

SYSTEM AND METHOD FOR HYDRATE PRODUCTION

FIELD

5 This relates to a system and method for hydrate production, e.g. methane hydrate production.

BACKGROUND

10 Methane hydrates are ice-like solids that include methane gas and water in the ice phase. Methane hydrate layers are known to include significant quantities of methane and so represent a significant source of natural gas.

15 Methane hydrate production involves drilling a well borehole ("wellbore") from surface which is then lined with sections of metal bore-lining tubing, commonly known as casing. Following completion of the wellbore, production fluid - which in the case of methane production includes amongst other things methane gas, water, and entrained solids such as sand - is allowed to enter the wellbore where it is transported to surface.

20 In order to control production from a given wellbore, a flow control arrangement including a valve arrangement known as a tree is typically located on the wellhead. The valve arrangement comprises a number of flow control valves and safety valves configured to control production fluid flow and/or facilitate well isolation. The valve arrangement also controls access into the wellbore for tools, equipment, and fluid.

25 There are a number of significant challenges involved in methane hydrate production.

30 For example, extraction of the methane hydrates requires local depressurisation of the methane hydrate layer. If the production rate is too high, then excessive water and sand can be produced, often at short notice. This causes problems with slugging and wear for pipework, pumps, separators and other production equipment downstream of the production well. Moreover, careful control and monitoring of the flow rate and well pressure is required to ensure that the flow is not so high that it will collapse the well.

Methane hydrates will readily reform at the ambient pressure and temperature found at the water depths typical in subsea well systems. If the pressure and temperature should return to the hydrate forming pressure and temperature, e.g. due to any flow disturbance, then solid methane hydrate will reform in the production equipment. While
5 chemicals and/or heating systems have been proposed to prevent formation of methane hydrates, the use of such chemicals and systems comes at a significant cost to the operator, to the point that the well may become economically unviable.

10 Designing a large full field system to drawdown multiple wells simultaneously will need to ensure the separator is operating in laminar flow as much as possible. An undersized system with high fluid velocity will have turbulent flow and pull the gas with the water. Keeping the fluid speed low will either require a very large volume separator or multiple separators, resulting in added complexity and cost.

15 Designing a system to accommodate a wide range of gas to water ratios from multiple wells and keep them producing at their optimum flowrate is particularly challenging.

SUMMARY

According to a first aspect, there is provided a system for hydrate production, wherein the system is configured to separate a water component from a multi-phase gas and water mixture present in a wellbore, the system being configured such that said separation occurs within the wellbore, wherein the system comprises:

a first flow line disposed in the wellbore, the flow line arranged such that an inlet of the first flow line is disposed in and receives the water component of said multi-phase gas and water mixture, so as to separate the water component from said multi-phase gas and water mixture;

a flow control device provided on or operatively associated with the first flow line; a sensor arrangement comprising one or more sensors configured to detect a water level of said water component in the wellbore and output an output signal indicative of said water level; and

a control system configured to receive the output signal indicative of said water level from the sensor arrangement and control the flow control device based on said water level so as to control the flow of the water component through the first flow line.

The system provides a number of significant benefits over conventional equipment and methodologies.

For example, the system utilises the hydrate production wellbore itself to separate the liquid component (in particular water) from the gas and solids, thereby eliminating or at least reducing the need for further separation of the phases downstream of the wellbore (or wellbores in the case of a well system comprising a plurality of wellbores).

Moreover, conventional equipment and methodologies involve transporting a multi-phase mixture to the surface which as described above can re-form into a hydrate at the pressure and temperature conditions typically found at the seabed. By contrast, in the present system separation occurs within the wellbore, such that the risk of hydrate re-formation is eliminated or at least significantly reduced. This in turn improves the availability and/or efficiency of the hydrate production system as well as reducing downtime associated with workover operations and the like and/or reducing or eliminating the need to use chemical hydrate inhibitors, heating equipment or other hydrate mitigations.

The provision of a system in which separation occurs in the wellbore eliminates or at least mitigates the problems of slugging and wear in production equipment such as pipework, pumps, separators which otherwise may result from excessive water and/or sand production, since greater control can be achieved when handling single-phase fluid flows compared to the current multi-phase fluid flows. Moreover, whereas conventional systems require equipment capable of handling multi-phase fluids the present system can utilise equipment designed for handling single-phase fluids. In addition to being simpler and generally less costly to implement, such single-phase equipment provides a greater degree of control of the liquid flowrate at the well, reducing the risk of wellbore collapse.

Moreover, hydrate wells are sensitive to high flow rates and thus the present system beneficially facilitates the flow rate to be controlled using the flow control device on the first flow line.

The system may comprise or take the form of a system for natural gas hydrate production, wherein the system is configured to separate a water component from a multi-phase natural gas and water mixture present in a wellbore. In particular, the system may comprise or take the form of a system for methane hydrate production, wherein the system is configured to separate a water component from a multi-phase methane gas and water mixture present in a wellbore.

As described above, the system comprises a first flow line disposed in the wellbore, the flow line arranged such that an inlet of the first flow line is disposed in and receives the water component of said multi-phase gas and water mixture.

The inlet of the first flow line may form the distal end of the first flow line.

Alternatively, the inlet may comprise one or more lateral flow ports in the first flow line.

The system may be configured so that the inlet of the first flow line is disposed below the hydrate layer. Beneficially, this facilitates ingress of water rather than a multi-phase gas and water mixture.

5 The first flow line may be defined as a water flow line.

The system may comprise a single first flow line.

10 Alternatively, the system may comprise a plurality of the first flow lines.

As described above, the system comprises a flow control device provided on or operatively associated with the first flow line.

15 The flow control device may comprise or take the form of a variable flow control device.

The flow control device may comprise or take the form of a choke.

20 The flow control device may comprise or take the form of a variable choke.

The system may comprise a pump.

The pump may be coupled to or operatively associated with the first flow line.

25 The pump may be configured to draw the water component of the multi-phase gas and water mixture present in the wellbore through the first flow line.

The pump may be configured to pump the water component of the multi-phase gas and water mixture towards surface.

30 In some instances, the system may be configured so that the pump directs the water component of the multi-phase gas and water mixture to surface.

In other instances, the system may be configured so that the pump directs the water component of the multi-phase gas and water mixture to the seabed or other location.

5 The pump may comprise or take the form of a single-phase pump, i.e. a pump configured to handle a single-phase fluid. The pump may comprise or take the form of a pump configured to handle a liquid.

10 Beneficially, the system is configured to separate the water component of the multi-phase gas and water mixture within the wellbore, and so can utilise a single-phase pump which offers greater control over the fluid flow through the first flow line.

15 However, it will be understood that the pump may alternatively comprise or take the form of a multi-phase pump, i.e. a pump configured to handle a multi-phase fluid.

 The pump may comprise or take the form of a centrifugal pump.

 The pump may comprise or take the form of a hybrid pump.

20 The pump may comprise or take the form of a vertical pump.

 The pump may comprise or take the form of an electric submersible pump (ESP).

25 The control system may be configured to control the pump. The control system may be configured to communicate with a pump control system.

 The flow control device, e.g. choke, may be provided at an intake of the pump.
The flow control device, e.g. choke, may be provided at a discharge of the pump.

30 The pump may be located on the seabed. The pump may be located below the seabed. The pump may be located on at least one of a platform, a vessel and/or at an intermediate location between the seabed and surface such as in a riser.

The pump may form, or form part of, the flow control device. The pump may comprise a motor. The motor speed may be variable based on the water level and/or the position of the flow control device provided on or operatively associated with the first flow line so as to control the flow of the water component through the first flow line.

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The system may comprise one or more isolation valves provided on or operatively associated with the first flow line. At least one of the isolation valves may comprise or take the form of a gate valve. At least one of the isolation valves may be configured for operation by an ROV.

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The system may comprise a second flow line. The second flow line may be disposed in the wellbore, the second flow line arranged such that an inlet of the second flow line is disposed in and receives the gas component of said multi-phase gas and water mixture.

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The inlet of the second flow line may form the distal end of the second flow line.

Alternatively, the inlet may comprise one or more lateral flow ports in the second flow line.

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The system may comprise a flow control device provided on or operatively associated with the second flow line.

The flow control device may comprise or take the form of a variable flow control device.

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The flow control device may comprise or take the form of a choke.

The flow control device may comprise or take the form of a variable choke.

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The system may comprise one or more isolation valves provided on or operatively associated with the second flow line. At least one of the isolation valves may comprise or take the form of an annulus isolation valve.

As described above, the system comprises a sensor arrangement comprising one or more sensors configured to detect a water level of said water component in the wellbore and output an output signal indicative of said water level.

5 The sensor arrangement may comprise one or more sensors configured to detect a minimum water level. The sensor arrangement may comprise one or more sensors configured to detect a maximum water level.

10 The sensor arrangement may comprise one or more digital sensors. The one or more digital sensors may be configured to detect the water level of said water component in the wellbore. The sensor arrangement may comprise one or more analogue sensors. The one or more analogue sensors may be configured to detect the water level of said water component in the wellbore. The sensor arrangement may comprise one or more optical sensors, e.g. optical fibre sensors. The one or more optical sensors may be
15 configured to detect the water level of said water component in the wellbore. The one or more optical fibre sensors may, for example, be configured to measure a change in temperature. The sensor arrangement may comprise a distributed temperature sensing (DTS) sensor arrangement. The DTS sensor arrangement may be configured to detect the water level of said water component in the wellbore.

20 The sensor arrangement may comprise one or more pressure and/or temperature sensors. The one or more pressure and/or temperature sensors may be configured to detect the water level of said water component in the wellbore. In particular, the sensor arrangement may comprise a plurality (i.e. two or more) pressure and/or
25 temperature sensors. The pressure and/or temperature sensors may comprise or take the form of downhole pressure and temperature (DHPT) gauges. The system may be configured to measure the pressure at two or more of the plurality of pressure and/or temperature sensors. Since the distance between the sensors is known, the water level may be readily determined.

30 The sensor arrangement may comprise one or more erosion sensors.

 The sensor arrangement may comprise one or more flow sensors.

The sensor arrangement may comprise one or more position sensors of the flow control device provided on or operatively associated with the first flow line, e.g. choke position sensors.

5 The system may comprise one or more check valves. At least one of the check valves may comprise or take the form of a gravity check valve. At least one of the check valves may comprise or take the form of a ball valve.

10 At least one of the check valves may be provided on the first flow line. The check valve provided on the first flow line may be configured to prevent or limit back flow of the water through the first flow line, i.e. flow back towards the inlet.

15 The check valve may be interposed between the inlet of the first flow line and the flow control device provided on or operatively associated with the first flow line.

 The check valve may be disposed downstream of the flow control device provided on or operatively associated with the first flow line.

20 At least one of the check valves may be provided on the second flow line. The check valve provided on the second flow line may be configured to prevent or limit back flow of the gas through the second flow line, i.e. flow back towards the inlet. The check valve may be interposed between the inlet of the second flow line and the flow control device provided on or operatively associated with the second flow line.

25 The check valve may be disposed downstream of the flow control device provided on or operatively associated with the second flow line.

 The system may comprise a wellhead. The first flow line may be disposed through the wellhead. The second flow line may be disposed through the wellhead.

30 The system may comprise a tubing hanger. The tubing hanger may be disposed on and/or supported by the wellhead. The first flow line may be disposed through the tubing hanger. The second flow line may be disposed through the tubing hanger.

The system may comprise a cap. The cap may comprise, may form part of, or may take the form of a tree, e.g. Christmas tree or the like. The cap may be coupled to and/or mounted on the wellhead. The first flow line may be disposed through the cap. The second flow line may be disposed through the cap.

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The system may comprise one or more control and/or communication lines. For example, the system may comprise one or more hydraulic lines. Alternatively or additionally, the system may comprise one or more electrical lines. Alternatively or additionally, the system may comprise one or more fibre optic lines. The control and/or communication lines may be provided to supply power and/or communicate with tools and equipment disposed in and/or forming part of the wellbore.

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The one or more control and/or communication lines may be disposed through the tubing hanger, wellhead and/or the cap.

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The one or more control and/or communication lines may be disposed through tubing hanger couplers.

The one or more control and/or communication lines may be disposed through a vertical clamp connection system (VCCS), e.g. a VCCS seal plate, or other means.

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The system may comprise a manifold.

The first flow line (or at least one of the first flow lines where the system comprises a plurality of the first flow lines) may be coupled to the manifold.

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The second flow line (or at least one of the second flow lines where the system comprises a plurality of the first flow lines) may be coupled to the manifold.

The control system may form or form part of a subsea well control system.

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The control system may comprise a control module, in particular but not exclusively a subsea control module.

The control system, in particular the subsea control module, may be configured and/or operable to monitor the water level and control flow so as to maintain an optimum level.

5 The control system, in particular the subsea control module, may be configured to receive sensor data from the one or more water level sensors.

 The control system, in particular the subsea control module, may be configured to receive sensor data from the one or more erosion sensors.

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 The control system, in particular the subsea control module, may be configured to receive sensor data from the one or more flow sensors.

 The control system, in particular the subsea control module, may be configured to receive sensor data from the one or more choke position sensors.

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 The control system, in particular the subsea control module, may be configured to receive sensor data from the one or more pressure and/or temperature sensors.

20 The control system, in particular the subsea control module, may be configured to:

 process sensor data received from one or more sensors of the sensor arrangement; and

 output one or more command signals to a position controller and/or actuation mechanism of the flow control device provided on or operatively associated with the first flow line, so as to control the position of said flow control device.

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 For example, the control system, in particular the subsea control module, may be configured to:

30 process the sensor data received from at least one of the one more water level sensors; and at least one of the one or more erosion sensors; the one or more flow sensors, the one or more position sensors of the flow control device provided on or operatively associated with the first flow line; and/or the one or more pressure and/or temperature sensors; and

output one or more command signals to a position controller and/or actuation mechanism of the flow control device provided on or operatively associated with the first flow line, so as to control the position of said flow control device.

5 Alternatively or additionally, the control system, in particular the subsea control module, may be configured to:

 process sensor data received from one or more sensors of the sensor arrangement; and

 output one or more command signals to a position controller and/or actuation
10 mechanism of at least one of the isolation valves provided on or operatively associated with the first flow line, so as to control the position of said isolation valves.

 For example, the control system, in particular the subsea control module, may be configured to:

15 process the sensor data received from at least one of the one more water level sensors; and at least one of the one or more erosion sensors; the one or more flow sensors, the one or more position sensors of the flow control device provided on or operatively associated with the first flow line; and/or the one or more pressure and/or temperature sensors; and

20 output one or more command signals to the position controller and/or actuation mechanism of at least one of the isolation valves provided on or operatively associated with the first flow line, so as to control the position of said isolation valves.

 The system may comprise, may be coupled to or communicate with a master
25 control station or module.

 The master control station or module may form part of the control system of the system or may take the form of a separate system with which the control system communicates.

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 The control module may be configured to communicate with the master control station or module.

The master control station may be configured to receive information from one or more topside system or module.

5 For example, the master control station may be configured to receive information from an emergency shut down (ESD) system or module.

For example, the master control station may be configured to receive information from a system flow demand system or module.

10 The control system, in particular the master control station or module, may be configured to process the information from the one or more topside systems or modules, e.g. at least one of the emergency shut down module and the system flow demand module, and output one or more command signal to a controller, in particular speed controller, of the pump.

15 The system may comprise, may be coupled to or communicate with a pump control system, in particular a subsea pump control system.

20 The pump control system may comprise a pump control module. The pump control system may comprise or take the form of a processor.

The pump control system may comprise one or more sensors associated with control of the pump.

25 The pump control system may comprise one or more actuators associated with control of the pump.

The pump control module may communicate with the speed controller of the pump.

30 The pump control module may communicate with at least one of the one or more sensors associated with control of the pump and the one or more actuators associated with control of the pump.

As described above, the system comprises a flow control device provided on or operatively associated with the first flow line.

5 The flow control device may be located in the wellbore. The flow control device may be located on the seabed. The flow control device may be coupled to, or form part of, the cap. The flow control device may be coupled to, or form part of, the wellhead. The flow control device may be located upstream of the wellhead e.g. on a flow line disposed between the wellhead and surface.

10 As described above, the system may comprise a flow control device provided on or operatively associated with the second flow line.

15 The flow control device may be located in the wellbore. The flow control device may be located on the seabed. The flow control device may be coupled to, or form part of, the cap. The flow control device may be coupled to, or form part of, the wellhead. The flow control device may be located upstream of the wellhead e.g. on a flow line disposed between the wellhead and surface.

20 According to a second aspect, there is provided a well system comprising the system for hydrate production of the first aspect.

The well system may comprise a subsea well system.

25 The well system may comprise a plurality of wellbores.

30 A third aspect relates to use of the system for hydrate production according to the first aspect or the well system according to the second aspect to separate a water component from a multi-phase gas and water mixture present in a wellbore, the system being configured such that said separation occurs within the wellbore.

The method may comprise the step of depressurising the hydrate from a solid state to the multi-phase gas and water mixture.

Alternatively or additionally, the method may comprise the step of heating and or the injection of a medium that allows the gas to disassociate.

5 The invention is defined by the appended claims. However, for the purposes of the present disclosure it will be understood that any of the features defined above or described below may be utilised in isolation or in combination. For example, features described above in relation to one of the above aspects or below in relation to the detailed description below may be utilised in any other aspect, or together form a new aspect.

BRIEF DESCRIPTION OF THE DRAWINGS

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

Figure 1 shows a diagrammatic view of a system for hydrate production;

5 Figure 2 shows another diagrammatic view of the system shown in Figure 1;

Figure 3 shows a cap assembly of the system shown in Figure 1;

Figure 4 shows a manifold for the flow lines of the system shown in Figure 1;

Figure 5 is a diagrammatic view of the control system of the system shown in Figure 1;

10 Figure 6 shows an alternative system for hydrate production, comprising multiple wellbores;

Figure 7 shows a logic diagram of how the system of Figure 6 will operate; and

Figure 8 shows a well system comprising the system for hydrate production shown in Figure 6.

DETAILED DESCRIPTION OF THE DRAWINGS

Referring first to Figures 1 and 2 of the accompanying drawings, there is shown diagrammatic views of a system 10 for hydrate production. The illustrated system 10 is for methane hydrate production.

20 In use, and as will be described further below, the system 10 is configured to separate a water component W from a multi-phase methane gas and water mixture M present in a wellbore 12, the system 10 being configured such that the separation occurs within the wellbore 12.

25 As shown in Figure 1, the system comprises a first flow line 14 disposed in the wellbore 12, the first flow line 14 arranged such that an inlet 16 of the first flow line 14 is disposed in and receives the water component W, so as to separate the water component W from the multi-phase methane gas and water mixture M.

30 In the illustrated system 10 shown in Figure 1, the inlet 16 of the first flow line 14 forms the distal end of the first flow line 14.

However, it will be understood that the inlet may for example alternatively or additionally comprise one or more lateral flow ports in the first flow line 14. Also, while the system 10 comprises a single flow line 14, the system 10 may alternatively comprise a plurality of first flow lines 14.

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As shown in Figure 1, the system 10 further comprises a flow control device 18 provided on or operatively associated with the first flow line 14.

10 In the illustrated system 10, the flow control device 18 takes the form of a variable flow control device, more particularly a variable choke.

The system 10 further comprises a check valve 20. In the illustrated system 10, the check valve 20 comprises or takes the form of a ball valve.

15 The check valve 20 is provided on the first flow line 14 and is configured to prevent or limit back flow of the water component W through the first flow line 14, i.e. flow back towards the inlet 16. In the illustrated system 10, the check valve 20 is interposed between the inlet 16 of the first flow line 14 and the flow control device 18.

20 The system 10 further comprises a sensor arrangement comprising sensors 22, 24 configured to detect a water level of the water component W in the wellbore 12 and output an output signal indicative of the water level.

25 In the illustrated system 10, the sensors 22, 24 each take the form of a downhole pressure and temperature (DHPT) gauge. The sensor 22 measures the pressure and/or temperature at a first wellbore location. The sensor 24 measures the pressure and/or temperature at a second wellbore location. Since the distance between the sensors 22, 24 is known, the water level can readily be determined. However, it will be understood that other suitable sensors for measuring the water level may be employed.

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As shown in Figure 1, the system 10 comprises a pump 26 coupled to or operatively associated with the first flow line 14.

The pump 26 is configured to draw the water component W from the wellbore 12 through the first flow line 14.

5 In the illustrated system 10, the pump 26 comprises or takes the form of a single-phase centrifugal pump, i.e. a pump configured to handle a single-phase fluid.

Beneficially, the system 10 is configured to separate the water component W of the multi-phase water and methane gas mixture M within the wellbore 12, and so can utilise a single-phase pump such as the pump 26 which offers greater control over the
10 fluid flow through the first flow line 14.

As shown in Figure 1, the system 10 comprises a second flow line 28. The second flow line 28 is disposed in the wellbore 12 and is arranged such that an inlet 30 of the second flow line 28 is disposed in and receives the methane gas component G of the multi-phase methane gas and water mixture M.
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In the illustrated system 10, the inlet 30 of the second flow line 28 forms the distal end of the second flow line 28.

20 However, it will be understood that the inlet 30 may for example alternatively or additionally comprise one or more lateral flow ports in the second flow line 28. Also, while the system 10 comprises a single flow line 28, the system 10 may alternatively comprise a plurality of second flow lines 28.

25 As shown in Figure 1, the system 10 comprises a flow control device 32 provided on or operatively associated with the second flow line 28. In the illustrated system 10, the flow control device 32 takes the form of a variable flow control device, more particularly a variable choke.

30 The system 10 further comprises an isolation valve 34 provided on or operatively associated with the second flow line 28. In the illustrated system 10, the isolation valve 34 takes the form of an annulus isolation valve.

As shown in Figure 1, and referring now also to Figures 2 and 3 of the accompanying drawings, the system 10 further comprises a cap 36. The cap 36 is coupled to and/or mounted on a wellhead 38 (shown in Figure 2) and as shown in Figure 2 it can be seen that in the illustrated system 10 the first and second flow lines 14, 28 are disposed through the wellhead 38.

As shown in Figure 2, the system 10 further comprises a tubing hanger 40. The tubing hanger 40 is disposed on and/or supported by the wellhead 38. The first and second flow lines 14, 28 are disposed through the tubing hanger 40.

As shown in Figure 3 of the accompanying drawings, the system 10 comprises a flow meter 42, which in the illustrated system 10 takes the form of a single-phase flow meter.

As shown in Figures 2 and 3, the system 10 further comprises a valve 44 suitable for opening and closing the first flow line 14, which in the illustrated system 10 takes the form of a ROV-operable gate valve.

As shown in Figure 4 of the accompanying drawings, the system 10 further comprises a manifold 48. As shown in Figure 4, first flow lines 14 feed into a water production header 47 and second flow lines 28 feed into a gas production header 49.

Referring now to Figure 5 of the accompanying drawings, there is shown a diagrammatic view of a control system 50 of the system 10 shown in Figure 1.

The control system 50 is configured to receive the output signal indicative of said water level from the sensor arrangement and control the flow control device 18 based on the water level so as to control the flow of the water component W through the first flow line 14. In the illustrated system 10, the control system 50 forms or forms part of a subsea well control system.

As shown in Figure 5, the control system 50 comprises a control module 52, which in the illustrated control system 50 takes the form of subsea control module.

The subsea control module 52 is configured to process sensor data received from at least one of the sensors of the sensor arrangement (and/or any other inputs to the subsea control module 52) and output one or more command signal to a position controller 60 of the choke 18 to control the position of the choke 18 and to a position controller 62 of the isolation valve(s) 46 to control the position of the isolation valve(s) 46. In the illustrated system 10, the subsea control module 52 is configured to process sensor data received from the one more water level sensors 22, 24; one or more erosion sensors 54; one or more flow sensors (such as flow meter 42), one or more choke position sensor 56; one or more pressure and/or temperature sensors 58.

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As shown in Figure 5, the control system 50 comprises a master control station or module 64. The control module 52 is configured to communicate with the master control station or module 64 and vice-versa.

15

The master control station or module 64 is configured to receive information from one or more topside systems or modules. In the illustrated system 10, the master control station or module 64 is configured to receive information from an emergency shut down (ESD) system or module 66 and a system flow demand system or module 68. However, it will be understood that the master control station or module 64 may receive one or more inputs from a variety of other sources in addition to or as an alternative to an emergency shut down (ESD) system or module 66 and a system flow demand system or module 68.

20

The master control station or module 64 is configured to process the information from the one or more topside modules, e.g. the emergency shut down module 66 and the system flow demand module 68 (and/or any other inputs to the master control station or module 64) and output one or more command signal to a controller 70, in particular speed controller, of the pump 28 (shown in Figure 1).

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The control system 50 comprises, is coupled to or communicates with a pump control system 72, which in the illustrated system 10 takes the form of a subsea pump control system.

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The pump control system 72 comprises a pump control module. The pump control system 72 comprises or takes the form of a processor.

5 The pump control module 74 communicates with one or more sensors associated with control of the pump and one or more actuators associated with control of the pump, collectively represented as reference 76 in Figure 6.

10 The system 10 provides a number of significant benefits over conventional equipment and methodologies.

For example, the system 10 utilises the methane hydrate production wellbore 12 itself to separate the water component W from the gas, thereby eliminating or at least reducing the need for further separation of the phases downstream of the wellbore 12

15 Moreover, conventional equipment and methodologies involve transporting a multi-phase mixture to the surface which as described above can re-form into a hydrate at the pressure and temperature conditions typically found at the seabed. By contrast, in the present system separation occurs within the wellbore, such that the risk of hydrate re-formation is eliminated or at least significantly reduced. This in turn improves the
20 availability and/or efficiency of the methane hydrate production system as well as reducing downtime associated with workover operations and the like and/or reducing or eliminating the need to use chemical hydrate inhibitors, heating equipment or other hydrate mitigations.

25 The provision of a system in which separation occurs in the wellbore eliminates or at least mitigates the problems of slugging and wear in production equipment such as pipework, pumps, separators which otherwise may result from excessive water and/or sand production, since greater control can be achieved when handling single-phase fluid flows compared to the current multi-phase fluid flows. Moreover, whereas conventional
30 systems require equipment capable of handling multi-phase fluids the present system can utilise equipment designed for handling single-phase fluids. In addition to being simpler and generally less costly to implement, such single-phase equipment provides a greater degree of control of the liquid flowrate at the well, reducing the risk of wellbore collapse.

Moreover, methane hydrates are sensitive to high flow rates and thus the present system beneficially facilitates the flow rate to be controlled using the flow control device on the first flow line.

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It will be understood that various modifications can be made without departing from the scope of the invention as defined in the claims.

For example, Figure 6 shows an alternative system 110 for methane hydrate production, comprising multiple wellbores 112a,b. The illustrated system 110 shows two wellbores 112a,b. However, it will be understood the system 110 may comprise any number of wellbores 112a,b,#.

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As shown in Figure 6, the system 110 comprises two flow lines 114a,b disposed in respective wellbores 112a,b, the flow lines 114a,b arranged such that inlets 116a,b of the flow line 114a,b is disposed in and receives the water component Wa,b so as to separate the water component Wa,b from the multi-phase methane gas and water mixture Ma,b.

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In the illustrated system 110 shown in Figure 6, the inlets 116a,b form the distal end of the first flow line 114a,b.

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However, it will be understood that the inlets 116a,b may for example alternatively or additionally comprise one or more lateral flow ports in the flow lines 114a,b. Also, while the system 110 comprises a single flow line 114a,b per wellbore 112a,b, the system 110 may alternatively comprise a plurality of flow lines 114a,b per wellbore 112a,b.

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As shown in Figure 6, the system 110 further comprises flow control devices 118a,b provided on or operatively associated with the flow lines 114a,b.

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In the illustrated system 10, the flow control devices 118 takes the form of a variable flow control device, more particularly variable chokes.

The system 110 further comprises check valves 120a,b. In the illustrated system 110, the check valves 120a,b comprise or takes the form of ball valves.

5 The check valves 120a,b are provided on the flow lines 114a,b and are configured to prevent or limit back flow of the water component Wa,Wb through the respective flow lines 114a,b. In the illustrated system 110, the check valves 120a,b are interposed between the inlets 116a,b of the first flow lines 114a,b and the flow control devices 118a,b.

10 The system 110 further comprises a sensor arrangement comprising sensors 122a,b, 124a,b configured to detect a water level of the water components Wa,b in the wellbores 112a,b and output an output signal indicative of the water level.

15 In the illustrated system 110, the sensors 122a,b, 124a,b each take the form of a downhole pressure and temperature (DHPT) gauge. The sensor 122a,b measure the pressure and/or temperature at respective first wellbore locations in the wellbores 112a,b. The sensors 124a,b measure the pressure and/or temperature at respective second wellbore locations in the wellbores 112a,b. Since the distance between the sensors 122a,b is known and the distance between the sensors 1224,b is known, the
20 water levels can readily be determined. However, it will be understood that other suitable sensors for measuring the water level may be employed.

 As shown in Figure 6, the system 110 comprises a pump 126 coupled to or operatively associated with the flow lines 114a,b.

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 The pump 126 is configured to draw the water components Wa,b from the wellbores 112a,b through the flow lines 114a,b.

30 In the illustrated system 110, the pump 26 comprises or takes the form of a single-phase vertical centrifugal pump, i.e. a pump configured to handle a single-phase fluid.

 Beneficially, the system 110 is configured to separate the water components Wa,b of the multi-phase water and methane gas mixture Ma,b within the wellbores

112a,b, and so can utilise a single-phase pump such as the pump 126 which offers greater control over the fluid flow through the flow lines 114a,b.

5 As shown in Figure 6, the system 110 comprises a flow lines 128a,b. The flow lines 128a,b are disposed in the wellbores 112a,b and are arranged such that inlets 130a,b of the flow lines 128a,b are disposed in and receive the methane gas component Ga,b of the multi-phase methane gas and water mixture Ma,b.

10 In the illustrated system 110, the inlets 130a,b of the flow lines 128a,b form the distal end of the second flow lines 128a,b.

However, it will be understood that the inlets 130a,b may for example alternatively or additionally comprise one or more lateral flow ports in the flow lines 128a,b. Also, while the system 110 comprises a single flow line 128a,b per wellbore 112a,b, the system 15 110 may alternatively comprise a plurality of flow lines 128a,b per wellbore 112a,b.

As shown in Figure 6, the system 10 comprises flow control devices 132a,b provided on or operatively associated with the flow lines 128a,b.

20 In the illustrated system 10, the flow control devices 132a,b take the form of variable flow control devices, more particularly variable chokes.

The system 110 further comprises isolation valves 134a,b provided on or operatively associated with the flow line 128a,b.

25 Figure 7 shows an example logic diagram of how the system of Figure 6 may operate. As described above, while the system 110 comprises two wellbores 112a,b the system 110 may comprise any number of wellbores. The additional wellbores is/are represented in Figure 7 by #.

30 Figure 8 shows a well system 1000 comprising the system 110 for methane hydrate production shown in Figure 6 coupled to a vessel V via a riser R.

This written description uses examples to disclose the invention, including the preferred embodiments, and also to enable any person skilled in the art to practice the invention, including making and using any devices or systems and performing any incorporated methods. The patentable scope of the invention is defined by the claims, and may include other examples that occur to those skilled in the art. Such other examples are intended to be within the scope of the claims if they have structural elements that do not differ from the literal language of the claims, or if they include equivalent structural elements with insubstantial differences from the literal languages of the claims. Aspects from the various embodiments described, as well as other known equivalents for each such aspects, can be mixed and matched by one of ordinary skill in the art to construct additional embodiments and techniques in accordance with principles of this application.

CLAIMS

1. A system for hydrate production, wherein the system is configured to separate a water component from a multi-phase gas and water mixture present in a wellbore, the system being configured such that said separation occurs within the wellbore, wherein the system comprises:
- 5 a first flow line disposed in the wellbore, the flow line arranged such that an inlet of the first flow line is disposed in and receives the water component of said multi-phase gas and water mixture, so as to separate the water component from said multi-phase gas and water mixture;
- 10 a flow control device provided on or operatively associated with the first flow line;
- a sensor arrangement comprising one or more sensors configured to detect a water level of said water component in the wellbore and output an output signal indicative of said water level; and
- 15 a control system configured to receive the output signal indicative of said water level from the sensor arrangement and control the flow control device based on said water level so as to control the flow of the water component through the first flow line.
2. The system of claim 1, wherein the flow control device comprises or takes the form of a variable flow control device.
- 20 3. The system of claim 1 or 2, wherein the flow control device comprises or takes the form of a choke.
- 25 4. The system of claim 1, 2 or 3, comprising a pump coupled to or operatively associated with the first flow line, wherein the pump is configured to draw the water component of the multi-phase gas and water mixture present in the wellbore through the first flow line.
- 30 5. The system of claim 4, wherein the pump comprises or takes the form of one of:
a single-phase pump; or
a multi-phase pump.

6. The system of claim 4 or 5, wherein the control system is configured to control the pump.
7. The system of any preceding claim, comprising a second flow line disposed in the wellbore, the second flow line arranged such that an inlet of the second flow line is disposed in and receives the gas component of said multi-phase gas and water mixture.
8. The system of claim 7, comprising a flow control device provided on or operatively associated with the second flow line.
9. The system of claim 8, wherein the flow control device comprises or takes the form of a variable flow control device.
10. The system of claim 8 or 9, wherein the flow control device comprises or takes the form of a choke.
11. The system of any preceding claim, wherein the sensor arrangement further comprises at least one of:
one or more erosion sensors;
one or more flow sensors;
one or more position sensors of the flow control device provided on or operatively associated with the first flow line; and
one or more pressure and/or temperature sensors.
12. The system of any preceding claim, wherein the control system comprises a control module, wherein the control module is configured to:
process sensor data received from the at least one of the sensors of the sensor arrangement; and at least one of:
output one or more command signals to a position controller and/or actuation mechanism of the flow control device provided on or operatively associated with the first flow line, so as to control the position of said flow control device; and/or
output one or more command signals to a position controller and/or actuation mechanism of at least one isolation valve provided on or operatively associated with the first flow line, so as to control the position of said isolation valve.

13. The system of any preceding claim, wherein the control system comprises, is coupled to or communicates with a master control station or module.
- 5
14. The system of claim 13, when dependent on claim 4, wherein the master control station or module is configured to:
- process information from at least one topside system or module; and
- output one or more command signals to a controller of the pump.
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15. The system of any preceding claim, wherein the control system comprises, is coupled to or communicates with a pump control system.
16. The system of any preceding claim, wherein the system comprises or takes the form of a system for natural gas hydrate production, wherein the system is configured to separate a water component from a multi-phase natural gas and water mixture present in a wellbore.
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17. The system of any preceding claim, wherein the system comprises or takes the form of a system for methane hydrate production, wherein the system is configured to separate a water component from a multi-phase methane gas and water mixture present in a wellbore.
- 20
18. A well system comprising the system for hydrate production according to any one of claims 1 to 17.
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19. The well system of claim 18, comprising a plurality of wellbores.
20. Use of the system for hydrate production according to any one of claims 1 to 17 or the well system according to claims 18 or 19 to separate a water component from a multi-phase gas and water mixture present in a wellbore, the system being configured such that said separation occurs within the wellbore.
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