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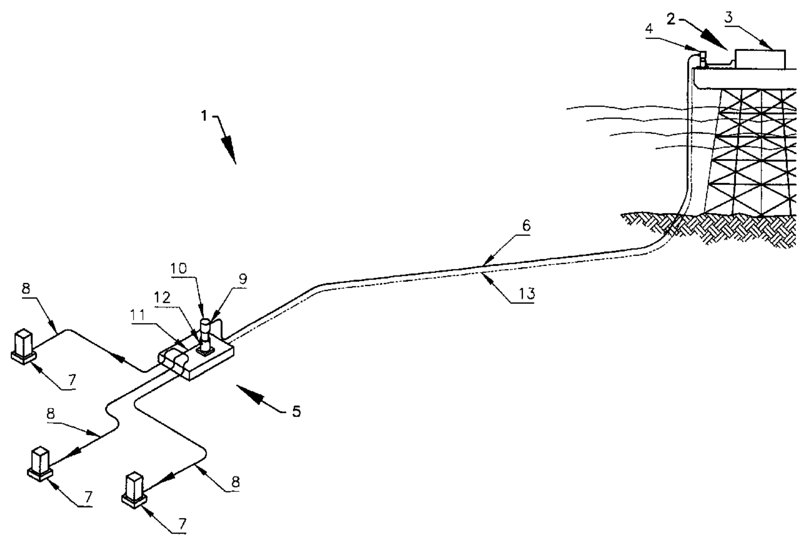

(57) **Abstract:** Gas is supplied from a host facility (2) to an underwater gas compressor (10) via a connecting pipeline (6) and the gas compressor is connected to a plurality of gas injection wells (7) for a hydrocarbon reservoir via well supply flowlines (8). The gas compressor (10) compresses the supplied gas to a higher pressure, and drives the gas into the reservoir via the flowlines (8) and gas injection wells (7) at a pressure at least as high as the pressure of the production fluid in the reservoir. This raises the overall pressure in the reservoir to drive production fluid there to the host facility (2). The compressed gas may alternatively be injected into production fluid in a production well to provide a gas lift effect.

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A SYSTEM AND METHOD FOR INJECTING GAS INTO A HYDROCARBON RESERVOIR

The present invention relates to a system and method for injecting gas into a hydrocarbon reservoir.

In a developed field, production fluid, extracted from the hydrocarbon reservoir by production wells, is driven to a host facility by the natural pressure of the reservoir. However, where the reservoir does not have enough natural pressure to drive the production fluid to the host facility which may be due to the production fluid comprising heavy, high density fluid that is essentially oil, a means of increasing the reservoir pressure or decreasing the specific gravity of the fluid is required.

In some cases the means may inject water from the host facility into the reservoir to boost its pressure.

In other cases the means may inject gas into the reservoir to boost its pressure via injection wells separate from the production wells. A known system for injecting gas into a reservoir comprises connecting the host facility to a seabed facility with a high pressure pipeline, and at the seabed facility, manifolding the pipeline into separate flowlines connected to injection wells. The gas for injection is processed at the host facility to a predetermined specification to make it suitable for compression and high pressure transportation. This processing may comprise drying the gas. The gas is then compressed by at least one gas compressor at the host facility and is conveyed by the high pressure pipeline down to the seabed facility and on into the reservoir via the well flowlines and the injection wells. The gas for injection is compressed to a pressure at least as high as that of the pressure of the reservoir at the bottom of the wellbores of the injection wells after taking into account the pressure losses incurred in the pipeline and flowlines so that it is able to drive production fluid from the reservoir up to the production wells and on to the host facility.

Alternatively, the gas pumped from the host facility may be used for a process known as "gas lift" in which gas is injected into production wells. The wellbore of each production well has riser tubing surrounded by an outer casing, the spacing between the tubing and the outer casing being known as the annulus. Gas is injected into the annulus and enters the tubing via perforations spaced along the length of the tubing and the gas combines with the heavy production fluid in the tubing to produce a less dense fluid. This enables the fluid to be lifted to the host facility by the well pressure. The gas used may be hydrocarbon gas which may be from the field being developed or from a nearby or separate field and any other suitable gas may be used.

The pipeline and flowlines for both gas injection and gas lift which are required to convey the gas to the wells have to have pipe walls thick enough to withstand the high pressure of the gas. The cost of the pipeline itself and the installation costs are high. This is particularly so when there is a long tie-back.

It is therefore an object of the present invention to provide a system and method which overcomes at least some of the above-mentioned disadvantages of the prior art.

According to one aspect of the present invention there is provided a system for injecting gas into a hydrocarbon reservoir, comprising:

a host facility having gas supply means;

an underwater gas compressor remote from the host facility, and connected to the gas supply means by a pipeline; and

at least one well connected to the underwater gas compressor, whereby the gas compressor is arranged to supply the gas received from the pipeline to the or each well and into the hydrocarbon reservoir to improve conveyance of production fluid at least towards the host facility.

At least one said well may be an injection well, the gas compressor being arranged to drive gas into the hydrocarbon reservoir via the or each injection well at a pressure at least as high as the pressure of the production fluid in the reservoir to raise the overall pressure in the reservoir.

At least one said well may be a production well, the gas compressor being connected to inject gas into production fluid in the or each production well, and the production well is considered to be part of the hydrocarbon reservoir.

The gas compressor may be connected to the at least one well by at least one flowline which is able to withstand conveyed gas of a higher pressure than the pipeline between the host facility and the gas compressor.

The gas compressor is preferably located at an underwater facility such as a seabed facility. By locating the gas compressor on the underwater facility, a pipeline able to convey gas at a high pressure is not required between the host facility and the underwater facility, as gas from the host facility is only at a high pressure once it has been compressed by the gas compressor of the underwater facility. Hence, the pipeline between the host facility and the underwater facility may have its pipe wall thickness reduced as it does not need to convey gas at such a high pressure. As there is a reduction in the quantity of pipe material for this pipeline, there is a significant cost saving.

The host facility would preferably have at least one lower pressure gas compressor for driving gas to the high pressure gas compressor at the underwater facility. By conveying the gas for injection at a lower pressure to the underwater facility, the pressure losses due to friction in the pipeline are reduced. Consequently, less power is required to compress the gas for injection, enabling gas compressors and their drive motors (which are preferably electric motors) at both the host facility and the underwater facility to be of a lower/smaller specification. This is likely to provide a cost saving when compared with having a high pressure gas compressor and its associated drive motor at the host facility. There is a further cost saving as the gas compressors at the host facility and underwater facility require less energy to drive them. The reduction in the size of the gas compressor and its associated drive motor at the host facility provides a saving in deck space on the host facility and in the weight to be supported by the host facility.

The reduction in pipe wall thickness enables the sections of the pipe for making up the pipeline to the underwater facility to be welded together more easily and quickly which considerably reduces fabrication costs. Furthermore, the reduction in pipe wall thickness may enable the pipeline to be reeled onto a drum and be laid from a pipe reel-lay barge which is a faster method of installing a pipeline than other conventional methods.

The savings in pipeline costs enables longer tie-backs to the host facility to be economically considered which may allow the use of an existing host facility to be used for a remote field as opposed to having to provide a new host facility. This is of particular benefit when the field to be developed is located beneath deep water.

The underwater facility may include fluid separating means for separating gas from the production fluid from said at least one production well and recirculation means for conveying gas from the fluid separating means into the gas compressor. The gas separated from the production fluid comprises gas supplied from the host facility, hence by conveying the separated gas from the separating means to the gas compressor, gas is being recirculated. Therefore, the pipeline from the host facility to the underwater facility can be of a smaller diameter when gas is recirculated as the quantity of gas required from the host facility for injection is significantly reduced.

By separating gas from the production fluid at the underwater facility, the diameter of the pipeline for conveying production fluid from the underwater facility to the host facility can be significantly reduced as this pipeline is no longer required to transport gas. As the production fluid in the pipeline is at least substantially free from gas, the problems of slugging, hydrate formation and of the flow of production fluid being choked due to gas expanding as pressure reduces along the pipeline is significantly reduced. Furthermore, the separation of gas from the production fluid at the underwater facility may enable only a single production fluid pipeline being required to convey production fluid to the host facility instead of two such pipelines. The reduction in the diameter of the production fluid pipeline also has the advantages mentioned in relation to the gas supply pipeline of requiring less material, being able to weld pipeline sections together more quickly or being able to be installed from a reel.

The underwater facility may be on a seabed and the production fluid pipeline may include a production riser from the seabed to the host facility at topsides, and the host facility may be connected to the production riser at or close to the seabed by a separate riser. The production riser is arranged to convey production fluid to the host facility and the separate riser is arranged to convey gas from the host facility for injection into the production riser. By injecting gas into the production riser at or near its base, gas is not required to be left in the production fluid coming from the underwater facility for lifting the production fluid up the production riser. Hence, only sufficient gas need be required to achieve flow of production fluid from the production wells to the base of the production riser. By having the separate riser, production fluid flow from production wells to the host facility, including absorbed/mixed gas, would be improved by having better slug flow and reducing hydrate formation. The production fluid pipeline from the underwater facility to the base of the production riser may only need to be of a sufficient diameter to convey at least substantially gas free production fluid and does not need to be increased in diameter or have an additional pipeline in order to convey gas or to avoid production fluid being choked by gas. Also, by injecting gas into the production riser, the need for pressure boosting of the production fluid at the underwater facility may be reduced or eliminated thus reducing the size of or eliminating the need for any pumps for such a purpose there.

The system preferably includes a power and control umbilical extending from the host facility to the underwater gas compressor for conveying power and control signals to the gas compressor. The power and control umbilical may be also arranged to convey power and control signals required for other underwater equipment such as Christmas trees and manifolds. Minimal additional cost is incurred when providing power to the underwater gas compressor if the same umbilical is used for the underwater gas compressor and other underwater equipment.

The underwater facility may include a retrievable module which incorporates the gas compressor. Hence, the gas compressor may be easily recovered for inspection, maintenance or repair, for example. The module may be of the general type forming part of the modular system designed by Alpha Thames Ltd of Essex, United Kingdom, and named AlphaPRIME.

According to another aspect of the present invention there is provided a method for injecting gas into a hydrocarbon reservoir, comprising the steps of:

supplying gas from a host facility to an underwater gas compressor via a connecting pipeline;

compressing the gas received by the underwater gas compressor to a higher pressure; and

injecting the compressed gas into at least one well connected to the underwater gas compressor, and into the hydrocarbon reservoir to improve conveyance of production fluid at least towards the host facility.

The step of injecting gas may include injecting gas into at least one injection well, and include driving the gas into the hydrocarbon reservoir via the or each injection well at a pressure at least as high as the pressure of the production fluid in the reservoir.

The step of injecting gas may include injecting gas into at least one production well, and include injecting gas into production fluid in the or each production well.

The method may include the additional steps of conveying production fluid from the reservoir, separating gas from the production fluid, and conveying the separated gas into the gas compressor. The gas separated from the production fluid may be disposed of into at least one cavity below the surface of the ground underneath the water in which the gas compressor is located. Present regulations do not allow flaring gas for new fields being developed, hence it is beneficial to dispose of gas in this way when there is no market for the gas or it is uneconomic to export the gas.

The method may include the steps of receiving production fluid at the host facility via a production riser from a seabed, and injecting gas from the host facility into the production riser at or close to the seabed.

The method may include the steps of using any of the system components referred to above.

According to yet another aspect of the present invention there is provided a method for handling production fluid, comprising the steps of:

receiving production fluid in an underwater facility from a hydrocarbon reservoir;

separating gas from the production fluid in the underwater facility; and

disposing of the gas into at least one cavity below the surface of the ground underneath the water in which the underwater facility is located.

Embodiments of the present invention will now be described, by way of example, with reference to the accompanying drawings, in which:-

Figure 1 is a schematic diagram of a system for putting the invention into practice;

Figure 2 is a schematic diagram of a modified system;

Figure 3 is a modified detail of Figure 2; and

Figures 4 to 7 are schematic diagrams of other modified systems.

Referring to Figure 1 of the accompanying drawings, a system 1 has a host facility 2 which may be, for example, onshore or an offshore fixed or floating rig. The host facility 2 has a gas processing plant 3 with a connected gas compressor 4 which is connected to a remote seabed facility 5 by an injection gas supply pipeline 6. The seabed facility 5 is connected to a plurality of gas injection wells 7 for a hydrocarbon reservoir whereby each well is connected to the facility 5 by a separate supply flowline 8 which is able to withstand conveyed gas of a higher pressure than the gas supply pipeline 6.

At the seabed facility 5 the gas supply pipeline 6 is connected to an inlet 9 of a high pressure gas compressor 10 and a conduit 11 from an outlet 12 of the compressor 10 is manifolded to the flowlines 8 connected to the injection wells 7.

The gas compressor 10 is arranged to be supplied with power and control signals from the host facility 2 via a power and control umbilical 13.

The operation of the system 1 will now be described.

The gas processing plant 3 dries gas for injection to a predetermined specification to make it suitable for compression by the compressor 4 at the host facility 2. The dried gas is routed into the gas supply pipeline 6 which conveys the gas to the seabed facility 5.

At the seabed facility 5, the gas is further compressed by the high pressure gas compressor 10 and is injected into the hydrocarbon reservoir via the well supply flowlines 8 and the gas injection wells 7. The pressure of the injected gas is at least as high as the pressure of the fluid in the reservoir so that it drives the production fluid to the host facility 2 via production wells and an arrangement of pipelines and flowlines (not shown).

Modifications to the system 1 will now be described in which parts which correspond to those shown in Figure 1 are designated with the same reference numerals and are not described in detail below.

Figure 2 illustrates one modification to the system 1 showing the production wells 25 which are each connected to the seabed facility 15 via a flowline 16 which are manifolded to a single conduit 17 at the facility 15. In the modified system 18, the seabed facility 15 has a fluid separation vessel 19 and the manifold conduit 17 is connected to an inlet 20 of this vessel. At the seabed facility 15, a first outlet 21 of the fluid separation vessel 19 is connected to the gas supply pipeline 6 by a recirculation conduit 22 and a second outlet 23 of the vessel 19 is connected to a production fluid pipeline leading to the host facility 2 indicated by arrow 24.

In use, gas compressed by the high pressure gas compressor 10 at the seabed facility 15 is injected into the hydrocarbon reservoir via the well supply flowlines 8 and the gas injection wells 7. This drives production fluid in the reservoir up to the heads of production wells 25, and on into the fluid separation vessel 19 via the flowlines 16 and the manifold conduit 17. The vessel 19 separates most gas from the production fluid. The at least substantially gas free production fluid leaves the fluid separation vessel 19 by the second outlet 23 and is driven to the host facility 2. The separated gas includes or comprises gas supplied from the host facility 2 and this gas leaves the fluid separation vessel 19 by the first outlet 21 and is conveyed by the recirculation conduit 22 into the gas supply pipeline 6 to be compressed by the gas compressor 10 for injection into the reservoir. As gas is now being recirculated for injection into the hydrocarbon reservoir to lift the production fluid, gas only needs to be supplied by the host facility 2 to top-up the recirculated gas, replacing gas not separated by the fluid separation vessel 19 or remaining in the reservoir.

In a modification to the system shown in Figure 2, the seabed facility 25 illustrated in Figure 3 comprises a base structure 26 which supports a retrievable module 27 that contains the high pressure gas compressor 10 and the fluid separation vessel 19. The gas compressor inlet 9 is connected to the injection gas supply pipeline 6 from the host facility 2 by a multi-ported fluid connector 28 such as that described in GB-A-2261271 and the gas compressor outlet 12 is connected by the outlet manifold conduit 11 to the well supply flowlines 8 via the same multi-ported fluid connector 28. Also, the fluid separation vessel inlet 20 is connected by the inlet manifold conduit 17 of the flowlines 16 via the same connector 28 and the first outlet 21 from the vessel 19 is connected to the inlet 9 of the gas compressor 10 via the recirculation conduit 22. The second outlet 23 from the vessel is connected to the production pipeline 24 leading to the host facility 2 via the same fluid connector 28.

This connector 28 enables the module 27 to be isolated from the pipelines 6,24 and flowlines 8,16 connected to the seabed facility 25 when the module 27 is to be retrieved.

In addition, the module 27 has a power and control pod 29 which is connected to the power and control umbilical 13 by a connector 30 whereby the pod 29 directs power and provides control signals to equipment within the module 27. In particular, the pod 29 controls the high pressure gas compressor 10 but it may be overridden by control signals received from the host facility 2 via the umbilical 13. The pod 29 also drives the gas compressor 10 with power received from the host facility 2 via the umbilical 13.

In use, gas from the host facility 2 is received by the high pressure gas compressor 10 in the retrievable module 27 which drives gas into the hydrocarbon reservoir. Production fluid from the reservoir is received by the fluid separation vessel 19 in the module 27 where gas is separated from the production fluid and is conveyed by the recirculation conduit 22 so as to be compressed by the high pressure gas compressor 10 for injection into the reservoir. The at least substantially gas free production fluid from the fluid separation vessel 19 leaves the module 27 via the fluid connector 28 and is conveyed to the host facility 2 via the production pipeline 24.

Another modification to the system 1 is shown in Figure 4 where the modified system 32 is for gas lift and the injection wells are replaced by production wells 25. The production wells 25, in addition to being connected to the seabed facility 33 by the flowlines 8, are also each connected to the seabed facility 33 via a separate flowline 16, the flowlines 16 being manifolded to a single conduit 17 at the facility 33. The conduit 17 is connected to a production fluid pipeline leading to the host facility 2 indicated by arrow 24.

In use, gas compressed by the high pressure gas compressor 10 at the seabed facility 33 is injected down the annulus of the wellbore of each production well 25 so that it enters the tubing via tubing perforations and combines with and lifts the production fluid from the hydrocarbon reservoir in the tubing of the wellbore. The production fluid is lifted up to the heads of production wells 25, and on to the host facility 2 via the flowlines 16, the manifold conduit 17 and the production fluid pipeline 24.

Figure 5 illustrates a modification to the system 32 shown in Figure 4 which is similar to the system 18 shown in Figure 2 except that the modified system 34 is directed to gas lift as opposed to gas injection with the flowlines 8 from the seabed facility 15 being connected to the production wells 25.

In use, gas compressed by the high pressure gas compressor 10 at the seabed facility 15 is injected down the wellbore of each production well 25 so that it combines with and lifts the production fluid from the reservoir. The production fluid is lifted into the fluid separation vessel 19 which separates most gas from the production fluid. The at least substantially gas free production fluid leaves the fluid separation vessel 19 by the second outlet 23 and is lifted to the host facility 2 and the separated gas is conveyed by the recirculation conduit 22 into the gas supply pipeline 6 to be compressed by the gas compressor 10 for injection into the wellbore of each production well 25.

Figure 6 illustrates one modification to the system 34 shown in Figure 5. The modified system 35 is particularly applicable to deepwater applications, and the host facility 36 is shown to be a floating production vessel as opposed to being a fixed production structure as previously illustrated. The production fluid pipeline 24 connects the seabed facility 15 to the host facility 36 and the portion of the pipeline 24 which rises from the seabed to the host facility 36 is known as a production fluid riser 37. At the host facility 36, the gas processing plant 3 is connected to a gas compressor 38 which is separate from the gas compressor 4 for the gas supply pipeline 6 and this gas compressor 38 is connected by a riser 39 to the base of the production fluid riser 37.

In use, at the base of the production fluid riser 37 production fluid from the seabed facility 15 has gas from the host facility 36 injected into it via the riser 39 so that sufficient lift is provided to raise the production fluid up the production riser 37 to the host facility 36.

The host facility 36 may have a fluid separation vessel (not shown) for processing production fluid including gas which has previously been injected into the production fluid via the riser 39. Such gas is separated from the production fluid by this vessel. The separated gas may be then recirculated by being injected into the base of the production riser 37 via the riser 39.

Figure 7 illustrates another modification to the system 34 shown in Figure 5 in which in the modified system 40, the gas separated by the fluid separation vessel 19 is disposed of beneath the seabed instead of being recirculated. The first outlet 21 of the fluid separation vessel 19 is connected by a pipeline 41 to a disposal well 42 which injects the gas into a cavity 43 beneath the seabed, such as a depleted reservoir.

Whilst particular embodiments have been described, it will be understood that various modifications may be made without departing from the scope of the invention. For example, the seabed facility shown in Figures 1 or 2 or any one of Figures 4 to 7 may have a retrievable module like that illustrated in Figure 3 and containing the high pressure gas compressor 10 and any fluid separation vessel 19. The power and control pod 29 in the retrievable module 27 is optional, as power and control could be provided/controlled externally of the module 27. Production fluid from the fluid separation vessel 19 may be boosted by a pump to enable the production fluid to be conveyed to the host facility and/or increase production rate and overall recovery of the production fluid. The pipelines and flowlines described may be of a rigid or flexible construction. The seabed facility may have a plurality of fluid separation vessels and/or retrievable modules possibly arranged to operate in parallel with each other.

Any of the above described embodiments may be used in combination with a water injection system.

Although the invention has been described in the context of a subsea hydrocarbon field, it would also be applicable to other areas such as swamps or other inaccessible areas whereby the system, including the high pressure gas compressor 10, would be land based.

CLAIMS:

1. A system for injecting gas into a hydrocarbon reservoir, comprising:

a host facility (2) having gas supply means (3,4);

an underwater gas compressor (10) remote from the host facility, and connected to the gas supply means by a pipeline (6); and

at least one well (7) connected to the underwater gas compressor (10), whereby the gas compressor is arranged to supply the gas received from the pipeline (6) to the or each well (7) and into the hydrocarbon reservoir to improve conveyance of production fluid at least towards the host facility (2).

2. A system as claimed in claim 1, wherein at least one said well (7) is an injection well, the gas compressor (10) being arranged to drive gas into the hydrocarbon reservoir via the or each injection well (7) at a pressure at least as high as the pressure of the production fluid in the reservoir to raise the overall pressure in the reservoir.

3. A system as claimed in claim 1 or 2, wherein at least one said well is a production well (25), the gas compressor (10) being connected to inject gas into production fluid in the or each production well.

4. A system as claimed in claim 1, 2 or 3, wherein the gas compressor (10) is connected to the at least one well (7) by at least one flowline (8) which is able to withstand conveyed gas of a higher pressure than the pipeline (6) between the host facility (2) and the gas compressor (10).

5. A system as claimed in any preceding claim, wherein the underwater gas compressor comprises a high pressure gas compressor (10) and the host facility (2) has at least one lower pressure gas compressor (4) for driving gas to the high pressure gas compressor (10).

6. A system as claimed in any preceding claim, wherein the underwater gas compressor (10) is located at an underwater facility (5).

7. A system as claimed in claim 6, wherein the underwater facility (15) includes fluid separating means (19) for separating gas from the production fluid and recirculation means (22) for conveying gas from the fluid separating means (19) into the gas compressor (10).

8. A system as claimed in claim 6 or 7, wherein the underwater facility (15) is on a seabed, and the system includes a production fluid pipeline (24) for conveying production fluid from the underwater facility (15) to the host facility (36), the production fluid pipeline (24) including a production riser (37) from the seabed to the host facility (36), and the host facility is connected to the production riser (37) at or close to the seabed by a separate riser (39).

9. A system as claimed in claim 6, 7 or 8, wherein the underwater facility (25) includes a retrievable module (27) which incorporates the gas compressor (10).

10. A system as claimed in any preceding claim, including a power and control umbilical (13) extending from the host facility (2) to the underwater gas compressor (10) for conveying power and control signals to the gas compressor.

11. A system as claimed in claim 10, wherein the power and control umbilical (13) is arranged to convey power and control signals required for other underwater equipment.

12. A method for injecting gas into a hydrocarbon reservoir, comprising the steps of:

supplying gas from a host facility (2) to an underwater gas compressor (10) via a connecting pipeline (6);

compressing the gas received by the underwater gas compressor (10) to a higher pressure; and

injecting the compressed gas into at least one well (7) connected to the underwater gas compressor (10), and into the hydrocarbon reservoir to improve conveyance of production fluid at least towards the host facility (2).

13. A method as claimed in claim 12, wherein the step of injecting gas includes injecting gas into at least one injection well (7), the gas being driven into the hydrocarbon reservoir via the or each injection well at a pressure at least as high as the pressure of the production fluid in the reservoir.

14. A method as claimed in claim 12 or 13, wherein the step of injecting gas includes injecting gas into at least one production well (25), the gas being injected into production fluid in the or each production well (25).

15. A method as claimed in claim 12, 13 or 14, including separating gas from the production fluid at an underwater facility (15) including the underwater gas compressor (10).

16. A method as claimed in claim 15, including conveying at least some of the separated gas into the gas compressor (10).

17. A method as claimed in claim 15 or 16, including disposing of at least some of the gas separated from the production fluid into at least one cavity (43) below the surface of the ground underneath the water in which the gas compressor (10) is located.

18. A method as claimed in any one of claims 12 to 17, including the steps of receiving production fluid at the host facility (36) via a production riser (37) from a seabed, and injecting gas from the host facility (36) into the production riser (37) at or close to the seabed.

19. A method for handling production fluid, comprising the steps of:

receiving production fluid in an underwater facility (15) from a hydrocarbon reservoir;

separating gas from the production fluid in the underwater facility (15); and

disposing of the gas into at least one cavity (43) below the surface of the ground underneath the water in which the underwater facility (15) is located.

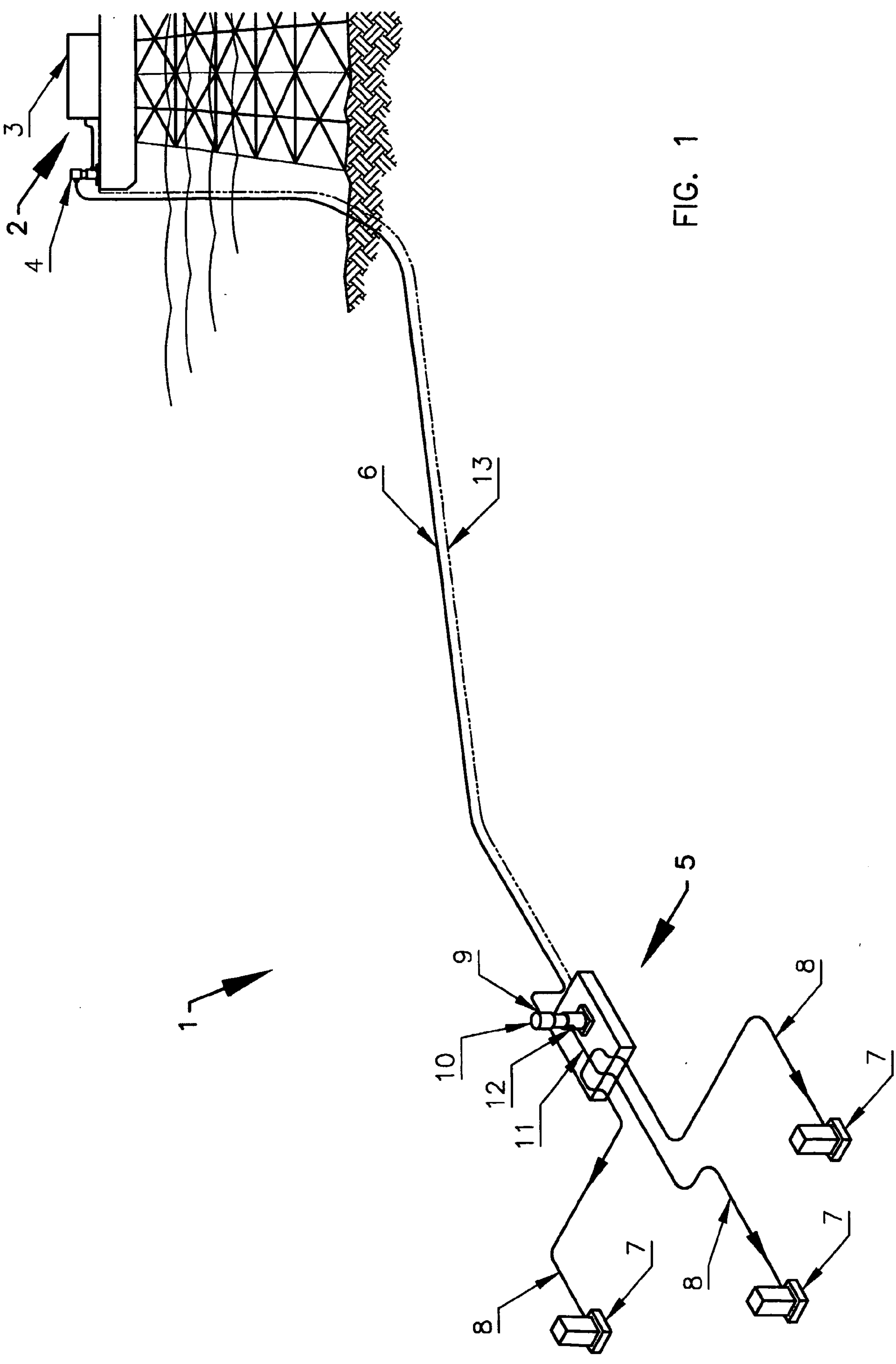

FIG. 1

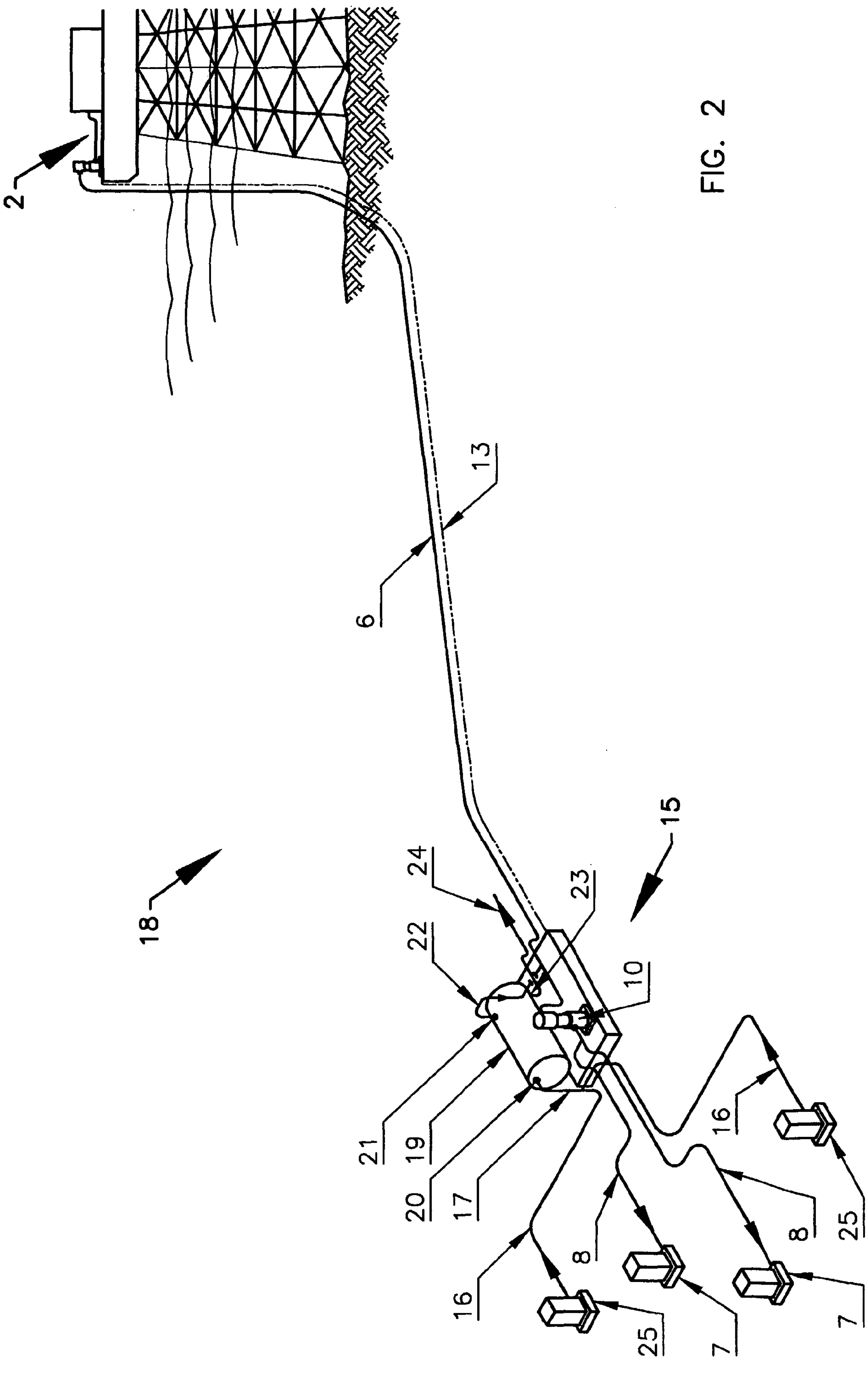

FIG. 2

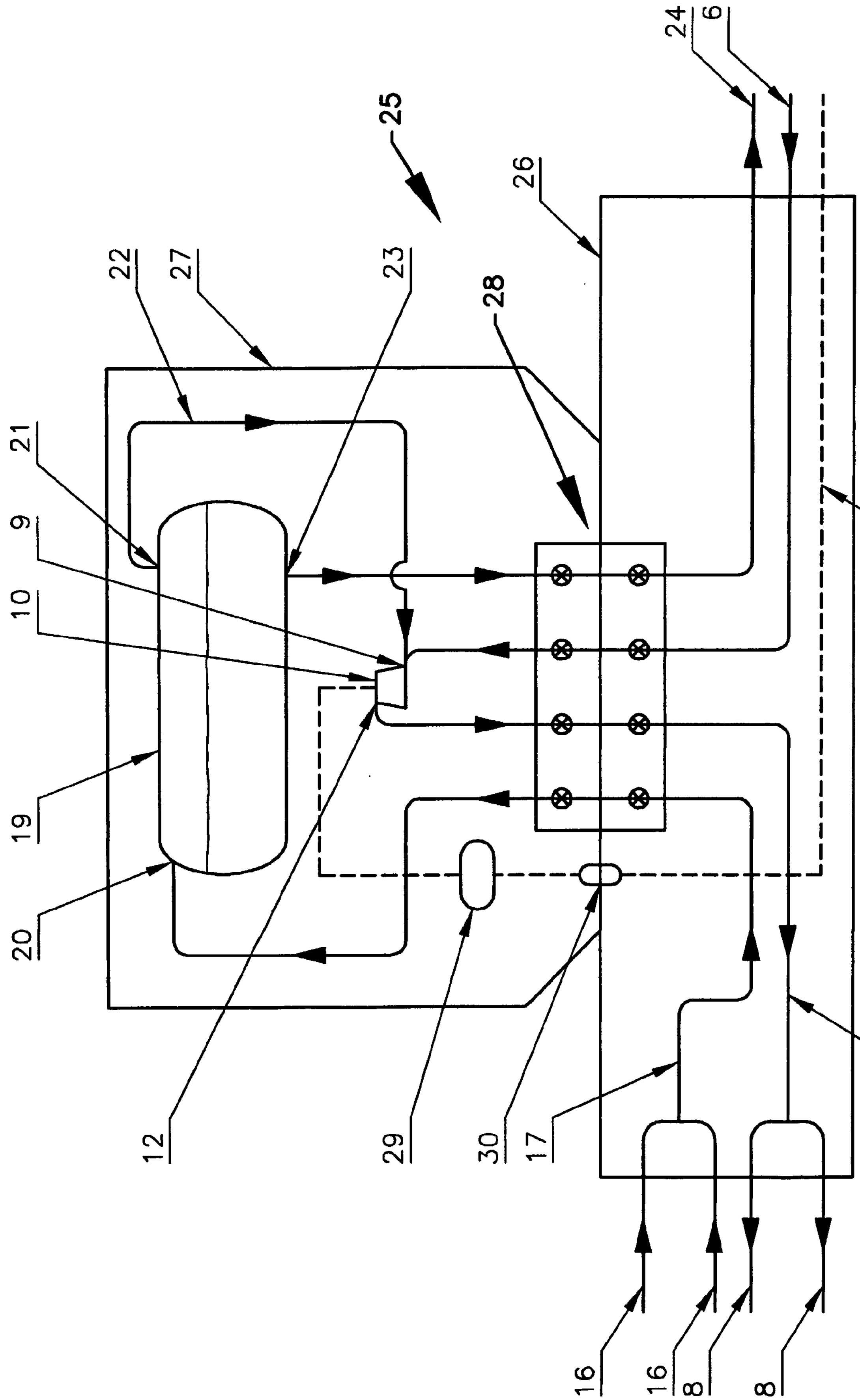

FIG. 3

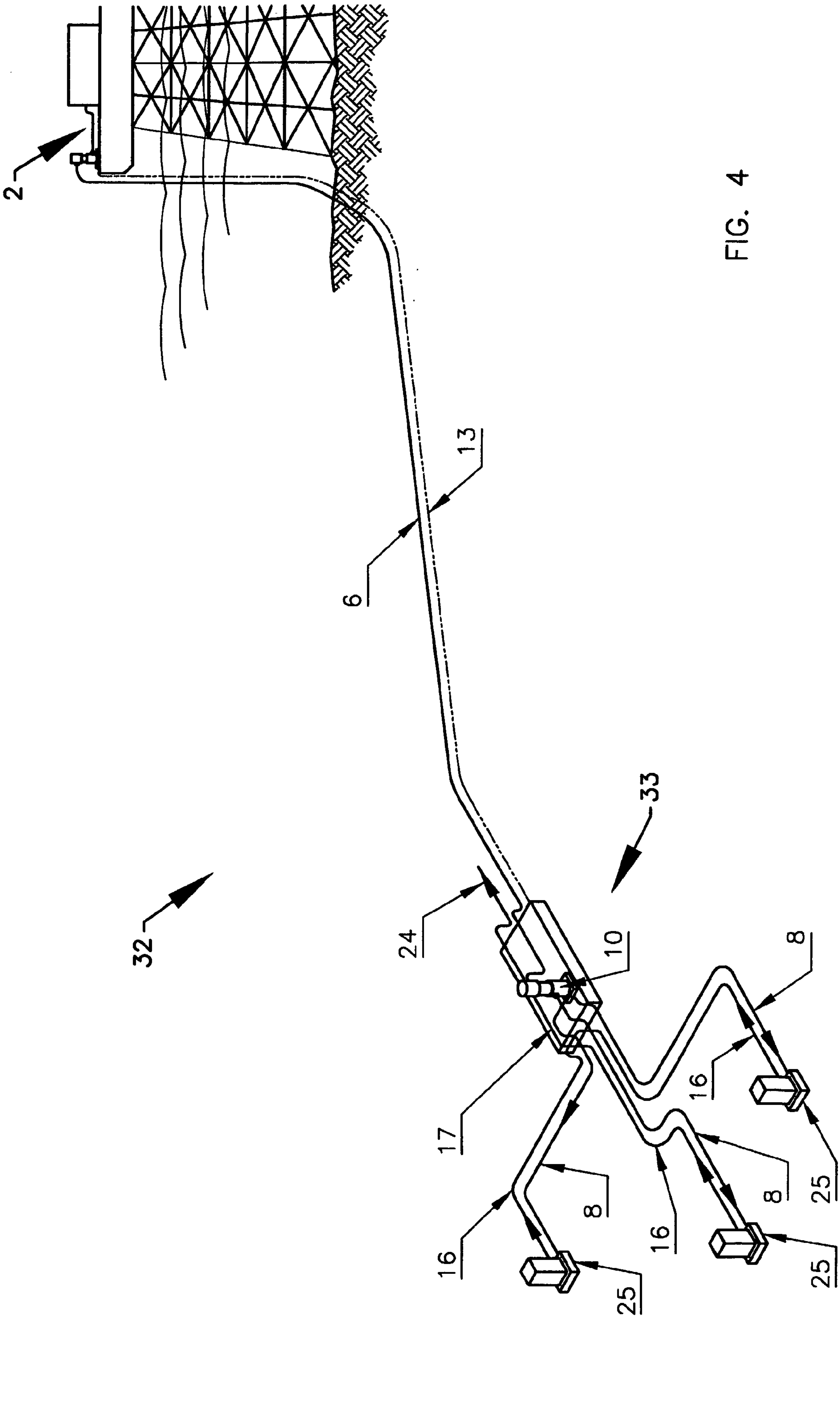

FIG. 4

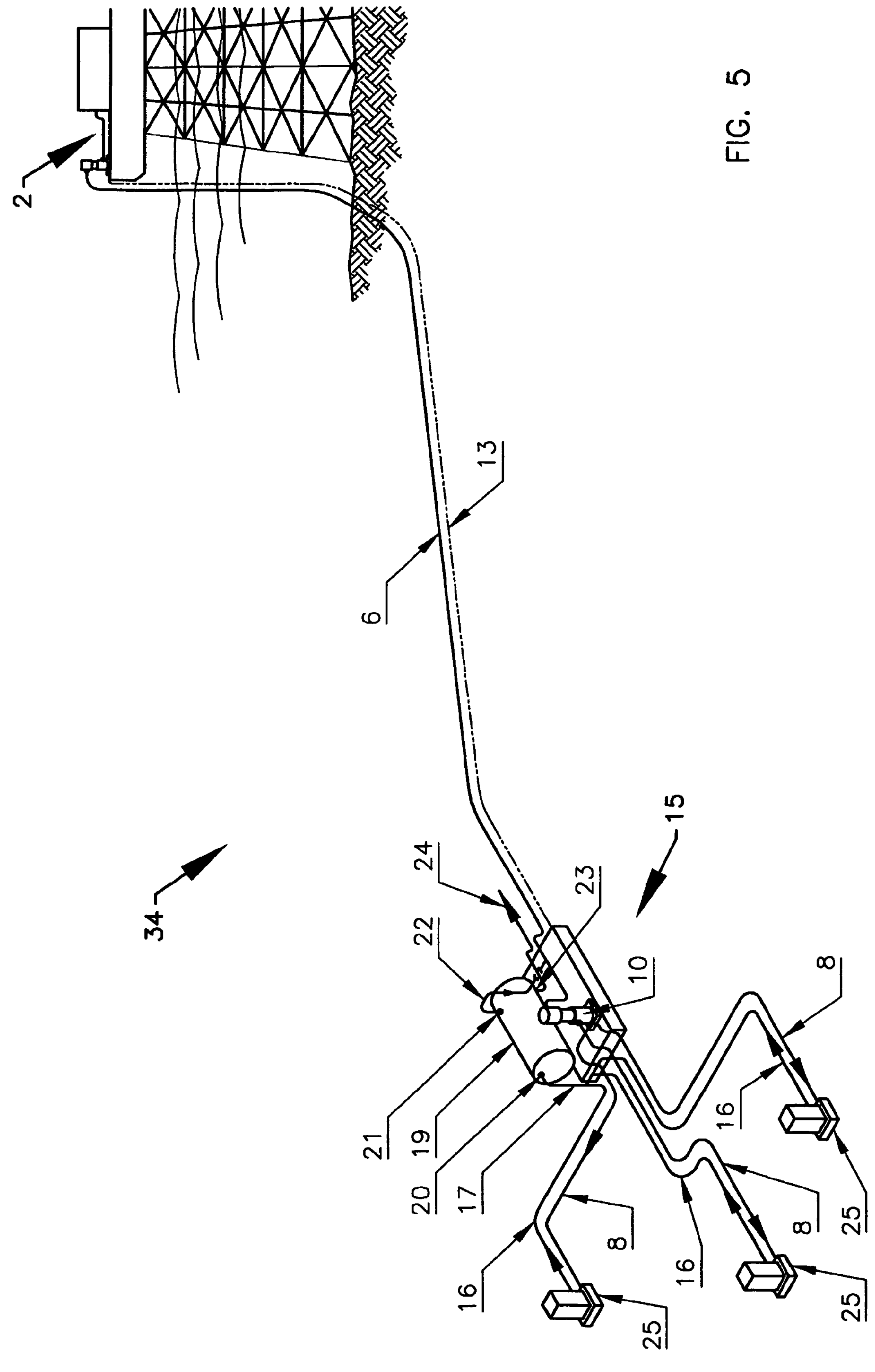

FIG. 5

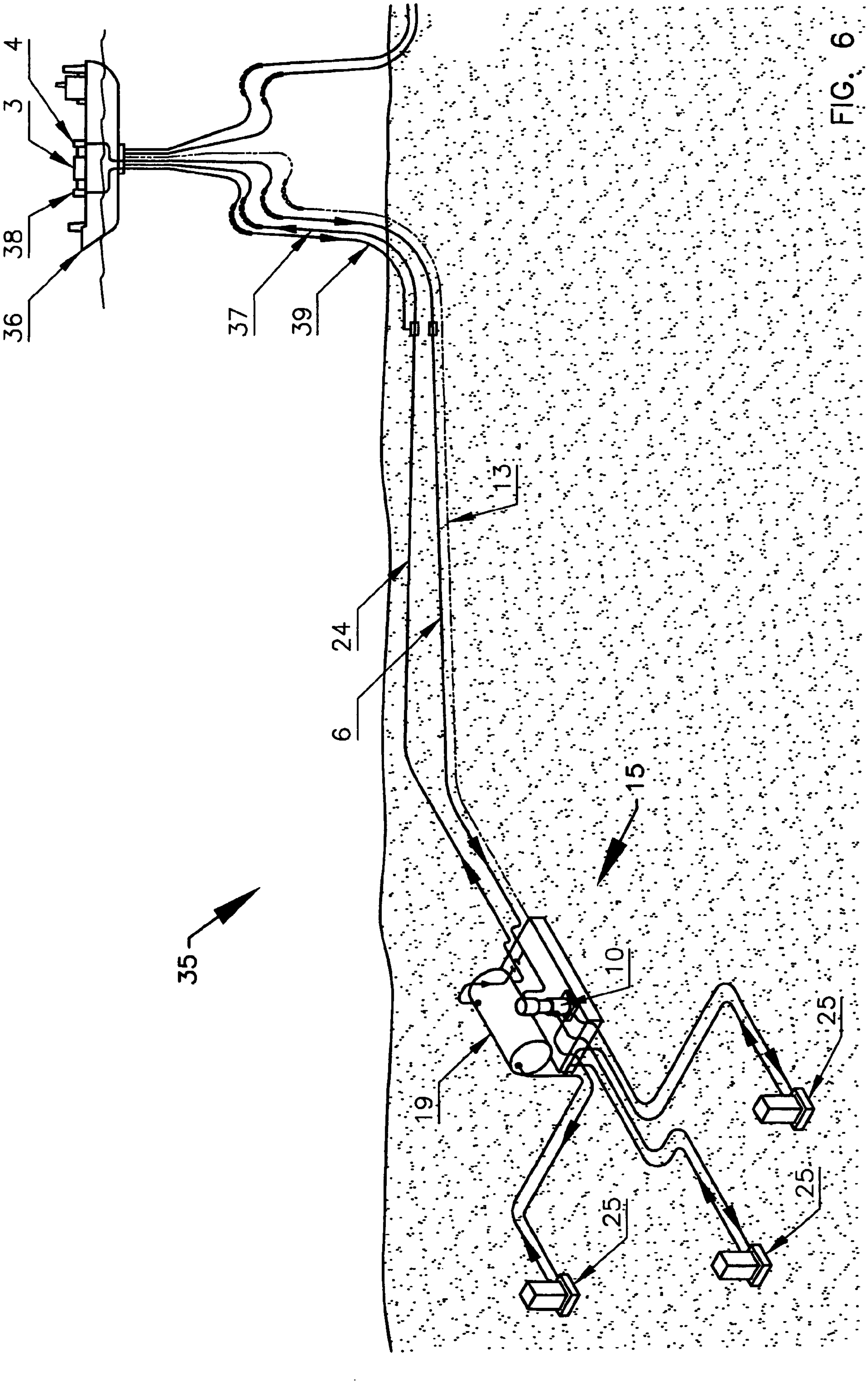

FIG. 6

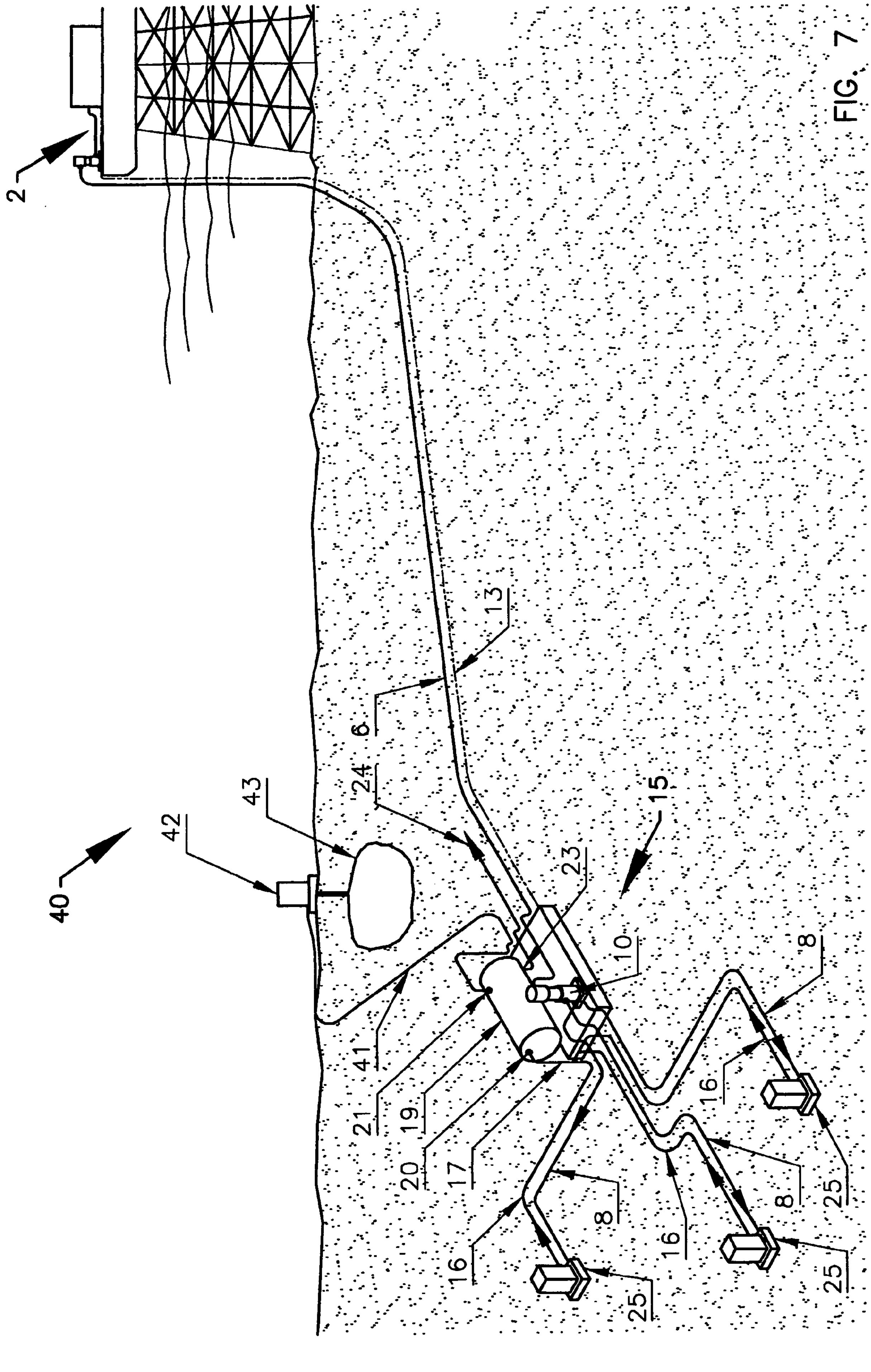

FIG. 7