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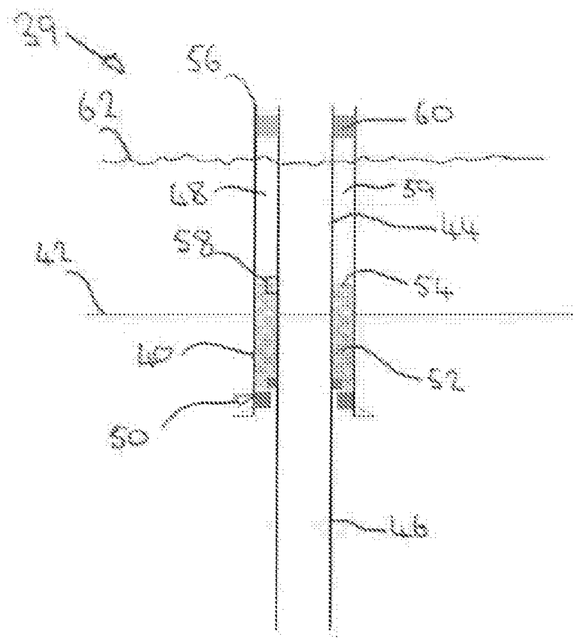

FIG. 3A

(57) Abstract: A method for forming an offshore well comprises forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending upwardly between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a plurality of concentrically arranged tubular strings and at least one annulus defined therebetween. The method includes steps for minimising the bending stiffness of the upper well portion, In one example minimising the bending stiffness of the upper well portion may comprise partially filling at least one annulus with cement to a height which is intermediate the seabed and the terminating upper end of the well structure, in another example minimising the bending stiffness of the upper well portion may comprise providing a cement disruptor within at least one annulus and locating cement within said at least one annulus to define a cement sheath, wherein the cement disruptor reduces resistance of at least a portion of the cement sheath to bending of the upper well portion. in a further example minimising the bending stiffness of the upper well portion may comprise locating a flexible material within at least one annulus; and in a further example minimising the bending stiffness of the upper well portion may comprise varying the bending stiffness along at least one of the plurality of tubular strings.

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METHODS AND APPARATUS FOR FORMING AN OFFHORE WELL

FIELD

The present invention relates to methods and apparatus associated with forming an offshore well.

BACKGROUND

In the offshore oil and gas industry wellbores are drilled below the seabed, and once a well has been drilled and appraised, it will be completed with the appropriate downhole infrastructure to permit production (and/or injection), and then capped at the wellhead with a production tree. The production tree may be located on a subsea wellhead, with a tie back to a surface production facility. In alternative arrangements the tree may be located at surface, on a wellhead platform. Multiple wellbores will typically be present, such that a cluster of trees are provided on the wellhead platform.

In surface wellhead installations a conductor pipe is first installed from a surface platform and into the seabed, for example by piling, such that a portion of the conductor pipe extends above the surface of the sea and terminates at a deck level on the surface platform. The well bore is then drilled through the conductor to a first depth, with a surface casing string installed into the drilled bore and extending back to the surface platform. In some installations the conductor pipe may include a casing support system or hanger near a lower end thereof for providing support to the surface casing.

The annulus defined between the conductor pipe and surface casing is filled with cement to form a cement sheath, which provides a sealing and support/stability function. In typical cementing operations a volume of cement is pumped downwardly through the surface casing string and upwardly within the annulus. Due to some uncertainties, such as potential loss of cement to the surrounding geology, cementing is may in some examples be performed until the cement is visually identified returning from the annulus at the surface platform, e.g. to ensure the annulus is completely filled. The wellbore may then be extended in stages, with intermediate and production casing strings run and cemented as required, until total depth is achieved.

With such conventional surface well installation techniques a well is thus constructed which has an upper well region extending upwardly from the seabed and terminating at an upper end, which is at the surface platform. The upper well region includes the conductor pipe, various casing strings and annulus cement sheaths.

The present applicant has developed a new type of offshore platform and procedure in which the upper end of the well is moveable, for example laterally moveable. Such a new type of offshore platform/procedure is disclosed in applicant's co-pending patent applications DK PA2015 00668 and GB 1522856.2, the disclosure of which is incorporated herein by reference. However, the bending stiffness of the upper region of the well can be significant, such that movement of the upper end may, in particular, generate large stresses within the individual well components which could lead to potential well integrity issues. Further, an important consideration is to avoid, as far as possible, impairing well life with such movements. Also the rigidity of the cement may result in cracking or failure of the cement when moving the upper part of the well. Such cracks may appear randomly throughout the length of the upper well region at unknown or undesired locations, potentially causing leak paths and/or compromising the stability of the well. Further, such cement cracking may potentially lead to unknown corrosion, or increased corrosion of the well components, for example by establishing leak paths.

SUMMARY

Aspects or embodiments may relate to methods and apparatus for improving the flexibility of an upper portion of an offshore well which extends upwardly between a seabed and a terminating upper end of the well.

Such aspects or embodiments may assist to maintain well integrity during bending of the upper portion of the well caused by movement of the terminating upper end of the well. It will be appreciated that the term "bending" as used herein encompasses elastic deformation of the upper part, plastic deformation of the upper part and a combination of the two. As such "bending" may be considered synonymous with flexing of the upper part such that the upper end will return to its original (or first) position after bending. Such movement may be performed in accordance with desired operator procedures, such as those described in the applicant's co-pending patent applications

DK PA2015 00668 and GB 1522856.2, the disclosure of which is incorporated herein by reference. Further, such aspects or embodiments may assist to reduce stresses generated within the well or individual components thereof during movement thereof.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion, which may also be termed a subterranean well portion, extending below a seabed and an upper well portion, which may also be termed an upper part of a well, extending upwardly between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a plurality of concentrically arranged tubular strings and at least one annulus defined therebetween; and

minimising the bending stiffness of the upper well portion.

Another aspect or embodiment relates to a method for forming an offshore well, comprising: forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending upwardly between the seabed and a terminating upper end of the well structure, wherein the upper part comprises at least one tubular string, such as a conductor pipe; and minimising the bending stiffness of the upper well portion. Such arrangements may comprise a subsea wellhead and the lower portion of the well below the subsea wellhead may comprise a well structure comprising a plurality of concentrically arranged tubular strings and at least one annulus defined therebetween.

Another aspect or embodiment relates to a method for forming an offshore well, comprising: forming a well structure which includes a well extending below a seabed; capping the well with a subsea wellhead; providing a rig link, such as a high pressure riser, extending upwardly to a terminating upper end; and minimising the bending stiffness of the upper part.

Minimising the bending stiffness of the upper well portion may comprise at least one of:

partially filling at least one annulus with cement to a height below the height of the terminating upper end of the upper well portion and/or a height which is intermediate the seabed and the terminating upper end of the well structure;

providing at least one cement disruptor within at least one annulus and locating cement within said at least one annulus to define a cement sheath, wherein the cement disruptor reduces resistance of at least a portion of the cement sheath to bending of the upper well portion;

locating a flexible material within at least one annulus; and

varying the bending stiffness along at least one of the plurality of tubular strings.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending upwardly between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a plurality of concentrically arranged tubular strings and at least one annulus defined therebetween;

wherein the method further comprises at least one of:

partially filling at least one annulus with cement to a height below the height of the terminating upper end of the upper well portion and/or a height which is intermediate the seabed and the terminating upper end of the well structure;

providing a cement disruptor within at least one annulus and locating cement within said at least one annulus to define a cement sheath, wherein the cement disruptor reduces resistance of at least a portion of the cement sheath to bending of the upper well portion; and

locating a flexible material within at least one annulus; and

varying the bending stiffness along at least one of the plurality of tubular strings.

In the methods and apparatus disclosed herein, the height that is intermediate the seabed and the terminating upper end of the well structure may be a specific, predetermined height.

The bending stiffness of the upper well portion may thus be intentionally minimised or reduced to improve its bending flexibility. This may assist in minimising risk of compromising well integrity during bending of the upper portion of the well caused by movement of the terminating upper end. Such movement of the terminating upper end may, for example, be in support of desired operator procedures. The improved bending flexibility may assist to reduce stresses generated within the well or individual well components, minimise leak path issues, avoid impairing the life of the well, and the like. Furthermore, the reduced bending stiffness may enable a larger movement amplitude to be achieved.

The upper well portion may extend above a surface of the sea with the terminating upper end of the well structure aligned with a surface platform, such as a wellhead platform.

The terminating upper end may be secured or securable to a wellhead. In specific arrangements, the upper end of the conductor pipe at the level of the wellhead may be arranged to receive a wellhead.

As noted above, the upper well portion comprises concentrically arranged tubular strings. However, the term “concentrically” is not intended to be limited to tubular strings which precisely share the same centre axis, but is intended to relate to the arrangement of one tubular string located inside another, and an eccentric alignment between tubular strings is possible. The term “annulus” is to be construed accordingly, and is intended to generally define a space between adjacent tubular strings, in accordance with normal parlance in the art.

It should also be understood that while terms such as “sea”, “seabed”, “sea surface” and the like are used herein, this is not intended to be strictly limited to bodies of water classed as seas, but should cover any body of water.

Further, the term “tubular string”, and generally the term “string” as used herein is intended to cover tubular, tubing or pipe structures of any length, whether formed as a single piece or as multiple pieces secured or otherwise arranged together.

At least one tubular string may comprise a conductor pipe.

At least one tubular string may comprise a casing string, such as a surface casing string, intermediate casing string, production casing string and/or the like.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

forming a well structure which includes a subterranean well portion extending below a seabed and an upper part extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

partially filling the first annulus with cement to a first height which is intermediate the seabed and the terminating upper end of the well structure.

A region of the first annulus above the first height may be substantially void of cement. The bending stiffness of the upper well portion may thus be intentionally minimised to improve bending flexibility. This may assist in minimising risk of compromising well integrity during bending of the upper well portion, for example by reducing stresses generated within the well or individual well components, by minimising leak path issues, and the like.

Bending of the upper well portion may be primarily focussed above the first height by virtue of the overall lower bending stiffness established by the absence of cement. This may minimise induced stresses within the cement below the first height and, for example, minimise potential compromise to the integrity of the cement in the first annulus below the first height.

The provision of a region of the first annulus above the first height which is substantially void of cement may permit a differential rate and/or magnitude of bending to be achieved between the first and second tubular strings during bending of the upper well portion. For example, during bending of the upper well portion the first (which may be defined as an outer) tubular string may be displaced further than the second (which may be defined as an inner) tubular string. This may, to a certain extent, minimise exposure of the second tubular string to bending induced stresses.

The upper well portion may extend above a surface of the sea with the terminating upper end of the well structure aligned with a surface platform, such as a wellhead platform. The upper well portion may extend around 1 to 30 meters above the surface of the sea, for example around 10 to 20 meters above the surface of the sea. In one embodiment the upper well portion may extend around 15 meters above the surface of the sea

The first tubular string may define an outermost tubular string of the upper well portion. Alternatively, the first tubular string may define an intermediate tubular string of the upper well portion. That is, the first tubular string may be located within a further tubular string.

The first and second tubular strings may extend at least from the level of the seabed to the terminating upper end of the well structure.

The method may comprise installing the first tubular string and then installing the second tubular string within the first tubular string. The second tubular string may extend through the first tubular string and into a drilled bore which extends below the first tubular string.

The first tubular string may comprise a conductor pipe. The method may comprise inserting the conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed to the terminating upper end of the well structure. The upper end of the well structure may also be termed the upper end of the conductor. The conductor pipe may be installed by piling, for example.

The second tubular string may comprise a casing string, for example a surface casing string. The method may comprise inserting the casing string within the conductor pipe to define the first annulus therebetween, wherein the casing string extends upwardly to the terminating upper end of the well structure. The casing string may extend into a drilled bore formed below the conductor pipe.

The first tubular string may comprise a first casing string, such as a surface casing string, intermediate casing string or the like. The second tubular string may comprise a second casing string located within the first casing string. The second casing string may comprise an intermediate casing string, production casing string or the like.

The method may comprise pumping cement into the first annulus, for example downwardly through the second tubular string and upwardly into the first annulus. Conventional cementing techniques may be used. The method may comprise ceasing pumping of the cement when the first height has been reached.

The first height of cement within the first annulus may be above seabed level, for example between 2 and 100 meters above seabed level. In one embodiment the first height may be around 5 meters above seabed level. The first height of cement within the first annulus may be below a sea surface level. In one embodiment the first height of cement may be, for example, between 2 and 100 meters below the sea surface, for example between 30 and 70 metres below the sea surface, such as around 65 meters below the sea surface. In other arrangements, the first height may be below the seabed level, for example in the lower well portion. In such arrangements, the first height may up to 20 metres below the seabed level.

The method may comprise measuring the height of cement within the first annulus during filling of said first annulus. Such an arrangement may permit an operator to determine when the first height of the cement has been achieved. The method may comprise measuring the level of cement with one or more of a smart casing system, measuring wire, string with gravity load, distributed sensing system, an ultrasonic imager tool (USIT) and the like, or by cement bond logging.

The method may comprise providing a desired volume of cement and placing this desired volume of cement within the annulus such that the first height is achieved.

A tubular string support system, such as a casing hanger, may be provided between the first and second tubular strings. The tubular string support system may function to permit load transference, for example axial load transference, between the first and second tubular strings. The tubular string support system may function as a guide, for example to space or centralise the second tubular string within the first tubular string. This may increase flexibility of the upper well portion.

A tubular guide system may be provided between the first and second tubular strings.

The method may comprise positioning cement within the first annulus at least to the level of the tubular string support system or guide. That is, the tubular string support system or guide may be located at, above or below the first height. The method may comprise embedding the tubular string support system or guide within the cement.

The method may comprise washing or flushing out the first annulus above the first height of the cement. Such an arrangement may assist to ensure the first annulus is only partially filled with cement.

The method may comprise manoeuvring or moving the terminating upper end of the well structure, wherein such movement induces bending of the upper well portion. Such movement may include moving the first tubing string only. Alternatively, such movement may include moving both the first and second tubing strings. Accordingly, references to movement of the terminating upper end of the well structure may include movement of one or both of the first and second tubular strings.

In one embodiment the method may comprise moving the terminating upper end of the well structure between first and second positions. Such movement may cause the upper well portion to bend or further bend. In one embodiment the upper well portion may be in an unbent or low-stress configuration when the terminating upper end is located in one of the first and second positions, and in a bent or increased-stress configuration when the terminating upper end is located in the other of the first and second positions.

The method may comprise forming at least a portion of the well structure with the terminating upper end thereof in one of the first and second positions, and subsequently moving the terminating upper end of the well structure to the other of the first and second positions. For example, the method may comprise forming the well structure with the terminating upper end thereof in the first position, and subsequently moving the terminating upper end of the well structure to the second position.

The first position may define an access position, which may be a parking, a storage, an injection, and/or a production position. The access position may be established to permit installation of one or more components of the well structure, deployment of downhole equipment such as completion equipment, tooling and the like. The access position may permit workover or intervention operations to be performed on the well structure and/or associated equipment. The access position may permit decommissioning of at least part of the well structure and/or associated equipment.

The first position may be generally aligned with a drill centre of a drilling rig.

The second position may define a use position, which may be a well processing and/or drilling position. The use position may be established when the well structure is to be used in its intended operation, such as production, injection and/or the like. In some embodiments the second position may be established for one or more intervention operations, such as to change completion equipment and the like.

The method may comprise moving the terminating upper end of the well structure to a third and optionally subsequent positions.

The method may comprise performing a subsequent cementing operation to add cement into the first annulus to a second height. The second height may be at or in the region of the terminating upper end of the well structure. This subsequent cementing operation may result in the first annulus being completely filled with cement.

The subsequent cementing operation may be performed following a desired movement of the terminating upper end of the well structure. In this way, the partial cement fill may permit improved flexibility of the upper well portion during the desired movement while minimising risks to well integrity, well life and the like, while the subsequent cementing operation may allow a more conventional final installation.

The subsequent cementing operation may comprise top-filling cement into the first annulus. The subsequent cementing operation may comprise creating a circulation path to permit circulation of cement into the first annulus. Such a circulation path may be partially defined within the second tubular string. Such a circulation path may be between the first annulus and a second annulus within the well structure. The subsequent cementing operation may comprise a cement squeeze operation.

The method may comprise placing a flexible material within the first annulus above the first height of the cement. The flexible material may provide a sealing function within the first annulus. The flexible material may permit sealing within the annulus without significantly affecting the improved flexibility of the upper well portion achieved by the partial cement fill.

The flexible material may assist to minimise corrosion of one or both of the first and second tubular strings.

The method may comprise placing the flexible material at one or more discrete locations along the first annulus. In one embodiment the method may comprise locating a discrete element of flexible material in the first annulus at or near the terminating upper end of the well structure.

The method may comprise placing flexible material along an extended length of the first annulus. For example, the remainder of the first annulus above the first height of the cement may be substantially filled with the flexible material.

The flexible material may exhibit a lower stiffness than cured cement. The flexible material may comprise a foam, elastomer, rubber, gel and/or the like. The flexible material may be pumpable. The flexible material may be curable.

The well structure may comprise a third tubular string, wherein a second annulus is defined between the third tubular string and one of the first and second tubular strings.

In one embodiment the third tubular string may be provided externally of the first tubular string, such that the second annulus is defined between the first and third tubular strings.

The third tubular string may be provided within the second tubular string, such that the second annulus is defined between the second and third tubular strings. The third tubular string may be installed subsequently to partially filling the first annulus with cement.

The third tubular string may comprise a conductor pipe.

The third tubular string may comprise a casing string, such as an intermediate casing string, production casing string or the like.

The method may comprise locating cement in the second annulus. The method may comprise partially filling the second annulus with cement, for example to around the level of the first height of cement in the first annulus. Such an arrangement may contribute to minimising bending stiffness of the upper well portion.

The method may comprise providing fluid communication between the first and second annuli. The method may comprise providing fluid communication between the first and second annuli above the first height. Such an arrangement may facilitate fluid communication between regions of the first and second annuli which are void from cement.

Fluid communication between the first and second annuli may be achieved via one or more valves, such as one or more one-way valves.

Fluid communication between the first and second annuli may permit circulation within one or both of the first and second annuli, for example to permit a wash-out operation, to place a subsequent material, such as further cement, a flexible material and the like.

The method may comprise varying the bending stiffness along at least one of the first and second tubular strings.

Optionally, the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform, and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system, the first height being arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

Optionally, the first height is one of: substantially level with the guide; and above the guide.

Optionally, the first height is above the guide by a distance of 1 meter or more, such as 2 meters or more, such as 3 meters or more, such as 4 meters or more, such as 5 meters or more, such as 6 meters or more. Optionally, the first height is above the guide by a distance within 90% of the distance to a higher guide or other engagement member, such as within 70% of that distance, such as within 50% of that distance, such as within 25% of that distance. Optionally, the first height is above the guide by a distance up to one of: 30 metres, 20 metres, 10 metres and 5 metres.

The method may comprise centralising the second tubular string within the first tubular string. Such centralisation may be achieved at one or more locations along the upper well portion. Centralisation may assist to ensure the first and second tubular strings are centralised, and remain substantially centralised following movement or bending of the upper well portion. This may assist to ensure appropriate cement placement (or even placement of a flexible material, for example), for example circumferential coverage, within the first annulus, for example initial cement placement and/or in a subsequent cementing operation, such as a top fill cementing operation.

The method may comprise centralising the first and second tubular strings using a centralisation system. The centralisation system may extend along substantially the complete length of the upper well portion (e.g., from around +/- 10 meters relative to seabed level). The centralisation system may comprise one or more centralisers. The centralisation system may permit the first and second tubular string to slide relative to each other to avoid or minimise generation of stress when the upper well portion is moved.

An aspect or embodiment relates to an offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

cement partially filling the first annulus to a first height which is intermediate the seabed and the terminating upper end of the well structure.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween;

locating cement within the first annulus to define a cement sheath; and

providing a cement disruptor within the first annulus, wherein the cement disruptor reduces resistance of the cement sheath to bending of the upper well portion.

Cement may thus be located within the first annulus, for example in conventional manner or otherwise, to provide benefits of support and/or sealing, while the use of a cement disruptor functions to reduce the effect the cement has in resisting bending of the upper well portion. Such bending of the upper well portion may occur by moving the terminating upper end of the well structure.

The upper well portion may extend above a surface of the sea with the terminating upper end of the well structure aligned with a surface platform, such as a wellhead platform.

The first tubular string may define an outermost tubular string of the upper well portion. Alternatively, the first tubular string may define an intermediate tubular string of the upper well portion. That is, the first tubular string may be located within a further tubular string.

The first and second tubular strings may extend at least from the level of the seabed to the terminating upper end of the well structure.

The method may comprise installing the first tubular string and then installing the second tubular string within the first tubular string. The second tubular string may extend through the first tubular string and into a drilled bore which extends below the first tubular string.

The first tubular string may comprise a conductor pipe. The method may comprise inserting the conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed to the terminating upper end of the well structure. The conductor pipe may be installed by piling, for example.

The second tubular string may comprise a casing string, for example a surface casing string. The method may comprise inserting the casing string within the conductor pipe to define the first annulus therebetween, wherein the casing string extends upwardly to the terminating upper end of the well structure. The casing string may extend into a drilled bore formed below the conductor pipe.

The first tubular string may comprise a first casing string, such as a surface casing string, intermediate casing string or the like. The second tubular string may comprise a second casing string located within the first casing string. The second casing string may comprise an intermediate casing string, production casing string or the like.

The method may comprise partially or completely filling the first annulus with cement such that the cement sheath extends along some or all of the first annulus.

The cement disruptor may comprise a physical component located within the first annulus.

The cement disruptor may provide a localised weakness at a location along the cement sheath. The cement disruptor may define or function to form a ductile fuse within the cement sheath. This arrangement may focus failure, for example cracking, of the cement sheath at the one or more preselected locations upon bending of the upper well portion. The failure of the cement may function to reduce resistance of the cement sheath to bending of the upper well portion. Furthermore, by focussing such failure at a preselected location the ability to control or ensure well integrity is maintained can be improved.

The cement disruptor may provide a localised reduction in the thickness of the cement sheath. Such a reduction in the thickness of the cement may provide a localised weakness or failure point along the length of the cement sheath.

The method may comprise bending the upper well portion to cause failure of the cement sheath at the location of the weakness. Optionally, the bending is caused by moving the terminating upper end of the well structure from a first position to a second position.

The cement disruptor may function to mechanically weaken or interfere with the cement sheath, such that mechanical failure of the cement sheath may be more readily achieved during bending of the upper well portion.

The cement disruptor may be provided separately from the first and second tubular strings. The cement disruptor may be mounted on one or both of the first and second tubular strings. The cement disruptor may be integrally formed with at least one of the first and second tubular strings.

The cement disruptor may comprise or define one or more flow passages or channels to permit cement to flow past the cement disruptor during location of cement within the first annulus. In such an arrangement the cement disruptor, or at least a portion thereof, may become embedded within the cement sheath.

The cement disruptor may comprise a sleeve. The sleeve may define a gap with one or both of the first and second tubular strings. The gap may permit flow of cement therethrough. The sleeve may comprise one or more surface channels or flow passages. The surface channels or flow passages may extend generally axially relative to the first annulus. The surface channels or flow passages may extend in a serpentine pattern.

The sleeve may be mounted on one or both of the first and second tubular strings.

The cement disruptor may comprise one or more protuberances which extend into the first annulus. The one or more protuberances may locally weaken the cement sheath. The one or more protuberances may mechanically interfere with the cement sheath during bending of the upper well portion. The one or more protuberances may extend from one or both of the first and second tubular strings. At least one protuberance may comprise a nodule, pin, boss or the like.

The cement disruptor may comprise a coating applied to one or both of the inner surface of the first tubular string and outer surface of the second tubular string, wherein the coating disrupts adherence of the cement sheath to one or both of the first and second tubular string. This arrangement may reduce shear stress between the cement sheath and the first and/or second tubular string. This may effectively improve the bending flexibility of the upper well portion.

The use of a coating may function to establish a microannulus.

The coating may comprise a mechanical barrier which reduces friction between the cement sheath and first/second tubular string.

The coating may comprise a low friction material, such as PTFE or the like.

The coating may comprise a chemical barrier. The chemical barrier may prevent or reduce the curing of the cement in the region of the chemical barrier. This arrangement may minimise cement adhesion with the first and/or second tubular string. This may minimise shear forces applied between the cement sheath and the first and/or second tubular string, thus assisting to improve bending flexibility of the upper well portion.

The coating may comprise a cement retarder. The coating may comprise a sugar based coating. The coating may comprise at least one of lignosulfonates, cellulose derivatives, hydroxycarboxylic acids, organophosphates, synthetic retarders, inorganic compounds and salt, such as sodium chloride.

The coating may be applied by spraying, painting, dipping, brushing or the like.

The cement disruptor may be provided along an entire length of the first annulus. Alternatively, the cement disruptor may be provided along a partial length of the first annulus. The cement disruptor may be provided at one or more discrete locations within the first annulus.

The method may comprise providing multiple cement disruptors axially along the first annulus.

The well structure may comprise a third tubular string, wherein a second annulus is defined between the third tubular string and one of the first and second tubular strings.

In one embodiment the third tubular string may be provided externally of the first tubular string, such that the second annulus is defined between the first and third tubular strings.

The third tubular string may be provided within the second tubular string, such that the second annulus is defined between the second and third tubular strings. The third tubular string may be installed subsequently to partially filling the first annulus with cement.

The third tubular string may comprise a conductor pipe.

The third tubular string may comprise a casing string, such as an intermediate casing string, production casing string or the like.

The method may comprise locating cement within the second annulus to define a second cement sheath. The method may comprise providing a cement disruptor within the second annulus, wherein the cement disruptor reduces resistance of the second cement sheath to bending of the upper well portion.

Optionally, the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform, and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system, the method comprising locating the cement disruptor at a location arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

Optionally, the location of the cement disruptor is one of: substantially level with the guide; and above the guide.

Optionally, the location of the cement disruptor is above the guide by a distance of 1 meter or more, such as 2 meters or more, such as 3 meters or more, such as 4 meters or more, such as 5 meters or more, such as 6 meters or more. Optionally, the location of the cement disruptor is above the guide by a distance within 90% of the distance to a higher guide or other engagement member, such as within 70% of that distance, such as within 50% of that distance, such as within 25% of that distance. Optionally, the location of the cement disruptor is above the guide by a distance up to one of: 30 metres, 20 metres, 10 metres and 5 metres.

Optionally, the upper well portion is configured to be moved at a location of a further guide, below the moving mechanism and above the guide, by an active guide system connectable between the further guide and the wellhead platform, the method further comprising configuring the well structure to have reduced axial stiffness at a point substantially aligned with the further guide.

Optionally, configuring the well to have reduced axial stiffness comprises one or more of: locating a further cement disruptor in the well structure; partially filling the annulus with cement; and locating a flexible material in the well structure.

An aspect or embodiment relates to an offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween;

a cement sheath at least partially filling the first annulus; and

a cement disruptor located within the first annulus.

An aspect or embodiment relates to an oilfield tubular comprising a cement disruptor. The oilfield tubular may comprise or form part of a conductor pipe, a casing string or the like.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

locating a flexible material within the first annulus.

The flexible material may provide the function of sealing and/or support within the first annulus, while assisting to minimise the bending stiffness of the upper well portion to improve bending flexibility.

The upper well portion may extend above a surface of the sea with the terminating upper end of the well structure aligned with a surface platform, such as a wellhead platform.

The first tubular string may define an outermost tubular string of the upper well portion. Alternatively, the first tubular string may define an intermediate tubular string of the upper well portion. That is, the first tubular string may be located within a further tubular string.

The first and second tubular strings may extend at least from the level of the seabed to the terminating upper end of the well structure.

The method may comprise installing the first tubular string and then installing the second tubular string within the first tubular string. The second tubular string may extend through the first tubular string and into a drilled bore which extends below the first tubular string.

The first tubular string may comprise a conductor pipe. The method may comprise inserting the conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed to the terminating upper end of the well structure. The conductor pipe may be installed by piling, for example.

The second tubular string may comprise a casing string, for example a surface casing string. The method may comprise inserting the casing string within the conductor pipe to define the first annulus therebetween, wherein the casing string extends upwardly to the terminating upper end of the well structure. The casing string may extend into a drilled bore formed below the conductor pipe.

The first tubular string may comprise a first casing string, such as a surface casing string, intermediate casing string or the like. The second tubular string may comprise a second casing string located within the first casing string. The second casing string may comprise an intermediate casing string, production casing string or the like.

The method may comprise locating the flexible material at one or more discrete locations along the first annulus. Alternatively, the method may comprise substantially filling the first annulus with the flexible material.

The method may comprise partially filling the first annulus with cement to a first height within the first annulus, and then locating the flexible material within the first annulus above the first height of the cement.

Optionally, the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform, and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system, the method comprising locating the flexible material at a location arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

Optionally, the location of the flexible material is one of: substantially level with the guide; and above the guide.

Optionally, the location of the flexible material is above the guide by a distance of 1 meter or more, such as 2 meters or more, such as 3 meters or more, such as 4 meters or more, such as 5 meters or more, such as 6 meters or more. Optionally, the location of the flexible material is above the guide by a distance within 90% of the distance to a higher guide or other engagement member, such as within 70% of that distance, such as within 50% of that distance, such as within 25% of that distance. Optionally, the location of the flexible material is above the guide by a distance up to one of: 30 metres, 20 metres, 10 metres and 5 metres.

Optionally, the upper well portion is configured to be moved at a location of a further guide, below the moving mechanism and above the guide, by an active guide system connectable between the further guide and the wellhead platform, the method further comprising configuring the well structure to have reduced axial stiffness at a point substantially aligned with the further guide.

Optionally, configuring the well to have reduced axial stiffness comprises one or more of: locating a cement disruptor in the well structure; partially filling the annulus with cement; and locating a further flexible material in the well structure.

The flexible material may exhibit a lower stiffness than cured cement. The flexible material may comprise a foam, elastomer, rubber, gel and/or the like. The flexible material may be pumpable. The flexible material may be curable.

The method may comprise varying the bending stiffness along at least one of the first and second tubular strings.

An aspect or embodiment relates to an offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

a flexible material located within the first annulus.

An aspect or embodiment relates to an offshore well pipe for use in forming an offshore well and including an upper portion to be installed above a seabed, wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of the well pipe. A well pipe may be a tubular string, such as a conductor, or any other type of pipe used in forming an offshore well.

Accordingly, the variation in bending stiffness between different axial wall sections may provide control over where the largest bending moment is preferred. Furthermore, the variation in bending stiffness may permit a desired shape of the well pipe to be achieved in response to an applied bending moment.

The variation in bending stiffness may assist to improve the ability to bend the well pipe. Such bending may be achieved while reducing stress within the well pipe.

The well pipe may comprise multiple well pipe sections secured together, in end-to-end relation, to form the well pipe. The well pipe sections may include end connectors, such as threaded end connectors to facilitate connecting individual sections together. Variations in bending stiffness may be achieved between axial wall sections which are located between end connectors of a well pipe section.

Different axial wall sections with different bending stiffness may be provided on a single well pipe section. Different axial wall sections with different bending stiffness may be provided on different well pipe sections. In such an arrangement the variation of bending stiffness along the length of the well pipe may be achieved by a suitable variation and construction of the individual well pipe sections.

The variation in bending stiffness between the at least two axial wall sections may be such that a variation in the flexural rigidity of the well pipe is achieved along its length.

The at least two axially extending wall sections may comprise a different modulus. The at least two axially extending wall sections may comprise a different second moment of area.

The at least two axially extending wall sections may comprise different wall thicknesses to provide a different bending stiffness.

The at least two axially extending wall sections may comprise different materials to provide a different bending stiffness.

The at least two axially extending wall sections may comprise different geometries to provide a different bending stiffness.

Different bending stiffness between different axial wall sections may be provided by use of one or more stiffeners, such as stiffener ribs or the like.

The well pipe may comprise or define a conductor pipe. The well pipe may comprise or define a casing pipe.

The well pipe may be used in combination with any other aspect.

An aspect or embodiment relates to a method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween,

wherein the first and second tubular strings include an upper portion to be installed above a seabed within the upper well portion, and wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of at least one of the first and second tubular strings.

An aspect or embodiment relates to an offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween,

wherein the first and second tubular strings include an upper portion installed above a seabed within the upper well portion, and wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of at least one of the first and second tubular strings.

An aspect or embodiment relates to a method for installing offshore well infrastructure, comprising:

inserting a conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

locating a first casing string within the conductor pipe to define a first annulus therebetween; and

partially filling the first annulus with cement to a first height below an upper end of the conductor pipe.

An aspect or embodiment relates to an offshore well installation, comprising:

a conductor pipe inserted into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

a first casing string located within the conductor pipe to define a first annulus therebetween; and cement partially filling the first annulus to a first height below an upper end of the conductor pipe.

An aspect or embodiment relates to a method for installing offshore well infrastructure, comprising:

inserting a conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

locating a first casing string within the conductor pipe to define a first annulus therebetween; and

locating a flexible material within the first annulus.

An aspect or embodiment relates to an offshore well installation, comprising:

a conductor pipe inserted into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

a first casing string located within the conductor pipe to define a first annulus therebetween; and

a flexible material located within the first annulus.

An aspect or embodiment relates to a method for installing offshore well infrastructure, comprising:

inserting a conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

locating a first casing string within the conductor pipe to define a first annulus therebetween;

locating cement within the first annulus to define a cement sheath; and

providing a cement disruptor within the annulus, wherein the cement disruptor reduces resistance of the cement sheath to bending of the conductor pipe.

An aspect or embodiment relates to an offshore well installation, comprising:

a conductor pipe inserted into the seabed such that a portion of the conductor pipe extends upwardly from the seabed;

a first casing string located within the conductor pipe with a first annulus therebetween;

a cement sheath at least partially filling the first annulus; and

a cement disruptor located within the first annulus.

An aspect or embodiment relates to an offshore conductor pipe for insertion within a seabed such that a portion of the conductor pipe extends above the seabed, wherein the conductor pipe comprises at least two axially extending wall sections which define a different bending stiffness.

Further aspects relate to a system for moving an upper end of a conductor pipe or well structure from a first position to a second position. The system may comprise a moving mechanism (e.g. a conductor moving mechanism) connected between the conductor pipe or well structure and a wellhead platform. The moving mechanism may be hydraulically operable to extend or retract and thereby move the upper end. The system may further comprise one or more guides laterally constraining the conductor pipe or well structure and each connected to the wellhead platform by a guide system. The one or more guides may be positioned at varying heights on the conductor pipe or well structure. The guide systems may comprise one or more of: an active guide system; a passive guide system; and a rigid guide system.

Further aspects of the invention relate to a method for moving an upper end of a conductor pipe or well structure from a first position to a second position using the system mentioned above and elsewhere herein.

Features defined in relation to one aspect may be provided in combination with any other aspect.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other examples will now be described with reference to the accompanying drawings, in which:

Figure 1 is a diagrammatic representation of an offshore surface well installation;

Figures 2A and 2B are diagrammatic illustrations, from above, of a cluster of conductor pipes of the surface well installation of Figure 1, with the conductor pipes shown in Figure 2A in a first position, with one of the conductor pipes shown in Figure 2B in a second position;

Figures 3A and 3B diagrammatically illustrate sequential stages in a method for installing offshore infrastructure;

Figure 4 diagrammatically illustrates a further method for installing offshore infrastructure;

Figures 5A and 5B diagrammatically illustrate sequential stages in a further method for installing offshore infrastructure;

Figure 6 diagrammatically illustrates a casing string with a cement disruptor installed thereon;

Figure 7 is a top view of the casing string and cement disruptor of Figure 6;

Figures 8A to 8C diagrammatically illustrate sequential stages during use of the cement disruptor first shown in Figure 7;

Figure 9 diagrammatically illustrates a conductor pipe with a cement disruptor installed therein;

Figure 10 is a top view of the conductor pipe and cement disruptor of Figure 9;

Figure 11 diagrammatically illustrates a casing string which includes a cement disruptor comprising a plurality of nodules;

Figure 12 is an enlarged view of one of the nodules of Figure 11;

Figure 13 is a top view of the casing string with the cement disruptor nodules of Figure 11;

Figures 14A to 14C diagrammatically illustrate sequential stages during use of the cement disruptor first shown in Figure 11;

Figures 15A and 15B show sequential stages of use of a cement disruptor coating;

Figures 16A and 16B show sequential stages of use of an alternative cement disruptor coating;

Figure 17 diagrammatically illustrates an offshore conductor installation;

Figure 18 diagrammatically illustrates a single conductor pipe section of the offshore conductor installation of Figure 17;

Figures 19a and 19b diagrammatically illustrate a system for moving a conductor or well structure between first and second positions; and

Figure 20 diagrammatically illustrates a system for compensating lateral forces when moving a conductor or well structure between first and second positions.

DETAILED DESCRIPTION OF THE DRAWINGS

Various aspects and embodiments disclosed herein relate to methods and apparatus for improving the ability to bend an upper well portion of an offshore well, while minimising risk of compromising well integrity and/or well life. There may be many reasons for improving or accommodating such bending, for example due to desired operator procedures. Figures 1, 2A and 2B diagrammatically illustrate an offshore installation method/apparatus proposed by the present applicant in which such bending of an upper well portion is desired.

Figure 1 diagrammatically illustrates an offshore surface or wellhead platform, generally identified by reference numeral 10, shown in use with a drilling platform operated in cantilever mode, with a cantilever rig portion 12 extended and aligned over the surface platform 10. The rig portion 12 is used in the drilling, completion and/or workover of multiple wells 14 associated with the surface platform 10.

A typical well 14 will be formed by first installing a conductor pipe 16 which extends into the seabed 18 and terminates at a deck level 20 on the surface platform 10. Drilling may then commence through the conductor pipe 16 to form a drilled bore 21, with one or more concentrically aligned casing strings 22 (one casing string shown in broken outline) installed and cemented within the conductor pipe 16 and drilled bore 21 and terminating at a wellhead 24 located generally at the level of a wellhead 26 of the platform 10. In the present example the conductor 16 also terminates at the wellhead 24. However, multiple options are possible, and in some instances the conductor pipe 16 could terminate below the wellhead 24. The well 14 is then capped with a production tree 28 (often termed a X-mas tree).

The result is that a well 14 is formed which includes a lower well portion 1 which extends below the seabed 18, and an upper well portion 2 which extends between the seabed 18 and a terminating upper end 3 of the well 14.

Generally, a wellhead or surface platform is a structure or structures, which support the upper end (opposite of the reservoir) of the well including any superstructures, one or more well processing stations or similar. Such a wellhead platform is typically a structure (such as a jacket based or gravity based platform) resting on the seabed ranging from very basic configurations to complex facilities. The offshore wellhead platform may comprise one or more well-processing stations. Alternatively, the offshore wellhead platform does not comprise any well-processing stations. In such cases, well-processing tasks such as drilling may be performed by a drilling unit placed next to the well head platform, as in the example illustrated in Figure 1.

The wellhead or surface platform typically fulfils one or more of the following functions in supporting a conductor:

(i) shield the conductor from accidental impacts from ships and vessels;

(ii) keeping a completed surface well from otherwise tipping over;

(iii) provide structure where pipes can be mounted for connecting to a valve assembly or production tree mounted on each conductor and interfacing these pipes with various equipment or manifolds on and/or off the platform, such as pumps and storage tanks;

(iv) supporting the production trees so that they are substantially static relative to the platform (at least during production) as the platform and/or conductor is exposed to forces from current, wind and wave.

In the example shown in Figure 1 the cantilever rig portion 12 includes first and second drill centres 30, 32, with all operations provided by the rig portion 12 being aligned on these centres 30, 32. For example, Figure 1 illustrates a drilling operation being performed on the first drill centre 30, through conductor 16a, while a new conductor 16b is shown being deployed on the second drill centre 32.

In the illustrated example individual clusters 34 of wells 14 are provided around each drill centre 30, 32. Figure 2A diagrammatically illustrates, from above, a well cluster 34 around the first drill centre 30. As described above, each well 14 includes a conductor pipe 16 and at least one casing string 22 installed and cemented therein, with a cement sheath illustrated in Figure 2A by reference numeral 36. Each well 14 in Figure 2A is illustrated in an operational position (or second position).

The ability to form such clusters 34 is permitted by the unique proposal made by the present applicant of moving the terminating upper ends 3 of each well 14 into line with the drill centres 30, 32 for suitable operations. In Figure 1 the terminating upper end 3 of well 14a is illustrated as being moved laterally and thus aligned with the first drill centre 30, as also illustrated in the top elevational view of Figure 2B. Such lateral movement of the terminating upper end is such that the upper well portion 2 is longitudinally bent (or flexed).

This proposal of moving the individual wells into and out of alignment with a drill centre 30, 32 may provide a number of advantages. For example, this may avoid the requirement to always move the cantilever rig portion 12 over the individual wells 14, which may not always be practical and increases rig time and thus costs. Furthermore, in some circumstances an operation may be completed on the first drill centre 30, while operations are still required or being performed on the second drill centre 32. With conventional installations this may mean the first drill centre and associated crew etc. become redundant until the operations along the second drill centre are completed, following which the rig portion can be realigned. The proposals of the applicant, however, in moving individual wells can permit operations to progress on different wells within the same cluster, without requiring rig movement and thus largely independently of the operations being performed on a different well cluster.

Appropriate bending of an individual well 14 may require large lateral forces. Further, such bending could potentially affect well integrity, for example by large induced stresses in well components, uncontrolled failure of the cement sheath 36 and the like.

Examples are provided below of assisting in improving the flexibility of an upper well portion 2 to address such an issue.

Figure 3A diagrammatically illustrates a first example. A well structure 39 includes a conductor pipe 40 which is installed into the seabed 42, with a casing string 44 (specifically a surface casing string) installed within the conductor pipe 40 and drilled bore 46, wherein a first annulus 48 is defined between the conductor pipe 40 and casing string 44. A casing hanger 50 allows the load of the casing string 44 to be supported by the conductor pipe 40 (other load transfer points may be present). Cement 52 is pumped into the first annulus 48 to a first height 54. In the exemplary arrangement of Figure 3A, the first height is intermediate the seabed 42 and the terminating upper end 56 of the conductor pipe 40. However, in other arrangements, the first height may be below the seabed level.

It will be recognised by those of skill in the art that such cement 52 is also provided in the annulus regions between the casing string 44 and the drilled bore 46. In one example the first height 54 may be approximately 5 meters above the seabed 42. The height of the cement 52 may be measured by a measuring system 58 to determine when the first height 54 has been achieved. Alternatively, a measured volume of cement may be delivered which will permit the first height 54 to be achieved. A flexible seal member or arrangement 60, for example formed of rubber, foam or the like, is located within the upper region of the first annulus 48, above the sea level 62 and adjacent the upper end 56 of the conductor pipe 40.

Accordingly, once the installation as illustrated in Figure 3A is formed, the first annulus 48 will comprise a region 59 substantially void of cement. This may therefore minimise or otherwise reduce the bending stiffness of the upper portion of the well 39 (i.e., that portion of the well 39 which extends above the seabed 42) when compared to an upper well portion having a fully cemented annulus. This improves bending flexibility. The same principle may be used when installing additional casing strings in the construction of the well.

Once the desired movement of the well 39 has been performed, such as described above in relation to Figures 1, 2A and 2B, the first annulus 48 may be topped up with further cement 62, as illustrated in Figure 3B, such that the annulus 48 is substantially completely filled in a final installation.

A further example is illustrated in Figure 4, in which a well 69 is formed by a conductor pipe 70 inserted into the seabed 72, with a casing string 74 installed within the conductor pipe 70 to define a first annulus 76 therebetween. A casing hanger 78 is provided between the conductor pipe 70 and casing string 74. The first annulus 76 is substantially filled with a flexible material 80, such as a foam, gel, elastomer or the like which functions to provide structural stability of the conductor pipe 70 while also providing a sealing function, for example to restrict gas migration within the annulus 76. The flexible material 80 may also provide a degree of corrosion protection to the conductor pipe 70 and casing string 74. Such benefits of structural stability and sealing (and corrosion resistance) may be achieved while still minimising or otherwise reducing the bending stiffness of the upper portion of the well (i.e., that portion of the well 69 which extends above the seabed 72) to improve bending flexibility.

In the example of Figure 4 a cement plug 82 is provided in the annulus 76, at the region of the casing hanger 78, prior to placing of the flexible material 80 to provide additional isolation. The cement plug extends to a height below the seabed 72.

A further example is diagrammatically illustrated in Figure 5A, in which a conductor pipe 90 is inserted into the seabed 92, with a first casing string 94 installed within the conductor pipe 90 to define a first annulus 96 therebetween. The first annulus 96 is partially filled with cement 98 to a first height 100, in a similar manner to the example of Figure 3A.

A second casing string 102 is installed within the first casing string 94 to define a second annulus 104 therebetween, wherein the second annulus 104 is also partially filled with cement 106 to approximately the same first height 100 of cement 98 within the first annulus 96. This may therefore minimise or otherwise reduce the bending stiffness of the installed well to improve bending flexibility.

The first casing string 94 includes a valve arrangement 108, such as a one-way valve arrangement, which, as illustrated in Figure 5B, permits a fluid 110 to be circulated down the first annulus 96, through the valve arrangement 108 and upwardly within the second annulus 104. The ability to provide such circulation may permit multiple operations. For example, fluid 110 may be a wash fluid permitting a wash-out or flushing operation to be achieved above the cement 98, 106 in each annulus 96, 104. In other applications the fluid 110 may comprise a cement, to permit subsequent completion of cementing within the first and second annuli 96, 104. Further, the fluid 110 may comprise a flexible material, allowing the remainder portions of the annuli 96, 104 to become filled with the flexible material.

In some further examples a cement disruptor may be utilised within an annulus which includes a cement sheath, wherein the cement disruptor reduces resistance of at least a portion of the cement sheath during bending of an upper well portion. Some examples of such a cement disruptor will be described below with reference to Figures 6 to 18.

Referring initially to Figure 6, a casing string or pipe 120 includes a cement disruptor in the form of a sleeve 122 mounted on its outer surface. The disruptor sleeve 122 may be defined as a flex-sleeve. The disruptor sleeve 122 includes a plurality of flow channels 124 formed in an outer surface thereof. Figure 7 provides a top view of the casing string 120 with mounted disruptor sleeve 122 and its circumferentially arranged flow channels 124.

The use and effect of the cement disruptor sleeve 122 will be described with reference to the sequential operational drawings of Figures 8A to 8C. In Figure 8A a well 129 includes a conductor pipe 130 inserted within the seabed 132, with the casing string 120 and mounted cement disruptor sleeve 122 installed within the conductor pipe 130 to define an annulus region 134. When installed, the cement disruptor sleeve 122 is located at a position above the seabed 132.

Cement 136 is then pumped into the annulus 134, as illustrated in Figure 8B, with the flow channels 124 of the cement disruptor sleeve 122 permitting a cement sheath to be formed both above and below the sleeve 122. The presence of the disruptor sleeve 122 creates a region of localised weakness within the cement sheath 136. Such a region of localised weakness may be defined as a ductile fuse.

Accordingly, in the event of bending or flexing of the well 129, as illustrated in Figure 8C, the cement 136 in the region of the disruptor sleeve 122 will more readily break/fail such that the effective bending stiffness of the installed well 129 will be reduced, allowing flexing to be more readily achieved with less additional stress. Furthermore, issues can arise during bending of a well of cement failure or cracking in unknown locations, which may cause sealing issues. The cement disruptor sleeve 122 permits control over the location of any cement failure.

In a modified example multiple disruptor sleeves may be provide along the length of the annulus 134. Further, in a modified example the well 129 may include multiple casing strings and multiple annuli, wherein the cement disruptor may be provided in multiple annuli.

In an alternative example, as illustrated in Figure 9, a cement disruptor sleeve 140 may be mounted internally of a conductor pipe 142, wherein the sleeve 140 and conductor pipe 142 are shown in longitudinal section in Figure 9. The disruptor sleeve 140 may also include circumferentially arranged flow channels 144, which are also seen in the top view illustrated in Figure 10. The disruptor sleeve may function in the same manner as sleeve 122 of Figure 6.

A further alternative example of a cement disruptor arrangement 152 is illustrated in Figure 11. In this example a casing string 150 includes the cement disruptor 152 in the form of a plurality of nodules 154 extending or protruding from an outer surface of the casing string 150, with an example nodule geometry illustrated in Figure 12. The nodules 154 extend circumferentially around the casing string 150, as illustrated in Figure 13.

The use and effect of the cement disruptor arrangement 152 will be described with reference to the sequential operational drawings of Figures 14A to 14C. In Figure 14A a well 149 includes a conductor pipe 160 inserted within the seabed 162, with the casing string 150 and cement disruptor arrangement 152 installed within the conductor pipe 160 to define an annulus region 164. When installed, the cement disruptor arrangement 152 is located at a position above the seabed 162.

Cement 166 is then pumped into the annulus 164 to form a cement sheath, as illustrated in Figure 14B, with the cement disruptor arrangement 152 effectively becoming embedded within the cement sheath.

In the event of bending or flexing of the well 149, as illustrated in Figure 14C, the cement 166 in the region of the disruptor arrangement 152 will more readily break/fail such that the effective bending stiffness of the installed conductor pipe 160 will be reduced, allowing flexing to be more readily achieved with less additional stress and with any cement failure provided at a predefined region. In a modified example multiple disruptor arrangements may be provided along the length of the annulus 164. Further, a similar disruptor arrangement may additionally or alternatively be provided on a casing string installed within the conductor pipe.

A further example of a cement disruptor is shown in Figure 15A, which is a diagrammatic illustration of a wall of a conductor pipe 170 which forms part of a surface well. In this example a low-friction coating 172, such as a PFTE or similar coating, is applied on an inner surface of the conductor pipe 170. The low-friction coating 172 provides a mechanical reduction of friction or adhesion between a cement sheath 174 and the conductor pipe 170. As such, during flexing or bending of the associated well the shear stress between the conductor pipe 170 and cement sheath 174 will be limited, allowing relative movement more readily, as illustrated in Figure 15B, which diagrammatically illustrates the effect of the reduced shear stress during a bending event.

Alternatively, or additionally, a similar coating may be applied on an outer surface of a casing string installed within the conductor pipe.

A further example is illustrated in Figure 16A, which diagrammatically illustrates a wall of a conductor pipe 180. In this example the cement disruptor is provided by a chemical coating 182 applied on an inner surface of the conductor pipe 170. The coating functions to prevent or reduce the curing of cement 184 in the region of the coating 182. This arrangement may provide an uncured or low adhesion region 186 of the cement 184, as illustrated in Figure 16B. This may minimise shear forces applied between the cement 184 and the conductor pipe 180, thus assisting to improve bending flexibility of the well.

The coating may comprise a cement retarder. In one example the coating 182 may comprise a sugar based chemical/solution.

Alternatively, or additionally, a similar chemical coating may be applied on an outer surface of a casing string installed within the conductor pipe.

Reference is now made to Figure 17 which is a diagrammatic illustration of an offshore installation which includes a conductor pipe 200 inserted within the seabed 202, with a casing string 204 installed within the conductor pipe 200 and extending into a drilled bore 206, with an annulus 208 formed between the conductor pipe 200 and casing string 204. In a similar manner to the example first shown in Figure 3A, the annulus 208 is partially filled with cement 210 to a first height 212 which is above the seabed 202, but below the upper end 214 of the conductor pipe 200. As described above, such an arrangement can improve the flexibility of the well.

In the present example of Figure 17 the conductor pipe 200 includes separate axial wall sections 200a, 200b which include a different bending stiffness, such that a variation in the bending stiffness or modulus of the conductor pipe 200 is achieved along its length. This may permit control to be achieved on the bending or flexing behaviour of the conductor pipe 200, for example to create a desired curve from the seabed 202 upwardly.

In the embodiment illustrated the varying bending stiffness or modulus is achieved by the different sections 200a, 200b having different thicknesses. In other examples a variation in material, geometry or the like may provide the varying stiffness or modulus.

In some examples the conductor pipe 200 may be formed of multiple pipe sections, coupled together in end-to-end relation. Figure 18 diagrammatically illustrates an example conductor pipe section 220, which includes opposing end threaded connectors 222, 224 permitting adjacent sections to be secured together. The wall of the pipe section 220 extending between the connectors 222, 224 includes a varying wall thickness, which may thus provide the variation between the different sections 200a, 200b of the conductor pipe 200.

In an alternative, unillustrated example, individual conductor pipe sections may include a common or uniform wall thickness between end connectors. In this case a variation of stiffness along the length of the conductor pipe 200 may be achieved by making up the conductor pipe 200 using different pipe sections of different thicknesses.

While Figures 17 and 18 are directed to a conductor pipe with varying bending stiffness along its length, this sample principle may be applied to casing strings, or indeed any other well pipe or tubular.

Figure 19a shows a bottom supported wellhead platform 1900 having a topside 1902 comprising one or more decks 1902a-c, such as weather deck 1902a, a production deck 1902b and a wellhead deck 1902c, and a plurality of legs 1904a-c. Together, the wellhead platform 1900 comprising topside 1902 and legs 1904a-c support the conductors and provides and provides a support structure for the conductors formed at least by elements of the wellhead platform accommodating or engaging with the conductors, such as one or more deck sections defining openings through the decks for the conductors to extend through the deck, fasteners, guides, locking, and/or securing mechanisms. The legs 1904a-c, along with other elements of the support structure of the wellhead platform 1900, allow for movement while supporting one or more conductors, possibly at a plurality of different heights. The term "support structure" as used herein encompasses a broad definition of providing mechanical support and also other functions that a platform provides such as shielding the conductor from impacts. Therefore, an opening in a deck may also be a part of the support structure of the wellhead platform 1900.

As shown in Figure 19a, a plurality of conductors 1906a-d are supported by the wellhead platform 1900. The remainder of the description of Figure 19a focusses on the conductor 1906a and its associated support structure, but one or more features or functions described may also relate to the other conductors 1906b-d and the associated support structure.

An upper part of the conductor 1906a (i.e. the part of the conductor that is above the seabed) may be laterally constrained by one or more guides 1908a-e and other elements which may connect or otherwise engage with the conductor 1906a. The guides 1908a-e may surround the conductor 1906a such that the conductor 1906a passes through the guides 1908a-e. Each guide 1908a-e is configured to be connected to one or more legs 1904a-c of a wellhead platform 1900 by a guide system 1910a-e. In the example of Figure 19a, the guide systems 1910a-e are configured to be used with the conductor 1906a and so are termed conductor guide systems 1910a-e, although in some embodiments they may be configured to be used with other tubular strings. Also in the example of Figure 19a, the guides 1908a-e are connected to the leg 1904a. One or more of the conductor guide systems 1910a-e is longitudinally extendable and/or retractable to alter a distance between the leg 1904a and the conductor 1906a. In addition, the upper part of the conductor 1906a is connected to the wellhead platform 1900 by a moving mechanism 1912. In the case of Figure 19b, the moving mechanism is configured to move the conductor 1906a and so is a conductor moving mechanism 1912, although the moving mechanism may be configured to move other types of tubular strings. The conductor moving mechanism 1912 is connected to the conductor 1906a proximal to an upper end, such that extension or retraction of the conductor moving mechanism 1912 controls the position of the upper end. In specific arrangements, the conductor moving mechanism 1912 is connected to the conductor 1906a close enough to the upper end of the conductor 1906a that movement of the conductor moving mechanism 1912 results in substantially the same amount of movement of the upper end of the conductor 1906.

In the exemplary apparatus of Figure 19a, five guides 1908a-e are shown per upper part of a conductor 1906a, although other numbers of guides 1908a-e may be used. In the exemplary arrangement of Figure 19a, first to fifth guides 1908a-e and corresponding guide systems 1910a-e are located below the conductor moving mechanism 1912 in consecutive order moving towards the seabed. The first guide system 1910a is an active guide system. The second and third guide systems 1910b-c are passive guide systems. The fourth and fifth guide systems 1910d-e are rigid or fixed guide systems. It will be appreciated that in other arrangements, the conductor moving mechanism, active, passive and rigid guide systems may be differently ordered and there may be more or fewer of each.

The conductor moving mechanism 1912 and the active guide system 1910a may be configured to extend and/or retract in order to move the upper end of the conductor 1906a. Exemplary conductor moving mechanisms 1912 and active guide systems 1910a may be configured to extend and/or retract under hydraulic power.

The passive guide systems 1910b-c may be configured to be extendable and/or retractable under force applied to them by the conductor 1906a when its upper end is moved by the conductor moving mechanism 1912 and/or the active guide system 1910a. Exemplary passive guide systems 1910b-c are not powered and do not directly cause movement of the conductor 1906a, although they may be damped such that when extending and/or retracting, or indeed when stationary, the amount of movement of the conductor 1906a is controlled. Each passive guide 1910b-c may have a different level of damping.

The rigid guide systems 1910d-e are configured not to be extendable or retractable. They may therefore provide a fixed point for a force applied to the upper end of the conductor 1906a by the conductor moving mechanism 1912 and/or the active guide system 1910a to react against.

Accordingly, the support structure provided by the wellhead platform 1900 may be considered to be a configurable support structure.

It is noted that in exemplary arrangements, a plurality of guide systems may connect each guide 1908a-e to the leg 1904a and/or to one or more further legs. Further, a plurality of conductor moving mechanisms 1912 may connect the conductor 1906a to the leg 1904a and/or one or more further legs). The plurality of conductor moving mechanisms and/or guide systems may extend in different directions transverse to a longitudinal axis of the conductor 1906a in order to provide increased control of the movement of the conductor 1906a.

Figure 19b shows the upper end of the conductor 1906a after it has been moved from a first position 1914 to a second position 1916. The first position 1914 may be at least one of a parking position, a storage position, an injection position, a well intervention position, and a production position. Typically, the first position (or production position) is also where any work over is performed. The second position 1916 may be a well processing and/or drilling position. The second position 1916 may be a shared second position for a plurality of conductors in that the second positions of the plurality of conductors coincide or overlap. Due to alignment issues the wellhead platform 1900 will typically provide a shared second position within a zone rather than at a single position.

The second position 1916 coincides with a first drilling (or well processing) centre 1918a of the wellhead platform 1900. Other conductors, for example conductors 1906c and 1906d, may have shared second positions coinciding with a second (or further) drilling (or well processing) centre 1918b.

The bottom supported wellhead platform 1900 allows movement of the upper part of each of the conductors 1906a-d between first and a second positions. It is noted that a conductor can have a position in three dimensions and the shared second position implicitly refers to the upper end of the conductor and might not refer to the entire conductor. If the conductor is installed with the upper end in the first (e.g. production) position, the three dimensional shape of the entire conductor may not be the same after it has been processed in the second position and reverted to the first position.

As can be seen in Figure 19b, the conductor moving mechanism 1912 and the active guide system 1910a have been extended, for example under hydraulic power, to move the upper end of the conductor 1906a from the first position 1914 to the second position 1916. The force applied by the conductor moving mechanism 1912 and the active guide system 1910a has reacted against the fixed position of the conductor 1906a at the rigid guide systems 1910d-e. The passive guide systems 1910b-c have extended to accommodate the movement of the upper part of the conductor 1906a resulting from the movement of the upper end of the conductor 1906a from the first position 1914 to the second position 1916. In exemplary arrangements, the relative extension of the conductor moving mechanism 1912 and the active guide system 1910a may be configured to align the upper end of the conductor 1906a vertically in the second position 1916. That is, the conductor 1906 may form a shallow "s-bend".

As explained above, the conductor 1906a has a casing string located therein and an annulus is formed between the two. In exemplary arrangements, a portion of the annulus may be configured in any way described herein to reduce the stiffness of the well at a point on the upper part of the conductor 1906a at which bending or flexing is desired on actuation of the conductor moving mechanism 1912 and/or the active guide system 1910a. For example, the stiffness of the well may be reduced at a point vertically aligned with the guide 1908d or with a point above the guide 1908d, for example, between the guide 1908d and the conductor moving mechanism 1912. In specific arrangements, the stiffness of the well may be reduced at a point between the guide 1908d and the guide 1908c having the passive guide system 1910c.

It will be appreciated that arrangements disclosed herein including a third tubular string defining a second annulus may also be applied to the arrangement of Figures 19a and 19b.

In specific exemplary arrangements, the annulus may be partially filled with cement to a first height aligned with or slightly below the point of the upper part of the conductor 1906a at which bending or flexing is desired. Therefore, the first height may be substantially level with the guide 1908d, which is connected to the leg 1904a by the rigid guide system 1910d. Alternatively, the first height may be above the guide 1908d, for example by a distance of 1 meter or more, such as 2 meters or more, such as 3 meters or more, such as 4 meters or more, such as 5 meters or more, such as 6 meters or more but typically within a distance of 90% of the distance to a higher guide or other engagement member (in this case 1908c), such as within 70% of that distance, such as within 50% of that distance, such as within 25% of that distance. In some embodiments this means within a distance of 30 meters, such as within 20 meters, such as within 10 meters or even within 5 meters.

In some exemplary arrangements, a cement disruptor may be aligned with a portion of the upper part of the conductor 1906a at which bending or flexing is desired on actuation of the conductor moving mechanism 1912 and/or the active guide system 1910a. In specific arrangements, the cement disruptor may be located at a portion of the conductor that is aligned with the guide 1908d, or may be between the guide 1908d and the conductor moving mechanism 1912. In specific arrangements, the cement disruptor may be located at a point between the guide 1908d and the guide 1908c having the passive guide system 1910c. The cement disruptor may be located, for example, as discussed in relation to the cement height in the previous paragraph above the guide 1908d. By any of the means discussed above, a cement disruptor may be positioned within the annulus and configured to reduce the stiffness of the well (e.g. conductor, cement sheath and casing string). In some embodiments, a cement disrupter may be placed in alignment with two or more guides, such as three or more guides, such as four or more guide such as all guides. In some embodiments cement disrupters are further or alternatively installed between one pair of guides or more, such as between two or more pairs, such as between three or more pairs. In this way improved flexibility of the well above the seabed may be improved.

In exemplary arrangements in which the cement disruptor is positioned at substantially the same height on the upper part of the conductor 1906a as the guide 1908d and the rigid guide system 1910d, the guide 1908d may have some play between the conductor 1906a and an inner surface of the guide 1908d in order to accommodate the flexing or bending of the conductor 1906 within the guide 1908d. In other exemplary arrangements, the cement disruptor may be positioned above the guide 1908d such that the force reacting against the guide 1908d and the rigid guide system 1910d applied by the conductor moving mechanism 1912 and/or the active guide system 1910a causes flexing or bending of the conductor 1906 above the guide 1908d. In such arrangements, there may be no (or minimal) play between the conductor 1906a and the inner surface of the guide 1908d.

The remainder of the annulus above a cement disruptor may comprise cement. Alternatively, one or more further cement disruptors may be positioned above the first cement disruptor to accommodate flexing or bending of the conductor 1906a. This may also be achieved by any of the other methods disclosed herein, such as partially filling the annulus above the cement disruptor 920 or locating a flexible material in the annulus above the cement disruptor.

In one example, a further cement disruptor (or any other means disclosed herein) may be positioned above the first cement disruptor to aid the formation of a shallow “s-bend” in the conductor 1906a. This may allow proper alignment of the upper end at the second position 1916, e.g. so that the upper end is substantially vertically aligned. In exemplary arrangements, a plurality of the further cement disruptors (or any other means disclosed herein) may provide different reductions in stiffness to that of the first cement disruptor 1920. In one exemplary arrangement, a further cement disruptor (or any other means disclosed herein) may be located in alignment with the guide 1908a and active guide system 1910a such that the conductor moving mechanism 1912 may control the upper end of the conductor 1906a by applying a force reacting against the active guide system 1910a. For example, a further cement disruptor may be located substantially level with the guide 1908a and the relative extension of the conductor moving mechanism 1912 and the active guide system 1910a may be configured to align the upper end of the conductor 1906a vertically in the second position 1916.

In some exemplary arrangements, a flexible material may be located within the annulus in any manner described herein. The flexible material may be located at substantially the same height on the upper part of the conductor 1906a as the guide 1908d and the rigid guide system 1910d. As mentioned above, in such arrangements, the guide 1908d may have some play between the conductor 1906a and an inner surface of the guide 1908d. In other exemplary arrangements, the flexible material may be positioned above the guide 1908d such that the force reacting against the rigid guide system 1910d applied by the conductor moving mechanism 1912 and the active guide system 1910a causes flexing or bending of the conductor 1906 above the guide 1908d. The flexible material may be located, for example, as discussed in relation to the cement height above the guide 1908d. In such arrangements, there may be no (or minimal) play between the conductor 1906a and the inner surface of the guide 1908d. As with the cement disruptors, flexible material may be applied to the annulus at a plurality of locations on the upper part of the conductor 1906a and may have varying resistances to bending.

Significant force may be required when moving an upper end of a conductor from the first position 1914 to the second position 1916. This force acts laterally on the wellhead platform 1900 in a direction opposite to the direction in which the upper end of the conductor 1906a is being moved and may result in unwanted movement of the wellhead platform 1900 and/or unwanted stresses in the structure of the wellhead platform 1900.

To overcome these effects, when a force is applied from the wellhead platform 1900 to a first upper end of a conductor to move it between first and second positions, a further force may be applied from the wellhead platform 1900 to one or more further upper ends, such that a resultant further force is substantially opposite in direction and/or substantially equal in magnitude to the force applied to the first upper end. One or more of the forces may be applied by one or more conductor moving mechanisms, as discussed above.

Figure 20 shows a cluster of upper ends of conductors. The upper ends 2000a-f may be retained in the support structure 2002 of the wellhead platform. In the exemplary arrangement shown in Figure 20, first positions are located equidistantly from a shared second position 2004, which is shown by the circle 2006 (shown dashed) about the shared second position 2004. The support structure 2000 is configured to allow further movement of each upper end beyond the first positions.

A first force 2008 (represented by an arrow) is applied from the wellhead platform to the first upper end 2000a. Second and third forces 2010, 2012 are applied respectively from the wellhead platform to further upper ends 2000b, 2000f. The second and third forces 2010, 2012 provide a resultant force that is substantially opposite the first force 2008. This has the effect of compensating for, or mitigating the effects of, the first force 2008.

It should be noted that the compensating force(s) (the second and third forces 2010, 2012 in the example of Figure 20) may be applied to one or more other the upper ends 2000b-f and in any direction, such that the resultant force mitigates the effect of the force 2008 applied to the first upper end 2000a. For example, to compensate for the force 2008 applied to the first upper end 2000a, one or more forces may be applied to one or more of the upper ends 2000c-e to move them towards the shared second position 2004. In exemplary arrangements, the resultant force may be in a substantially opposite direction to the first force and will have a substantially equal magnitude.

One or more of the forces 2008, 2010, 2012 (or any other forces associated with Figure 20) may be applied by the guide systems discussed in relation to Figures 19a-b.

It should be understood that the examples described herein are indeed exemplary and that various modifications may be made thereto without departing form the scope of the present invention. For example, the bending flexibility of a well may be achieved by a combination of examples provided above.

In the examples described above a centralisation system may be used between adjacent tubular strings (e.g., between conductor pipe and surface casing string, and/or between adjacent casing strings). This may assist to ensure the tubular strings are centralised, and remain substantially centralised following movement or bending of the upper well portion. This may assist to ensure appropriate cement placement (or even placement of a flexible material, for example), for example circumferential coverage, within the first annulus, for example initial cement placement and/or in a subsequent cementing operation, such as a top fill cementing operation.

CLAIMS:

1. A method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

partially filling the first annulus with cement to a first height which is intermediate the seabed and the terminating upper end of the well structure.

2. The method of claim 1, wherein a region of the first annulus above the first height is substantially void of cement.

3. The method of claim 1 or 2, wherein the upper well portion extends above a surface of the sea with the terminating upper end of the well structure aligned with a surface platform.

4. The method of any preceding claim, wherein the first tubular string comprises a conductor pipe, and the method comprises inserting the conductor pipe into the seabed such that a portion of the conductor pipe extends upwardly from the seabed to the terminating upper end of the well structure.

5. The method of claim 4, wherein the second tubular string comprises a casing string, and the method comprises inserting the casing string within the conductor pipe to define the first annulus therebetween, wherein the casing string extends upwardly to the terminating upper end of the well structure.

6. The method of any one of claims 1, 2 or 3, wherein the first tubular string comprises a first casing string and the second tubular string comprises a second casing string located within the first casing string.

7. The method of any preceding claim, comprising pumping cement into the first annulus, and ceasing pumping of the cement when the first height has been achieved.

8. The method of any preceding claim, comprising measuring the height of cement within the first annulus during filling of said first annulus to determine when the first height of the cement has been achieved.

9. The method of any preceding claim, comprising providing a desired volume of cement and placing this desired volume of cement within the first annulus such that the first height is achieved.

10. The method of any preceding claim, wherein a tubular string support or guide arrangement is provided between the first and second tubular strings to provide load transference and/or guiding between the first and second tubular strings, at least prior to locating cement within the first annulus, wherein the method comprises embedding the tubular string support or guide arrangement within the cement.

11. The method of any preceding claim, comprising washing or flushing out the first annulus above the first height of the cement.

12. The method of any preceding claim, comprising moving the terminating upper end of the well structure between first and second positions, wherein such movement induces bending of the upper well portion.

13. The method of claim 12, comprising performing a subsequent cementing operation following movement of the terminating upper end of the well structure to add cement into the first annulus to a second height.

14. The method of any preceding claim, comprising placing a flexible material within the first annulus above the first height of the cement.

15. The method of claim 14, comprising placing the flexible material at one or more discrete locations along the first annulus.

16. The method of claim 14, comprising placing flexible material along the first annulus between the first height of the cement and the terminating upper end of the well structure.

17. The method according to any preceding claim, comprising installing a third tubular string as part of the well structure, wherein a second annulus is defined between the third tubular string and one of the first and second tubular strings.

18. The method according to claim 17, comprising locating cement in the second annulus.

19. The method according to claim 18, comprising partially filling the second annulus with cement.

20. The method according to any one of claims 17 to 19, comprising providing fluid communication between the first and second annuli above the first height, wherein fluid communication is provided via a valve.

21. The method according to claim 20, comprising circulating a fluid between the first and second annuli.

22. The method according to any preceding claim, comprising varying the bending stiffness along at least one of the first and second tubular strings.

23. The method of any preceding claim, wherein the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform,

and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system,

the first height being arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

24. The method of claim 23, wherein the first height is one of: substantially level with the guide; and above the guide.

25. The method of claim 24, wherein the first height is above the guide by a distance of up to 5 metres.

26. An offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

cement partially filling the first annulus to a first height which is intermediate the seabed and the terminating upper end of the well structure.

27. A method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween;

locating cement within the first annulus to define a cement sheath; and

providing a cement disruptor within the first annulus, wherein the cement disruptor reduces resistance of the cement sheath to bending of the upper well portion.

28. The method of claim 27, wherein the cement disruptor provides a localised weakness at a location along the cement sheath.

29. The method of claim 28, comprising bending the upper well portion to cause failure of the cement sheath at the location of the weakness.

30. The method of claim 29, wherein the bending is caused by moving the terminating upper end of the well structure from a first position to a second position.

31. The method of any one of claims 27 to 30, wherein the cement disruptor provides a localised reduction in the thickness of the cement sheath.

32. The method of any one of claims 27 to 31, wherein the cement disruptor mechanically weakens the cement sheath.

33. The method of any one of claims 27 to 32, wherein the cement disruptor comprises or defines one or more flow passages or channels to permit cement to flow past the cement disruptor during location of cement within the first annulus, and the method comprises embedding at least a portion of the cement disruptor in the cement.

34. The method of any one of claims 27 to 33, wherein the cement disruptor comprises a sleeve.

35. The method of claim 34, wherein the sleeve is mounted on at least one of an inner surface of the first tubular string and an outer surface of the second tubular string.

36. The method of any one of claims 27 to 35, wherein the cement disruptor comprises one or more protuberances which extend into the first annulus, wherein the one or more protuberances extend from one or both of the first and second tubular strings.

37. The method of any one of claims 27 to 36, wherein the cement disruptor comprises a coating applied to one or both of the inner surface of the first tubular string and outer surface of the second tubular string, wherein the coating disrupts adherence of the cement sheath to one or both of the first and second tubular string.

38. The method of claim 37, wherein the coating comprises a mechanical barrier which reduces friction between the cement sheath and first/second tubular string.

39. The method of claim 37 or 38, wherein the coating comprises a chemical barrier for preventing or reducing curing of the cement in the region of the chemical barrier to reduce cement adhesion with the first and/or second tubular string.

40. The method of any one of claims 27 to 39, comprising providing multiple cement disruptors axially along the first annulus.

41. The method according to any one of claims 27 to 40, wherein the well structure comprises a third tubular string, wherein a second annulus is defined between the third tubular string and one of the first and second tubular strings.

42. The method according to claim 41, comprising locating cement within the second annulus to define a second cement sheath, and providing a cement disruptor within the second annulus, wherein the cement disruptor reduces resistance of the second cement sheath to bending of the upper well portion.

43. The method of any of claims 27 to 42, wherein the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform,

and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system,

the method comprising locating the cement disruptor at a location arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

44. The method of claim 43, wherein the location of the cement disruptor is one of: substantially level with the guide; and above the guide.

45. The method of claim 44, wherein the location of the cement disruptor is above the guide by a distance of up to 5 metres.

46. The method of any of claims 43 to 45, wherein the upper well portion is configured to be moved at a location of a further guide, below the moving mechanism and above the guide, by an active guide system connectable between the further guide and the wellhead platform,

the method further comprising configuring the well structure to have reduced axial stiffness at a point substantially aligned with the further guide.

47. The method of claim 46, wherein configuring the well to have reduced axial stiffness comprises one or more of: locating a further cement disruptor in the well structure; partially filling the annulus with cement; and locating a flexible material in the well structure.

48. An offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween;

a cement sheath at least partially filling the first annulus; and

a cement disruptor located within the first annulus.

49. A method for forming an offshore well, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

locating a flexible material within the first annulus.

50. The method of claim 49, comprising locating the flexible material at one or more discrete locations along the first annulus.

51. The method of claim 49, comprising substantially filling the first annulus with the flexible material.

52. The method of any one of claims 49 to 51, comprising partially filling the first annulus with cement to a first height within the first annulus, and then locating the flexible material within the first annulus above the first height of the cement.

53. The method according to any of claims 49 to 52, wherein the terminating upper end of the well structure is configured to be moved between first and second positions by a moving mechanism connectable between the first tubular string and a wellhead platform,

and wherein the first tubular string is configured to be laterally constrained by a guide, the guide being connected to the wellhead platform by a rigid guide system,

the method comprising locating the flexible material at a location arranged to allow bending of the well structure at or above the guide on actuation of the moving mechanism.

54. The method of claim 53, wherein the location of the flexible material is one of: substantially level with the guide; and above the guide.

55. The method of claim 54, wherein the location of the flexible material is above the guide by a distance of up to 5 metres.

56. The method of any of claims 53 to 55, wherein the upper well portion is configured to be moved at a location of a further guide, below the moving mechanism and above the guide, by an active guide system connectable between the further guide and the wellhead platform,

the method further comprising configuring the well structure to have reduced axial stiffness at a point substantially aligned with the further guide.

57. The method of claim 56, wherein configuring the well to have reduced axial stiffness comprises one or more of: locating a cement disruptor in the well structure; partially filling the annulus with cement; and locating a further flexible material in the well structure.

58. An offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween; and

a flexible material located within the first annulus.

59. An offshore well pipe for use in forming an offshore well and including an upper portion to be installed above a seabed, wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of the well pipe.

60. The offshore well pipe according to claim 59, comprising multiple well pipe sections secured together, in end-to-end relation, to form the well pipe.

61. The offshore well pipe according to claim 60, wherein the well pipe sections include end connectors and variations in bending stiffness is provided between axial wall sections which are located between end connectors of a well pipe section.

62. The offshore well pipe according to claim 60 or 61, wherein different axial wall sections with different bending stiffness are provided on a single well pipe section.

63. The offshore well pipe according to any one of claims 60 to 62, wherein different axial wall sections with different bending stiffness are provided on different well pipe sections.

64. The offshore well pipe according to any one of claims 59 to 63, wherein the at least two axially extending wall sections comprise different wall thicknesses to provide a different bending stiffness.

65. The offshore well pipe according to any one of claims 59 to 64, wherein the at least two axially extending wall sections comprise different materials to provide a different bending stiffness.

66. The offshore well pipe according to any one of claims 59 to 55, wherein the at least two axially extending wall sections comprise different geometries to provide a different bending stiffness.

67. The offshore well pipe according to any one of claims 59 to 55, defining at least one of a conductor pipe and a casing string.

68. A method for forming an offshore well, comprising:

forming a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween,

wherein the first and second tubular strings include an upper portion to be installed above a seabed within the upper well portion, and wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of at least one of the first and second tubular strings.

69. An offshore well installation, comprising:

a well structure which includes a lower well portion extending below a seabed and an upper well portion extending between the seabed and a terminating upper end of the well structure, wherein the well structure comprises a first tubular string and a second tubular string located within the first tubular string with a first annulus defined therebetween,

wherein the first and second tubular strings include an upper portion installed above a seabed within the upper well portion, and wherein the bending stiffness varies between at least two axially extending wall sections of the upper portion of at least one of the first and second tubular strings.

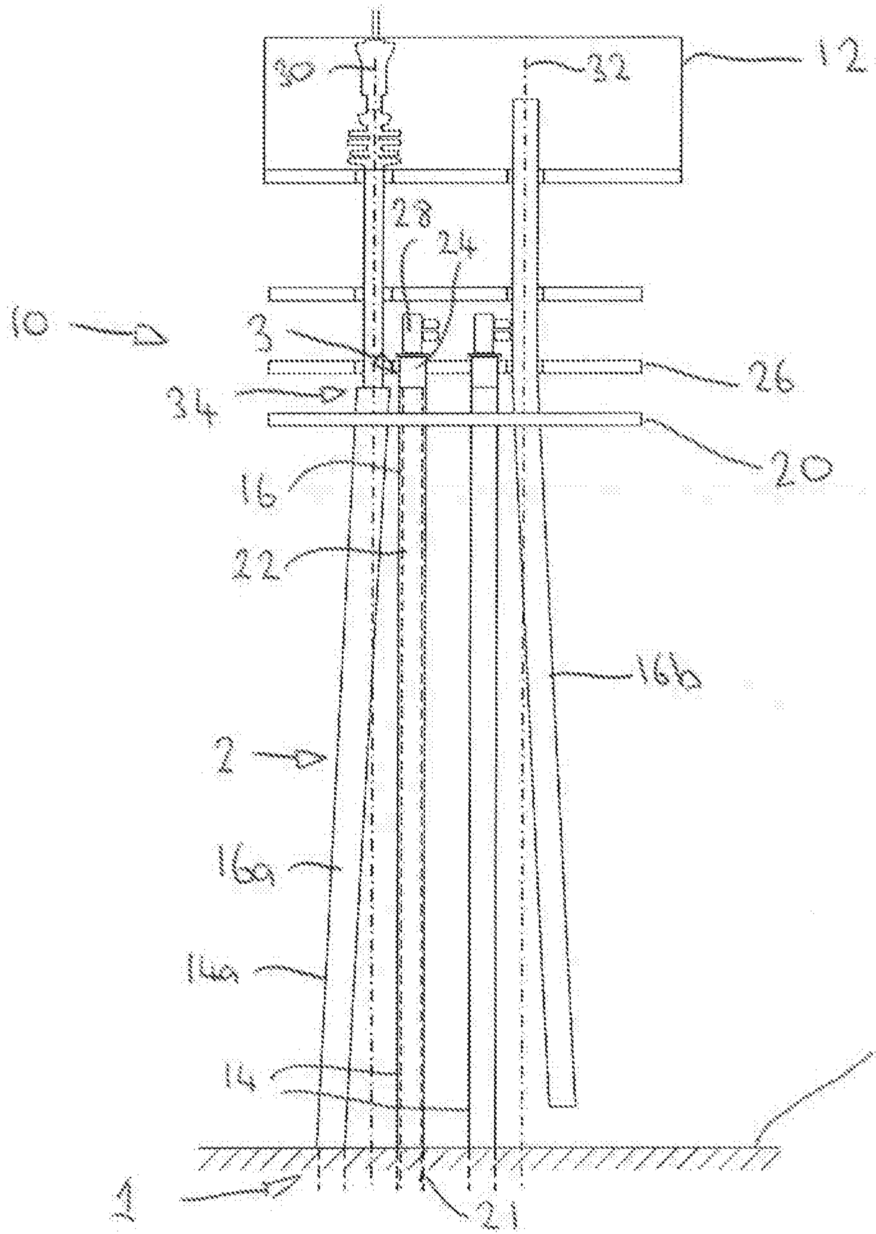


FIG. 1

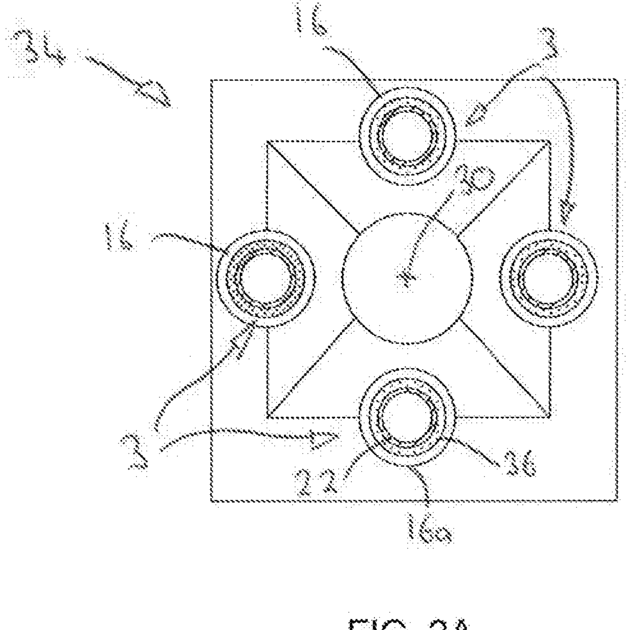


FIG. 2A

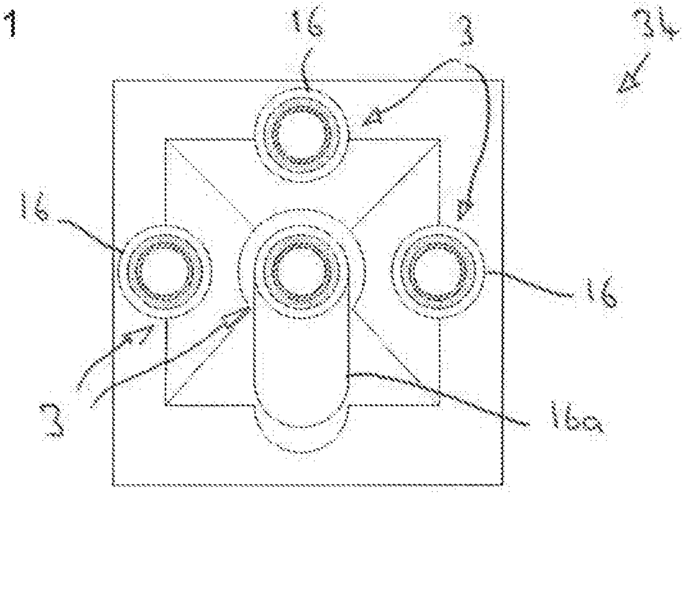


FIG. 2B

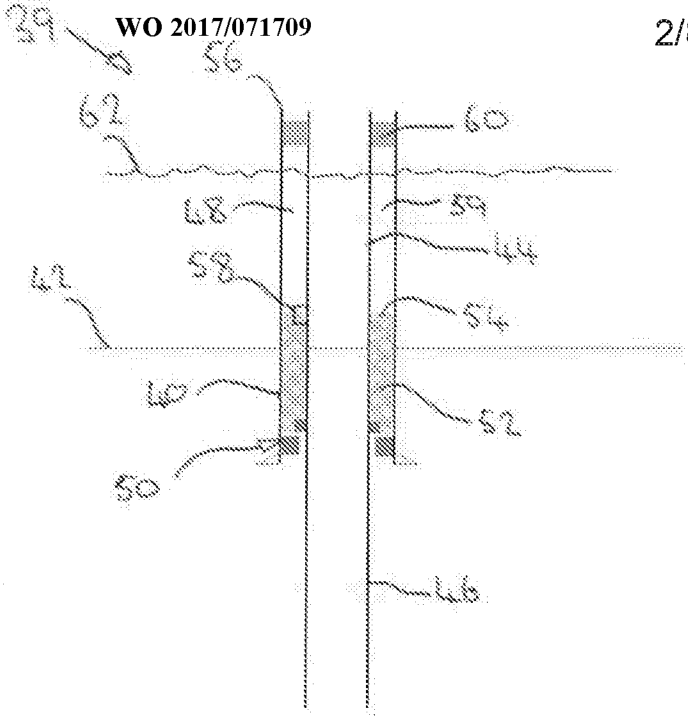


FIG. 3A

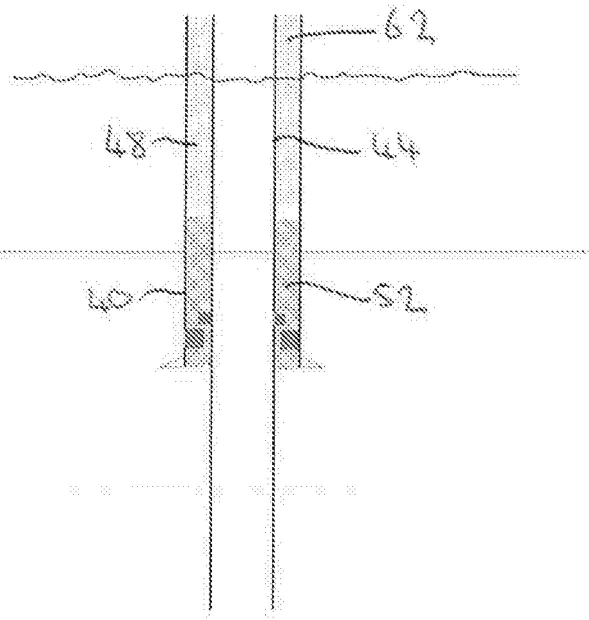


FIG. 3B

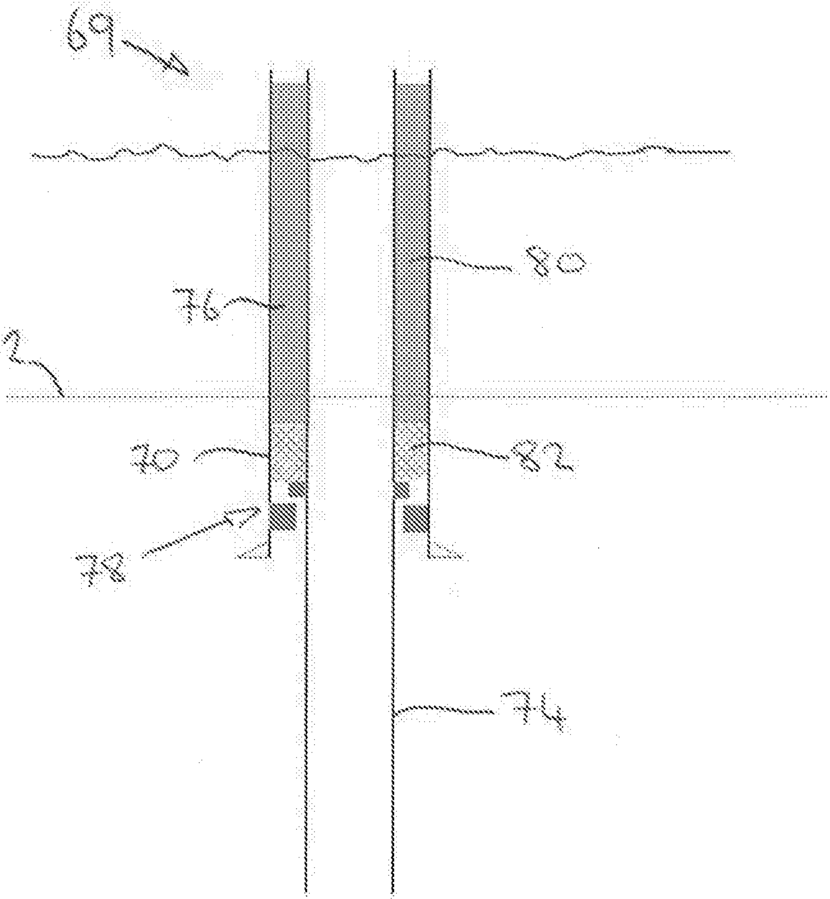


FIG. 4

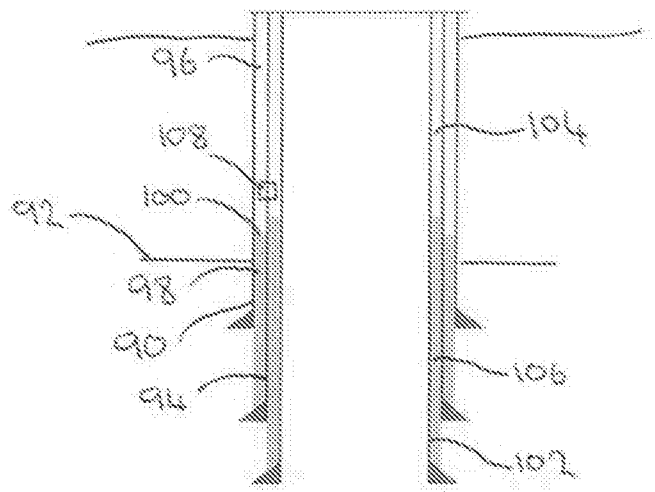


FIG. 5A

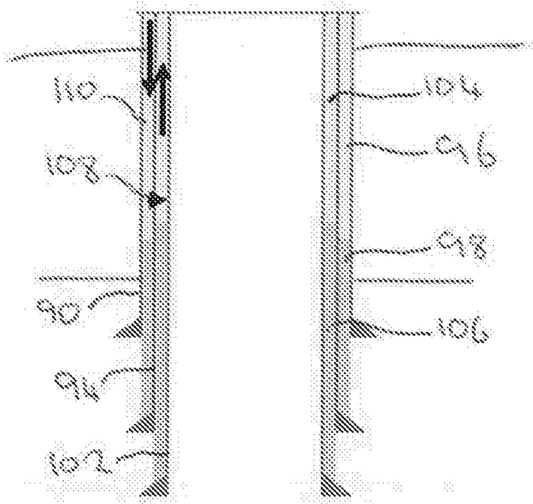


FIG. 5B

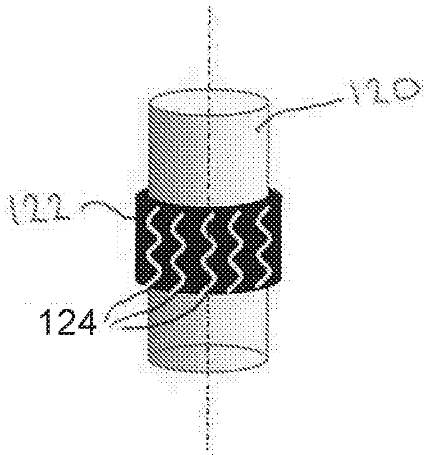


FIG. 6

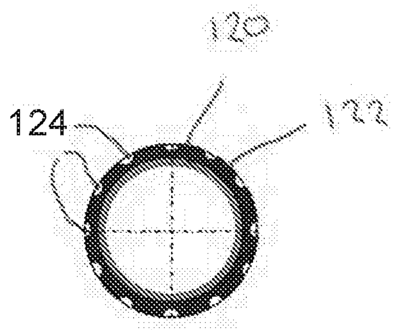


FIG. 7

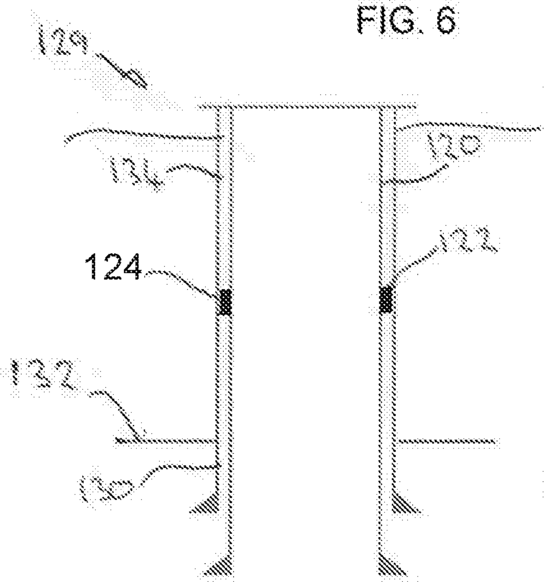


FIG. 8A

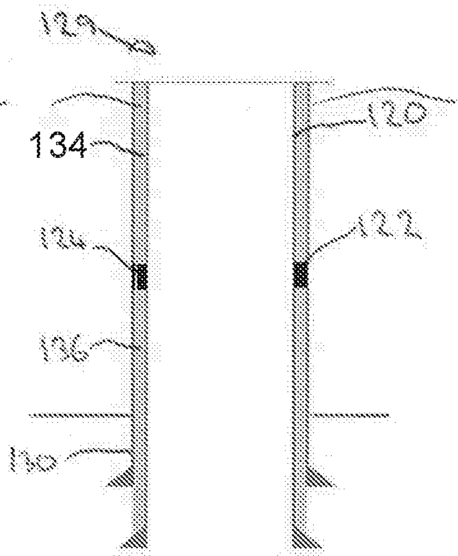


FIG. 8B

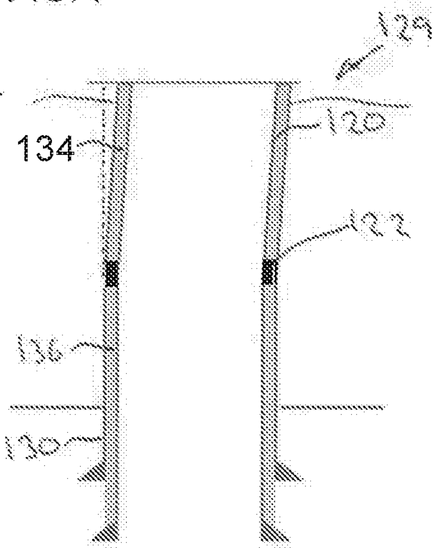


FIG. 8C

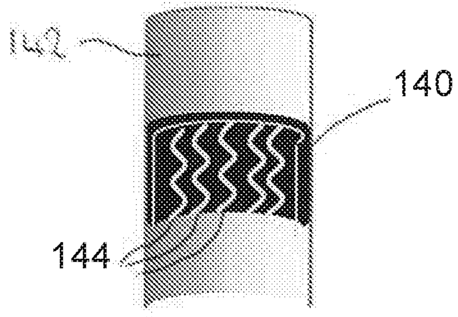


FIG. 9

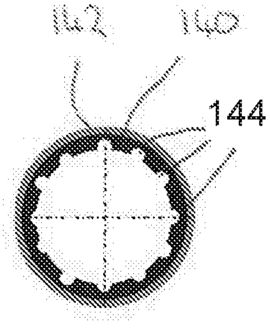


FIG. 10

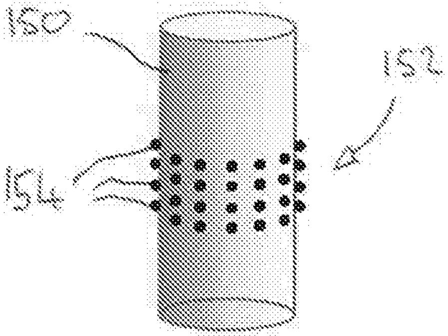


FIG. 11

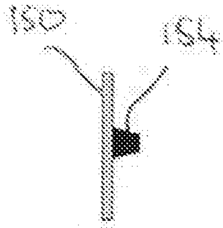


FIG. 12

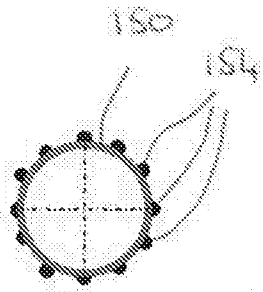


FIG. 13

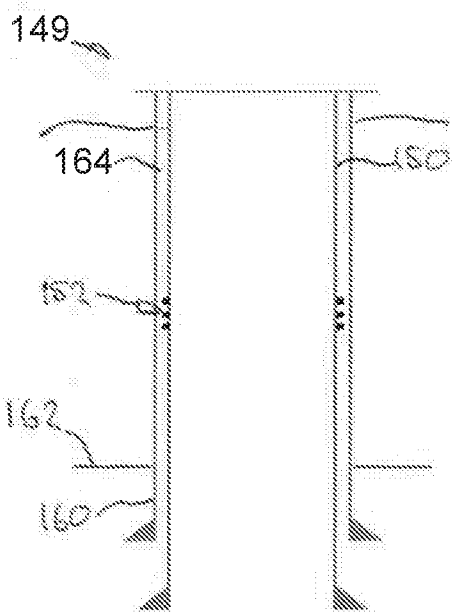


FIG. 14A

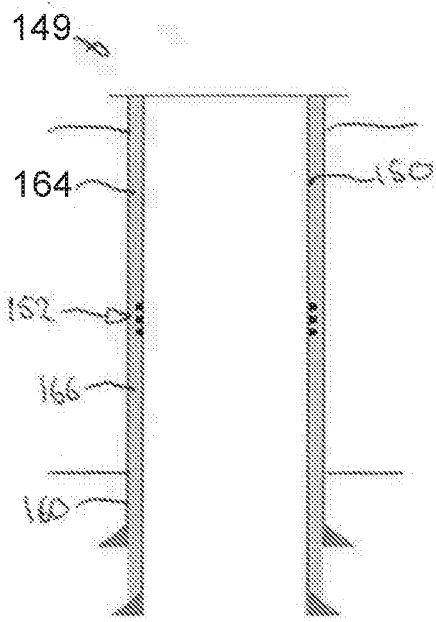


FIG. 14B

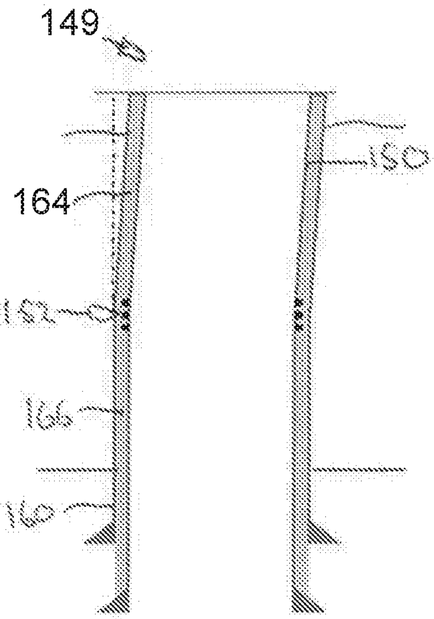


FIG. 14C

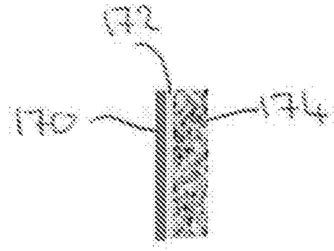


FIG. 15A

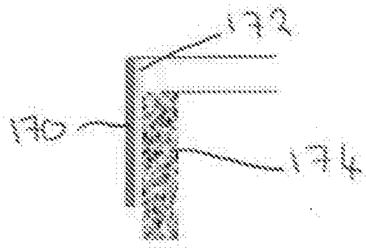


FIG. 15B

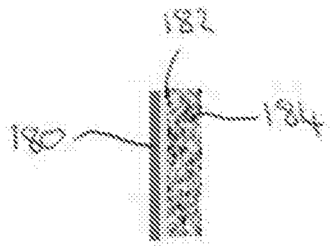


FIG. 16A

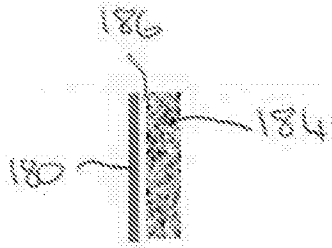


FIG. 16B

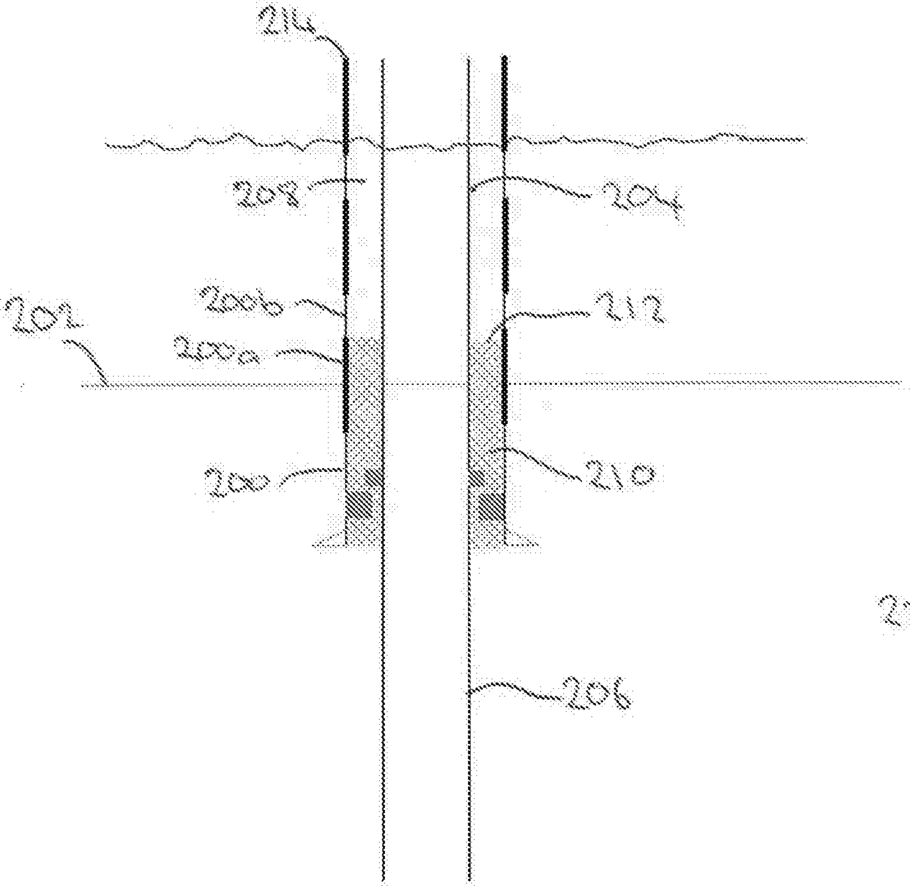


FIG. 17

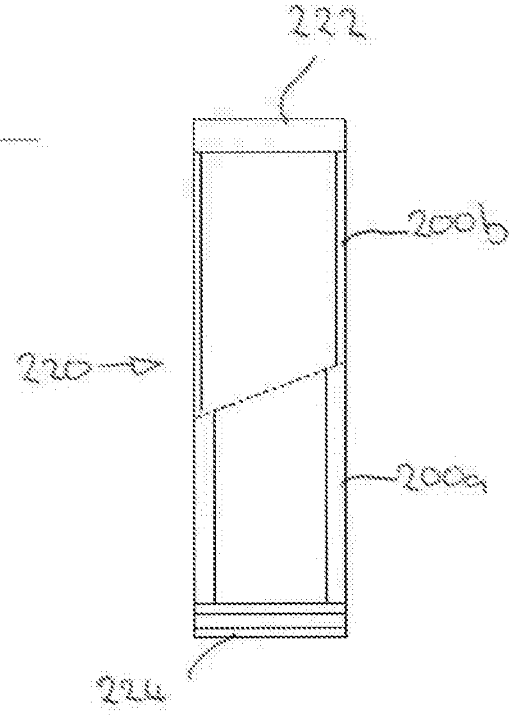
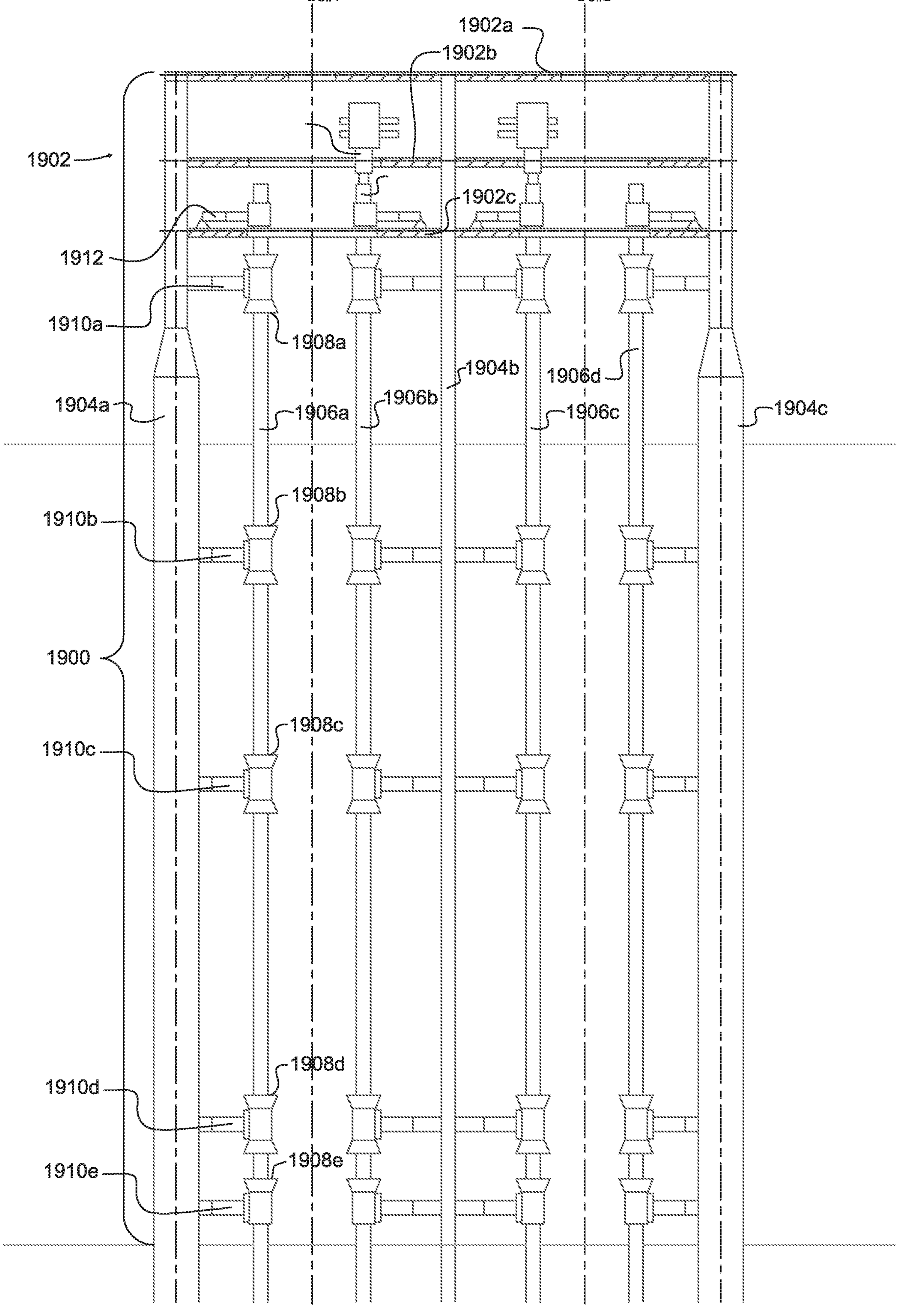


FIG. 18

FIG. 19A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1906a
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1908d
1910d
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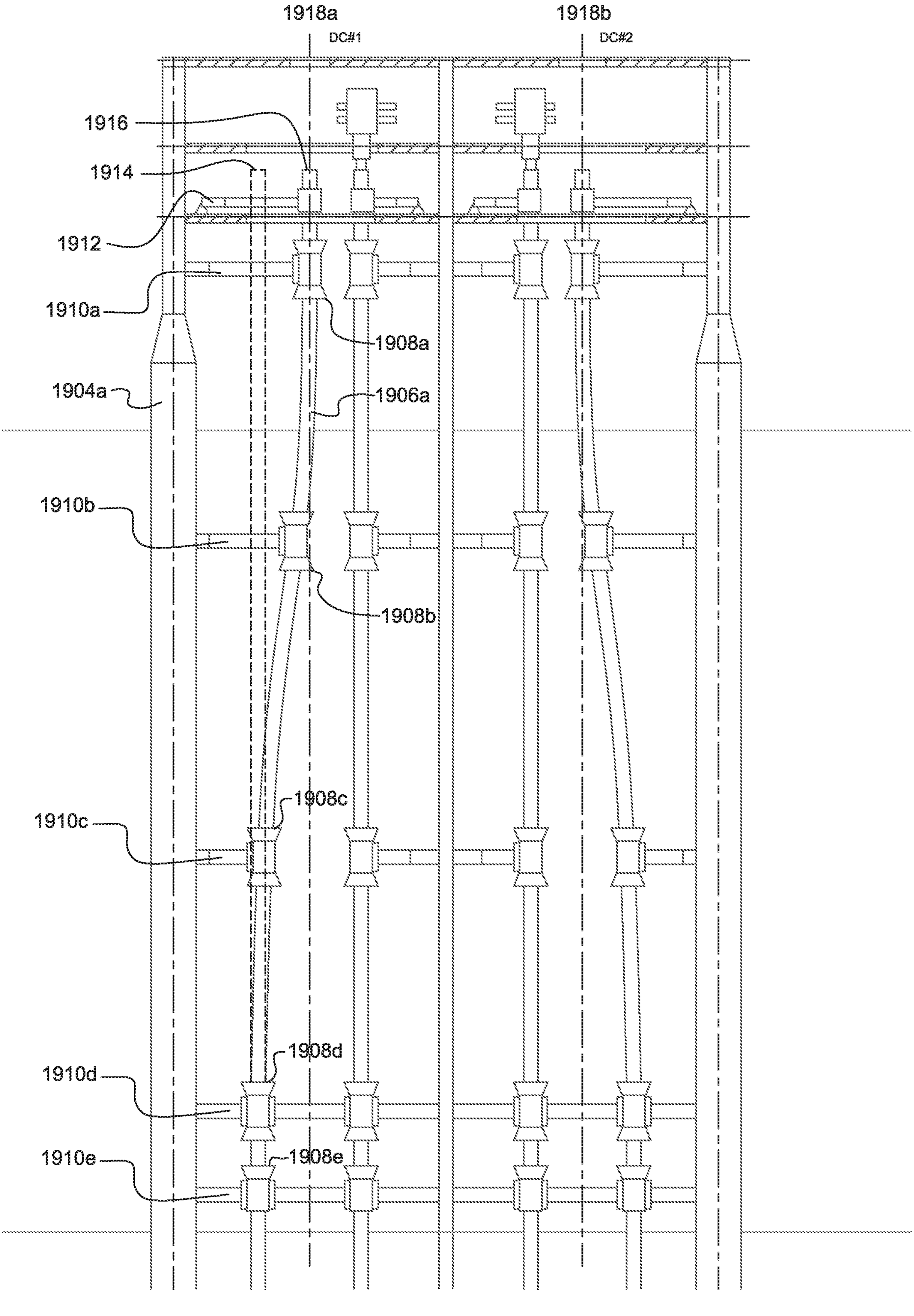
1910e

FIG. 19B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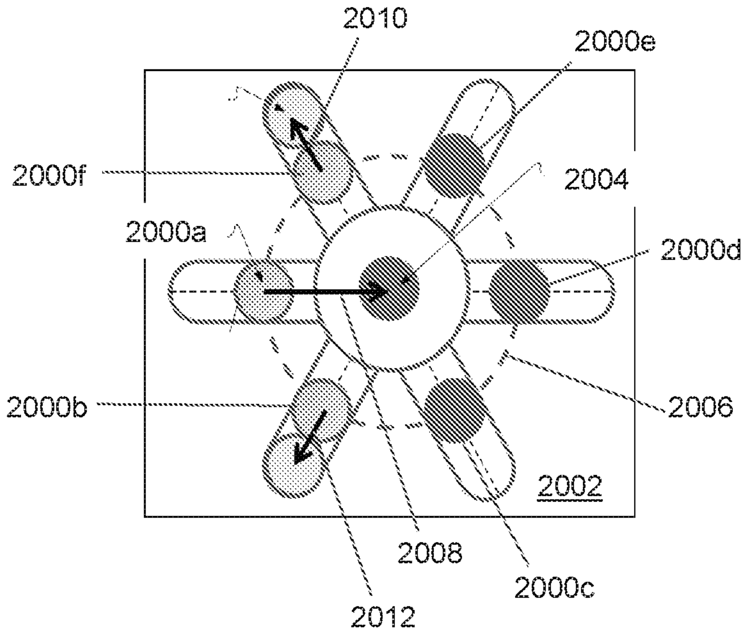
2010
2000e
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2004
2000a
2000d
2000b
2006
2002
2008
2000c
2012

Fig. 20