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(71) Applicant: **MAERSK OLIE OG GAS A/S** [DK/DK];
Esplanaden 50, 1263 Copenhagen K (DK).

(72) Inventors: **DAVIDSEN, Soren Mylius**; Bukkeballevæg 6,
2960 Rungsted Kyst (DK). **HOWELL, John Michael**; c/o
Maersk Olie og Gas A/S, Esplanaden 50, 1263 Copenhagen K (DK).

(74) Agent: **DOCHERTY, Andrew**; Marks & Clerk LLP, 120
Bothwell Street, Glasgow G2 7JS (GB).

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(54) Title: ENHANCED RECOVERY METHOD AND APPARATUS

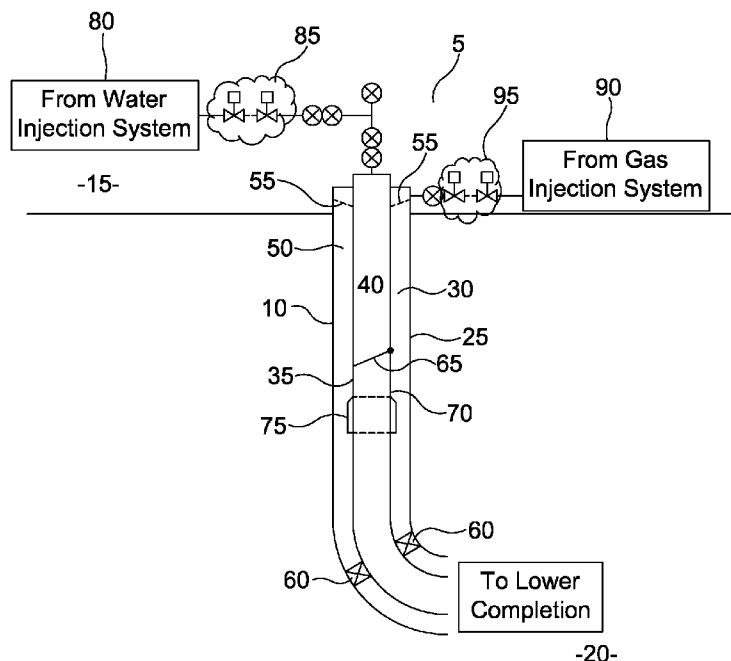


Figure 1

(57) Abstract: A water-alternating gas (WAG) apparatus and associated method of operation, the apparatus being located or locatable in a wellbore that extends from a surface to a subsurface location, the apparatus comprising at least one first channel configured to convey a liquid downhole from the surface; at least one second channel configured to convey a gas downhole from the surface; and wherein the apparatus comprises one or more downhole valve systems for switching the downhole apparatus between alternately providing the liquid at the downhole location and gas at the downhole location.



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ENHANCED RECOVERY METHOD AND APPARATUS

FIELD

- 5 The present invention relates to an apparatus and method for enhanced oil recovery, and specifically relates to a water-alternating gas recovery process and apparatus.

BACKGROUND

- 10 Various methods are available for improving oil recovery from reservoirs. One such method is the water-alternating-gas (WAG) technique. In the WAG technique, an injection well is drilled into a reservoir in proximity to one or more production wells. Water and gas are then sequentially injected into the injection well in an alternating manner in order to enhance oil recovery at the nearby production well(s). This
15 technique has been used in order to improve the sweep efficiency of the reservoir.

- Enhanced oil recovery using water alternating gas injection can increase both production rates and ultimate recovery from a field. However, traditional WAG techniques present challenges relating to health and safety, operations and
20 CAPEX/OPEX.

- Traditional WAG switch-overs give rise to a safety challenge in that it must be ensured that high pressure gas cannot enter the water injection system. For onshore WAG operations, this problem is overcome by having a 'WAG skid' where one injection
25 system is physically disconnected, for example, by removing pipe spools or by inserting blinds and having a double block and bleed system. For offshore operations, spools and extensive manual work are often used when executing a WAG cycle. These operations are time consuming, hazardous and expensive, but ensure that the water and gas injection systems are always physically separated. For future developments,
30 WAG operations could be considered in the design of surface equipment. For example, by providing a fail-safe switch over system that can be operated remotely on an unmanned platform. However, this will add significant expense and complexity to the design.

An additional issue with traditional WAG switchover techniques, is that pressures at surface are higher when switching from a gas cycle to a water cycle, than vice-versa. This is due to the weight of the hydrostatic column being less on the gas cycle. This means that the pressure at surface at the end of a gas cycle is higher than the supply pressure from conventional water injection systems. This problem is solved in traditional onshore and offshore WAG techniques by using a 'kill pump' to pump inhibited water into the well at high pressures, in order to create a column of water and lower the pressure at surface to a level where the regular water injection system can be used. This is a manual operation that requires rig up of equipment, several hours of pumping time and high pressure operations.

Hydrate formation at surface is a risk during traditional WAG switchovers due to the lower pressure and temperature present at surface, the mixing of hydrocarbon gas and water and temperature reductions due to the Joule-Thomson effect during surface equipment bleed downs.

SUMMARY

An aspect or embodiment relates a downhole water-alternating-gas (WAG) switchover apparatus located or locatable in a wellbore that extends from a surface to a subsurface location.

The apparatus may comprise:

- at least one first channel configured to convey a liquid downhole from the surface; and

- at least one second channel configured to convey a gas downhole from the surface.

The apparatus may comprise one or more downhole valve or switching systems. The one or more downhole valve or switching systems may be configured to switch the downhole apparatus between alternately providing the liquid downhole and the gas downhole. The one or more downhole valve or switching systems may be configured to selectively provide the liquid or the gas downhole from the respective first and second channels.

5 The apparatus may comprise an injection apparatus, which may be configured to alternately inject the liquid and/or gas downhole. The apparatus may comprise water-alternating-gas injection apparatus. The gas may be or comprise natural gas. The liquid may be or comprise water, e.g. the liquid may be or comprise an aqueous solution.

10 The one or more downhole valve systems may comprise one or more first valves or devices for regulating flow of the liquid to the downhole location and/or one or more second valves or devices for regulating flow of the gas to the downhole location.

15 The downhole apparatus may be switchable between at least first and second configurations, wherein, in the first configuration, the first valves or devices may be closed and the second valves or devices may be open such that gas may be injected or injectable to the downhole location via the at least one second channel and the at least one second valve or device and, in a second configuration, the first valves or devices may be open and the second valves or devices may be closed such that the liquid may be injected or injectable to the downhole location via the at least one first channel and the at least one first valves or devices.

20 It will be appreciated that at least some of the components for switchover between liquid and gas injection may be located downhole. For example, the one or more downhole valve or switching systems (e.g. the first and/or second valves or devices) may be located or locatable downhole, in use, e.g. in a subsurface location, such as in the wellbore.

25 The apparatus may comprise a tubular or other hollow conduit. The tubular or other conduit may define or comprise the first channel therewithin. The first channel may extend longitudinally within the tubular or other conduit.

30 The apparatus may comprise one or more hollow casings, such as tubular casings, at least one or each of which may define a passage. The tubular or other conduit may be located or comprised within the one or more casings, e.g. within the passage(s) of the one or more casings. The apparatus may comprise a plurality of casings. At least one of the casings may be provided within at least one of the other casings. The second channel may be at least partially defined between at least one of the casings and the at

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least one other casing or the tubular or other conduit. The second flow channel may extend longitudinally along and/or between the casing and/or tubular or other conduit.

5 The second channel may be comprised or located in or at least partially defined by one or more annuli, which may be provided or at least partially defined between the tubular or other conduit and an inner wall of one of the casings and/or between two casings. The one or more annuli may be provided radially outwardly of the tubular or other conduit.

10 The second channel may be closed at one end, e.g. a downhole end, for example using one or more packers or other sealing devices or means.

15 The first channel may comprise an inner or innermost channel. The second channel may be provided radially outwardly of the first channel. The second channel may comprise or be comprised or located in the first annulus out from the innermost channel. The second channel may comprise and/or be comprised in one or more side pocket mandrels (SPMs) and may include a hanger device for the innermost channel through which the second channel fluid may flow.

20 The at least one second valve or device may comprise a gas injection device such as a gas lift valve. The at least one second valve or device may be operable to control communication from the second channel to the first channel. The at least one second valve or device may be provided on or in the wall of the tubular or other conduit. The at least one second valve may be configured to selectively allow passage of gas from the
25 second channel to the first channel or downhole location. The at least one second valve or device may be switchable between a closed configuration in which flow of gas to the downhole location and/or first channel is blocked and an open and/or partially open configuration in which the gas may pass from the second channel to the downhole location and/or first channel via the at least one second valve or device.

30 The at least one second valve or device may be provided or providable downhole, downstream and/or lower than the at least one first valve or device.

35 The at least one first valve or device may comprise a sub-surface safety valve. The at least one first valve or device may be configured to selectively open and/or close the

first channel. The at least one first valve or device may be configured to be selectively switchable between an open configuration in which the liquid may pass through the at least one first valve to the downhole location and a closed configuration in which flow of liquid through the at least one first valve to the downhole location is blocked. The at least one first valve or device may be provided uphole or upstream of or higher than the at least one second valve.

The apparatus may be adapted to retain a head of liquid in the first channel uphole or upstream of the at least one first valve when the first valve is closed, e.g. during a gas injection operation, for example, when the second valve is open.

The apparatus may comprise or be connectable to a liquid injection system. The liquid injection system may be connected or connectable to the first channel, e.g. via a liquid control valve. The liquid injection system may be located or locatable on the surface. The at least one first channel may be configured to convey the liquid from the surface to the downhole location.

The apparatus may comprise or be connectable to a gas injection system. The gas injection system may be connected or connectable to the second channel, e.g. via a gas control valve. The gas injection system may be located or locatable on the surface. The at least one second channel may be configured to convey gas downhole from above surface or ground.

The apparatus may be switchable between configurations in which the gas and liquid are alternately injected. The apparatus may be switchable into a liquid injection configuration by opening the liquid control valve and/or the first valve and closing the gas control valve and/or the second valve. The apparatus may be switchable in to a gas injection configuration by opening the gas control valve and/or the second valve and closing the liquid control valve and/or the first valve

The apparatus may be configured to provide gas at flow rates of greater than 5 MMscf/d, preferably greater than 8 MMscf/d, for example greater than 10 MMscf/d. The apparatus may be configured to provide gas at flow rates of between 5 and 30 MMscf/d. The apparatus may be configured to provide gas at flow rates of greater than 12, e.g. greater than 15 MMscf/d

An aspect or embodiment relates to a method for performing a downhole WAG switchover operation in a wellbore that extends from a surface, the method comprising:

- 5 conveying a liquid downhole from the surface in a first channel; and
 conveying a gas downhole from the surface in a second channel.

The method may comprise operating one or more downhole valve systems so as to switch the downhole apparatus between alternately providing the liquid downhole and the gas downhole.

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The method may comprise operating the one or more downhole valve systems to selectively provide the liquid or the gas to a downhole location from the respective first and second channels.

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The method may be or comprise an injection method, e.g. a method for alternately injecting a gas downhole and a fluid downhole, such as a water-alternating-gas injection method. The gas may be or comprise natural gas. The liquid may be or comprise water, e.g. an aqueous solution.

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The method may comprise using an apparatus as described above in relation to the first aspect. The method may be for operating the apparatus of the first aspect to perform a downhole WAG switchover.

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The method may comprise performing a downhole gas injection to liquid injection switchover. The gas injection to liquid injection switchover may comprise using or closing a gas control valve and/or using or closing a second valve. The gas injection to liquid injection switchover may comprise using or opening a liquid control valve. The gas injection to liquid injection switchover may comprise using or opening a first valve, which may be performed after the liquid control valve has been opened or operated.

30

The gas injection to liquid injection switchover may comprise releasing a head of liquid retained upstream by the first valve, e.g. by using or opening the first valve.

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The method may comprise performing a downhole liquid injection to gas injection switchover. The liquid injection to gas injection switchover may comprise closing the liquid control valve and/or the first valve. The liquid injection to gas injection switchover

may comprise retaining a head of liquid upstream of the first valve. The liquid injection to gas injection switchover may comprise opening the gas control valve and/or the second valve. The liquid injection to gas injection switchover may comprise ramping up or gradually increasing pressure of gas, e.g. by gradually opening the gas control valve.

The method may comprise providing gas at flow rates of greater than 5 MMscf/d, preferably greater than 8 MMscf/d, for example greater than 10 MMscf/d, such as between 5 and 30 MMscf/d.

It should be understood that the features defined above in accordance with any aspect of the present invention or below in relation to any specific embodiment of the invention may be utilised, either alone or in combination with any other defined feature, in any other aspect or embodiment of the invention. Furthermore, the present invention is intended to cover apparatus configured to perform any feature described herein in relation to a method and/or a method of using or producing or manufacturing any apparatus feature described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

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

Figure 1 is a cross-sectional representation of a wellbore system;

Figure 2 is a flowchart illustrating a method of operating the wellbore system of Figure 1;

Figure 3 is a cross-sectional representation of the wellbore system of Figure 1 in use during a water injection cycle;

Figure 4 is a cross-sectional representation of the wellbore system of Figure 1 in use at the end of a water injection cycle;

Figure 5 is a cross-sectional representation of the wellbore system of Figure 1 in use during initiation of gas injection;

Figure 6 is a cross-sectional representation of the wellbore system of Figure 1 in use during gas injection;

Figure 7 is a cross-sectional representation of the wellbore system of Figure 1 in use wherein gas injection has been stopped, the gas injection system isolated and the water injection system is also still isolated;

5 Figure 8 is a cross-sectional representation of the wellbore system of Figure 1 in use during initiation of water injection;

Figure 9 is a cross-sectional representation of the wellbore system of Figure 1 in use with water injection resumed; and

Figure 10 is a schematic showing a comparison of the components of the wellbore system of Figure 1 against a conventional WAG wellbore system.

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DETAILED DESCRIPTION OF THE DRAWINGS

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Figure 1 shows a wellbore system 5 for use in a water-alternating-gas enhanced oil recovery procedure. The wellbore system 5 of Figure 1 is advantageously arranged such that switchover of the wellbore system 5 between a gas injection configuration and a water injection configuration is carried out downhole. It will be readily appreciated that use of downhole or downstream herein refers to subsurface positions in a wellbore 10 that are away or further away from the surface and the use of uphole or upstream herein refers to positions that are towards to further toward the surface.

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The wellbore system 5 extends within the wellbore 10 from the surface 15 to a subsurface completion location 20. The wellbore system 5 comprises a hollow metallic or composite casing 25 defining a longitudinally extending passage 30 therein. The wellbore system 5 also comprises a hollow conduit in the form of a tubular 35 at least part of which is located within the passage 30 of the casing 25. A longitudinally extending first flow path or passage 40 is defined within the tubular 35. An annular space is at least partially defined between the casing 25 and the tubular 35, the annular space forming or comprising a second flow path or passage 50.

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The tubular 35 is supported using a high injection rate tubing hanger 55. The hanger 55 is configured to pass high gas rates, e.g. 8MMscf/d or higher. As such, the hanger 55 is provided with holes having a sufficient area to make the hanger suitable for high injection rate use. Packers 60 or other sealing arrangements known in the art seal between the tubular 35 and the casing 25 in order to close off a downhole end of the second flow path 50, for example at between 2500 and 6500 ftTVDRT (true vertical

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depth rotary table), which is equivalent to approximately between 1000 mTVDRT and 2000 mTVDRT. However, it will be appreciated that other packer depths could be used.

5 The tubular 35 is provided with a subsurface valve system 65 at a downhole location for selectively opening and closing the first flow path 40 that runs within the tubular 35. A sub-surface safety valve (SSSV) can be conveniently used for this purpose. It will be appreciated that the subsurface valve system 65 is operable remotely, e.g. from the surface 15, in order to selectively open and close the subsurface valve system 65 and
10 thereby the first flow path 40, for example, using hydraulic, electrical, mechanical or other means that would be apparent to a skilled person.

Gas injection devices 75, such as a high rate gas lift valve(s) installed into side pocket mandrels (SPMs), are provided in the wall of the tubular 35 such that the gas injection
15 device 75 extends between the first and second flow paths 40, 50. In this way, pressurised gas supplied via the second flow path 50 in the annulus can be selectively and controllably injected into the first flow path 40 within the tubular 35 using the gas injection device 75. The gas injection device 75 is provided downhole of and/or lower than the subsurface valve system 65 (e.g. the SSSV). It will be appreciated that the
20 gas injection device 75 is remotely controllable and/or comprises one or more check valves to permit flow of gas from the second flow path 50 into the first flow path 40 of the tubular 35 downstream of the subsurface valve system 65 during gas injection but prevent fluid from the first flow path 40 of the tubular 35 from flowing into the annular space during the liquid injection cycle. For example, the gas injection device may be
25 controllable using hydraulic, electrical, mechanical, pressure or other means that would be apparent to a skilled person.

At the surface 15, a water injection system 80 is connected to the tubular 35 via a water control valve system 85 for selectively injecting water into the first flow path 40.
30 The water control valve system 85 is arranged to selectively isolate the water injection system 80 from the first flow path 40. A gas injection system 90 is connected to the annular space via a gas control valve system 95, for selectively injecting gas into the second flow path 50. The gas control valve system 95 is arranged to selectively isolate the gas injection system 90 from the second flow path 50.

In this way, in contrast to a traditional WAG arrangement in which the water injection system and the gas injection system are alternately connected to a single flow path at the surface, the water injection system 80 of the wellbore system 5 of Figure 1 is connected to the first flow path 40 at the surface whilst the gas injection system 90 is connected to a different (i.e. the second) flow path 50. Instead of performing switchover between water and gas injection at the surface (generally by physically disconnecting one injection system and physically connecting the required injection system), both water and gas are provided downhole using different flow paths 40, 50 and switching between water and gas injection is performed downhole by selectively controlling the gas injection device 75 and the subsurface valve system 65.

The process of performing downhole switchover of the water-alternating-gas injection process is detailed in Figure 2 and illustrated in Figures 3 to 9.

The process is initiated by performing water injection (step 205 of Figure 2) into the subsurface completion location with the gas injection system 90 isolated using the gas control valve system 95 and the gas injection device 75. In this case, as shown in Figure 3, the water control valve system 85 is opened so that water is injected into the first flow path 40 within the tubular 35 by the water injection system 80. The subsurface valve system 65 is also set to the open position such that the injected water passes through the subsurface valve system 65 to the lower completion position 20.

When it is desired to perform switchover of the wellbore system 5 from water injection to gas injection, the water injection system 80 is isolated using the water control valve system 85 and the subsurface valve system 65 (i.e. the SSSV) is closed in step 210 of Figure 2, and as shown in Figure 4. This has the effect of holding a column of water 100 within the first flow path 40 of the tubular 35 uphole of the subsurface valve system 65.

Thereafter, as shown in Figure 5, the gas control valve system 95 is operable to de-isolate the gas injection system 90 in order to slowly increase the pressure of gas being supplied from the gas injection system 90 into the second flow path 50 in step 215 of Figure 2. The gas injection device 75 is operable to inject the gas from the second flow path 50 into the first flow path 40 at a location downstream or downhole of the subsurface valve system 65. In this way, the water below the subsurface valve system

65 is gradually displaced by the gas and forced into the subsurface completion location 20 and thereby into neighbouring geological formations. The bottom hole pressure (BHP) is monitored to ensure that the formation is not fractured. Since the subsurface valve system 65 is closed, the column of water is retained within the tubular 35 upstream / uphole of the subsurface valve system 65 during the entire gas injection cycle.

Once the water has been displaced into the formation, the pressure of the gas is ramped up in step 220 of Figure 2 so that the gas can be injected at high pressure to perform the gas injection portion of the WAG process, as shown in Figure 6. The gas is generally injected at high pressure and could be, for example, in the range of 5 to 30 million standard cubic feet per day (MMscf/d), equivalent to between 5,900 and 35,400 $\text{Nm}^3 \cdot \text{hr}^{-1}$, preferably above 12 MMscf/d ($14,150 \text{ Nm}^3 \cdot \text{hr}^{-1}$) and even above 15 MMscf/d ($17,700 \text{ Nm}^3 \cdot \text{hr}^{-1}$). Thus the wellbore system may operate at significantly higher pressures than a conventional gas lift arrangement. Thus, the thickness of the tubing and/or casing may be greater than a conventional gas lift arrangement and/or a higher yield strength, e.g. stronger, material may be used for the materials of the tubing & casing.

After the gas injection cycle is complete, the gas injection via the gas injection device 75 is stopped and the gas injection system 90 is isolated using the gas control valve system 95 in step 225 of Figure 2, and as shown in Figure 7.

The water control valve system 85 is then opened in step 230 of Figure 2 such that water is supplied by the water injection system 80 to the first flow 40 path in the tubular 35 such that pressure is applied to the water column 100 in the tubular 35. Thereafter, the subsurface valve system 65 is opened as shown in Figure 8 and step 235 of Figure 2, and the water column 100 in the tubular 35 above the subsurface valve system 65 travels down towards the bottom of the well. The head of pressure of the water column 100 combined with the pressure applied by the water injection system 80 results in a pressure that is high enough to displace most of the gas downwards and into the lower completion location 20 and thereby into the formation. The well head pressure then decreases as the water column 100 applies a hydrostatic head to the well.

In this case, the hydrostatic head provided by the water column 100 above the subsurface valve system 65 should be sufficient to compensate for differences in pressure between the gas injection pressure and the water injection pressure. For

example, if the gas injection system 90 operates at a maximum pressure of 180barg, and the water injection system 80 operates at 120barg, a hydrostatic head of 60 bar (870 psi) is required. This is equivalent to a water column 100 of approximately 1930 ft (588m). Since the sub-surface safety valve (SSSV) is typically located at around 1900-
5 2000 ft TVDRT (580-610m total vertical depth rotary table or TVDRT), this makes the SSSV a convenient mechanism for use as the subsurface valve system 65 whilst providing sufficient hydrostatic head in the column to allow downhole switch over from gas to water.

10 The behaviour of the well can be field tested, for example, in order to ensure that the formation fracture pressure is not exceeded when the column of water is dropped by opening the subsurface valve system 65.

The water injection part of the WAG process can then be carried out, as shown in
15 Figure 9, after which the process can then return back to step 205 of Figure 2 if required in order to carry out additional alternations between water and gas injection as part of the WAG process.

By using downhole WAG switchover, the wellbore system 5 of the present invention
20 may require less components than some conventional WAG systems. For example, since any mixing of gas and water occurs downhole and at high temperature, hydrate formation may be less of an issue, such that systems designed to avoid hydrate formation such as Triethylene glycol (TEG) injection systems may not be required.

25 Furthermore, prior art systems often provide a "kill pump" in order to allow switching from gas cycle to water cycle. The kill pump is required because the hydrostatic pressure of the gas column is low, and results at pressures at surface which are higher than standard water injection systems. The kill pump is used to inject high pressure inhibited water or brine and build a water column which lowers the pressure at surface
30 to a level where the regular water injection system can be used. This operation is manual and requires rig up and several hours of pumping time. It also requires higher pressure operations at surface. The WAG system 5 of embodiments of the present invention retains the column of liquid 100 above the subsurface valve system 65 during the gas injection part of the WAG process. This column of liquid 100 can function as
35 the kill fluid, which allows the well to cycle from gas to liquid. This may also allow the

number of components to be further reduced, e.g. by dispensing with the kill pump. In addition, in the case of breakthrough from the injector well 10 to a producer well, embodiments of the present invention allow the injector to be quickly switched over from gas to water injection, leading to a reduced overall gas compression requirement and increased recovery due to a faster response.

Even in the event that the column of water 100 is lost due to opening of the subsurface valve system 65 during a gas injection operation, it is still possible to kill the well and allow switchover either by employing a kill pump or by closing the subsurface valve system 65, bleeding off gas in the tubular 35 and refilling the tubular 35 with water.

In addition, the simpler downhole switching of embodiments of the present invention may allow simpler optimisation of the WAG process and more frequent switchover, which may lead to improved recovery.

Furthermore, since embodiments of the present invention have less components and a simpler switching mechanism relative to some traditional WAG methods, the embodiments of the present invention may be particularly suitable for automation of the WAG process.

In addition, in many prior art systems, both high pressure gas injection and lower pressure water injection must be connected to the same well. This may result in safety issues in ensuring that high pressure gas cannot enter the low pressure water injection system. This can be addressed by physically disconnecting and connecting the relevant injection systems or by using spools. However, each of these approaches are time consuming, hazardous and expensive. In the downhole apparatus of embodiments of the present invention, the water injection and gas injection are not directly connected at surface level and can be isolated individually. In addition, the subsurface safety valve (SSSV), hydraulic master valve (HMV), water control valve (WCV) and the column of liquid 100 maintained above the subsurface valve system 65 may also act as additional barriers for segregating the two injection systems 80, 90. Therefore, embodiments of the present invention may provide a simpler and safer WAG switchover arrangement.

It should be understood that the embodiments described herein are merely exemplary and that various modifications may be made thereto without departing from the scope of the invention.

5 For example, although the space between the radially outward walls of the tubular and/or conduit and/or one or more further conduits is described in examples as a annular space, it will be appreciated that the space need not be annular, and that the invention is also effective with other, non-annular spaces.

10 In addition, although water is given as an example of a liquid and natural gas is given as an example of a gas, it will be appreciated that other fluids and/or liquids may be used.

15 Furthermore, although the second flow path is described as being comprised in or defined by an annular space between the tubular and a single casing, it will be appreciated that the downhole system may comprise a plurality of casings and that the second flow path may be comprised or defined between two casings, such as an outer two casings.

CLAIMS

1. A water-alternating gas (WAG) apparatus located or locatable in a wellbore that extends from a surface to a subsurface location, the apparatus comprising:
 - at least one first channel configured to convey a liquid downhole from the surface;
 - at least one second channel configured to convey a gas downhole from the surface;and
 - one or more downhole valve systems for switching the downhole apparatus between alternatingly providing the liquid downhole and the gas downhole.
2. The WAG apparatus of claim 1, wherein the one or more downhole valve systems are adapted to selectively provide the liquid or the gas downhole from the respective first and second channels.
3. The WAG apparatus of claim 1 or claim 2, wherein the one or more downhole valve systems comprise one or more first valves or devices for regulating flow of the liquid downhole and/or one or more second valves or devices for regulating flow of the gas downhole; wherein
 - the downhole apparatus is switchable between a first configuration in which the first valves or devices are closed and the second valves or devices are open such that gas is injected or injectable downhole via the at least one second channel and the at least one second valves or devices and a second configuration in which the first valves or devices are open and the second valves or devices are closed such that the liquid is injected or injectable downhole via the at least one first channel and the at least one first valves or devices.
4. The WAG apparatus according to any preceding claim, comprising:
 - a tubular or other hollow conduit defining or comprising the first channel therewithin;and
 - one or more hollow casings each defining a passage; wherein
 - the tubular or other conduit is located or comprised within the passage(s) of the one or more casings and the second channel is comprised in or at least partially defined by one or more annuli provided or at least partially defined between the tubular or other conduit and an inner wall of one of the casings and/or between two casings.

5. The WAG apparatus according to claim 3 or any claim dependent thereon, wherein the at least one second valve comprises a gas injection device for providing selective communication from the second channel to the first channel.

6. The WAG apparatus according to claim 3 or any claim dependent thereon, wherein the at least one second valve is provided or providable downhole, downstream and/or lower than the at least one first valve.

7. The WAG apparatus according to claim 3 or any claim dependent thereon, wherein the at least one first valve comprises a sub-surface safety valve configured to selectively open and/or close the first channel.

8. The WAG apparatus according to claim 3 or any claim dependent thereon, wherein the apparatus is adapted to retain a head of liquid in the first channel uphole or upstream of the at least one first valve when the first valve is closed during an injection operation.

9. The WAG apparatus according to any preceding claim, wherein:
the apparatus comprises or is connectable to a liquid injection system, the liquid injection system being connected or connectable to the first channel via a liquid control valve and/or

the apparatus comprises or is connectable to a gas injection system, the gas injection system being connected or connectable to the second channel via a gas control valve.

10. The WAG apparatus according to claim 9, wherein the apparatus is switchable between configurations in which the gas and liquid are alternately injected, wherein

the apparatus is switchable into a liquid injection configuration by opening the liquid control valve and/or the first valve and closing the gas control valve and/or the second valve; and/or

the apparatus is switchable into a gas injection configuration by opening the gas control valve and/or the second valve and closing the liquid control valve and/or the first valve.

11. The WAG apparatus according to any preceding claim, wherein the apparatus is configured to provide gas at flow rates between 5 and 30 MMscf/d (between $5,900 \text{ Nm}^3 \cdot \text{hr}^{-1}$ and $35,400 \text{ Nm}^3 \cdot \text{hr}^{-1}$).

12. A method for performing a water-alternating-gas injection operation in a wellbore that extends from a surface, the method comprising:

conveying a liquid downhole from the surface in a first channel;

conveying a gas downhole from the surface in a second channel; and

operating one or more downhole valve systems so as to switch the downhole apparatus between alternately providing the liquid downhole and the gas downhole.

13. The method of claim 12, comprising operating the one or more downhole valve systems to selectively provide the liquid or the gas to a downhole location from the respective first and second channels.

14. The method according to claim 12 or claim 13, comprising using an apparatus according to any of claims 1 to 11.

15. The method of any of claims 12 to 14, wherein the method comprises performing a downhole gas injection to liquid injection switchover.

16. The method of claim 15, wherein the gas injection to liquid injection switchover comprises:

closing a downhole gas control valve for controlling gas supplied by a gas injection system and/or using a second valve for regulating flow of the gas downhole; and

opening a downhole liquid valve for controlling liquid supplied by a liquid injection system and/or using a first valve for regulating flow of the liquid downhole.

17. The method of claim 16, wherein the method comprises retaining a head of liquid upstream by the first valve and the gas injection to liquid injection switchover comprises releasing the head of liquid by opening the first valve.

18. The method according to any of claims 12 to 17, wherein the method comprises performing a liquid injection to gas injection switchover.

19. The method according to claim 18, wherein the liquid injection to gas injection switchover comprises:

closing the liquid control valve and/or the first valve; and

opening the gas control valve and/or the second valve.

20. The method according to claim 19, wherein the liquid injection to gas injection switchover comprises ramping up or gradually increasing pressure of gas, e.g. by gradually opening the gas control valve.

21. The method according to any of claims 12 to 20, wherein the method comprises providing gas at flow rates between 8 and 30 MMscf/d.

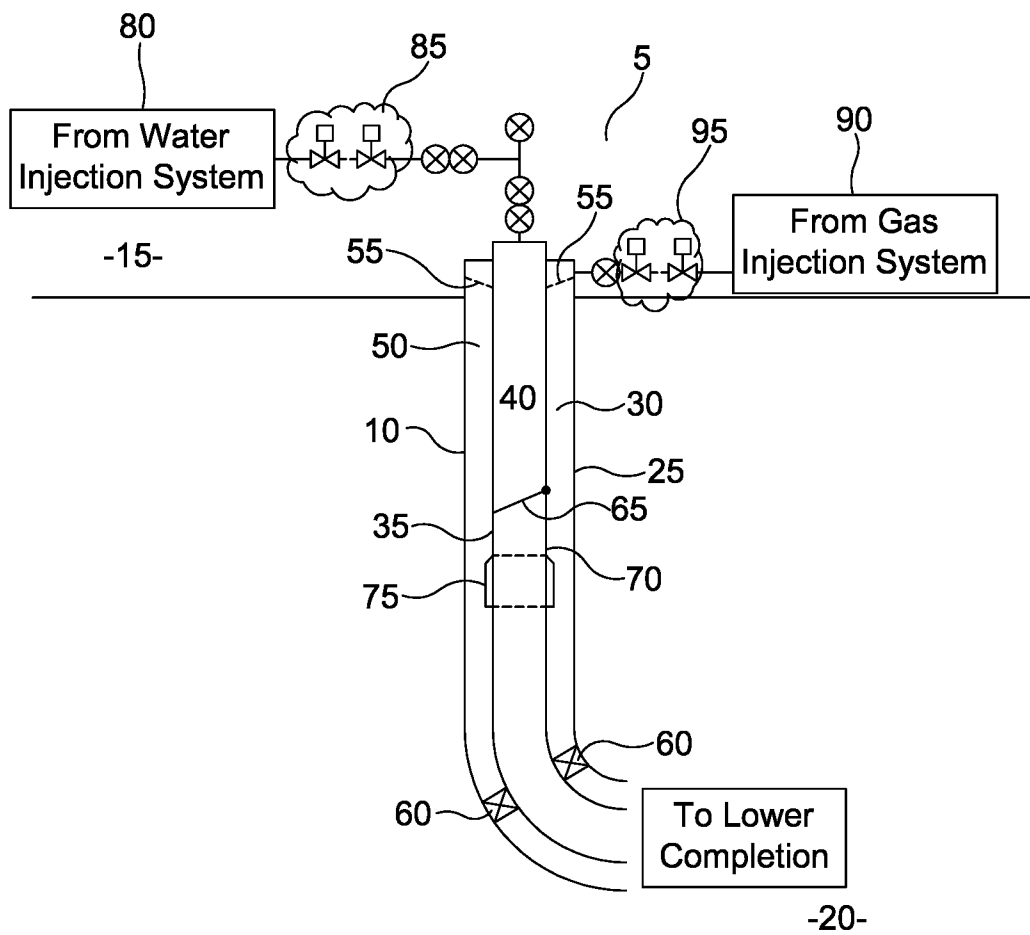


Figure 1

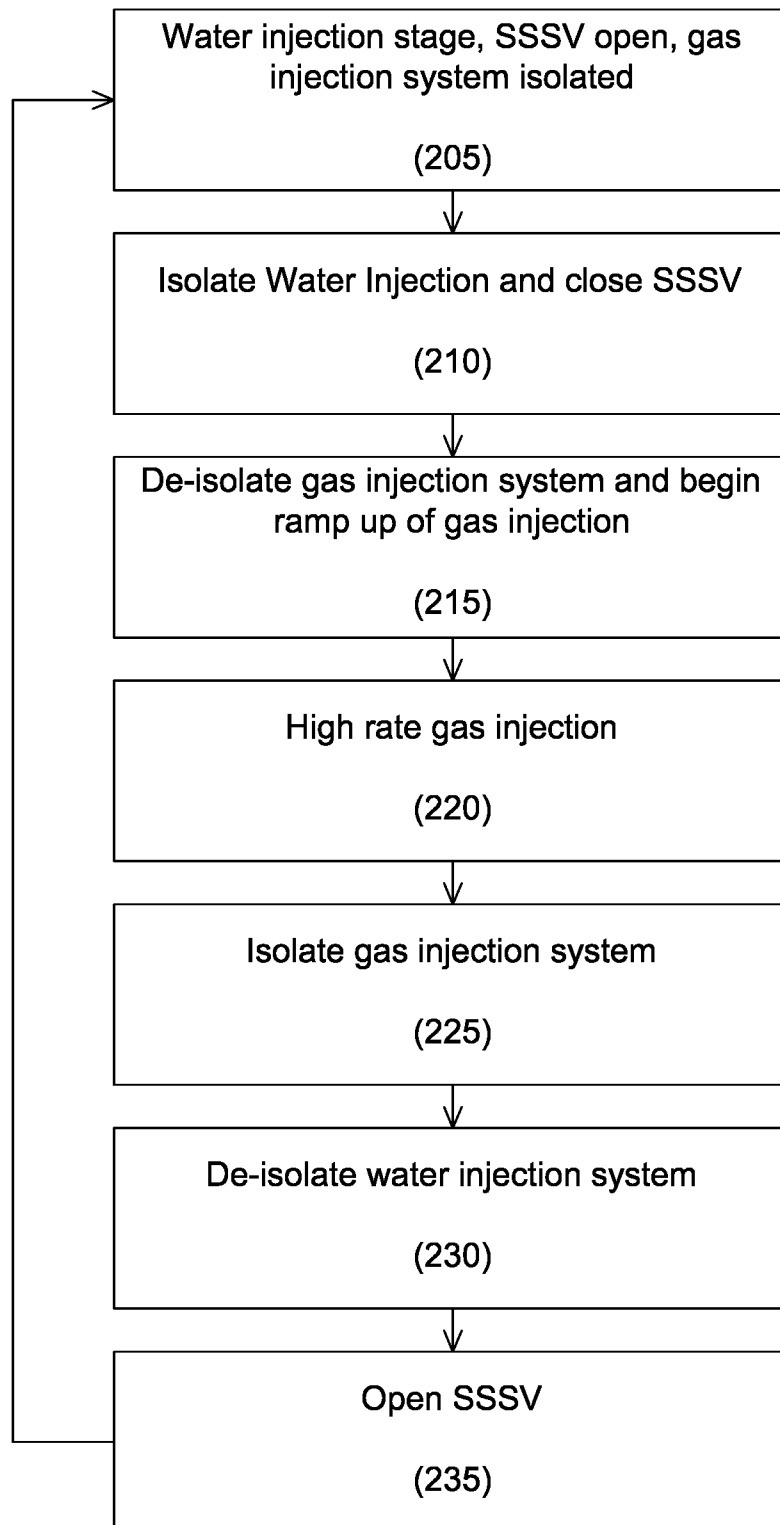


Figure 2

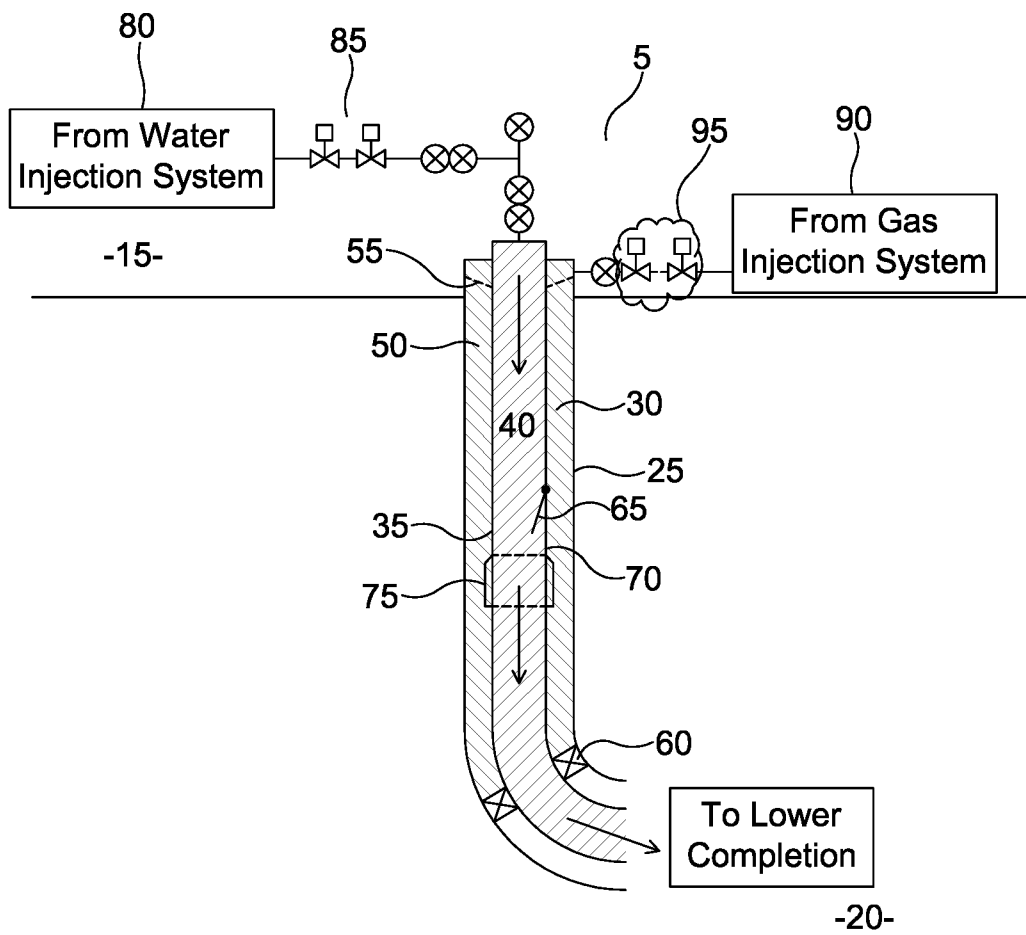


Figure 3

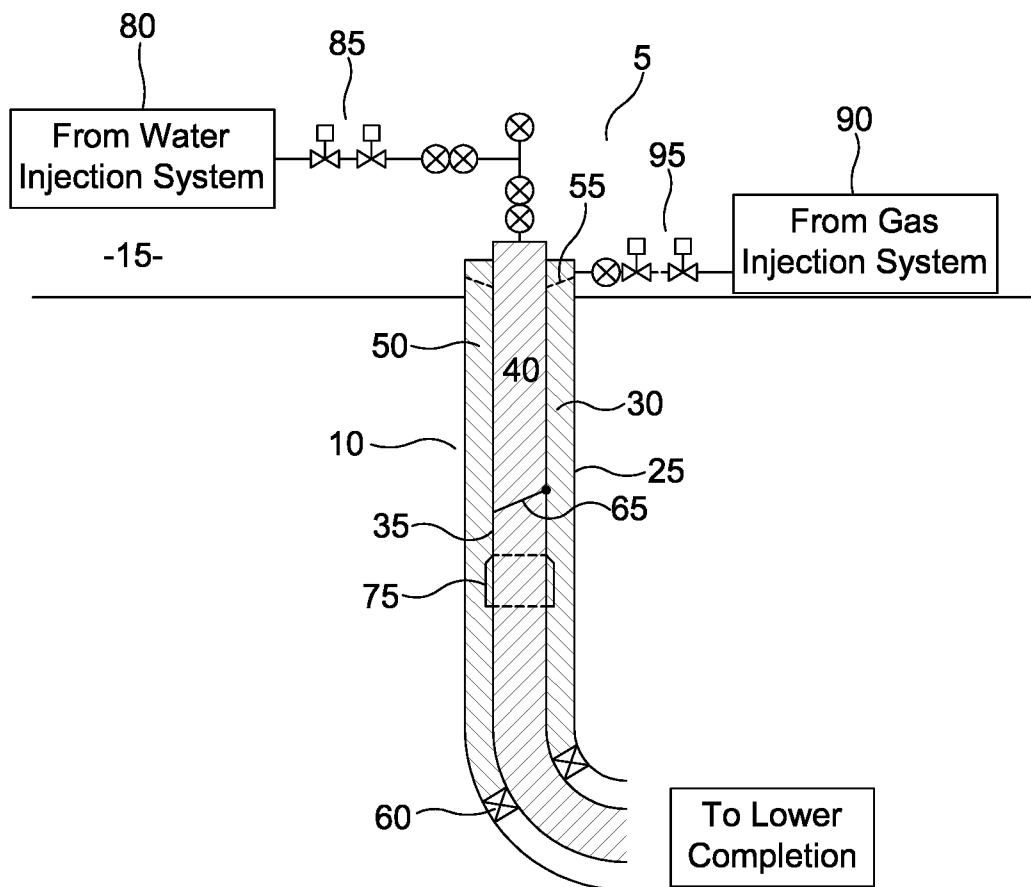


Figure 4

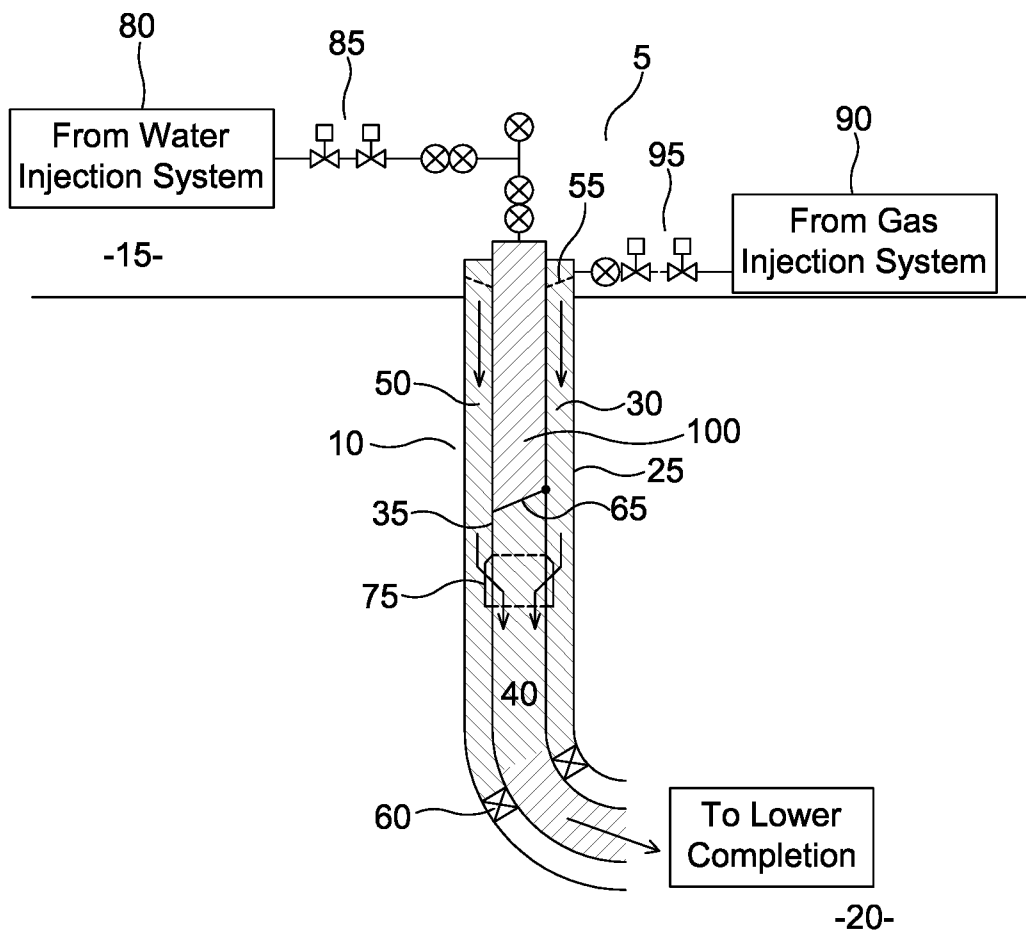


Figure 5

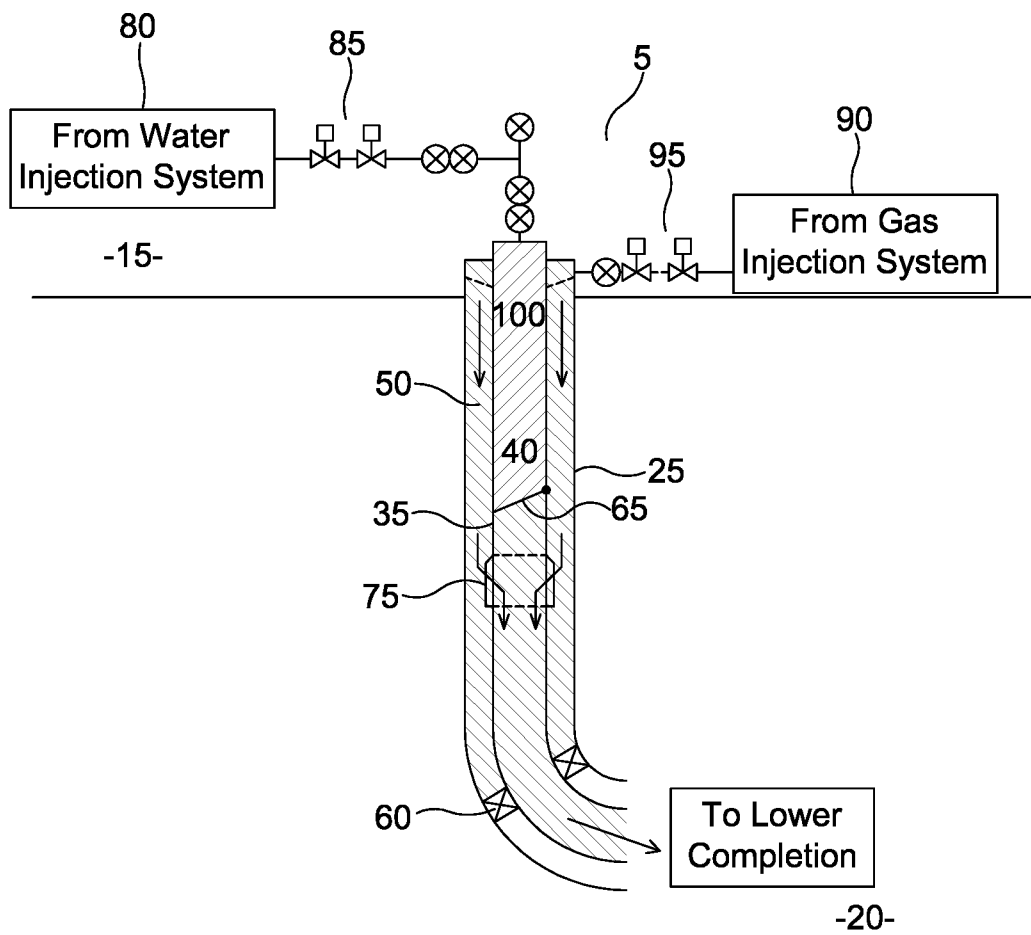


Figure 6

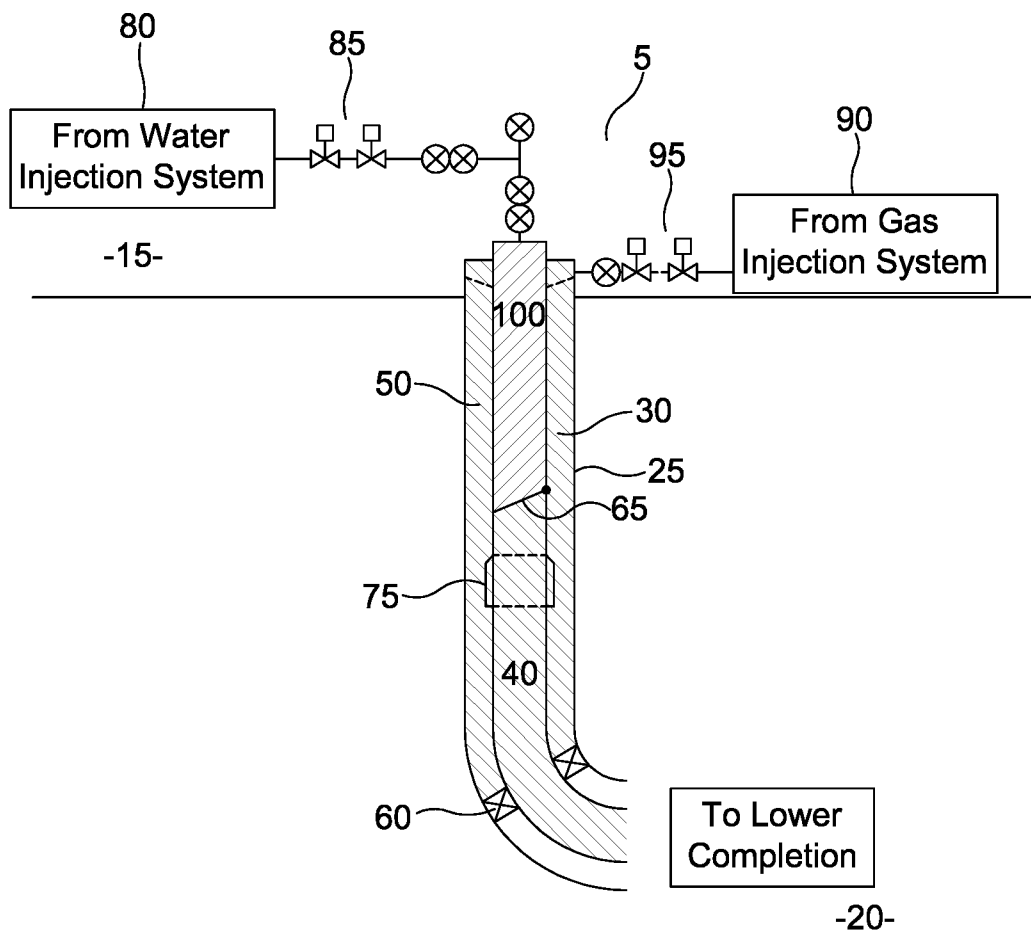


Figure 7

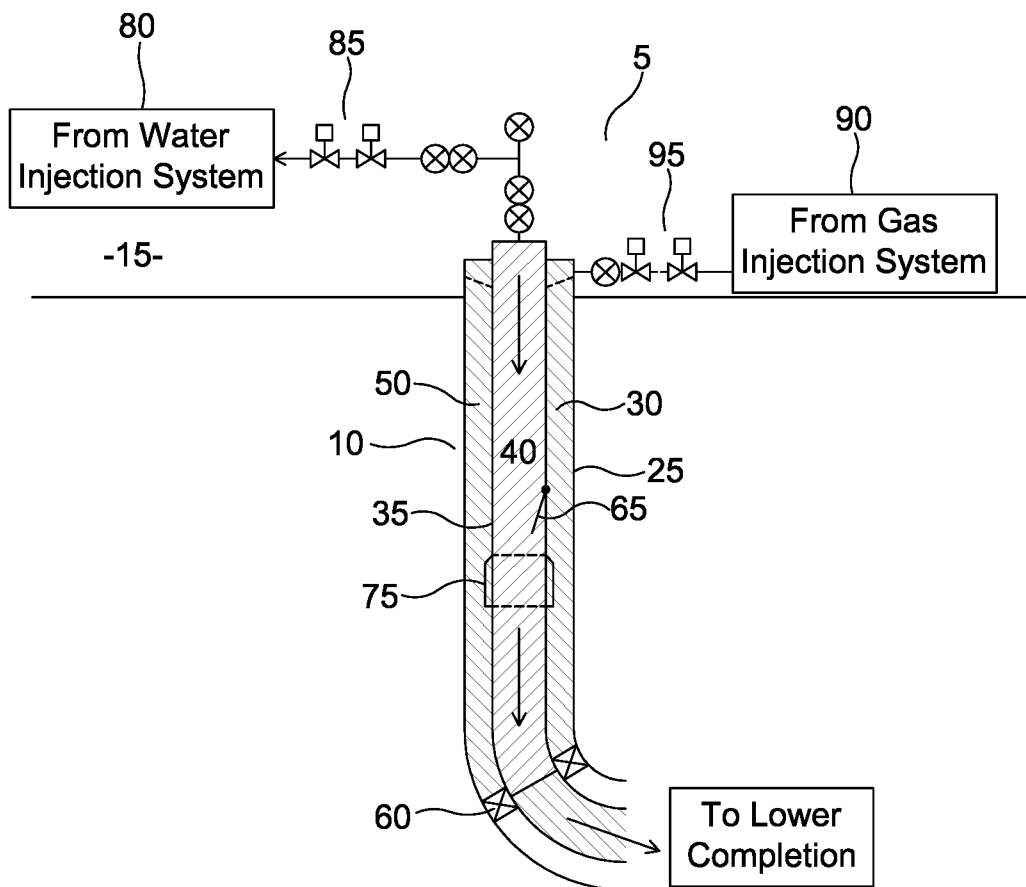


Figure 8

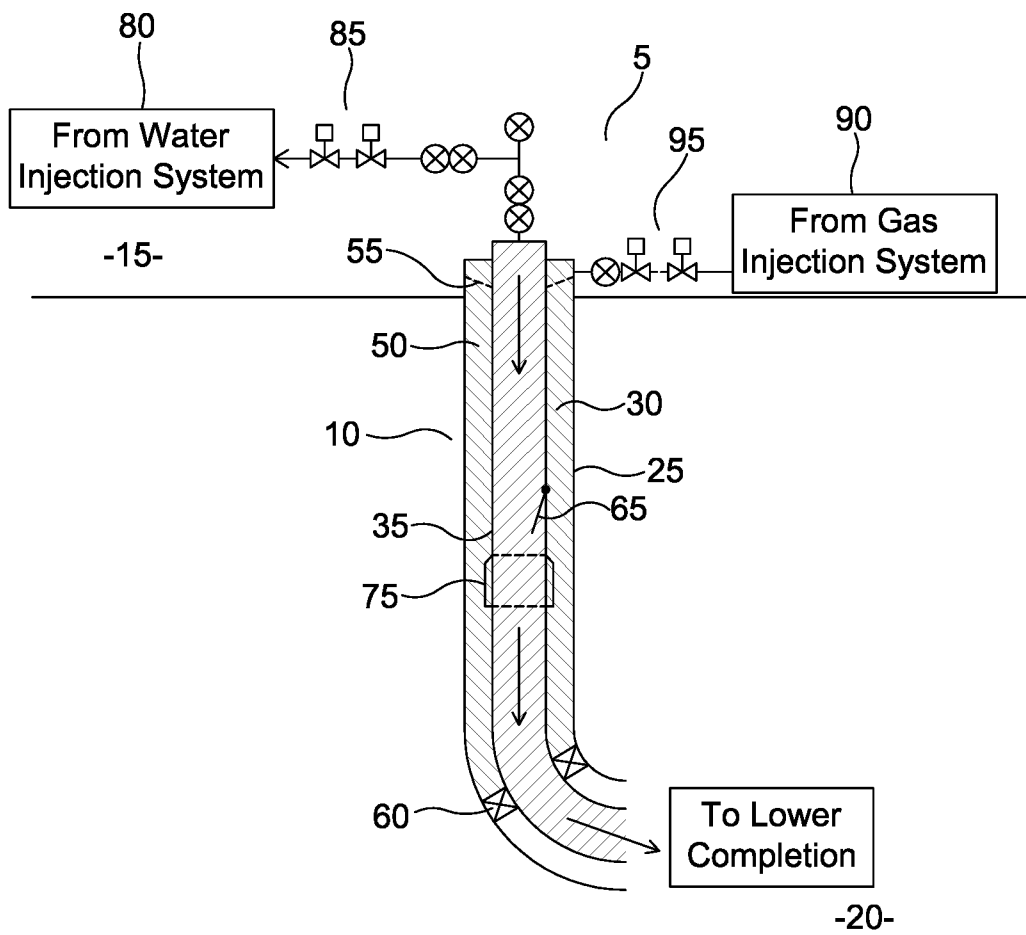


Figure 9

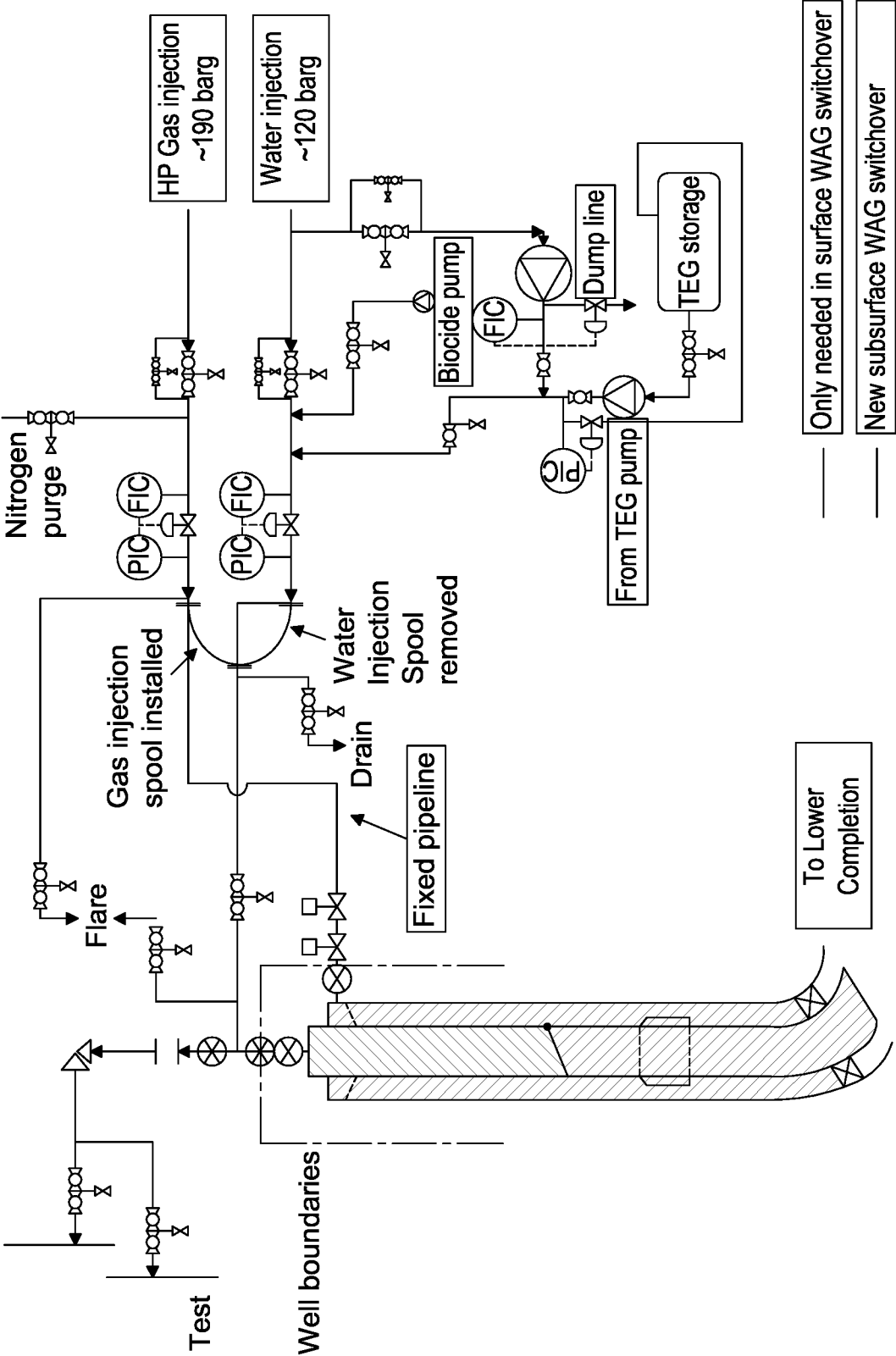


Figure 10