing string **12** is only partially cemented **13** from its casing shoe **14**, though sufficiently isolating the pay zone **3**. Note how in the **Figure 1A** depiction of a typical horizontal wellbore, conventional perforations **15** within the production casing **12** are shown in up-and-down pairs, and are depicted with subsequent hydraulic fracture half-planes (or, "frac wings") **16**.

[139] **Figure 1B** is an enlarged view of the lower portion of the wellbore **4** of **Figure 1A**. Here, the horizontal section **4c** between the heel **4b** and the toe **4d** is more clearly seen. In this depiction, application of the subject apparati and methods herein replaces the conventional perforations (**15** in **Figure 1A**) with pairs of opposing horizontal UDP's **15** as depicted in **Figure 1B**, again with subsequently generated fracture half-planes **16**. Specifically depicted in **Figure 1B** is how the frac wings **16** are now better confined within the pay zone **3**, while reaching much further out from the horizontal wellbore **4c** into the pay zone **3**. Stated another way, in-zone fracture propagation is significantly enhanced by the pre-existence of the UDP's **15** as generated by the assembly and methods disclosed herein.

[140] **Figure 2** provides a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly **50** of the present invention, in one embodiment. The jetting assembly **50** is shown residing within a string of production casing **12**. The production casing **12** may have, for example, a 4.5-inch O.D. (4.0-inch I.D.). The production casing **12** is presented along a horizontal portion **4c** of the wellbore **4**. As noted in connection with **Figures 1A** and **1B**, the horizontal portion **4c** defines a heel **4b** and a toe **4d**.

[141] The jetting assembly **50** generally includes an internal system **1500** and an external system **2000**. The jetting assembly **50** is designed to be run into a wellbore **4** at the end of a working string, sometimes referred to herein as a "conveyance medium." Preferably, the working string is a string of coiled tubing **100**. The conveyance medium **100** may be conventional coiled tubing. Alternatively, a "bundled" product that incorporates electrically conductive wiring and data conductive cables (such as fiber optic cables) around the coiled tubing core, protected by an erosion/abrasion resistant outer layer(s), such as PFE and/or Kevlar, or even another (outer) string of coiled tubing may be used. It is observed that fiber

optic cables have a practically negligible diameter, and are oilfield-proven to be efficient in providing direct, real-time data transmission and communications with downhole tools. Other emerging transmission media such as carbon nanotube fibers may also be employed.

[142] Other conveyance media may be used for the jetting assembly **50**. These include, for example, a standard e-coil system, a customized FlatPAK® assembly, PUMPTEK's® Flexible Steel Polymer Tubing ("FSPT") or Flexible Tubing Cable ("FTC") tubing. Alternatively, tubing have PTFE (Polytetrafluorethylene) and Kevlar®-based materials, or Draka Cableteq USA, Inc.'s® Tubing Encapsulated Cable ("TEC") system may be used. In any instance, it is desirable that the conveyance medium **100** be flexible, somewhat malleable, non-conductive, pressure resistant (to withstand high pressure fracturing fluids optionally being pumped down the annulus), temperature resistant (to withstand bottom hole wellbore operating temperatures, often in excess of 200° F, and sometimes exceeding 300° F), chemical resistant (at least in resistance to the additives included in the frac fluids), friction resistant (to minimize the downhole pressure loss due to friction while pumping the frac treatment), erosion resistant (to withstand the erosive effects of afore-mentioned annular fracturing fluids) and abrasion resistant (to withstand the abrasive effects of proppants suspended in the aforementioned annular fracturing fluids).

[143] If a standard coiled tubing string is employed, communications and data transmission may be accomplished by hydro-pulse technology (or so-called mud-pulse telemetry), acoustic telemetry, EM telemetry, or some other remote transmission/reception system. Similarly, electricity for operating the apparatus may be generated downhole by a conventional mud motor(s), which would allow the electrical circuitry for the system to be confined below the end of the coiled tubing. The present hydraulic jetting assembly **50** is not limited by the data transmission system or the power transmission or the conveyance medium employed unless expressly so stated in the claims.

[144] It is preferred to maintain an outer diameter of the coiled tubing **100** that leaves an annular area within the approximate 4.0" I.D. of the casing **12** that is greater than or equal to the cross-sectional area open to flow for a 3.5" O.D. frac (tubing) string. This is because, in the preferred method (after jetting one or more, preferably two opposing mini-laterals, or even

specially contoured "clusters" of small-diameter lateral boreholes), fracture stimulation can immediately (after repositioning the tool string slightly uphole) take place down the annulus between the coiled tubing conveyance medium **100** plus the external system **2000**, and the well casing **12**. For 9.2#, 3.5" O.D. tubing (i.e., frac string equivalent), the I.D. is 2.992 inches, and the cross-sectional area open to flow is 7.0309 square inches. Back-calculating from this same 7.0309 in^2 equivalency yields a maximum O.D. available for both the coiled tubing conveyance medium **100** and the external system **2000** (having generally circular cross-sections) of 2.655". Of course, a smaller O.D. for either may be used provided such accommodate a jetting hose **1595**.

[145] In the view of **Figure 2**, the assembly **50** is in an operating position, with a jetting hose **1595** being run through a whipstock **1000**, and a jetting nozzle **1600** passing through a first window "**W**" of the production casing **12**. At the end of the jetting assembly **50**, and below the whipstock **1000**, are several optional components. These include a conventional mud motor **1300**, an external (conventional) tractor **1350** and a logging sonde **1400**. These components are shown and described more fully below in connection with **Figure 4**.

[146] **Figure 3** is a longitudinal, cross-sectional view of the internal system **1500** of the hydraulic jetting assembly **50** of **Figure 2**. The internal system **1500** is a steerable system that, when in operation, is able to move within and extend out of the external system **2000**. The internal system **1500** is comprised primarily of:

(1) power and geo-control components;

(2) a jetting fluid intake;

(3) the jetting hose **1595**; and

(4) the jetting nozzle **1600**.

[147] The internal system **1500** is designed to be housed within the external system **2000** while being conveyed by the coiled tubing conveyance medium **100** and the attached external system **2000** in to and out of the parent wellbore **4**. Extension of the internal system **1500** from and retraction back into the external system **2000** is accomplished by the application of: (a) hydraulic forces; (b) mechanical forces; or (c) a combination of hydraulic and mechanical

forces. Beneficial to the design of the internal **1500** and external **2000** systems comprising the hydraulic jetting apparatus **50** is that transport, deployment, or retraction of the jetting hose **1595** never requires the jetting hose to be coiled. Specifically, the jetting hose **1595** is never subjected to a bend radius smaller than the I.D. of production casing **12**, and that only incrementally while being advanced along the whipstock **1050** of the jetting hose whipstock member **1000** of the external system **2000**. Note the jetting hose **1595** is typically ¼th" to $^{5}/_{8}$ths" I.D., and up to approximately 1" O.D., flexible tubing that is capable of withstanding high internal pressures.

[148] The internal system **1500** first includes a battery pack **1510**. **Figure 3A** provides a cut-away perspective view of the battery pack **1510** of the internal system **1500** of **Figure 3**. Note this section **1510** has been rotated 90° from the horizontal view of **Figure 3** to a vertical orientation for presentation purposes. An individual AA battery **1551** is shown in a sequence of end-to-end like batteries forming the battery pack **1550**. Protection of the batteries **1551** is primarily via a battery pack casing **1540** which is sealed by an upstream battery pack end cap **1520** and a downstream battery pack end cap **1530**. These components (**1540**, **1520**, and **1530**) present exterior faces exposed to the high pressure jetting fluid stream. Accordingly, they are preferably constructed of or are coated with a non-conductive, highly abrasion/erosion/corrosion resistant material.

[149] The upstream battery pack end cap **1520** has a conductive ring about a portion of its circumference. When the internal system **1500** is "docked" (i.e., matingly received into a docking station **325** of the external system **2000**) the battery pack end cap **1520** can receive and transmit current and, thus, re-charge the battery pack **1550**. Note also that the end caps **1520** and **1530** can be sized so as to house and protect any servo, microchip, circuitry, geospatial or transmitter/receiver components within them.

[150] The battery pack end-caps **1520**, **1530** may be threadedly attached to the battery pack casing **1540**. The battery pack end-caps **1520**, **1530** may be constructed of a highly erosive- and abrasive-resistant, high pressure material, such as titanium, perhaps even further protected by a thin, highly erosive- or abrasive-resistant coating, such as polycrystalline diamond. The shape and construction of the end-caps **1520**, **1530** are preferably such that they

can deflect the flow of high pressure jetting fluid without incurring significant wear. The upstream end cap **1520** must deflect flow to an annular space (not shown in **Figure 3**) between the battery casing **1540** and a surrounding jetting hose conduit **420** (seen in **Figure 3C**) of a jetting hose carrier system (shown at **400** in **Figure 4D-1**). The downstream end-cap **1530** bounds part of the flow path of the jetting fluid from this annular space down into the I.D. of the jetting hose **1595** itself through a jetting fluid receiving (or, "intake") funnel (shown at **1570** in **Figure 3B-1**).

[151] Thus, the path of the high pressure hydraulic jetting fluid (with or without abrasives) is as follows:

(1) Jetting fluid is discharged from a high pressure pump at the surface **1** down the I.D. of the coiled tubing conveyance medium **100**, at the end of which it enters the external system **2000**;

(2) Jetting fluid enters the external system **2000** through a coiled tubing transition connection **200**;

(3) Jetting fluid enters the main control valve **300** through a jetting fluid passage **345**;

(4) Because the main control valve **300** is positioned to receive jetting fluid (as opposed to hydraulic fluid), a sealing passage cover **320** will be positioned to seal a hydraulic fluid passage **340**, leaving the only available fluid path through the jetting fluid passage **345**, the discharge of which is sealingly connected to the jetting hose conduit **420** of the jetting hose carrier system **400**;

(5) Upon entering the jetting hose conduit **420**, the jetting fluid will first pass by a docking station **325** (which is affixed within the jetting hose conduit **420**) through the annulus between the docking station **325** and the jetting hose conduit **420**;

(6) Because the jetting hose **1595** itself resides in the jetting hose conduit **420**, the high pressure jetting fluid must now either go through or around the jetting hose **1595**; and

(7) Because of the internal system's **1500** seal **1580U**, which seals the annulus between the jetting hose **1595** and the jetting hose conduit **420**, jetting fluid cannot go around the jetting hose **1595** (note this hydraulic pressure on the seal assembly **1580** is the force that tends to pump the internal system **1500**, and hence the jetting hose **1595**, "down the hole") and thus jetting fluid is forced to go through the jetting hose **1595** according to the following path:

(a) jetting fluid first passes the top of the internal system **1500** at the upstream battery pack end cap **1520**,

(b) jetting fluid then passes through the annulus between the battery pack casing **1540** and the jetting hose conduit **420** of the jetting hose carrier system **400**;

(c) after jetting fluid passes the downstream battery pack end cap **1530**, it is forced to flow between battery pack support conduits **1560**, and into a jetting fluid receiving funnel **1570**; and

(d) because the jetting fluid receiving funnel **1570** is rigidly and sealingly connected to the jetting hose **1595**, jetting fluid is forced into the I.D. of jetting hose **1595**.

[152] Worthy of note in the above-described jetting fluid flow sequence are the following initiation conditions:

(i) an internal tractor system **700** is first engaged to translate a discreet length of jetting hose **1595** in a downstream direction, such that the jetting nozzle **1600** and jetting hose **1595** enter the jetting hose whipstock **1000** and specifically, after traveling a fixed distance within the inner wall (shown at **1020** in **Figure 4H-1**), are forced radially outward to engage first the interior wall of production casing **12** and then engage the upper curved face **1050.1** of whipstock member **1050**, at which point,

(ii) the jetting hose **1595** is curvedly 'bent' approximately 90°, assuming its pre-defined bend radius (shown at **1599** in **Figure 4H-1**) and directing the jetting nozzle

1600 attached to its terminal end to engage the precise point of desired casing exit **"W"** within the I.D. of the production casing **12**; at which point

(iii) increased torque within the internal tractor system's **700** gripper assemblies **750** is then realized, a signal for which is immediately conveyed electronically to the surface, signaling the operator to shut down rotation of the grippers (illustrative griper seen at **756** in **Figure 4F-2b**).

(Practically, such shut-down could be pre-programmed into the operating system at a certain torque level.) Note that during stages (i) through (iii), a pressure regulator valve (seen at **610** in **Figure 4E-2**) is in an "open" position This allows hydraulic fluid in the annulus between the jetting hose **1595** and the surrounding jetting hose conduit **420** to bleed-off. Once the tip of jetting nozzle **1600** engages the I.D. (casing wall) of production casing **12**, then the operator may:

(iv) reverse the direction of rotation of the grippers **756** to translate the jetting hose **1595** back into the jetting hose (or inner) conduit **420**; and

(v) switch a main control valve **300** to begin pumping hydraulic fluid though the hydraulic fluid passage **340**, down the conduit-carrier annulus **440**, through the pressure regulator valve **610**, and into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** to both: (1) pump upwards against lower seals **1580L** of the jetting hose's seal assembly **1580** to re-extend the jetting hose **1595** in a taught position; and, (2) assist the (now reversed) gripper assemblies **750** in positioning the internal system **1500** such that the jetting nozzle **1600** has the desired stand-off distance (preferably less than 1 inch) between itself and the I.D. of the production casing **12** to begin jetting the casing exit.

Upon reaching this desired stand-off distance, rotation of grippers **756** ceases, and pressure regulator valve **610** is closed to lock down the internal system at the desired, fixed position for jetting the casing exit **"W"**.

[153] Referring back to **Figure 3A**, in one embodiment the interior of the downstream end-cap **1530** houses a micro-geo-steering system. The system may include a micro-transmitter, a micro-receiver, a micro-processor, and one or more current regulators. This geo-

steering system is electrically or fiber-optically connected to a small geo-spatial IC chip (shown at **1670** in **Figure 3F-1c** and discussed more fully below) located in the body of the jetting nozzle **1600**. In this way, nozzle orientation data may be sent from the jetting nozzle **1600** to the micro-processor (or appropriate control system) which, coupled with the values of dispensed hose length, can be used to calculate the precise geo-location of the nozzle at any point, and thus the contour of the UDP's path. Conversely, geo-steering signals may be sent from the control system (such as a micro-processor in the docking station or at the surface) to modify, through one or more electrical current regulators, individualized current strengths down to each of the (at least three) actuator wires (shown at **1590A** in **Figure 3F-1c**), thus redirecting the nozzle as desired.

[154] The geo-steering system can also be utilized to control the rotational speed of a rotor body within the jetting nozzle **1600**. As will be described more fully below, the rotating nozzle configuration utilizes the rotor portion **1620** of a miniature direct drive electric motor assembly to also form a throat and end discharge slot **1640** of the rotating nozzle itself. Rotation is induced via electromagnetic forces of a rotor/stator configuration. In this way, rotational speeds can be governed in direct proportion to the current supplied to the stators.

[155] As depicted in **Figures 3F-1** through **3F-3**, the upstream portion of the rotor (in this depiction, a four-pole rotor) **1620** includes a near-cylindrical inner diameter (the I.D. actually reduces slightly from the fluid inlet to the discharge slot to further accelerate the fluid before it enters the discharge slot) that provides a flow channel for the jetting fluid through the center of the rotor **1620**. This near-cylindrical flow channel then transitions to the shape of the nozzle's **1600** discharge slot **1640** at its far downstream end. This is possible because, instead of the typical shaft and bearing assembly inserted longitudinally through the center diameter of the rotor **1620**, the rotor **1620** is stabilized and positioned for balanced rotation about the longitudinal axis of the rotor **1620** by a single set of bearings **1630** positioned about the interior of the upstream butt end, and outside the outer diameter of the flow channel ("nozzle throat") **1650**, such that the bearings **1630** stabilize the rotor body **1620** both longitudinally and axially.

[156] Referring now to **Figure 3B-1a**, and again discussing the internal system **1500**, a cross-sectional view of the battery pack section **1510**, taken across line **A-A'** of **Figure 3B-1** is

shown. The view is taken at the top of the bottom end cap **1530** of the battery pack **1510** looking down into a jetting fluid receiving funnel **1570**. Visible in this figure are three wires **1590** extending away from the battery pack **1510**. Using the wires **1590**, power is sent from the "AA"-size lithium batteries **1551** to the geo-steering system for controlling the rotating jet nozzle **1600**. By adjusting current through the wires **1590**, the geo-steering system controls the rate of rotation of the rotor **1620** along with its orientation.

[157] Note that because the longitudinal axis of the nozzle's discharge stream is designed to be continuous to and aligned with that of the nozzle throat, there is virtually no axial moment acting on the nozzle from thrust of the exiting jetting fluid. That is, as the nozzle is designed to operate in an axially "balanced" condition, the torque moment required to actually rotate the nozzle about its longitudinal axis is relatively small. Similarly, in that relatively low rotational speeds (RPM's) are required for rotational excavation, the electromagnetic force required from the nozzle's rotor/stator interaction is relatively small as well.

[158] Note from **Figure 3** that the jetting nozzle **1600** is located at the far downstream end of the jetting hose **1595**. Though the diameters of the components of the internal system **1500** must meet some rather stringent diameter constraints, the respective lengths of each component (with the exception of the jetting nozzle **1600** and, if desired, one or more jetting collars) are typically far less restricted. This is because the jetting nozzle **1600** and collars are the only components affixed to the jetting hose **1595** that will ever have to make the approximate 90° bend as directed by the whipstock face **1050.1**. All other components of the internal system **1500** will always reside at some position within the jetting hose carrier system **400**, and above the jetting hose pack-off section **600** (discussed below).

[159] The length of many of the components can also be adjusted. For example, though the battery pack **1510** in **Figure 3A** is depicted to house six AA batteries **1551**, a much greater number could be easily accommodated by simply constructing a longer battery pack casing **1540**. Similarly, the battery pack end-caps **1520**, **1530**, the support columns **1560**, and the fluid intake funnel **1570** may be substantially elongated as well to accommodate fluid flow and power needs.

[160] Referring again to the docking station **325**, the docking station **325** serves as a physical "stop" beyond which the internal system **1500** can no longer travel upstream. Specifically, the upstream limit of travel of the internal system **1500** (comprised primarily of the jetting hose **1595**) is at that point where the upstream battery pack end cap **1520** lodges (or, "docks") within a bottom, conically-shaped receptacle **328** of the docking station **325**. The receptacle **328** serves as a lower end cap. The receptacle **328** provides matingly conductive contacts which line up with the upstream battery pack end cap **1520** to form a docking point. In this way, a transfer of data and/or electrical power (specifically, to recharge batteries **1551**) can occur while "docked."

[161] The docking station **325** also has a conically-shaped end-cap **323** at the upstream (proximal) end of the docking station **325**. The conical shape serves to minimizing erosive effects by diverting the flow of jetting fluid around the body thereof, thereby aiding in the protection of the system components housed within the docking station **325**. Depending on the guidance, steering, and communications capabilities desired, an upper portion **323** of the docking station **325** can house the servo, transmission, and reception circuitry and electronics systems designed to communicate directly (either in continuous real time, or only discretely while docked) with counterpart systems in the internal system **1500**. Note, as shown in **Figure 3**, the O.D. of the cylindrical docking station **325** is approximately equal to that of the jetting hose **1595**.

[162] The internal system **1500** next includes a jetting fluid receiving funnel **1570**. **Figure 3B-1** includes a cut-away perspective view of the jetting fluid receiving funnel **1570**, with an axial cross-sectional view along **B-B'** shown as **Figure 3B-1b**. The jetting fluid receiving funnel **1570** is located below the base of the battery pack section **1510**, shown and described above in connection with **Figure 3A**. As the name implies, the jetting fluid receiving funnel **1570** serves to guide the jetting fluid into the interior of the jetting hose **1595** during the casing exit and mini-lateral formation process. Specifically, the annular flow of jetting fluid (e.g., passing along the outside of battery pack casing **1540** and subsequently the battery pack end cap **1530**, and inside the I.D. of jetting hose conduit **420**) is forced to transition to flow between the three battery pack support conduits **1560**, because an upper seal (seen in **Figure 3** at **1580U**) precludes any fluid flow along a path exterior to the jetting hose

1595. Thus, all flow of jetting fluid (as opposed to hydraulic fluid) is forced between conduits **1560** and into fluid receiving funnel **1570**.

[163] In the design of **Figure 3B-1**, three columnar supports **1560** are used to house the wires **1590**. The columnar supports **1560** also provide an area open to fluid flow. The spacing between the supports **1560** is designed to be significantly greater than that provided by the I.D. of the jetting hose **1595**. At the same time, the supports **1560** have I.D.'s large enough to house and protect up to an AWG #5 gauge wire **1590**. The columnar supports **1560** also support the battery pack **1510** at a specific distance above the jetting fluid intake funnel **1570** and the jetting hose seal assembly **1580**. The supports **1560** may be sealed with sealing end caps **1562**, such that removal of the end caps **1562** provides access to the wiring **1590**.

[164] **Figure 3B-1b** provides a second axial, cross-sectional view of the fluid intake funnel **1570**. This view is taken across line **B-B'** of **Figure 3B-1**. The three columnar supports **1560** are again seen. The view is taken at the top of the jetting fluid inlet, or receiving funnel **1570**.

[165] Downstream from the jetting fluid receiving funnel **1570** is a jetting hose seal assembly **1580**. **Figure 3C** is a cut-away perspective view of the seal assembly **1580**. In the view of **Figure 3C**, columnar support members **1560** and electrical wiring **1590** have been removed for the sake of clarity. However, the receiving funnel **1570** is again seen at the upper end of the seal assembly **1580**.

[166] Also visible in **Figure 3C** is an upper end of the jetting hose **1595**. The jetting hose **1595** has an outermost jetting hose wrap O.D. **1595.3** (also seen in **Figure 3D-1a**) that, at points, may engage the jetting hose conduit **420**. A micro-annulus **1595.420** (shown in **Figures 3D-1** and **3D-1a**) is formed between the jetting hose **1595** and the surrounding conduit **420**. The jetting hose **1595** also has a core (O.D. **1595.2,** I.D. **1595.1**) that transmits jetting fluid during the jetting operation. The jetting hose **1595** is fixedly connected to the seal assembly **1580**, meaning that the seal assembly **1580** moves with the jetting hose **1595** as the jetting hose advances into a mini-lateral.

[167] As previously described, the upper seal **1580U** of the jetting hose's seal assembly **1580** (shown as a solid portion with a slightly concave upwards upper face) precludes any continued downstream flow of jetting fluid outside of the jetting hose **1595**. Similarly, the lower seal **1580L** of this seal assembly **1580** (shown as a series of concave-downwards cup faces) precludes any upstream flow of hydraulic fluid from below. Note how any upstream-to-downstream hydraulic pressure from the jetting fluid will tend to expand the jetting fluid intake funnel **1570** and, thus, urge the upper seal **1580U** of the seal assembly **1580** radially outwards to sealingly engage the I.D. **420.1** of the jetting hose carrier's (inner) jetting hose conduit **420**. Similarly, any downstream-to-upstream hydraulic pressure from the hydraulic fluid radially expands bottom cup-like faces making up the lower seal **1580L** to sealingly engage the I.D. **420.1** of the jetting hose carrier's inner conduit **420**. Thus, when jetting fluid pressure is greater than the trapped hydraulic fluid pressure, the overbalance will tend to "pump" the entire assembly "down-the-hole". Conversely, when the pressure overbalance is reversed, hydraulic fluid pressure will tend to "pump" the entire seal assembly **1580** and connected hose **1595** back "up-the-hole".

[168] Returning to **Figures 2** and **3**, the upper seal **1580U** provides an upstream pressure and fluid-sealed connection for the internal system **1500** to the external system **2000**. (Similarly, as will be discussed further below, a pack-off seal assembly **650** within a pack-off section **600** provides a downstream pressure and fluid-sealed connection between the internal system **1500** and the external system **2000**.) The seal assembly **1580** includes seals **1580U**, **1580L** that hold incompressible fluid between the hose **1595** and the surrounding conduit **420**. In this way, the jetting hose **1595** is operatively connected to the coiled tubing string **100** and sealingly connected to the external system **2000**.

[169] **Figure 3C** illustrates utility of the sealing mechanisms involved in this upstream seal **1580**. During operation, jetting fluid passes:

(1) through an annulus **420.2** between the battery pack casing **1540** and the jetting hose carrier inner conduit **420**;

(2) between the battery pack support conduits **1560**;

(3) into the fluid receiving funnel **1570**;

(4) down the core **1595.1** (I.D.) of the jetting hose **1595**; and

(5) then exits the jetting nozzle **1600**.

[170] As noted, the downward hydraulic pressure of the jetting fluid acting upon the axial cross-sectional area of the jetting hose's fluid receiving funnel **1570** creates an upstream-to-downstream force that tends to "pump" the seal assembly **1580** and connected jetting hose **1595** "down the hole." In addition, because the components of the fluid receiving funnel **1570** and the supporting upper seal **1580U** of the seal assembly **1580** are slightly flexible, the net pressure drop described above serves to swell and flare the outer diameters of upper seal **1580U** radially outwards, thus producing a fluid seal that precludes fluid flow behind the hose **1595**.

[171] **Figure 3D-1** provides a longitudinal, cross-sectional view of the "bundled" jetting hose **1595** of the internal system **1500** as it resides in the jetting hose carrier's inner conduit **420**. Also included in the longitudinal cross section are perspective views (dashed lines) of electrical wires **1590** and data cables **1591**. Note from the axial cross-sectional view of **Figure 3D-1a**, that all of the electrical wires **1590** and data cables **1591** in the "bundled" jetting hose **1595** safely reside within the outermost jetting hose wrap **1595.3**.

[172] In the preferred embodiment, the jetting hose **1595** is a "bundled" product. The hose **1595** may be obtained from such manufacturers as Parker Hannifin Corporation. The bundled hose includes at least three electrically conductive wires **1590**, and at least one, but preferably two dedicated data cables **1591** (such as fiber optic cables), as depicted in **Figures 3B-1b** and **3D-1a**. Note these wires **1590** and fiber optic strands **1591** are located on the outer perimeter of the core **1595.2** of the jetting hose **1595**, and surrounded by a thin outer layer of a flexible, high strength material or "wrap" (such as Kevlar®) **1595.3** for protection. Accordingly, the wires **1590** and fiber optic strands **1591** are protected from any erosive effects of the high-pressure jetting fluid.

[173] Moving now down the hose **1595** to the distal end, **Figure 3E** provides an enlarged, cross sectional view of the end of the jetting hose **1595**. Here, the jetting hose **1595** is passing through the whipstock member **1000**, and ultimately along the whipstock face **1050.1** to casing exit "**W**". A jetting nozzle **1600** is attached to the distal end of the jetting hose **1595**. The

jetting nozzle **1600** is shown in a position immediately subsequent to forming an exit opening, or window "**W**" in the production casing **12**. Of course, it is understood that the present assembly **50** may be reconfigured for deployment in an uncased wellbore.

[174] As described in the related applications, the jetting hose **1595** immediately preceding this point of casing exit "**W**" spans the entire I.D. of the production casing **12**. In this way, a bend radius "**R**" of the jetting hose **1595** is provided that is always equal to the I.D. of the production casing **12**. This is significant as the subject assembly **50** will always be able to utilize the entire casing (or wellbore) I.D. as the bend radius "**R**" for the jetting hose **1595**, thereby providing for utilization of the maximum I.D./O.D hose. This, in turn, provides for placement of maximum hydraulic horsepower ("HHP") at the jetting nozzle **1600**, which further translates in the capacity to maximize formation jetting results such as penetration rate, or the lateral borehole diameter, or some optimization of the two.

[175] It is observed here that there is a consistency of three "touch points" for the bend radius "**R**" of the jetting hose **1595**. First, there is a touch point where the hose **1595** contacts the I.D. of the casing **12**. This occurs at a point directly opposite and slightly (approximately one casing I.D. width) above the point of casing exit "**W**." Second, there is a touch point along a whipstock curved face **1050.1** of the whipstock member **1000** itself. Finally, there is a touch point against the I.D. of the casing **12** at the point of casing exit "**W**," at least until the window "**W**" is formed.

[176] As depicted in **Figure 3E** (and in **Figure 4H-1**), the jetting hose whipstock member **1000** is in its set and operating position within the casing **12**. (U.S. Patent No. 8,991,522, also demonstrates the whipstock member **1050** in its run-in position.) The actual whipstock **1050** within the whipstock member **1000** is supported by a lower whipstock rod **1060**. When the whipstock member **1000** is in its set-and-operating position, the upper curved face **1050.1** of the whipstock member **1050** itself spans substantially the entire I.D. of the casing **12**. If, for example, the casing I.D. were to vary slightly larger, this would obviously not be the case. The three aforementioned "touch points" of the jetting hose **1595** would remain the same, however, albeit while forming a slightly larger bend radius "**R**" precisely equal to the (new) enlarged I.D. of casing **12**.

[177] As described in greater detail in the co-owned U.S. Patent No. 8,991,522, the whipstock rod is part of a tool assembly that also includes an orienting mechanism, and an anchoring section that includes slips. Once the slips are set, the orienting mechanism utilizes a ratchet-like action that can rotate the upstream portion of the whipstock member **1000** in discreet 10° increments. Thus, the angular orientation of the whipstock member **1000** within the wellbore may be incrementally changed downhole.

[178] In one embodiment, the whipstock **1050** is a single body having an integral curved face configured to receive the jetting hose and redirect the hose about 90 degrees. Note the whipstock **1050** is configured such that, at the point of casing exit when in set and operating position, it forms a bend radius for the jetting hose that spans the entire ID of the parent wellbore's production casing **12**.

[179] **Figure 4H-1** is a cross-sectional view of the whipstock member **1000** of the external system of **Figure 4**, but shown vertically instead of horizontally. The jetting hose of the internal system (**Figure 3**) is shown bending across the whipstock face **1050**, and extending through a window "**W**" in the production casing **12**. The jetting nozzle of the internal system **1500** is shown affixed to the distal end of the jetting hose **1595**.

[180] **Figure 4H-1a** is an axial, cross-sectional view of the whipstock member **1000**, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member **1000** at line **O-O′** to the start of the jetting hose's bend radius as it approaches line **P-P′**.

[181] **Figure 4H-1b** depicts an axial, cross-sectional view of the whipstock member **1000** at line **P-P′**. Note the adjustments in location and configuration of both the whipstock member's wiring chamber and hydraulic fluid chamber from line **O-O′** to line **P-P′**.

[182] As noted above, the present assembly **50** is preferably used in connection with a nozzle having a unique design. **Figures 3F-1a** and **3F-1b** provide enlarged, cross-sectional views of the nozzle **1600** of **Figure 3**, in a first embodiment. The nozzle **1600** takes advantage of a rotor/stator design, wherein the forward portion **1620** of the nozzle **1600**, and hence the forward jetting slot (or "port") **1640**, is rotated. Conversely, the rearward portion of the nozzle

1600, which itself is directly connected to jetting hose **1595**, remains stationary relative to the jetting hose **1595**. Note in this arrangement, the jetting nozzle **1600** has a single forward discharge slot **1640**.

[183] First, **Figure 3F-1a** presents a basic nozzle body having a stator **1610** . The stator **1610** defines an annular body having a series of inwardly facing shoulders **1615** equi-distantly spaced therein. The nozzle **1600** also includes a rotor **1620**. The rotor **1620** also defines a body and has a series of outwardly facing shoulders **1625** equi-distantly spaced therearound. In the arrangement of **Figure 3F-1a**, the stator body **1610** has six inwardly-facing shoulders **1615**, while the rotor body **1620** has four outwardly-facing shoulders **1625**.

[184] Residing along each of the shoulders **1615** is a small diameter, electrically conductive wire **1616** wrapping the stator's inwardly facing shoulders (or "stator poles") **1615** with multiple wraps. Movement of electrical current through the wires **1616** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** (or battery pack **1550**) of **Figure 3A**.

[185] As noted above, the stator **1610** and rotor **1620** bodies are analogous to a direct drive motor. The stator **1610** (in this depiction, a six-pole stator) of this direct drive electric motor analog is included within the outer body of the nozzle **1600** itself, with each pole protruding directly from the body **610**, and commensurately wrapped in electric wire **1616**. The current source for the wire **1616** wrapping the stator poles is derived through the 'bundled' electrical wires**1590** of the jetting hose **1595**, and is thereby manipulated by the current regulator and micro-servo mechanism housed in the conically-shaped battery pack's (downstream) end-cap **1530**. Rotation of the rotor **1620** of the nozzle **1600**, and particularly the speed of rotation (RPM's), is controlled via induced electro-magnetic forces of a DC rotor/stator system.

[186] Note that **Figure 3F-1a** could serve as a representative axial cross section of essentially any basic direct current electromagnetic motor, with the central shaft/bearing assembly removed. By eliminating a central shaft and bearings, the nozzle **1600** can now accommodate a nozzle throat **1650** placed longitudinally through its center. The throat **1650** is suitable for conducting high pressure fluid flow.

[187] **Figure 3F-1b** provides a longitudinal, cross-sectional view of the nozzle **1600** of **Figure 3F-1a**, taken across line **C-C'** of **Figure 3F-1b**. The rotor **1620** and surrounding stator **1610** are again seen. Bearings **1630** are provided to facilitate relative rotation between the stator body **1610** and the rotor body **1620**.

[188] It is observed in **Figure 3F-1b** that the nozzle throat **1650** has a conically-shaped narrowing portion before terminating in the single fan-shaped discharge slot **1640**. This profile provides two benefits. First, additional non-magnetic, high-strength material may be placed between the throat **1650** and the magnetized rotor portion **1625** of the forward portion of the nozzle body **1620**. Second, final acceleration of the jetting fluid through the throat **1650** is accommodated before entering the discharge slot **1640**. The size, placement, load capacity, and freedom of movement of the bearings **1630** are considerations as well. The forward slot **1640** begins with a relatively semi-hemispherically shaped opening, and terminates at the forward portion of the nozzle **1600** in a curved, relatively elliptical shape (or, optionally, a curved rectangle with curved small ends.)

[189] Simulations were conducted with the single planar slot slightly twisted such that the discharge angle(s) of the fluid generated sufficient thrust so as to rotate the nozzle **1600**. The observed problem was that nozzle rotation rates were hypersensitive to changes in fluid flow rates, leaving the concern of instantaneous and frequent overloading (with resultant failure) of the bearings **1630**. The solution was to design, as nearly as possible, a balanced single slot system, such that there is no appreciable axial thrust generated by fluid discharge. In other words, the nozzle **1600** is no longer sensitive to injection rate.

[190] At this point it is important to note the basic nozzle design criteria for the flow capacity of the combined flow path comprised of the throat **1650** and slot **1640** elements. That is, that these inner throat **1650** and slot **1640** elements of the nozzle **1600** retain dimensions that can approximate the dimensions, and resultant hydraulics, of conventional hydraulic jet casing perforators. Specifically, the nozzle **1600** depicted in **Figures 3F-1a** and **3F-1b** throat **1650** and slot **1640** dimensions that can approximate the perforating hydraulics obtained by a perforator's 1/8th-inch orifice. Note that the terminal width of slot **1640** can not only accommodate 100 mesh sand as an abrasive, but the larger sizes such as 80 mesh sand as well.

[191] Angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown in **Figure 3F-1b**. (These angles are also shown in **Figures 3F-2b** and **3F-3b**, discussed below.) Angle Θ_{SLOT} **1641** represents the actual angle of the outer edges of the slot **1640**, and angle Θ_{MAX} **1642** represents the maximum Θ_{SLOT} **1641** achievable within the existing geometric and construction constraints of the nozzle **1600**. In **Figures 3F-1b, 3F-2b** and **3F-3b**, both angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown at 90 degrees. This geometry, coupled with rotation of the rotor body **1620** (and, consequently, rotation of the jetting slot **1640**) provides for the erosion of a hole diameter that is at least equal to the nozzle's outer diameter even at a stand-off (e.g., the distance from the very tip of the nozzle **1600** at the longitudinal center line to the target rock along the same centerline) of zero.

[192] **Figures 3F-2a** and **3F-2b** provide longitudinal, cross-sectional views of the jetting nozzle of **Figure 3E**, in an alternate embodiment. In this embodiment, multiple ports are used, including both a forward discharge port **1640** and a plurality of rearward thrust jets **1613**, for a modified nozzle **1601**.

[193] The nozzle configuration of **Figures 3F-2a** and **3F-2b** is identical to the nozzle configuration **1600** of **Figure 3F-1a**, with the exception of three additional components:

(1) the use of rearward thrusting jets **1613**;

(2) the use of a slideable collar **1633** biased by a biasing mechanism (spring) **1635**; and

(3) the use of a slideable nozzle throat insert **1631**.

The first of these three additional components, rearward thrusting jets **1613**, provide a rearward thrust that effectively drags the jetting hose **1595** along the lateral borehole, or mini-lateral, as it is formed. Preferably, five rearward thrust jets **1613** are used along the body **1610**, although variations of the number and/or exit angles **1614** of the jets **1613** may be utilized.

[194] **Figure 3F-2c** is an axial, cross-sectional view of the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**. This demonstrates the star-shaped jet pattern created by the multiple rearward thrust jets **1613**. Five points are seen in the star, indicating five illustrative rearward thrust jets **1613**.

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[195] Note particularly in a homogeneous host pay zone, the forward (jetting) hydraulic horsepower requirement necessary to excavate fresh rock at a given rate of penetration would be essentially constant. The rearward thrust hydraulic horsepower requirement, however, is constantly increasing in proportion to the growth in length of the mini-lateral. As continued extension of the mini-lateral requires dragging an ever-increasing length of jetting hose **1595** along an ever-increasing distance, the rearward thrusting hydraulic horsepower requirement to maintain forward propulsion of the jetting nozzle **1601** and hose **1595** increases commensurately.

[196] It may be required to consume upwards of two-thirds of available horsepower through the rearward thrust jets **1613** in order to extend the jetting hose **1595** and connected nozzles **1601**, **1602** to the furthest lateral extent. If this maximum requirement is utilized constantly throughout the borehole jetting process, much of the available horsepower will be wasted in the early stages in jetting the bore. This is particularly detrimental when the same jetting nozzle and assembly utilized in rock excavation is also utilized to form the initial casing exit "**W**." Further, if the same rearwards jetting forces cutting the 'points' of the star-shaped rock excavation are active in the wellbore tubulars (particularly, while jetting the casing exit "**W**") significant damage to the nearby tool string (particularly, the whipstock member **1000**) and the well casing **12** could result. Hence, the optimum design would provide for the activation/deactivation of the rearward thrust jets **1613** when desired, particularly, after the casing exit is formed and after the first 5 or 10 feet of lateral borehole is formed.

[197] There are several possible mechanisms by which jet activation/deactivation may be enabled to help conserve HHP and protect the tool string and tubulars. One approach is mechanical, whereby the opening and closing of flow to the jets **1613** is actuated by overcoming the force of a biasing mechanism. This is shown in connection with the spring **1635** of **Figures 3F-2a** and **3F-2b**, where a throat insert **1631** and a slideable collar **1633** are moved together to open rearward thrust jets **1613**. Another approach is electromagnetic, wherein a magnetic port seal is pulled against a biasing mechanism (spring **1635**) by electromagnetic forces. This is shown in connection with **Figures 3F-3a** and **3F-3c**, discussed below.

[198] The second of the three additions incorporated into the nozzle design of **Figures 3F-2a** and **3F-2b** is that of a slideable collar **1633**. The collar **1633** is biased by a biasing mechanism (spring) **1635**. The function of this collar **1633**, whether directly or indirectly (by exerting a force on the slideable nozzle throat insert **1631**), is to temporarily seal the fluid inlets of the thrust jets **1613**. Note that this sealing function by the slideable collar **1633** is "temporary"; that is, unless a specific condition determined by the biasing mechanism **1635** is satisfied. As shown in the embodiment presented in **Figures 3F-2a** and **3F-2b**, the biasing mechanism **1635** is a simple spring.

[199] In **Figure 3F-2a**, the collar **1633** is in its closed position, while in **Figure 3F-2b** the collar **1633** is in its open position. Thus, a specific differential pressure exerted on the cross-sectional area of the slideable nozzle throat insert **1631** has overcome the pre-set compressive force of the spring **1635**.

[200] The third of the three additions incorporated into the nozzle **1601** design of **Figures 3F-2a** and **3F-2b** is that of a slideable nozzle throat insert **1631**. The slideable throat insert **1631** has two basic functions. First, the insert **1631** provides an intentional and pre-defined protrusion into the flow path within the nozzle throat **1650**. Second, the insert **1631** provides an erosion- and abrasion-resistant surface within the highest fluid velocity portion of the internal system **1500**. For the first of these functions, the degree of protrusion to be designed into the slideable nozzle throat insert **1631** is a function of at what point in mini-lateral formation the operator anticipates actuating the thrust jets **1613**.

[201] To illustrate, suppose that system hydraulics provide for a suitable pump rate of 0.5 BPM through the nozzle **1601** at the point of casing exit "**W**," and that this can be sustained at a surface pumping pressure of 8,000 psi. Suppose further that actuation of the thrust jets **1613** in the nozzle **1601** is not required until the nozzle **1601** achieves a lateral distance of 50 feet from the parent wellbore. That is, particularly while jetting the casing exit **"W"** itself and an abrasive mixture (say, of 1.0 ppg of 100 mesh sand in a 1 pound guar-based fresh water gel system) is being pumped, none of the jets**1613** have been opened (which could risk clogging by the abrasive in the jetting fluid mixture.) Consequently, no abrasives are included in the jetting fluid after it is sure that the nozzle **1600** has sufficiently cleared the casing exit "**W**".

Accordingly, while jetting the hole in production casing **12** to form casing exit "**W**", no rearwards jetting forces from fluids expelled through thrust jets **1613** can pose a threat to unintentionally damage either the jetting hose **1595**, the whipstock member **1000**, or the production casing **12**.

[202] Later, after generating the casing exit "**W**" plus a mini-lateral length of, say, approximately 50 feet, the pump pressure is increased to 9,000 psi, the incremental 1,000 psi increase in surface pumping pressure being sufficient to overcome the force of the biasing mechanism **1635** and act against the cross-sectional area of the protrusion of the insert **1631** to actuate the jets **1613**. Thus, at mini-lateral length of 50 feet from the parent wellbore **4**, the thrust jets **1613** are actuated, and high pressure rearwards thrust flow is generated through the jets **1613**.

[203] Suppose these conditions are sufficient to continue jetting a mini-lateral out to a lateral length of 300 feet. At 300 feet, the length of jetting hose laying against the floor of the mini-lateral is causing a commensurate frictional resistance such that it and the thrust forces generated through the thrust jets **1613** are in approximate equilibrium. (Instrumentation such as tensiometers, for example, would indicate this.) At this point, the pump rate is increased to, say, 10,000 psi, and the rearward thrust jets **1613** remain actuated, but at higher differential pressures and flow rates, thus generating higher pull force on the jetting hose **1595**.

[204] **Figures 3F-3a and 3F-3c** provide longitudinal, cross-sectional views of a jetting nozzle **1602**, in yet another alternate embodiment. Here, multiple rearward thrust jets **1613,** and a single forward jetting slot **1640**, are again used. A collar **1633** and spring **1635** are again used for providing selective fluid flow through rearward thrust jets **1613**.

[205] **Figures 3F-3b** and **3F-3d** provide axial, cross-sectional views of the jetting nozzle **1602** of **Figures 3F-3a** and **3F-3c**, respectively. These demonstrate the star-shaped jet pattern created by the multiple jets **1613**. Eight points are seen in the star, indicating two sets of four (alternating) illustrative thrust jets **1613**. In **Figures 3F-3a** and **3F-3b**, the collar **1633** is in its closed position, while in **Figures 3F-3c** and **3F-3d** the collar **1633** is in its open position permitting fluid flow through the jets **1613**. The biasing force provided by the spring **1635** has been overcome.

[206] The nozzle **1602** of **Figures 3F-3a** and **3F-3c** is similar to the nozzle **1601** of **Figures 3F-2a** and **3F-2b**; however, in the arrangement of **Figures 3F-3a** and **3F-3c**, an electro-magnetic force generating a downstream magnetic pull against the slideable collar **1633**, sufficient to overcome the biasing force of the biasing mechanism (spring) **1635**, replaces the hydraulic pressure force against the slideable throat insert **1631** in the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**.

[207] The nozzle **1602** of **Figures 3F-3a and 3F-3c** presents yet another preferred embodiment of a rotating nozzle **1602**, also suitable for forming casing exits and continued excavation through a cement sheath and host rock formation. In **Figures 3F-3a** and **3F-3c** (and in Figure **3G-1**, described in more detail below), it is the electromagnetic force generated by the rotor/stator system that must overcome the spring **1635** force to open hydraulic access to the rearward thrust jets **1613** (and **1713**). (Note that in **Figure 3G-1**, depicting an in-line hydraulic jetting collar, discussed more fully below, direct mechanical connection of internal turbine fins **740** to the slideable collar **733** change the biasing criteria to one of differential pressure, as with the jetting nozzle depicted in **Figure 3F-2a**). The key here is the ability to keep the fluid inlets to the rearward thrust jets **1613** (and **1713**) closed until the operator initiates opening them, specifically by increasing the pump rate, such that either (or both) the differential pressure through the nozzle and/or the nozzle rotation speed's proportional increase of electromagnetic pull on the slideable collars **1633 / 1733** opens access to the fluid inlets of the thrust jets **1613 / 1713**.

[208] It is also observed that in the nozzle **1602**, the number of rearward thrust jets **1613**, though also symmetrically placed about the circumference of the rotor **1610**, has been increased from a single set of five to two sets of four. Note that each of the four jets **1613** within each of the two sets are also symmetrically placed about the rotor **1610** circumference, orthogonally relative to each other; hence, the two sets of jets **1613** must overlap. Additionally, the path of each jet now not only travels through the rearward (stator) portion **1610** of the nozzle **1602**, but now also through the forward (rotor) section **1620** of the nozzle **1602**. Note, however, as depicted in **Figures 3F-3b** and **3F-3d**, whereas there are eight individual jet passages through the rearward (stator) portion **1610** of the nozzle **1602**, there are only four passing through the forward (rotor) section **1620** of the nozzle **1600**. Hence, rotation

of the forward (rotor) section **1620** of the nozzle **1602** will only provide for the alignment of, and subsequent fluid flow through, only one set of four jets **1613** at a time. In fact, for most of a single rotation's duration, the flow channels of the rotor **1620** will have no access to those of the stator **1610**, and are thereby effectively sealed. The result will be an oscillating (or, "pulsating") jetting flow through the rearward thrust jets **1613**.

[209] The commensurate subtraction of jetting fluid volumes going through the nozzle port **1640** produces a commensurate pulsating forward jetting flow for excavation, as well. The benefits of pulsating flow over and against continuous flow for excavation systems are well documented, and will not be repeated here. Note, however, the subject nozzle design not only captures the rock excavation benefits of a rotating jet, but also the benefits of a pulsating jet.

[210] Another embodiment of a thrust collar that employs an electromagnetic force is provided in **Figures 3G-1a** and **3G-1b**. **Figures 3G-1a** presents an axial, cross-sectional view of a basic body for a thrust jetting collar **1700** of the internal system **1500** of **Figure 3**. The view is taken through line **D-D'** of **Figure 3G-1b**. Here, as with the jetting nozzle **1602**, two layers of rearward thrust jets **1713** are again offered.

[211] The collar **1700** has a rear stator **1710** and an inner (rotating) rotor **1720**. The stator **1710** defines an annular body having a series of inwardly facing shoulders **1715** equi-distantly spaced therein, while the rotor **1720** defines a body having a series of outwardly facing shoulders **1725** equi-distantly spaced therearound. In the arrangement of **Figure 3G.1.a**, the stator body **1710** has six inwardly-facing shoulders **1715**, while the rotor body **1720** has four outwardly-facing shoulders **1725**.

[212] Residing along each of the shoulders **1715** is a small diameter, electrically conductive wire **1716** wrapping the stator's **1710** inwardly facing shoulders (or, "stator poles") **1715** with multiple wraps. Movement of electrical current through the wires **1716** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** of **Figure 3A**.

[213] **Figure 3G-1b** is a longitudinal, cross-sectional view of the nozzle **1700**. **Figure 3G-1c** is an axial cross section intersecting the thrust jets **1713** along line **d-d'** of **Figure 3G-1b**.

[214] **Figures 3G-1a** thru **3G-1c** show the embodiment of similar concepts for the rotating nozzles **1600**, **1601**, and **1602**, but with modifications adapting the apparatus for use as an in-line thrust jetting collar **1700**. Note particularly the retention of a flow-through rotor **1725** providing a collar throat **1750**, coupled with a stator **1715** and bearings **1730**. However, the stationary flow channels for the rearward thrusting jets **1713** penetrating the stator **1710** are staggered, being in two sets of four. The single set of four orthogonal jets penetrating the rotor **1725** will, for each full rotation, "match-up" four times each with the jets penetrating the stator **1710**, each match-up providing a four-pronged instantaneous pulsed flow spaced equi-distant about the outer circumference of the collar **1700**. Similar to the rotating nozzle **1602**, the slideable collar **1733** is moved electromagnetically against a biasing mechanism (spring) **1735** to actuate flow through the rearward thrust jets **1713**.

[215] **Figure 3G-1c** is another cross-sectional view, showing the star pattern of the rearward thrust jets **1713**. Eight points are seen.

[216] A unique opportunity exists to configure the collar **1733** as either a net power consumer or a net power provider. The former would rely on the battery pack-provided power, just as the jetting nozzle **1600** does, to fire the stator, rotate the rotor, and generate the requisite electromagnetic field. The latter is accomplished by incorporating interior, slightly angled turbine fins **1740** within the I.D. of the rotor **1720**, hence harnessing the hydraulic force of the jetting fluid as it is pumped through the collar**1700**. Such force would be dependent only on the pump rate and the configuration of the turbine fins **1740**.

[217] In one aspect, internal turbine fins **1740** are placed equi-distant about the collar throat **1750**, such that hydraulic forces are harnessed both to rotate the rotor **1720** and to supply a net surplus of electrical current to be fed back into the internal system's circuitry. This may be done by sending excess current back up wires **1590**. The ability to incorporate a rotor/stator configuration into construction of the rearward thrust jet collar enables a full-opening I.D. equal to that of the jetting hose. More than ample hydroelectric power could be obtained to

generate the electromagnetic field needed to operate the slideable port collar **1733**, the surplus being available to be fed into the now "closed" electrical system incurred once the internal system **1500** disengages from the docking station **325**. Hence, this surplus hydroelectric power generated by the collar **1700** may beneficially be used to maintain charges of the batteries **1551** in the battery pack **1550**.

[218] It is observed that the various nozzle designs **1600**, **1601, 1602** discussed above are designed to jet not only through a rock matrix, but also through the steel casing and the surrounding cement sheath of the wellbore **4c** in order to reach the rock. The nozzle designs incorporate the ability to handle relatively large mesh-size abrasives through the forward nozzle jetting port **1640** prior to engaging the RTJ's **1613**. It is understood though that other nozzle designs may be used that accomplish the purpose of forming mini-laterals but which are not so robust as to cut through steel.

[219] In the various nozzle designs **1600**, **1601, 1602** discussed above, a single forward port in a hemispherically-shaped nozzle is used. The forward port **1640** is defined by the angles θ_{MAX} (whereby the width of the jet is equal to the width of the nozzle when the outermost edge of the jet reaches a point forward equivalent to the nozzle tip) and θ_{SLOT} (the actual slot angle). Note $\theta_{SLOT} \leq \theta_{MAX}$. For presentation purposes herein, $\theta_{SLOT} = \theta_{MAX}$, such that even if the tip of the rotating nozzle was against the host rock (or casing I.D.) face while jetting, it would still excavate a tunnel diameter equal to the outer (maximum) nozzle diameter. It is this single-plane, rotating slot configuration that will provide a maximum width in order to accommodate ample pass-through capacity for any abrasives that may be incorporated in the jetting fluid.

[220] The preferred rearward orifice jet orientation is from 30° to 60° from the longitudinal axis. The rearward thrust jets **1613/1713** are designed to be symmetrical about the circumference of the nozzle's/collar's stator body **1610/1710**. This maintains a purely forwards orientation of the jetting nozzle **1600**, **1601**, **1602** along the longitudinal axis. Accordingly, there should be at least three jets **1613/1713** spaced equi-distant about the circumference, and preferably at least five equi-distant jets **1613/1713**.

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[221] As noted above, the nozzle in any of its embodiments may be deployed as part of a guidance, or geo-steering, system. In this instance, the nozzle will include at least one geo-spatial IC chip, and will employ at least three actuator wires. The actuator wires **1590A** are spaced equi-distant about the distal end of the jetting hose and extend into the nozzle, and receive electrical current, or excitation, from the electrical wires **1590** already provided in the jetting hose **1595**.

[222] **Figure 3F-1c** is a longitudinal cross-sectional view of the jetting nozzle **1600** of **Figure 3F-1b**, in a modified embodiment. Here, the jetting nozzle **1600** is shown connected to a jetting hose **1595**. The connection may be a threaded connection; alternatively, the connection may be by means of welding. In **Figure 3F-1c**, an illustrative weld connection is shown at **1660**.

[223] In the arrangement of **Figure 3F-1c**, the jetting nozzle **1600** includes a geo-spatial IC chip **1670**. The geo-spatial chip **1670** resides within a port seal **1675**. The geo-spatial chip **1670** may comprise a two-axial or a three-axial accelerometer, a bi-axial or a tri-axial gyroscope, a magnetometer, or combinations thereof. The present inventions are not limited by the type or number of geo-spatial chips, or their respective locations within the assembly, used unless expressly so stated in the claims. Preferably, the chip **1670** will be associated with a micro-electro-mechanical system residing on or near the nozzle body such as shown and described in connection with the nozzle embodiments (**1600**, **1601**, **1602**) described above.

[224] **Figure 3F-1d** is an axial-cross-sectional view of the jetting hose **1590** of **Figure 3F-1c**, taken across line **c-c'**. Visible in this view are power wires **1590** and actuator wires **1590A**. Also visible are optional fiber optic data cables **1591**. The wires **1590**, **1590A**, **1591** may be used to transmit geo-location data from the chip **1670** up to a micro-processor in the battery pack section **1550**, and then wirelessly to a receiver located in the docking station (shown best at **325** in **Figure 4D-1b**), wherein the receiver communicates with the micro-processor in the docking station **325**. Preferably, the micro-processor in the docking station **325** processes the geo-location data, and makes adjustments to electrical current in the actuator wires **1590A** (using one or more current regulators), in order to ensure that the nozzle is oriented to hydraulically bore the lateral boreholes in a pre-programmed direction.

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[225] The micro-transmitter in the battery pack is preferably housed in the battery pack's downstream end cap **1530**, while the docking station **325** is preferably affixed to the interior of a jetting hose carrier system **400** (described below in connection with **Figures 3A, 3B-1,** and **4D-1**). The receiver housed in the docking station **325** may be in electrical or optical connection with a micro-processor at the surface **1**. For example, a fiber optic cable **107** may run along the coiled tubing conveyance system **100**, to the surface **1**, where the geo-location data is processed as part of a control system.

[226] The reverse (surface-to-downhole instrumentation) communication is likewise facilitated by hard-wired (again, preferably fiber optic) connection of surface instrumentation, through fiber optic cable **107** within coiled tubing conveyance medium **100** and external system **2000**, to a specific terminus receiver (not shown) housed within the docking station **325**. An adjoining wireless transmitter within the docking station **325** then transmits the operator's desired commands to a wireless receiver housed within the end cap **1530** of the internal system **1500**. This communication system allows an operator to execute commands setting both the rotational speed and/or the trajectory of the jetting nozzle **1600**.

[227] When the nozzle **1600** exits the casing, the operator knows the location and orientation of the nozzle **1600**. By monitoring the length of jetting hose **1590** that is translated out of the jetting hose carrier, integrated with any changes in orientation, the operator knows the geo-location of the nozzle **1600** in the reservoir.

[228] In one option, a desired geo-trajectory is first sent as geo-steering command from the surface **1**, down the coiled tubing **100**, and to the micro-processor associated with the docking station **325**. Upon receiving a geo-steering command from the surface **1**, such as from an operator or a surface control system, the micro-processor will forward the signals on wirelessly to a corresponding micro-receiver associated with the battery pack section **1550**. That signal will engage one or more current regulators to alter the current conducted down one, two, or all three of the at least three electric wires **1590**, connected directly to the jetting nozzle **1600**. Note that at least part of these electrical wire connections, preferably segments closest to the jetting nozzle **1600**, are comprised of actuator wires **1590A**, such as the Flexinol® actuator wires manufactured by Dynalloy, Inc. These small diameter, nickel-titanium wires contract

when electrically excited. This ability to flex or shorten is characteristic of certain alloys that dynamically change their internal structure at certain temperatures. The contraction of actuator wires is opposite to ordinary thermal expansion, is larger by a hundredfold, and exerts tremendous force for its small size. Given close temperature control under a constant stress, one can get precise position control, i.e., control in microns or less. Accordingly, given (at least) three separate actuator wires **1590A** positioned at-or-near equidistant around the perimeter and within the body of the jetting hose (toward its end, adjacent to the jetting nozzle **1600**), a small increase in current in any given wire will cause it to contract more than the other two, thereby steering the jetting nozzle **1600** along a desired trajectory. Given an initial depth and azimuth via the geo-spatial IC chip in the nozzle **1600**, a determined path for a lateral borehole **15** may be pre-programmed and executed automatically.

[229] Of interest, the actuator wires **1590A** have a distal segment residing along a chamber or sheath, or even interwoven within the matrix of the distal segment of the jetting hose **1595**. Further, the distal end of the actuator wires **1590A** may continue partially into the nozzle body, wrapping the stator poles **1615** to connect to, or even form the electro-magnetic coils **1616**. This is also demonstrated in **Figure 3F-1c**. In this way, electrical power is provided from the battery pack section **1550** to induce the relative rotational movement between the rotor body and the stator body.

[230] As can be seen from the above discussion, an internal system **1500** for a hose jetting assembly **50** is provided. The system **1500** enables a powerful hydraulic nozzle (**1600**, **1601**, **1602**) to jet away subsurface rock in a controlled (or steerable) manner, thereby forming a mini-lateral borehole that may extend many feet out into a formation. The unique combination of the internal system's **1500** jetting fluid receiving funnel **1570**, the upper seal **1580U**, the jetting hose **1595**, in connection with the external system's **2000** pressure regulator valve **610** and pack-off section **600** (discussed below) provide for a system by which advancement and retraction of the jetting hose **1595**, regardless of the orientation of the wellbore **4**, can be accomplished entirely by hydraulic means. Alternatively, mechanical means may be added through use of an internal tractor system **700**, described more fully below.

[231] Not only can the above-listed components be controlled to determine the direction of the jetting hose **1595** propulsion (e.g., either advancement or retraction), but also the rate of propulsion. The rate of advancement or retraction of the internal system **1500** may be directly proportional to the rate of fluid (and pressure) bleed-off and/or pump-in, respectively. Specifically, "pumping the hose **1595** down-the-hole" would have the following sequence:

(1) the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose carrier's inner conduit **420** is filled by pumping hydraulic fluid through the main control valve **310**, and then through the pressure regulator valve **610**; then

(2) the main control valve **310** is switched electronically using surface controls to begin directing jetting fluid to the internal system **1500**; which

(3) initiates a hydraulic force against the internal system **1500** directing jetting fluid through the intake funnel **1570**, into the jetting hose **1595**, and "down-the-hole"; such force being resisted by

(4) compressing hydraulic fluid in the micro-annulus **1595.420**; which is

(5) bled-off, as desired, from surface control of the pressure regulator valve **610**, thereby regulating the rate of "down-the-hole" decent of the internal system **1500**.

[232] Similarly, the internal system **1500** can be pumped back "up-the-hole" by directing the pumping of hydraulic fluid through (first) the main control valve **310** and (secondly) through the pressure regulator valve **610**, thereby forcing an ever-increasing (expanding) volume of hydraulic fluid into the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose conduit **420**, which pushes upwardly against the bottom seals **1580L** of the jetting hose seal assembly **1580**, thereby driving the internal system **1500** back "up-the-hole". The direction and rate of propulsion of the internal system **1500** by hydraulic means can be either augmented or replaced by propulsion of the internal system **1500** via the mechanical means of the internal tractor system **700**, also described below.

[233] Beneficially, once the jetting hose assembly **50** is deployed to a downhole location adjacent a desired point of casing exit "**W**" within a parent wellbore **4** of any inclination (including at-or-near horizontal), the entire length of jetting hose **1595** can be deployed and retrieved without any assistance from gravitational forces. This is because the propulsion

forces used to both deploy and retrieve the jetting hose **1595**, and to maintain its proper alignment while doing so, are either hydraulic or mechanical, as described more fully, below. Note also these propelling hydraulic and mechanical forces are available in more than sufficient quantities as to overcome any frictional forces from movement of the internal system **1500** (including, specifically, the jetting hose **1595**) within the external system **2000** (including, specifically, the jetting hose conduit **420**) induced by any non-vertical alignment, and to maintain the hose **1595** in a substantially taught state along the hose length within the external system **2000**. Hence, these hydraulic and mechanical propulsion forces overcome the "can't-push-a-rope" limitation in its entirety.

[234] Hydraulic force to advance the jetting hose **1595** within and subsequently out of the external system **2000** will be observed any time jetting fluid is being pumped; specifically, force in a plane parallel to the longitudinal axis of the jetting hose **1595**, in an upstream-to-downstream direction, as hydraulic force is exerted against the upstream end-cap of the battery pack **1520**, the fluid intake funnel **1570**, the interior face of the jetting nozzle **1600**, e.g., any internal system **1500** surface that is both: (a) exposed to the flow of jetting fluid; and, (b) having a directional component not parallel to the longitudinal axis of the parent wellbore. As these surfaces are rigidly attached to the jetting hose **1595** itself, this upstream-to-downstream force is conveyed directly to the jetting hose **1595** whenever jetting fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100** (seen in **Figure 2**), and through the jetting fluid passage **345** within the main control valve **300** (described below in connection with **Figure 4C-1**). Note the function of the only other valve in this system, the pressure regulator valve **610** located just upstream of the pack-off seal assembly **650** of pack-off section **600** (seen and described in connection with **Figures 4E-1** and **4E-2**), is simply to release pressure from the compression of hydraulic fluid within the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** (seen in **Figures 3D-1a** and **4D-2**) commensurate with the operator's desired rate of decent of the internal system **1500**.

[235] Conversely, hydraulic forces are operational in propelling the internal system **1500** in a downstream-to-upstream direction whenever hydraulic fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100**, and through the hydraulic fluid passage **340** within the main control valve **300**. In this configuration, the pressure regulator

valve **610** allows the operator to direct injected fluids into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** commensurate with the operator's desired rate of ascent of the internal system **1500**. Thus, hydraulic forces are available to assist in both conveyance and retrieval of the jetting hose **1595**.

[236] Similarly, mechanical forces applied by the internal tractor system **700** assist in conveyance, retrieval, and maintaining alignment of the jetting hose **1595**. The close tolerance between the O.D. of the jetting hose **1595** and the I.D. of the jetting hose conduit **420** of jetting hose carrier system **400**, thus defining annulus **1595.420**, serves to provide confining axial forces that assist in maintaining the alignment of the hose **1595**, such that the portion of the hose **1595** within the jetting hose carrier system **400** can never experience significant buckling forces. Direct mechanical (tensile) force for both deployment and retrieval of the jetting hose **1595** is applied by direct frictional attachment of grippers **756** of specially-designed gripper assemblies **750** of the internal tractor system **700** to the jetting hose **1595** , discussed below in connection with **Figures 4F-1** and **4F-2**.

[237] As described above, jetting hose conveyance is also assisted by the hydraulic forces emanating from the rearward thrusting jets **1613** of the jetting nozzle **1601, 1602** itself; and, if included, from the rearward thrust jets **1713** of any added jetting collar(s) **1700**. These furthest downstream hydraulic forces serve to advance the jetting hose **1595** forward into the pay zone **3** simultaneously with the creation of the UDP **15 (Figure 1B)**, maintaining the forward-aimed jetting fluid proximally to the rock face being excavated. The balance between deploying hydraulic energy forward proximate to the nozzle (for excavating new hole) versus rearward (for propulsion) requires balance. Too much rearward propulsion, and there is not enough residual hydraulic horsepower focused forward to excavate new hole. If there is too much forward propulsion expulsion of jetting fluid, there is insufficient fluid available for the rearward thrust jets **1613** / **1713** to generate the requisite horsepower to drag the jetting hose along the lateral borehole. Hence, the ability to redirect either rearward or forward focused hydraulic horsepower through the nozzle *in situ* as described herein is a major enhancement.

[238] For presentation purposes, two configurations of rearward thrust jets **1613/1713** have been included herein – one for pulsating flow wherein eight rearward thrust jets, each

inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are grouped into two sets of four, with rearwards flow alternating (or 'pulsing') between the two sets; and one for continuous flow, wherein a single set of five jets, each inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are shown. However, other jet numbers and angles may be employed.

[239] The **Figure 3** series of drawings, and the preceding paragraphs discussing those drawings, are directed to the internal system **1500** for the hydraulic jetting assembly **50**. The internal system **1500** provides a novel system for conveying the jetting hose **1595** into and out of a parent wellbore **4** for the subsequent steerable generation of multiple mini-lateral boreholes **15** in a single trip. The jetting hose **1595** may be as short as 10 feet or as long as 300 feet or even 500 feet, depending on the thickness and compressive strength of the formation or the desired geo-trajectory of each lateral borehole.

[240] As noted, the hydraulic jetting assembly **50** also provides an external system **2000**, uniquely designed to convey, deploy, and retrieve the internal system **1500** previously described. The external system **2000** is conveyable on conventional coiled tubing **100**; but, more preferably, is deployed on a "bundled" coiled tubing product (**Figures 3D-1a**, **4A-1** and **4A-1a**) providing for real-time power and data transmission.

[241] Consistent with the related and co-owned patent documents cited herein, the external system **2000** includes a jetting hose whipstock member **1000** including a whipstock **1050** having a curved face **1050.1** that preferably forms the bend radius for the jetting hose **1595** across the entire I.D. of the production casing **12**. The external system **2000** may also include a conventional tool assembly comprised of mud motor(s) **1300**, (external) coiled tubing tractor(s) **1350**, logging tools **1400** and/or a packer or a bridge plug (preferably, retrievable) that facilitate well completion. In addition, the external system **2000** provides for power and data transmission throughout, so that real time control may be provided over the downhole assembly **50**.

[242] **Figure 4** is a longitudinal, cross-sectional view of an external system **2000** of the downhole hydraulic jetting assembly **50** of **Figure 2**, in one embodiment. The external system **2000** is presented within the string of production casing **12**. For clarification, **Figure 4**

presents the external system **2000** as "empty"; that is, without containing the components of the internal system **1500** described in connection with the **Figure 3** series of drawings. For example, the jetting hose **1595** is not shown. However, it is understood that the jetting hose **1595** is largely contained in the external system during run-in and pull-out.

[243] In presenting the components of the external system **2000**, it is assumed that the system **2000** is run into production casing **12** having a standard 4.50" O.D. and approximate 4.0" I.D. In one embodiment, the external system **2000** has a maximum outer diameter constraint of 2.655" and a preferred maximum outer diameter of 2.500". This O.D. constraint provides for an annular (i.e., between the system **2000** O.D. and the surrounding production casing **12** I.D.) area open to flow equal to or greater than 7.0309 in^2, which is the equivalent of a 9.2#, 3.5" frac (tubing) string.

[244] The external system **2000** is configured to allow the operator to optionally "frac" down the annulus between the coiled tubing conveyance medium **100** (with attached apparatus) and the surrounding production casing **12**. Preserving a substantive annular region between the O.D. of the external system **2000** and the I.D. of the production casing **12** allows the operator to pump a fracturing (or other treatment) fluid down the subject annulus immediately after jetting the desired number of lateral bores and without having to trip the coiled tubing **100** with attached apparatus **2000** out of the parent wellbore **4**. Thus, multiple stimulation treatments may be performed with only one trip of the assembly **50** in to and out of the parent wellbore **4**. Of course, the operator may choose to trip out of the wellbore for each frac job, in which case the operator would utilize standard (mechanical) bridge plugs, frac plugs and/or sliding sleeves. However, this would impose a much greater time requirement (with commensurate expense), as well as much greater wear and fatigue of the coiled tubing-based conveyance medium **100**.

[245] In actuality, rigorous adherence to the (O.D.) constraint is perhaps only essential for the coiled tubing conveyance medium **100**, which may comprise over 90% of the length of the system **50**. Slight violations of the O.D. constraint over the comparatively minute lengths of the other components of the external system **2000** should not impose significant annular hydraulic pressure drops as to be prohibitive. If these outer diameter constraints can be

satisfied, while maintaining sufficient inner diameters so as to accommodate the design functionality of each of the components (particularly of the external system **2000**), and this can be accomplished for a system **50** that operates in the smaller of standard oilfield production casing **4** sizes of 4.5" O.D., then there should be no significant barriers to adapting the system **50** to any of the larger standard oilfield production casing sizes (5.5", 7.0", etc.).

[246] Presentation of each of the major components of the external system **2000**, which follows below, will be in an upstream-to-downstream direction. Note in **Figure 4** the demarcation of the major components of the external system **2000**, with the corresponding Figure(s) herein:

a. the coiled tubing conveyance medium **100**, presented in **Figures 4A-1** and **4A-2**;

b. the first crossover connection (the coiled tubing transition) **200**, presented in **Figure 4B-1**;

c. the main control valve **300**, presented in **Figure 4C.1**;

d. the jetting hose carrier system, **400** with its docking station **325**, presented in **Figures 4D-1** and **4D-2**;

e. the second crossover connection **500** (transitioning the outer body from circular to star-shaped) and the jetting hose pack-off section **600**, presented in **Figures 4E-1** and **4E-2**;

f. the internal tractor system **700** and the third crossover connection **800**, presented in **Figures 4F-1** and **4F-2**;

g. the third crossover connection **800** and the upper swivel **900**, presented in **Figure 4G-1**;

h. the whipstock member **1000**, presented in **Figure 4H-1**;

i. the lower swivel **1100**, presented in **Figure 4I-1**; and, lastly,

j. the transitional connection **1200** to the conventional coiled tubing mud motor **1300** and a conventional coiled tubing tractor **1350**,

coupled to a conventional logging sonde **1400**, presented in **Figure 4J**.

[247] **Figure 4A-1** is a longitudinal, cross-sectional view of a "bundled" coiled tubing conveyance medium **100**. The conveyance medium **100** serves as a conveyance system for the downhole hydraulic jetting assembly **50** of **Figure 2**. The conveyance medium **100** is shown residing within the production casing **12** of a parent wellbore **4**, and extending through a heel **4b** and into the horizontal leg **4c**.

[248] **Figure 4A-1a** is an axial, cross-sectional view of the coiled tubing conveyance medium **100** of **Figure 4A-1**. It is seen that the conveyance medium **100** includes a core **105**. In one aspect, the coiled tubing core **105** is comprised of a standard 2.000" O.D. (**105.2**) and 1.620" I.D. (**105.1**), 3.68 lbm/ft. HSt110 coiled tubing string, having a Minimum Yield Strength of 116,700 lbm and an Internal Minimum Yield Pressure of 19,000 psi. This standard sized coiled tubing provides for an inner cross-sectional area open to flow of 2.06 in^2. As shown, this "bundled" product **100** includes three electrical wire ports **106** of up to .20" in diameter, which can accommodate up to AWG #5 gauge wire, and 2 data cable ports **107** of up to .10" in diameter.

[249] The coiled tubing conveyance medium **100** also has an outermost, or "wrap," layer **110**. In one aspect, the outer layer **110** has an outer diameter of 2.500", and an inner diameter bonded to and exactly equal to that of the O.D. **105.2** of the core coiled tubing string **105** of 2.000".

[250] Both the axial and longitudinal cross-sections presented in **Figures 4A-1** and **4A-1a** presume bundling the product **100** concentrically, when in actuality, an eccentric bundling may be preferred. An eccentric bundling provides more wrap layer protection for the electrical wiring **106** and data cables **107**. Such a depiction is included as **Figure 4A-2** for an eccentrically bundled coiled tubing conveyance medium **101**. Fortunately, eccentric bundling would have no practical ramifications on sizing pack-off rubbers or wellhead injector components for lubrication into and out of the parent wellbore, since the O.D. **105.2** and circularity of the outer wrap layer **110** of an eccentric conveyance medium **101** remain unaffected.

[251] The conveyance medium **101** may have, for example, an internal flow area of 2.0612 in^2, a core wall thickness **105** of 0.190 in^2, and an average outer wall thickness of 0.25 in^2. The outer wall **110** may have a minimum thickness of 0.10 in^2.

[252] Note the main design criteria of the conveyance medium, whether concentrically **100** or eccentrically **101** bundled, is to provide real-time power (via electrical wiring **106**) and data (via data cabling **107**) transmission capacities to an operator located at the surface **1** while deploying, operating, and retrieving apparatus **50** in the wellbore **4**. For example, in a standard e-coil system, components **106** and **107** would be run within the coiled tubing core **105**, thereby exposing them to any fluids being pumped via the I.D. **105.1** of the core **105**. Given the subject method provides for pumping abrasives within a high-pressure jetting fluid (particularly, while eroding casing exit "**W**" from within production casing **12**), it is preferred instead to locate components **106** and **107** at the O.D. **105.2** of the core **105**.

[253] Similarly, the subject method provides for pumping proppants within high pressure hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and production casing **12**. Hence, the protective coiled tubing wrap layer **110** is preferably of sufficient thickness, strength, and erosive resistance to isolate and protect components **106** and **107** during fracturing operations.

[254] The present conveyance medium **100** (or **101**) also maintains a sufficiently large inner diameter **105.1** of the core wall **105** such as to avoid appreciable friction losses (as compared to the losses incurred in the internal system **1500** and external system **2000**) while pumping jetting and/or hydraulic fluids. At the same time, the system maintains a sufficiently small outer diameter **110.2** so as to avoid prohibitively large pressure losses while pumping hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and the production casing **12**. Further, the system **50** maintains a sufficient wall thickness for the outer wrap layer **110**, whether it is concentrically or eccentrically wrapped about the inner coiled tubing core **105**, so as to provide adequate insular protection and spacing for the electrical transmission wiring **106** and the data transmission cabling **107**. It is understood that other dimensions and other tubular bodies may be used as the conveyance medium for the external system **2000**.

[255] Moving further down the external system **2000**, **Figure 4B-1** presents a longitudinal, cross-sectional view of the first crossover connection, the coiled tubing crossover connection **200**. **Figure 4B-1**a shows a portion of the coiled tubing crossover connection **200** in perspective view. Specifically, the transition between lines **E-E'** and line **F-F'** is shown. In this arrangement, an outer profile transitions from circular to oval to bypass the main control valve **300**.

[256] The main functions of this crossover connection **200** are as follows:

(1) To connect the coiled tubing conveyance medium **100** (or **101**) to the jetting assembly **50** and, specifically, to the main control valve **300**. In **Figure 4B-1**, this connection is depicted by the steel coiled tubing core **105** connected to the main control valve's outer wall **290** at connection point **210**.

(2) To transition the electrical cables **106** and data cables **107** from the outside of the core **105** of the coiled tubing conveyance medium **100** (or **101**) to the inside of the main control valve **300**. This is accomplished with wiring port **220** facilitating the transition of wires/cables **106**/**107** inside outer wall **290**.

(3) To provide an ease-of-access point, such as the threaded and coupled collars **235** and **250**, for the splicing/connection of electrical cables **106** and data cables **107.**

and

(4) To provide separate, non-intersecting and non-interfering pathways for electrical cables **106** and data cables **107** through a pressure- and fluid-protected conduit, that is, a wiring chamber **230**.

[257] The next component in the external system **2000** is a main control valve **300**. **Figure 4C-1** provides a longitudinal, cross-sectional view of the main control valve **300**. **Figure 4C-1a** provides an axial, cross-sectional view of the main control valve **300**, taken across line **G-G'** of **Figure 4C-1**. The main control valve **300** will be discussed in connection with both **Figures 4C-1** and **4C-1a** together.

[258] The function of the main control valve **300** is to receive high pressure fluids pumped from within the coiled tubing **100**, and to selectively direct them either to the internal system **1500** or to the external system **2000**. The operator sends control signals to the main control valve **300** by means of the wires **106** and/or data cable ports **107**.

[259] The main control valve **300** includes two fluid passages. These comprise a hydraulic fluid passage **340** and a jetting fluid passage **345**. Visible in **Figures 4C-1, 4C-1a** and **4C-1b** (longitudinal cross-sectional, axial cross-sectional, and perspective view, respectively) is a sealing passage cover **320**. The sealing passage cover **320** is fitted to form a fluid-tight seal against inlets of both the hydraulic fluid passage **340** and the jetting fluid passage **345**. Of interest, **Figure 4C-1b** presents a three dimensional depiction of the passage cover **320**. This view illustrates how the cover **320** can be shaped to help minimize frictional and erosional effects.

[260] The main control valve **300** also includes a cover pivot **350**. The passage cover **320** rotates with rotation of the passage cover pivot **350**. The cover pivot **350** is driven by a passage cover pivot motor **360**. The sealing passage cover **320** is positioned by the passage cover pivot **350** (as driven by the passage cover pivot motor **360**) to either: (1) seal the hydraulic fluid passage **340**, thereby directing all of the fluid flow from the coiled tubing **100** into the jetting fluid passage **345**, or (2) seal the jetting fluid passage **345**, thereby directing all of the fluid flow from the coiled tubing **100** into the hydraulic fluid passage **340**.

[261] The main control valve **300** also includes a wiring conduit **310**. The wiring conduit **310** carries the electrical wires **106** and data cables **107**. The wiring conduit **310** is optionally elliptically shaped at the point of receipt (from the coiled tubing transition connection **200**, and gradually transforms to a bent rectangular shape at the point of discharging the wires **106** and cables **107** into the jetting hose carrier system **400**. Beneficially, this bent rectangular shape serves to cradle the jetting hose conduit **420** throughout the length of the jetting hose carrier system **400**.

[262] The next component of the external system **2000** is a jetting hose carrier system **400**. **Figure 4D-1** is a longitudinal, cross-sectional view of the jetting hose carrier system **400**. The jetting hose carrier system **400** is attached downstream of the main control valve **300**. The

jetting hose carrier system **400** is essentially an elongated tubular body that houses the docking station **325**, the internal system's battery pack section **1550**, the jetting fluid receiving funnel **1570**, the seal assembly **1580** and connected jetting hose **1595**. In the view of **Figure 4D-1**, only the docking station **325** is visible so that the profile of the jetting hose carrier system **400** itself is more clearly seen.

[263] **Figure 4D-1a** is an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D.1**, taken across line **H-H'** of **Figure 4D-1**. **Figure 4D-1b** is an enlarged view of a portion of the jetting hose carrier system **400** of **Figure 4D-1**. Here, the docking station **325** is visible. The jetting hose carrier system **400** will be discussed with reference to each of **Figures 4D-1**, **4D-1a** and **4D-1b**, together.

[264] The jetting hose carrier system **400** defines a pair of tubular bodies. The first tubular body is a jetting hose conduit **420**. The jetting hose conduit **420** houses, protects, and stabilizes the internal system **1500** and, particularly, the jetting hose **1595**. As previously presented in the discussion of the internal system **1500**, it is the size (specifically, the I.D.), strength, and rigidity of this fluid-tight and pressure-sealing conduit **420** that provides the pathway and particularly, the micro-annulus (shown at **1595.420** in **Figure 3D-1a**, **Figure 4D-2** and **Figure 4D-2a**) for the jetting hose **1595** of internal system **1500** to be "pumped down" and reversibly "pumped up" the longitudinal axis of the external system **2000** as it operates within the production casing **12**.

[265] The jetting hose carrier section **400** also has an outer conduit **490**. The outer conduit **490** resides along and circumscribes the inner conduit **420**. In one aspect, the outer conduit **490** and the jetting hose conduit **420** are simply concentric strings of 2.500" O.D. and 1.500" O.D. HSt100 coiled tubing, respectively. The inner conduit, or jetting hose conduit **420**, is sealed to and contiguous with the jetting fluid passage **345** of the main control valve **300**. When high pressure jetting fluid is directed by the valve **300** into the jetting fluid passage **345**, the fluid flows directly and only into the jetting hose conduit **420** and then into the jetting hose **1595**.

[266] An annular area **440** exists between the inner (jetting hose) conduit **420** and the surrounding outer conduit **490**). The annular area **440** is also fluid tight, directly sealed to and

contiguous with the hydraulic fluid passage **340** of the control valve **300**. When high pressure hydraulic fluid is directed by the main control valve **300** into the hydraulic fluid passage **340**, the fluid flows directly into the conduit-carrier annulus **440**.

[267] The jetting hose carrier section **400** also includes a wiring chamber **430**. The wiring chamber **430** has an axial cross-section of an upwardly-bent rectangular shape, and receives the electrical wires **106** and data cables **107** from the main control valve's **300** wiring conduit **310**. This fluid-tight chamber **430** not only separates, insulates, houses, and protects the electrical wires **106** and data cables **107** throughout the entire length of the jetting hose carrier section **400**, but its cradle shape serves to support and stabilize the jetting hose conduit **420**. Note the jetting hose carrier section **400** wiring chamber **430** and inner (jetting hose) conduit **420** may or may not be attached either to each other, and/or to the outer conduit **490**.

[268] In addition to housing and protecting wires **106** and data transmission cables **107**, the wiring conduit **430** within the jetting hose carrier system **400** supports the jetting hose conduit's **420** horizontal axis at a position slightly above a horizontal axis that would bifurcate the outer conduit **490**. Different types of materials may be utilized in its construction, given its design constraints are significantly less stringent than those for the outer layer(s) of the CT-based conveyance medium, particularly in regard to chemical and abrasion resistance, as the exterior of the wiring conduit **430** will only be exposed to hydraulic fluid – never jetting or fracturing fluids.

[269] Additional design criteria for the wiring conduit **430** may be invoked if it is desired for it to be rigidly attached to either the jetting hose conduit **420**, the outer conduit **490**, or both. In one aspect, the wiring conduit **430** has a width of approximately 1.34", and provides three 0.20" diameter circular channels for electrical wiring, and two 0.10" diameter circular channels for data transmission cables. It is understood that other diameters and configurations for the wiring conduit **430** may vary, depending on design objectives, so long as an annular area **440** open to flow of hydraulic fluid is preserved.

[270] Also visible in **Figure 4D-1** is the docking station **325**. The docking station **325** resides immediately downstream of the connection between the main control valve **300** and the jetting hose carrier system **400**. The docking station **325** is rigidly attached within the interior

of the jetting hose conduit **420**. The docking station **325** is held in the jetting hose conduit **420** by diagonal supports. The diagonal supports are hollow, the interior(s) of which serving as a fluid- and pressure-tight conduit(s) of leads of electrical wires **106** and data cables **107** into the communications/control/electronics systems of the docking station **325**. This is similar to functions of the battery pack support conduits **1560** of the internal system **1500**. Whether connected to a servo device, a transmitter, a receiver, or other device housed within the docking station **325**, these devices are thereby "hard-wired" via electrical wires **106** and data cables **107** to an operator's control system (not shown) at the surface **1**.

[271] **Figure 4D-2** provides an enlarged, longitudinal cross-sectional view of a portion of the jetting hose carrier system **400** of external system **2000**, depicting its operational hosting of a commensurate length of jetting hose **1595**. **Figure 4D-2a** provides an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D-2**, taken across line **H-H'**. Note that the cross-sectional view of **Figure 4D-2a** matches the cross-sectional view of **Figure 4D-1a**, except that the conduit **420** in **Figure 4D-1a** is "empty," meaning that the jetting hose **1595** is not shown.

[272] The length of the jetting hose conduit **420** is quite long, and should be approximately equivalent to the desired length of jetting hose **1595**, and thereby defines the maximum reach of the jetting nozzle **1600** orthogonal to the wellbore **4**, and the corresponding length of the mini-lateral **15**. The inner diameter specification defines the size of the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. The I.D. should be close enough to the O.D. of the jetting hose **1595** so as to preclude the jetting hose **1595** from ever becoming buckled or kinked, yet it must be large enough to provide sufficient annular area for a robust set of seals **1580L** by which hydraulic fluid can be pumped into the sealed micro-annulus **1595.420** to assist in controlling the rate of deployment of the jetting hose **1595**, or assisting in hose retrieval.

[273] It is the hydraulic forces within the sealed micro-annulus **1595.420** that keep the segment of jetting hose (above the internal tractor system **700**) straight, and slightly in tension. The I.D. of jetting hose conduit **420** can likewise not be too close to the O.D. of the jetting hose **1595** so as to place unnecessarily high frictional forces between the two. The O.D. of the

jetting hose conduit **420** (in conjunction with the I.D. of the outer conduit **490**, less the external dimensions of the jetting hose carrier's wiring chamber **430**) define the annular area **440** through which hydraulic fluid is pumped. Certainly, if the jetting hose carrier system's inner conduit **420** O.D. is too large, it thereby invokes undue frictional losses in pumping hydraulic fluid. However, if not large enough, then the inner conduit **420** will not have sufficient wall thickness to support either the inner or outer operating pressures required. Note, for the subject apparatus designed to be deployed in 4.5" wellbore casing, the inner string is comprised of 1.5" O.D. and 1.25" I.D. (i.e., .125" wall thickness) coiled tubing. If this were 1.84#/ft., HSt110, for example, it would provide for an Internal Minimum Yield Pressure rating of 16,700 psi. Similarly, the outer conduit **490** can be constructed of standard coiled tubing. In one aspect, the outer conduit **490** is comprised of 2.50" O.D. and 2.10" I.D., thereby providing for a wall thickness of 0.20".

[274] Progressing again uphole-to-downhole, the external system **2000** next includes the second crossover connection **500,** transitioning to the jetting hose pack-off section **600**. **Figure 4E-1** provides an elongated, cross-sectional view of both the crossover connection (or transition) **500** and the jetting hose pack-off section **600**. Figure **4E-1a** is an enlarged perspective view highlighting the transition's **500** outer body shape, transitioning from circular- to star-shaped. Axial cross-sectional lines **I-I'** and **J-J'** illustrate the profile of the transition **500** fittingly matching the dimensions of the outer wall **490** of jetting hose carrier system **400** at its beginning, and an outer wall **690** of the pack-off section **600** at its end.

[275] **Figure 4E-2** shows an enlarged portion of the jetting hose pack-off section **600** of **Figure 4E-1**, and particularly sealing assembly **650**. The transition **500** and the jetting hose pack-off section **600** will be discussed with reference to each of these views together.

[276] As its name implies, the main function of the jetting hose pack-off section **600** is to "pack-off", or seal, an annular space between the jetting hose **1595** and a surrounding inner conduit **620**. The jetting hose pack-off section **600** is a stationary component of the external system **2000.** Through transition **500**, and partially through pack-off section **600**, there is a direct extension of the micro-annulus **1595.420**. This extension terminates at the pressure/fluid seal of the jetting hose **1595** against the inner faces of seal cups making up the pack-off seal

assembly **650**. Immediately prior to this terminus point is the location of the pressure regulator valve, shown schematically as component **610** in **Figures 4E-1** and **4E-2**. It is this valve **610** that serves to either communicate or segregate the annulus **1595.420** from the hydraulic fluid running throughout the external system **2000**. The hydraulic fluid takes its feed from the inner diameter of the coiled tubing conveyance medium **100** (specifically, from the I.D. **105.1** of coiled tubing core **105**) and proceeds through the continuum of hydraulic fluid passages **240**, **340**, **440**, **540**, **640**, **740**, **840**, **940**, **1040**, and **1140**, then through the transitional connection **1200** to the coiled tubing mud motor **1300**, and eventually terminating at the tractor **1350**. (Or, terminating at the operation of some other conventional downhole application, such as a hydraulically set retrievable bridge plug.)

[277] The crossover connection **500** from the jetting hose carrier system **400** to the pack off section **600** is notable for several reasons:

[278] First, within this transition **500**, the free flow of hydraulic fluid from the conduit-carrier annulus **440** of the jetting hose carrier section **400** will be re-directed and re-compartmentalized within the upper (triangular-shaped) quadrant of the star-shaped outer conduit **690**. Toward the upstream end of the inner conduit **620** is the pressure regulator valve **610**. The pressure regulator valve **610** provides for increasing or decreasing the hydraulic fluid (and commensurately, the hydraulic pressure) in the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. It is the operation of this valve **610** that provides for the internal system **1500** (and specifically, the jetting hose **1595**) to be "pumped down," and then reversibly "pumped up" the longitudinal axis of the production casing **12**.

[279] The upwardly bent, rectangular-shaped fluid-tight chamber **430** that separates, insulates, houses, and protects the electrical wires **106** and data cables **107** along the length of the jetting hose carrier body **400** is transitioned via wiring chamber **530** into a lower (triangular-shaped) quadrant **630** of the star-shaped outer body **690** of the pack-off section **600**. This preserves the separation, insulation, housing, and protection of the electrical wires **106** and the data cables **107** in the jetting hose pack-off section **600**. The star-shaped outer body **690** forms an annulus between itself and the I.D. of the surrounding production casing **12**.

[280] Given the prong-tip-to-opposite-prong-tip distances of the four-pronged star-shaped outer conduit **690** are just slightly less than the I.D. of the production casing **12**, the pack-off section **600** also serves to nearly centralize the jetting hose **1595** in the parent wellbores production casing **12**. As will be explained later, this near-centralization will translate through the internal tractor system **700** so as to beneficially centralize the upstream end of the whipstock member **1000**.

[281] Recall the outer diameter of the upstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the inner conduit **420** of the jetting hose carrier system **400** by virtue of the jetting hose's upper **1580U** and lower **1580L** seals, forming a single seal assembly **1580**. The seals **1580U** and **1580L**, being formably affixed to the jetting hose **1595**, travel up and down the inner conduit **420**. Similarly, the outer diameter of the downstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the pack-off section's **600** inner conduit **620** by virtue of the seal assembly **650** of the pack-off section **600**. Thus, when the internal system **1500** is "docked" (i.e., when the upstream battery pack end cap **1520** is in contact with the external system's docking station **325**) then the distance between the two seal assemblies **1580**, **620** approximates the full length of the jetting hose **1595**. Conversely, when the jetting hose **1595** and jetting nozzle **1600** have been fully extended into the maximum length lateral borehole (or UDP) **15** attainable by the jetting assembly **50**, then the distance between the two seal assemblies **1580**, **620** is negligible. This is because, though the internal system's jetting hose seal assembly **1580** essentially travels the entire length of the external system's **2000** jetting hose carrier system **400**, the seal assembly **650** (of the pack-off section **600** in the external system **2000**) is relatively stationary, as the seal cups comprising seal assembly **650** must reside between opposing seal cup stops **615**.

[282] Note further how the alignment of the two opposing sets of seal cups comprising seal assembly **650** (e.g., an upstream set facing upstream, placed back-to-back with a downstream set facing downstream) thereby provides a pressure/fluid seal against differential pressure from either the upstream direction or the downstream direction. These opposing sets of seal cups comprising seal assembly **650** are shown with a longitudinal cross section of jetting hose **1595** running concentrically through them, in the enlarged view of **Figure 4E-2**.

[283] As noted, the pressure maintained in the micro-annulus **1595.420** by the pressure regulator valve **610** provides for the hydraulic actions of "pumping the hose down the hole" or, reversibly, "pumping the hose up the hole". These annular hydraulic forces also serve to mitigate other, potentially harmful forces that could be imposed on the jetting hose **1595**, such as buckling forces when advancing the hose **1595** downstream, or internal burst forces while jetting. Hence, combined with the upper hose seal assembly **1580** and the jetting hose conduit **420**, the jetting hose pack-off section **600** serves to maintain the jetting hose **1595** in an essentially taut condition. Hence, the diameter of the hose **1595** that can be utilized will be limited only by the bend radius constraint imposed by the I.D. of the wellbore's production casing **12**, and the commensurate pressure ratings of the hose **1595**. At the same time, the length of the hose **1595** that may be utilized is certainly well into the hundreds of feet.

[284] Note the most likely limiting constraint of hose **1595** length will not be anything imposed by the external system **2000**, but instead will be the hydraulic horsepower distributable to the rearward thrust jets **1613/1713**, such that sufficient horsepower can remain forward-focused for excavating rock. As one might expect, the length (and commensurate volume) of mini-laterals that can be jetted will ultimately be a function of rock strength in the subsurface formation. This length limitation is quite unlike the system posited in U.S. Patent No. 6,915,853 (Bakke, *et al.*) that attempts to convey the entirety of the jetting hose downhole in a coiled state within the apparatus itself. That is, in Bakke, *et al.*, the hose is stored and transported while in horizontally stacked, 360° coils contained within the interior of the device. In this case, the bend radius/pressure hose limitations are imposed by (among other constraints), not the I.D. of the casing, but by the I.D. of the device itself. This results in a much smaller hose I.D./O.D., and hence, geometrically less horsepower deliverable to Bakke's jetting nozzle.

[285] In operation, after a UDP **15** has been formed and the main control valve **300** has been shifted to shut-off the flow of hydraulic jetting fluid to the internal system **1500** and is then providing flow of hydraulic fluid to the external system **2000**, the pressure regulator valve **610** can feed flow into the micro-annulus **1595.420** in the opposite direction. This downstream-to-upstream force will "pump" the assembly back into the wellbore **4** and "up the

hole," as the bottom, downwards facing cups **1580L** of the seal assembly **1580** will trap flow (and pressure) below them.

[286] The next component within the external system **2000** (again, progressing uphole-to-downhole) is an optional internal tractor system **700**. **Figure 4F-1** provides an elongated, cross-sectional view of the tractor system **700**, downstream from the jetting hose pack-off section **600**. **Figure 4F-2** shows an enlarged portion of the tractor system **700** of **Figure 4F-1**. **Figure 4F-2a** is an axial, cross-sectional view of the internal tractor system **700**, taken across line **K-K'** of **Figures 4F-1** and **4F-2**. Finally, **Figure 4F-2b** is an enlarged half-view of a portion of the internal tractor system **700** of **Figure 4F-2a**. The internal tractor system **700** will be discussed with reference to each of these four views together.

[287] It is first observed that two types of tractor systems are known. These are the wheeled tractor systems and the so-called inch-worm tractor systems. Both of these tractor systems are "external" systems, meaning that they have grippers designed to engage the inner wall of the surrounding casing (or, if in an open hole, to engage the borehole wall). Tractor systems are used in the oil and gas industry primarily to advance either a wireline or a string of coiled tubing (and connected downhole tools) along a horizontal (or highly deviated) wellbore – either uphole or downhole.

[288] In the present assembly **50**, a unique tractor system has been developed which employs "internal," grippers. This means that gripper assemblies **750** are aimed inwardly, for the purpose of either advancing or retracting the jetting hose **1595** relative to the external system **2000**. The result of this inversion is that the coiled tubing string **100** and attached external system **2000** can now be stationary while the somewhat flexible hose **1595** is being translated in the wellbore **4c**. The outwardly-aimed electrically driven wheels of a conventional ("external") tractor are replaced with inwardly-aimed concave grippers **756**. The result is the inwardly-aimed concave grippers **756** frictionally attach to the jetting hose **1595**, with subsequent rotation of the grippers **756** propelling the jetting hose **1595** in a direction that corresponds with the direction of rotation.

[289] Note specifically the following consequence of this inversion: In a conventional system, the relative movement that occurs is that of the rigidly gripper-attached body (i.e., the

coiled tubing) relative to the stationary, frictionally attached body (i.e., the borehole wall). Conversely, the subject internal tractor system is rigidly attached to the stationary body (i.e., the external system **2000**) and the grippers **756** rotate to move the jetting hose **1595**. Accordingly, when the internal tractor system **700** is actuated, the whipstock member **1000** will already be in its set and operating position; e.g., the slips of the whipstock member **1000** will be engaged with the inner wall of the casing **12**. Hence, all advancement/retraction of the jetting hose **1595** by the tractor system **700** takes place when the external system **2000** itself is set and is stationary within the production casing **12**.

[290] It is next observed that the internal tractor system **700** preferably maintains the star-shape profile of the jetting hose pack-off system **600**. The star shape profile of the internal tractor system **700**, with its four points, helps centralizes the tractor system **700** within the production casing **12**. This is beneficial inasmuch as the slips of the whipstock member **1000** (located relatively close to tractor system **700**, due to the short lengths of the third crossover connection (or transition) **800** and upper swivel **900** between them, discussed below) will be engaged when operating the tractor system **700**, meaning that centralization of the tractor system **700** serves to align the defined path of the jetting hose **1595** and precludes any undo torque at the connection with the jetting hose whipstock device **1000**. It is observed in **Figures 4F-1** and **4F-2a** that the position of the jetting hose **1595** is approximately centered, both within the tractor system **700** and, therefore, within the production casing **12**. This places the hose **1595** in optimum position to be either fed into or retracted from the jetting hose whipstock device **1000**.

[291] In addition to centralizing the hose **1595**, another function served by the star-shape profile of the tractor system **700** is that it accommodates interior room for placement of two opposing sets of gripper assemblies **750**. Specifically, the gripper assemblies **750** reside inside the 'dry' working room of the two side chambers, while simultaneously providing for separate chambers for the electrical wires **106** and data cabling **107** (shown in lower chamber **730**) and the hydraulic fluid (in upper chamber **740**). At the same time, ample cross-sectional flow area is preserved between the tractor system **700** and the I.D. of the production casing **12** within their respective annular area **700.12** for conducting fracturing fluids.

[292] As shown within the 4.5" production casing **12**, the annular area **700.12** open to flow is approximately 10.74 in^2, equating to an equivalent pipe diameter (I.D.) of 3.69 in. Recall the design objective is to maintain an annular flow area greater than or equal to the interior area of a typical 3.5" O.D. (2.922" I.D., 10.2#/ft.) frac string, i.e. 6.706 in^2. Note then, if the tip-to-tip dimension of opposing prongs of the "star" is, for example, 3.95 in, and (to gain additional internal volume within the four chambers of the tractor system **700**) the star shape were changed to a perfect square, then the external area of the square would be 7.801 in^2, and the remaining annular area (open to flow of frac fluid) inside the 4.00" I.D. production casing would be 4.765 in^2, which is equivalent to a 2.463" pipe I.D. Hence, though the base of each triangular chamber within the star shape could be somewhat expanded to provide additional internal volumes or wall thickness, the outer perimeter cannot be completely squared-off and still satisfy the preferred 3.5" frac string criteria. Note, however, there is no reason the triangular dimensions of each chamber must remain symmetrical; e.g., the dimensions could be varied individually in order to accommodate each chamber's internal volume requirements, just as long as the 3.5" frac string requirement is still preferably satisfied.

[293] Each of the gripper assemblies **750** is comprised of a miniature electric motor **754**, and a motor mount **755** securing the motor **754** to the outer wall **790**. In addition, each of the gripper assemblies **750** includes a pair of axles. These represent a gripper axle **751** and a gripper motor axle **753**. Finally, each of the gripper assemblies **750** includes gripper gears **752**.

[294] The tractor system **700** also includes bearing systems **760**. The bearing systems **760** are placed along the length of inner walls **720**. These bearing systems **760** isolate frictional forces against the jetting hose **1595** at the contact points of the grippers **756**, and eliminate unwanted frictional drag against the inner walls **720**.

[295] Rearward rotation of the grippers **756** serve to advance the hose **1595**, while forward rotation of the grippers **756** serves to retract the hose **1595**. Propulsion forces provided by the grippers **756** help advance the jetting hose **1595** by pulling it through the jetting hose carrier system **400**, transition **500**, and pack-off section **600**, and assist in advancing the jetting hose **1595** by pushing it into the lateral borehole **15** itself.

[296] The view of **Figure 4F-1** depicts only two sets of opposing gripper assemblies **750**. However, gripper assemblies **750** may be added to accommodate virtually any length and construction of jetting hose **1595**, depending on compressional, torsional and horsepower constraints. Additional gripper assemblies **750** should add tractor force, which may be desirable for extended length lateral boreholes **15**. Though it is presumed maximum grip force will be obtained when pairs of gripper assemblies **750** are placed axially opposing one another in the same plane (as shown in **Figure 4F-2.a**), that is, maximizing a "pinch" force on the jetting hose **1595**, other arrangements/placements of gripper systems **750** are within the scope of this aspect of the inventions.

[297] Optionally, the internal tractor system **700** also includes a tensiometer. The tensiometer is used to provide real-time measurement of the pulling tension of the upstream section of hose **1595** and the pushing compression on the downstream section of hose **1595**. Similarly, mechanisms could be included to individualize the applied compressional force of each set of grippers **756** upon the jetting hose **1595**, so as to compensate for uneven wear of the grippers **756**.

[298] Again proceeding in presentation of the external system's **2000** main components from upstream-to-downstream, **Figure 4G-1** shows a longitudinal, cross-sectional view of the internal tractor-to-upper swivel (or third) crossover connection **800**, and the upper swivel **900** itself. Figure **4G-1a** depicts a perspective view of the crossover connection **800** between its upstream and downstream ends, denoted by lines **L-L'** and **M-M'**, respectively. **Figure 4G-1b** presents an axial, cross-sectional view within the upper swivel **900** along line **N-N'**. The third transition **800** and upper swivel **900** are discussed in connection with **Figures 4G-1**, **4G-1a** and **4G-1b** together.

[299] The transition **800** functions similarly to previous transitional sections (**200**, **500**) of the external system **2000** discussed herein. Suffice it to say the main function of the transition **800** is to convert the axial profile of the star-shaped internal tractor system **700** back to a concentric circular profile as used for the swivel **900**, and to do so within I.D. restrictions that meet the 3.5" frac string test.

[300] The upper swivel **900** simultaneously accomplishes three important functions:

(1) First, it allows the indexing mechanism to rotate the connected whipstock member **1000** without torqueing any upstream components of the system **50**.

(2) Second, it provides for rotation of the whipstock **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107** through wiring chamber **930** between the transition **800** and the whipstock member **1000**; while simultaneously providing.

(3) Third, it provides a horseshoe-shaped hydraulic fluid chamber **940** that accommodates rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path between the transition **800** and the whipstock member **1000**.

[301] Desirable for the simultaneous satisfaction of the above design criteria are the double sets of bearings **960** (the inner bearings) and **965** (the outer bearings). In one aspect, the upper swivel **900** has an O.D. of 2.6 in.

[302] The outer wall **990** of the upper swivel **900** maintains the circular profile achieved by an outer wall **890** of transition **800**. Similarly, concentric circular profiles are obtained in the upper swivel's **900** middle body **950** and inner wall **920**. These three sequentially and concentrically smaller cylindrical bodies (**990**, **950**, and **920**) provide for placement of an inner set of circumferential bearings **960** (between the inner wall **920** and the middle body **950**) and an outer set of circumferential bearings **965** (between the middle body **950** and the outer wall **990**). The larger cross-sectional area of the middle body **950** allows it to host a horseshoe-shaped hydraulic fluid chamber **940**, and an arc-shaped wiring chamber **930**. The bearings **960**, **965** facilitate relative rotation of the three sequentially and concentrically smaller cylindrical bodies **990**, **950**, and **920**. The bearings **960**, **965** also provide for rotatable translation of the whipstock member **1000** below the upper swivel **900** (also shown in **Figure 4G-1**) while in its set and operating position. This, in turn, provides for a change in orientation of subsequent lateral boreholes jetted from a given setting depth in the parent wellbore **4**. Stated another way, the upper swivel **900** allows an indexing mechanism (described in the related U.S. Patent No. 8,991,522 and incorporated herein in its entirety) to rotate the

whipstock member **1000** without torqueing any upstream components of the external system **2000**.

[303] It is also observed that the upper swivel **900** provides for rotation of the whipstock member **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107**. The upper swivel **900** also permits the horseshoe-shaped hydraulic fluid chamber **940** to provide for rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path down to the whipstock member **1000** and beyond.

[304] Returning to **Figure 4**, and as noted above, the external system **2000** includes a whipstock member **1000**. The jetting hose whipstock member **1000** is a fully reorienting, resettable, and retrievable whipstock means similar to those described in the precedent works of U.S. Provisional Patent Application No. 61/308,060 filed February 25, 2010, U.S. Patent No. 8,752,651 filed February 23, 2011, and U.S. Patent No. 8,991,522 filed August 5, 2011. Those applications are again referred to and incorporated herein for their discussions of setting, actuating and indexing the whipstock. Accordingly, detailed discussion of the jetting hose whipstock device **1000** will not be repeated herein.

[305] **Figure 4H.1** provides a longitudinal cross-sectional view of a portion of the wellbore **4** from **Figure 2**. Specifically, the jetting hose whipstock member **1000** is seen. The jetting hose whipstock member **1000** is in its set position, with the upper curved face **1050.1** of the whipstock **1050** receiving a jetting hose **1595**. The jetting hose **1595** is bending across the hemispherically-shaped channel that defines the face **1050.1**. The face **1050.1**, combined with the inner wall of the production casing **12**, forms the only possible pathway within which the jetting hose **1595** can be advanced through and later retracted from the casing exit "**W**" and lateral borehole **15**.

[306] A nozzle **1600** is also shown in **Figure 4H.1**. The nozzle **1600** is disposed at the end of the jetting hose **1595**. Jetting fluids are being dispersed through the nozzle **1600** to initiate formation of a mini-lateral borehole into the formation. The jetting hose **1595** extends down from the inner wall **1020** of the jetting hose whipstock member **1000** in order to deliver the nozzle **1600** to the whipstock member **1050**.

[307] As discussed in U.S. Patent No. 8,991,522, the jetting hose whipstock member **1000** is set utilizing hydraulically controlled manipulations. In one aspect, hydraulic pulse technology is used for hydraulic control. Release of the slips is achieved by pulling tension on the tool. These manipulations were designed into the whipstock member **1000** to accommodate the general limitations of the conveyance medium (conventional coiled tubing) **100**, which can only convey forces hydraulically (e.g., by manipulating surface and hence, downhole hydraulic pressure) and mechanically (i.e., tensile force by pulling on the coiled tubing, or compressive force by utilizing the coiled tubing's own set-down weight).

[308] The jetting hose whipstock member **1000** is herein designed to accommodate the delivery of wires **106** and data cables **107** further downhole. To this end, a wiring chamber **1030** (conducting electrical wires **106** and data cables **107**) is provided. Power and data are provided from the external system **2000** to conventional logging equipment **1400**, such as a Gamma Ray – Casing Collar Locator logging tool, in conjunction with a gyroscopic tool. This would be attached immediately below a conventional mud motor **1300** and coiled tubing tractor **1350**. Hence, for this embodiment, hydraulic conductance through the whipstock **1000** is desirable to operate a conventional ("external") hydraulic-over-electric coiled tubing tractor **1350** immediately below, and electrical (and preferably, fiber optic) conductance to operate the logging sonde **1400** below the coiled tubing tractor **1350**. The wiring chamber **1030** is shown in the cross-sectional views of **Figures 4H-1a** and **4H-1b**, along lines **O-O′** and **P-P′**, respectively, of **Figure 4H-1**.

[309] Note that this tractor **1350** is placed below the point of operation of the jetting nozzle **1600**, and therefore will never need to conduct either the jetting hose **1595** or high pressure jetting fluids to generate either the casing exit "**W**" or subsequent lateral borehole. Hence, there are no I.D. constraints for this (bottom) coiled tubing tractor **1350** other than the wellbore itself. The coiled tubing tractor **1350** may be either of the conventional wheel ("external roller") type, or the gripper (inch worm) type.

[310] A hydraulic fluid chamber **1040** is also provided along the jetting hose whipstock member **1000**. The wiring chamber **1030** and the fluid chamber **1040** become bifurcated while transitioning from semi-circular profiles (approximately matching their respective counterparts

930 and **940** of the upper swivel **900**) to a profile whereby each chamber occupies separate end sections of a rounded rectangle (straddling the whipstock member **1050**). Once sufficiently downstream of the whipstock member **1050**, the chambers can be recombined into their original circular pattern, in preparation to mirror their respective dimensions and alignments in a lower swivel **1100**. This enables the transport of power, data, and high pressure hydraulic fluid through the whipstock member **1000** (via their respective wiring chamber **1030** and hydraulic fluid chamber **1040**) down to the mud motor **1300**.

[311] Below the whipstock member **1000** and the nozzle **1600** but above the tractor **1350** is an optional lower swivel **1100**. **Figure 4I-1** is a longitudinal cross-sectional view of the lower swivel **1100**, as it resides between the jetting hose whipstock member **1000** and crossover connection **1200**, and within the production casing **12**. A slip **1080** is shown set within the casing **12**. **Figure 4I-1a** is an axial cross-sectional view of the lower swivel **1100**, taken across **line Q-Q'** of **Figure 4I.1**. The lower swivel **1100** will be discussed with reference to **Figures 4I-1** and **4I-1a** together.

[312] The lower swivel **1100** is essentially a mirror-image of the upper swivel **900**. As with the upper swivel **900**, the lower swivel **1100** includes an inner wall **1120**, a middle body **1150**, and an outer wall **1190**. In a preferred embodiment, the outer conduit has an O.D. of 2.60", or slightly less. The constraint of the O.D. outer conduit **1190** is the self-imposed 3.5" frac string equivalency test.

[313] The middle body **1150** further houses wiring chamber **1130** and a hydraulic fluid chamber **1140**. The fluid chamber **1140** transports hydraulic fluid to crossover connection **1200** and eventually to the mud motor **1300**.

[314] The lower swivel **1100** also includes a wiring chamber **1130** that houses electrical wires **106** and data cables **107**. Continuous electrical and/or fiber optic conductance may be desired when real time conveyance of logging data (gamma ray and casing collar locator, "CCL" data, for example) or orientation data (gyroscopic data, for example) is desired. Additionally, continuous electrical and/or fiber optic conductance capacity enables direct downhole assembly manipulation from the surface **1** in response to the real time data received.

[315] It is noted that while the inner conduit **920** of the upper swivel **900** defines a hollow core of sufficient dimensions to receive and conduct the jetting hose **1595**, the lower swivel **1100** has no such requirement. This is because in the design of the assembly **50** and the methods of usage thereof, the jetting hose **1595** is never intended to proceed downstream to a point beyond the whipstock member **1050**. Accordingly, the innermost diameter of the lower swivel **1100** may in fact be comprised of a solid core, as depicted in **Figure 4I-1a**, thereby adding additional strength qualities.

[316] The lower swivel **1100** resides between the jetting hose whipstock member **1000** and any necessary crossover connections **1200** and downhole tools, such as a mud motor **1300** and the coiled tubing tractor **1350**. Logging tools **1400**, a packer, or a bridge plug (preferably retrievable, not shown) may also be provided. Note that, depending on the length of the horizontal portion **4c** of the wellbore **4**, the respective sizes of the conveyance medium **100** and production casing **12**, and hence the frictional forces to be encountered, more than one mud motor **1300** and/or CT tractor **1350** may be needed.

[317] The final figure presented is **Figure 4J**. **Figure 4J** depicts the final transitional component **1200**, the conventional mud motor **1300**, and the (external) coiled tubing tractor **1350**. Along with the tools listed above, the operator may also choose to use a logging sonde **1400** comprised of, for example, a Gamma Ray – Casing Collar Locator and gyroscopic logging tools. The gyroscopic logging tools provide real-time data describing not only the precise downhole location, but the initial alignment of the whipstock face **1050.1** of the preceding jetting hose whipstock member **1000**. This data is useful in determining:

(1) how many degrees of re-alignment, via the whipstock face **1050.1** alignment, are desired to direct the initial lateral borehole along its preferred azimuth; and

(2) subsequent to jetting the first lateral borehole, how many degrees of re-alignment are required to direct subsequent lateral borehole(s) along their respective preferred azimuth(s).

[318] It is anticipated that, in preparation for a subsequent hydraulic fracturing treatment in a horizontal parent wellbore **4c**, an initial borehole **15** will be jetted substantially perpendicular to and at or near the same horizontal plane as the parent wellbore **4c**, and a

second lateral borehole will be jetted at an azimuth of 180° rotation from the first (again, perpendicular to and at or near the same horizontal plane as the parent wellbore). In thicker formations, however, and particularly given the ability to steer the jetting nozzle **1600** in a desired direction, more complex lateral bores may be desired. Similarly, multiple lateral boreholes (from multiple setting points typically close together) may be desired within a given "perforation cluster" that is designed to receive a single hydraulic fracturing treatment stage. The complexity of design for each of the lateral boreholes will typically be a reflection of the hydraulic fracturing characteristics of the host reservoir rock for the pay zone **3**. For example, an operator may design individually contoured lateral boreholes within a given "cluster" to help retain a hydraulic fracture treatment predominantly "in zone."

[319] It can be seen that an improved downhole hydraulic jetting assembly **50** is provided herein. The assembly **50** includes an internal system **1500** comprised of a guidable jetting hose and rotating jetting nozzle that can jet both a casing exit and a subsequent lateral borehole in a single step. The assembly **50** further includes an external system **2000** containing, among other components, a carrier apparatus that can house, transport, deploy, and retract the internal system to repeatably construct the requisite lateral boreholes during a single trip into and out of a parent wellbore **4**, and regardless of its inclination. The external system **2000** provides for annular frac treatments (that is, pumping fracturing fluids down the annulus between the coiled tubing deployment string and the production casing **12**) to treat newly jetted lateral boreholes. When combined with stage isolation provided by a packer and/or spotting temporary or retrievable plugs, thus providing for repetitive sequences of plug-and-UDP-and-frac, completion of the entire horizontal section **4c** can be accomplished in a single trip.

[320] In one aspect, the assembly **50** is able to utilize the full I.D. of the production casing **12** in forming the bend radius **1599** of the jetting hose **1595**, thereby allowing the operator to use a jetting hose **1595** having a maximum diameter. This, in turn, allows the operator to pump jetting fluid at higher pump rates, thereby generating higher hydraulic horsepower at the jetting nozzle **1600** at a given pump pressure. This will provide for substantially more power output at the jetting nozzle, which will enable:

(1) optionally, jetting larger diameter lateral boreholes within the target formation;

(2) optionally, achieving longer lateral lengths;

(3) optionally, achieving greater erosional penetration rates; and

(4) achieving erosional penetration of higher strength and threshold pressure (σ_M and P_{Th}) oil/gas formations heretofore considered impenetrable by existing hydraulic jetting technology.

[321] Also of significance, the internal system **1500** allows the jetting hose **1595** and connected jetting nozzle **1600** to be propelled independently of a mechanical downhole conveyance medium. The jetting hose **1595** is not attached to a rigid working string that "pushes" the hose and connected nozzle **1600**, but instead uses a hydraulic system that allows the hose and nozzle to travel longitudinally (in both upstream and downstream directions) within the external system **2000**. It is this transformation that enables the subject system **1500** to overcome the "can't-push-a-rope" limitation inherent to all other hydraulic jetting systems to date. Further, because the subject system does not rely on gravitational force for either propulsion or alignment of the jetting hose/nozzle, system deployment and hydraulic jetting can occur at any angle and at any point within the host parent wellbore **4** to which the assembly **50** can be "tractored" in.

[322] The downhole hydraulic jetting assembly allows for the formation of multiple mini-laterals, or bore holes, of an extended length and controlled direction, from a single parent wellbore. Each mini-lateral may extend from 10 to 500 feet, or greater, from the parent wellbore. As applied to horizontal wellbore completions in preparation for subsequent hydraulic fracturing ("frac") treatments in certain geologic formations, these small lateral wellbores may yield significant benefits to optimization and enhancement of fracture (or fracture network) geometry and subsequent hydrocarbon production rates and reserves recovery. By enabling: (1) better extension of the propped fracture length; (2) better confinement of the fracture height within the pay zone; (3) better placement of proppant within the pay zone; and (4) further extension of a fracture network prior to cross-stage breakthrough, the lateral boreholes may yield significant reductions of the requisite fracturing fluids, fluid additives, proppants, hydraulic horsepower , and hence related fracturing costs previously required to obtain a desired fracture geometry, if it was even attainable at all. Further, for a

fixed input of fracturing fluids, additives, proppants, and horsepower, preparation of the pay zone with lateral boreholes prior to fracturing could yield significantly greater Stimulated Reservoir Volume, to the degree that well spacing within a given field may be increased. Stated another way, fewer wells may be needed in a given field, providing a significance of cost savings. Further, in conventional reservoirs, the drainage enhancement obtained from the lateral boreholes themselves may be sufficient as to preclude the need for subsequent hydraulic fracturing altogether.

[323] As an additional benefit, the downhole hydraulic jetting assembly **50** and the methods herein permit the operator to apply radial hydraulic jetting technology without "killing" the parent wellbore. In addition, the operator may jet radial lateral boreholes from a horizontal parent wellbore as part of a new well completion. Still further, the jetting hose may take advantage of the entire I.D. of the production casing. Further yet, the reservoir engineer or field operator may analyze geo-mechanical properties of a subject reservoir, and then design a fracture network emanating from a customized configuration of directionally-drilled lateral boreholes.

[324] The hydraulic jetting of lateral boreholes may be conducted to enhance fracture and acidization operations during completion. As noted, in a fracturing operation, fluid is injected into the formation at pressures sufficient to separate or part the rock matrix. In contrast, in an acidization treatment, an acid solution is pumped at bottom-hole pressures less than the pressure required to break down, or fracture, a given pay zone. (In an acid frac, however, pump pressure intentionally exceeds formation parting pressure.) Examples where the pre-stimulation jetting of lateral boreholes may be beneficial include:

(a) prior to hydraulic fracturing (or prior to acid fracturing) in order to help confine fracture (or fracture network) propagation within a pay zone and to develop fracture (network) lengths a significant distance from the parent wellbore before any boundary beds are ruptured, or before any cross-stage fracturing can occur; and

(b) using lateral boreholes to place stimulation from a matrix acid treatment far beyond the near-wellbore area before the acid can be "spent," and before pumping pressures approach the formation parting pressure.

[325] The downhole hydraulic jetting assembly **50** and the methods herein permit the operator to conduct acid fracturing operations through a network of lateral boreholes formed through the use of a very long jetting hose and connected nozzle that is advanced through the rock matrix. In one aspect, the operator may determine a direction of a pressure sink in the reservoir, such as from an adjacent producer. The operator may then form one or more lateral boreholes in an orthogonal direction, and then conduct acid fracturing through that borehole. In this instance, fractures will open in the direction of the pressure sink.

[326] The operator may alternatively consider or determine a flux-rate of acid (or other formation-dissolving fluid) in the rock matrix. In this instance, the acid is not injected at a formation parting pressure, but allows wormholes to form in the direction of the pressure sink. The operator may also conduct the steps of creating a pressure boundary in the reservoir by injecting fluids into a first lateral borehole in a first direction, and then performing acid-fracturing through a second lateral borehole in a second direction offset from the first direction. The acid fractures are in the form of wormholes in a direction that does not intersect the pressure boundary.

[327] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to pre-determine a path for the jetting of lateral boreholes. Such boreholes may be controlled in terms of length, direction or even shape. For example, a curved borehole or each "cluster" of curved boreholes may be intentionally formed to further increase SRV exposure of the formation **3** to the wellbore **4c**. Wellbores may optionally be formed in corkscrew patterns to further expose the formation **3** to the wellbore **4c**.

[328] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to re-enter an existing wellbore that has been completed in an unconventional formation, and "re-frac" the wellbore by forming one or more lateral boreholes using hydraulic jetting technology. The hydraulic jetting process would use the hydraulic jetting assembly **50**

of the present invention in any of its embodiments. There will be no need for a workover rig, a ball dropper / ball catcher, drillable seats or sliding sleeve assemblies.

[329] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to create a network of lateral boreholes that includes side mini-lateral boreholes formed off of newly-created boreholes. Such a method may include the steps of:

(a) partially withdrawing the jetting hose and connected nozzle from the first lateral borehole;

(b) identifying a location of the jetting nozzle within the rock matrix;

(c) re-orienting the jetting nozzle; and

(d) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a first side mini-lateral borehole within the rock matrix in the pay zone off of the first lateral borehole.

[330] The method may further comprise:

(e) withdrawing the jetting hose and connected nozzle from the first side mini-lateral borehole;

(f) repeating steps (a) through (c); and

(g) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a second side mini-lateral borehole within the rock matrix in the pay zone off of the first mini-lateral borehole.

[331] The method may further comprise (h) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes, the network being configured to optimize a Stimulated Reservoir Volume (SRV) (i) from a subsequent hydraulic fracturing treatment, (ii) from a subsequent acid treatment, or (iii) both. Alternatively, the method may further comprise:

(i) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes;

(j) injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing;

(k) further injecting the fracturing fluids into the network of side mini-lateral boreholes at an injection pressure sufficient to part the rock matrix in the pay zone to form a network of hydraulic fractures; and

(l) monitoring the growth of the network of hydraulic fracture and Stimulated Reservoir Volume (SRV) emanating from the network of mini-lateral boreholes in real time using (i) tiltmeters, (ii) micro-seismic surveys, (iii) ambient micro-seismic surveys, (iv) microphones, or combinations thereof.

[332] The method may then include producing hydrocarbon fluids from the network of side mini-lateral boreholes.

[333] Based on the downhole hydraulic jetting assembly **50** described above, a unique method of forming a wellbore may be conducted. The method, in one embodiment, includes:

- running a jetting hose into a horizontal section of a parent wellbore using a conveyance medium, the jetting hose having a nozzle at a distal end;
- injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into a surrounding formation, thereby forming a first lateral borehole off of the horizontal section from a first wellbore exit location;
- withdrawing the jetting hose and connected nozzle from the first lateral borehole at the first wellbore exit location, and re-locating the nozzle to a second wellbore exit location (either by placing a whipstock at a different depth, or by placing the whipstock at the same depth but at a different angular orientation) in the same trip; and
- injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into the surrounding formation, thereby forming a second lateral borehole off of the horizontal section from the second wellbore exit location.

[334] In this method, advancing the jetting hose into each of the lateral boreholes is done at least in part through a hydraulic force acting on a sealing assembly along (such as at an upstream end of) the jetting hose. Further, the jetting hose is advanced and subsequently withdrawn without coiling or uncoiling the jetting hose in the wellbore.

[335] In one embodiment, advancing the jetting hose into each of the lateral boreholes is further done through a mechanical force applied by rotating grippers of a mechanical tractor assembly located within the wellbore, wherein the grippers frictionally engage an outer surface of the jetting hose.

[336] In another embodiment, advancing the jetting hose into each of the lateral boreholes is accomplished by forward thrust forces generated from flowing jetting fluid through rearward thrust jets located in the jetting assembly. These rearward thrust jets are specifically located in the jetting nozzle, or in a combination of the nozzle and one or more in-line jetting collars strategically located along the jetting hose. Preferably, the nozzle permits a flow of the jetting fluid through rearward thrust jets in response to a designated hydraulic pressure level. In this instance, the flowing of fluid through the rearward thrust jets is only activated after the jetting hose has advanced into each borehole at least 5 feet from the parent wellbore. The additional rearward thrust jets located in the in-line jetting collar(s) are then activated at incrementally higher operating pressures, typically when the jetting hose has been extended such a significant length from the parent wellbore that the rearward thrust jets within the nozzle alone can no longer generate significant pull force to continue dragging the full length of jetting hose along the lateral borehole.

[337] In a related aspect, the method may include monitoring tensiometer readings at a surface. The tensiometer readings are indicative of drag experienced by the jetting hose as lateral boreholes are formed. In this instance, the flowing of fluid through the rearward thrust jets is activated in each of the plurality of boreholes in response to a designated tensiometer reading.

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CLAIMS

What is claimed is:

1. A method of forming a lateral borehole in a pay zone located within an earth subsurface, comprising:

determining a depth of a pay zone in the earth subsurface, the pay zone defining a rock matrix;

forming a wellbore within the pay zone;

conveying a hydraulic jetting assembly into the wellbore on a working string, the hydraulic jetting assembly comprising:

an external system having:

an external conduit,

a whipstock member placed a lower end of the external conduit and having a concave face, and

a jetting hose carrier residing within the external conduit above the whipstock and forming an annular region between the jetting hose carrier and the surrounding external conduit; and

an internal system having:

a jetting hose having a proximal end and a distal end,

a jetting nozzle disposed at a distal end of the jetting hose, and

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to allow the jetting hose to be translated out of and back into the jetting hose carrier without buckling;

setting the whipstock at a desired first casing exit location along the wellbore, wherein the face of the whipstock is configured to bend the jetting hose substantially across an entire inner diameter of the wellbore when the jetting hose is translated out of the jetting hose carrier;

translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock;

injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix in the pay zone;

further injecting the jetting fluid while further translating the jetting hose and connected jetting nozzle through the jetting hose carrier and along the face of the whipstock, thereby forming a first lateral borehole that extends at least 5 feet from the horizontal wellbore.

2. The method of claim 1, wherein the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting forming a lateral borehole into the rock matrix within the pay zone, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed to allow a location of the whipstock within the wellbore to be adjusted.

3. The method of claim 2, wherein:

the wellbore is completed with a string of production casing;

the inner diameter of the wellbore is the inner diameter of the production casing; and

the method further comprises further injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby cutting a first casing exit through the production casing before excavating the borehole in the rock matrix.

4. The method of claim 3, further comprising:

producing hydrocarbon fluids from the wellbore for a period of time before forming the lateral borehole.

5. The method of claim 3, wherein:

the wellbore is a horizontal wellbore; and

the method further comprises determining a vertical thickness of the pay zone

wherein forming a lateral borehole comprises hydraulically forming a lateral borehole that extends to proximate an upper boundary or to proximate a lower boundary of the pay zone.

6. The method of claim 5, further comprising:

identifying a particular hydrocarbon-rich portion of the pay zone; and

directing the lateral borehole through the hydrocarbon-rich portion.

7. The method of claim 5, further comprising:

forming perforations along the horizontal wellbore in sequential stages using one or more perforating guns;

hydraulically fracturing the rock matrix along the horizontal wellbore through the perforations in sequential stages; and

conducting a flowback operation to at least partially remove hydraulic fluids injected in connection with the hydraulic fracturing before forming the later borehole.

8. The method of claim 5, wherein:

the lateral borehole penetrates through the rock matrix in a direction that is substantially orthogonal to the horizontal wellbore; and

forming a lateral borehole comprises hydraulically forming a lateral borehole that extends to proximate an upper boundary or to proximate a lower boundary of the pay zone.

9. The method of claim 5, further comprising:

retracting the jetting hose and connected nozzle from the first casing exit;

re-orienting the whipstock at the desired first location;

injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit;

further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone; and

still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore from the second casing exit.

10. The method of claim 9, wherein each of the first and second lateral boreholes has an internal diameter of between about 0.4 and 2.5 inches.

11. The method of claim 10, wherein the second lateral borehole is offset from the first lateral borehole by between 10-degrees and 180-degrees.

12. The method of claim 11, further comprising:

producing hydrocarbon fluids from the first and second lateral boreholes.

13. The method of claim 5, further comprising:

retracting the jetting hose and connected nozzle from the first casing exit;

moving the whipstock to a desired second location;

injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit at the second location;

further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone at the second location; and

still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore along the second desired location.

14. The method of claim 13, wherein each of the first and second lateral boreholes has an internal diameter of between about 0.4 and 2.5 inches.

15. The method of claim 14, wherein the second lateral borehole is separated from the first lateral borehole by 5 to 200 feet.

16. The method of claim 5, further comprising:

injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing; and

injecting the fracturing fluids into the first lateral borehole at an injection pressure sufficient to part the rock matrix in the pay zone.

17. The method of claim 16, wherein:

the hydraulic jetting assembly further comprises a retrievable bridge plug disposed below the whipstock member; and

the method further comprises setting the bridge plug before injecting a fracturing fluid.

18. The method of claim 17, further comprising:

injecting an acid treatment through the annulus and into the lateral borehole before the hydraulic fracturing.

19. The method of claim 5, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises:

a main control valve disposed proximate the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into the annular region formed between the jetting hose carrier and the surrounding outer conduit.

20. The method of claim 19, the jetting assembly further comprises:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the jetting hose carrier, and slidably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus.

21. The method of claim 20, wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the working string, through the main control valve, and against

the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the working string, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

22. The method of claim 21, wherein:

the micro-annulus defines an elongated pressure chamber formed between the movable upper seal assembly and the jetting hose pack-off section;

the main control valve resides proximate an upper end of the outer conduit;

the jetting hose carrier is dimensioned to hold the jetting hose from the upper sealing assembly down proximate to the jetting nozzle when the assembly is in a run-in position; and

the method further comprises sending a signal from the surface to the main control valve to place the main control valve in its first position.

23. The method of claim 22, wherein the pressure regulator valve is configured such that:

(i) when pressure is released from the micro-annulus and fluids are injected through the main control valve in its first position, the upper seal assembly glides down an inner bore of the jetting hose carrier while still sealing, thereby pushing the jetting hose forward through the jetting hose carrier without buckling; and

(ii) when pressure is increased in the micro-annulus by the injection of fluids through the main control valve in its second position, increased fluid pressure against the upper seal assembly urges the jetting hose to glide back up the jetting hose carrier.

24. The method of claim 23, wherein:

the jetting hose is at least 25 feet in length;

a controlled release of fluids from the micro-annulus and through the pressure regulator valve regulates the jetting hose's rate of descent down-the-hole; and

a controlled intake of fluids through the regulator valve and into the micro-annulus regulates the jetting hose's rate of ascent up-the-hole.

25. The method of claim 24, wherein:

the translation force comprises both the hydraulic force and a mechanical force; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

26. The method of claim 25, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers and translate the jetting hose into and out of the inner conduit portion as the grippers engage the jetting hose.

27. The method of claim 5, wherein:

the translation force comprises a mechanical force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

28. The method of claim 27, wherein:

each prong of the outer conduit portion provides an inner chamber around the inner conduit portion;

a first of the inner chambers is configured to conduct the jetting fluid down the assembly;

a second of the inner chambers is configured to house the electrical wires, data cables, or both;

at least third and fourth opposing inner chambers house grippers;

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers as the grippers engage and translate the jetting hose.

29. The method of claim 5, wherein:

the working string a string of coiled tubing;

the coiled tubing carries electrical wires, data cables, or combinations thereof along its length;

the internal system further comprises a battery pack for providing power to electrical components within the assembly, the battery pack residing at the proximal end of the jetting hose; and

the assembly further comprises a docking station located at an upper end of the external system configured to mate with the battery pack, the docking station having a processor and being in communication with an operator at the surface by means of the electrical wires, the data cables or both of the coiled tubing.

30. The method of claim 29, further comprising:

sending commands from the surface to the docking station;

sending data from a logging tool downstream from the whipstock to the docking station; and

sending data from the docking station to the surface.

31. The method of claim 29, wherein:

the string of coiled tubing comprises a wall or a sheath that houses the electrical wires, the data cables, or both along its length, extending down to the docking station; and

the battery pack comprises a series of batteries located in an elongated, fluid-sealed housing, and an end cap located at each of opposing ends of the battery pack, wherein the end caps are shaped to deflect jetting fluid during operation of the assembly.

32. The method of claim 31, wherein the docking station:

houses a micro-processor, a micro-transmitter, a micro-receiver, an electrical current regulator, or combinations thereof; and

is configured to transfer: (1) power to the battery pack, said power either originating from generation at the surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between an at least one geo-spatial chip housed at or near the nozzle and the operator at the surface.

33. The method of claim 32, further comprising:

at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle, the actuator wires being equi-distantly spaced about the circumference of the jetting hose at its distal end, and further being configured to contract in response to electrical current sent through the actuator wires, whereby differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle; and

wherein the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires, and thus control a geo-orientation of the nozzle for directional hydraulic boring.

34. The hydraulic jetting assembly of claim 33, wherein:

the geo-location signals of the at least one geo-spatial chip are indicative of both the location and orientation of the jetting nozzle, such signals being transmitted as data from the geo-spatial chips to the micro-receiver in the battery pack via (i) the electrical wiring, the data cables, or (iii) both, bundled in the jetting hose;

contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives, thereby enabling geo-steering of the nozzle; and

wherein the actuator wires are fabricated from a material comprising nickel, titanium or a combination thereof.

35. The hydraulic jetting assembly of claim 34, wherein

the micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station; and

the docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

36. The hydraulic jetting assembly of claim 35, wherein the bending moment applied to the distal end of the jetting hose is configured to be controlled by an operator at the surface through the delivery of geo-location signals sent to a micro-transmitter in the docking station through (i) wireless signals sent downhole, (ii) the electrical wires bundled in the coiled tubing, or (iii) the data cables bundled in the coiled tubing, such geo-location signals adjusting the currents being transmitted through the actuator wires.

37. The method of claim 5, further comprising:

obtaining geo-mechanical data for the pay zone, the data comprising porosity, permeability, Poisson ratio, modulus of elasticity, shear modulus, Lame' constant, Vp/Vs, or combinations thereof;

conducting a geo-mechanical analysis of the rock matrix in the pay zone to determine a direction of least minimum principle stress; and

forming at least two lateral boreholes in the pay zone using the downhole hydraulic jetting assembly by steering the nozzle (i) in a direction perpendicular to the direction of least minimum principle stress, or (ii) in a direction parallel to the direction of least minimum principle stress.

38. The method of claim 37, wherein:

a longitudinal axis of the horizontal wellbore is oriented parallel to the plane of least principle stress of the rock matrix comprising the pay zone; and

the first lateral borehole is formed in a direction perpendicular to the plane of least principle stress of the rock matrix.

39. The method of claim 37, wherein conducting a geo-mechanical analysis of the rock matrix comprises creating a finite element mesh representing the pay zone, the mesh defining a plurality of nodes representing points in space, each point having potential displacement in more than one direction; and predicting changes in strain within the rock matrix as a result of the formation of the lateral boreholes.

40. The method of claim 5, further comprising:

(a) partially withdrawing the jetting hose and connected nozzle from the first lateral borehole;

(b) identifying a location of the jetting nozzle within the rock matrix;

(c) re-orienting the jetting nozzle; and

(d) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a first side mini-lateral borehole within the rock matrix in the pay zone off of the first lateral borehole.

41. The method of claim 40, further comprising:

(e) withdrawing the jetting hose and connected nozzle from the first side mini-lateral borehole;

(f) repeating steps (a) through (c); and

(g) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a second side mini-lateral borehole within the rock matrix in the pay zone off of the first mini-lateral borehole

42. The method of claim 41, further comprising:

(h) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes, the network being configured to optimize a Stimulated Reservoir Volume (SRV) (i) from a subsequent hydraulic fracturing treatment, (ii) from a subsequent acid treatment, or (iii) both.

43. The method of claim 42, further comprising:

(i) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes;

(j) injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing;

(k) further injecting the fracturing fluids into the network of side mini-lateral borehole at an injection pressure sufficient to part the rock matrix in the pay zone to form a network of hydraulic fractures; and

(l) monitoring the growth of the network of hydraulic fracture and Stimulated Reservoir Volume (SRV) emanating from the network of mini-lateral boreholes in real time using (i) tiltmeters, (ii) micro-seismic surveys, (iii) microphones, (iv) ambient micro-seismic surveys, (v) or combinations of such data.

44. The method of claim 43, further comprising:

(l) based upon the real-time geophysical data, custom designing geometries of a next network of lateral boreholes to optimally receive a hydraulic fracturing treatment stage in order to optimize SRV to be obtained from that particular stage; and

(m)producing hydrocarbon fluids from the network.

45. A method of forming a wellbore, comprising:

running a jetting hose into a horizontal section of a parent wellbore using a conveyance medium, the jetting hose having a nozzle at a distal end;

injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into a surrounding formation, thereby forming a first lateral borehole off of the horizontal section from a first wellbore exit location;

withdrawing the jetting hose and connected nozzle from the first lateral borehole at the first wellbore exit location, and re-locating the nozzle to a second wellbore exit location in the same trip; and

injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into the surrounding formation, thereby forming a second lateral borehole off of the horizontal section from the second wellbore exit location;

wherein advancing the jetting hose into each of the lateral boreholes is done at least in part through a hydraulic force acting on a sealing assembly along the jetting hose and without coiling or uncoiling the jetting hose in the wellbore.

46. The method of claim 45, wherein advancing the jetting hose into each of the lateral boreholes is further done through a mechanical force applied by rotating grippers of a mechanical tractor assembly located within the wellbore, wherein the grippers frictionally engage an outer surface of the jetting hose.

47. The method of claim 45, wherein advancing the jetting hose into each of the lateral boreholes is further done through flowing jetting fluid through rearward thrust jets located in the nozzle, or through thrust jets located in the nozzle and one or more in-line jetting collars.

48. The method of claim 47, wherein the flow of the jetting fluid through the rearward thrust jets of the nozzle is in response to a designated hydraulic pressure level, and subsequent flow through the thrust jets of the one or more jetting collars is at an incrementally higher hydraulic pressure level.

49. The method of claim 48, wherein the flowing of fluid through the rearward thrust jets of the nozzle is only activated after the jetting hose has advanced into each borehole at least 5 feet from the horizontal section.

50. The method of claim 48, further comprising:

monitoring tensiometer readings at a surface, the tensiometer readings being indicative of drag experienced by the jetting hose as lateral boreholes are formed; and

wherein the flowing of fluid through the rearward thrust jets of the one or more collars is incrementally activated in each of the plurality of boreholes in response to a designated tensiometer reading.

51. The method of claim 45, wherein:

the seal assembly is at an upstream end of the jetting hose; and

each of the lateral boreholes has a diameter of between 0.5 and 2.5 inches.

52. The method of claim 45, wherein:

the jetting hose comprises:

a tubular stator body forming a bore along a longitudinal axis of the nozzle;

a tubular rotor body residing within the bore of the stator body, and also forming a bore along the longitudinal axis of the nozzle;

one or more bearings residing between the stator body and the surrounding rotor body to accommodate relative rotational movement between the rotor body and the stator body;

electro-magnetic coils which designed to induce the relative rotational movement between the rotor body and the stator body in response to electrical current;

a proximal end configured to sealingly connect to an end of a jetting hose, and to receive a jetting fluid; and

a discharge slot at the end of the rotor body configured to deliver the high pressure jetting fluid at a designated spray angle for erosion of a rock matrix;

the jetting hose comprises:

power wires for transmitting electrical energy towards the nozzle; and

at least three actuator wires proximate the nozzle configured to contract in response to receiving the electrical energy from the power wires; and

the method further comprises steering the nozzle while forming at least one of the of lateral boreholes by adjusting electrical current through the power wires and the at least three actuator wires, wherein the actuator wires induce a bending moment to the nozzle, thereby controlling a direction of the high pressure jetting fluid passing through the discharge slot.

53. The method of claim 52, wherein:

the nozzle further comprises at least one geo-spatial chip;

the jetting hose further comprises electrical wires or data cables for sending geo-location signals from the nozzle to a processor; and

steering the nozzle comprises:

sending geo-trajectory instructions from the processor to a current regulator configured to control electrical energy received by the at least three actuator wires.

54. The method of claim 53, wherein:

the geo-location signals comprise orientation and azimuth of the nozzle; and

each of the lateral boreholes is at least 25 feet in length.

55. The method of claim 54, further comprising:

determining upper and lower boundaries of the formation; and

advancing the nozzle into each of the lateral boreholes from the wellbore no further than the boundaries.

56. The method of claim 45, wherein:

the wellbore is completed with a string of production casing;

the conveyance medium is a string of coiled tubing; and

the jetting hose is part of a hydraulic jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end, the jetting hose being at least 10 feet in length; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to the coiled tubing for running the assembly into the production casing, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier slidably receiving the jetting hose, and forming an annular region between the jetting hose carrier and the surrounding outer conduit;

a whipstock member placed at lower end of the external conduit and having a concave face, and

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to allow the jetting hose to be translated out of and back into the jetting hose carrier without buckling; and

the method further comprises:

setting the whipstock at a desired first casing exit location along the horizontal wellbore, wherein the face of the whipstock is configured to bend the jetting hose substantially across an entire inner diameter of the wellbore when the jetting hose is translated out of the jetting hose carrier;

translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock to form the lateral boreholes.

57. The method of claim 56, wherein:

the jetting hose is at least 100 feet in length; and

each of the lateral boreholes extends at least 75 feet from the horizontal section.

58. The method of claim 45, wherein the parent wellbore comprises:

a string of production casing placed substantially along the horizontal section; and

perforations within the production casing, through which hydraulic fracturing and subsequent production operations have previously been conducted before the first and second lateral boreholes were formed; and

the method further comprises:

identifying non-performing or under-performing intervals of the pay zone; and

recompleting the parent wellbore by jetting windows through the production casing at one or more wellbore exit locations adjacent corresponding non-performing or under-performing intervals using the jetting hose and connected jetting nozzle, and forming new lateral boreholes.

59. The method of claim 58, further comprising:

(i) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby steerably excavating one or more side mini-lateral boreholes within the rock matrix in the pay zone off of selected lateral boreholes, (ii) pumping a new hydraulic fracture treatment into each lateral borehole to form fractures, or (iii) both.

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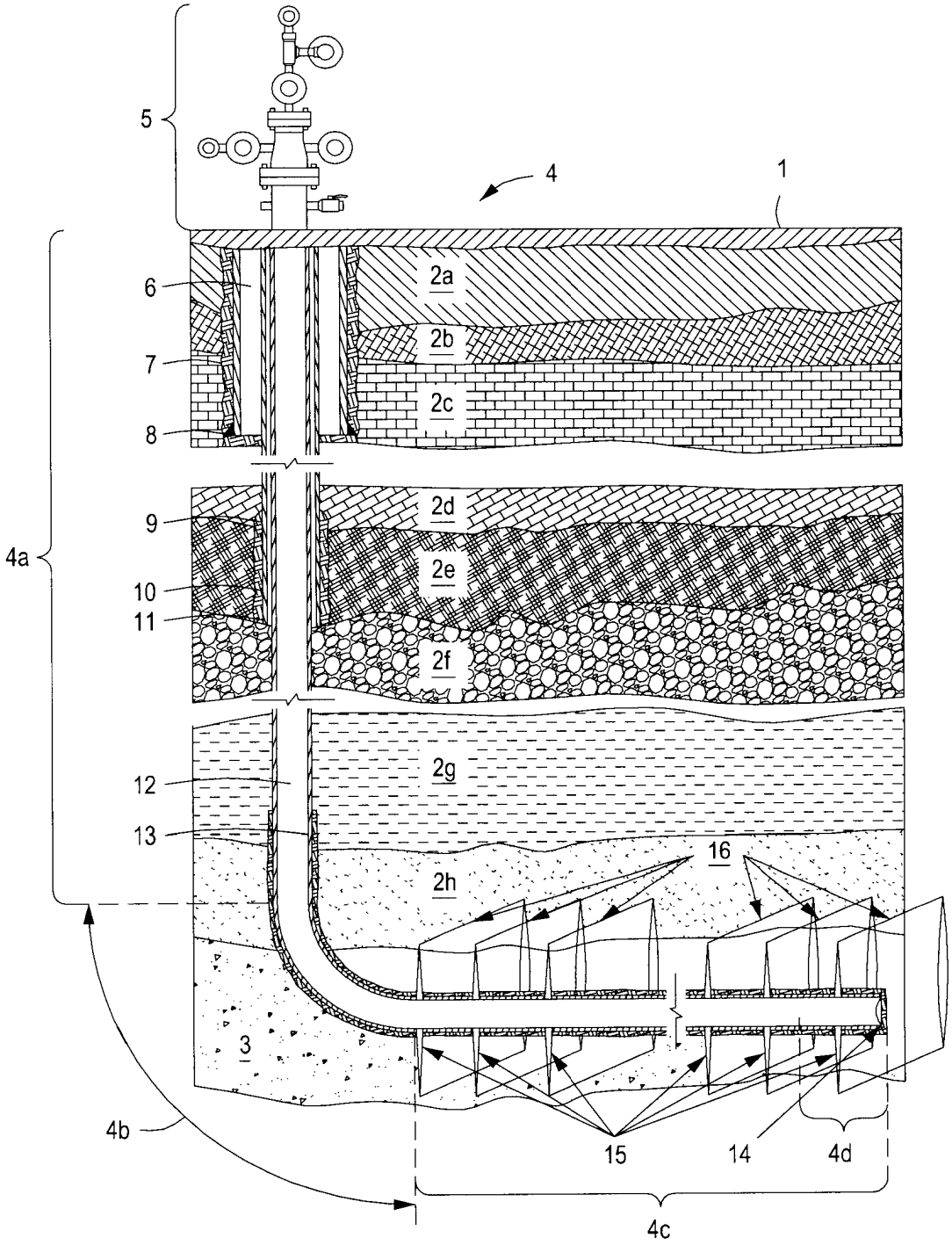


FIG. 1A

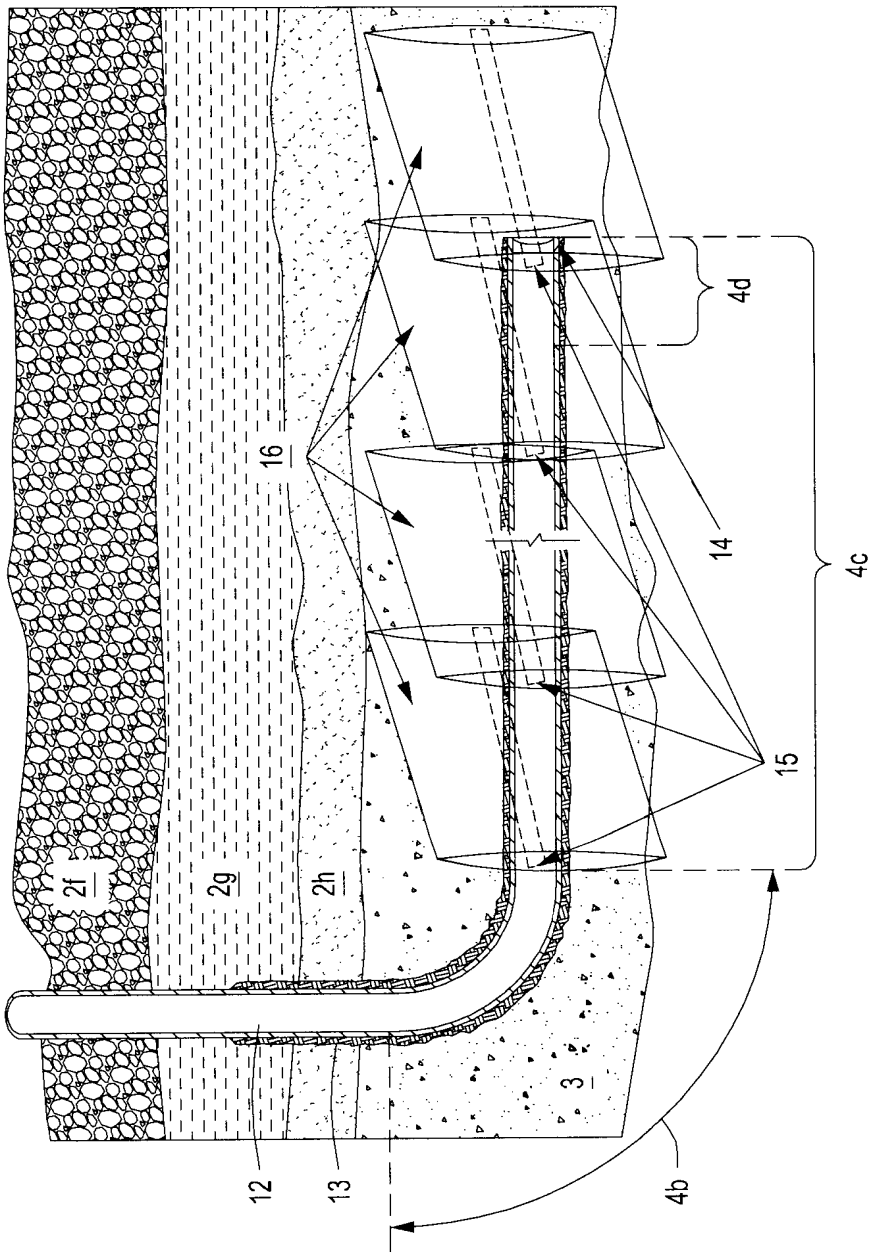


FIG. 1B

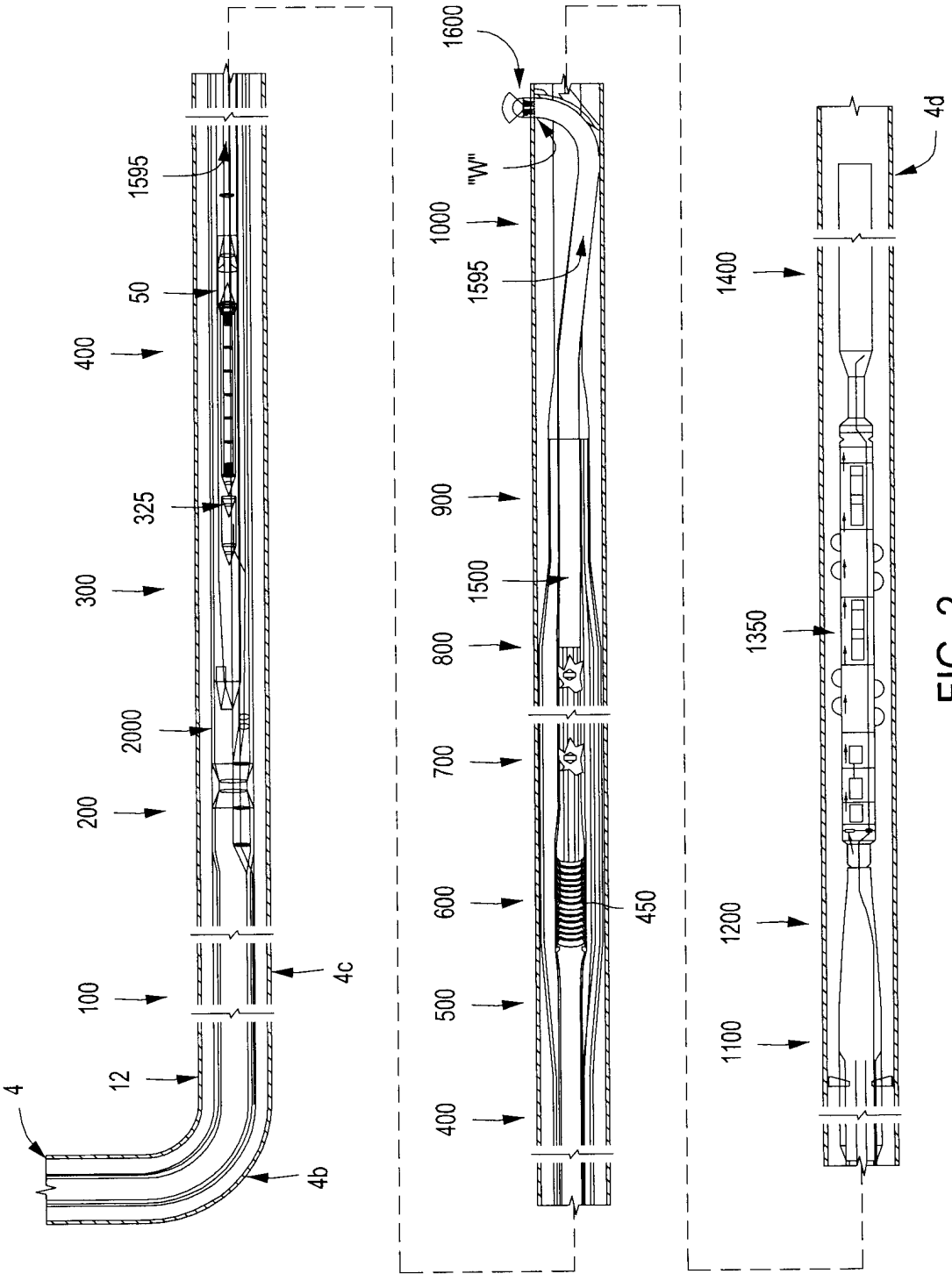

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4d
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1100

FIG. 2

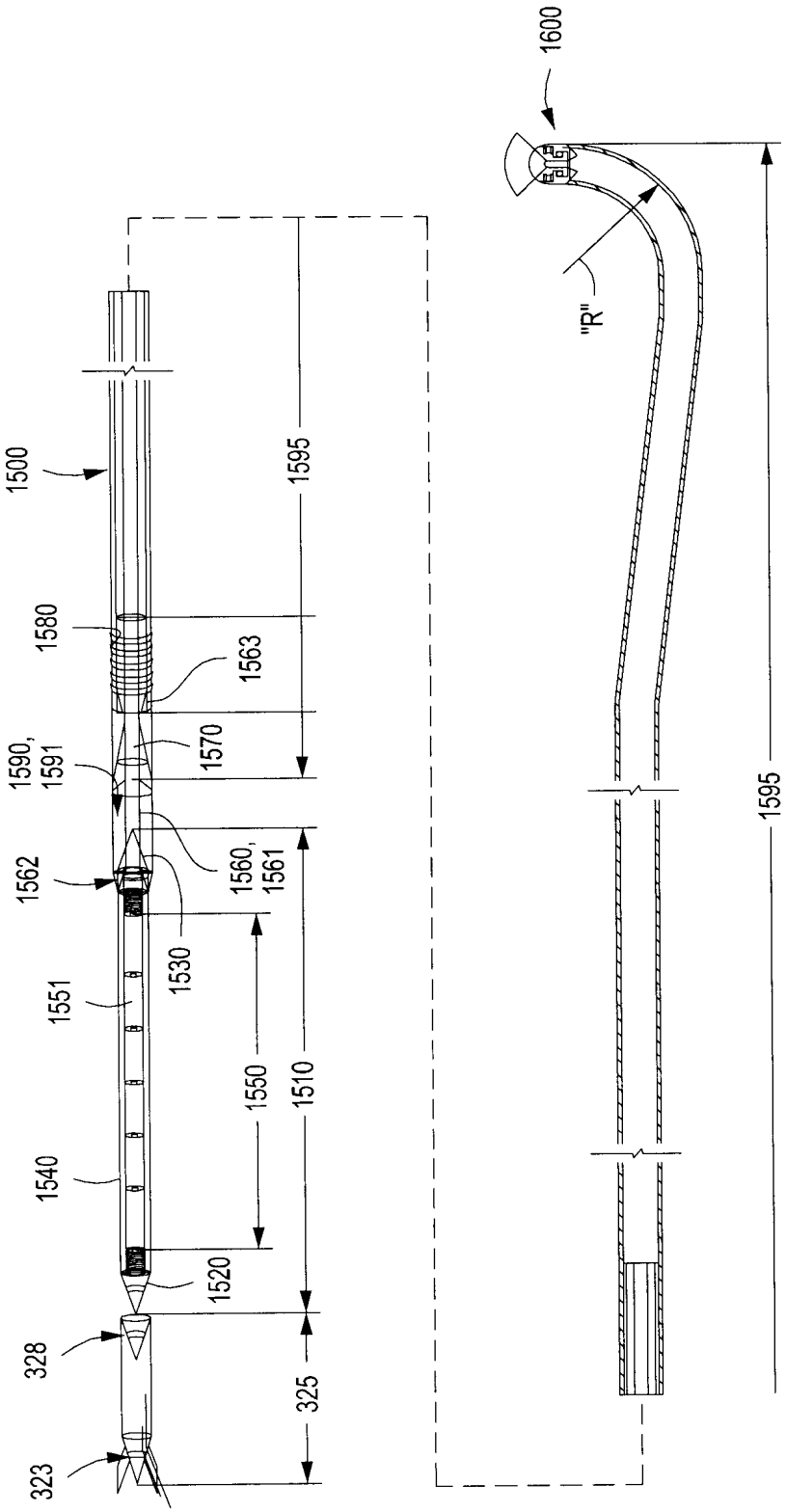

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FIG. 3

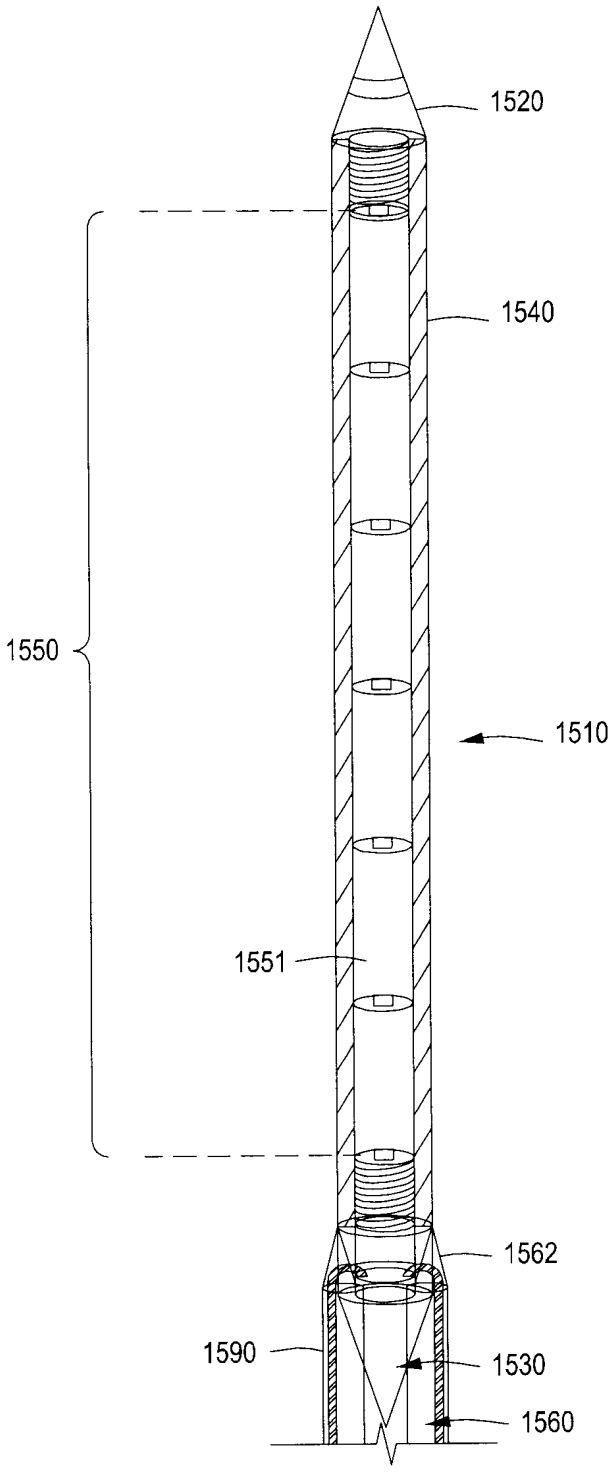


FIG. 3A

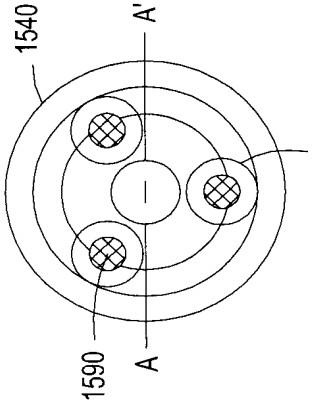


FIG. 3B-1a

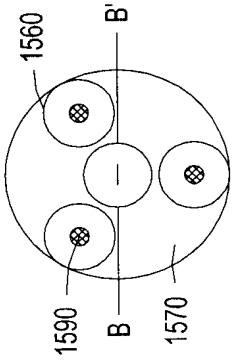


FIG. 3B-1b

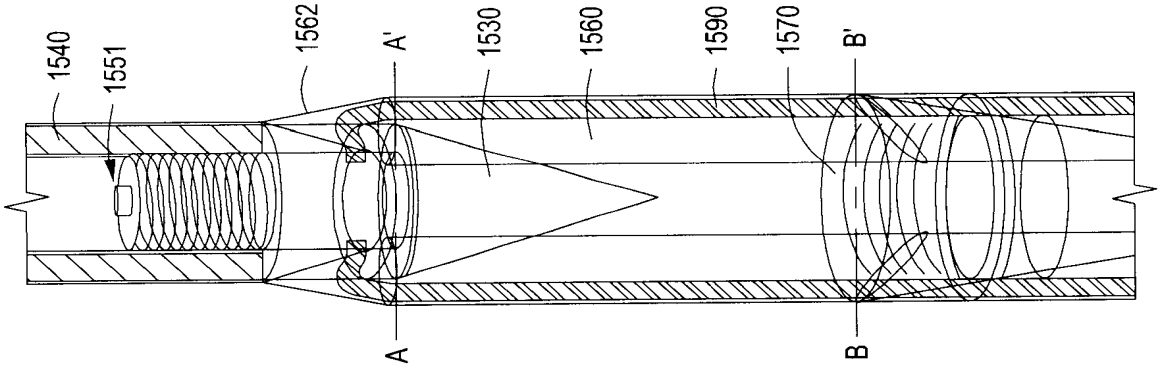


FIG. 3B-1

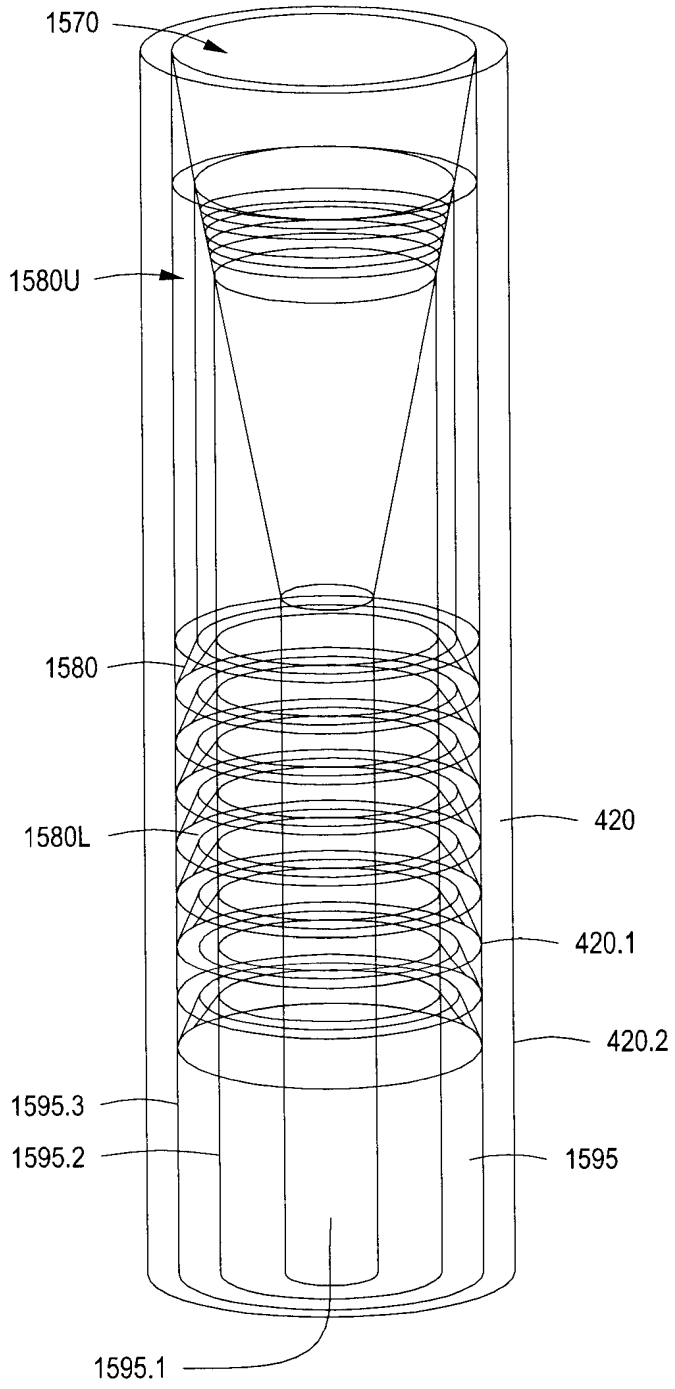


FIG. 3C

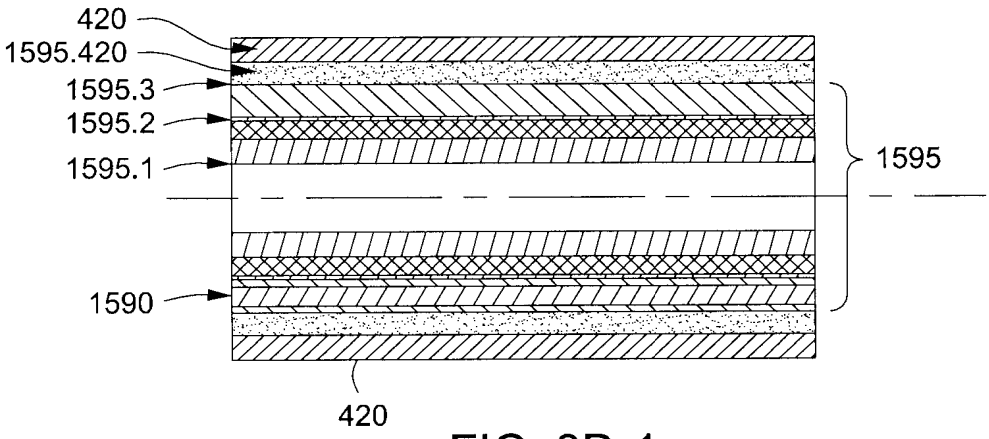


FIG. 3D-1

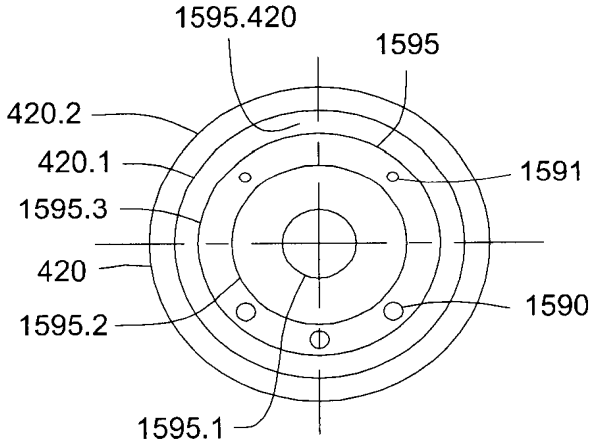


FIG. 3D-1a

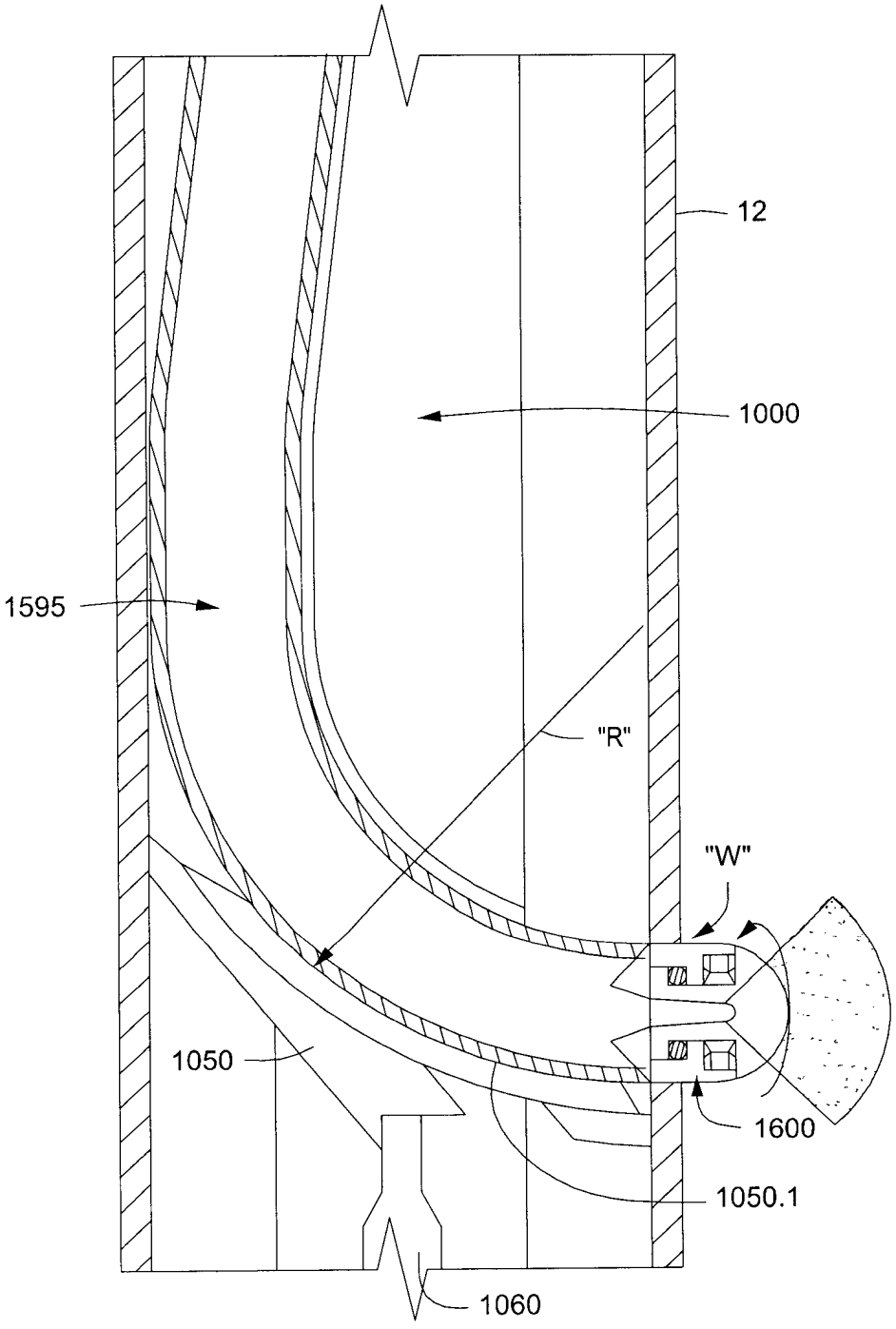


FIG. 3E

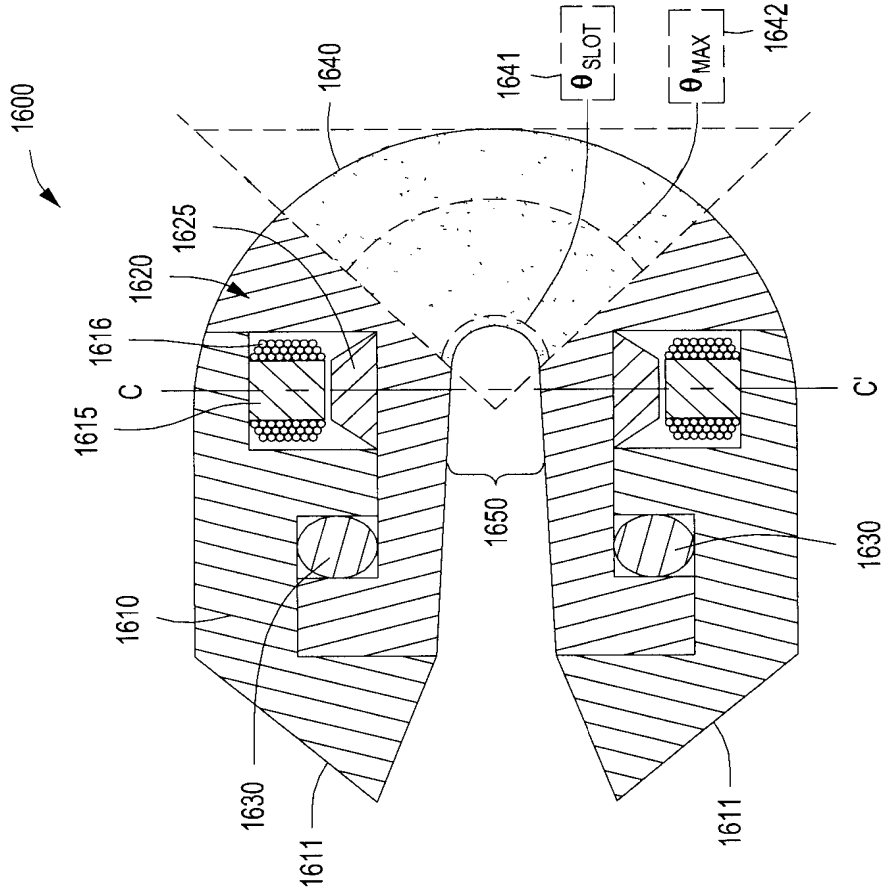


FIG. 3F-1b

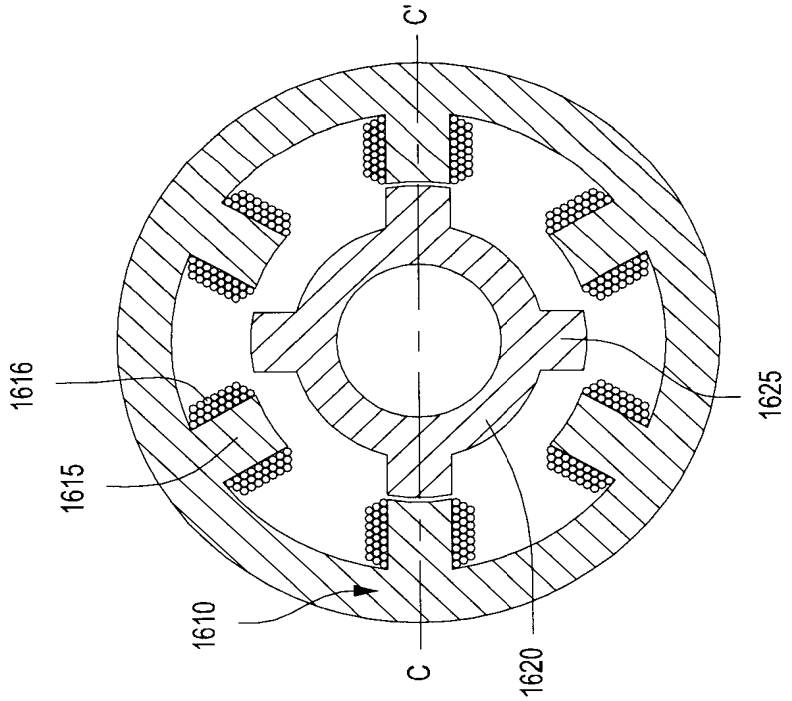


FIG. 3F-1a

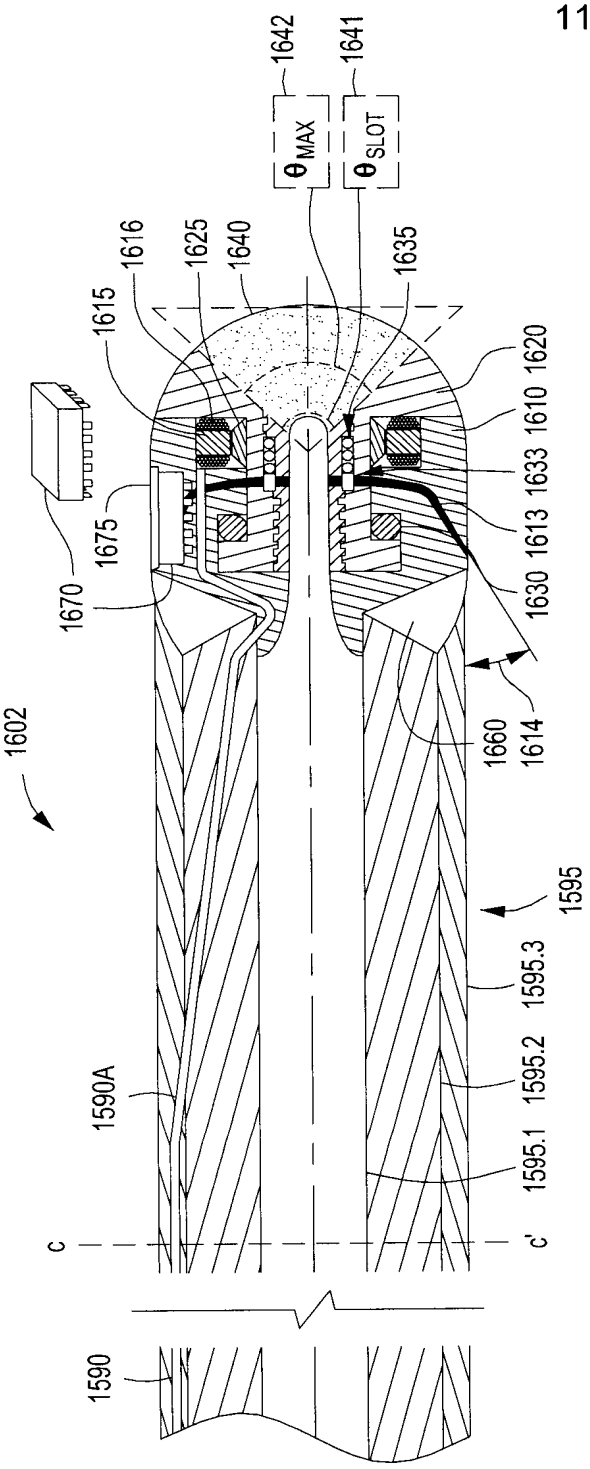


FIG. 3F-1c

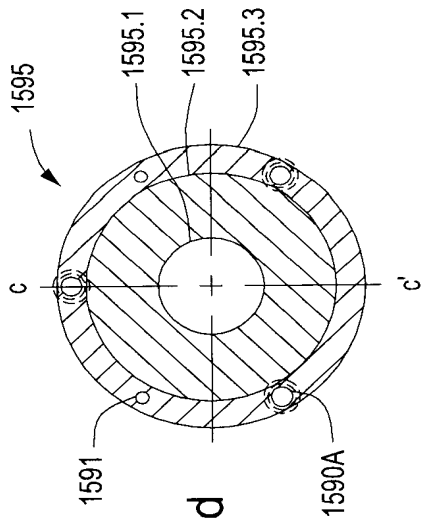


FIG. 3F-1d

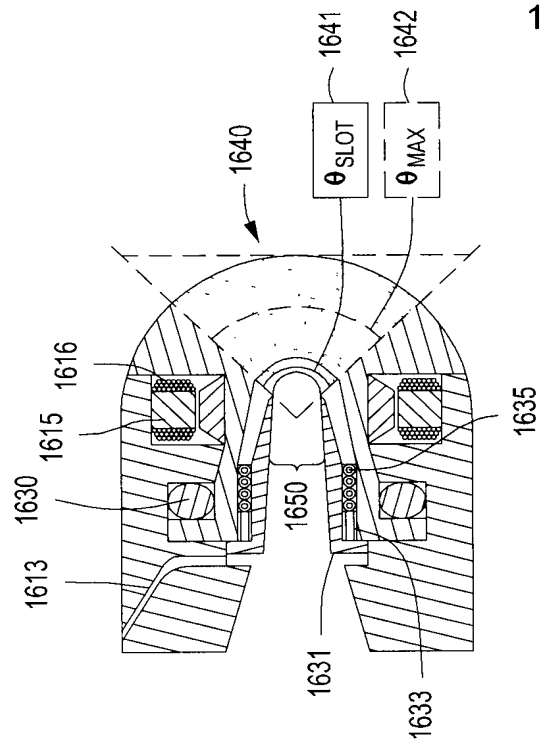


FIG. 3F-2b

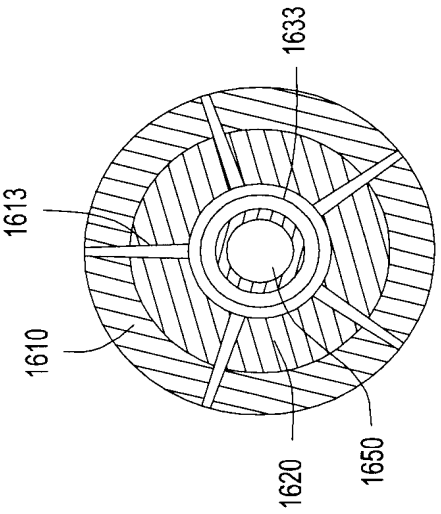


FIG. 3F-2c

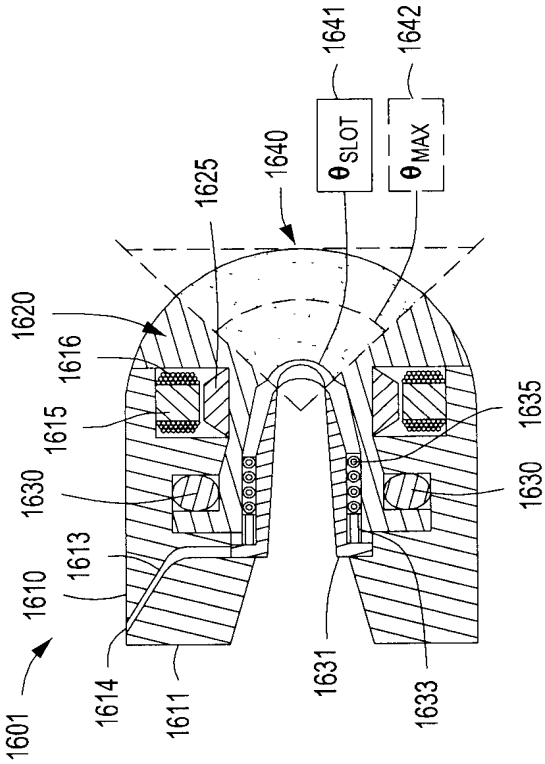


FIG. 3F-2a

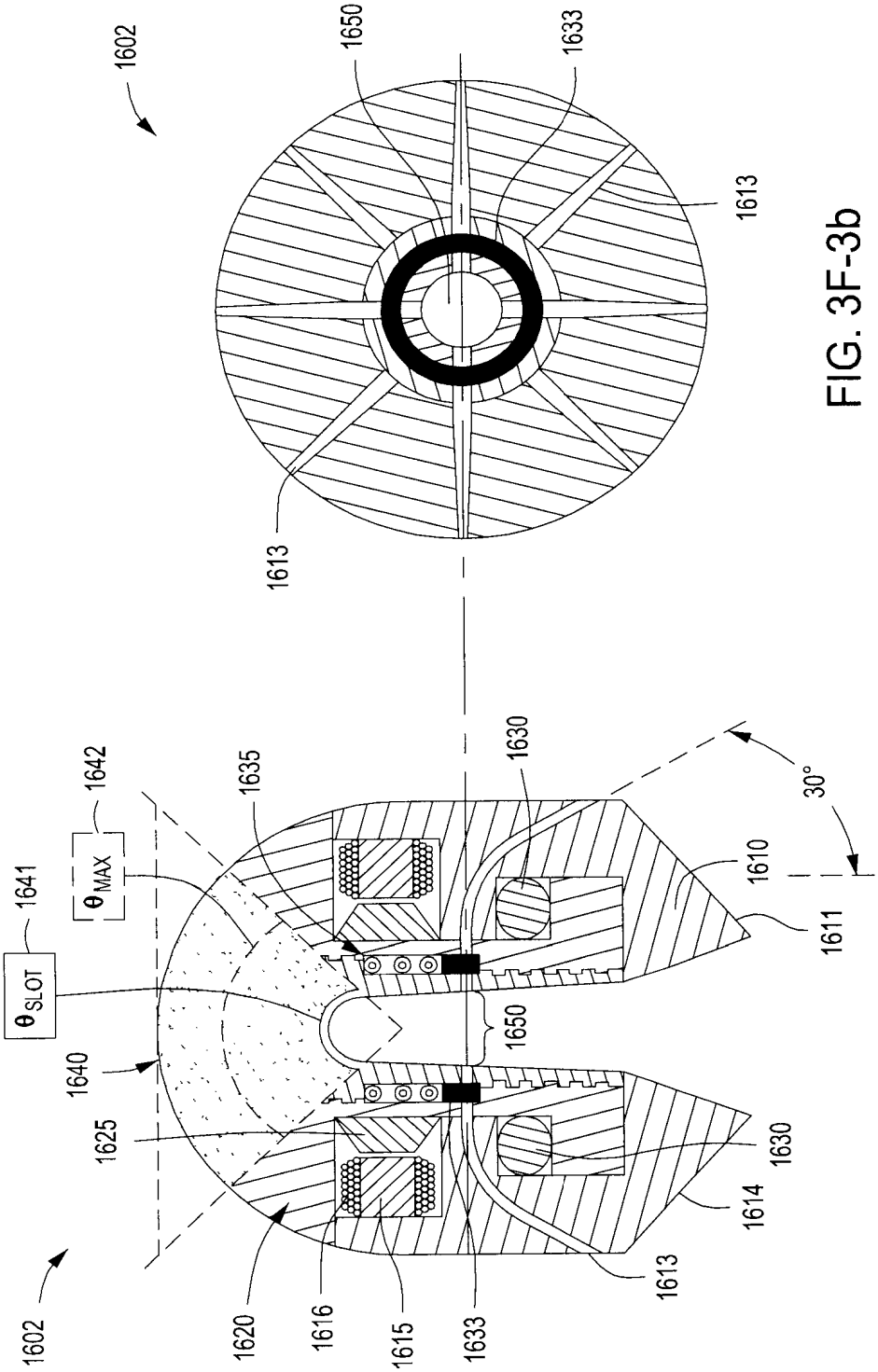


FIG. 3F-3b

FIG. 3F-3a

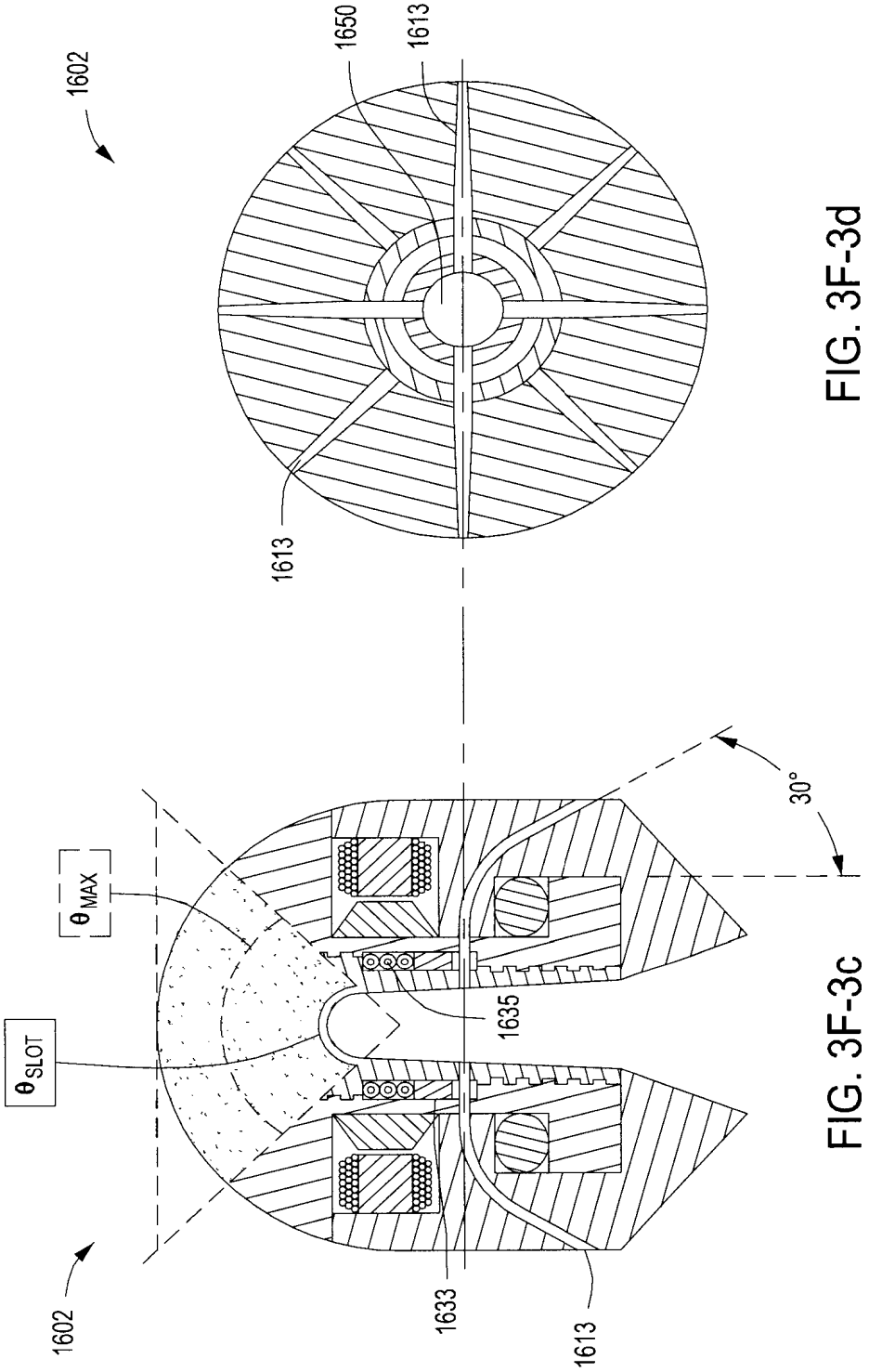


FIG. 3F-3d

FIG. 3F-3c

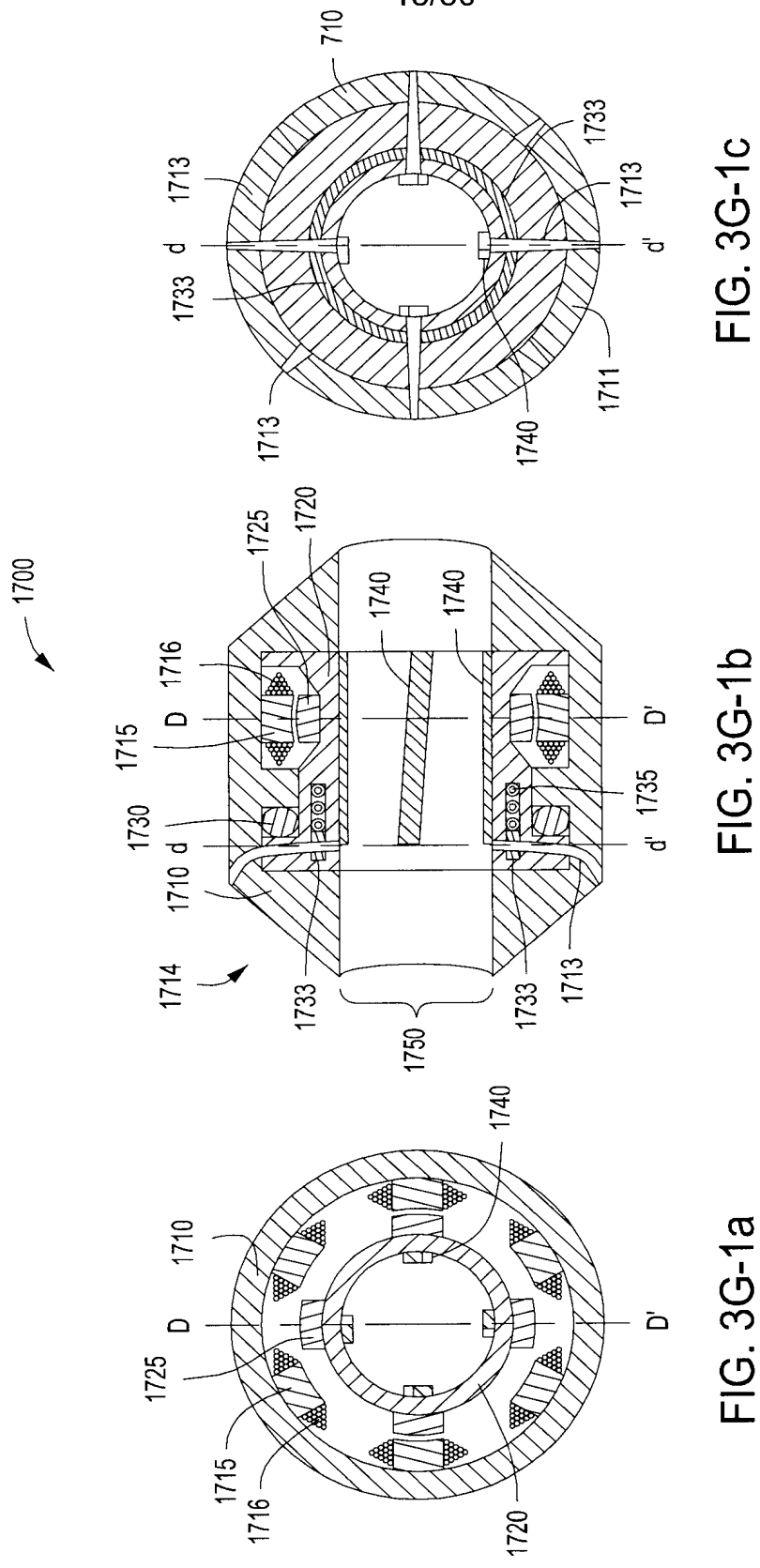


FIG. 3G-1c

FIG. 3G-1b

FIG. 3G-1a

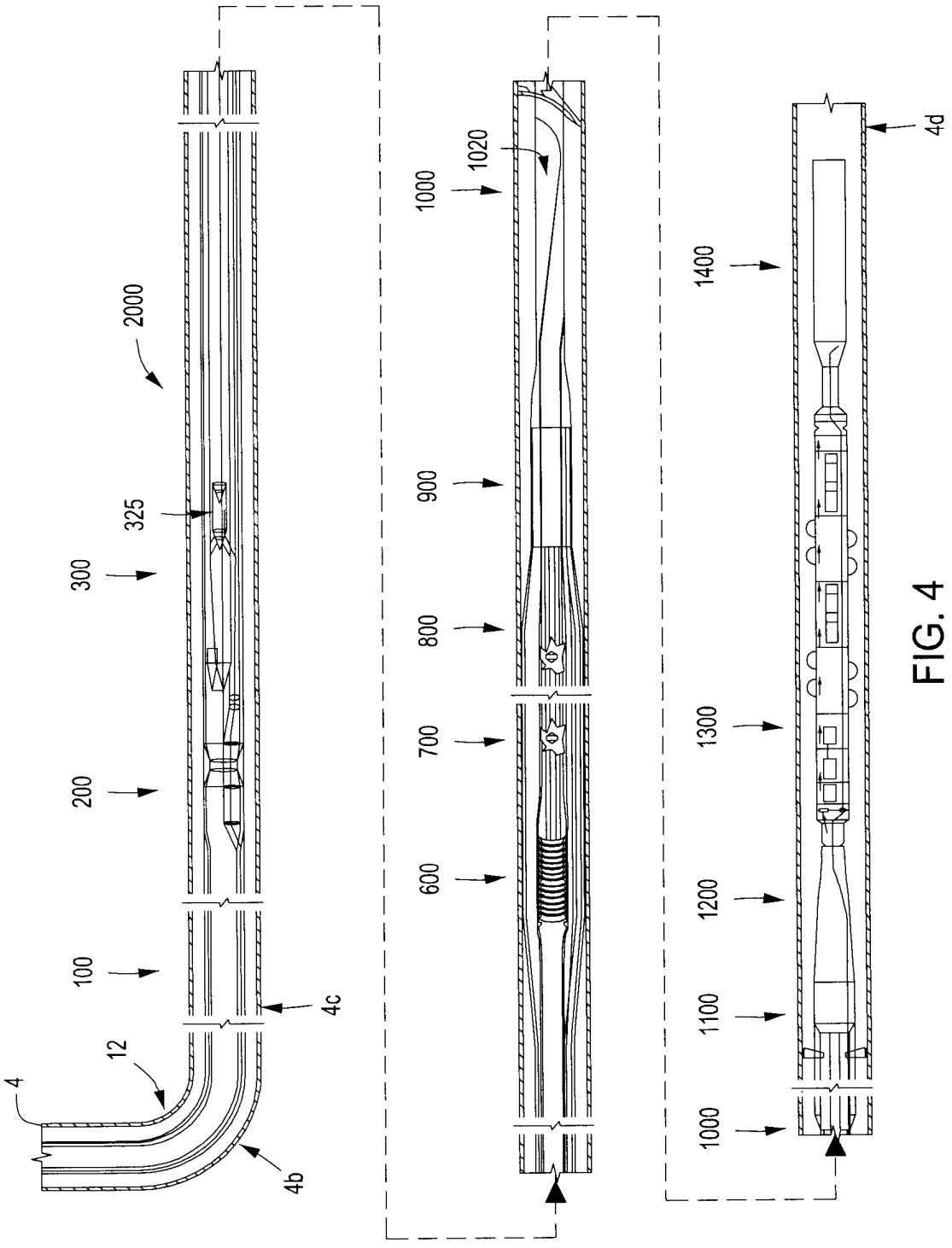

2000
325
300
200
100
12
4
4c
4b
1000
1020
900
800
700
600
1400
1300
1200
1100
1000
4d

FIG. 4

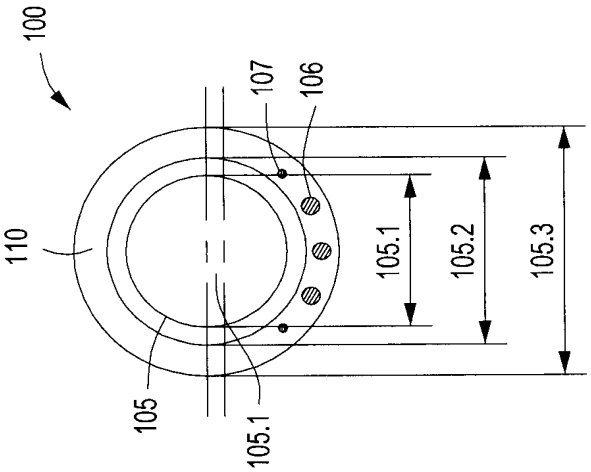


FIG. 4A-1a

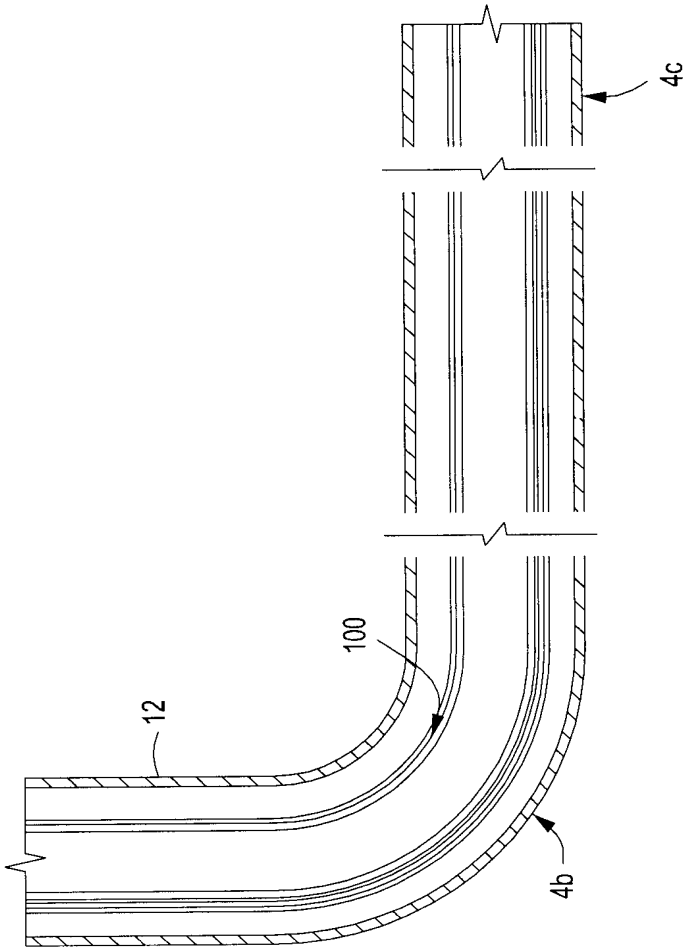


FIG. 4A-1

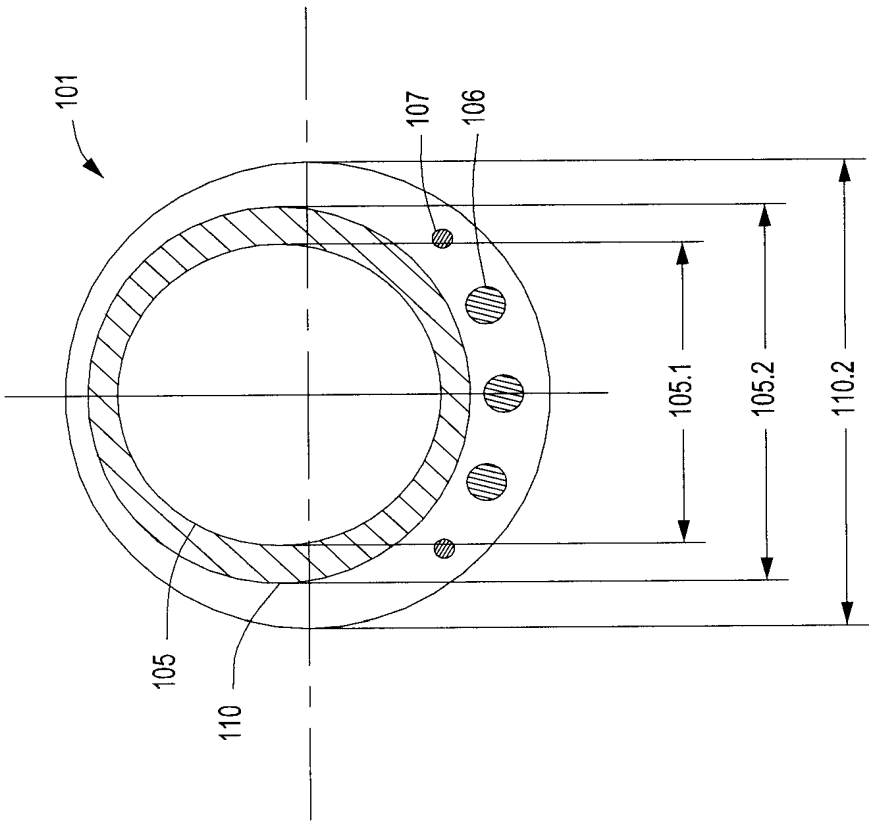


FIG. 4A-2

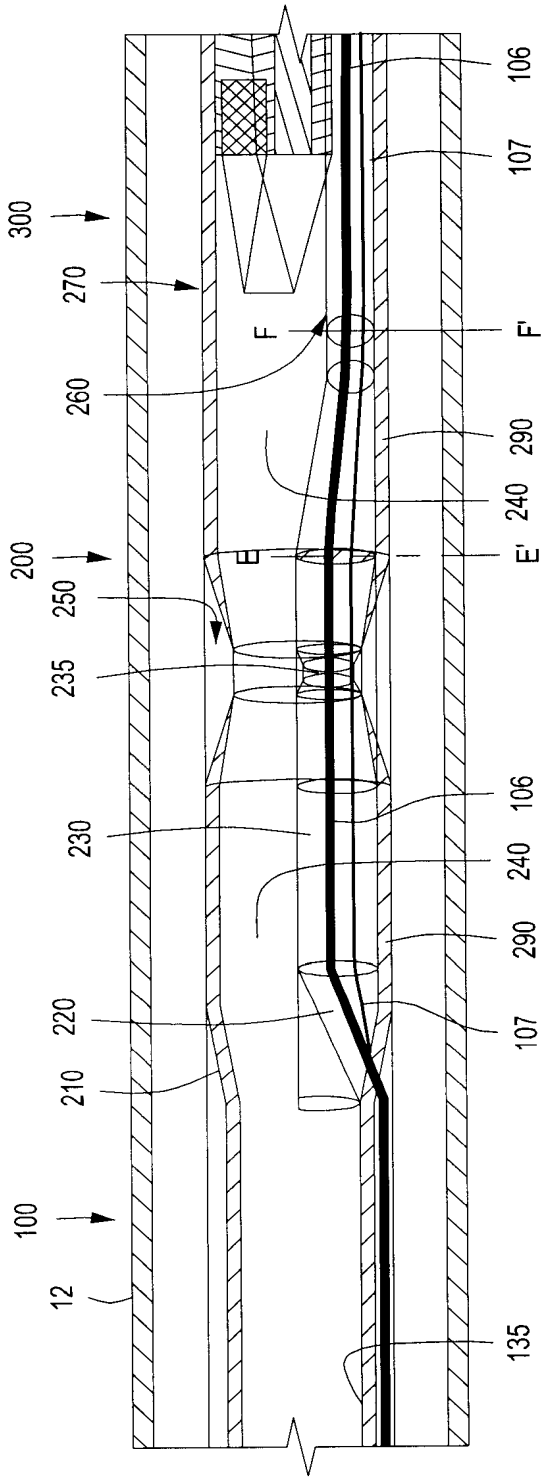


FIG. 4B-1

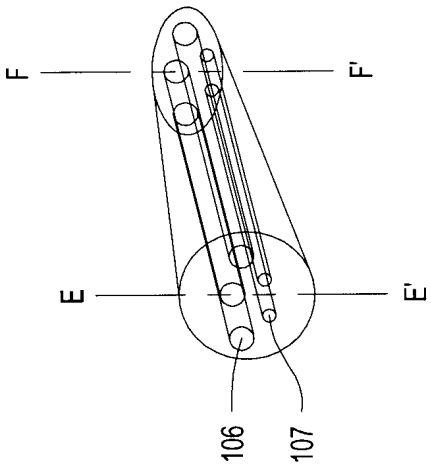


FIG. 4B-1a

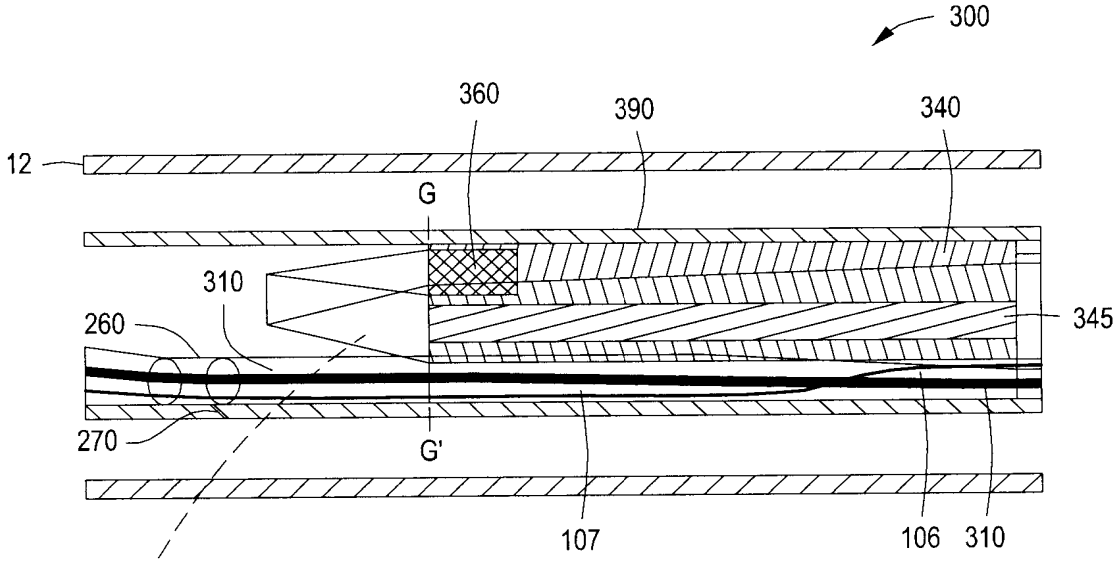


FIG. 4C-1

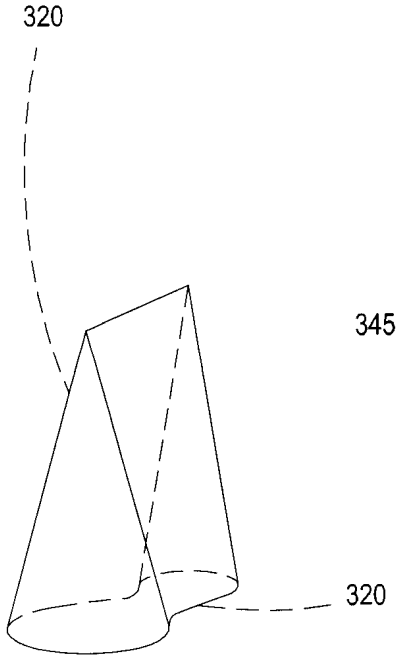


FIG. 4C-1b

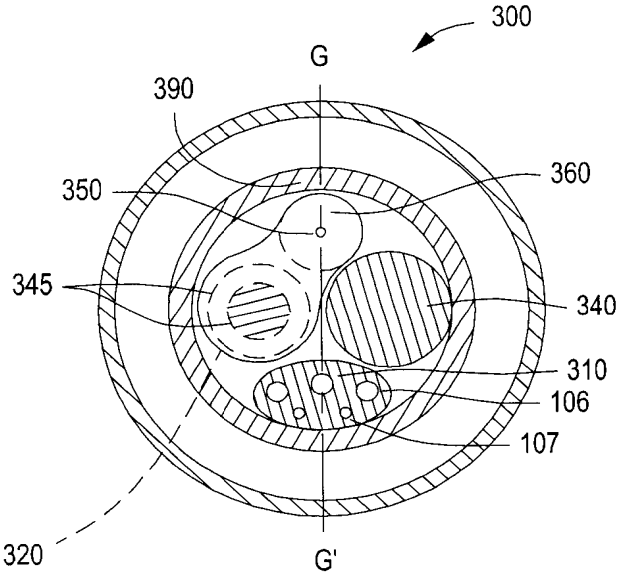


FIG. 4C-1a

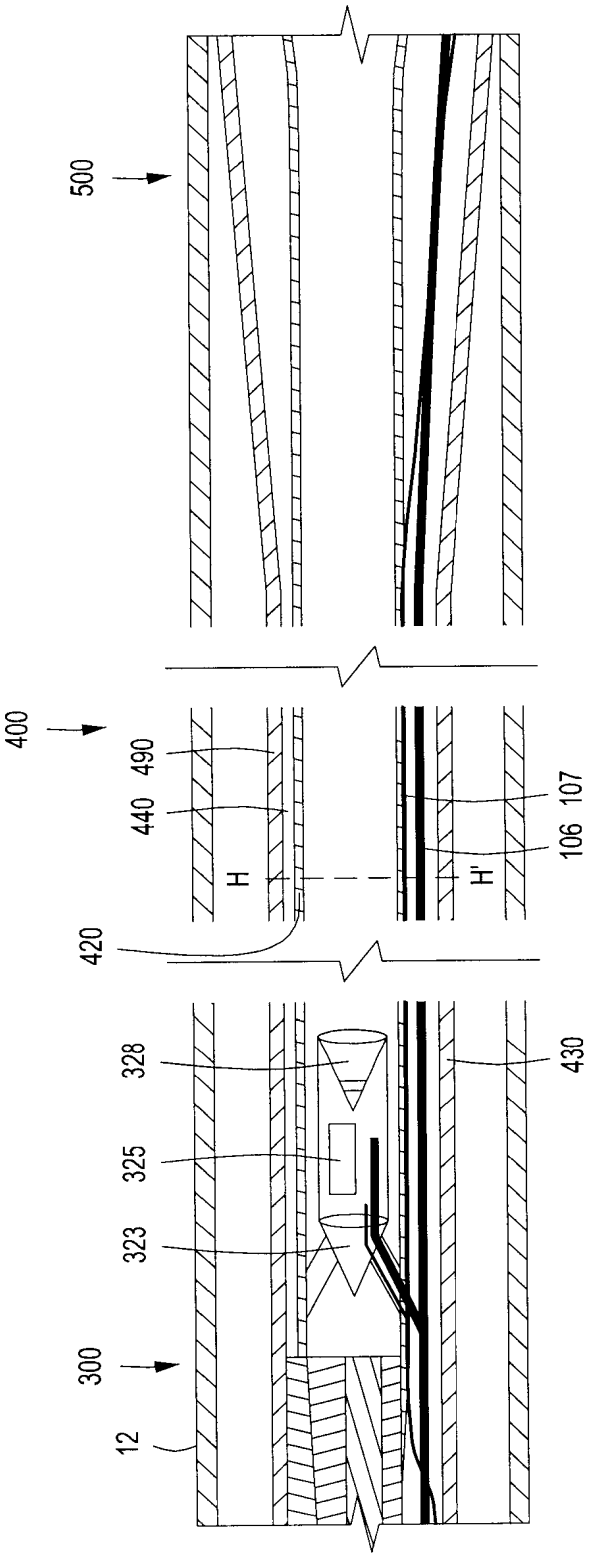


FIG. 4D-1

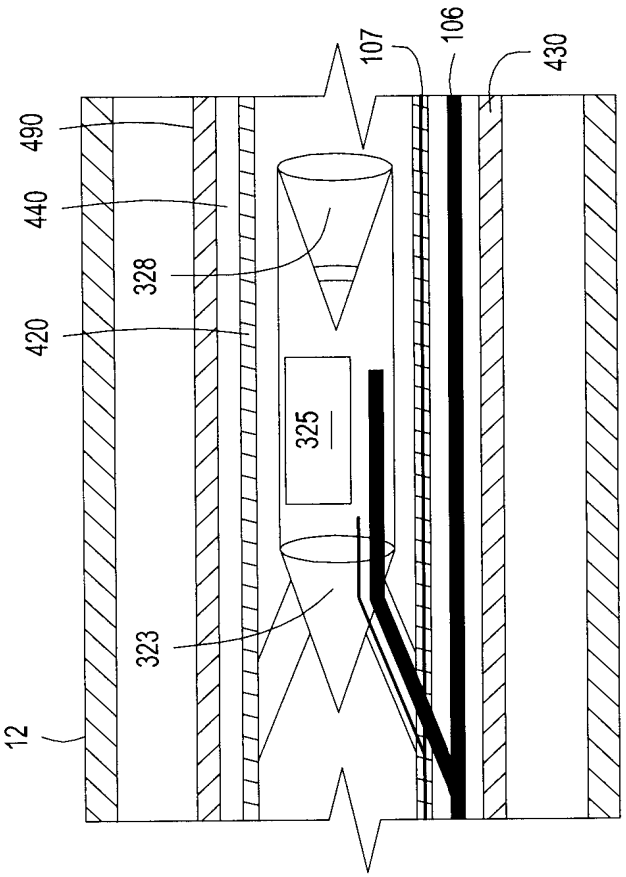


FIG. 4D-1b

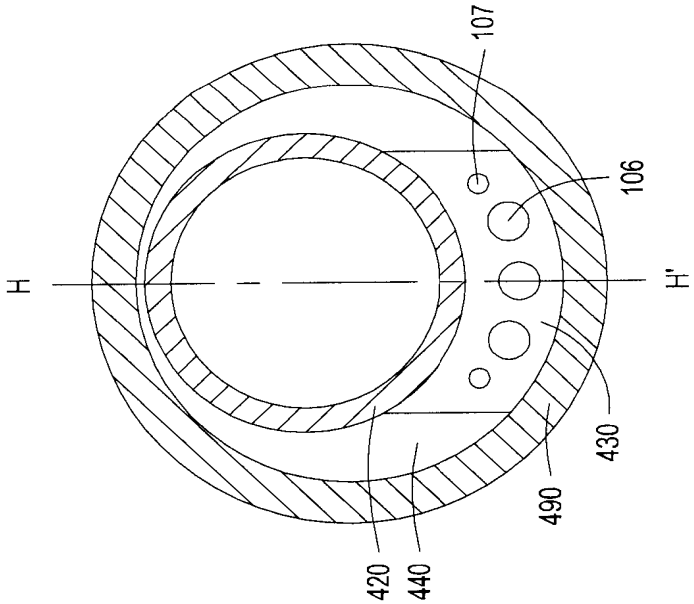


FIG. 4D-1a

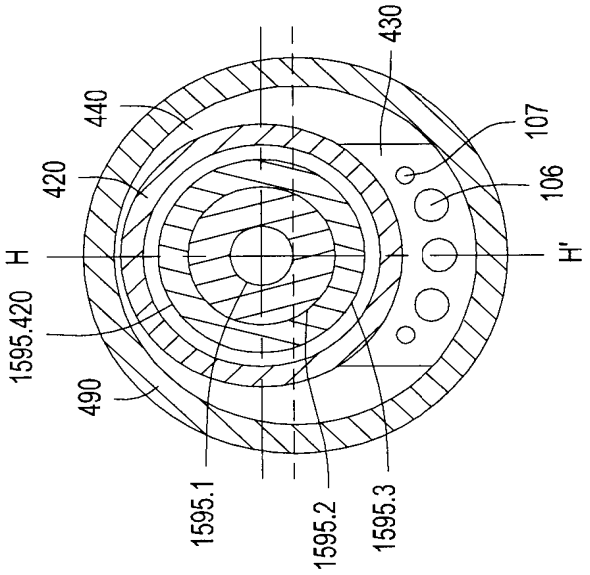


FIG. 4D-2a

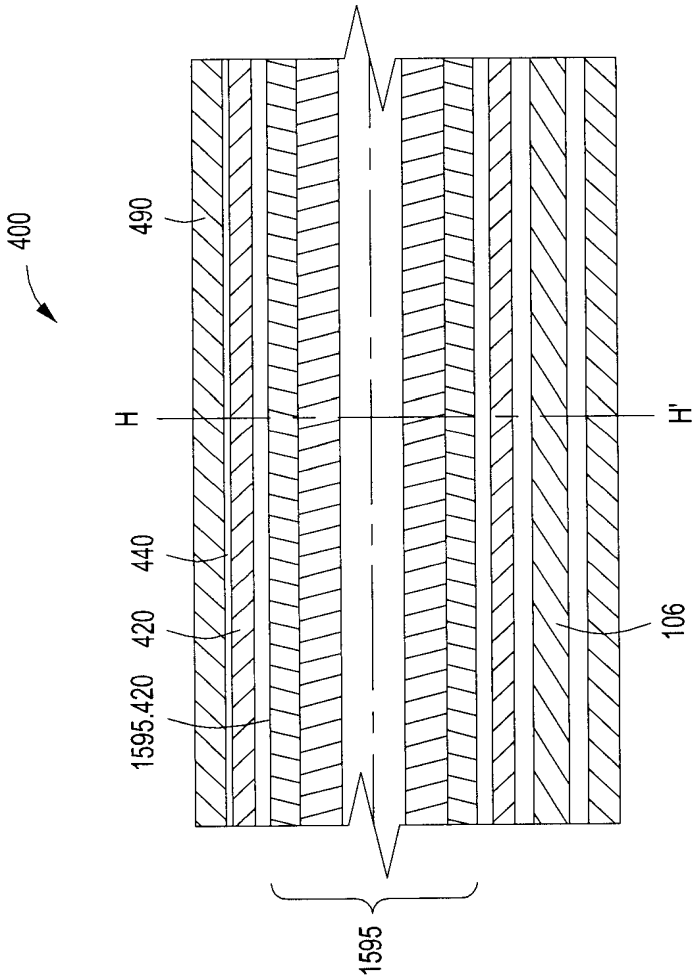


FIG. 4D-2

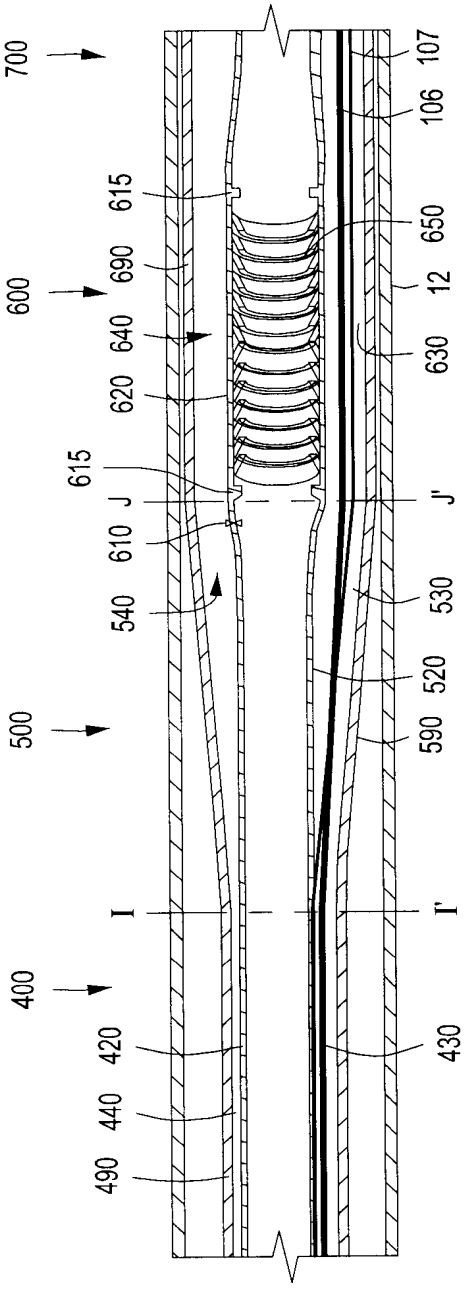


FIG. 4E-1

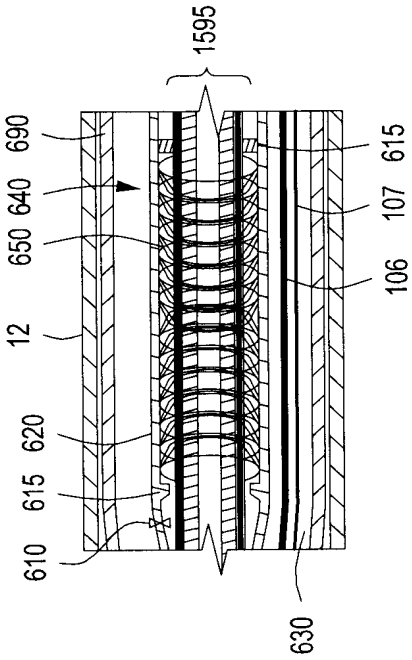


FIG. 4E-2

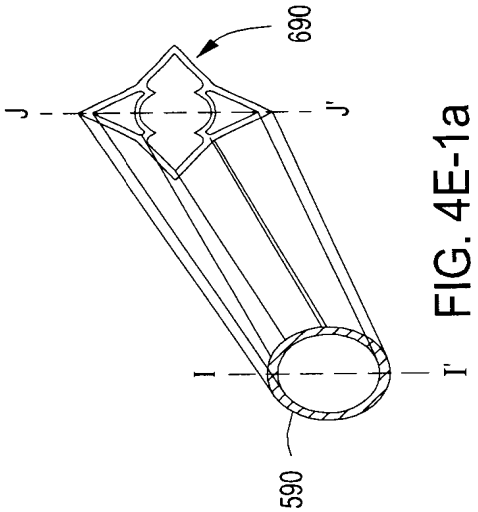


FIG. 4E-1a

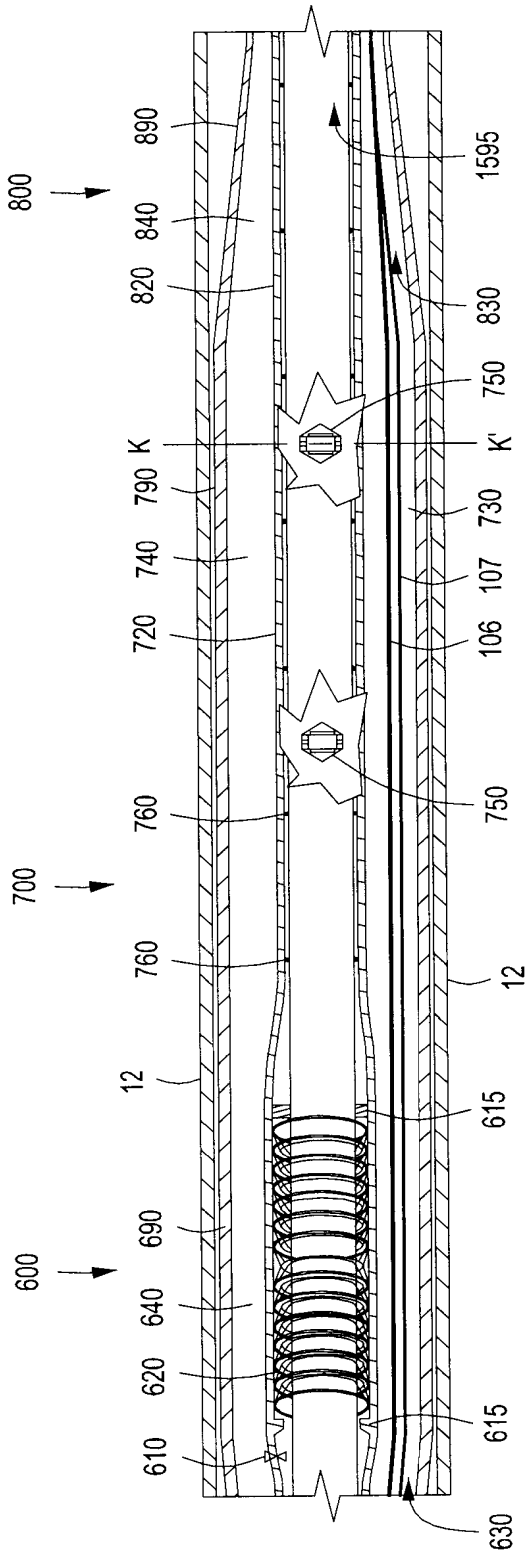

800
890
840
820
K
790
740
720
760
700
760
12
12
690
600
640
620
610
1595
830
750
K'
730
107
106
750
615
615
630

FIG. 4F-1

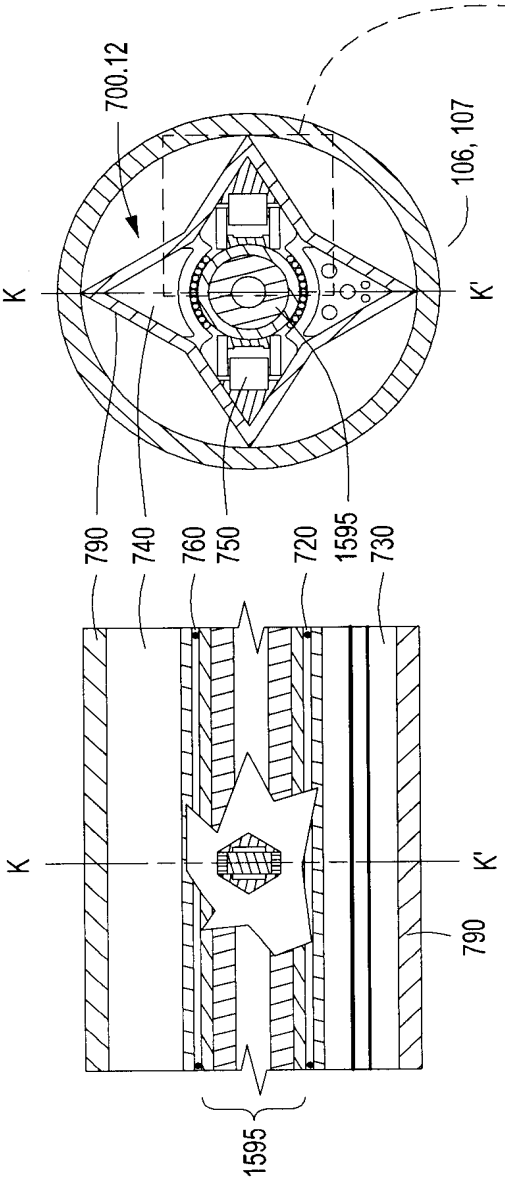


FIG. 4F-2

FIG. 4F-2a

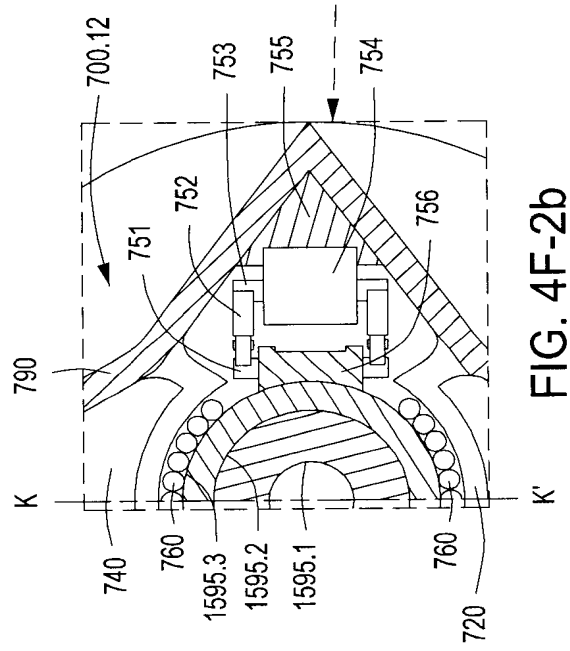


FIG. 4F-2b

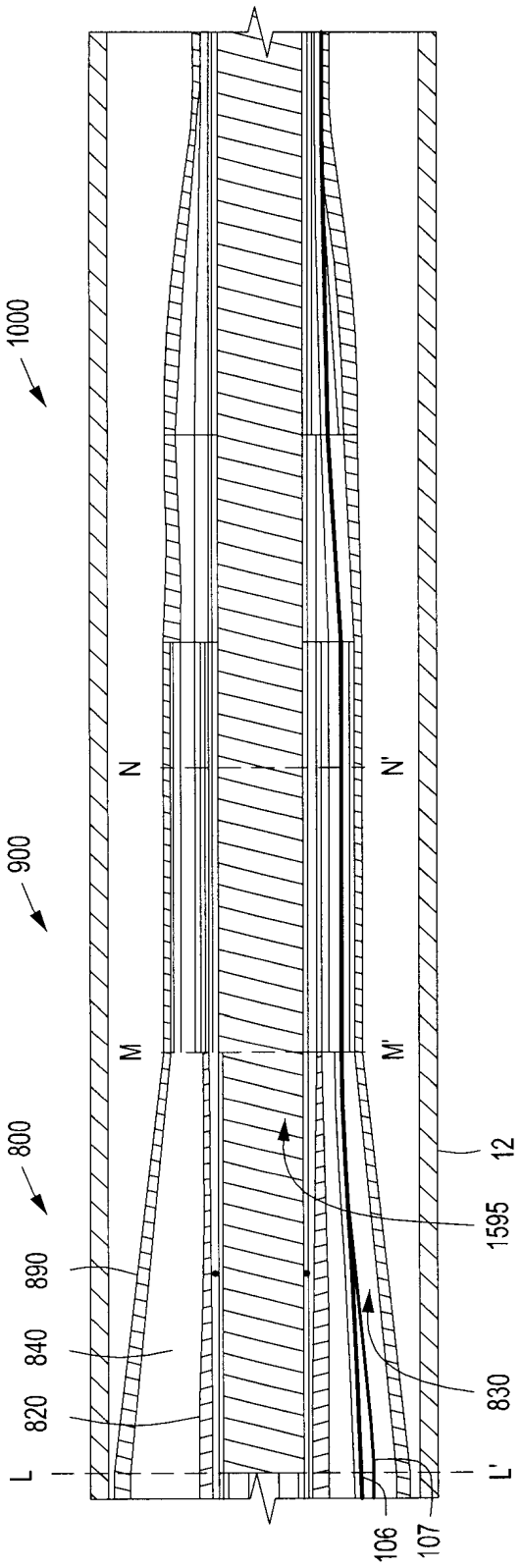


FIG. 4G-1

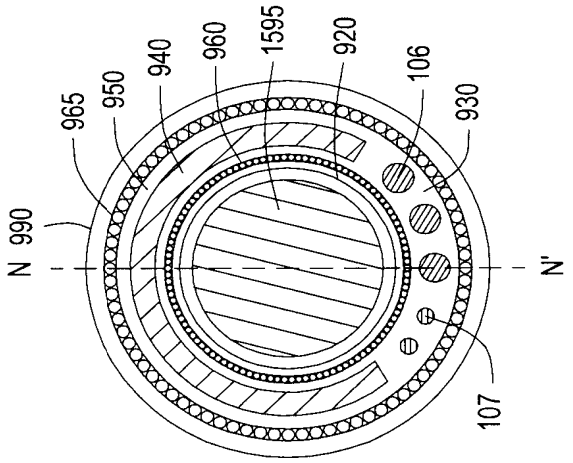


FIG. 4G-1b

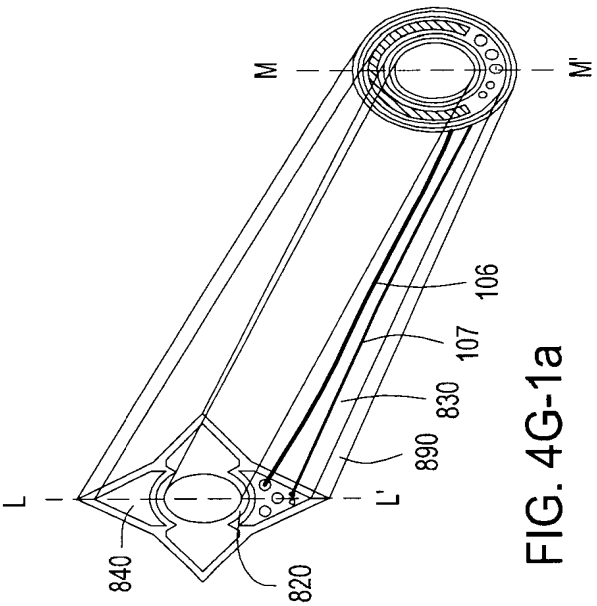


FIG. 4G-1a

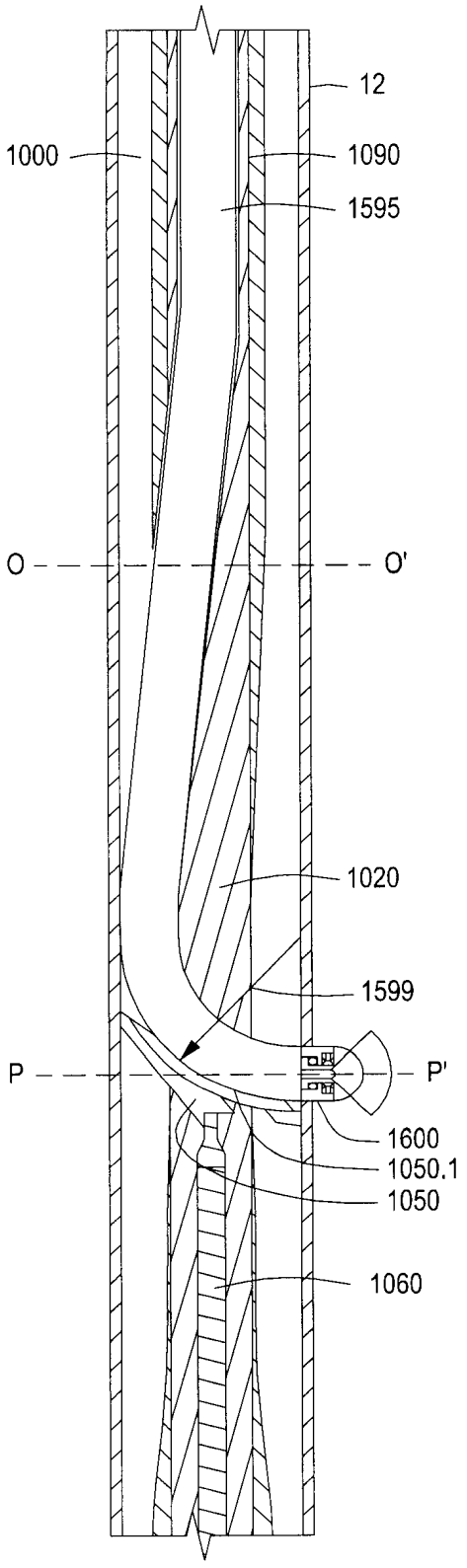


FIG. 4H-1

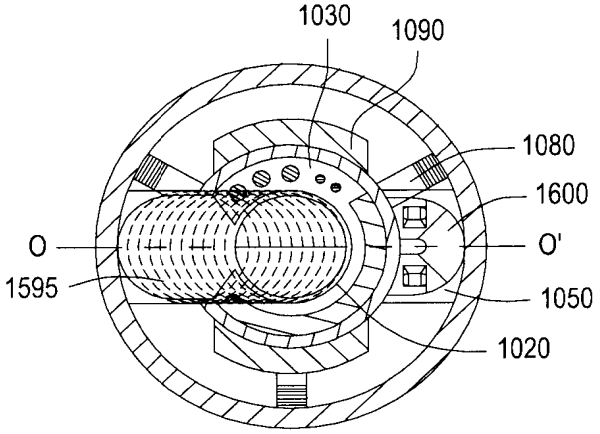


FIG. 4H-1a

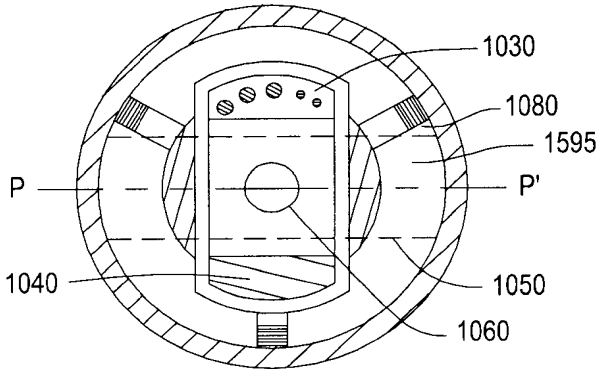


FIG. 4H-1b

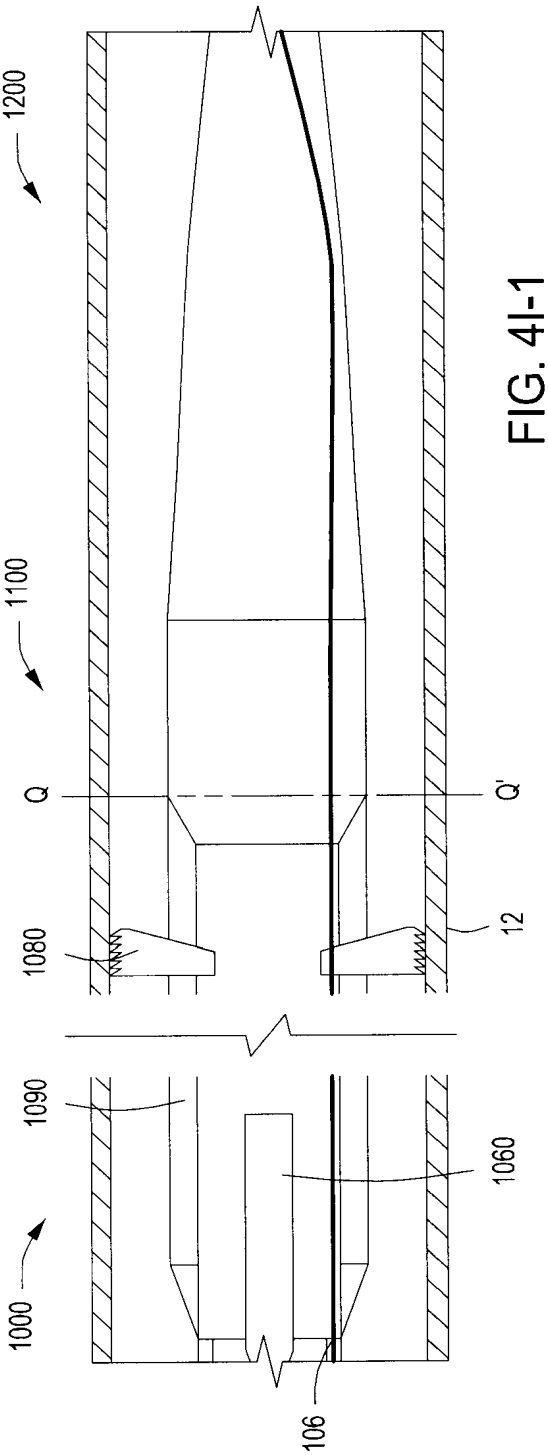


FIG. 4I-1

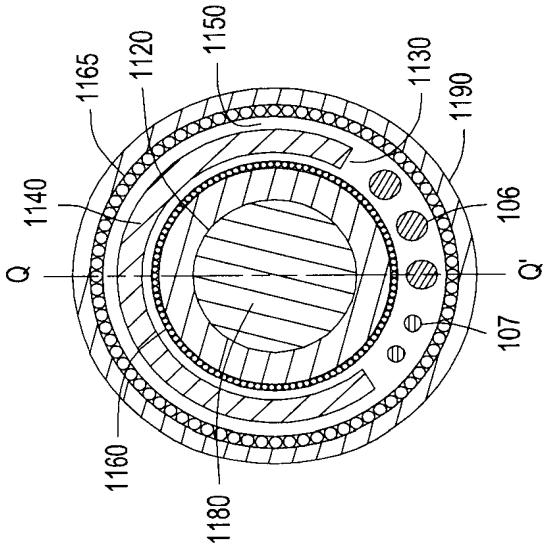


FIG. 4I-1a

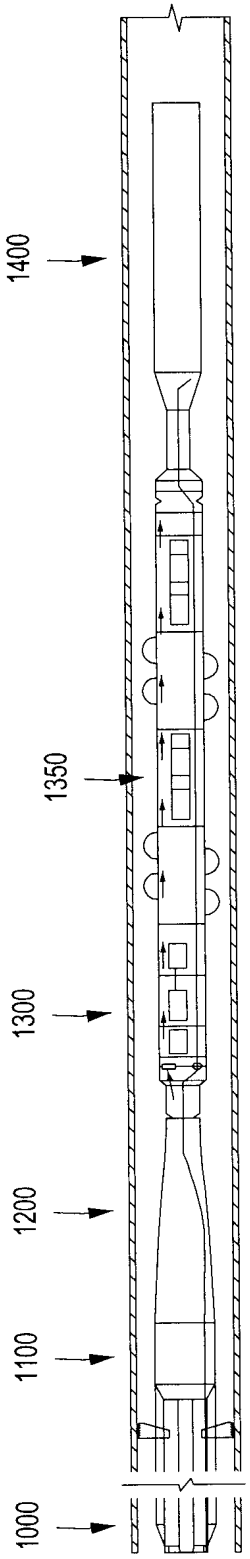
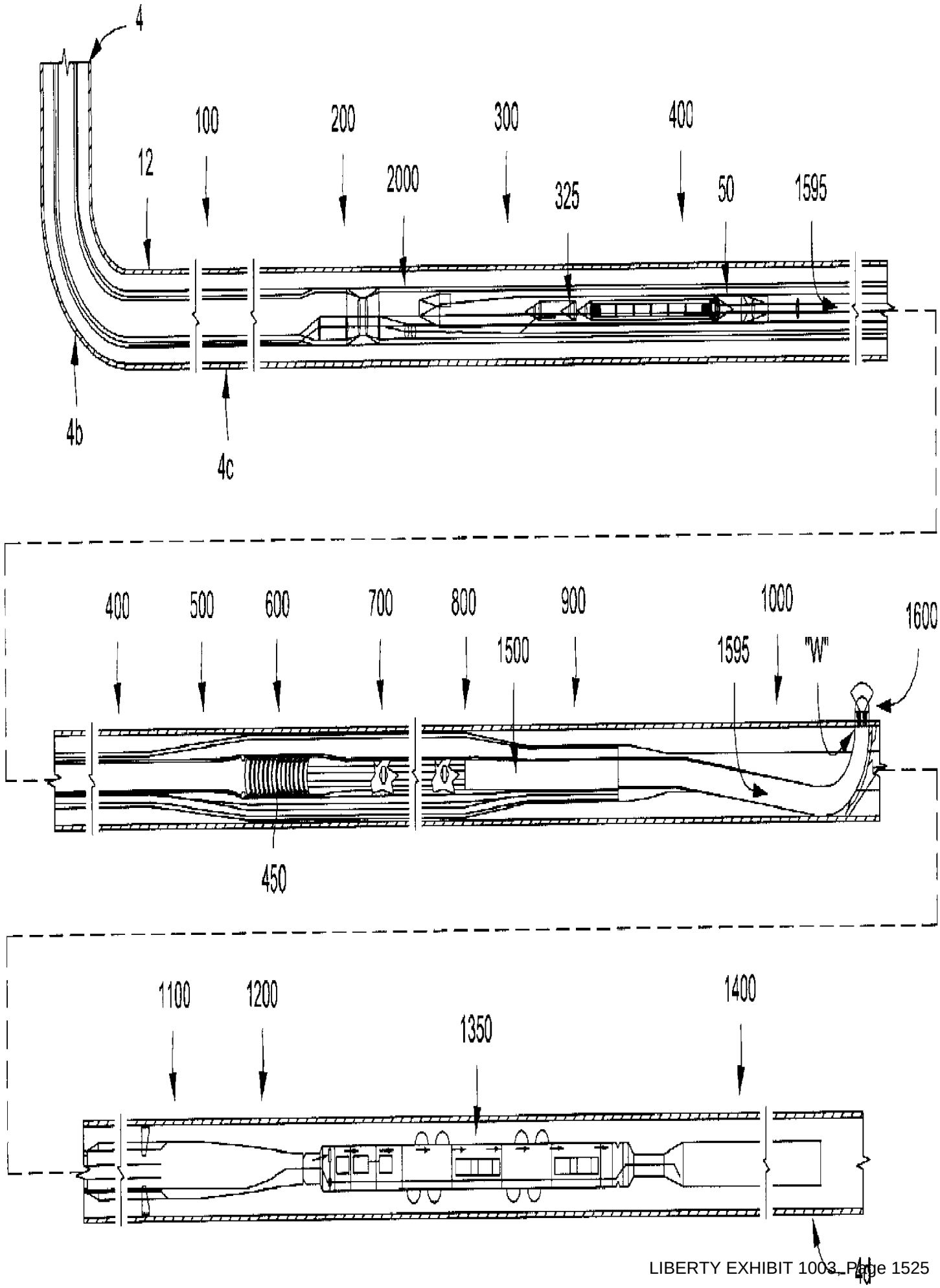


FIG. 4J


4
100
200
300
400
12
2000
325
50
1595
4b
4c
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500
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800
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1000
1600
1500
1595
"W"
450
1100
1200
1400
1350
40

ABSTRACT

A system and method that remotely monitors and controls proppant usage in a fracturing operation. The system and method allow operators to wirelessly monitor and control proppant storage units from inside a datavan through sensors and control mechanisms that interface with fracturing software to schedule the flow of the proppant. A sensor monitors the weight, container level, or volume of the proppant being used to keep the induced hydraulic fracture open. A serial to Ethernet converter converts this information and sends it wirelessly to a datavan. A user at the datavan controls the proppant usage through a display in the datavan of the storage units with the appropriate weight. The container monitoring software links with the fracturing software, providing real-time information about proppant usage so that the user can properly schedule proppant flow to the well through valves, conveyor belts, and other control mechanisms.

CROSS-REFERENCE TO RELATED APPLICATIONS

[001] This application claims priority to U.S. Provisional Patent Application No. 62/204,331 filed on August 12, 2015 and is a continuation-in-part of, and claims priority to and the benefit of co-pending U.S. Patent Application Serial No. 15/202,085 filed July 5, 2016, which is a continuation of U.S. Patent No. 9,410,410 filed November 16, 2012, the full disclosures of which are hereby incorporated by reference herein for all purposes.

BACKGROUND OF THE INVENTION

1. Technical Field

[002] Embodiments of the present disclosure relate to systems and methods for wirelessly monitoring and controlling proppant usage in real time in a hydraulic fracturing operation.

2. Description of Related Art

[003] Horizontal drilling and hydraulic fracturing are two ways in which unconventional sources of hydrocarbons can be tapped to provide energy resources. Hydraulic fracturing (fracking) operations typically require powering numerous components in order to recover oil and gas resources from the ground. For example, pumps that inject fracking fluid down the wellbore, blenders that mix proppant into the fluid, cranes, wireline units, and many other components all must perform different functions in concert to carry out fracturing operations.

[004] Fracturing operations are highly complex and involve pumping fracturing fluid at a high pressure to hydraulically fracture the reservoir rock in the well in order to form fractures and stimulate production of hydrocarbons. The formed fractures can then be used to access hydrocarbons that could not have been accessed with traditional oil & gas well techniques. The fracturing fluid that is pumped down into the well usually includes a proppant that is a solid particulate such as sand or ceramic beads. In many known fracking systems, proppant, such as sand, glass beads, ceramic material, bauxite, dry powders, rock salt, benzoic acid, fiber material,

or cement plastics, is mixed with other materials and enhances the flow capacity of the fractures. The proppant props open the fractures and remains in the fractures after the end of the hydraulic fracturing operation.

[005] The proppant is supplied to the blenders and mixers and then to the well through a proppant delivery system located at the wellsite. The proppant is usually stored in large containers that are heavy and are connected to conveyor belts which lead to other mixing equipment and finally into the wellbore, where the mixture is pumped into the reservoir. The containers usually are refilled at the site by trucks that come in and empty the proppant into them. Gates are controlled by the user to open and close the proppant containers. However, in this operational scenario operators of the hydraulic fracturing system need to be stationed outside at the containers using hydraulic valves, or a short range wireless remote control that is hand held for controls.

[006] The operators report in to the datavan using a radio headset to communicate the container weights or fill levels. This is inconvenient and there are not always extra personnel available for the task. Also, having a worker walk over to the container to adjust the flow takes minutes, which is a long time to have to manually check the proppant level. Further there is airborne silica around the container, which can cause silicosis. Silicosis is lung fibrosis caused by inhalation of dust containing silica. Silica is usually found in the sand used as a proppant. Operators are also exposed to dangerous weather in extremely cold, hot, or hazardous environments. Also, operators would normally have to determine what container and how much to use manually, which can lead to operator error. The incorrect aggregate of proppant could be used by selecting the wrong container.

[007] Another issue with the manual control of the containers is that when the gates controlling proppant flow from the containers are left open spilling product, this causes profit loss. It also causes environmental harm and there is a major safety concern. When a wrong container is open and the incorrect aggregate or proppant is sent out to be mixed with the fracturing slurry, it is hard to figure out what tank the proppant came from and can result in a violation of customer contract. There is also confusion that occurs at the pre-stage planning because operators are unsure what container is being used and how the containers are being scheduled for later use.

[008] These and other problems with manually monitoring and controlling the proppant usage have been observed in the field.

SUMMARY OF THE INVENTION

[009] The method and system of the present invention provide real-time remote monitoring of proppant, such as sand and glass beads, as it is being fed from proppant containers and mixed into the fracturing fluid. Operators inside a datavan are able to wirelessly monitor the weight, container level or volume of the proppant and control the proppants in the proppant containers through remote monitoring software in a datavan.

[0010] Embodiments of systems and methods of the present disclosure include a proppant container with control box connected to a sensor for monitoring the amount of proppant, an RS232 or RS435 serial data protocol on the control box, a wireless Ethernet converter to send the signal from the control box located at the proppant container, a wireless receiver with signal out ports for serial or Ethernet ports to receive the data from the sensor to the datavan and a piece of software on an information handling system in the datavan that computes the total and allows the user to interface with the fracturing control software to schedule proppant usage and flow.

[0011] Embodiments of the invention include software that acquires and displays the proppant data to a user in a datavan, and power supplies that supply power to the serial to Ethernet converter, measuring sensor, and transmitter.

[0012] Embodiments of the invention also include wireless control of the storage containers and conveyor belts.

[0013] Embodiments of the invention include a serial to Ethernet converter that takes the serial data output from a sensor at a proppant container and converts it to the Ethernet protocol to be sent to a datavan with an Ethernet receiver where it is processed and displayed to a user who is monitoring and controlling the proppant flow. The software also allows for scheduling and remote monitoring of the weight, volume and amount of proppant in each proppant container.

The monitoring software, which receives the signal from the proppant equipment can also communicate with fracturing software in the datavan to allow for more automation of the fracturing process as a whole.

[0014] Embodiments of the invention can schedule and automate which containers to run the proppant from, allowing for the proper mixture of proppants from different containers to make up the fracturing fluid.

[0015] Embodiments of the invention can relay the container weight to a datavan information handling system, a personal laptop or a separate Human Machine Interface (HMI) mounted in the datavan.

[0016] Embodiments of the present invention measure the containers weight by gamma ray gauges, radar gauges, laser gauges, and ultrasonic gauges. Also weight measuring load cells and pressure sensors along the vertical height of the vessel can be used.

[0017] Embodiments of the invention include that the communications can be wired or wireless.

[0018] Embodiments of the invention can convert the serial data to wireless, but it is possible to transmit the signal without converting it first.

[0019] Embodiments of the invention can include only the monitoring of the proppant flow and not control.

[0020] Embodiments of the invention can be used on several type of proppant storage containers including silos, capable of holding 200,000 lbs to 300,000 lbs, kings, or sand hogs, large trailer mounted containers similar to a fracturing tank on wheels that holds from 300,000 lbs to 400,000 lbs, or smaller individual proppant boxes, which hold from 40,000 lbs to 60,000 lbs and can be set directly on a conveyor belt.

BRIEF DESCRIPTION OF DRAWINGS

[0021] The foregoing aspects, features, and advantages of embodiments of the present disclosure will further be appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0022] FIG. 1 is a block diagram of an embodiment of the present invention.

[0023] FIG. 2 is a block diagram of a second embodiment of the invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0024] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0025] The present invention provides a system and method for wirelessly monitoring and controlling proppant flow from proppant storage containers in a hydraulic fracturing operation. The proppant can include sand, glass beads and other known materials that is mixed into a fracturing fluid and that is pumped through a wellbore into a well in order to create fractures and extract hydrocarbons. The proppant storage containers can be stationary or attached to a trailer and can be of various sizes depending on the application.

[0026] Components of a system for monitoring proppant usage and flow can include a control box at the proppant container with sensors which are coupled to the proppant storage container and have serial connections, such as RS232 or RS485 serial connectors, a wireless Ethernet converter to send data signals indicating the readings of the sensors that monitor the weight of the container in real time, and a wireless receiver with signal out ports for serial or Ethernet that receives the signals sent from the control box and formulates them for viewing to a user in a datavan. A variety of power supplies can be used to power the converters. In addition, the software to acquire and display the data, as well as to communicate with the fracturing control software can be included as well. For the control of the storage, there can be a control

box outside or inside the proppant storage containers that can contain wiring and a display for operations that is wirelessly connected to the datavan.

[0027] FIG. 1 shows in schematic form an embodiment of a system 100 for remote and real-time monitoring of proppant storage in a container. In one example of the system 100, there is a datavan 102 where a user operates an information handling system 107 with a processor and memory for storing computer readable media accessible by the processor with instructions and with a display 106.. The information handling system 107 may also include nonvolatile storage area accessible by the processor, and logics for performing each of the steps described herein. In the illustrated example, the information handling system 107 interfaces with a wireless receiver 108 that can be connected to a LAN or other type of wireless network through normal wireless connections or serial to Ethernet devices. Serial to Ethernet devices can be provided by Moxa (640 Herman Road, Suite 5, Jackson, NJ 08527, http://www.moxastore.com), which manufactures serial to Ethernet devices and servers. Other wireless receivers can also be customized for this particular application. Due to the distances between equipment being up to 400 feet, and other electromagnetic inference, Ethernet may not be reliable and therefore another suitable long range protocol may be used such as Radio Frequency (AM or FM).

[0028] In the exhibit shown in FIG. 1, the datavan 102 communicates with a proppant container 114 through a control box 104 at a well site 112. The proppant monitoring system 100 includes a control box 104 shown connected to a proppant container 114. The control box 104 can contain circuitry and wiring along with computer readable media for storing instructions and a processor and input means for the user to manually operate the container 114. In most embodiments the control box 104 will be attached to and be a part of the proppant container 114. Included in the control box 104 is a serial receiver 128 that can connect to a serial to Ethernet

converter 110, also potentially produced by Moxa. The control box 104 can further contain a wireless transmitter 130 for transmitting information to the datavan 102.

[0029] Further, the control box 104 has a serial receiver 128 that is connected via a serial cable to a serial transmitter 126 in a proppant container 114. The proppant container has a sensor 118 which monitors the weight of the proppant container 114 and its contents. The sensor 118 gathers information about the weight of the proppant in the container and sends it via serial or analog connection to the serial transmitter 126 to the control box 104 through its own serial receiver 128. That information is then converted by a serial to Ethernet converter 110 and sent via wireless transmitter 130 to the datavan 102. Proppant can be selectively dispensed from proppant container 114 by opening and closing gate 120, such as with an actuator 122. Sensor readings from sensor 118 are constantly sent back to the datavan 102 through the serial to Ethernet converter 110. There is also a conveyor 124 that can be selectively activated in this embodiment.

[0030] The weight of the proppant container 114 and its contents can be relayed to one or more of the datavan information handling system 107, a personal laptop, and/or a separate human machine interface (HMI) mounted in the datavan 102 through the control box 104. In the datavan a wireless receiver 108 receives the data (wireless transmission is indicated by a dashed line in FIG. 1) and then the information is sent to the information handling system 107 and displayed to the user via a display 106 in multiple formats. The connections between the wireless receiver 108 and the information handling system 107 can be Ethernet or the wireless receiver can be directly installed in the information handling system 107. Further the connection between the information handling system 107 and the display 106 can be Ethernet or serial connection types.

[0031] In addition, the amount of proppant in the proppant container 114 can be gauged by measuring its total weight and subtracting the weight of the proppant container 114 itself, such as with a load cell. In one example a load cell includes a strain gauge that mounts to the proppant container 114 and emits a signal that is representative of the weight of proppant in the proppant container 114. This embodiment is not limited to any one sensor and there are several different ways an accurate weight measurement can be obtained. Optionally, volume of the proppant can be measured. Gamma ray (radioactive) gauges, radar gauges, laser gauges, and ultrasonic gauges can optionally be used in place of weight measuring load cells or as a redundancy to load cells. Even pressure sensors along the vertical height of the proppant container 114 can be used. Furthermore, the communications can be either wired or wireless. Although the above-discussed embodiments seek to convert the serial communications to Ethernet, it is possible to transmit serial data wirelessly without converting it. Proppant is tracked based on weight using load cells, and if a level sensor is used such as a gamma, radar, laser or sonic sensor, then the geometry of the container is taken into consideration when the weight is calculated. An algorithm is used that takes into account the current proppant level, the proppant weight per volume, the density of the proppant and the geometry of the container.

[0032] According to one embodiment of the invention shown in FIG. 1, the signal and electrical characteristics of communications associated with the control box 104 and weight sensor 118 can be in accordance with Serial RS232 or RS485 protocol standards. Serial RS232 or RS485 protocols are standard communications protocols within the industry and other embodiments of the invention can include different standards. Optionally the operation of the control box 104 and weight sensor 118 can be in accordance with Ethernet standards, and the data from these devices transmitted wirelessly to the datavan 102. The datavan 102 can then

receive the wireless signal and output it to display 106. The display 106 shows a representation of each container and a number with the appropriate scale weight. To keep each container unconfused and receiving properly, an output signal and an input signal can be separated on respectively numbered com ports. For example, container one can be received through com port one, container two can be routed to com port two, etc. Another option is to order the data sent in the serial stream so that the first value in the data packet can pertain to the weight of the first container, the second value can pertain to the second container, and so on.

[0033] In an example of operation, the weight or volume of the proppant (or sand) in the proppant container 114 is monitored, either instantaneously or over time, and compared to a designated weight (or volume) or change in weight (or volume) over time. To ensure a sufficient amount of proppant is on hand in the container(s) 114 for use in the fracturing process, a threshold low point of proppant in the container 114 is established, and operations protocol is to keep the amount of proppant in the container 114 to be at least or greater than the threshold low point. Thus an advantage of employing the monitoring system 100 described herein is that by monitoring the proppant amount in the container 114 with the controls described herein, if the threshold low point is approached, or soon to be approached, proppant can be added to that particular container 114. In another example of operation, if a rate change of weight of a proppant container 114 deviates from a designated value, the gate 120 on the particular proppant container 114 can be adjusted so that the rate change of weight is at or close to the designated value. Excursions of the rate change of weight from the designated value, which can be less than or greater than the designated rate change of weight of the proppant container, can indicate that the amount of proppant being dispensed from the container 114 exceeds a capacity of proppant handling hardware, such as a conveyor, thereby resulting in spillage of proppant, or generating

proppant dust. This can be corrected (via monitoring software in the information handling system) that identifies the rate of weight change excursion and contains instructions to send controlling commands to the actuator 122 that in turn adjust a position of the gate 120 to affect a flow of proppant from the container 114. Additionally, monitoring a rate of weight change of a proppant container 114 can provide an indication of how much, if any, proppant is being dispensed from the container 114. Thus if it is desired that proppant be dispensed from a one of the containers 114, but not from another one of the containers 114, logics in the information handling system 107 can compare monitored rate weight changes of proppants in the containers 114 to determine if proppant is being dispensed from designated proppant containers 114, and if not, command signals can be transmitted from the information handling system 107 to the actuator 122 to open a gate 120 on a container 114 from which proppant is to be dispensed, and close a gate 120 on a container 114 from which proppant is not to be dispensed.

[0034] FIG. 2 shows in schematic form an alternate embodiment of a system 200 for monitoring and controlling proppant flow. The wireless proppant monitoring and controlling system 200 of FIG. 2 includes a datavan 202 with a wireless connection inside via a wireless transceiver 208. The datavan 202 can contain a human machine interface (HMI) 206 such as a display and an information handling system (IHS) 207 with a processor, memory and storage for storing the data gathered through the wireless connection. A control box 204 contains a serial transceiver 228 that selectively communicates with a sensor 218 for monitoring the weight of the proppant container 214 and its contents via a serial transceiver 226.

[0035] In the example of FIG. 2, the information is transmitted after it is sent from the sensor 218 via analog connection from a serial transceiver 226 to another serial transceiver 228 in the control box 204. The information is then sent through a serial connection to another information

handling system (IHS) 234 in the control box 204. This IHS 234 may have another human machine interface (HMI) 232 connected to it for access by a user. The IHS 234 then selectively converts the data through a serial to Ethernet converter 210 and sends it back to the datavan 202 through a wireless transceiver 230 on the control box 204 where it is processed by the wireless transceiver 208. The datavan 202 can control an actuator 222 on the proppant container 214 by sending a control command through the HMI 206 connected to the IHS 207 at the datavan 202 through the wireless transceiver 208 to the control box 204. The wireless transceiver 230 in the control box 204 receives the command, converts it to serial through the serial to Ethernet converter 210, sends it to the IHS 234, which then sends it to the proppant container 214 through the serial transceiver 228. A serial transceiver 226 at the proppant container receives the command and actuates the actuator 222 connected to the gate 220. The serial transceiver 226 can also actuate the conveyor 224 as shown in FIG.2.

[0036] The information related to the weight of the container from the sensor 218 can also be catalogued and displayed to a user in the datavan 202. The information can be updated in real time through the wireless connection in the datavan 202 and the user can also control the operations of the conveyor belts 224 and actuator 222 that release the proppant through an actuator 222, which in some embodiments is an proportional hydraulic valve, into the mixing system by interfacing with fracturing software that is also stored in the datavan 202. In one embodiment there are multiple computers in the datavan, one that is in charge of proppant delivery and another for the fracturing operation. These different computers run programs that can share data between themselves. In another embodiment the proppant monitoring and control system will be integrated into fracturing software which monitors the entire fracturing operation.

[0037] To control proppant flow from the containers, the same software can be modified to send commands through the same wireless transceiver 208 on the datavan 202 to the wireless transceiver 230 at the control box 204 at the well site 212 where it can then be converted back to serial for use by the control box's own IHS 234 to open/close sand gates, speed up/slow down the conveyor belt 224, *etc*. The monitoring and control system that receives the signal from the control box 204 and proppant container 214 can also communicate with a portion of the fracturing system in the datavan 202 to allow for a higher level of automation if desired (as described below). Proppant in the container 214 may be released through the wireless control of the valve gate 220 located at the container 214. This can release proppant onto a conveyor 224 for mixing into the fracturing slurry. This data can be used with the data that is gathered from the weight sensor 218 to more accurately control the proppant flow.

[0038] In some alternate embodiments, the system 200 allows for two way communications to allow for monitoring and control of the container 214 and conveyor belt (also referred to as a dual belt) 224. In addition, system 200 can be used on several different types of proppant storage containers including silos (tall containers similar to farm silos capable of holding 200,000 lbs to 300,000 lbs), sand kings (sometimes called sand hogs, large trailer mounted containers similar in idea to a frac tank on wheels, capable of holding 300,000 lbs to 400,000 lbs), or sand boxes (which are smaller containers which are set on top of the conveyor belt and unloaded which can contain 40,000 lbs to 60,000 lbs). The sand equipment units can be electric powered, diesel powered, gravity fed, and/or solar powered. In addition, the system 200 is not limited to use with vertical sand silos, but the can be applied to other sand storage equipment as well. Various sensors can be added to the system to control the flow of proppant and weight and the embodiment described above should not be limited to a single configuration.

[0039] One advantage of the system 200 is the ability to keep personnel away from air born silica that exists around proppant storage units, and which can cause silicosis or other health problems. Silicosis is lung fibrosis caused by the inhalation of dust containing silica. Operators can also be kept out of the weather in extremely cold, hot, or hazardous environments. Another advantage is the removal of human error of dispensing proppant from the wrong storage container. In some embodiments of the invention, there are multiple gates on the container or containers and different levels of open and close for the multiple gates that can be set by the user at the datavan. Some gates can only open fully or close fully as well depending on the application.

[0040] In some embodiments, a live video feed can be directed from the container 214 to the datavan 202 through a camera 236 that sends a Radio-Frequency (RF) signal back to the IHS 234 at the control box 204, thereby making it possible to know instantly if a gate 220 was left open, spilling product on the ground and costing profit loss or causing an environmental or safety hazard, or conversely, if a gate commanded to open was stuck shut due to a mechanism failure. An improperly operating gate can cause the failure of a fracturing operation. This information is converted to wireless and transmitted to the datavan 202. Datavan operators can also use the video feed to determine if the wrong container was opened, causing an incorrect aggregate to be mixed into the fracturing slurry. The same weight monitoring can also allow datavan operators to see if a certain container is being unloaded into which will help prevent confusion regarding logistics and pre-stage planning.

[0041] Set points for proppant delivery and conveyor speed can be a simple PID closed feedback loop. A sensor can monitor the speed of the conveyor and that sensor sends a signal to the datavan via the system to indicate if the desired speed has been reached. If the sensor

indicates it has reached the proper speed, then the conveyor will hold the speed. If it indicates the speed value has been overshot, the system will send out a command signal to slow down the belt. This process is repeated multiple times until the correct weight goal has been achieved by the system The P, I, and D values will determine the stability and response time of the control system, and these values are dependent upon the user's desired response times, and the determined amount of overshoot and undershoot that is tolerable in the positioning of the gate. User entered set points for the desired weight of sand remaining in the container(s) will signal the end of the job once that weight is reached and will trigger the gate(s) to close, thus ending the feedback control loop. Further, other components in the fracturing system, such as the blender can alter these values as part of the overall fracturing software depending on the uses of the system.

[0042] According to certain embodiments, which include multiple containers, it is possible to schedule and automate which of these containers to access. For example, the fracturing system can issue a command to close a 40/70 aggregate sand container, while simultaneously issuing a command to open a 20/40 aggregate container. In an embodiment, closing a particular sand (or proppant) container involves closing the gate 220 on the container 214 through which proppant/sand is dispensed from the container 214 to suspend the flow of proppant from the container 214. Similarly, in one example, opening a container 214 is done by opening the respective gate 220 on the container 214 so that proppant can be dispensed to a designated conveyor 224. Opening and closing the gates 220 can be performed by activating the respective actuators 222 coupled with the gates 220. The speed of a belt on conveyor 224 can be controlled remotely, as well as the container outlet gate 220 which can be choked to control the amount of sand being fed to the belt. If wellhead pressure exceeds a set point, or if an emergency stop (E-

Stop/E-Kill) button or emergency power off (EPO) button is pressed, the gates 220 on the containers can be automatically closed thereby preventing lost product (proppant). The conveyor belt 224 can also be linked to the E-Stop and EPO in case of an emergency.

[0043] The connections between the HMI 206 and the IHS 207 can be serial or Ethernet. The dashed line in FIG. 2 represents wireless communications between the wireless transceiver 230 in the control box 204 and the wireless transceiver in the datavan 202, but also wired communications can be used as well. The HMI 232 on the control box 204 can also be external or internal and the IHS 234 can be a small programmable logic control device. The actuator 222 can also be an electrical or air actuator instead of a proportional hydraulic valve. Additionally, the conveyor can be a part of the proppant container, or a separate piece of equipment.

[0044] A further embodiment of the invention includes a blender that is connected to the IHS 207 of the datavan 202. The blender can have an information handling system and a human machine interface that communicates with the datavan 202 in order to further control the proppant flow. The blender is capable of making changes to the proppant flow in a similar manner as the datavan 202. The blender can send control signals to the datavan 202 through its own information handling system to the IHS 207 of the datavan indicating a certain flow of proppant and these signals can be sent to the control box 204 and the proppant container 214. Therefore any changes requested by a user operating the blender are taken into consideration when delivering the proppant. The connections can be either serial or Ethernet, but are not limited in this embodiment.

[0045] Embodiments of the system 200 described herein allow for the wireless monitoring and control of proppant and proppant storage containers 214 in a remote location. Proppant container 214 in the embodiment of Fig. 2 contains a single type of proppant, however, it is

possible to have multiple proppants in multiple containers with multiple valves actuated remotely, or different compartments in the same container which contain different aggregates of proppant, so that the user in the datavan 202 can schedule a different mixture of proppants for the desired fracturing fluid and application. Persons of ordinary skill in the art will appreciate that the systems and methods described herein are not limited to the particular structures described but that changes to the invention can be made that are consistent with this disclosure.

CLAIMS

What is claimed is:

1. A system for use with a fracturing operation comprising:

a weight monitoring system in selective cooperation with a proppant container that selectively contains proppant used in fracturing;

an information handling system in communication with the weight monitoring system; and

a proppant dispensing system coupled with the proppant container and that is in communication with and selectively activated by the information handling system.

2. The system of claim 1, further including a serial to Ethernet converter for sending and receiving Ethernet data to and from the information handling system, and for sending and receiving serial data to and from the proppant container.

3. The system of claim 1, wherein the information handling system selectively sends commands to actuate a valve coupled with the proppant container to provide a designated amount of proppant for use by a fracturing operation.

4. The system of claim 1, where the information handling system alerts a user if an amount of proppant in the proppant container is below a threshold level, and where the information handling system estimates the amount of proppant in the proppant container based on a signal received from the weight monitoring system.

5. The system of claim 1, where the weight monitoring system comprises a sensor for measuring one or more of a weight of the proppant container, a level of proppant in the proppant container, and a volume of proppant in the proppant container, and wherein the sensor comprises a measuring device selected from the group consisting of gamma ray gauges, radar

gauges, laser gauges, weight measuring load cells, pressure sensors, ultrasonic gauges, and combinations thereof.

6. The system of claim 1, where the control is either wired or wireless.

7. The system of claim 1, where the proppant storage containers include one of silos or trailer mounted containers.

8. The system of claim 1, where the equipment is electric powered, diesel powered, gravity fed or solar powered.

9. The system of claim 1, further comprising:

a plurality of electric pumps fluidly connected to the well and powered by at least one electric motor, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation; and

a variable frequency drive connected to the electric motor to control the speed of the motor, wherein the variable frequency drive frequently performs electric motor diagnostics to prevent damage to the at least one electric motor.

10. A method for conducting a fracturing operation comprising:

sensing an amount of proppant contained in at least one proppant storage container;

comparing the amount of proppant sensed in the proppant storage container with a designated amount of proppant; and

regulating a flow of proppant from the proppant storage container based on the step of comparing the amount of proppant sensed and the designated amount of proppant.

11. The method of claim 10, further comprising a scheduling step that includes interfacing with a fracturing system that can actuate valves and other control mechanisms to provide proppant to fracturing operations on conveyor belts.

12. The method of claim 10, further comprising directing an amount of proppant toward a well through the use of conveyor belts that are controlled by a user at a datavan.

13. The method of claim 10, further comprising generating an alert if proppant in the proppant storage container goes below a threshold level.

14. The method of claim 10, where the sensing the amount of proppant in the proppant storage container comprises using a device that is selected from the group consisting of gamma ray gauges, radar gauges, laser gauges, weight measuring load cells, pressure sensors, ultrasonic gauges.

15. The method of claim 10, where the transmitting step is either wired or wireless.

16. The method of claim 10, where the proppant storage containers include one of silos or trailer mounted containers.

17. The method of claim 10, where the equipment is electric powered, diesel powered, gravity fed or solar powered.

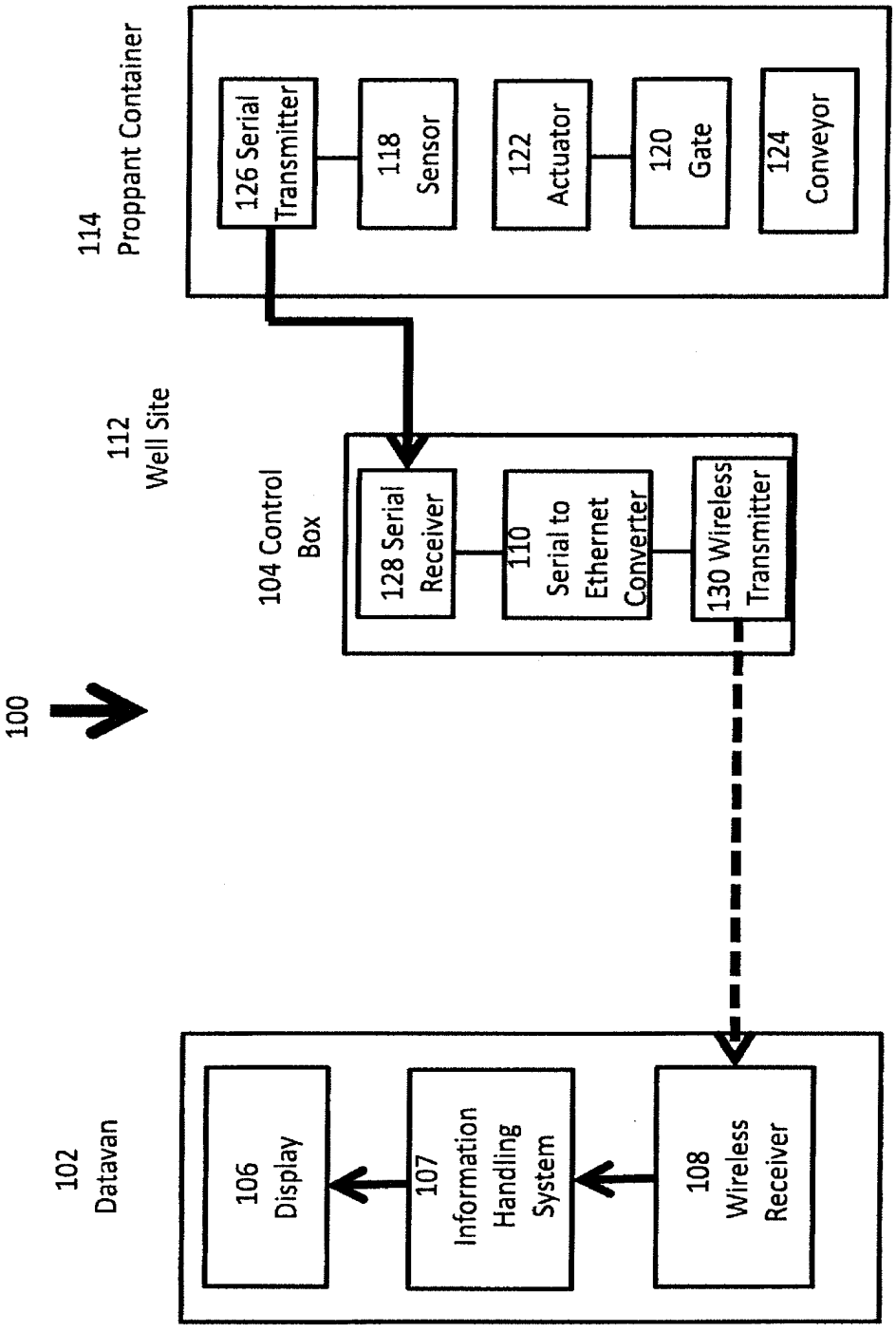

100
102
Datavan
106
Display
107
Information
Handling
System
108
Wireless
Receiver
104 Control
Box
128 Serial
Receiver
110
Serial to
Ethernet
Converter
130 Wireless
Transmitter
112
Well Site
114
Proppant Container
126 Serial
Transmitter
118
Sensor
122
Actuator
120
Gate
124
Conveyor

FIG. 1

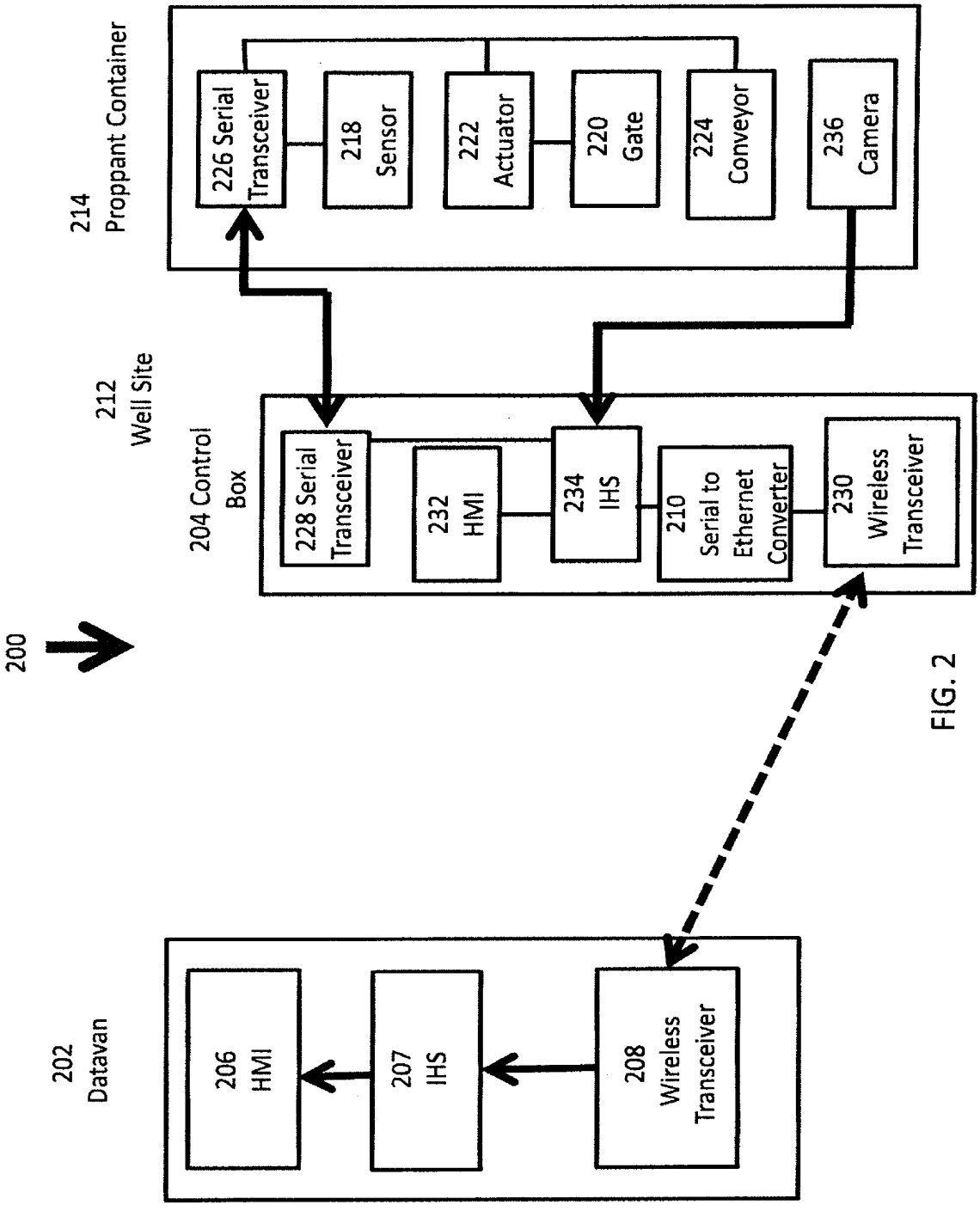
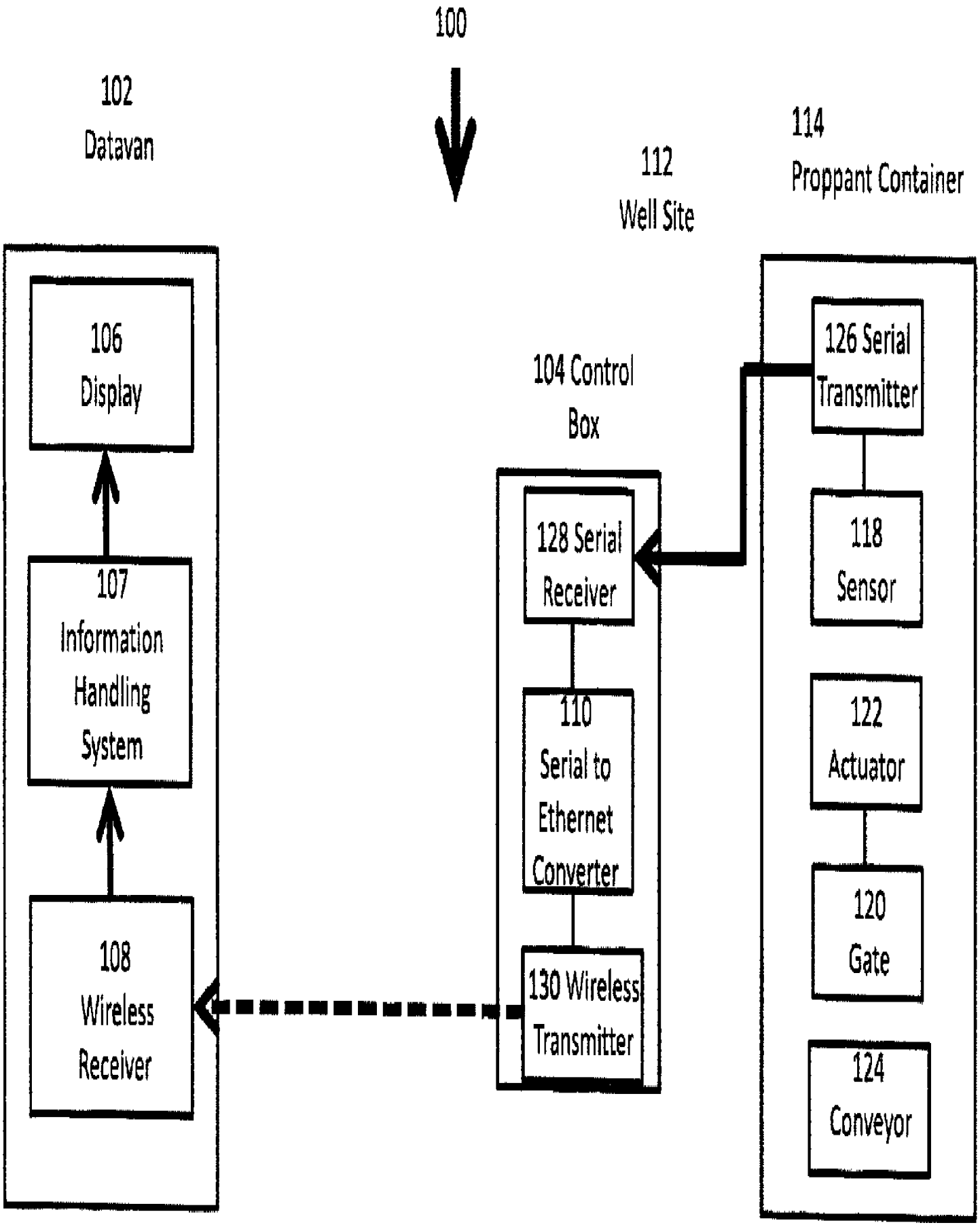

200
202
Datavan
206
HMI
207
IHS
208
Wireless
Transceiver
212
Well Site
204 Control
Box
228 Serial
Transceiver
232
HMI
234
IHS
210
Serial to
Ethernet
Converter
230
Wireless
Transceiver
214
Proppant Container
226 Serial
Transceiver
218
Sensor
222
Actuator
220
Gate
224
Conveyor
236
Camera

FIG. 2


100
102
Datavan
112
Well Site
114
Proppant Container
106
Display
107
Information
Handling
System
108
Wireless
Receiver
104 Control
Box
128 Serial
Receiver
110
Serial to
Ethernet
Converter
130 Wireless
Transmitter
126 Serial
Transmitter
118
Sensor
122
Actuator
120
Gate
124
Conveyor

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Canadian Intellectual Property Office
An agency of Industry Canada

CA 2945579 A1 2017/04/16

(21) 2 945 579

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2016/10/17

(41) Mise à la disp. pub./Open to Public Insp.: 2017/04/16

(30) Priorités/Priorities: 2015/10/16 (US62/242,566); 2016/07/05 (US15/202,085)

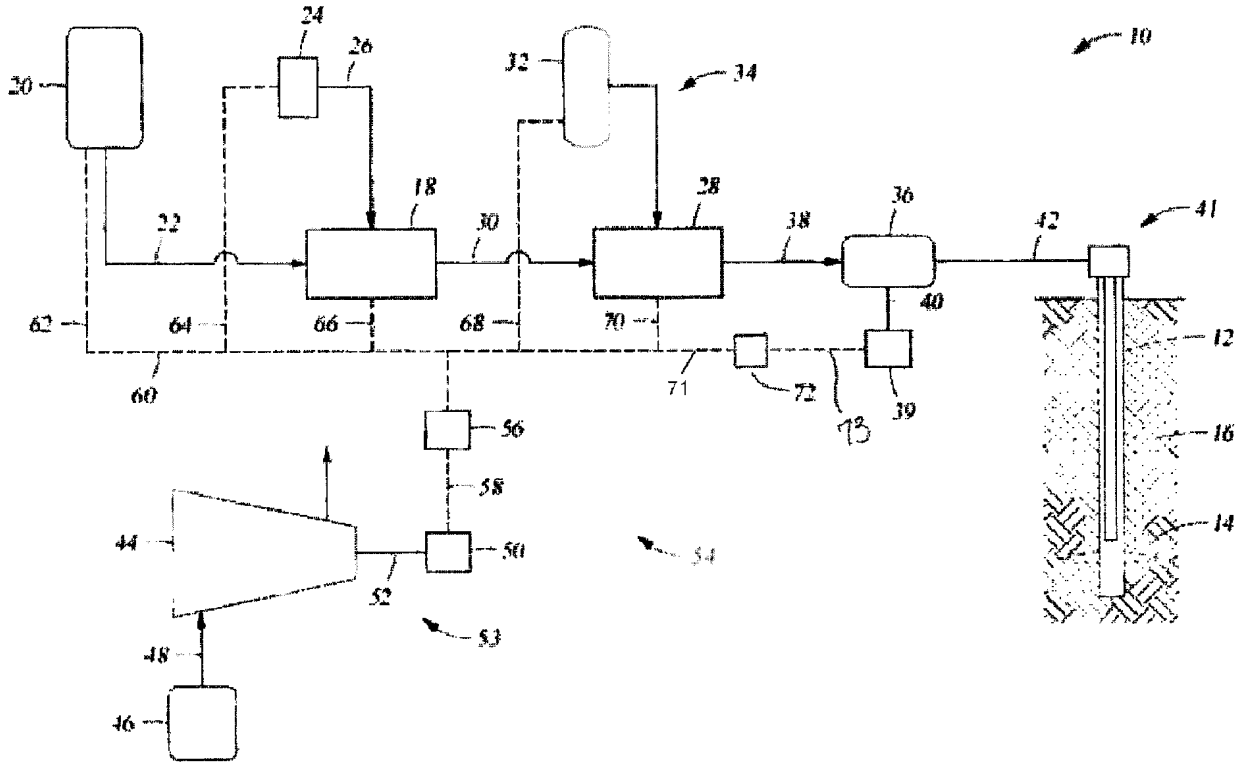
(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01), *E21B 43/267* (2006.01), *E21B 47/00* (2012.01)

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(54) Titre : SURVEILLANCE A DISTANCE D'EQUIPEMENT DE FRACTURATION HYDRAULIQUE
(54) Title: REMOTE MONITORING FOR HYDRAULIC FRACTURING EQUIPMENT



(57) Abrégé/Abstract:
A hydraulic fracturing system for fracturing a subterranean formation including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry.

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(13) A1

(57) Abrégé(suite)/Abstract(continued):
The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

ABSTRACT

[0044] A hydraulic fracturing system for fracturing a subterranean formation including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry. The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

REMOTE MONITORING FOR HYDRAULIC FRACTURING EQUIPMENT

BACKGROUND OF THE INVENTION

1. Field of Invention

[0001] The present disclosure relates to hydraulic fracturing operations in a subterranean formations. In particular, the present disclosure relates to a hydraulic fracturing system with imaging devices that are strategically positioned to remotely monitor portions of the system.

2. Description of Prior Art

[0002] Hydraulic fracturing is a technique used to stimulate production from some hydrocarbon producing wells. The technique usually involves injecting fluid into a wellbore at a pressure sufficient to generate fissures in the formation surrounding the wellbore. Typically the pressurized fluid is injected into a portion of the wellbore that is pressure isolated from the remaining length of the wellbore so that fracturing is limited to a designated portion of the formation. The fracturing fluid slurry, whose primary component is usually water, includes proppant (such as sand or ceramic) that migrate into the fractures with the fracturing fluid slurry and remain to prop open the fractures after pressure is no longer applied to the wellbore. A primary fluid for the slurry other than water, such as nitrogen, carbon dioxide, foam (nitrogen and water), diesel, or other fluids is sometimes used as the primary component instead of water. Typically hydraulic fracturing fleets include a data van unit, blender unit, hydration unit, chemical additive unit, hydraulic fracturing pump unit, sand equipment, and other equipment.

[0003] The process of making the fracturing fluid slurry necessarily includes combining, such as in the blender, hydration unit, chemical additive unit, etc., the individual components of the slurry. Such operation can be dangerous to operating personnel. For example, moving proppant into the blender unit can generate silica dust which, if inhaled by personnel, can cause permanent damage to the lungs. Common proppant types include silica sand, resin coated sand, and ceramic beads. Ceramic can be very harmful to inhale, and typically consists of very fine particles that become airborne and are difficult to filter out. Resin coated sand is the most dangerous and harmful to inhale since the resin coating can chip off and become airborne dust particles. Silica itself is very harmful to inhale as well.

[0004] Other components, such as chemicals, can be damaging and present hazards as well. One dangerous source of chemical contact comes from residue on tankers, trailer decks, reused hoses and camlock fittings, or leaky valves. In addition, there is always a risk for a major hose or chemical pump failure, or a tank/tote puncture. Some chemicals (such as, for example the viscosifier guar gel, and some friction reducers) can be hazardous because of how slick and slippery they are. Thus, a small amount on the skin, clothing, ground, or equipment can cause personnel to slip and fall, or lose their grip while climbing ladders, leading to injuries.

[0005] In addition, chemicals such as acids and breakers (for breaking down viscosifiers) are extremely corrosive to skin, damaging to inhale, can cause blindness, and other immediate hazards. Chemicals such as breakers are also very flammable, which becomes a hazard if there is a chance of contact with, for example, diesel fuel or gasoline. On diesel powered fracturing sites, it is very common for personnel to have diesel or oil residue on their hands, boots, or clothes.

[0006] Furthermore, in fracturing operations, it is also common to use biocides to kill bacteria deep in a well, such as to prevent deadly hydrogen sulfide gas build up. Biocides can be very damaging to living tissue, especially if ingested or inhaled. Additional chemicals that are dangerous if ingested or inhaled include stabilizers, pH buffers, and inhibitors.

[0007] In addition to the above, hydraulic fracturing operations can be dangerous for operating personnel because of high pressure and high voltage equipment. For example, high pressure zones are present where the discharge piping leaves the hydraulic fracturing pumps at pressures of up to 15,000 pounds per square inch (psi) or more. If the pipes fail, they can explode, causing shrapnel to fly. Furthermore, iron pipes can shift and pivot with the pressure release striking employees.

[0008] Some voltages in the electric hydraulic fracturing systems can reach up to 13,800 volts or more. Dangers in high voltage zones include arc flashes, fires, electrocution, and explosions. Hazards can result from breaker or cable coupler failures, or even natural gas vapors entering the area. It is desirable, therefore, to design a hydraulic fracturing system to minimize such dangerous exposure of operating personnel.

SUMMARY OF THE INVENTION

[0009] The present technology provides a hydraulic fracturing system for fracturing a subterranean formation, including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid including a fracturing fluid slurry. The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system

components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

[0010] In some embodiments, the monitoring system can include a camera, a controller, a display, a human machine interface, and communication means between the camera, controller, human machine interface, and the monitor. In addition, the display can include a monitor from which the images are viewed. In some example embodiments, the display can be disposed within a passenger compartment mounted to a fluid blender, so that the images can be viewed by operations personnel in the passenger compartment.

[0011] According to some embodiments, the hydraulic fracturing components can be selected from the group consisting of a chemical tanker, a hydration unit, a hopper, a blender unit, and auger associated with a blender unit, a conveyor, and an acid tanker. In addition, the pump components can be selected from the group consisting of intake piping, discharge piping, hoses, fittings, and valves associated with a hydraulic fracturing pump. Furthermore, the monitoring system can include a camera disposed on a trailer, and wherein the hydraulic fracturing components or pump components include hose or pipe connections on the trailer. In alternate embodiments, the monitoring system can include a camera disposed on a first trailer, and wherein the hydraulic fracturing components or pump components include hose or pipe connections on a second trailer that is adjacent the first trailer.

[0012] In some example embodiments, the monitoring system can selectively capture and transmit real time images of a silica exposure zone, or of an opening to a vessel, so that a level within the vessel is discernible in the images. In some embodiments, the vessel can contain proppant, acid, or chemicals.

[0013] Another embodiment of the present technology provides including the steps of driving a pump to pressurize fluid in a hydraulic fracturing system containing hydraulic fracturing components and pump components, fracturing the formation by directing the pressurized fluid into a wellbore that intersects the formation, and monitoring the hydraulic fracturing system. The step of monitoring the hydraulic fracturing system includes obtaining images of hydraulic fracturing components and pump components of the hydraulic fracturing system, and viewing the images remotely.

[0014] In some embodiments, the hydraulic fracturing components and pump components can be disposed in areas where there is a greater possibility of personal injury than where the images are being viewed. In some embodiments, step of obtaining images can be performed by a camera that is disposed adjacent at least one of the hydraulic fracturing components or the pump components, and the step of viewing can be performed within an enclosure.

[0015] In certain other embodiments, the method can include selectively obtaining images of different hydraulic fracturing components or pump components on a single monitor. Furthermore, the hydraulic fracturing components and pump components can include discharge piping that is in fluid communication with the pump, and vessel openings, and the images of the hydraulic fracturing system can include images of at least one of a silica exposure zone, hose connections,a high pressure zone that includes discharge pumps or discharge pipes or both, a chemical exposure zone, high voltage zones, and natural gas supply piping.

BRIEF DESCRIPTION OF DRAWINGS

[0016] Some of the features and benefits of the present invention having been stated, others will become apparent as the description proceeds when taken in conjunction with the accompanying drawings, in which:

[0017] FIG. 1 is a schematic example of a hydraulic fracturing system for use in fracturing a subterranean formation.

[0018] FIG. 2 is a plan schematic view of an alternate example of the system of FIG. 1, and which includes examples of visual monitoring equipment.

[0019] FIG. 3 is a perspective view of an example of a visual monitoring device mounted on a blender, where the blender is included with the hydraulic fracturing system of FIG. 1.

[0020] FIGS. 4 and 5 are perspective views of an example of a monitor displaying images captured by a visual monitoring device.

[0021] FIGS. 6 and 7 are lower and upper views of an example of a visual monitoring device that is mounted on the blender of FIG. 3.

[0022] While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to that embodiment. On the contrary, it is intended to cover all alternatives, modifications, and equivalents, as may be included within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF INVENTION

[0023] The method and system of the present disclosure will now be described more fully hereinafter with reference to the accompanying drawings in which embodiments are shown. The method and system of the present disclosure may be in many different forms and should not be construed as limited to the illustrated embodiments set forth herein; rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey its scope to those skilled in the art. Like numbers refer to like elements throughout. In an embodiment, usage of the term "about" includes +/- 5% of the cited magnitude. In an embodiment, usage of the term "substantially" includes +/- 5% of the cited magnitude.

[0024] It is to be further understood that the scope of the present disclosure is not limited to the exact details of construction, operation, exact materials, or embodiments shown and described, as modifications and equivalents will be apparent to one skilled in the art. In the drawings and specification, there have been disclosed illustrative embodiments and, although specific terms are employed, they are used in a generic and descriptive sense only and not for the purpose of limitation.

[0025] Figure 1 is a schematic example of a hydraulic fracturing system 10 that is used for pressurizing a wellbore 12 to create fractures 14 in a subterranean formation 16 that surrounds the wellbore 12. Included with the system 10 is a hydration unit 18 that receives fluid from a fluid source 20 via line 22, and also selectively receives additives from an additive source 24 via line 26. Additive source 24 can be separate from the hydration unit 18 as a stand-alone unit, or can be included as part of the same unit as the hydration unit 18. The fluid, which in one example is water, is mixed inside of the hydration unit 18 with the additives. In an embodiment,

the fluid and additives are mixed over a period of time, to allow for uniform distribution of the additives within the fluid. In the example of Figure 1, the fluid and additive mixture is transferred to a blender unit 28 via line 30. A proppant source 32 contains proppant, which is delivered to the blender unit 28 as represented by line 34, where line 34 can be a conveyer. Inside the blender unit 28, the proppant and fluid/additive mixture are combined to form a fracturing slurry, which is then transferred to a fracturing pump system 36 via line 38; thus fluid in line 38 includes the discharge of blender unit 28 which is the suction (or boost) for the fracturing pump system 36.

[0026] Blender unit 28 can have an onboard chemical additive system, such as with chemical pumps and augers. Optionally, additive source 24 can provide chemicals to blender unit 28; or a separate and standalone chemical additive system (not shown) can be provided for delivering chemicals to the blender unit 28. In an example, the pressure of the slurry in line 38 ranges from around 80 psi to around 100 psi. The pressure of the slurry can be increased up to around 15,000 psi by pump system 36. A motor 39, which connects to pump system 36 via connection 40, drives pump system 36 so that it can pressurize the slurry. In one example, the motor 39 is controlled by a variable frequency drive ("VFD").

[0027] After being discharged from pump system 36, slurry is pumped into a wellhead assembly 41. Discharge piping 42 connects discharge of pump system 36 with wellhead assembly 41 and provides a conduit for the slurry between the pump system 36 and the wellhead assembly 41. In an alternative, hoses or other connections can be used to provide a conduit for the slurry between the pump system 36 and the wellhead assembly 41. Optionally, any type of fluid can be pressurized by the fracturing pump system 36 to form injection fracturing fluid that is then

pumped into the wellbore 12 for fracturing the formation 14, and is not limited to fluids having chemicals or proppant.

[0028] An example of a turbine 44 is provided in the example of Figure 1. The turbine can be gas powered, receiving a combustible fuel from a fuel source 46 via a feed line 48. In one example, the combustible fuel is natural gas, and the fuel source 46 can be a container of natural gas or a well (not shown) proximate the turbine 44. Combustion of the fuel in the turbine 44 in turn powers a generator 50 that produces electricity. Shaft 52 connects generator 50 to turbine 44. The combination of the turbine 44, generator 50, and shaft 52 define a turbine generator 53. In another example, gearing can also be used to connect the turbine 44 and generator 50.

[0029] An example of a micro-grid 54 is further illustrated in Figure 1, and which distributes electricity generated by the turbine generator 53. Included with the micro-grid 54 is a transformer 56 for stepping down voltage of the electricity generated by the generator 50 to a voltage more compatible for use by electrically powered devices in the hydraulic fracturing system 10. In another example, the power generated by the turbine generator and the power utilized by the electrically powered devices in the hydraulic fracturing system 10 are of the same voltage, such as 4160 V, so that main power transformers are not needed. In one embodiment, multiple 3500 kVA dry cast coil transformers are utilized. Electricity generated in generator 50 is conveyed to transformer 56 via line 58. In one example, transformer 56 steps the voltage down from 13.8 kV to around 600 V. Other step down voltages can include 4,160 V, 480 V, or other voltages.

[0030] The output or low voltage side of the transformer 56 connects to a power bus 60, lines 62, 64, 66, 68, 70, and 71 connect to power bus 60 and deliver electricity to electrically powered

components of the system 10. More specifically, line 62 connects fluid source 20 to bus 60, line 64 connects additive source 24 to bus 60, line 66 connects hydration unit 18 to bus 60, line 68 connects proppant source 32 to bus 60, line 70 connects blender unit 28 to bus 60, and line 71 connects bus 60 to an optional variable frequency drive ("VFD") 72. Line 73 connects VFD 72 to motor 39. In one example, VFD 72 can be used to control operation of motor 39, and thus also operation of pump 36.

[0031] In an example, additive source 24 contains ten or more chemical pumps for supplementing the existing chemical pumps on the hydration unit 18 and blender unit 28. Chemicals from the additive source 24 can be delivered via lines 26 to either the hydration unit 18 and/or the blender unit 28. In one embodiment, the elements of the system 10 are mobile and can be readily transported to a wellsite adjacent the wellbore 12, such as on trailers or other platforms equipped with wheels or tracks.

[0032] Referring now to Figure 2 shown in a plan schematic view is an example of the hydraulic fracturing system 10 as arranged at a well site 80. In this example, a series of cameras $82_{1\text{-}13}$ are shown strategically located about the system 10 in order to capture real time images of designated portions of the hydraulic fracturing system 10. Image zones $84_{1\text{-}13}$ are shown that are associated with each of the cameras $82_{1\text{-}13}$ and depict an example of objects in an area or space whose image is captured by the cameras $82_{1\text{-}13}$. Cameras $82_{1,2}$ of Figure 2 are depicted mounted respectively on chemical tankers $86_{1,2}$ and are oriented so that their respective image zones $84_{1,2}$ encompass rear portions of the chemical tankers $86_{1,2}$. Thus the image(s) captured by cameras $82_{1,2}$ includes images of the rear portions of the chemical tankers $86_{1,2}$. Specific hardware imaged in one example of the image zones $84_{1,2}$ include hose connections and booster pumps (not shown) on the rear of these tankers $86_{1,2}$. Optionally, the image zones $84_{1,2}$ may extend to an

adjacent chemical trailer 88 shown adversely located adjacent tankers $86_{1,2}$. Mounted on hydration unit 18 is camera 82_3 whose image zone 84_3 covers a rear portion of chemical tanker 88; images captured by camera 82_3 may be analyzed for leaks or failed hose connections. Trailer mounted blender units $28_{1,2}$ are shown disposed on a side of hydration unit 18 and opposite from chemical trailer 88. Ends of the trailers includes hoppers $90_{1,2}$ that selectively contain sand or proppant that is drawn from the hoppers $90_{1,2}$ with auger sets $92_{1,2}$. Cameras $82_{6,7}$ are mounted on augers $92_{1,2}$, and wherein the associated image zones $84_{6,7}$ of the cameras $86_{6,7}$ includes the hoppers $90_{1,2}$. Thus, analyzing information collected by cameras $82_{6,7}$ can provide information indicating a level of sand or proppant within hoppers $90_{1,2}$, without an operator approaching the hoppers $90_{1,2}$.

[0033] As described above, the sand or proppant drawn from hoppers $90_{1,2}$ by augers $94_{1,2}$ is deposited within tubs $94_{1,2}$ where it can be mixed with fluids in order to form a slurry. Cameras $82_{4,5}$ are mounted on blender units $28_{1,2}$ respectively, and have image zones $84_{4,5}$ that capture the opening of the hoppers $90_{1,2}$. Thus analyzing data or images captured by cameras $82_{4,5}$ provides information real time about the level of the slurry mixture within hoppers $90_{1,2}$, again without an operator approaching the hoppers $90_{1,2}$.

[0034] Camera 82_9 is shown mounted on a dust collector 96 which is disposed adjacent an end of conveyor 34 that is distal from blender units $28_{1,2}$. The image zone 84_9 encompasses an end of conveyor 34 distal from blender units $28_{1,2}$. Silos $98_{1\text{-}5}$ or other proppant dispensers are shown disposed on alternating sides of conveyor 34 and which can be used to dispense sand or proppant onto conveyor 34, which then deposits the sand or proppant into the hoppers $90_{1,2}$. Camera 82_8 has a corresponding image zone 84_8 that captures information along conveyor 34 proximate to hoppers $90_{1,2}$ and distal from dust collector 96. Shown having an end proximate where conveyor

34 interfaces with hoppers $90_{1,2}$ is an acid tanker 100 which can optionally be used to deposit acidic material into the fluid being deposited into the wellbore 12 (Figure 1). Camera 82_{11} is mounted on acid tanker 100 and shown having an image zone 84_{11} that encompasses openings on the acid tanker 100 so that levels of material within acid tanker 100 can be monitored by viewing images captured by camera 82_{11}. Camera 82_{11} can be useful to make sure the acid tanker 100 does not overflow, which condition could be caused by a valve failure and resultant fluid backflush. Typically, an operator monitors the acid tanker, and regularly gives hand signals to indicate the operating conditions of the acid tanker 100. Hand signals are preferable to radios when communicating such information, since the operator near the acid tanker typically dresses in protective clothing that can make it difficult to use a radio. Camera 82_{11} can be used either to view the acid tanker itself, or also to view the operator displaying hand signals.

[0035] Arranged in rows and transverse to acid tanker 100 are pump trucks $102_{1\text{-}12}$, which make up the pump system 36 for pressurizing the slurry so that it can be injected into wellhead 41. Discharge piping 42 is shown extending along a path adjacent each of the pump trucks $102_{1\text{-}12}$ and having an end connected to wellhead assembly 41. Cameras $82_{10,12}$ are shown with image zones $84_{10,12}$ that cover hoses, fittings, and an area where discharge leads from the specific pumps on the pump trucks $102_{1,12}$ interface with discharge piping 42. While a pair of cameras $82_{10,12}$ are illustrated, cameras may be provided for each pair of the pump trucks $102_{1,12}$ or each one individually. Shown spaced away from the rows of pump trucks $102_{1\text{-}12}$ is a data van 104 and on which camera 82_{13} is mounted. The corresponding image zone 84_{13} of camera 82_{13} is directed towards wellhead assembly 41 and can observe the wellhead assembly 41 as well as all discharge piping 42 and at least some of the leads connecting to piping 42. Thus situated, camera 82_{13} allows personnel to stay out of the high pressure zones around the pumps. This is useful because

is a pipe fails at high pressure, it can seriously injure personnel with, for example, flying shrapnel.

[0036] Shown in an end perspective view in Figure 3 is an example of camera $82_{6,7}$ mounted on one of the auger elements that make up auger system $92_{1,2}$. Here each of the auger elements includes a tube and a screw-like member that rotates within the tube in order to urge the proppant upward from the hopper $90_{1,2}$ and into hopper $94_{1,2}$ (Figure 2). Further illustrated in Figure 3 is an example of a hydraulic system 106 for raising and lowering the auger system, $92_{1,2}$. As shown, camera $82_{6,7}$ is mounted to one of the auger tubes via a bolted connection.

[0037] Figure 4 illustrates an example of viewing an image of hopper $90_{1,2}$ within a blender cab $108_{1,2}$ that is part of the blender unit $28_{1,2}$ (Figure 2). A monitor $110_{1,2}$ is mounted within cab $108_{1,2}$ that is in communication with camera $82_{6,7}$. Accordingly, a designated portion within system 10 (Figure 2) can be remotely viewed by operations personnel in an enclosed space and away from an area that may present hazards to personnel. Alternately, this camera feed can also be viewed within the datavan.

[0038] Figure 5 illustrates one example where operations personnel can selectively change the image being viewed to that of a separate camera. For example, within cab $108_{1,2}$, monitor $110_{1,2}$ is displaying an example of mixing tub $94_{1,2}$. In an example, changing the display on the monitor $110_{1,2}$ to view other images is accomplished by an operator manipulating a human machine interface ("HMI") which can be a keyboard, joystick, panel, or any other device that allows a user to adjust operation or control of what is being viewed on monitor $110_{1,2}$. Again, the image of the tub $94_{1,2}$ is being remotely viewed in an enclosed space that is away from a potentially hazardous area.

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[0039] Figure 6 illustrates an example of camera $82_{4,5}$ mounted on blender unit $28_{1,2}$ (Figure 2) and outside of cab $108_{1,2}$. Here, the end of the camera $82_{4,5}$ having a lens is pointing away from cab $108_{1,2}$ and mounting hardware in brackets are shown suspending camera $82_{4,5}$ at a strategically located orientation so that designated portions can be monitored with camera $82_{4,5}$.

[0040] Figure 7 shows in a perspective view an example of camera $82_{4,5}$ taken from a rear view and having lead $112_{4,5}$ leading from camera $82_{4,5}$ so that images captured by camera $82_{4,5}$ can be processed and transmitted to a location that is remote to camera $82_{4,5}$ for viewing.

[0041] Referring back to Figure 2, a schematic example of monitoring system 114 is shown which includes cameras $82_{1\text{-}13}$, monitor 110, a communication means 116, controller 118, and human machine interface 120. Communication means 116 can be any form of communicating data that represents images within system 114, and can be wireless, hard-wired, or fiber optic material. Controller 118 can be an information handling system, and may include a processor, memory accessible by the processor, non-volatile storage area accessible by the processor, and logics for performing each of the steps required for operation of the controller 118.

[0042] Advantages of the monitoring system 114 described herein are that all parts of silica exposure zones, including the silos $98_{1\text{-}5}$, or any other sand storage container, sand conveyor, and dust vacuum system, can be monitored without the requirement for operations personnel to enter this region, thereby shielding personnel from harmful silica dust. Moreover, high-pressure zones where high-pressure fluid is being pumped within piping can be imaged without requiring operations personnel to be proximate the piping when high pressure fluid is within the piping. Chemical areas can also be monitored remotely and so that operations personnel are not subject to exposure to hazardous chemicals. Moreover, areas of the system 10 that contain cables at a

high voltage may also be remotely monitored thereby avoiding the need for personnel to enter these zones. In addition, cameras can be used to monitor fuel gas lines for the turbines that power the electric motors on an electric fleet. In one optional embodiment, mounts for the cameras 82_{1-13} are able to pivot on two axes and can be adjusted up down and left and right. The imaging can be displayed on video and discernible by operations personnel such that visual images reproduced real time. In one alternative, infrared imaging is performed.

[0043] The present invention described herein, therefore, is well adapted to carry out the objects and attain the ends and advantages mentioned, as well as others inherent therein. While a presently preferred embodiment of the invention has been given for purposes of disclosure, numerous changes exist in the details of procedures for accomplishing the desired results. These and other similar modifications will readily suggest themselves to those skilled in the art, and are intended to be encompassed within the spirit of the present invention disclosed herein and the scope of the appended claims.

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CLAIMS

What is claimed is.

1. A hydraulic fracturing system for fracturing a subterranean formation comprising:

a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry;

hydraulic fracturing system components for making the fracturing fluid slurry; and

a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

2. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises:

a camera;

a controller;

a display;

a human machine interface; and

communication means between the camera, controller, human machine interface, and the monitor.

3. The hydraulic fracturing system of Claim 1, wherein the display comprises a monitor from which the images are viewed.

4. The hydraulic fracturing system of Claim 3, wherein the display is disposed within a passenger compartment mounted to a fluid blender, so that the images can be viewed by operations personnel in the passenger compartment.

5. The hydraulic fracturing system of Claim 1, wherein the hydraulic fracturing components are selected from the group consisting of a chemical tanker, a hydration unit, a hopper, a blender unit, and auger associated with a blender unit, a conveyor, and an acid tanker.

6. The hydraulic fracturing system of Claim 1, wherein the pump components are selected from the group consisting of intake piping, discharge piping, hoses, fittings, and valves associated with a hydraulic fracturing pump.

7. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises a camera disposed on a trailer, and wherein the hydraulic fracturing components or pump components comprise hose or pipe connections on the trailer.

8. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises a camera disposed on a first trailer, and wherein the hydraulic fracturing components or pump components comprise hose or pipe connections on a second trailer that is adjacent the first trailer.

9. The hydraulic fracturing system of Claim 1, wherein the monitoring system selectively captures and transmits real time images of a silica exposure zone.

10. The hydraulic fracturing system of Claim 1, wherein the monitoring system selectively captures and transmits real time images of an opening to a vessel, so that a level within the vessel is discernable in the images.

11. The hydraulic fracturing system of Claim 10, wherein the vessel contains proppant.

12. The hydraulic fracturing system of Claim 10, wherein the vessel contains acid.

13. The hydraulic fracturing system of Claim 10, wherein the vessel contains chemicals.

14. A method of fracturing a subterranean formation comprising:

driving a pump to pressurize fluid in a hydraulic fracturing system containing hydraulic fracturing components and pump components;

fracturing the formation by directing the pressurized fluid into a wellbore that intersects the formation; and

monitoring the hydraulic fracturing system by:

obtaining images of hydraulic fracturing components and pump components of the hydraulic fracturing system; and

viewing the images remotely.

15. The method of Claim 14, wherein the hydraulic fracturing components and pump components are disposed in areas where there is a greater possibility of personal injury than where the images are being viewed.

16. The method of Claim 14, wherein the step of obtaining images is performed by a camera that is disposed adjacent at least one of the hydraulic fracturing components or the pump components.

17. The method of Claim 16, wherein the step of viewing is performed within an enclosure.

18. The method of Claim 14, further comprising:

selectively obtaining images of different hydraulic fracturing components or pump components on a single monitor.

19. The method of Claim 14, wherein the hydraulic fracturing components and pump components comprise discharge piping that is in fluid communication with the pump, and vessel openings, and wherein the images if of the hydraulic fracturing system include images of at least one of a silica exposure zone, hose connections, a high pressure zone that includes discharge pumps or discharge pipes or both, a chemical exposure zone, high voltage zones, and natural gas supply piping.

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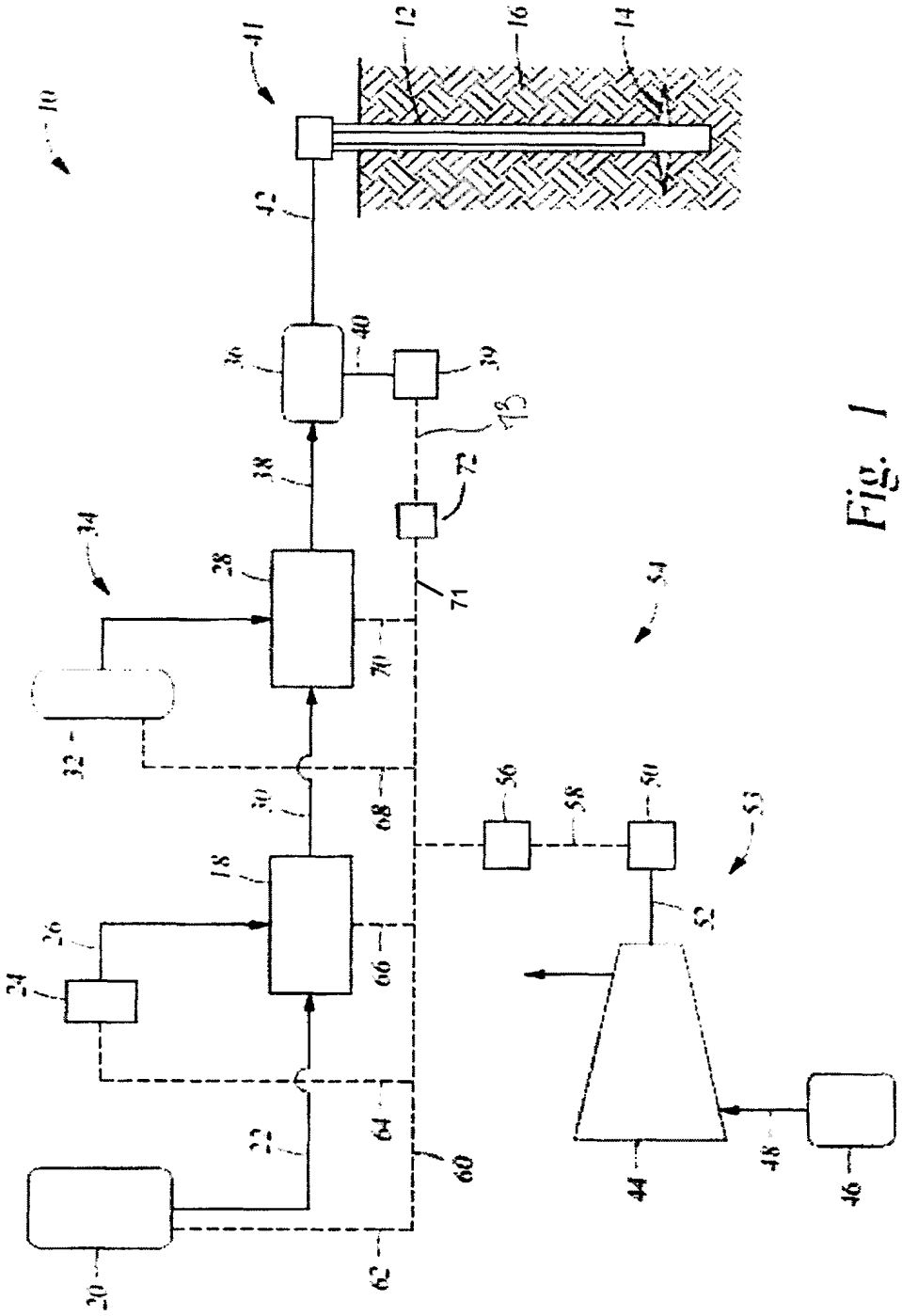

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Fig. 1

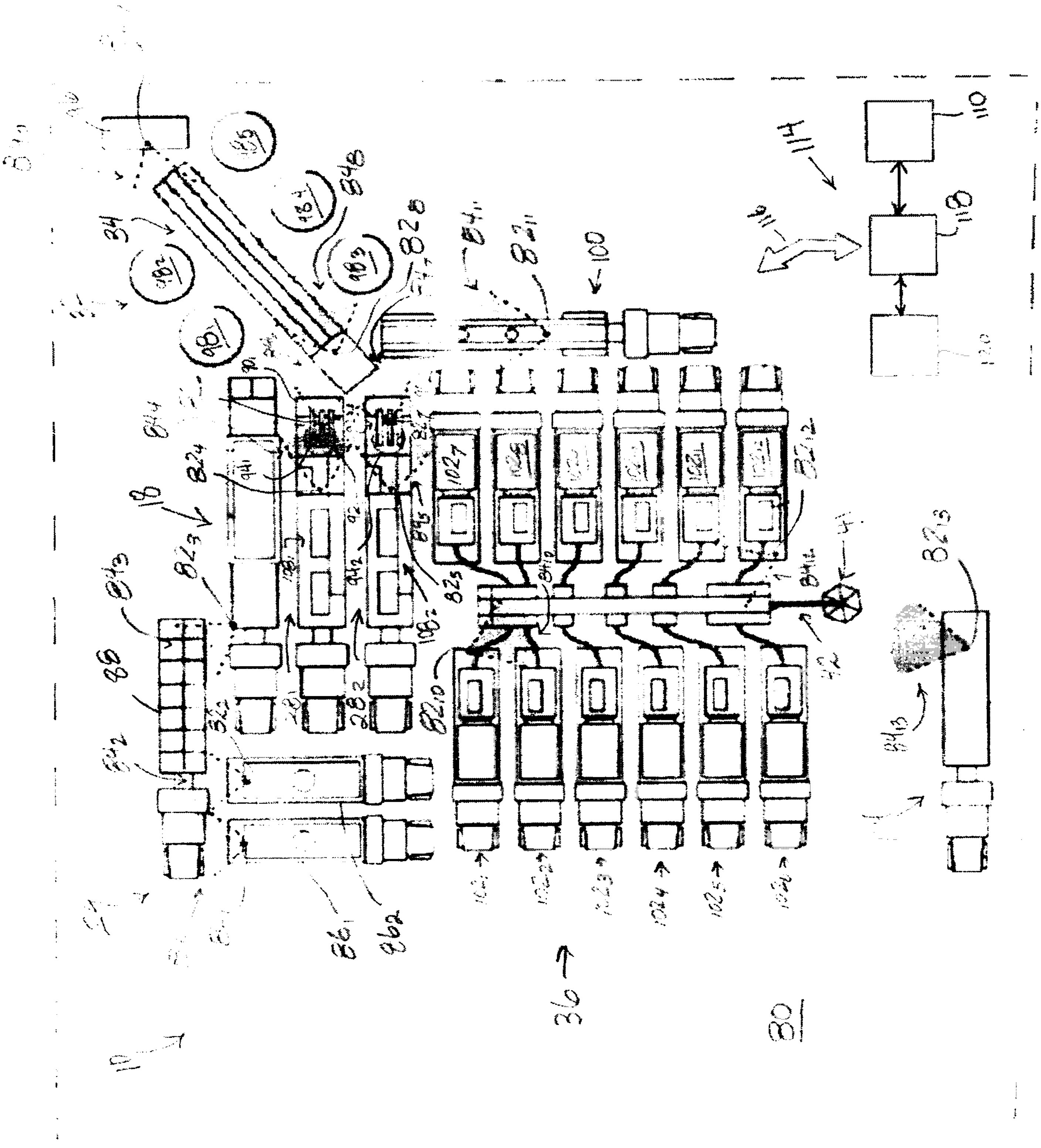


FIG. 2

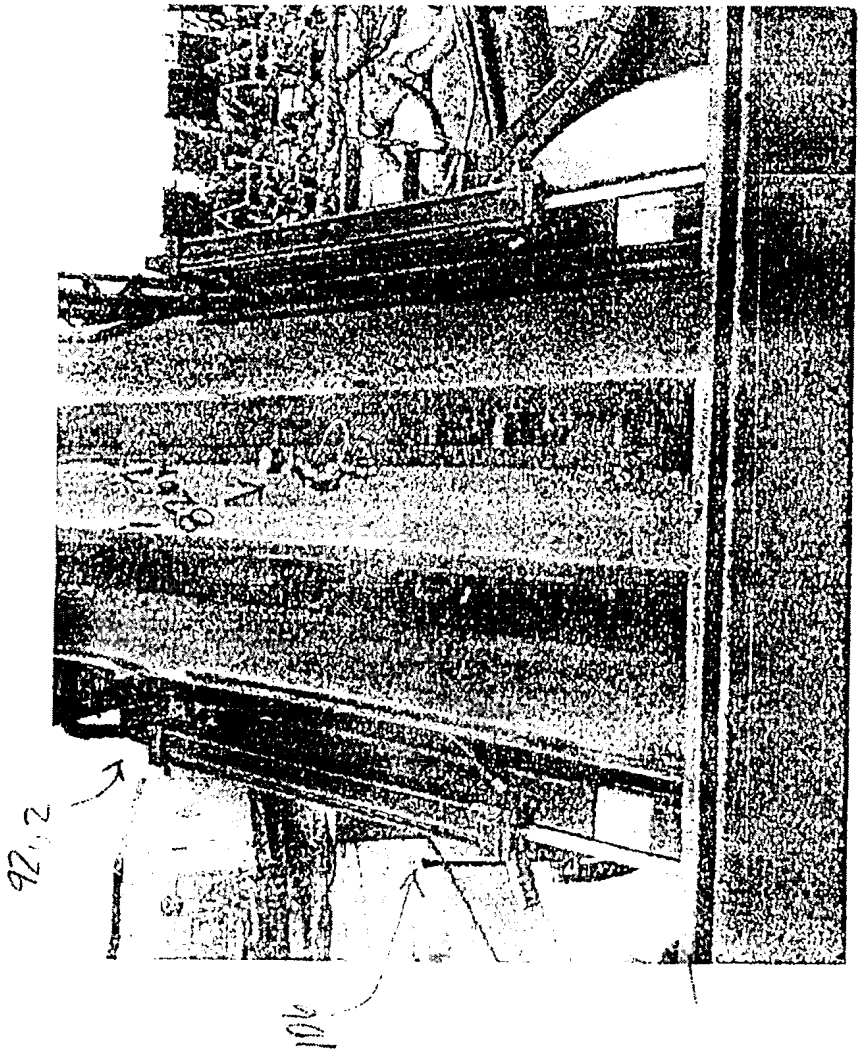

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FIG. 4

FIG. 5



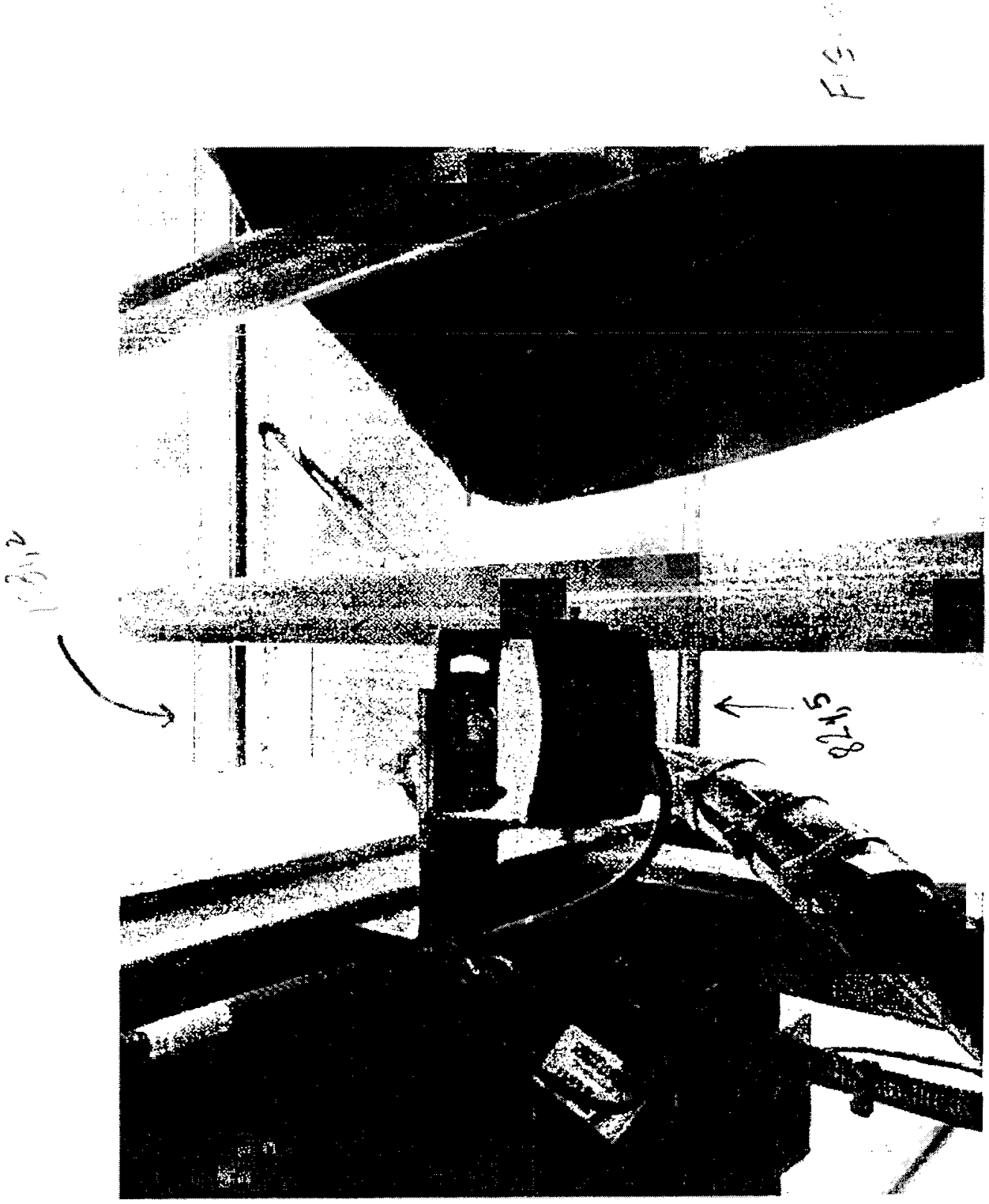
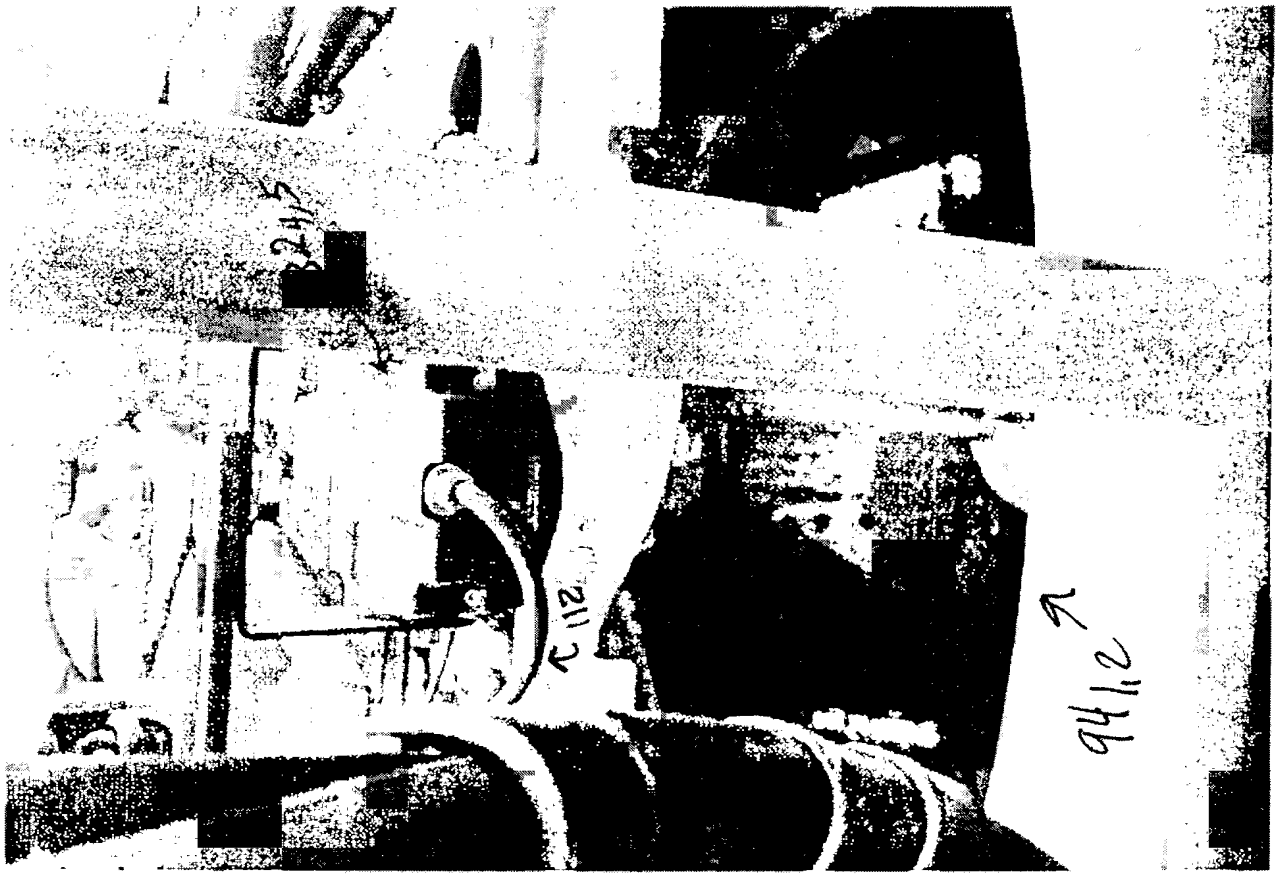
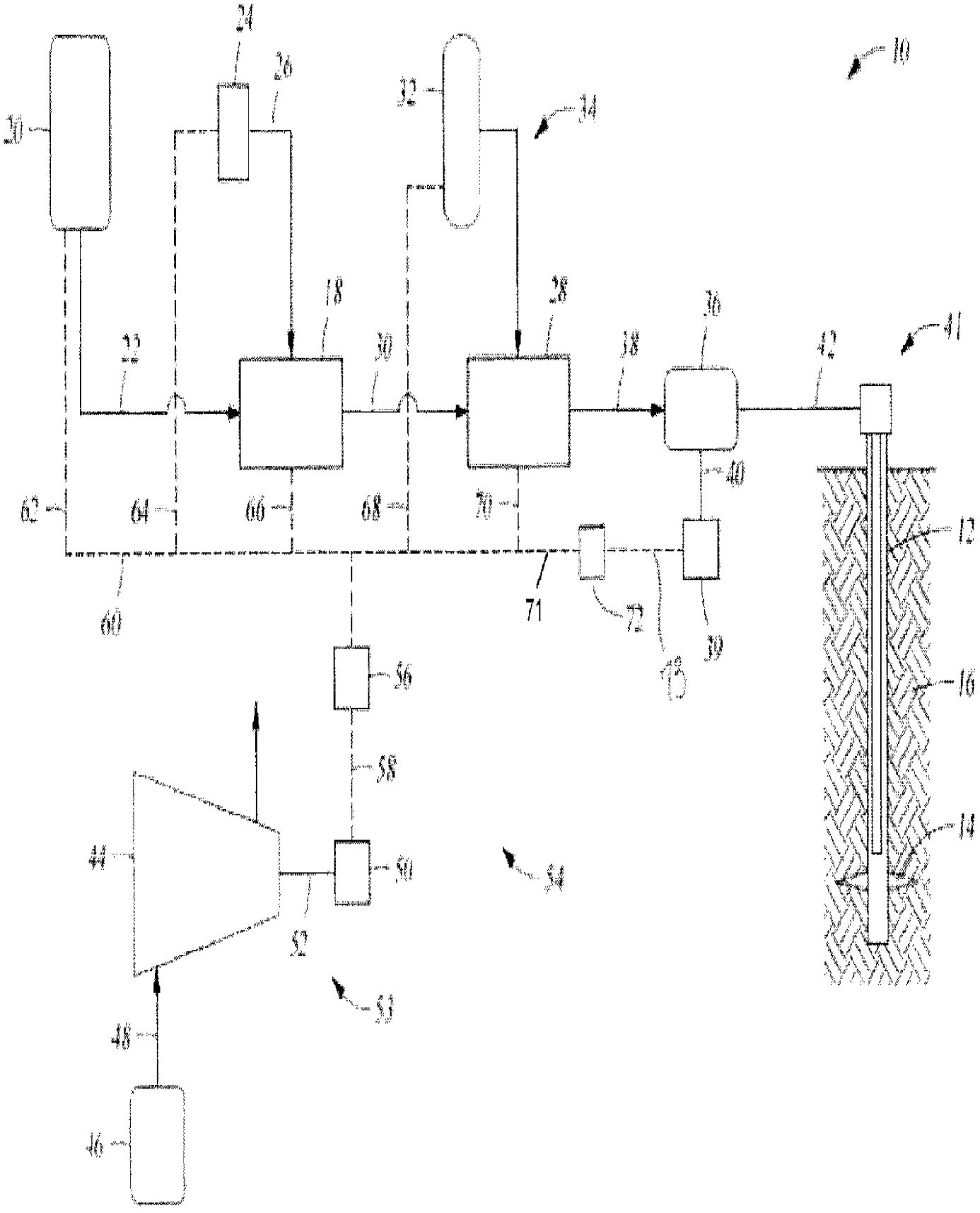

FIG. 6
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FIG. 7




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CA 2955706 A1 2012/10/07

(21) 2 955 706

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2012/04/10

(41) Mise à la disp. pub./Open to Public Insp.: 2012/10/07

(62) Demande originale/Original Application: 2 835 904

(30) Priorité/Priority: 2011/04/07 (US61/472,861)

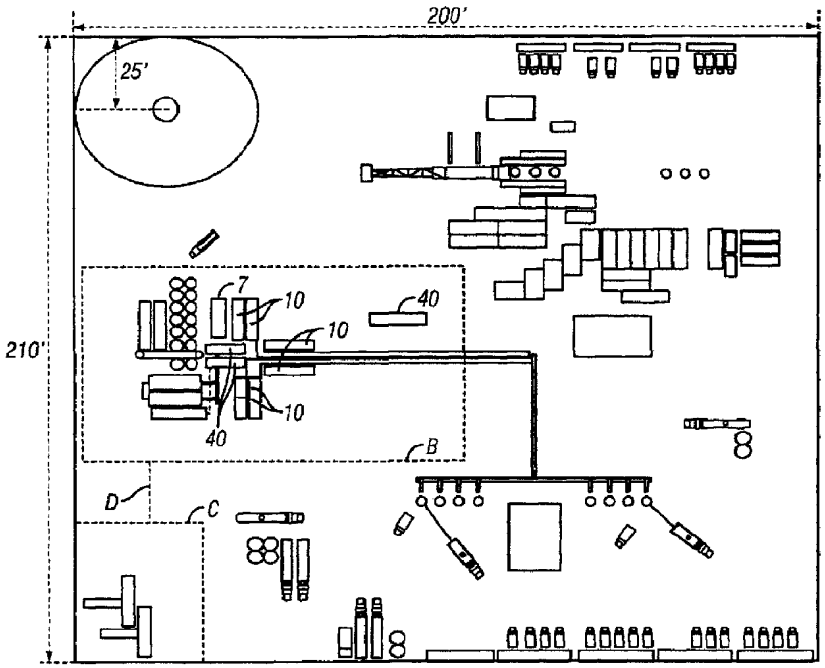
(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01),
E21B 41/00 (2006.01)

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(54) Titre : SYSTEME ELECTRIQUE MOBILE ET MODULAIRE UTILISE POUR FRACTURER DES FORMATIONS SOUTERRAINES
(54) Title: MOBILE, MODULAR, ELECTRICALLY POWERED SYSTEM FOR USE IN FRACTURING UNDERGROUND FORMATIONS



(57) Abrégé/Abstract:
The present invention provides a method and system for providing on-site electrical power to a fracturing operation, and an electrically powered fracturing system. Natural gas can be used to drive a turbine generator in the production of electrical power. A scalable, electrically powered fracturing fleet is provided to pump fluids for the fracturing operation, obviating the need for a constant supply of diesel fuel to the site and reducing the site footprint and infrastructure required for the fracturing operation, when compared with conventional systems.

ABSTRACT

The present invention provides a method and system for providing on-site electrical power to a fracturing operation, and an electrically powered fracturing system. Natural gas can be used to drive a turbine generator in the production of electrical power. A scalable, electrically powered fracturing fleet is provided to pump fluids for the fracturing operation, obviating the need for a constant supply of diesel fuel to the site and reducing the site footprint and infrastructure required for the fracturing operation, when compared with conventional systems.

MOBILE, MODULAR, ELECTRICALLY POWERED SYSTEM FOR USE IN FRACTURING UNDERGROUND FORMATIONS

[0001] This application is a divisional application of Canadian Patent Application No. 2,835,904 filed April 10, 2012 which is a divisional of Canadian Patent Application No. 2,773,843 filed April 10, 2012.

BACKGROUND

2. Field of Invention

[0002] This invention relates generally to hydraulic stimulation of underground hydrocarbon-bearing formations, and more particularly, to the generation and use of electrical power to deliver fracturing fluid to a wellbore.

3. Description of the Related Art

[0003] Over the life cycle of a typical hydrocarbon-producing wellbore, various fluids (along with additives, proppants, gels, cement, etc...) can be delivered to the wellbore under pressure and injected into the wellbore. Surface pumping systems must be able to accommodate these various fluids. Such pumping systems are typically mobilized on skids or tractor-trailers and powered using diesel motors.

[0004] Technological advances have greatly improved the ability to identify and recover unconventional oil and gas resources. Notably, horizontal drilling and multi-stage fracturing have led to the emergence of new opportunities for natural gas production from shale formations. For example, more than twenty

fractured intervals have been reported in a single horizontal wellbore in a tight natural gas formation. However, significant fracturing operations are required to recover these resources.

[0005] Currently contemplated natural gas recovery opportunities require considerable operational infrastructure, including large investments in fracturing equipment and related personnel. Notably, standard fluid pumps require large volumes of diesel fuel and extensive equipment maintenance programs. Typically, each fluid pump is housed on a dedicated truck and trailer configuration. With average fracturing operations requiring as many as fifty fluid pumps, the on-site area, or "footprint", required to accommodate these fracturing operations is massive. As a result, the operational infrastructure required to support these fracturing operations is extensive. Greater operational efficiencies in the recovery of natural gas would be desirable.

[0006] When planning large fracturing operations, one major logistical concern is the availability of diesel fuel. The excessive volumes of diesel fuel required necessitates constant transportation of diesel tankers to the site, and results in significant carbon dioxide emissions. Others have attempted to decrease fuel consumption and emissions by running large pump engines on "Bi-Fuel", blending natural gas and diesel fuel together, but with limited success. Further, attempts to decrease the number of personnel on-site by implementing remote monitoring and operational control have not been successful, as personnel are still required on-site to transport the equipment and fuel to and from the location.

SUMMARY

[0007] Various illustrative embodiments of a system and method for hydraulic stimulation of underground hydrocarbon-bearing formations are provided herein. In accordance with an aspect of the disclosed subject matter, a method of delivering fracturing fluid to a wellbore is provided. The method can comprise the steps of: providing a dedicated source of electric power at a site containing a wellbore to be fractured; providing one or more electric fracturing modules at the site, each electric fracturing module comprising an electric motor and a coupled fluid pump, each electric motor operatively associated with the dedicated source of electric power; providing a wellbore treatment fluid for pressurized delivery to a wellbore, wherein the wellbore treatment fluid can be continuous with the fluid pump and with the wellbore; and operating the fracturing unit using electric power from the dedicated source to pump the treatment fluid to the wellbore.

[0008] In certain illustrative embodiments, the dedicated source of electrical power is a turbine generator. A source of natural gas can be provided, whereby the natural gas drives the turbine generator in the production of electrical power. For example, natural gas can be provided by pipeline, or natural gas produced on-site. Liquid fuels such as condensate can also be provided to drive the turbine generator.

[0009] In certain illustrative embodiments, the electric motor can be an AC permanent magnet motor and/or a variable speed motor. The electric motor can be capable of operation in the range of up to 1500 rpms and up to 20,000 ft/lbs of torque. The pump can be a triplex or quintiplex plunger style fluid pump.

[0010] In certain illustrative embodiments, the method can further comprise the steps of: providing an electric blender module continuous and/or operatively associated with the fluid pump, the blender module comprising: a fluid source, a fluid additive source, and a centrifugal blender tub, and supplying electric

power from the dedicated source to the blender module to effect blending of the fluid with fluid additives to generate the treatment fluid.

[0011] In accordance with another aspect of the disclosed subject matter, a system for use in delivering pressurized fluid to a wellbore is provided. The system can comprise: a well site comprising a wellbore and a dedicated source of electricity; an electrically powered fracturing module operatively associated with the dedicated source of electricity, the electrically powered fracturing module comprising an electric motor and a fluid pump coupled to the electric motor; a source of treatment fluid, wherein the treatment fluid can be continuous with the fluid pump and with the wellbore; and a control system for regulating the fracturing module in delivery of treatment fluid from the treatment fluid source to the wellbore.

[0012] In certain illustrative embodiments, the source of treatment fluid can comprise an electrically powered blender module operatively associated with the dedicated source of electricity. The system can further comprise a fracturing trailer at the well site for housing one or more fracturing modules. Each fracturing module can be adapted for removable mounting on the trailer. The system can further comprise a replacement pumping module comprising a pump and an electric motor, the replacement pumping module adapted for removable mounting on the trailer. In certain illustrative embodiments, the replacement pumping module can be a nitrogen pumping module, or a carbon dioxide pumping module. The replacement pumping module can be, for example, a high torque, low rate motor or a low torque, high rate motor.

[0013] In accordance with another aspect of the disclosed subject matter, a fracturing module for use in delivering pressurized fluid to a wellbore is provided. The fracturing module can comprise: an AC permanent magnet motor capable of operation in the range of up to 1500 rpms and up to 20,000 ft/lbs of torque; and a plunger-style fluid pump coupled to the motor.

[0014] In accordance with another aspect of the disclosed subject matter, a method of blending a fracturing fluid for delivery to a wellbore to be fractured is provided. A dedicated source of electric power can be provided at a site containing a wellbore to be fractured. At least one electric blender module can be provided at the site. The electric blender module can include a fluid source, a fluid additive source, and a blender tub. Electric power can be supplied from the dedicated source to the electric blender module to effect blending of a fluid from the fluid source with a fluid additive from the fluid additive source to generate the fracturing fluid. The dedicated source of electrical power can be a turbine generator. A source of natural gas can be provided, wherein the natural gas is used to drive the turbine generator in the production of electrical power. The fluid from the fluid source can be blended with the fluid additive from the fluid additive source in the blender tub. The electric blender module can also include at least one electric motor that is operatively associated with the dedicated source of electric power and that effects blending of the fluid from the fluid source with the fluid additive from the fluid additive source.

[0015] In certain illustrative embodiments, the electric blender module can include a first electric motor and a second electric motor, each of which is operatively associated with the dedicated source of electric power. The first electric motor can effect delivery of the fluid from the fluid source to the blending tub. The second electric motor can effect blending of the fluid from the fluid source with the fluid additive from the fluid additive source in the blending tub. In certain illustrative embodiments, an optional third electric motor may also be present, that can also be operatively associated with the dedicated source of electric power. The third electric motor can effect delivery of the fluid additive from the fluid additive source to the blending tub.

[0016] In certain illustrative embodiments, the electric blender module can include a first blender unit and a second blender unit, each disposed adjacent to the other on the blender module and each capable of

independent operation, or collectively capable of cooperative operation, as desired. The first blender unit and the second blender unit can each include a fluid source, a fluid additive source, and a blender tub. The first blender unit and the second blender unit can each have at least one electric motor that is operatively associated with the dedicated source of electric power and that effects blending of the fluid from the fluid source with the fluid additive from the fluid additive source. Alternatively, the first blender unit and the second blender unit can each have a first electric motor and a second electric motor, both operatively associated with the dedicated source of electric power, wherein the first electric motor effects delivery of the fluid from the fluid source to the blending tub and the second electric motor effects blending of the fluid from the fluid source with the fluid additive from the fluid additive source in the blending tub. In certain illustrative embodiments, the first blender unit and the second blender unit can each also have a third electric motor operatively associated with the dedicated source of electric power, wherein the third electric motor effects delivery of the fluid additive from the fluid additive source to the blending tub.

[0017] In a broad aspect, the invention pertains to an electric blender module for fracturing operations. The electric blender module comprises a first electrically driven blender unit, a first inlet manifold coupled to the first electrically driven blender unit and capable of delivering an unblended fracturing fluid thereto, a first outlet manifold coupled to the first electrically driven blender unit and capable of delivering the blended fracturing fluid away therefrom, a second electrically driven blender unit, and a second inlet manifold coupled to the second electrically driven blender unit and capable of delivering the unblended fracturing fluid thereto. A second outlet manifold is coupled to the second electrically driven blender unit and is capable of delivering the blended fracturing fluid away therefrom. An inlet crossing line is coupled to the first inlet manifold and the second inlet manifold such that unblended fracturing fluid that enters the first inlet manifold is capable of being delivered to both the first electrically driven blender unit and the second electrically driven blender unit. An outlet crossing line couples the first electrically driven blender unit to the first outlet manifold and the second outlet manifold.

[0017a] In accordance with another aspect, there is provided a system for hydraulically fracturing an underground hydrocarbon bearing formation at a wellbore that pumps fluid from the wellbore into the formation, the system comprising: a plurality of pumps powered by one or more electric motors and fluidly connected to the wellbore, the pumps configured to pump fluid into the wellbore at a pressure sufficient so that the fluid passes from the wellbore into the formation, and fractures the formation; at least one variable frequency drive connected to the electric motors to control the speed of the motors, the at least one variable frequency drive capable of performing monitoring and controlling of the electric motors; and one or more generators electrically connected to the plurality of pumps to provide electrical power to the pumps.

[0017b] In accordance with another aspect, there is provided a system for fracturing an underground hydrocarbon bearing formation in an oil or gas well by pumping hydraulic fracturing fluid into the wellbore, the system comprising: a pump for pumping the hydraulic fracturing fluid into the wellbore, and then from the wellbore into the formation, the pump mounted on a trailer and capable of pumping the hydraulic fracturing fluid at a pressure sufficient to crack the formation; an electric motor attached to the pump and configured to drive the pump; a variable frequency drive connected to the electric motor to control the speed of the motor, the variable frequency drive capable of performing monitoring and controlling of the electric motor; and a generator connected to the electric motor that provides electric power to the electric motor.

[0017c] In accordance with another aspect, there is provided a system for hydraulically fracturing an underground hydrocarbon bearing formation at a wellbore that permits passage of fluid from the wellbore into the formation, the system comprising: a trailer; two or more pumps attached to the trailer and fluidly connected to the well, the pumps configured to pump fluid into the wellbore at a high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation; one or more electric motors attached to the pumps to drive the pumps; at least one variable frequency drive connected to the electric motors to control the speed of the motors, the at least one variable frequency drive capable of performing monitoring and controlling of the electric motors; and a generator for connection to the one or more electric motors that provides electric power to the one or more electric motors.

[0018] Other aspects and features of the present invention will become apparent to those of ordinary skill in the art upon review of the following detailed description in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0019] A better understanding of the presently disclosed subject matter can be obtained when the following detailed description is considered in conjunction with the following drawings, wherein:

[0020] Figure 1 is a schematic plan view of a traditional fracturing site;

[0021] Figure 2 is a schematic plan view of a fracturing site in accordance with certain illustrative embodiments described herein;

[0022] Figure 3 is a schematic perspective view of a fracturing trailer in accordance with certain illustrative embodiments described herein;

[0023] Figure 4A is a schematic perspective view of a fracturing module in accordance with certain illustrative embodiments described herein;

[0024] Figure 4B is a schematic perspective view of a fracturing module with maintenance personnel in accordance with certain illustrative embodiments described herein;

[0025] Figure 5A is a schematic side view of a blender module in accordance with certain illustrative embodiments described herein;

[0026] Figure 5B is an end view of the blender module shown in Figure 4A;

[0027] Figure 5C is a schematic top view of a blender module in accordance with certain illustrative embodiments described herein;

[0028] Figure 5D is a schematic side view of the blender module shown in Figure 5C;

[0029] Figure 5E is a schematic perspective view of the blender module shown in Figure 5C;

[0030] Figure 6 is a schematic top view of an inlet manifold for a blender module in accordance with certain illustrative embodiments described herein; and

[0031] Figure 7 is a schematic top view of an outlet manifold for a blender module in accordance with certain illustrative embodiments described herein.

DETAILED DESCRIPTION

[0032] The presently disclosed subject matter generally relates to an electrically powered fracturing system and a system and method for providing on-site electrical power and delivering fracturing fluid to a wellbore at a fracturing operation.

[0033] In a conventional fracturing operation, a "slurry" of fluids and additives is injected into a hydrocarbon bearing rock formation at a wellbore to propagate fracturing. Low pressure fluids are mixed with chemicals, sand, and, if necessary, acid, and then transferred at medium pressure and high rate to vertical and/or deviated portions of the wellbore via multiple high pressure, plunger style pumps driven by diesel fueled prime movers. The majority of the fluids injected will be flowed back through the wellbore and recovered, while the sand will remain in the newly created fracture, thus "propping" it open and providing a permeable membrane for hydrocarbon fluids and gases to flow through so they may be recovered.

[0034] According to the illustrative embodiments described herein, natural gas (either supplied to the site or produced on-site) can be used to drive a dedicated source of electrical power, such as a turbine generator, for hydrocarbon-producing wellbore completions. A scalable, electrically powered fracturing fleet is provided to deliver pressurized treatment fluid, such as fracturing fluid, to a wellbore in a fracturing operation, obviating the need for a constant supply of diesel fuel to the site and reducing the site footprint and infrastructure required for the fracturing operation, when compared with conventional operations. The treatment fluid provided for pressurized delivery to the wellbore can be continuous with the wellbore and with one or more components of the fracturing fleet, in certain illustrative embodiments. In these embodiments, continuous generally means that downhole hydrodynamics are dependent upon constant flow (rate and pressure) of the delivered fluids, and that there should not be any interruption in fluid flow during delivery to the wellbore if the fracture is to propagate as desired. However, it should not

be interpreted to mean that operations of the fracturing fleet cannot generally be stopped and started, as would be understood by one of ordinary skill in the art.

[0035] With reference to Figure 1, a site plan for a traditional fracturing operation on an onshore site is shown. Multiple trailers 5 are provided, each having at least one diesel tank mounted or otherwise disposed thereon. Each trailer 5 is attached to a truck 6 to permit refueling of the diesel tanks as required. Trucks 6 and trailers 5 are located within region A on the fracturing site. Each truck 6 requires a dedicated operator. One or more prime movers are fueled by the diesel and are used to power the fracturing operation. One or more separate chemical handling skids 7 are provided for housing of blending tanks and related equipment.

[0036] With reference to Figure 2, an illustrative embodiment of a site plan for an electrically powered fracturing operation on a onshore site is shown. The fracturing operation includes one or more trailers 10, each housing one or more fracturing modules 20 (see Figure 3). Trailers 10 are located in region B on the fracturing site. One or more natural gas-powered turbine generators 30 are located in region C on the site, which is located a remote distance D from region B where the trailers 10 and fracturing modules 20 are located, for safety reasons. Turbine generators 30 replace the diesel prime movers utilized in the site plan of Figure 1. Turbine generators 30 provide a dedicated source of electric power on-site. There is preferably a physical separation between the natural gas-based power generation in region C and the fracturing operation and wellbore located in region B. The natural gas-based power generation can require greater safety precautions than the fracturing operation and wellhead. Accordingly, security measures can be taken in region C to limit access to this more hazardous location, while maintaining separate safety standards in region B where the majority of site personnel are typically located. Further, the natural gas powered supply of electricity can be monitored and regulated remotely such that, if desired, no personnel are required to be within region C during operation.

[0037] Notably, the setup of Figure 2 requires significantly less infrastructure than the setup shown in Figure 1, while providing comparable pumping capacity. Fewer trailers 10 are present in region B of Figure 2 than the trucks 6 and trailers 5 in region A of Figure 1, due to the lack of need for a constant diesel fuel supply. Further, each trailer 10 in Figure 2 does not need a dedicated truck 6 and operator as in Figure 1. Fewer chemical handling skids 7 are required in region B of Figure 2 than in region A of Figure 1, as the skids 7 in Figure 2 can be electrically powered. Also, by removing diesel prime movers, all associated machinery necessary for power transfer can be eliminated, such as the transmission, torque converter, clutch, drive shaft, hydraulic system, etc ...., and the need for cooling systems, including circulating pumps and fluids, is significantly reduced. In an illustrative embodiment, the physical footprint of the on-site area in region B of Figure 2 is about 80% less than the footprint for the conventional system in region A of Figure 1.

[0038] With reference to the illustrative embodiments of Figure 3, trailer 10 for housing one or more fracturing modules 20 is shown. Trailer 10 can also be a skid, in certain illustrative embodiments. Each fracturing module 20 can include an electric motor 21 and a fluid pump 22 coupled thereto. During fracturing, fracturing module 20 is operatively associated with turbine generator 30 to receive electric power therefrom. In certain illustrative embodiments, a plurality of electric motors 21 and pumps 22 can be transported on a single trailer 10. In the illustrative embodiments of Figure 3, four electric motors 21 and pumps 22 are transported on a single trailer 10. Each electric motor 21 is paired to a pump 22 as a single fracturing module 20. Each fracturing module 20 can be removably mounted to trailer 10 to facilitate ease of replacement as necessary. Fracturing modules 20 utilize electric power from turbine generator 30 to pump the fracturing fluid directly to the wellbore.

[0039] Electrical Power Generation

[0040] The use of a turbine to directly drive a pump has been previously explored. In such systems, a transmission is used to regulate turbine power to the pump to allow for speed and torque control. In the present operation, natural gas is instead used to drive a dedicated power source in the production of electricity. In illustrative embodiments, the dedicated power source is an on-site turbine generator. The need for a transmission is eliminated, and generated electricity can be used to power the fracturing modules, blenders, and other on-site operations as necessary.

[0041] Grid power may be accessible on-site in certain fracturing operations, but the use of a dedicated power source is preferred. During startup of a fracturing operation, massive amounts of power are required such that the use of grid power would be impractical. Natural gas powered generators are more suitable for this application based on the likely availability of natural gas on-site and the capacity of natural gas generators for producing large amounts of power. Notably, the potential for very large instantaneous adjustments in power drawn from the grid during a fracturing operation could jeopardize the stability and reliability of the grid power system. Accordingly, a site-generated and dedicated source of electricity provides a more feasible solution in powering an electric fracturing system. In addition, a dedicated on-site operation can be used to provide power to operate other local equipment, including coiled tubing systems, service rigs, etc...

[0042] In an illustrative embodiment, a single natural gas powered turbine generator 30, as housed in a restricted area C of Figure 2, can generate sufficient power (for example 31 MW at 13,800 volts AC power) to supply several electric motors 21 and pumps 22, avoiding the current need to deliver and operate each fluid pump from a separate diesel-powered truck. A turbine suitable for this purpose is a TM2500+ turbine generator sold by General Electric. Other generation packages could be supplied by Pratt & Whitney or Kawasaki for example. Multiple options are available for turbine power generation,

depending on the amount of electricity required. In an illustrative embodiment, liquid fuels such as condensate can also be provided to drive turbine generator 30 instead of, or in addition to, natural gas. Condensate is less expensive than diesel fuels, thus reducing operational costs.

[0043] Fracturing Module

[0044] With reference to Figures 4A and 4B, an illustrative embodiment of fracturing module 20 is provided. Fracturing module 20 can include an electric motor 21 coupled to one or more electric pumps 22, in certain illustrative embodiments. A suitable pump is a quintiplex or triplex plunger style pump, for example, the SWGS-2500 Well Service Pump sold by Gardner Denver, Inc.

[0045] Electric motor 21 is operatively associated with turbine generator 30, in certain embodiments. Typically, each fracturing module 20 will be associated with a drive housing for controlling electric motor 21 and pumps 22, as well as an electrical transformer and drive unit 50 (see Figure 3) to step down the voltage of the power from turbine generator 30 to a voltage appropriate for electric motor 21. The electrical transformer and drive unit 50 can be provided as an independent unit for association with fracturing module 20, or can be permanently fixed to the trailer 10, in various embodiments. If permanently fixed, then transformer and drive unit 50 can be scalable to allow addition or subtraction of pumps 22 or other components to accommodate any operational requirements.

[0046] Each pump 22 and electric motor 21 are modular in nature so as to simplify removal and replacement from fracturing module 20 for maintenance purposes. Removal of a single fracturing module 20 from trailer 10 is also simplified. For example, any fracturing module 20 can be unplugged and unpinned from trailer 10 and removed, and another fracturing module 20 can be installed in its place in a matter of minutes.

[0047] In the illustrative embodiment of Figure 3, trailer 10 can house four fracturing modules 20, along with a transformer and drive unit 50. In this particular configuration, each single trailer 10 provides more

pumping capacity than four of the traditional diesel powered fracturing trailers 5 of Figure 1, as parasitic losses are minimal in the electric fracturing system compared to the parasitic losses typical of diesel fueled systems. For example, a conventional diesel powered fluid pump is rated for 2250 hp. However, due to parasitic losses in the transmission, torque converter and cooling systems, diesel fueled systems typically only provide 1800 hp to the pumps. In contrast, the present system can deliver a true 2500 hp directly to each pump 22 because pump 22 is directly coupled to electric motor 21. Further, the nominal weight of a conventional fluid pump is up to 120,000 lbs. In the present operation, each fracturing module 20 weighs approximately 28,000 lbs., thus allowing for placement of four pumps 22 in the same physical dimension (size and weight) as the spacing needed for a single pump in conventional diesel systems, as well as allowing for up to 10,000 hp total to the pumps. In other embodiments, more or fewer fracturing modules 20 may be located on trailer 10 as desired or required for operational purposes.

[0048] In certain illustrative embodiments, fracturing module 20 can include a electric motor 21 that is an AC permanent magnet motor capable of operation in the range of up to 1500 rpms and up to 20,000 ft/lbs of torque. Fracturing module 20 can also include a pump 22 that is a plunger-style fluid pump coupled to electric motor 21. In certain illustrative embodiments, fracturing module 20 can have dimensions of approximately 136" width x 108" length x 100" height. These dimensions would allow fracturing module 20 to be easily portable and fit with a ISO intermodal container for shipping purposes without the need for disassembly. Standard sized ISO container lengths are typically 20' , 40' or 53'. In certain illustrative embodiments, fracturing module 20 can have dimensions of no greater than 136" width x 108" length x 100" height. These dimensions for fracturing module 20 would also allow crew members to easily fit within the confines of fracturing module 20 to make repairs, as illustrated in Figure 4b. In certain illustrative embodiments, fracturing module 20 can have a width of no greater than 102" to fall within shipping configurations and road restrictions. In a specific embodiment, fracturing module 20 is

capable of operating at 2500 hp while still having the above specified dimensions and meeting the above mentioned specifications for rpms and ft/lbs of torque.

[0049] Electric Motor

[0050] With reference to the illustrative embodiments of Figures 2 and 3, a medium low voltage AC permanent magnet electric motor 21 receives electric power from turbine generator 30, and is coupled directly to pump 22. In order to ensure suitability for use in fracturing, electric motor 21 should be capable of operation up to 1,500 rpm with a torque of up to 20,000 ft/lbs, in certain illustrative embodiments. A motor suitable for this purpose is sold under the trademark TeraTorq® and is available from Comprehensive Power, Inc. of Marlborough, Massachusetts. A compact motor of sufficient torque will allow the number of fracturing modules 20 placed on each trailer 10 to be maximized.

[0051] Blender

[0052] For greater efficiency, conventional diesel powered blenders and chemical addition units can be replaced with electrically powered blender units. In certain illustrative embodiments as described herein, the electrically powered blender units can be modular in nature for housing on trailer 10 in place of fracturing module 20, or housed independently for association with each trailer 10. An electric blending operation permits greater accuracy and control of fracturing fluid additives. Further, the centrifugal blender tubs typically used with blending trailers to blend fluids with proppant, sand, chemicals, acid, etc... prior to delivery to the wellbore are a common source of maintenance costs in traditional fracturing operations.

[0053] With reference to Figures 5A-5E and Figures 6-7, illustrative embodiments of a blender module 40 and components thereof are provided. Blender module 40 can be operatively associated with turbine generator 30 and capable of providing fractioning fluid to pump 22 for delivery to the wellbore. In certain embodiments, blender module 40 can include at least one fluid additive source 44, at least one fluid

source 48, and at least one centrifugal blender tub 46. Electric power can be supplied from turbine generator 30 to blender module 40 to effect blending of a fluid from fluid source 48 with a fluid additive from fluid additive source 44 to generate the fracturing fluid. In certain embodiments, the fluid from fluid source 48 can be, for example, water, oils or methanol blends, and the fluid additive from fluid additive source 44 can be, for example, friction reducers, gellents, gellent breakers or biocides.

[0054] In certain illustrative embodiments, blender module 40 can have a dual configuration, with a first blender unit 47a and a second blender unit 47b positioned adjacent to each other. This dual configuration is designed to provide redundancy and to facilitate access for maintenance and replacement of components as needed. In certain embodiments, each blender unit 47a and 47b can have its own electrically-powered suction and tub motors disposed thereon, and optionally, other electrically-powered motors can be utilized for chemical additional and/or other ancillary operational functions, as discussed further herein.

[0055] For example, in certain illustrative embodiments, first blender unit 47a can have a plurality of electric motors including a first electric motor 43a and a second electric motor 41a that are used to drive various components of blender module 40. Electric motors 41a and 43a can be powered by turbine generator 30. Fluid can be pumped into blender module 40 through an inlet manifold 48a by first electric motor 43a and added to tub 46a. Thus, first electric motor 43a acts as a suction motor. Second electric motor 41a can drive the centrifugal blending process in tub 46a. Second electric motor 41a can also drive the delivery of blended fluid out of blender module 40 and to the wellbore via an outlet manifold 49a. Thus, second electric motor 41a acts as a tub motor and a discharge motor. In certain illustrative embodiments, a third electric motor 42a can also be provided. Third electric motor 42a can also be powered by turbine generator 30, and can power delivery of fluid additives to blender 46a. For example,

proppant from a hopper 44a can be delivered to a blender tub 46a, for example, a centrifugal blender tub, by an auger 45a, which is powered by third electric motor 42a.

[0056] Similarly, in certain illustrative embodiments, second blender unit 47b can have a plurality of electric motors including a first electric motor 43b and a second electric motor 41b that are used to drive various components of blender module 40. Electric motors 41b and 43b can be powered by turbine generator 30. Fluid can be pumped into blender module 40 through an inlet manifold 48b by first electric motor 43b and added to tub 46b. Thus, second electric motor 43a acts as a suction motor. Second electric motor 41b can drive the centrifugal blending process in tub 46b. Second electric motor 41b can also drive the delivery of blended fluid out of blender module 40 and to the wellbore via an outlet manifold 49b. Thus, second electric motor 41b acts as a tub motor and a discharge motor. In certain illustrative embodiments, a third electric motor 42b can also be provided. Third electric motor 42b can also be powered by turbine generator 30, and can power delivery of fluid additives to blender 46b. For example, proppant from a hopper 44b can be delivered to a blender tub 46b, for example, a centrifugal blender tub, by an auger 45b, which is powered by third electric motor 42b.

[0057] Blender module 40 can also include a control cabin 53 for housing equipment controls for first blender unit 47a and second blender unit 47b, and can further include appropriate drives and coolers as required.

[0058] Conventional blenders powered by a diesel hydraulic system are typically housed on a forty-five foot tractor trailer and are capable of approximately 100 bbl/min. In contrast, the dual configuration of blender module 40 having first blender unit 47a and second blender unit 47b can provide a total output capability of 240 bbl/min in the same physical footprint as a conventional blender, without the need for a separate backup unit in case of failure.

[0059] Redundant system blenders have been tried in the past with limited success, mostly due to problems with balancing weights of the trailers while still delivering the appropriate amount of power. Typically, two separate engines, each approximately 650 hp, have been mounted side by side on the nose of the trailer. In order to run all of the necessary systems, each engine must drive a mixing tub via a transmission, drop box and extended drive shaft. A large hydraulic system is also fitted to each engine to run all auxiliary systems such as chemical additions and suction pumps. Parasitic power losses are very large and the hosing and wiring is complex.

[0060] In contrast, the electric powered blender module 40 described in certain illustrative embodiments herein can relieve the parasitic power losses of conventional systems by direct driving each piece of critical equipment with a dedicated electric motor. Further, the electric powered blender module 40 described in certain illustrative embodiments herein allows for plumbing routes that are unavailable in conventional applications. For example, in certain illustrative embodiments, the fluid source can be an inlet manifold 48 that can have one or more inlet crossing lines 51 (see Figure 6) that connect the section of inlet manifold 48 dedicated to delivering fluid to first blender unit 47a with the section of inlet manifold 48 dedicated to delivering fluid to second blender unit 47b. Similarly, in certain illustrative embodiments, outlet manifold 49 can have one or more outlet crossing lines 50 (see Figure 7) that connect the section of outlet manifold 49 dedicated to delivering fluid from first blender unit 47a with the section of outlet manifold 49 dedicated to delivering fluid from second blender unit 47b. Crossing lines 50 and 51 allow flow to be routed or diverted between first blender unit 47a and second blender unit 47b. Thus, blender module 40 can mix from either side, or both sides, and/or discharge to either side, or both sides, if necessary. As a result, the attainable rates for the electric powered blender module 40 are much larger that of a conventional blender. In certain illustrative embodiments, each side (i.e., first blender unit 47a and second blender unit 47b) of blender module 40 is capable of approximately 120 bbl/min. Also, each

side (i.e., first blender unit 47a and second blender unit 47b) can move approximately 15 t/min of sand, at least in part because the length of auger 45 is shorter (approximately 6') as compared to conventional units (approximately 12').

[0061] In certain illustrative embodiments, blender module 40 can be scaled down or "downsized" to a single, compact module comparable in size and dimensions to fracturing module 20 described herein. For smaller fracturing or treatment jobs requiring fewer than four fracturing modules 20, a downsized blender module 40 can replace one of the fracturing modules 20 on trailer 10, thus reducing operational costs and improving transportability of the system.

[0062] Control System

[0063] A control system can be provided for regulating various equipment and systems within the electric powered fractioning operation. For example, in certain illustrative embodiments, the control system can regulate fracturing module 20 in delivery of treatment fluid from blender module 30 to pumps 22 for delivery to the wellbore. Controls for the electric-powered operation described herein are a significant improvement over that of conventional diesel powered systems. Because electric motors are controlled by variable frequency drives, absolute control of all equipment on location can be maintained from one central point. When the system operator sets a maximum pressure for the treatment, the control software and variable frequency drives calculate a maximum current available to the motors. Variable frequency drives essentially "tell" the motors what they are allowed to do.

[0064] Electric motors controlled via variable frequency drive are far safer and easier to control than conventional diesel powered equipment. For example, conventional fleets with diesel powered pumps utilize an electronically controlled transmission and engine on the unit. There can be up to fourteen different parameters that need to be monitored and controlled for proper operation. These signals are typically sent via hardwired cable to an operator console controlled by the pump driver. The signals are

converted from digital to analog so the inputs can be made via switches and control knobs. The inputs are then converted from analog back to digital and sent back to the unit. The control module on the unit then tells the engine or transmission to perform the required task and the signal is converted to a mechanical operation. This process takes time.

[0065] Accidental over-pressures are quite common in these conventional operations, as the signal must travel to the console, back to the unit and then perform a mechanical function. Over-pressures can occur in milliseconds due to the nature of the operations. These are usually due to human error, and can be as simple as a single operator failing to react to a command. They are often due to a valve being closed, which accidentally creates a "deadhead" situation.

[0066] For example, in January of 2011, a large scale fractioning operation was taking place in the Horn River Basin of north-eastern British Columbia, Canada. A leak occurred in one of the lines and a shutdown order was given. The master valve on the wellhead was then closed remotely. Unfortunately, multiple pumps were still rolling and a system over-pressure ensued. Treating iron rated for 10,000 psi was taken to well over 15,000 psi. A line attached to the well also separated, causing it to whip around. The incident caused a shutdown interruption to the entire operation for over a week while investigation and damage assessment were performed.

[0067] The control system provided according to the present illustrative embodiments, being electrically powered, virtually eliminates these types of scenarios from occurring. A maximum pressure value set at the beginning of the operation is the maximum amount of power that can be sent to electric motor 21 for pump 22. By extrapolating a maximum current value from this input, electric motor 21 does not have the available power to exceed its operating pressure. Also, because there are virtually no mechanical systems between pump 22 and electric motor 21, there is far less "moment of inertia" of gears and clutches to deal with. A near instantaneous stop of electric motor 21 results in a near instantaneous stop of pump 22.

[0068] An electrically powered and controlled system as described herein greatly increases the ease in which all equipment can be synced or slaved to each other. This means a change at one single point will be carried out by all pieces of equipment, unlike with diesel equipment. For example, in conventional diesel powered operations, the blender typically supplies all the necessary fluids to the entire system. In order to perform a rate change to the operation, the blender must change rate prior to the pumps changing rates. This can often result in accidental overflow of the blender tubs and/or cavitation of the pumps due to the time lag of each piece of equipment being given manual commands.

[0069] In contrast, the present operation utilizes a single point control that is not linked solely to blender operations, in certain illustrative embodiments. All operation parameters can be input prior to beginning the fractioning. If a rate change is required, the system will increase the rate of the entire system with a single command. This means that if pumps 22 are told to increase rate, then blender module 40 along with the chemical units and even ancillary equipment like sand belts will increase rates to compensate automatically.

[0070] Suitable controls and computer monitoring for the entire fracturing operation can take place at a single central location, which facilitates adherence to pre-set safety parameters. For example, a control center 40 is indicated in Figure 2 from which operations can be managed via communications link 41. Examples of operations that can be controlled and monitored remotely from control center 40 via communications link 41 can be the power generation function in Area B, or the delivery of treatment fluid from blender module 40 to pumps 22 for delivery to the wellbore.

[0071] Comparison Example

[0072] Table 1, shown below, compares and contrasts the operational costs and manpower requirements for a conventional diesel powered operation (such as shown in Figure 1) with those of a electric powered operation (such as shown in Figure 2).

[0073] **Table 1**

[0074] **Comparison of Conventional Diesel Powered Operation vs. Electric Powered Operation**

Diesel Powered Operation	Electric Powered Operation
Total fuel cost (diesel) - about $80,000 per day	Total fuel cost (natural gas) - about $2,300 per day
Service interval for diesel engines - about every 200-300 hours	Service interval for electric motor - about every 50,000 hours
Dedicated crew size - about 40 people	Dedicated crew size - about 10 people

[0075] In Table 1, the "Diesel Powered Operation" utilizes at least 24 pumps and 2 blenders, and requires at least 54,000 hp to execute the fracturing program on that location. Each pump burns approximately 300-400 liters per hour of operation, and the blender units burn a comparable amount of diesel fuel. Because of the fuel consumption and fuel capacity of this conventional unit, it requires refueling during operation, which is extremely dangerous and presents a fire hazard. Further, each piece of conventional equipment needs a dedicated tractor to move it and a driver/operator to run it. The crew size required to operate and maintain a conventional operation such as the one in Figure 1 represents a direct cost for the site operator.

[0076] In contrast, the electric powered operation as described herein utilizes a turbine that only consumes about 6mm scf of natural gas per 24 hours. At current market rates (approximately $2.50 per mmbtu), this equates to a reduction in direct cost to the site operator of over $77,000 per day compared to

the diesel powered operation. Also, the service interval on electric motors is about 50,000 hours, which allows the majority of reliability and maintainability costs to disappear. Further, the need for multiple drivers/operators is reduced significantly, and electric powered operation means that a single operator can run the entire system from a central location. Crew size can be reduced by around 75%, as only about 10 people are needed on the same location to accomplish the same tasks as conventional operations, with the 10 people including off-site personnel maintenance personnel. Further, crew size does not change with the amount of equipment used. Thus, the electric powered operation is significantly more economical.

[0077] Modular Design and Alternate Embodiments

[0078] As discussed above, the modular nature of the electric powered fracturing operation described herein provides significant operational advantages and efficiencies over traditional fracturing systems. Each fracturing module 20 sits on trailer 10 which houses the necessary mounts and manifold systems for low pressure suctions and high pressure discharges. Each fracturing module 20 can be removed from service and replaced without shutting down or compromising the fractioning spread. For instance, pump 22 can be isolated from trailer 10, removed and replaced by a new pump 22 in just a few minutes. If fracturing module 20 requires service, it can be isolated from the fluid lines, unplugged, un-pinned and removed by a forklift. Another fracturing module 20 can be then re-inserted in the same fashion, realizing a drastic time savings. In addition, the removed fracturing module 20 can be repaired or serviced in the field. In contrast, if one of the pumps in a conventional diesel powered system goes down or requires service, the tractor/trailer combination needs to be disconnected from the manifold system and driven out of the location. A replacement unit must then be backed into the line and reconnected. Maneuvering these units in these tight confines is difficult and dangerous.

[0079] The presently described electric powered fracturing operation can be easily adapted to accommodate additional types of pumping capabilities as needed. For example, a replacement pumping

module can be provided that is adapted for removable mounting on trailer 10. Replacement pumping module can be utilized for pumping liquid nitrogen, carbon dioxide, or other chemicals or fluids as needed, to increase the versatility of the system and broaden operational range and capacity. In a conventional system, if a nitrogen pump is required, a separate unit truck/trailer unit must be brought to the site and tied into the fractioning spread. In contrast, the presently described operation allows for a replacement nitrogen module with generally the same dimensions as fractioning module 20, so that the replacement module can fit into the same slot on the trailer as fractioning module 20 would. Trailer 10 can contain all the necessary electrical power distributions as required for a nitrogen pump module so no modifications are required. The same concept would apply to carbon dioxide pump modules or any other pieces of equipment that would be required. Instead of another truck/trailer, a specialized replacement module can instead be utilized.

[0080] Natural gas is considered to be the cleanest, most efficient fuel source available. By designing and constructing "fit for purpose equipment" that is powered by natural gas, it is expected that the fracturing footprint, manpower, and maintenance requirements can each be reduced by over 60% when compared with traditional diesel-powered operations.

[0081] In addition, the presently described electric powered fracturing operation resolves or mitigates environmental impacts of traditional diesel-powered operations. For example, the presently described natural gas powered operation can provide a significant reduction in carbon dioxide emissions as compared to diesel-powered operations. In an illustrative embodiment, a fractioning site utilizing the presently described natural gas powered operation would have a carbon dioxide emissions level of about 2200 kg/hr, depending upon the quality of the fuel gas, which represents an approximately 200% reduction from carbon dioxide emissions of diesel-powered operations. Also, in an illustrative embodiment, the presently described natural gas powered operation would produces no greater than about

80 decibels of sound with a silencer package utilized on turbine 30, which meets OSHA requirements for noise emissions. By comparison, a conventional diesel-powered fractioning pump running at full rpm emits about 105 decibels of sound. When multiple diesel-powered fractioning pumps are running simultaneously, noise is a significant hazard associated with conventional operations.

[0082] In certain illustrative embodiments, the electric-powered fractioning operation described herein can also be utilized for offshore oil and gas applications, for example, fracturing of a wellbore at an offshore site. Conventional offshore operations already possess the capacity to generate electric power on-site. These vessels are typically diesel over electric, which means that the diesel powerplant on the vessel generates electricity to meet all power requirements including propulsion. Conversion of offshore pumping services to run from an electrical power supply will allow transported diesel fuel to be used in power generation rather than to drive the fracturing operation, thus reducing diesel fuel consumption. The electric power generated from the offshore vessel's power plant (which is not needed during station keeping) can be utilized to power one or more fracturing modules 10. This is far cleaner, safer and more efficient than using diesel powered equipment. Fracturing modules 10 are also smaller and lighter than the equipment typically used on the deck of offshore vessels, thus removing some of the current ballast issues and allowing more equipment or raw materials to be transported by the offshore vessels.

[0083] In a deck layout for a conventional offshore stimulation vessel, skid based, diesel powered pumping equipment and storage facilities on the deck of the vessel create ballast issues. Too much heavy equipment on the deck of the vessel causes the vessel to have higher center of gravity. Also, fuel lines must be run to each piece of equipment greatly increasing the risk of fuel spills. In illustrative embodiments of a deck layout for an offshore vessel utilizing electric-powered fractioning operations as described herein, the physical footprint of the equipment layout is reduced significantly when compared to the conventional layout. More free space is available on deck, and the weight of equipment is

dramatically decreased, thus eliminating most of the ballast issues. A vessel already designed as diesel-electric can be utilized. When the vessel is on station at a platform and in station keeping mode, the vast majority of the power that the ship's engines are generating can be run up to the deck to power modules. The storage facilities on the vessel can be placed below deck, further lowering the center of gravity, while additional equipment, for instance, a 3-phase separator, or coiled tubing unit, can be provided on deck, which is difficult in existing diesel-powered vessels. These benefits, coupled with the electronic control system, give a far greater advantage over conventional vessels.

[0084] While the present description has specifically contemplated a fracturing system, the system can be used to power pumps for other purposes, or to power other oilfield equipment. For example, high rate and pressure pumping equipment, hydraulic fracturing equipment, well stimulation pumping equipment and/or well servicing equipment could also be powered using the present system. In addition, the system can be adapted for use in other art fields requiring high torque or high rate pumping operations, such as pipeline cleaning or dewatering mines.

[0085] It is to be understood that the subject matter herein is not limited to the exact details of construction, operation, exact materials, or illustrative embodiments shown and described, as modifications and equivalents will be apparent to one skilled in the art. Accordingly, the subject matter is therefore to be limited only by the scope of the appended claims.

CLAIMS

What is claimed is:

1. A system for hydraulically fracturing an underground hydrocarbon bearing formation at a wellbore that pumps fluid from the wellbore into the formation, the system comprising:

a plurality of pumps powered by one or more electric motors and fluidly connected to the wellbore, the pumps configured to pump fluid into the wellbore at a pressure sufficient so that the fluid passes from the wellbore into the formation, and fractures the formation;

at least one variable frequency drive connected to the electric motors to control the speed of the motors, the at least one variable frequency drive capable of performing monitoring and controlling of the electric motors; and

one or more generators electrically connected to the plurality of pumps to provide electrical power to the pumps.

2. The system of claim 1, wherein the at least one variable frequency drive is capable of performing monitoring and controlling of the electric motors by regulating a maximum current available to the electric motors.

3. The system of claim 1, wherein at least some of the plurality of generators are powered by a fuel selected from a group consisting of natural gas and liquid fuel.

4. The system of claim 1, wherein at least some of the plurality of generators are turbine generators.

5. The system of claim 1, further comprising a control system.

6. The system of claim 1, wherein the plurality of pumps are mounted on a trailer and transportable on the trailer.

7. The system of claim 1, further comprising a plurality of variable frequency drives attached to the electrical motors coupled to the plurality of pumps.

8. A system for fracturing an underground hydrocarbon bearing formation in an oil or gas well by pumping hydraulic fracturing fluid into the wellbore, the system comprising:

a pump for pumping the hydraulic fracturing fluid into the wellbore, and then from the wellbore into the formation, the pump mounted on a trailer and capable of pumping the hydraulic fracturing fluid at a pressure sufficient to crack the formation;

an electric motor attached to the pump and configured to drive the pump;

a variable frequency drive connected to the electric motor to control the speed of the motor, the variable frequency drive capable of performing monitoring and controlling of the electric motor; and

a generator connected to the electric motor that provides electric power to the electric motor.

9. The system of claim 8, wherein the variable frequency drive is capable of performing monitoring and controlling of the electric motors by regulating a maximum current available to the electric motor.

10. The system of claim 8, wherein the pump is a plunger-style fluid pump.

11. The system of claim 8, wherein the pump is a triplex or a quintuplex pump rated up to about 2500 horsepower.

12. The system of claim 8, wherein the electric motor has a power output of up to about 2500 horsepower.

13. The system of claim 8, wherein the electric motor has a torque of up to about 20,000 foot per pound (ft/lb).

14. The system of claim 8, wherein the generator is a turbine generator.

15. The system of claim 8, wherein the variable frequency drive is mounted to the trailer.

16. The system of claim 8, wherein the trailer has three axles.

17. The system of claim 8, wherein the electric motor is attached to the trailer.

18. The system of claim 8, wherein the trailer has mounts attaching the variable frequency drive to the trailer.

19. A system for hydraulically fracturing an underground hydrocarbon bearing formation at a wellbore that permits passage of fluid from the wellbore into the formation, the system comprising:

a trailer;

two or more pumps attached to the trailer and fluidly connected to the well, the pumps configured to pump fluid into the wellbore at a high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation;

one or more electric motors attached to the pumps to drive the pumps;

at least one variable frequency drive connected to the electric motors to control the speed of the motors, the at least one variable frequency drive capable of performing monitoring and controlling of the electric motors; and

a generator for connection to the one or more electric motors that provides electric power to the one or more electric motors.

20. The system of claim 19, wherein the at least one variable frequency drive is capable of performing monitoring and controlling of the electric motors by regulating a maximum current available to the electric motors.

21. The system of claim 19, wherein the two or more pumps are attached to the trailer.

22. The system of claim 19, wherein the one or more electric motors are attached to the trailer.

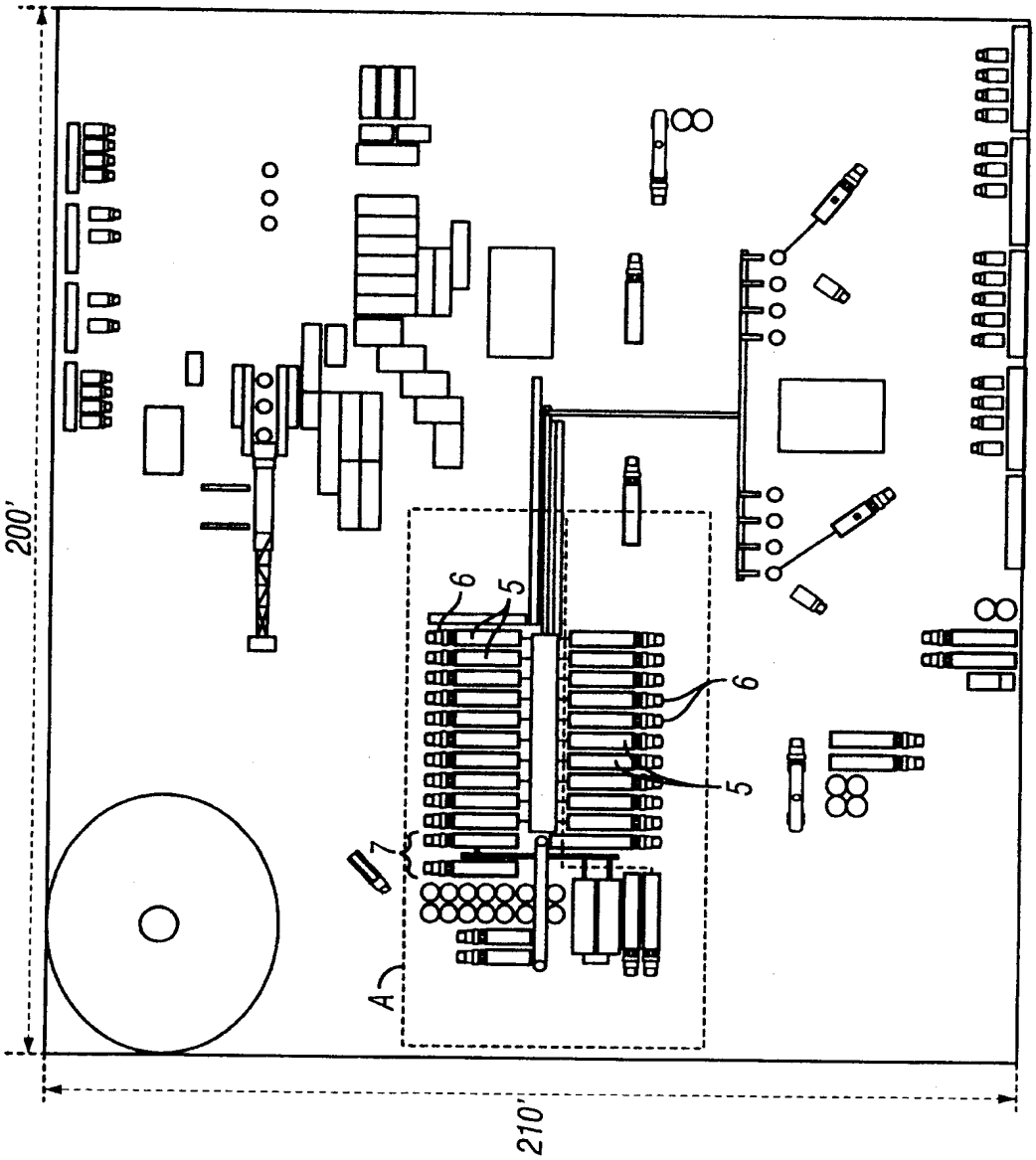


FIG. 1
(Prior Art)

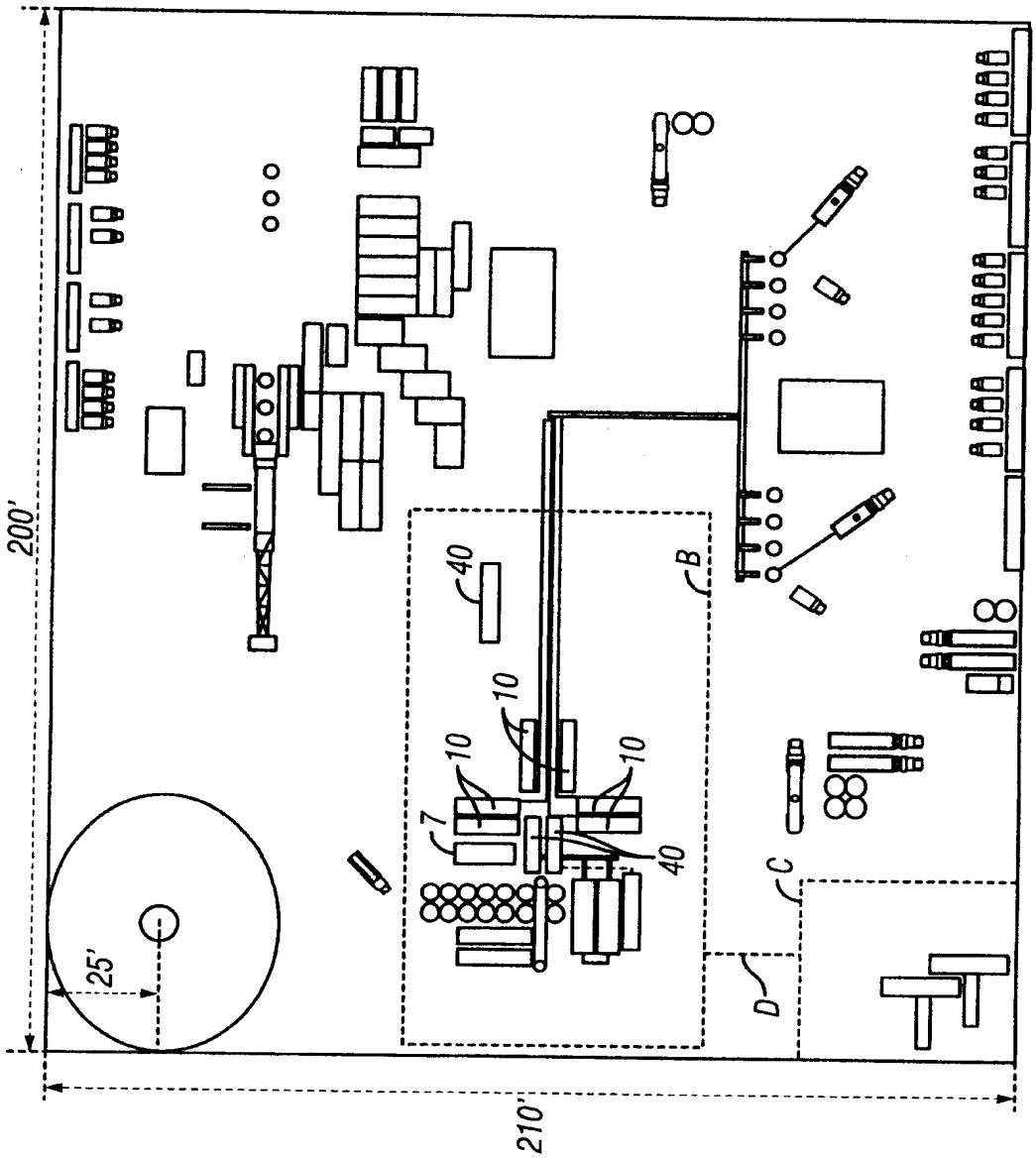


FIG. 2

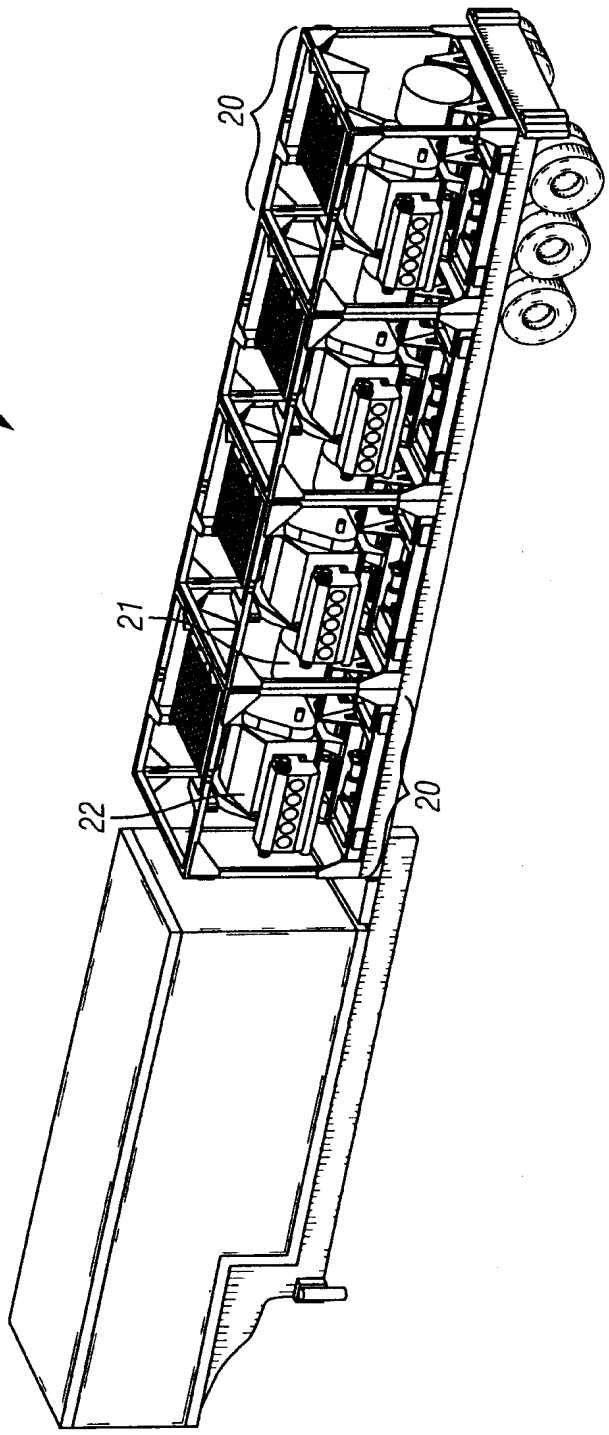


FIG. 3

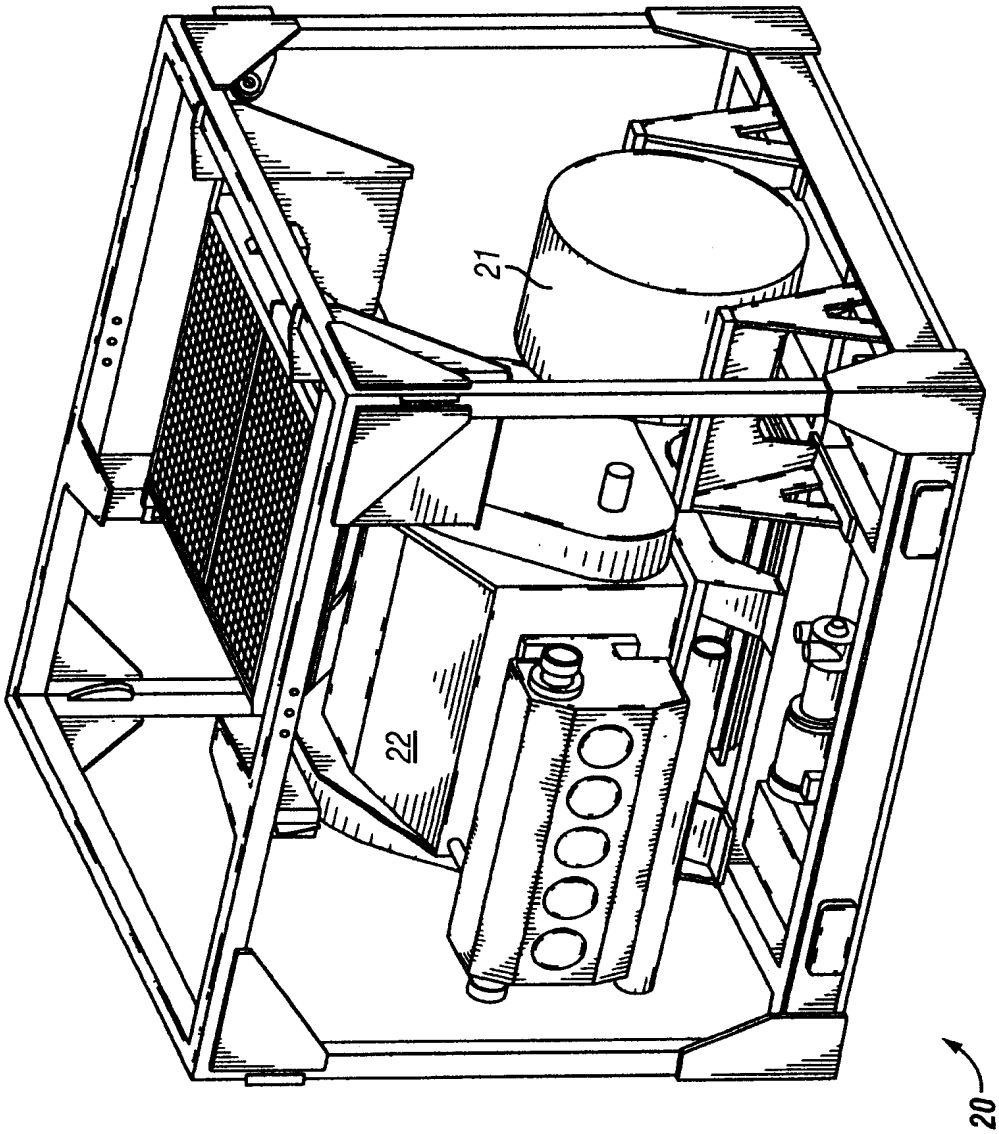


FIG. 4A

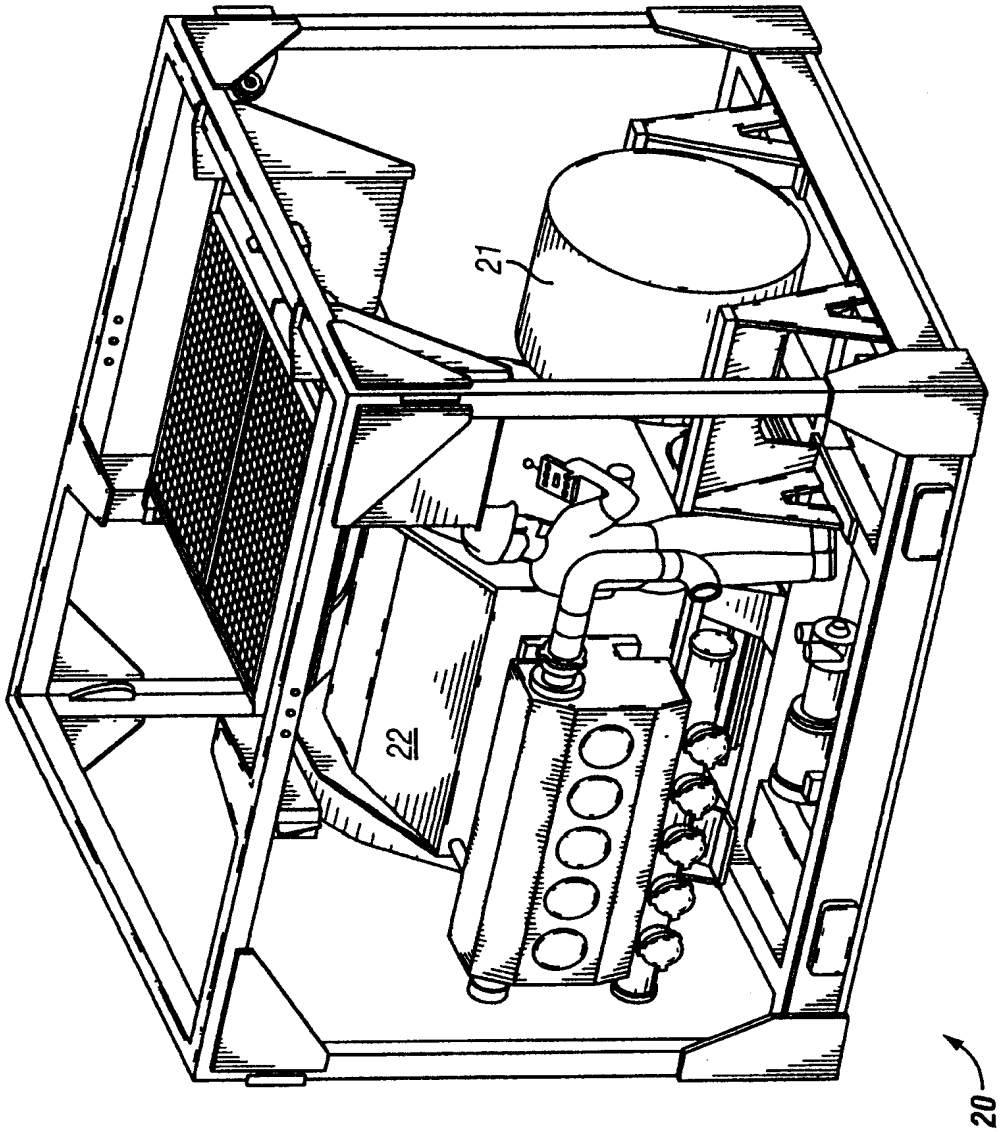


FIG. 4B

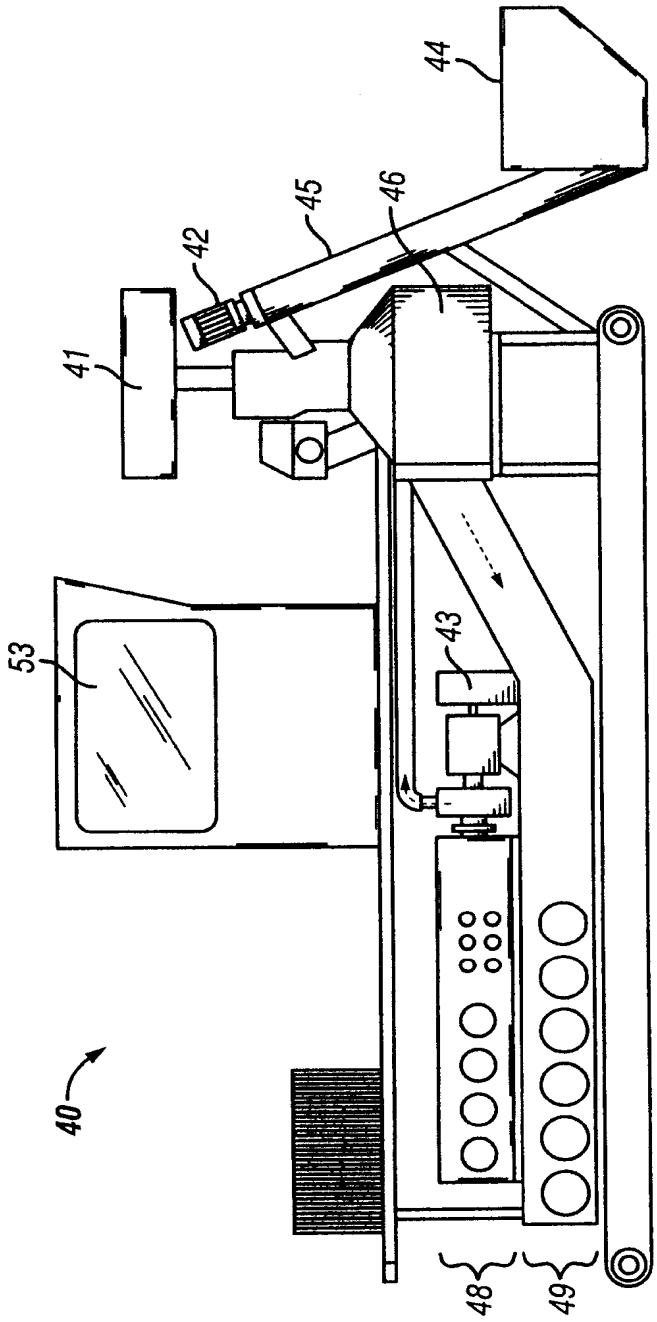


FIG. 5A

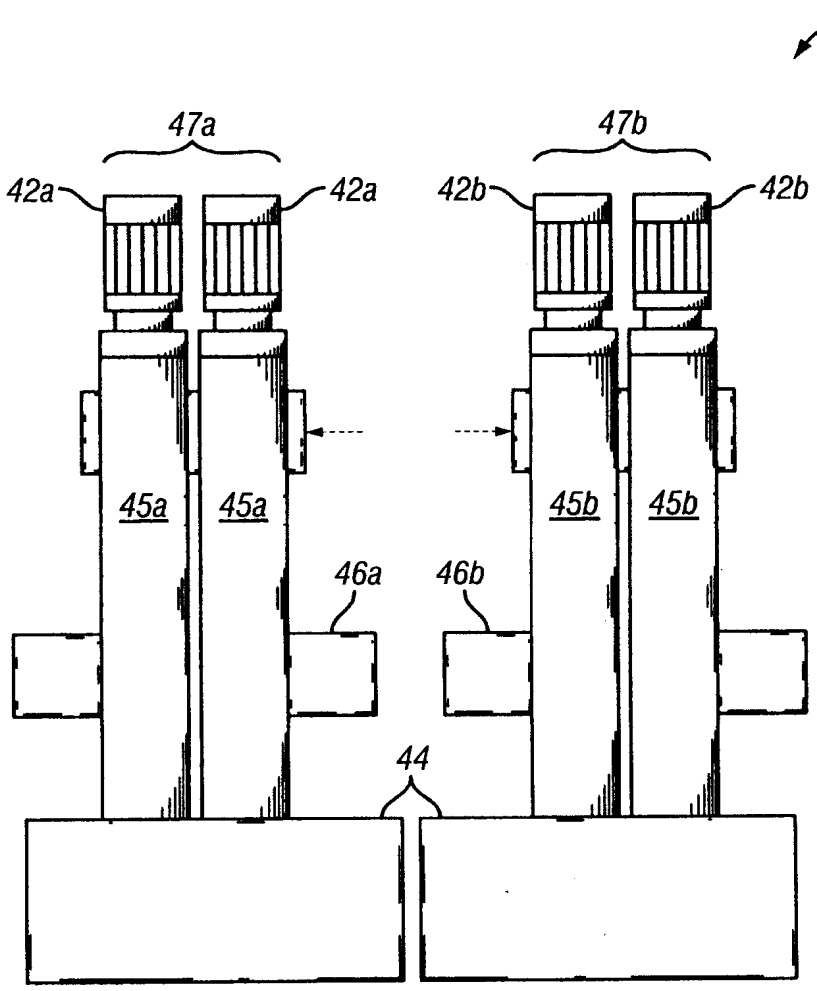


FIG. 5B

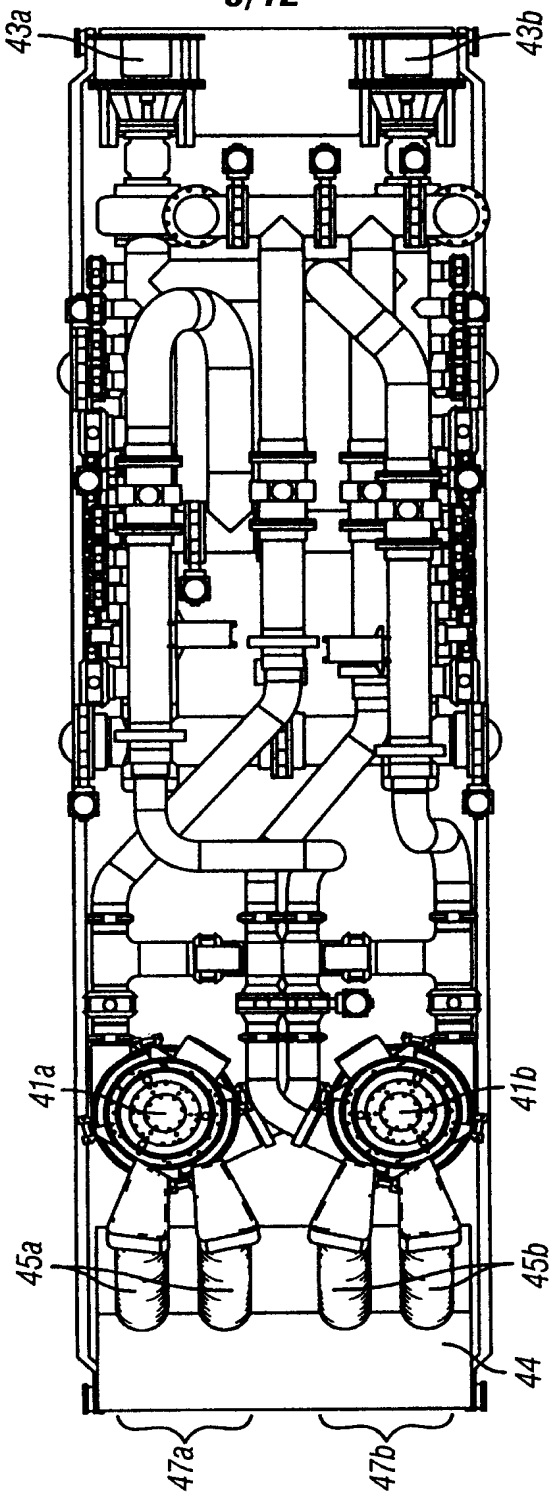


FIG. 5C

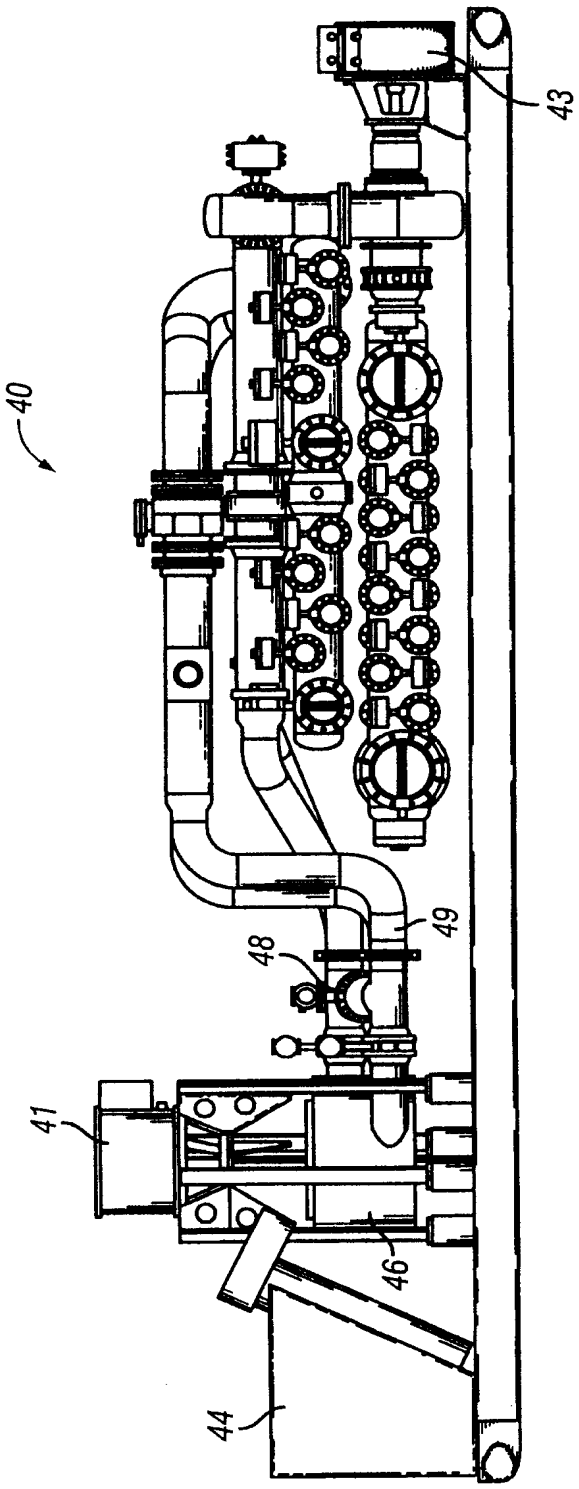


FIG. 5D

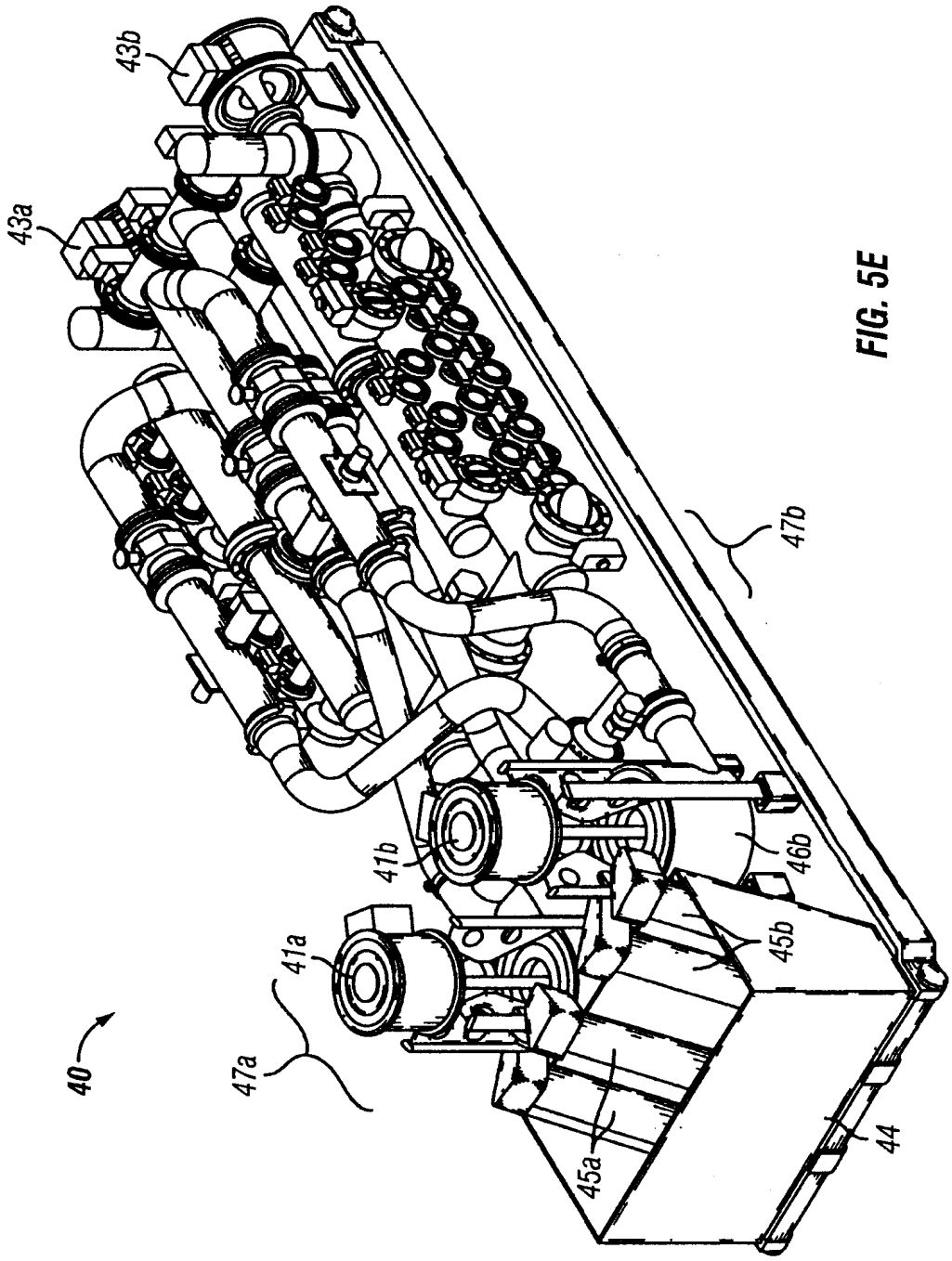


FIG. 5E

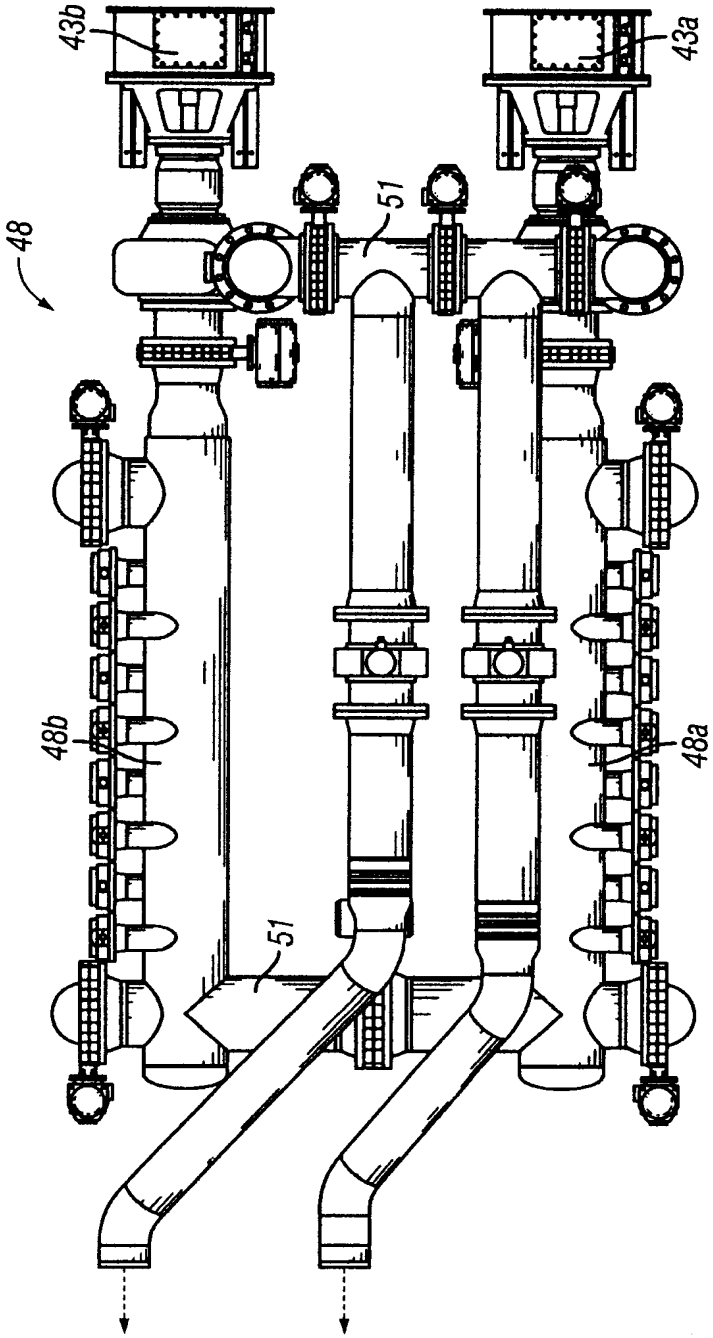


FIG. 6

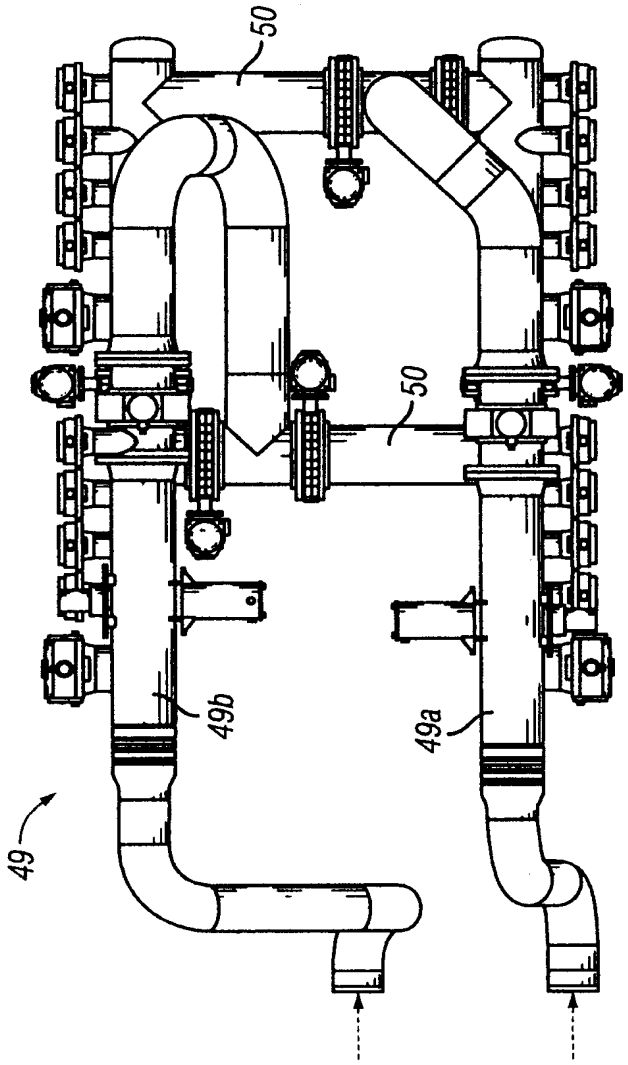
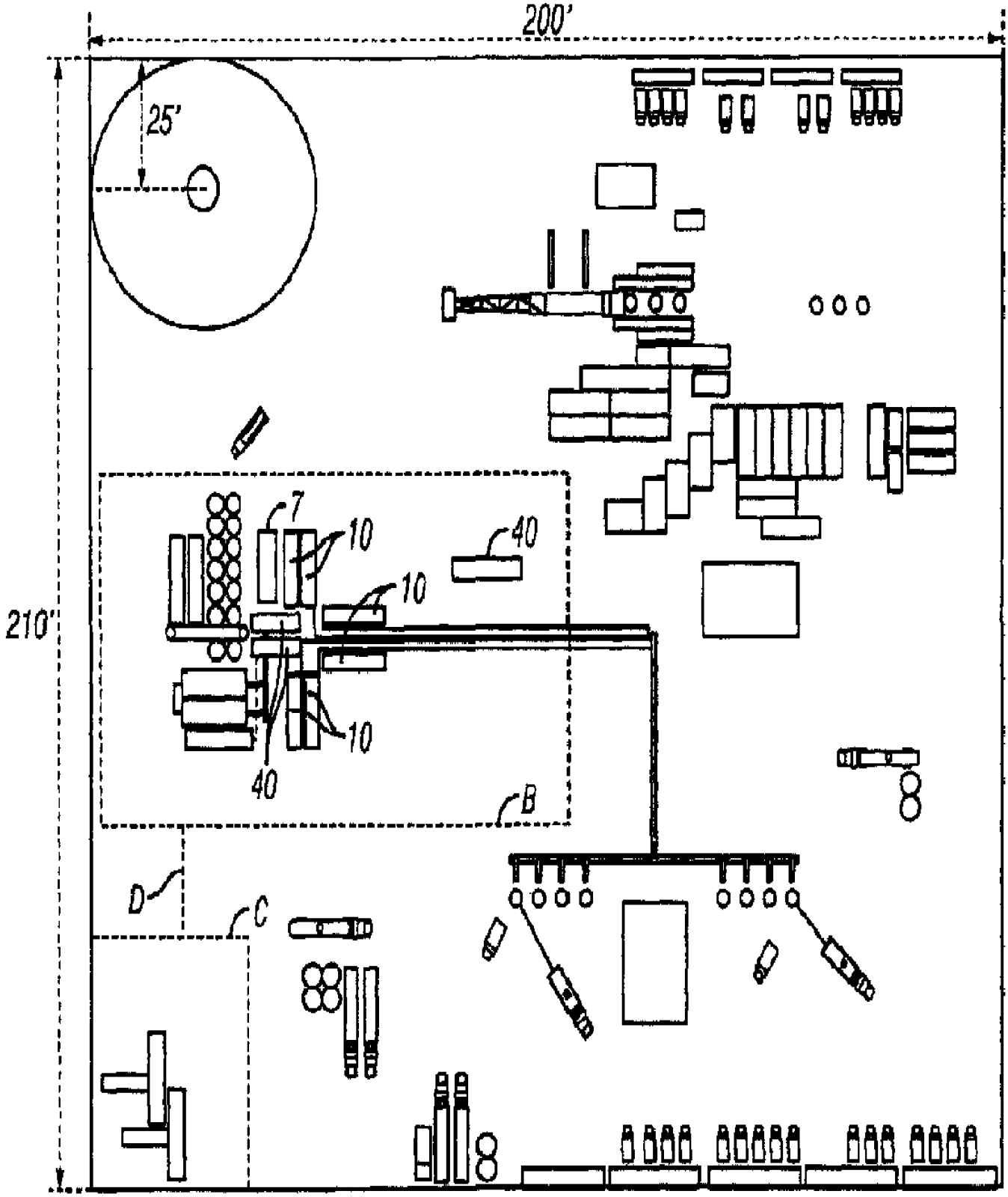


FIG. 7


200'
25'
210'
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