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

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
05 March 2020 (05.03.2020)

WIPO | PCT

(10) International Publication Number
WO 2020/044034 A1

(51) International Patent Classification:
E21B 17/20 (2006.01) *E21B 43/16* (2006.01)

(21) International Application Number:
PCT/GB2019/052398

(22) International Filing Date:
28 August 2019 (28.08.2019)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
1814060.8 29 August 2018 (29.08.2018) GB

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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, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JO, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, 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, SA, 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, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, 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, KM, ML, MR, NE, SN, TD, TG).

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

(54) **Title:** COILED TUBING SYSTEM

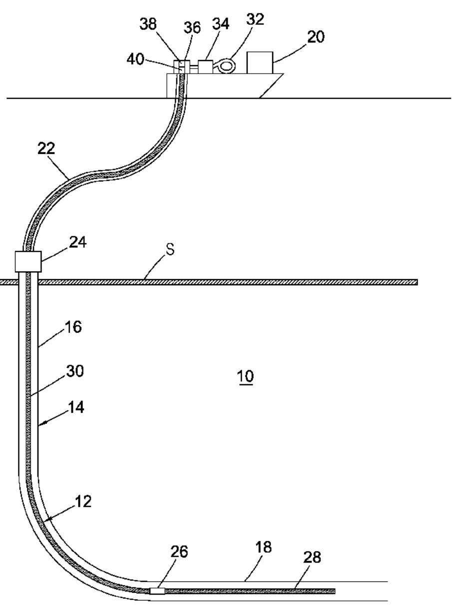

Fig. 1

(57) **Abstract:** A coiled tubing system (10) comprises a tubing string (12) including a first tubing portion (28) and a second tubing portion (30), a flow line (42) and a lateral flow passage (44) for directing fluid from the flow line to an exterior of the tubing string (12).

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COILED TUBING SYSTEM

FIELD

This relates to a coiled tubing system for deployment into a conduit, in particular but not exclusively, a coiled tubing system for deployment into a fluid conduit for transporting hydrocarbons such as an extended reach horizontal wellbore.

BACKGROUND

In the oil & gas exploration and production industry, in order to access hydrocarbons from a formation, a well borehole (“wellbore”) is drilled from surface. The wellbore is then lined with sections of bore-lining metal tubulars, known as casing, and production infrastructure installed to facilitate the ingress of hydrocarbons into the wellbore and transport them to surface.

The development of directional drilling techniques has facilitated the creation of high angle and horizontal wellbores (referred to below collectively as horizontal wellbores) which deviate from vertical and thus permit the wellbore to follow the hydrocarbon bearing formation to a greater extent. Amongst other things, horizontal wellbores beneficially facilitate increased production rates due to the greater length of the wellbore which is exposed to the reservoir.

In view of the benefits of horizontal wellbores, e.g. in increasing production rates, there is a continuing desire to extend the length or “reach” of horizontal wellbores. However, the operation of extended reach horizontal wellbores nevertheless poses a number of significant challenges.

For example, in order to perform an intervention or workover operation in a horizontal wellbore, the intervention tools and equipment must be capable of being advanced along the horizontal portion of the wellbore, which may define a tortuous path over several kilometres.

In the case of mechanical intervention tool systems, the ability to transmit push and/or pull forces to the intervention tool may be severely limited in the horizontal portion of the wellbore, for example due to frictional losses between the intervention tool system and the low side of the wellbore and/or the capstan effect at the heel of the wellbore (that is, the transition from the vertical to the horizontal sections of the wellbore).

Coiled tubing intervention systems – which employ a long continuous length of metal piping wound on a spool - provide the advantage over mechanical intervention tools in that coiled tubing facilitates the transportation of fluid downhole, for example as a cleaning or jetting fluid in a wellbore cleaning operation, as a power fluid to operate fluid-powered downhole tools, or as a treatment fluid, e.g. fracturing fluid, chemical wash operations, or the like. Coiled tubing systems are also particularly, but not exclusively, suited to offshore operations where it is necessary to direct intervention equipment through a flexible marine riser.

However, while coiled tubing intervention systems are used effectively in numerous applications, there are drawbacks with conventional coiled tubing systems. For example, friction between the coiled tubing and the wellbore caused by the weight of the coiled tubing lying against the low side of the wellbore, axial tension or compression forces in the coiled tubing when it transitions around curves in the wellbore and/or axial compressive force in the coiled tubing causing it to helically buckle, typically limit the extent to which coiled tubing can be pushed along the wellbore. Moreover, as coiled tubing systems are deployed from a reel they are not suitable for rotation, which may traditionally be used to reduce frictional effects during deployment.

These and other factors therefore typically limit the extent to which coiled tubing can be utilised in longer extended reach wellbores.

SUMMARY

According to a first aspect, there is provided a coiled tubing system for deployment into a conduit, comprising:

a tubing string comprising a first tubing portion and a second tubing portion configured for coupling to a proximal end of the first tubing portion;

a flow line configured for location in the second tubing portion; and

a lateral flow passage configured for fluid communication with the flow line, the lateral flow passage configured to direct fluid from the flow line to an exterior of the tubing string.

In use, the coiled tubing system may be run into the conduit while a fluid is directed through the flow line and the lateral flow passage to the exterior of the coiled tubing system and into an annulus between the coiled tubing system and the conduit. The fluid may then be returned (“circulated”) to surface. The fluid may have a specific gravity less than conventional fluids used in gas lift operations. For example, the fluid may comprise nitrogen gas and/or diesel. This has the beneficial effect of reducing the hydrostatic fluid pressure in the fluid column in the conduit. The fluid may be returned to surface via the annulus between the coiled tubing system and the conduit. A second fluid, for example but not exclusively comprising brine or the like, may be directed through the tubing string for example through an axial flow passage of the tubing string. The second fluid may be directed through the first tubing portion and at least part of the second tubing portion of the tubing string. The coiled tubing system may be configured to direct the second fluid to an exterior of the tubing string at a downhole location relative to lateral flow passage, for example at a distal end of the first tubing portion. The second fluid may then be returned to surface. The second fluid may have a specific gravity higher than conventional fluids. For example, the second fluid may have a specific gravity of 1.2 as compared to 0.85 of a conventional fluid. Conventional teaching provides that the use of “heavy” fluids having a higher specific gravity poses a significant risk of inadvertent overbalancing of a well, which in extreme cases may “kill” the well. Beneficially, however, the provision of a coiled tubing system comprising a flow line and a lateral flow passage for directing fluid from the flow line to the exterior of the tubing string around the second tubing portion facilitates the use of such heavy fluids due to the reduced hydrostatic pressure in the fluid column in the annulus around the second tubing portion. This is turn facilitates the deployment of the coiled tubing system to a distance (or “reach”) not previously attainable using conventional coiled tubing systems.

The coiled tubing system may be run into the conduit in order to perform, or as part of an intervention operation, in the conduit.

The fluid may be directed through the flow line and the lateral flow passage and/or the second fluid may be directed through the tubing string during the intervention operation.

As described above, the tubing string comprises a first tubing portion and a second tubing portion configured for coupling to a proximal end of the first tubing portion.

The first tubing portion may comprise composite coiled tubing.

The second tubing portion may comprise metallic coiled tubing.

Beneficially, the provision of a coiled tubing system having a “hybrid” tubing string comprising composite coiled tubing and metallic coiled tubing facilitates the deployment of the coiled tubing system to a distance (or “reach”) not previously attainable using conventional coiled tubing systems. The composite coiled tubing has a lower coefficient of static friction than conventional metallic coiled tubing, e.g. 0.15 compared to 0.25, such that for the same input force the reach of the tubing string can be extended.

As described above, the tubing string includes a first tubing portion and a second tubing portion.

The first tubing portion may define a distal portion of the tubing string. Thus, on locating the system in the conduit, the first tubing portion may define a downhole or downstream portion of the tubing string.

The second tubing portion may define a proximal portion of the tubing string. Thus, on locating the system in the conduit, the second tubing portion may define an uphole or upstream portion of the tubing string.

It will be understood that the term proximal means closer to surface and that the term distal means further from surface.

In instances where the conduit comprises a horizontal wellbore, the system may be configured for deployment into the wellbore, with the first tubing portion disposed in the horizontal section of the wellbore and the second tubing portion disposed in the vertical section of the wellbore. The second tubing portion may also be disposed partially in the horizontal section of the wellbore. For example, the system may be deployed into the wellbore until the second tubing portion is disposed around the heel of the wellbore and into the horizontal section of the wellbore.

As described above, the tubing string is configured for deployment into the conduit.

The first tubing portion may be configured for storage on and deployment from a reel. By constructing the first tubing portion from coiled tubing, the first tubing portion may be configured to be stored on and deployed from the reel.

The second tubing portion may be configured for storage on and deployment from a reel. By constructing the second tubing portion from coiled tubing, the second tubing portion may be configured to be stored on and deployed from the reel.

In use, the first tubing portion may be deployed into the conduit by unreeling the first tubing portion from the reel. In instances where the conduit comprises a horizontal wellbore, for example, the system may be configured to deploy the first tubing portion into the horizontal section of the wellbore. The first tubing portion may comprise a single run of composite coiled tubing. Alternatively, where required the first tubing portion may comprise a plurality of runs of composite coiled tubing coupled together. The first tubing portion may thus be deployed into the conduit to an initial deployment location, at which the distal end of the tubing string is disposed in the conduit and the proximal end of the first tubing portion is at surface. The second tubing portion may then be coupled to the proximal portion of the first tubing portion, the second tubing portion then being unreeled from the reel.

As an alternative, the first and second tubing portions may be coupled together at surface and deployed into the conduit together.

The first tubing portion may take a number of different forms.

The first tubing portion may comprise a base pipe.

The base pipe may be constructed or formed from a polymeric material.

The polymeric material may be a thermoplastic material.

The thermoplastic material may be at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); polycarbonate (PC) or the like.

In particular embodiments, the base pipe is constructed or formed from polyetheretherketone (PEEK).

The composite coiled tubing may comprise a composite laminate disposed around the base pipe.

The composite laminate may comprise a matrix.

The matrix may comprise a polymeric material.

The matrix may, for example, comprise a thermoplastic material.

The matrix may comprise at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); polycarbonate (PC) or the like.

The composite laminate may comprise a plurality of reinforcing elements disposed within the matrix.

The reinforcing elements may be embedded in the matrix.

The reinforcing elements may comprise fibres, strands, filaments, nanotubes or the like.

For example, the reinforcing elements may comprise glass fibres, carbon fibres or the like.

In particular embodiments, the reinforcing elements comprise carbon fibres.

The first tubing portion may have a diameter of between 25 mm (1inch) and 83 mm (3.25 inches).

The second tubing portion may take a number of different forms.

The second tubing portion may be constructed or formed from steel.

The second tubing portion may have a diameter of between 25 mm (1inch) and 83 mm (3.25 inches).

The system may comprise a connector arrangement for connecting the first tubing portion and the second tubing portion.

The connector arrangement may comprise a body.

The connector arrangement may comprise an axial flow passage.

The axial flow passage of the connector arrangement may be formed or disposed in the body.

The axial flow passage of the connector arrangement may provide fluid communication between the first tubing portion and the second tubing portion.

The axial flow passage of the connector arrangement may provide fluid communication between an axial flow passage of the first tubing portion and an axial flow passage of the second tubing portion.

In use, a fluid, e.g. brine, may be directed through the second tubing portion, the axial flow passage of the connector arrangement communicating the second fluid into the first tubing portion. The axial flow passage of the connector may thus define a bypass channel for the second fluid.

The lateral flow passage may be formed or disposed in the connector arrangement.

The lateral flow passage may be formed or disposed in the body of the connector arrangement.

The connector may comprise a first coupling arrangement for coupling to the first tubing portion.

The first coupling arrangement may comprise a stepped and tapered outer surface portion formed or disposed on the body of the connector arrangement.

The first coupling arrangement may comprise one or more gripping members.

The gripping members may be disposed on the stepped and tapered outer surface portion.

The gripping members may comprise slips.

In use, the gripping members may engage and grip an inner surface of the first tubing portion to couple the connector arrangement to the first tubing portion.

The first coupling arrangement may comprise a stepped outer surface portion of the body of the connector arrangement.

The first coupling arrangement may comprise a sleeve.

The sleeve may be disposed on the stepped outer surface portion of the body of the connector arrangement.

The sleeve may be coupled to the stepped outer surface portion of the body of the connector arrangement.

The sleeve may be coupled to the stepped outer surface portion of the body of the connector arrangement via a thread connection or other suitable means.

A distal end portion of the sleeve may be disposed on a collar disposed around an end portion of the first tubing portion.

The collar may be disposed on the first tubing portion by an interference fit, although it will be recognised that other suitable coupling means may be utilised.

On initial assembly, the sleeve may be threaded onto the body in which position the gripping members may define a radially retracted position in which the gripping members are offset from the first tubing portion. In order to couple the body to the first tubing portion, the body may be rotated which, by virtue of the thread connection, may results in axial movement of the sleeve towards the gripping members. This may apply an axial force to the gripping members. As the gripping members move along the stepped and tapered outer surface portion, the taper angle of the stepped and tapered outer surface portion may drive the gripping members radially outwards into engagement with the first tubing portion.

A spacer may be provided to prevent reverse movement of the sleeve. The spacer may for example comprise a split ring locatable on the body.

The first tubing portion may comprise an outer housing. The outer housing may be formed from high density polyethylene (HDPE). A ferrule may be disposed around the outer housing and may comprise gripping members, e.g. in the form of teeth for gripping the outer housing.

The connector may comprise a second coupling arrangement for coupling to the second tubing portion.

The second coupling arrangement may comprise a recessed outer surface portion of the body of the connector arrangement for receiving a distal end portion of the second tubing portion.

The second tubing portion and the body may be coupled together via a push fit, although it will be recognised that the body 46 and the second tubing portion 30 may be coupled together by other suitable means.

As described above, the flow line is configured for location in the second tubing portion of the tubing string.

In particular, but not exclusively, the flow line comprises a separate component to the second tubing portion. The flow line and the second tubing portion may be configured to be run into the conduit simultaneously. Alternatively, the flow line may be run into the second tubing portion separately.

The flow line and the second tubing portion may be directly coupled.

Alternatively, the flow line and the second tubing portion may be indirectly coupled, for example via a connector.

As an alternative to the flow line and second tubing portion comprising separate components, the flow line may be integrally formed with the second tubing portion.

The flow line will have a smaller outer diameter than the inner diameter of an axial flow passage of the second tubing portion.

The flow line may comprise or take the form of capillary tubing, or the like.

The flow line may comprise or take the form of coiled tubing.

The flow line may be configured for storage on and deployment from a reel. The flow line may be configured to be stored on and deployed from the reel.

The system may comprise a tubing anchor for coupling the flow line to the second tubing portion.

The tubing anchor may comprise a body configured to receive the flow line.

The tubing anchor may comprise gripping members for gripping the flow line.

The gripping members may comprise teeth or the like formed or disposed on the body of the tubing anchor.

As described above, the system comprises a lateral flow passage configured for fluid communication with the flow line, the lateral flow passage configured to direct fluid from the flow line to an exterior of the tubing string.

The lateral flow passage may be interposed between the first tubing portion and the second tubing portion.

The lateral flow passage may comprise or take the form of an exhaust channel.

As described above, the lateral flow passage may be formed or disposed in the connector arrangement.

Alternatively, the lateral flow passage may be formed or disposed in a gas lift mandrel.

The system may comprise a valve arrangement.

The valve arrangement may be interposed between the flow line and the lateral flow passage.

The valve arrangement may be configured to prevent or at least mitigate fluid communication from the lateral flow passage to the flow line.

The valve arrangement may comprise a non-return valve.

The valve arrangement may comprise a check valve.

The tubing system may comprise a tubing injector. The tubing injector may be configured to apply a push force on the tubing string which urges the tubing string along the conduit.

The tubing system may comprise a pressure control arrangement. The pressure control arrangement may be interposed between the injector and the tubing string.

The tubing string may be disposed through the pressure control arrangement, the pressure control arrangement configured to prevent loss of containment.

As described above, the coiled tubing system facilitates the deployment of coiled tubing systems to total depth in a conduit.

The conduit may take a number of different forms.

The conduit may comprise a wellbore.

In particular embodiments, the conduit comprises an extended reach horizontal wellbore.

Alternatively or additionally, the conduit may comprise one or more of: a pipeline, e.g. a hydrocarbon production or transportation pipeline; a riser, e.g. a marine riser; and an umbilical.

A second aspect relates to a method for deploying a tubing string into a conduit using the coiled tubing system of the first aspect.

The method may comprise running the first tubing portion into the conduit.

Running the first tubing portion into the conduit may comprise unreeling the first tubing portion from a reel.

The first tubing portion may be run into the conduit using the injector.

The method may comprise coupling the second tubing portion to the proximal end of the first tubing portion.

The method may comprise running the second tubing portion into the conduit.

Running the second tubing portion into the conduit may comprise unreeling the second tubing portion from a reel.

The second tubing portion may be run into the conduit using the injector.

The method may comprise flowing fluid through the tubing string.

The method may comprise applying a fluid pressure via the tubing string.

The method may comprise pumping fluid from a fluid source through the tubing string.

The fluid may comprise a gas.

In particular, but not exclusively, the fluid may comprise nitrogen gas.

The fluid may comprise a liquid.

In particular, but not exclusively, the fluid may comprise a hydrocarbon liquid, such as diesel.

In use, the coiled tubing system may be run into the conduit while a fluid is directed through the flow line and the lateral flow passage to the exterior of the coiled tubing system and into an annulus between the coiled tubing system and the conduit. The fluid may then be returned (“circulated”) to surface. The fluid may have a specific gravity less than production fluid. For example, the fluid may comprise nitrogen gas and/or diesel. This has the beneficial effect of reducing the hydrostatic fluid pressure in the conduit. The fluid may be returned to surface via the annulus between the coiled tubing system and the conduit. A second fluid, for example but not exclusively comprising brine or the like, may be directed through an axial flow passage of the tubing string. The second fluid may be directed through the first tubing portion and at least part of the second tubing portion. The second fluid may then be directed to an exterior of the coiled tubing system at a downhole location relative to lateral flow passage, for example at a distal end of the first tubing portion. The second fluid may be returned to surface. The second fluid may have a specific gravity higher than conventional fluids. For example, the second fluid may have a specific gravity of 1.2 as compared to 0.85 of a conventional fluid. Conventional teaching provides that the use of “heavy” fluids risks overbalancing a well. Beneficially, however, the provision of a coiled tubing system comprising a flow line and a lateral flow passage for directing fluid from the flow line to the exterior of the tubing string around the second tubing portion facilitates the use of such heavy fluids due to the reduced hydrostatic pressure in the fluid column in the annulus. This is turn facilitates the deployment of the coiled tubing system to a distance (or “reach”) not previously attainable using conventional coiled tubing systems.

It will be understood that the features defined above or described below may be utilised in isolation or in combination with any other defined feature.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other aspects will now be described, by way of example, with reference to the accompanying drawings, of which:

Figure 1 shows a schematic view of a coiled tubing system;

Figure 2 shows a perspective cut-away view of the part of the coiled tubing system shown in Figure 1;

Figure 3 shows a longitudinal sectional view of part of the coiled tubing system shown in Figure 1;

Figures 4 and 5 show enlarged views of the connector of the coiled tubing system shown in Figure 1;

Figure 6 shows an enlarged view of part of the coiled tubing system shown in Figure 1, showing the flow line and lateral flow passage; and

Figure 7 illustrates operation of the coiled tubing system shown in Figure 1.

DETAILED DESCRIPTION OF THE DRAWINGS

Referring first to Figure 1 of the accompanying drawings, there is shown a coiled tubing system, generally depicted at 10, for use in deploying a tubing string 12 into a conduit 14.

In the illustrated system 10, the conduit 14 takes the form of an extended reach horizontal wellbore having a vertical section 16 and a horizontal section 18, the conduit 14 being accessible from intervention vessel 20 via a marine riser 22 coupled to wellhead 24 disposed at the seabed S.

As shown in Figure 1, the tubing string 12 comprises vertical and horizontal portions coupled together via a connector 26, as will be described further below.

The system 10 includes the tubing string 12, the tubing string 12 including a first tubing portion 28 and a second tubing portion 30.

In the illustrated system 10, the first tubing portion 28 takes the form of composite coiled tubing and the second tubing portion 30 takes the form of metallic coiled tubing.

The first tubing portion 28 has a base pipe constructed or formed from polyetheretherketone (PEEK) and has a composite laminate disposed around the base pipe, the composite laminate constructed or formed from a plurality of carbon fibre reinforcing elements disposed within a matrix constructed or formed from polyetheretherketone (PEEK) while the second tubing portion 30 is constructed or formed from steel.

Beneficially, the provision of a coiled tubing system 10 having a “hybrid” tubing string 12 comprising composite coiled tubing and metallic coiled tubing facilitates the deployment of coiled tubing systems to a distance not previously attainable using conventional coiled tubing systems.

In use, and as will be described further below, the system 10 is configured to deploy the tubing string 12 into the conduit 14. The tubing string 12 is deployed from a reel 32 using an injector apparatus 34. Before passing into the riser 22, the tubing string 12 passes through a pressure control arrangement 36 which, in the illustrated system 10 comprises a stripper 38 and a blowout preventer 40.

Referring now also to Figures 2, 3, 4 and 5 of the accompanying drawings, in addition to the connector 26, first tubing portion 28 and the second tubing portion 30, the system 10 comprises a flow line 42 configured for location in the second tubing portion 30 and a lateral flow passage 44 configured for fluid communication with the flow line 42, the lateral flow passage 44 configured to direct fluid from the flow line 42 to an exterior of the tubing string for return to surface via annulus A, as will be described further below.

The connector 26 is interposed between the first tubing portion 28 and the second tubing portion 30 and comprises a body 46 having an axial flow passage 48 in the form of an axial throughbore. In use, fluid, e.g. brine, may be directed through the second tubing portion 30, the axial flow passage 48 of the connector 26 communicating the fluid into the first tubing portion 28. In the illustrated system 10, the lateral flow passage 44 is also formed in the connector 26 and takes the form of an exhaust channel.

As shown in Figures 2 and 3, it can be seen that the connector 26 comprises a first coupling arrangement, generally depicted at 50, for coupling to the first tubing portion 28 and a second coupling arrangement, generally depicted at 52, for coupling to the second tubing portion 30.

Reference is now made in particular to Figures 4 and 5 of the accompanying drawings, which show enlarged views of the coupling arrangement 50. Figure 4 shows the connector 26 prior to engagement with the first tubing portion 28. Figure 5 shows the connector 26 engaged with the first tubing portion 28.

As shown in Figures 4 and 5, the body 46 has a stepped and tapered outer surface portion 54 for receiving slips 56 (two slips 56 are shown in Figures 4 and 5). In use, the slips 56 engage and grip an inner surface of the first tubing portion 28 to couple the connector 26 to the first tubing portion 28. Seal elements 58, which in the illustrated system 10 take the form of elastomeric T-seals, are provided on the body 46 and prevent fluid leakage between the body 46 and the first tubing portion 28.

As shown in Figures 4 and 5, the body 46 also has a stepped outer surface portion 60 for receiving a sleeve 62, the outer surface portion 60 and the sleeve 62 coupled together via thread connection 64. A seal element 66, which in the illustrated system 10 takes the form of an elastomeric T-seal, is provided on the body 46 to prevent fluid leakage between the body 46 and the sleeve 60. A distal end portion of the sleeve 62 is disposed on a collar 68 disposed around an end portion of the first tubing portion 28. The collar 68 is disposed on the first tubing portion 28 by an interference fit, although it will be recognised that other suitable coupling means may be utilised. Seal elements 70, which in the illustrated system 10 take the form of elastomeric o-ring seals, are provided on the collar 68 to prevent fluid leakage between the collar 68 and the sleeve 62.

On initial assembly, the sleeve 62 is threaded onto the body 46 as shown in Figure 4, in which position the slips 56 define a radially retracted position in which the slips 56 are offset from the first tubing portion 28. In order to couple the body 46 to the first tubing portion 28, the body 46 is rotated which, by virtue of the thread connection 64, results in axial movement of the sleeve 62 towards the slips 56. This applies an axial force to the slips 56. As the slips 56 move along the stepped and tapered outer surface portion 54, the taper angle of the stepped and tapered outer surface portion 54 drives the slips 56 radially outwards into engagement with the first tubing portion 28 (as shown in Figure 5). As shown in Figure 5, a spacer 72 – which in the illustrated system 10 takes the form of a split ring - is then located on the body 46 to prevent reverse movement of the sleeve 62.

As shown in Figures 4 and 5, in the illustrated system 10 the first tubing portion 28 comprises an outer housing 74 constructed from high density polyethylene (HDPE). A ferrule 76 is disposed around the outer housing 74 and comprises gripping members 78 in the form of teeth for gripping the outer housing 74.

Referring again to Figure 3 of the accompanying drawings, it can be seen that the body 46 comprises a recessed outer surface portion 78 for receiving a distal end portion of the second tubing portion 30. In the illustrated system 10, the second tubing portion 30 and the body 46 are coupled together via a push fit, although it will be recognised that the body 46 and the second tubing portion 30 may be coupled together by other suitable means. Seal elements 80, which in the illustrated system 10 take the form of elastomeric seals, are provided between the body 46 and the second tubing portion 30 to prevent fluid leakage therebetween.

Referring now also to Figure 6 of the accompanying drawings, there is shown an enlarged view of part of the coiled tubing system 10 shown in Figure 2, showing the flow line 42 and lateral flow passage 44.

As shown in Figure 6, the flow line 42 is configured for location in the second tubing portion 30 of the tubing string 12. In the illustrated system 10, the flow line 42 takes the form of a capillary tube.

A tubing anchor 82 is provided to couple the flow 42 to the body 46 and thus the second tubing portion 30. The tubing anchor 82 comprises a body 84 and gripping members 86 in the form of teeth for gripping the flow line 42 (see Figure 3). In use, the flow line 42 and the second tubing portion 30 are configured to be run into the conduit 14 simultaneously, the flow line 42 configured for storage on and deployment from a reel (not shown).

As shown in Figure 6, a valve arrangement 88 is disposed between the flow line 42 and the lateral flow passage 44, the valve arrangement 88 configured to prevent or at least mitigate reverse fluid communication from the lateral flow passage 44 to the flow line 42. In the illustrated system 10, the valve arrangement 88 is disposed in the connector 26 and takes the form of a non-return check valve having a valve body 90 and a valve member 92 in the form of a ball.

As shown in Figure 6, the lateral flow passage 44 is formed in the body 46 of the connector 26 and is interposed between the first tubing portion 28 and the second tubing portion 30. In use, the lateral flow passage 44 communicates fluid, e.g. nitrogen gas and/or diesel from the flow line 42 to an exterior of the tubing string 12 at the interface region between the first tubing portion 28 and the second tubing portion 30, the fluid then returning to surface via the annulus A.

Operation of the system 10 will now be described with reference in particular to Figure 7 of the accompanying drawings.

In use, the first tubing portion 28 is deployed into the conduit 14 by unreeling the first tubing portion 28 from a reel (not shown). In the illustrated system 10, the first tubing portion 28 is deployed into the horizontal section 18. The first tubing portion 28 may comprise a single run of composite coiled tubing. Alternatively, where required the first tubing portion 28 may comprise a plurality of runs of composite coiled tubing coupled together. The first tubing portion 28 is thus deployed into the conduit 14 to an initial deployment location, at which the distal end of the first tubing portion 28 is disposed in the conduit 14 and the proximal end of the first tubing portion 28 is at surface. The connector 26 and the second tubing portion 30 are then coupled to the proximal portion of the first tubing portion 28, the second tubing portion 30 then being unreeled from reel 32 (shown in Figure 1) to further deploy the tubing string 12 into the conduit 14.

In use, the coiled tubing system 10 is run into the conduit 14 while a fluid (in particular but not exclusively nitrogen gas and/or diesel) is directed through the flow line 42 and the lateral flow passage 44 to the exterior of the coiled tubing system 10 and into the annulus A between the coiled tubing system 10 and the conduit 14. The fluid is then returned (“circulated”) to surface. This has the beneficial effect of reducing the hydrostatic fluid pressure in the fluid column in the conduit 14. A second fluid, for example but not exclusively comprising brine or the like, is directed through the tubing string 12, the second fluid directed through the first tubing portion 28 and at least part of the second tubing portion 30 of the tubing string 12. The coiled tubing system 10 is configured to direct the second fluid to an exterior of the tubing string 12 at a downhole location relative to lateral flow passage 44, for example at a distal end of the first tubing portion 28. The second fluid is then returned to surface. The second fluid has a specific gravity higher than conventional fluids.

In the illustrated system 10, for example, the second fluid comprises Sodium Chloride brine having a specific gravity of 1.19. Based on a coefficient of friction of 0.15, the system 10 would generate 42kg/1km of drag.

However, other fluids may be used where required. For example, a Calcium Chloride brine having a specific gravity of 1.35 would generate 21kg/1km of drag and a 15ppg Calcium Bromide brine having a specific gravity of 1.52 would generate less than 2kg/1km of drag.

Conventional teaching provides that the use of “heavy” fluids having a higher specific gravity poses a significant risk of inadvertent overbalancing of a well, which in extreme cases may “kill” the well. Beneficially, however, the provision of a coiled tubing system comprising a flow line and a lateral flow passage for directing fluid from the flow line to the exterior of the tubing string around the second tubing portion facilitates the use of such heavy fluids due to the reduced hydrostatic pressure in the fluid column in the annulus around the second tubing portion. This is turn facilitates the deployment of the coiled tubing system to a distance (or “reach”) not previously attainable using conventional coiled tubing systems.

It will be recognised that the system 10 described above is merely exemplary and that various modifications may be made without departing from the scope of the claimed invention as defined by the appended claims.

CLAIMS

1. A coiled tubing system for deployment into a conduit, comprising:

a tubing string comprising a first tubing portion and a second tubing portion configured for coupling to a proximal end of the first tubing portion;

a flow line configured for location in the second tubing portion; and

a lateral flow passage configured for fluid communication with the flow line, the lateral flow passage configured to direct fluid from the flow line to an exterior of the tubing string.

2. The system of claim 1, wherein the first tubing portion comprises composite coiled tubing and the second tubing portion comprises metallic coiled tubing.

3. The system of claim 1 or 2, wherein the first tubing portion comprises a base pipe.

4. The system of claim 3, wherein the base pipe is constructed or formed from a polymeric material.

5. The system of claim 4, wherein the polymeric material is a thermoplastic material.

6. The system of claim 5, wherein the thermoplastic material comprises at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); and polycarbonate (PC).

7. The system of any one of claims 3 to 6, wherein the composite coiled tubing comprises a composite laminate disposed around the base pipe.

8. The system of claim 7, wherein the composite laminate comprises a matrix and a plurality of reinforcing elements disposed within the matrix.

9. The system of claim 8, wherein the matrix comprises a polymeric material.

10. The system of claim 9, wherein the polymeric material is a thermoplastic material.

11. The system of claim 10, wherein the matrix comprises at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); and polycarbonate (PC).

12. The system of any one of claims 8 to 11, wherein the reinforcing elements comprise at least one of: fibres; strands; filaments; or nanotubes.

13. The system of claim 12, wherein the reinforcing elements comprise carbon fibres.

14. The system of any preceding claim, wherein the second tubing portion is constructed or formed from steel.

15. The system of any preceding claim, comprising a connector arrangement for connecting the first tubing portion and the second tubing portion.

16. The system of claim 15, wherein the connector arrangement comprises a body and an axial flow passage for providing fluid communication between the first tubing portion and the second tubing portion.

17. The system of claim 15 or 16, wherein the connector arrangement comprises a first coupling arrangement for coupling to the first tubing portion and a second coupling arrangement for coupling to the second tubing portion.

18. The system of claim 16 or 17, wherein the lateral flow passage is formed or disposed in the body of the connector arrangement.

19. The system of any preceding claim, wherein the lateral flow passage is formed or disposed in a gas lift mandrel.

20. The system of any preceding claim, wherein the lateral flow passage is interposed between the first tubing portion and the second tubing portion.

21. The system of any preceding claim, wherein the flow line comprises or takes the form of capillary tubing.

22. The system of any preceding claim, wherein the flow line is configured for storage on and deployment from a reel.

23. The system of any preceding claim, comprising a tubing anchor for coupling the flow line to the second tubing portion.

24. The system of any preceding claim, comprising a valve arrangement.

25. The system of claim 24, wherein the valve arrangement is interposed between the flow line and the lateral flow passage.

26. The system of claim 24 or 25, wherein the valve arrangement comprises a non-return valve.

27. The system of any preceding claim, comprising a tubing injector configured to apply a push force on the tubing string which urges the tubing string along the conduit.

28. A method for deploying a tubing string into a conduit using the coiled tubing system according to any preceding claim.

29. The method of claim 28, comprising running the first tubing portion into the conduit.

30. The method of claim 28 or 29, comprising at least one of:
coupling the second tubing portion to the proximal end of the first tubing portion;
running the second tubing portion into the conduit.

31. The method of claim 28, 29 or 30, comprising directing fluid through the flow line during deployment of the tubing string into the conduit.

32. The method of claim 31, wherein the fluid comprises nitrogen gas.

33. The method of claim 31 or 32, wherein the fluid comprises a hydrocarbon such as diesel.

34. The method of any one of claims 28 to 33, comprising directing fluid through the tubing string.

35. The method of claim 34, wherein the fluid comprises brine.

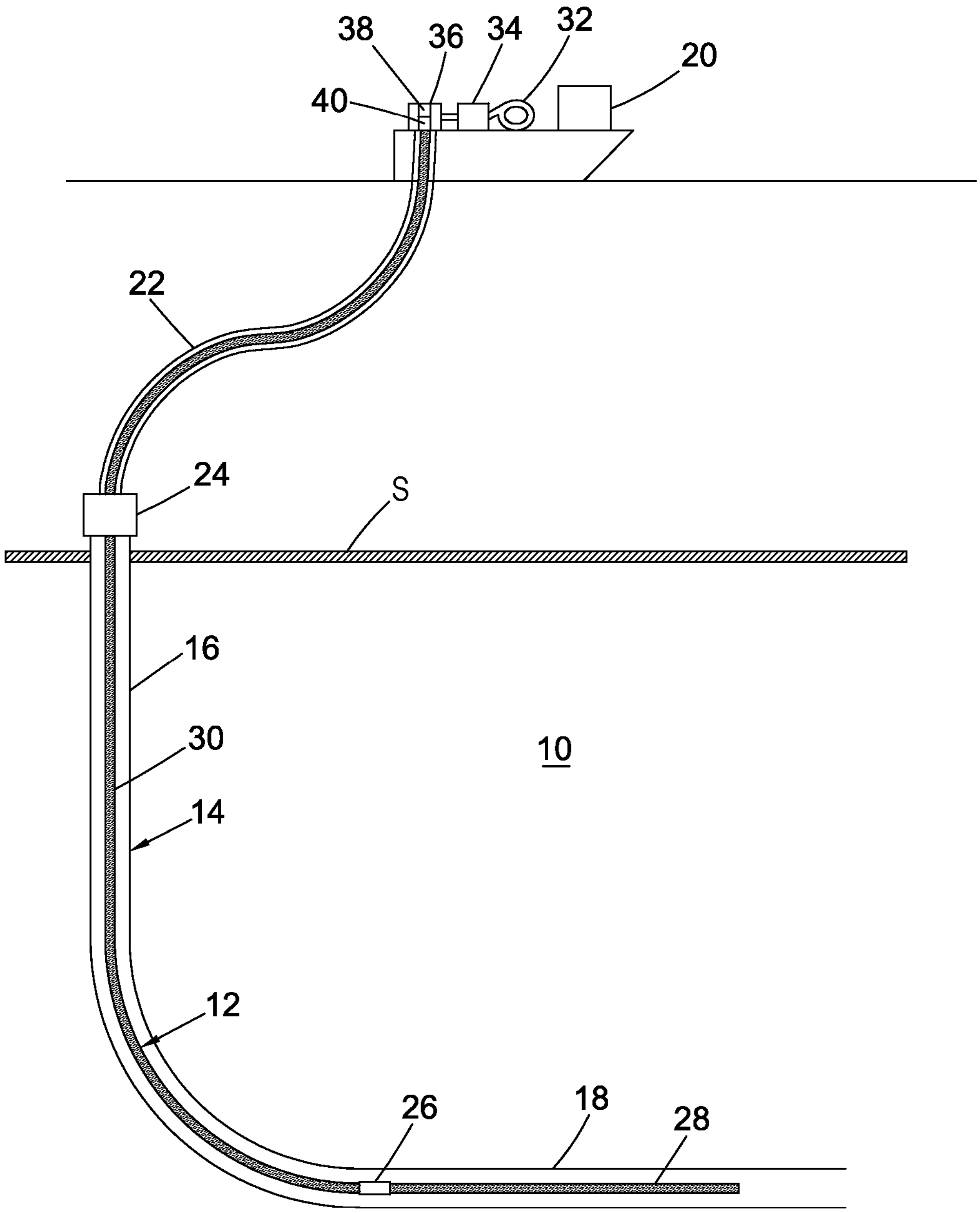


Fig. 1

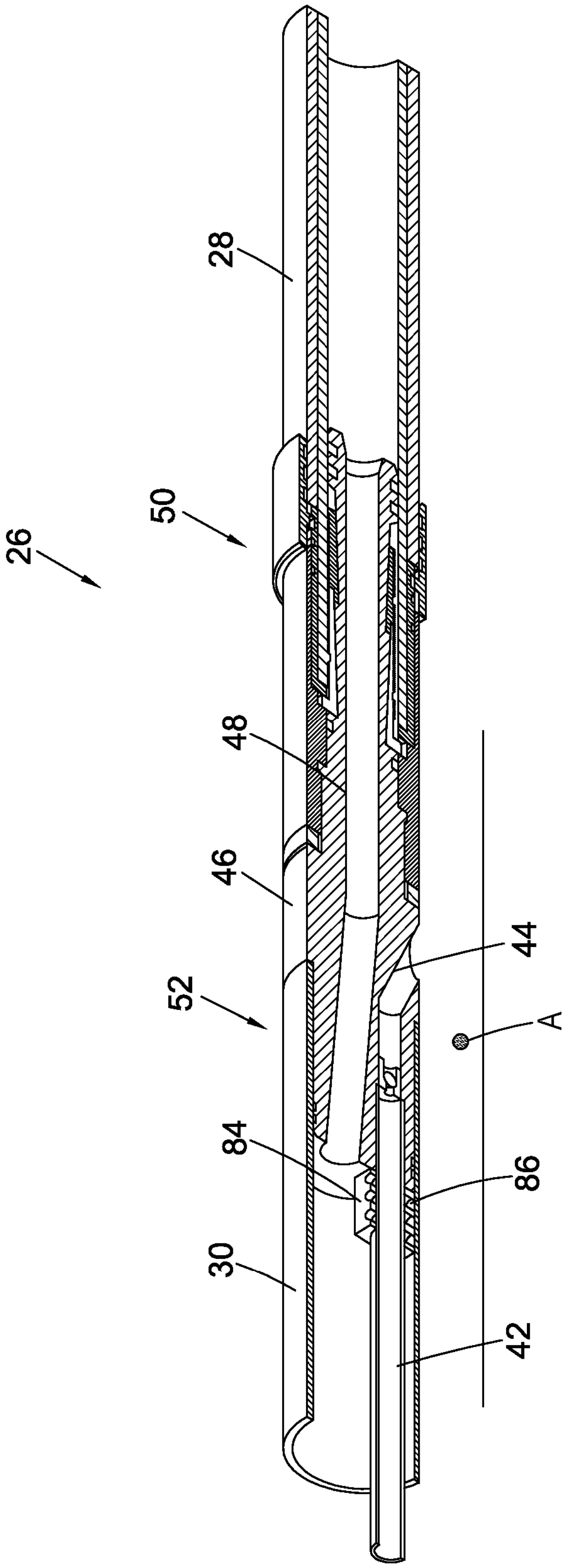
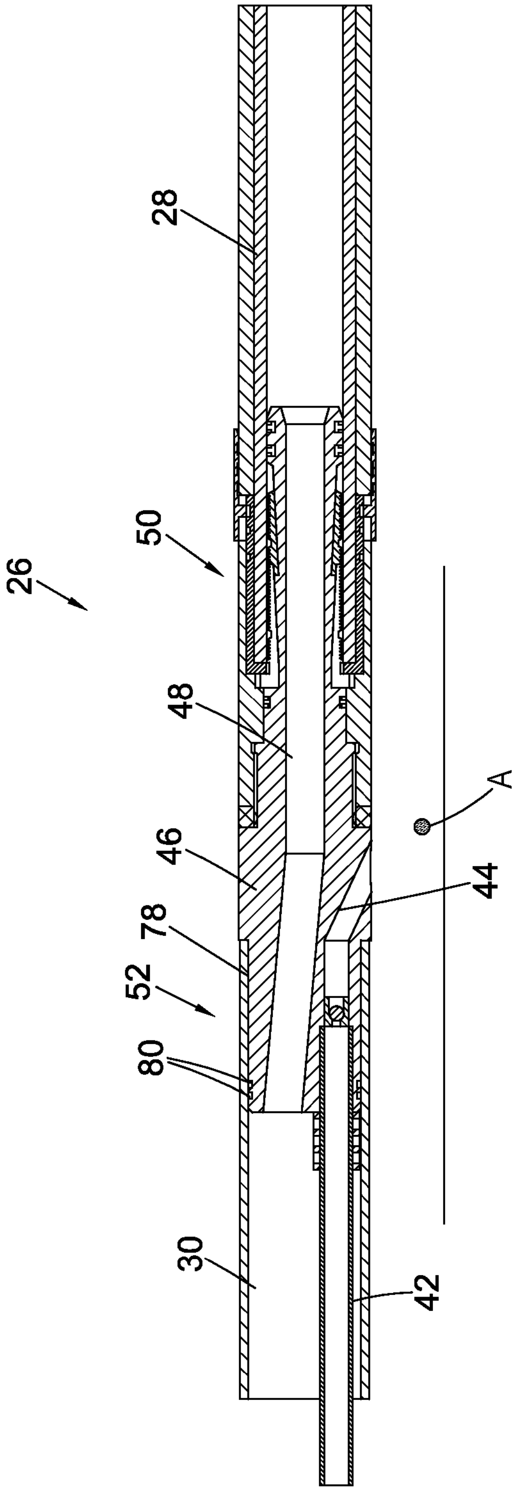


Fig. 2



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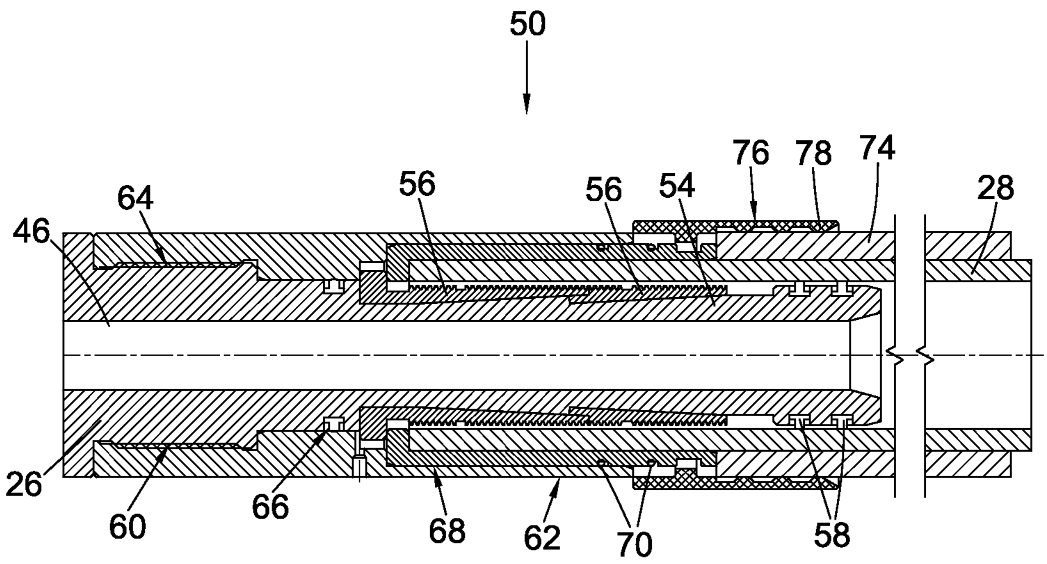
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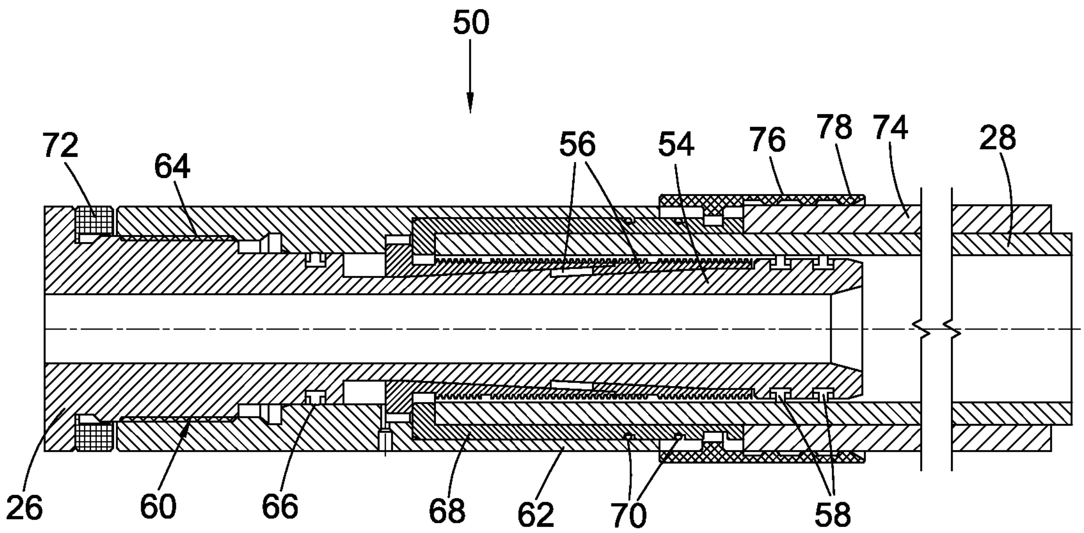
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Fig. 5

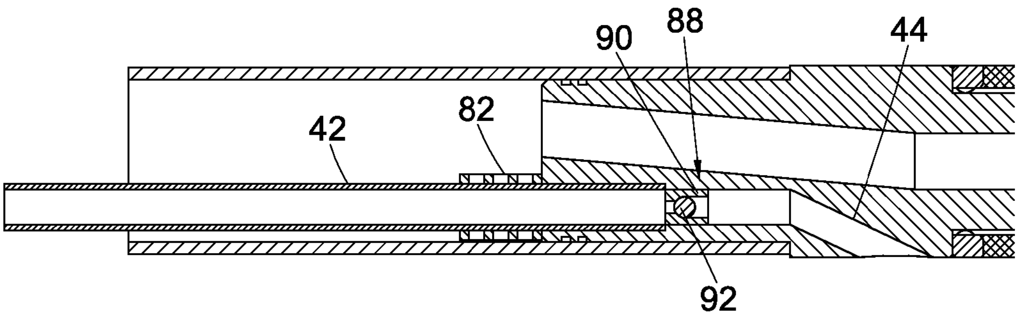
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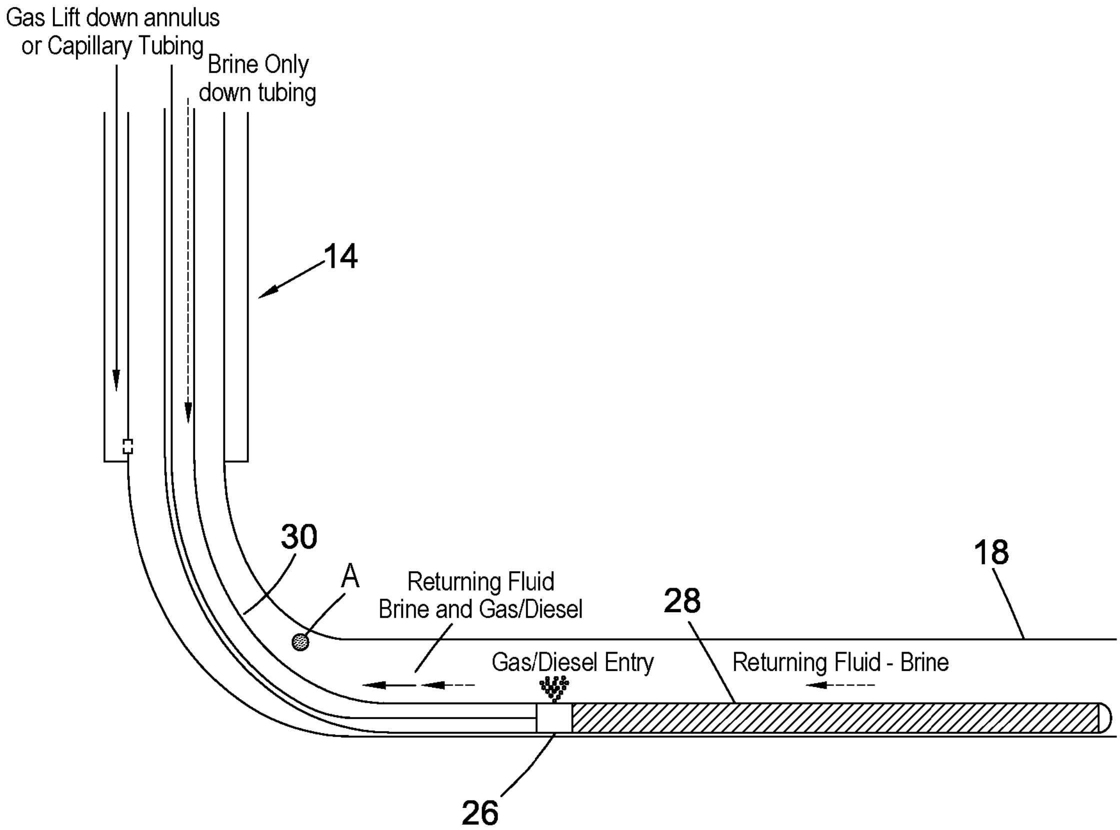
Fig. 6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or Capillary Tubing
Brine Only
down tubing
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30
A
Returning Fluid
Brine and Gas/Diesel
18
28
Gas/Diesel Entry
Returning Fluid - Brine
26

Fig. 7

INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2019/052398

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B17/20 E21B43/16
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GB 2 454 895 A (SCHLUMBERGER HOLDINGS [VG]) 27 May 2009 (2009-05-27) paragraphs [0001] - [0039] figures 1-8	1-35
A	US 2017/275979 A1 (CHALIFOUX GERALD V [CA]) 28 September 2017 (2017-09-28) paragraphs [0002] - [0070] figures 1-2	1-35
A	US 2004/112645 A1 (EPPINK JAY M [US] ET AL) 17 June 2004 (2004-06-17) paragraphs [0007] - [0133] figures 1-52	1-35

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents :

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
5 November 2019	14/11/2019

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Kecman, Ivan

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/GB2019/052398

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