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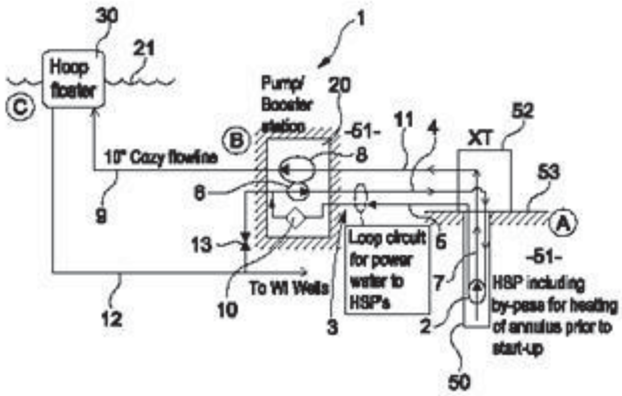
(54) Title **Improvements in producing fluids from reservoirs**

(57) Abstract

A method of producing fluid from a hydrocarbon reservoir is described in which, in particular embodiments, a production tubing section is provided in a well and is arranged to contain therein a flow of production fluid, and a power fluid for a downhole HSP is circulated adjacent to the production tubing section, so that the power fluid protects the production fluid against any one or more of: hydrate formation; wax appearance; and wax deposition. A circulation pump can be used to circulate the power fluid and the power fluid is preferably supplied with heat from the pump to keep the power fluid warm.



Improvements in producing fluids from reservoirs

Technical field

The present invention relates to the field of fluid production from subsurface reservoirs. In particular embodiments, it relates to flow assurance in subsea wells and subsea pipelines, which may be used to transport hydrocarbon production fluids from the well long distances.

Background

Production wells are used to produce fluid from reservoirs in the geological subsurface. In particular, fluids in the form of oil and gas are produced through wells, as is routinely the case in the oil and gas industry. The production fluid is typically received in the well from the subsurface reservoir due to the natural pressure conditions, and then flows out of the well inside a dedicated production tubing disposed in the well. A production pump may be installed in the well to help draw fluid into the well and along the production tubing to the surface. The production fluid from the well is then transported along pipelines to a downstream facility, for example a floating production platform (in the case of an offshore well) where the fluid may be processed further. Additional “booster pumps” may be provided in the production system at the surface, for example on the seabed, to help pump the production fluid from the well along the pipeline to the downstream facility at a suitable rate.

The fluid received in the well may in general vary in composition between different reservoirs and oil fields. For example, the production fluid may be multiphase fluid containing oil, gas and water in varying amounts, depending upon the oil field or reservoir in question. In addition, various solids may be carried in the fluid. This leads to challenges with transporting the fluid, and it is important to ensure that the produced fluid can flow and be transported effectively over time, as the costs of shutdowns and repair are substantial. In the transport of oils, wax may precipitate out in solid form and deposit on internal surfaces of the pipelines or other flow channels if the temperature of the oil drops below a certain wax appearance temperature (WAT). In addition, hydrates may form inside the pipe, below the relevant hydrate limit. Such wax deposits and hydrates can cause blockages in the pipe. Thus, it is important to design systems for producing and transporting fluids that take into consideration such challenges, to provide so-called “flow assurance” in the fluid production system.

Wax and hydrate control is particularly an issue in cases of transporting produced fluids along pipelines over long distances (e.g. 10 km or more) in the subsea environment, as the temperature of the production fluid will tend to drop significantly as heat is lost across the pipeline walls into the surrounding sea. The sea can typically have a temperature at the seabed of around 4-5°C, and even sub-zero temperatures can exist in deep areas.

Some reservoirs are much more difficult to exploit than others. Remote reservoirs at shallow depth and low temperature and/or pressure (close to the wax or hydrate limits) have been considered to have such onerous requirements that they have been considered uneconomic or unfeasible for production with existing flow assurance approaches.

Summary

In various embodiments, the inventors have developed solutions for producing fluids from shallow low temperature reservoirs, such as those described above. In particular embodiments, the solutions go against traditional approaches to flow assurance design.

According to a first aspect of the invention, there is provided a method of producing fluid from a hydrocarbon reservoir, the method comprising the steps of:

a. providing a production tubing section in a well, the tubing section arranged to contain a flow of production fluid therethrough; and

b. circulating a circulation fluid adjacent to the production tubing section, so as to protect the production fluid from dropping below a predetermined temperature.

The predetermined temperature may comprise a wax appearance, hydrate formation or hydrate equilibrium temperature, e.g. a threshold temperature for wax appearance or hydrate formation.

According to a second aspect of the invention, there is provided a method of producing fluid from a hydrocarbon reservoir, the method comprising the steps of:

a. providing a production tubing section in a well, the tubing section arranged to contain therein a flow of production fluid; and

b. circulating a circulation fluid adjacent to the production tubing section, so that the circulation fluid protects the production fluid against any one or more of: hydrate formation; wax appearance; and wax deposition.

The circulated fluid may comprise power fluid for operating a downhole production pump. The power fluid may comprise or be based on any one or more of: i) injected liquid or liquid to be injected into the reservoir via a further, injection well; ii) treated seawater; and iii) water produced from the reservoir.

Typically, the method may further comprise using at least one circulation pump provided on the seabed to circulate the circulation fluid. The method may further comprise using at least one topside circulation pump to circulate the circulation fluid.

The method may further comprise using at least one downhole production pump to pump the production fluid to help the flow through the production tubing section toward the surface and out of the well. Typically, the downhole production pump comprises a hydraulic submersible pump.

The circulating step may be performed during production fluid being pumped out of the well using the downhole production pump. Alternatively, or additionally, the circulating step may be performed prior to starting production from the well using the production pump.

The circulation fluid may be circulated into the well and then out of the well, through a bypass arrangement at the downhole production pump. The bypass arrangement may comprise at least one valve. The valve may be arranged to generate thermal energy in the fluid, for example the valve may provide a restriction or tortuous flow path which may agitate the circulation fluid so as to generate heat. The circulation fluid may be circulated in the well along an annulus surrounding the production tubing section.

Preferably, the circulation fluid is circulated in a closed loop. The circulation fluid may be circulated out of the well in a tubing inside the production tubing. By operating the pump, heat can be generated in the pump. Accordingly, heat energy generated in the pump, e.g. by virtue of its working mechanisms, can be added to the circulating circulation fluid at the pump, as it passes therethrough. The method may further comprise using using a heater to add heat energy to the circulation fluid. Thus, the circulation pump and/or the heater can heat the circulating fluid. Since the fluid is circulating, preferably in a closed loop, such heat energy is added in an incremental fashion, on a continual basis, to maintain or heat up the circulation fluid to a desired temperature. The flow passage for the circulation fluid may for example be defined in a region, for example an annulus between an outer surface of the production tubing and an inner surface of an outer tubing in which the production tubing is placed. The outer tubing may for example be a well casing, or another tubing between well casing and the production tubing. The circulation fluid can therefore flow through the passageway adjacent to, and in contact with, these surfaces. The control of the circulation pump to pump the circulation fluid at a high level, e.g. pump speed, can generate substantial heat in the pump and consequently in the circulation fluid, which may be used in this invention to protect the production tubing against wax appearance and deposition, or hydrate formation. Preferably, the heat energy from the pump can enable the temperature of the circulation fluid to remain at or above the predetermined temperature, e.g. the wax appearance or hydrate formation temperature, throughout the length the flow passage in the well, so that in turn, the production fluid exiting the well also cannot drop below that temperature.

Thus, the circulating step may be performed to generate heat energy, which protects the production fluid from hydrate or wax deposition, or which prevents the production fluid from dropping below the predetermined temperature, whilst in the well. By operating in this way, the production tubing can allow the production fluid to flow therethrough in a wax-safe or hydrate-safe operational envelope.

Once the production fluid has exited the well, the production fluid may be pumped onward downstream using boosting pump. To this end, the method may thus further comprise using at least one seabed boosting pump to pump and transport the production fluid from the well through a subsea pipeline to a downstream destination. The subsea boosting pump is preferably operated so that the production fluid in the pipeline interacts with a surface in the pipe and generates friction heat so that wax appearance, wax deposition and/or hydrate formation is prevented. The pipeline is preferably insulated and may typically have an insulation coefficient U equal to or less than 1 W/m^2K . The pipeline is typically greater than 30 km in length.

The boosting pump and the circulation pump are preferably provided in a common seabed facility.

The present method is particularly of use preferably when the hydrocarbon reservoir (and hydrocarbon fluids therein to be produced) is at low temperature, for example close to a wax appearance temperature,hydrate equilibrium or hydrate formation temperature, for example when the hydrocarbon reservoir (and hydrocarbon fluids therein to be produced) are above said wax appearance, hydrate equilibrium or hydrate formation temperature, by for example 5 to 10°C or less, such as for example by 4°C or less, 2°C or less or 1°C or less. Typically, hydrate equilibrium temperatures may be 20°C or less, in some instances 30°C or less, or even 40°C or less. Wax appearance temperatures would typically be in the range of 15 to 30°C. The fluid from the reservoir typically comprises oil, which can be of any kind. The present method may be particularly useful where the fluid comprises heavy oil, for example extra heavy oil with components susceptible to wax formation. The fluid from the reservoir may have a low gas-to-oil ratio (GOR) and/or a low bubble point.

According to a third aspect of the invention there is provided a method of producing fluid from a hydrocarbon reservoir, the method comprising:

a. providing a production tubing section and at least one downhole production pump in the well, the downhole production pump being configured to be driven by a power fluid; and

b. supplying the power fluid to the downhole production pump to operate the production pump to pump the production fluid through the production tubing section, wherein the power fluid is in thermal communication with the production tubing, and thermally protects the production fluid from any one or more of: hydrate formation; wax appearance; and wax deposition.

The power fluid may be supplied to prevent the fluid from the reservoir from dropping below a predetermined temperature in the tubing, e.g. in the flow of the production fluid out of the well, and, for example to a seabed booster pump or to other production fluid processing equipment located downstream from the well.

According to a fourth aspect of the invention, there is provided a method of producing fluid from a hydrocarbon reservoir comprising:

a. providing at least one production tubing section; and

b. circulating a circulation fluid adjacent to the production tubing section, the circulation fluid providing thermal energy to protect the contents of the production tubing against any one or more of: hydrate formation; wax appearance; and wax deposition..

According to a fifth aspect of the invention, there is provided a method of transporting a production fluid comprising providing at least one pipe section arranged to transport the production fluid, and circulating a circulation fluid so as to be in thermal communication with the pipe section and provide thermal energy that serves to protect the production fluid from any one or more of: hydrate formation; wax appearance; and wax deposition..

The circulated fluid and the production fluid are typically present on opposite sides of a wall of the pipe section. The circulation fluid is preferably circulated in an annulus around the pipe section.

According to a sixth aspect of the invention, there is provided apparatus for performing the method of any of the first to fifth aspects.

Further advantages of the particular features and embodiments the invention will be apparent from the description, drawings and claims.

Each of the above aspects may have further features as described in any other aspect, and features described anywhere herein in relation to one embodiment may be included in other embodiments or aspects, as an additional feature or in exchange for another like feature.

Description

There will now be described, by way of example only, embodiments of the invention with reference to the accompanying drawings, of which:

Figure 1 is a schematic representation of apparatus for producing fluid from a well according to an embodiment of the invention;

Figure 2 is a cross-sectional representation of the well and tubing therein of Figure 1 (with the exception of the pump and annular packer which are merely shown schematically);

Figures 3A and 3B are graphs of simulation results for production fluid temperature and fluid velocity against distance for a pump-driven flow;

Figure 4 is a block diagram representation of a method of producing fluid from a well according to an embodiment of the invention; and

Figure 5 is a block diagram representation of method of producing fluid from a well according to another embodiment.

With reference to Figure 1, there is depicted apparatus 1 for producing oil from a well 50. The apparatus is shown as being distributed across locations A, B and C. The well is a subsea well and is shown at location A as extending from the seabed into a subsurface hydrocarbon reservoir 51. The well 50 is fitted with a Christmas tree 52 at the seabed 53 at the top of the well, which provides valves and connections for controlling the well and providing access for fluids into and out of the well. At location B, also on the seabed 51, the apparatus 1 has a pump station 20, and at location C the apparatus has a floating production facility 30 on the sea surface 21 to which the produced fluid from the well is transported.

With further reference to Figure 2, the apparatus has a downhole production pump, in the form of hydraulic submersible pump (HSP) 2 which is disposed in the bore of the well 50. The HSP 2 is powered hydraulically by a power fluid such as water which is supplied into the well to the HSP 2 in a closed loop circuit 3. The power fluid for the pump is supplied along a circulation-In pipe 4, along an annular flow region 13, and back out of the well along a circulation-Out pipe 5. The apparatus has a circulation pump 6 at the pump station 20 which pumps the power fluid along the closed loop circuit 3 to the HSP 2 in the well.

The production pump 2 is used to draw production fluid, e.g. hydrocarbon fluid such as oil and gas, from the reservoir into the production tubing 7 and pump the production fluid out of the well toward the production facility. To facilitate carrying the production fluid to the production facility, the apparatus has a booster pump 8, which is also provided on the pump station 20 at the seabed. The booster pump 8 is arranged to pump the production fluid along a pipeline 9 to the production facility 30.

The apparatus 1 is applied particularly to help produce oil from shallow reservoirs where reservoir temperatures are relatively low and the oil is close to the temperature below which wax may precipitate from the oil or below which hydrate may form. In such conditions, there is a risk of wax being deposited and blockages forming inside the production tubing as the oil cools as it is transported out of the well.

The circulation pump 6 is run at a speed by which significant heat energy is generated in the pump. The heat transfers to the power fluid in the pump, as the fluid passes through. The power fluid is delivered into the well through the circulation-In pipe and the flow space 13 in the well, so that it circulates adjacent to the production tubing. The flow space 13 is provided between the production tubing 7 and an outer tubing, such as casing 14, which lines the formation wall 15 of the well. Heat energy in the power fluid can be transferred between the power fluid and the production fluid across the production tubing, e.g. across the production tubing wall.

By circulating the power fluid in the closed loop, heat energy is added to the power fluid incrementally at the pump. In this way, the circulation pump provides sufficient heat in the power fluid to keep the temperature in the fluid at or above a desired temperature. By keeping the temperature at or above the desired temperature, the presence of the power fluid around the production tubing can prevent the fluid in the production tubing from dropping below a certain temperature. The addition of heat energy at the pump can compensate for heat losses in the loop, so as to maintain a consistent temperature in the power fluid as the power fluid is circulated through the well. The desired temperature in the power fluid can be determined according to requirements, but is preferably not less than the temperature at which wax or hydrate is produced, in order to prevent deposition or blocking issues. In some cases, the temperature sought in the production fluid may be a few degrees above the temperature at which wax is precipitated or above the hydrate equilibrium temperature in order to give a suitable error margin. In practice therefore the power fluid that is circulated has a temperature, which is equal to or above the minimum temperature sought for the production temperature, e.g. a minimum temperature limit. The power fluid in the annulus surrounding the production tubing acts in effect as a layer of insulation or thermal “blanket” which stops temperature in the production fluid from falling too low. The production tubing is heat conductive so that heat energy from the power fluid can be transferred conductively across the wall of the production tubing from the power fluid into the production fluid. In this way, there is provided thermal communication between the power fluid and the production fluid.

In the variant of Figure 1, the closed loop includes a heater 10 which serves to add heat energy to the circulation fluid returning out of the well, if the necessary temperature in the power fluid is not achievable with only the heat energy generated in the circulation pump 6. It can be noted that the apparatus may include temperature sensors to monitor the temperature in the power fluid and/or the production fluid. Data from the temperature sensors may be used to control the circulation pump 6, and optionally the heater if used, so that the necessary temperatures are generated in power fluid and the production fluid, in order to perform as described above.

In Figure 1, the apparatus is shown during production. Thus, the power fluid is circulated continuously into and out of the well along the circuit 3 while production fluid is being produced via the production pump 2. The production fluid and the circulating power fluid are carried out of the well separately, along separate flow paths.

Prior to production starting, the power fluid can be circulated in the well and heated with the circulation pump 6 in the same way as described above, to prepare the production tubing for production. For example, the power fluid may be used to bring the production tubing up to temperature, to avoid wax problems at the start-up of production (when using the HSP production pump). To do so, a valve may be provided at the HSP for the power fluid to bypass the HSP when not operational. The valve may be configured to produce a thermal effect in the power fluid to generate heat or increase the temperature in the circulation fluid at the bypass or valve location, so as to improve the performance of the circulation fluid and enhance supply of heat energy for the production tubing.

Upon exiting the well, the production fluid flows through a connecting pipe 11 to the booster pump 8. The booster pump 8 is used to pump the production fluid along the subsea pipeline 9 to the floating production facility 30.

The booster pump 8 is operated to generate significant pressure and velocity in the pipeline 9 downsteam of the booster pump 8. This, in turn, generates substantial friction heat due to the frictional resistance between the production fluid and the pipeline wall. The generated friction heat prevents the production fluid in the pipeline 9 from dropping below a certain temperature over the length of the pipeline, to prevent wax appearance, deposition and/or hydrate formation. Preferably, the pipeline 9 is insulated with insulation provided around the outside of the pipeline. For example, thermal insulation with a coefficient U of equal or less than 1 W/m^2K could be used for a pipeline which is 200 km long, although the technique could be suitable for pipelines in general of for example 30 km upwards. Good insulation properties may allow the pump speed and capacity to be reduced. The friction heat effect generated in the pipeline by operation of the booster pump 8 to yield high fluid rates and pressure is described in further detail below.

In other embodiments, a plurality of booster pumps operating such as the pump 8 is provided sequentially along the pipeline. In this way, a given pump in the sequence only needs to operate to provide a sufficient effect for the length of the pipeline onward to the next pump (or, in the case of the final pump, onward to the facility). This can help to reduce capacity requirements of individual pumps.

In certain embodiments, the power fluid can comprise water. Such water can be supplied through a supply tubing 12 and valve 13 from the floating production facility. The tubing 12 is primarily used to supply separate injection wells with water for injecting into the reservoir but can also supply water to the loop circuit if required. However, as the loop circuit 13 is a self-contained closed loop, there is in general little need for it to be supplied with water once it has been filled.

Turning to Figure 4, a method 100 for producing fluid from the well 50 is illustrated by steps S1 to S3 in the figure. At S1, hydrocarbon fluid from the reservoir is transported out of the well. The fluid is passed onward to a subsea booster pump. At S2, the booster pump pumps the hydrocarbon fluid to facilitate transport of the fluid to a processing platform destination downstream. The booster pump is operated at a high level so that it produces high pressure in the fluid immediately downstream of the pump. The pressure drives the flow against frictional resistance between the production fluid and the inside wall surface of the pipeline, generating friction heat energy along the pipeline that keeps the temperature in the fluid high. The energy generated replenishes the heat loss to the sea from the pipeline along its length, keeping the temperature of the fluid more or less constant, above the wax and hydrate limits. The fluid is carried in the pipeline and, at S3, is received at the processing platform, where the fluid may be processed further. The booster pump serves to pressurise the fluid both to transport fluid and generate friction heat in the pipeline downstream to keep it warm over long distances.

In Figure 5, a method 200 for producing fluid from the well 50 is illustrated by steps T1 to T3 in the figure. This method is concerned with flow assurance particularly in the well and in the transport of the hydrocarbon fluid from the well to the booster pump. At T1, the power fluid is pumped into the well using the power fluid circulation pump. The power fluid is at a temperature above wax/ hydrate limits of the hydrocarbon fluid to be produced. The power fluid is supplied with heat energy by the pump to keep the power fluid warm. At T2, the power fluid is circulated along a flow path where the fluid contacts the surfaces of the production tubing (which is pre-provided in the well). In this way, there is thermal communication between the power fluid and the production tubing, and provision for the transfer of heat energy there between (The production tubing is heat conductive). This circulation takes place in this example prior to production has started. At T3, the HSP in the well is activated and production starts, with the HSP operating to pump hydrocarbon fluid from the reservoir out of the well and the power fluid driving the HSP. The power fluid continues to circulate in contact with the production tubing and provides an insulative blanket for the production tubing such that the production fluid temperature does not drop below the hydrate or wax limits, in the flow to the seabed booster pump 8. The power fluid has a dual purpose in that it is used both to power the production HSP and to keep the production tubing warm.

It should be distinguished between the generation of friction heat as used in the production transport pipeline 9 and that of "pump heat" as used in the circulating power fluid in the well bore. With regard to the latter, as the circulation pump 6 operates, heat energy is generated in the circulation pump 6. The circulation pump becomes "warm" due to the interaction and working of moving parts in the pump, including for example the pump motor. The generated heat energy can transfer to the power fluid in the pump, to heat the power fluid, or maintain a temperature therein. It can be noted that a similar heat generative effect is produced in the booster pump 8, although in general it is not sufficient to provide the necessary protection against wax deposition and hydrate formation in the pipeline 9. Accordingly, the booster pump 8 operates to produce pressure and fluid velocity downstream of the pump so that substantial friction heat is generated against the frictional resistance of the pipeline. Likewise, the circulation of power fluid using the circulation pump 6 will result in some downstream friction heat generation due to the flow of power fluid in the supply pipes and fluid passageway of the closed loop. However, the friction heat in this case is not substantial compared with the incremental heat energy generated in the circulation pump 6, and added to the power fluid as it is circulated. It can further be noted that different conditions are applicable to the use of the circulation pump 6 and circulation of power fluid in the well (compared with the transport of production fluid with booster pumps), in particular: the power fluid is circulated in a closed loop whereby it repeatedly passes through the circulation pump; the circulated power fluid travels typically a lesser distance; and heat loss is less extreme, as the well environment is "warmer."

Design principles

The principle of using the booster pumps to generate friction heat in the pipeline downstream of the pump provides a technique for flow assurance in long distance transport of liquid dominated well streams.

The temperature in the well stream (comprising production fluids) is maintained above the hydrate and wax limits through balancing frictional heat production and thermal heat loss. The flow is kept warm through its own work. It is kept just warm enough so that hydrate or wax precipitation does not occur.

In order to produce the necessary effect, a high pressure drop and good insulation of the pipeline is needed. The pump is configured to drive flow through a small internal diameter pipeline, adding energy to the system as pressure. Insulation with a thermal coefficient of U equal to or less than 1 might typically be used, for example by providing the pipeline through which the fluid is pumped as a Pipe-in-Pipe arrangement.

This is an opposite design mind set to that in normal flow assurance design. In normal design, it is sought to minimise pressure drop and insulation, with a view to saving energy and minimising cost. In the design in the present invention, pressure drop is maximised and super insulation is used to balance heat loss and generation. This allows fields to be developed which ordinarily would have been rendered as “not feasible” for production by normal flow assurance design considerations.

Heat is generated through viscous dissipation when the pressure gradient in the pipe does work against friction on the pipe wall. Heat is lost through temperature gradient driven conduction through the pipe wall. These phenomena are sought to be balanced by the operating the pumps and configuring the pipe suitably.

When these are balanced, the temperature of the fluid stays constant along the pipeline (neglecting other thermodynamic effects due to pressure drop along pipeline, which is usually small in liquid systems but may be significant when gas is present (J-T-cooling). The energy which is provided as pressure at the inlet to drive flow becomes available as heat along the pipeline, to help solve flow assurance issues such as hydrates and wax.

Heat generated, force*distance/ time, can be defined as:

$$Q_G = \frac{dP}{dx} A_{xs} V \qquad \text{(Equation 1)}$$

where *dP/dx* is the pressure gradient, A_{xs} is the pipe cross-sectional area, and *V* is the fluid velocity.

Heat lost, thermal loss coefficient*surface area*temperature difference, can be defined as:

$$Q_L = UA_{ps}\Delta T \qquad \text{(Equation 2)}$$

where U is overall heat transfer coefficient, A_{ps} is pipe surface area, and ΔT is temperature difference.

If the heat generated is larger than or equal to the heat lost, then the temperature will not decrease along the pipeline. This relation can be expressed as follows:

$$Q_G \geq Q_L \;\rightarrow\; \frac{dP}{dx}A_{xs}V \geq UA_{ps}\Delta T \quad \text{or} \quad \frac{32\dot{m}^3 f}{\pi^2\rho^2 D^5} \geq U\pi D\Delta T$$

(Equation 3)

where dP/dx is the pressure gradient, A_{xs} is the pipe cross-sectional area, V is the fluid velocity, U is overall heat transfer coefficient, A_{ps} is pipe surface area, ΔT is temperature difference, $\dot{m}$ is mass flow rate, f is Fanning friction factor, D is pipe internal diameter, and ρ is fluid density.

The relation of Equation 3 can be manipulated to give, for an otherwise given system, a minimum insulation (maximum U) value, minimum mass (production) rate $\dot{m}$, the minimum velocity V, maximum pipe diameter D, maximum temperature difference ΔT, and the e-folding length L_e approaching ΔT. The expressions for these parameters are listed below:

$$U \leq \frac{32\dot{m}^3 f}{\pi^3\rho^2 D^6\Delta T} \qquad \text{(Equation 4)}$$

$$\dot{m} \geq \frac{\pi D^2}{4}\sqrt[3]{\frac{2\rho^2 U\Delta T}{f}} \qquad \text{(Equation 5)}$$

$$V \geq \sqrt[3]{\frac{2U\Delta T}{\rho f}} \qquad \text{(Equation 6)}$$

$$D \leq \sqrt[6]{\frac{32\dot{m}^3 f}{\pi^3\rho^2 U\Delta T}} \qquad \text{(Equation 7)}$$

$$\Delta T = \frac{32\dot{m}^3 f}{\pi^3\rho^2 D^6 U} \qquad \text{(Equation 8)}$$

$$L_e = \frac{\dot{m}C_p}{\pi DU} \qquad \text{(Equation 9)}$$

The e-folding length parameter indicates exponential change and is the distance from the pipeline inlet where temperature has changed by $(1-1/e^n)*\Delta T$. At the first e-folding length, ΔT has reached about 63% of the final/maximum/steady state value. In the e-folding expression of Equation 9, the parameter C_p is the fluid heat capacity.

Feasibility example

Simulations for transport along a 40 km pipeline have been performed. The pipeline inlet temperature was 20°C after boosting, somewhat above a wax appearance temperature of 17°C. The pipeline has a PiP configuration with U-value of 1 W/m^2K, a Fanning friction factor of 0.004, 50% water cut with mixture density of 900, and the ambient temperature (mimicking the seawater environment at the seabed) is 5°C, providing a ΔT of 15°C. The equation 7 indicates that the diameter of the pipeline needs to be less than 0.2707 m, and equation indicates that the velocity will be 2.03 m/s.

Results from an OLGA simulation are shown in Figures 3A and 3B. OLGA is commercially available software. Figure 3A shows that the temperature remains roughly constant at 20°C along the length of the pipeline, well over the hydrate and wax limits, and velocity is just over 2 m/s. A small effect of pressure dipping below the bubble point is evident in the results after about 30 km. The simulation assumed a well stream with a gas to oil ratio (GOR) of 48, and a bubble point of about 70 bar. The inlet pressure is 114 bar, with a suction pressure of 14 bar, giving 100 bar boosting by the booster pump. In order to provide this, the power required might typically be less than 1.5 MW, and typically is less than 0.5 MW to heat the PiP pipeline using EHT to above the hydrate limit. It was also found in the simulations that the time to reach the hydrate limit upon shutdown in this configuration is about 20 hours, which is a long cool down time and facilitates flow assurance during an unplanned shutdown situation.

Further aspects

Further aspects of the invention may be defined with reference to the following numbered paragraphs and statements:

1. A method of transporting production fluid from a well, comprising pumping the production fluid through at least one section of pipe so as to prevent the fluid in said section of pipe from dropping below a predetermined temperature.

2. A method of transporting production fluid from a well, comprising pumping the production fluid through at least one section of pipe so as to protect the fluid against any one or more of: hydrate formation; wax appearance; and wax deposition.

3. A method of transporting production fluid from a well, comprising using at least one pump to pump the fluid through at least one pipe section, the pump and pipe section being arranged so that the fluid interacts with a surface of the pipe section and generates friction heat so that wax appearance or deposition or hydrate formation is thereby prevented.

4. A method as in any preceding paragraph, wherein the production fluid is pumped to generate friction heat equal to or greater than the heat loss from the pipe section to its surroundings.

5. A method of transporting production fluid in a pipe, the method comprising operating at least one pump to pump the fluid through at least one section of the pipe and generate friction heat at said section, the friction heat being equal to or greater than a predicted heat loss, to protect against any one or more of: hydrate formation; wax appearance; and wax deposition.

6. A method as in paragraph 5, which further comprises predicting said loss of heat.

7. A method as in any of paragraphs 1 to 6, wherein the production fluid is pumped using a pump operating at a predetermined level based upon the predicted heat loss.

8. A method as in any of paragraphs 1 to 7, wherein the pipe is greater than 30 km in length.

9. A method as in any of paragraphs 1 to 8, wherein the pipe comprises at least one pipe-in-pipe section comprising an inner pipe section disposed within an outer pipe section, wherein the production fluid is pumped through the inner pipe section.

10. A method as in any of paragraphs 1 to 9, wherein the pipe is insulated with an insulation coefficient U equal to or less than 1 W/m^2K.

11. A method as in any of paragraphs 1 to 10, wherein the production fluid comprises multiphase fluid from a well, and wherein said pump used to pump the production fluid comprises a first, multiphase pump, and the method comprises operating the multiphase pump to pressurise the fluid to produce single phase production fluid downstream of the pump.

12. A method as in paragraph 11, wherein the pump used to pump the production fluid further comprises a second, single phase pump, and the method comprises using the single phase pump to pump the produced single phase production fluid, the first and second pumps together operating to generate said friction heat in the pipe to protect the fluid from any one or more of: hydrate formation; wax appearance; and wax deposition.

13. A method as in paragraph 12, wherein the first and second pumps are provided on a common production facility on the seabed.

14. A method of transporting a production fluid comprising providing at least one pipe section arranged to transport the production fluid, and circulating a circulation fluid so as to be in thermal communication with the pipe section and provide thermal energy that serves to protect the production fluid from any one or more of: hydrate formation; wax appearance; and wax deposition.

15. A method as in paragraph 14, wherein the circulated fluid and the production fluid are present on opposite sides of a wall of the pipe section.

16. A method as in paragraph 14 or 15 wherein the circulation fluid is circulated in an annulus around the pipe section.

17. A method of transporting production fluid in a subsea pipeline, which comprises generating friction heat by way of said fluid flowing through the pipeline, so that wax appearance or deposition, or hydrate formation, is thereby prevented.

18. A method as in paragraph 17, which further comprises using a pump to pump the fluid through said pipeline to generate the friction heat.

19. A method as in paragraph 18, wherein the generated friction heat is equal to or greater than the heat loss from the pipeline to the sea

20. Apparatus for performing the method of any of paragraphs 1 to 19.

In transporting the fluid from the well, the pumping is preferably performed by at least one “booster” pump which acts to boost the flow of production fluid from the well. This booster pump may for example be a seabed booster pump, e.g. placed on the seafloor, for boosting the flow of production fluid from the well. By way of pumping, a thermal effect can be generated in the fluid and/or the pipeline, which restricts or limits the cooling of the production fluid. The effect by the pump is necessary and sufficient to prevent the cooling of the fluid below the predetermined temperature, e.g. wax appearance or hydrate equilibrium temperature. By operating in this way, the pipe can transport the fluid in a wax-safe or hydrate-safe operational envelope. The fluid is preferably pumped to generate heat equal to or greater than the heat loss from the pipe to its surroundings. The pipe can be any length, but this solution is particularly applicable to long distance pipelines, for example those of over 30 km in length, and in particular those greater than 50 km, and yet more so in pipelines over 100 or 200 km in length, for example pipelines in the range of 100 to 200 km. The pipe is preferably insulated providing a low insulation coefficient U, which is typically equal to or less than 1 W/m^2K. Preferably, the pipe comprises at least one pipe-in-pipe (PIP) section, for insulating the pipe. The PIP section may comprise an inner pipe section disposed within an outer pipe section, wherein the production fluid is pumped through the inner pipe section. The pipeline can have a diameter which is in general dependent upon the application or reservoir case, but typically, for example for a long distance pipeline, a diameter is selected which is less than normally used in the prior art, where the normal strategy is to minimise pressure loss. The diameter may be for example less than 10 inches. The fluid can be pumped to boost the pressure in the production fluid to generate for example 100 bar pressure drop along the pipeline, although this is in general application dependent.

The necessary pressure can be generated using known booster pump technology, for example by connecting several pumps in series which each help to increase the pressure and flow rate of the fluid. In certain variants, the production fluid may comprise multiphase fluid from a well, and said pump used to pump the production fluid may comprise a first, multiphase pump. The method may then comprise operating the multiphase pump to pressurise the fluid to produce single phase production fluid downstream of the pump. The pump used to pump the production fluid may further comprises a second, single phase pump, and the method may comprise using the single phase pump to pump the produced single phase production fluid from the first pump, the first and second pumps together operating to generate said friction heat in the pipe to protect the fluid from wax or hydrate deposition. It will be noted that the first and second pumps could be provided on a common production facility on the seabed. It can be preferably to pump the pipeline in single phase and using single phase equipment, because single phase flows are generally less demanding in terms of equipment to process and their flow stability.

The booster pump advantageously provides both the boost for carrying the fluid the necessary distance to the destination for the production fluid and also can act to keep temperatures from dropping below wax and hydrate limits. Accordingly, dedicated heating equipment to prevent wax may be unnecessary.

Frictional resistance arises between the flowing production fluid and the surface of the pipe through which the production fluid passes. Heat is generated due to frictional resistance and the heat generation increases with increased pressure gradient, which in this case can be manipulated through a slightly smaller than normal pipe internal diameter. The frictional resistance, and heat to be generated, can also depend upon the fluid type, in particular the viscosity of the fluid. The fluid is typically a hydrocarbon fluid, and may comprise oil, gas, and/or water. In the envisaged application, the fluid may include heavy oil for example from a shallow reservoir. The frictional resistance depends also on the material roughness of the pipe section(s) through which the production fluid is pumped. The pipe may have a diameter adapted to generate heat by work against frictional resistance using the pump.

Modelling of the system may be performed to take into account any one or more of the following parameters: the surface roughness of pipe section along which the fluid passes upon being pumped, the pressure to be generated by the pump, the fluid type or viscosity, the gas oil ratio (GOR), length of pipe or pipe sections, pipe insulation coefficient, pipe diameter. Based on such modelling, the pump parameters needed to produce the friction heat for preventing the wax deposition or hydrate formation. The parameters of the system, and in particular the pump operational level required to produce the preventative heat effect, can be optimised based on this modelling.

The present techniques are particularly of use when the hydrocarbon reservoir (and hydrocarbon fluids therein to be produced) is at low temperature, for example close to a wax appearance temperature or hydrate equilibrium or hydrate formation temperature, for example less than 5°C, such as 1°C or less or 2°C or less, above that temperature. Hydrate equilibrium temperatures may typically be 20°C or less, 30°C or less, or even 40°C or less. Wax appearance temperatures would typically be in the range of 15 to 30°C. The fluid from the reservoir typically comprises oil, which can be of any kind. The present techniques may be particularly useful where the fluid comprises heavy oil, for example extra heavy oil with components susceptible to wax formation. The fluid from the reservoir may have a low gas-to-oil ratio (GOR) and/or a low bubble point.

Various modifications and improvements may be made without departing from the scope of the invention herein described.

CLAIMS:

1. A method of producing fluid from a hydrocarbon reservoir, the method comprising the steps of:

a. providing a production tubing section in a well, the tubing section arranged to contain a flow of production fluid therethrough; and

b. circulating a circulation fluid adjacent to the production tubing section, so as to protect the production fluid from dropping below a predetermined temperature.

2. A method as claimed in claim 1, wherein the predetermined temperature comprises a wax or hydrate appearance temperature.

3. A method of producing fluid from a hydrocarbon reservoir, the method comprising the steps of:

a. providing a production tubing section in a well, the tubing section arranged to contain therein a flow of production fluid; and

b. circulating a circulation fluid adjacent to the production tubing section, so that the circulation fluid protects the production fluid against any one or more of: hydrate formation; wax appearance; and wax deposition.

4. A method as claimed in any preceding claim, wherein the circulated fluid comprises power fluid for operating a downhole production pump.

5. A method as claimed in claim 4, wherein the power fluid comprises or is based on any one or more of: i) injected liquid or liquid to be injected into the reservoir via a further, injection well; ii) treated seawater; and iii) water produced from the reservoir.

6. A method as claimed in any preceding claim, which further comprises using at least one seabed circulation pump to circulate the circulation fluid.

7. A method as claimed in any preceding claim, which further comprises using at least one topside circulation to circulate the circulation fluid.

8. A method as claimed in any preceding claim, which further comprises using at least one downhole production pump to pump the production fluid to help the flow through the production tubing section toward the surface and out of the well.

9. A method as claimed in claim 8, wherein the downhole production pump comprises a hydraulic submersible pump.

10. A method as claimed in claim 8 or 9, wherein the circulating step is performed during production fluid being pumped out of the well using the downhole production pump.

11. A method as claimed in any of claims 8 to 10, wherein the circulating step is performed prior to starting production from the well using the production pump.

12. A method as claimed in any of claims 8 to 11, wherein the circulation fluid is circulated into the well and then out of the well, through a bypass arrangement at the downhole production pump.

13. A method as claimed in any preceding claim, wherein the circulation fluid is circulated in the well along an annulus surrounding the production tubing section.

14. A method as claimed in any preceding claim, wherein the circulation fluid is circulated into the well and out of the well in a closed loop.

15. A method as claimed in any of claims 1 to 13, wherein the circulation fluid is circulated out of the well in a further tubing inside the production tubing.

16. A method as claimed in any preceding claim, which further comprises using the circulation pump to heat the circulation fluid.

17. A method as claimed in any preceding claim, which further comprises using a heater to heat the circulation fluid.

18. A method as claimed in any preceding claim, wherein the circulating step is performed to generate heat energy, which protects the production fluid from hydrate

formation or wax deposition, or which prevents the production fluid from dropping below the predetermined temperature, whilst in the well.

19. A method as claimed in any preceding claim, which further comprises using at least one seabed boosting pump to pump and transport the production fluid from the well through a subsea pipeline to a downstream destination.

20. A method as claimed in claim 19, wherein the subsea boosting pump is operated so that the production fluid in the pipeline interacts with a surface in the pipe and generates friction heat so that wax deposition or hydrate formation in the pipe is prevented.

21. A method as claimed in claim 20 or 21, wherein the pipeline is insulated and has an insulation coefficient U equal to or less than 1 W/m^2K .

22. A method as claimed in any of claims 19 to 21, wherein the pipeline is greater than 30 km in length.

23. A method as claimed in any of claims 19 to 22, wherein the boosting pump and the circulation pump are provided in a common seabed facility.

24. A method of producing fluid from a hydrocarbon reservoir, the method comprising:

a. providing a production tubing section and at least one downhole production pump in the well, the downhole production pump being configured to be driven by a power fluid;

b. supplying the power fluid to the downhole production pump to operate the production pump to pump the production fluid through the production tubing section, wherein the power fluid is in thermal communication with the production tubing, and thermally protects the production fluid from any one or more of: hydrate formation; wax appearance; and wax deposition..

25. A method as claimed in claim 24, wherein the power fluid is supplied to prevent the fluid from the reservoir from dropping below a predetermined temperature in the tubing.

26. A method of producing fluid from a hydrocarbon reservoir, the method comprising:

a. providing at least one production tubing section; and

b. circulating a circulation fluid adjacent to the production tubing section, the circulation fluid providing thermal energy to protect the contents of the production tubing against any one or more of: hydrate formation; wax appearance; and wax deposition.

27. A method of transporting a production fluid comprising providing at least one pipe section arranged to transport the production fluid, and circulating a circulation fluid so as to be in thermal communication with the pipe section and provide thermal energy that serves to protect the production fluid from any one or more of: hydrate formation; wax appearance; and wax deposition.

28. A method as claimed in claim 27, wherein the circulated fluid and the production fluid are present on opposite sides of a wall of the pipe section.

29. A method as claimed in claim 27 or 28 wherein the circulation fluid is circulated in an annulus around the pipe section.

30. Apparatus for performing a method as claimed in any preceding claim.

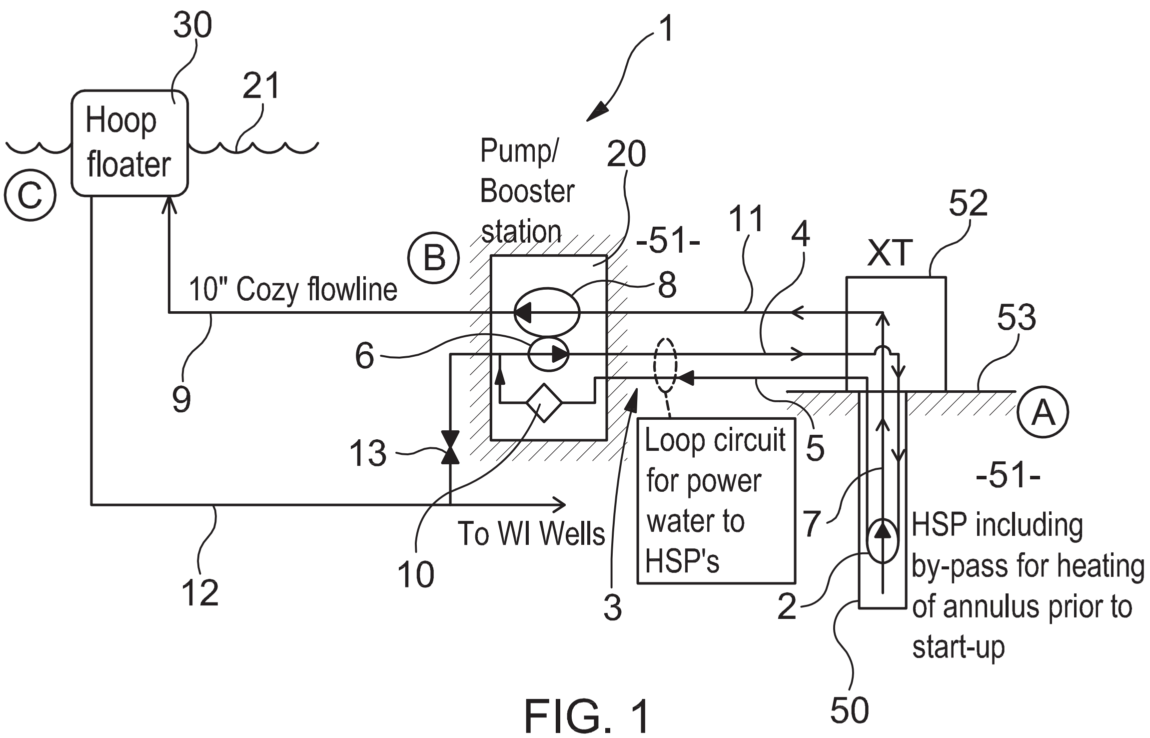

30
Hoop floater
21
C
1
Pump/ Booster station
20
B
-51-
11
4
XT
52
10" Cozy flowline
8
6
53
A
9
13
Loop circuit for power water to HSP's
5
-51-
7
To WI Wells
HSP including by-pass for heating of annulus prior to start-up
12
10
3
2
50

FIG. 1

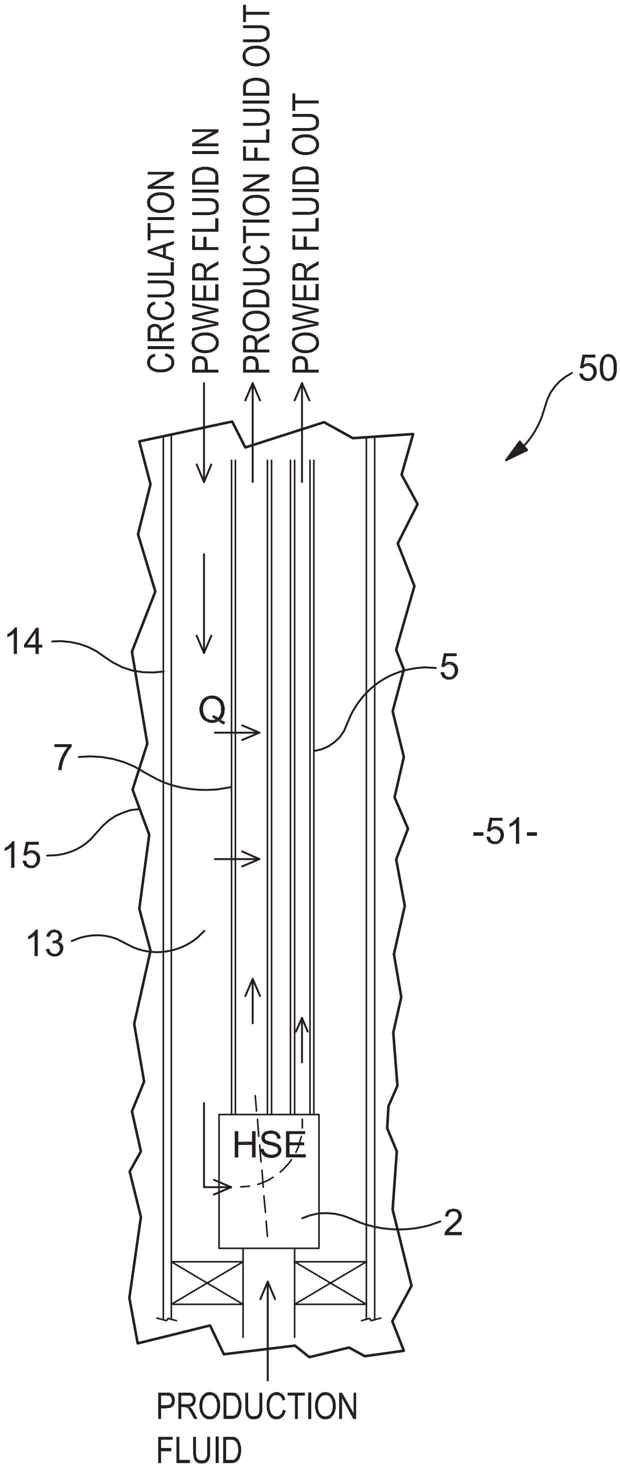
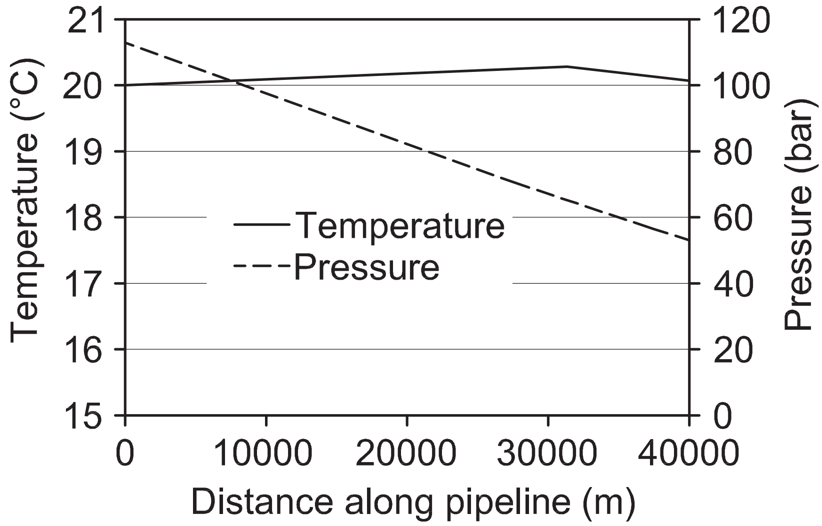
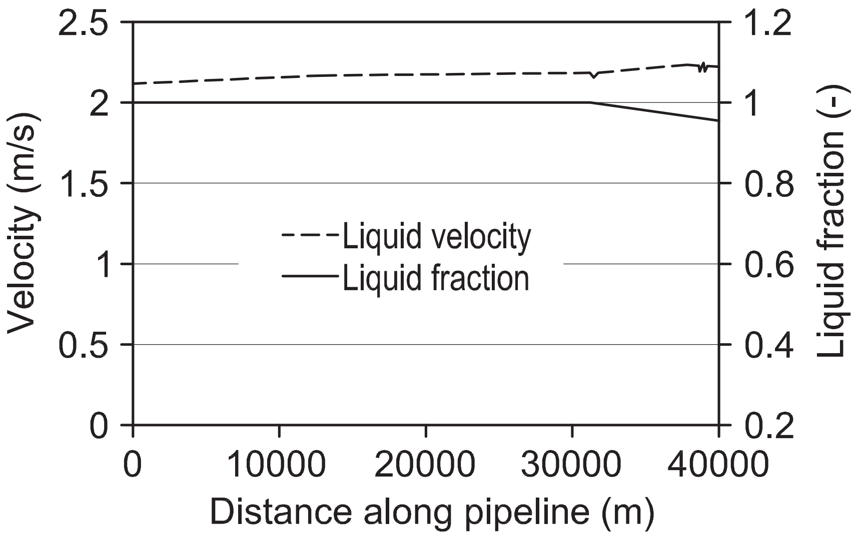

CIRCULATION
POWER FLUID IN
PRODUCTION FLUID OUT
POWER FLUID OUT
50
14
5
Q
7
15
-51-
13
HSE
2
PRODUCTION
FLUID

FIG. 2



Temperature (°C)
Pressure (bar)
21
20
19
18
17
16
15
120
100
80
60
40
20
0
Temperature
Pressure
0
10000
20000
30000
40000
Distance along pipeline (m)

FIG. 3A



Velocity (m/s)
Liquid fraction (-)
2.5
2
1.5
1
0.5
0
1.2
1
0.8
0.6
0.4
0.2
Liquid velocity
Liquid fraction
0
10000
20000
30000
40000
Distance along pipeline (m)

FIG. 3B

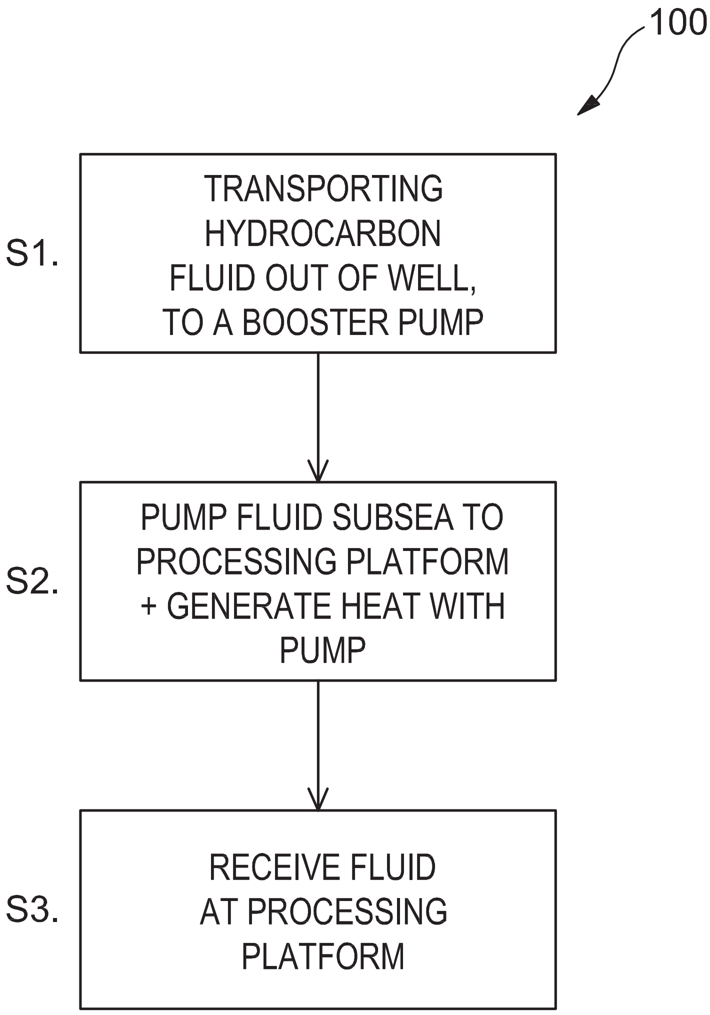

100
S1.
TRANSPORTING HYDROCARBON FLUID OUT OF WELL, TO A BOOSTER PUMP
S2.
PUMP FLUID SUBSEA TO PROCESSING PLATFORM + GENERATE HEAT WITH PUMP
S3.
RECEIVE FLUID AT PROCESSING PLATFORM

FIG. 4

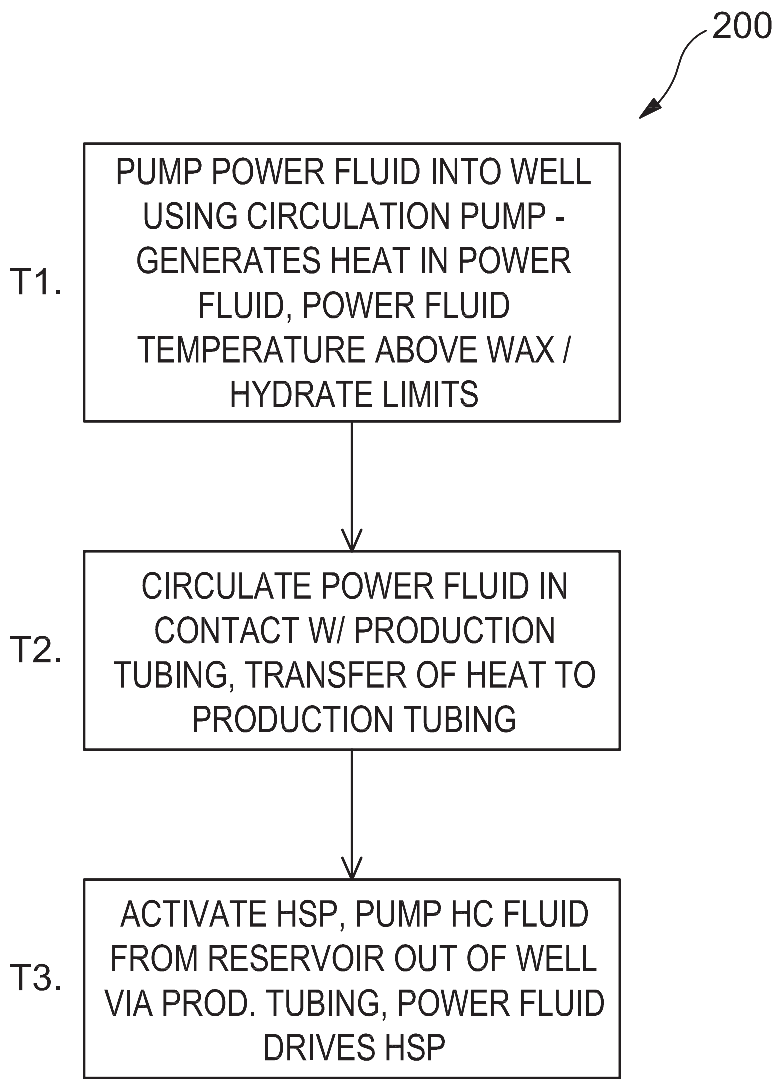

200
T1.
PUMP POWER FLUID INTO WELL USING CIRCULATION PUMP - GENERATES HEAT IN POWER FLUID, POWER FLUID TEMPERATURE ABOVE WAX / HYDRATE LIMITS
T2.
CIRCULATE POWER FLUID IN CONTACT W/ PRODUCTION TUBING, TRANSFER OF HEAT TO PRODUCTION TUBING
T3.
ACTIVATE HSP, PUMP HC FLUID FROM RESERVOIR OUT OF WELL VIA PROD. TUBING, POWER FLUID DRIVES HSP

FIG. 5