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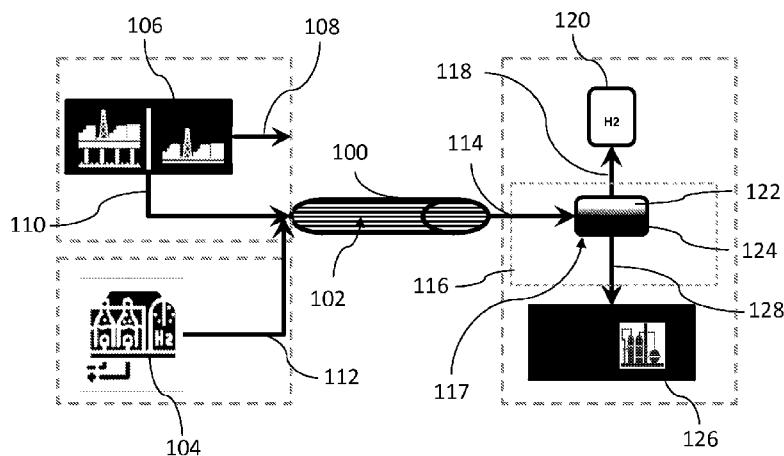


FIG. 1

(57) Abstract: It is provided a method for hydrogen transport, the method comprising flowing oil from an oil source into an oil pipeline and through the oil pipeline; flowing hydrogen from a hydrogen source into the oil pipeline and through the oil pipeline, the hydrogen and the oil forming a multi-phase flow; flowing the multi-phase flow to a separation facility fluidically connected to the pipeline; separating the multi-phase flow at the separation facility to recover the hydrogen. This forms an improved solution for transporting hydrogen.

HYDROGEN TRANSPORT

Technical field

5 The present disclosure relates to the field of hydrogen transport, and more specifically to a method and installation for the transport of hydrogen.

Technical background

10 Hydrogen production frequently takes place offshore, by means of high purity seawater treatment. The hydrogen is then collected and transported by a dedicated hydrogen pipeline (i.e. constructed for the sole purpose of transporting hydrogen) to a location of use. However, such a transport system for the hydrogen is very costly and does not become economical until the hydrogen production is well established, i.e. it produces the hydrogen in vast quantities. Further, the
15 installation of a transport system for the hydrogen can be difficult to establish, and in some cases the hydrogen production may be “stranded” and therefore cannot carry a dedicated hydrogen pipeline.

 Within this context, there is still a need for an improved solution for transporting hydrogen.

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Summary

 It is therefore the object of this disclosure to provide a method for hydrogen transport, the method comprising:

- 25 - flowing oil from an oil source into an oil pipeline and through the oil pipeline;
- flowing hydrogen from a hydrogen source into the oil pipeline and through the oil pipeline, the hydrogen and the oil forming a multi-phase flow;
- flowing the multi-phase flow to a separation facility fluidically connected to the pipeline;
- 30 - separating the multi-phase flow at the separation facility to recover the hydrogen.

 The method may further comprise one or more of the following features:

- the oil is a low gas-oil-ratio (GOR) oil or a stabilized oil;
- the oil from the oil source, before flowing through the pipeline, has a
35 concentration of up to 50 mol% of gases;
- the method comprises simultaneously flowing the oil into the pipeline and flowing the hydrogen into the pipeline;

- the pipeline is over-dimensioned for flowing the oil alone through the pipeline;
- recovering the oil from the separating of the multi-phase flow and transporting the recovered oil to an oil refinery;
- 5 - adjusting the flowing of hydrogen into the pipeline according to a flow behavior of the oil flowing into the pipeline so that minimal slugging occurs as the multi-phase flow flows through the pipeline;
- determining a flow schedule for the oil flowing into the pipeline and adjusting the flowing of hydrogen into the pipeline according to the
- 10 schedule;
- adjusting the flowing of hydrogen so that a maximum quantity of hydrogen flows into the pipeline;
- forming a graph based on oil flow parameters and using the graph to determine a quantity of hydrogen to flow into the pipeline;
- 15 - using the graph to determine the maximum quantity of hydrogen to flow into the pipeline;
- the multi-phase flow is a concentric flow, the hydrogen flowing along a longitudinal axis of the pipeline and the oil flowing along walls of the pipeline;
- 20 - the hydrogen has a maximum concentration of 80 wt % in the multi-phase flow;
- the hydrogen has a minimum concentration of 2 wt % in the multi-phase flow;
- taking measurements of the flowrate of the oil after flowing from the oil
- 25 source and before flowing the oil into the pipeline;
- pumping the oil from the oil source into the pipeline;
- taking pressure measurements and/or temperature measurements of the oil after flowing from the oil source and before flowing the oil into the pipeline;
- 30 - taking measurements of the flowrate of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline;
- compressing the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline;
- 35 - cooling the hydrogen before flowing the hydrogen into the pipeline;
- taking pressure measurements and/or temperature measurements of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline;

- flowing the hydrogen into the pipeline at a first inlet of the pipeline and flowing the oil into the pipeline at a second inlet of the pipeline;
- the hydrogen source is fluidically connected to the pipeline by a hydrogen pipeline, the hydrogen pipeline having a length ranging from 50 km to 500 km;
- the hydrogen source is fluidically connected to the second inlet of the pipeline by the hydrogen pipeline;
- taking pressure measurements and/or temperature measurements of the multi-phase flow at the first inlet and second inlet of the pipeline;
- the first inlet and the second inlet are both located at the same position on the pipeline, for example at one end of the pipeline;
- the length of the pipeline ranges from 50 km to 500 km, for example 100 km, or of such order;
- the separating comprises separation by gravity in a settling tank;
- the separating takes place over a duration ranging from 30 s to 5 mins, for example 1 min, or of such order;
- further separating water from the oil after separating the multi-phase flow;
- the multi-phase flow flows at a minimum speed of 0.1 m/s within the pipeline;
- the multi-phase flow flows at a maximum speed 10 m/s;
- the pressure in the pipeline ranges from 1000 kPa to 25000 kPa, for example 200 kPa, or of such order;
- the temperature in the pipeline ranges from 3 °C to 30 °C, for example from 3 °C to 20 °C, for example 5 °C, or of such order;
- the hydrogen source is a hydrogen production facility;
- treating seawater to produce the hydrogen;
- at least part of the pipeline is offshore;
- at least part of the pipeline is onshore; and/or
- the separated hydrogen has a purity ranging from 50 mol% to 100 mol%.

It is also provided an installation configured for hydrogen transport according to the method, the installation comprising:

- the oil source;
- the hydrogen source;
- the oil pipeline, the oil pipeline being fluidically connected to the oil source and to the hydrogen source;
- the separation facility fluidically connected to the oil pipeline.

The installation may further comprise one or more of the following features:

- the pipeline is over-dimensioned for flowing oil alone through the pipeline;
- an oil refinery downstream of the separation facility;
- a flowmeter between the oil source and before the pipeline;
- a pump between the oil source and the pipeline;
- one or more pressure sensors and/or one or more temperature sensors between the oil source and before the pipeline;
- a flowmeter between the hydrogen source and before the pipeline;
- a compressor between the hydrogen source and the pipeline;
- a heat exchanger after the compressor and before the pipeline;
- one or more pressure sensors and/or one or more temperature sensors between the hydrogen source and the pipeline;
- a first inlet of the pipeline fluidically connected to the hydrogen source and a second inlet of the pipeline fluidically connected to the oil source;
- the hydrogen source is fluidically connected to the pipeline by a hydrogen pipeline, the hydrogen pipeline having a length ranging from 50 km to 500 km;
- the hydrogen source is fluidically connected to the second inlet of the pipeline by the hydrogen pipeline;
- one or more pressure sensors and/or one or more temperature sensors at the first inlet and/or second inlet of the pipeline;
- the first inlet and the second inlet are located at one end of the pipeline;
- the length of the pipeline ranges from 50 km to 500 km, for example 100 km, or of such order;
- the separation facility comprises a settling tank;
- the pressure in the pipeline ranges from 1000 kPa to 25000 kPa, for example 200 kPa;
- the temperature in the pipeline ranges from 3 °C to 30 °C, for example from 3 °C to 20 °C, for example 5 °C;
- the hydrogen source is a hydrogen production facility;
- at least part of the pipeline is offshore; and/or
- at least part of the pipeline is onshore.

Brief description of the drawings

Non-limiting examples will now be described in reference to the accompanying drawings, where:

FIG. 1 to FIG. 3 each show a respective schematic example of the installation of the disclosure.

Detailed description

5 It is provided a method for hydrogen transport. The method comprises flowing oil from an oil source (e.g. an oil production facility) into an oil pipeline and through the oil pipeline. The method comprises flowing hydrogen from a hydrogen source (e.g. a hydrogen production facility) into the oil pipeline and through the oil pipeline, the hydrogen and the oil forming a multi-phase flow. The method
10 comprises flowing the multi-phase flow to a separation facility fluidically connected to the pipeline. The method comprises separating the multi-phase flow at the separation facility to recover the hydrogen (e.g. for use as an energy source, for example as an e-fuel).

It is further provided an installation configured for such hydrogen transport.
15 The installation comprises the oil source and the hydrogen source. The installation comprises the oil pipeline. The oil pipeline is fluidically connected to the oil source and to the hydrogen source. The installation also comprises the separation facility. The separation facility is fluidically connected to the oil pipeline.

Such a method and installation form an improved solution for hydrogen
20 transport.

By the method comprising flowing oil from an oil source into an oil pipeline, the method can make use of a readily available infrastructure to transport the hydrogen as opposed to having to construct and provide a dedicated hydrogen pipeline to do so. The oil pipeline may be an existing oil pipeline. In other words,
25 the oil pipeline may have been installed initially for the purpose of transporting oil. The oil pipeline may be an oil pipeline which is not (or is no longer) used at a maximum capacity for oil transport. Therefore, the method can be particularly advantageous as it can provide a further use for an oil pipeline which is not used to its maximum capacity for transporting oil.

30 The method allows for the transport of hydrogen in an efficient manner, *i.e.* without the need for implementing a new dedicated hydrogen pipeline for transporting the hydrogen, in particular for an initial production stage of the hydrogen (*i.e.* at a time when there is not yet a maximum production of hydrogen or a time where there is yet to be a fully established production of hydrogen from
35 the hydrogen production facility).

The method allows for flowing both hydrogen and oil through the oil pipeline. Therefore, the oil pipeline can serve two different functions simultaneously; the flow of oil and the flow of hydrogen.

The solution is based on the finding that hydrogen and oil can be transported simultaneously into a same oil pipeline where they form a multi-phase flow, and then be separated relatively easily.

Further, by forming a multi-phase flow, the flow comprises at least two phases, such as for example oil (liquid) and hydrogen (gas). Consequently, separating the multi-phase flow at the separation facility to recover the hydrogen allows for an easy recovery of gas with a majority mole percentage of hydrogen, as the hydrogen and oil may rest substantially in different respective phases (i.e. gas for hydrogen, liquid for oil). The separating is further facilitated by the fact that the hydrogen is much lighter than the oil.

The pipeline may be at least partly onshore and/or at least partly offshore. The installation can therefore allow for the transport of hydrogen to and/or from both onshore and offshore locations.

The oil source may be an oil production facility or oil field. The production facility may be an onshore facility or an offshore facility.

The hydrogen source may be a hydrogen production facility or hydrogen production plant. The method may comprise treating seawater to produce the hydrogen. At least part of the hydrogen production facility may be offshore. At least part of the hydrogen production facility may be an island used for hydrogen production. Treating seawater may comprise generating electricity (e.g. by one or more offshore wind turbines) and using the electricity to power a process of electrolyzing seawater (e.g. by one or more electrolyzers on an island, or energy island) to produce the hydrogen. The treating may comprise cleaning the hydrogen to reach a desired purity. The treating may comprise storing the hydrogen prior to flowing to the oil pipeline. Alternatively, the produced hydrogen may flow directly from the hydrogen production facility to the oil pipeline. The hydrogen may flow to the oil pipeline by a hydrogen pipeline. The hydrogen source may be fluidically connected to the oil pipeline by the hydrogen pipeline. The pipeline may have a length long enough so as to enable offshore production and onshore treatment. This also facilitates the forming of the multi-phase flow between the hydrogen and oil. The pipeline may have a length short enough so as to enable correct flow and later separation. For example, the hydrogen pipeline may have a length higher than 50 km and/or lower than 500 km. Length of such values may enable the multi-phase mixture to retain desired flow characteristics.

By oil pipeline it is meant a pipeline with design characteristics that render the pipeline suitable for the transport of (at least partly liquid) oil. The oil pipeline may be a pipeline that formerly (i.e. before implementation of the method)

transported oil at full capacity (for example, at 100% capacity or between 80% and 100% capacity). The oil pipeline may transport oil at a capacity that is less than 100%, for example, between 2% and 80% capacity. The pipeline may be designed to operate at maximum temperatures of up to 40 °C. The pipeline may be designed to operate at minimum temperatures equal to that of seawater, for example temperatures as low as 0 °C.

The method comprises separating the multi-phase flow at the separation facility to recover the hydrogen. Separating the multi-phase flow, may be facilitated by the fact that the hydrogen is much lighter than the oil (the oil having an at least substantially liquid form). In other words, a step of the separating may be completed thanks to the lower mass of the hydrogen relative to the oil. The separating may be further facilitated by the nature of the multi-phase flow. The multi-phase flow may be one for which the hydrogen and oil rest substantially separate, i.e. not a dispersed or at least not a fully dispersed flow. A step of the separating therefore may too be completed thanks to the nature of the multi-phase flow. Consequently, the separating facility can easily separate the hydrogen from the oil and in a manner that results in a recovery of hydrogen of a high purity. The recovered hydrogen may then be transported for its intended application, for example for use as an e-fuel.

The oil may be a low gas-oil-ratio (GOR) oil or a stabilized oil. This can facilitate an easy separation of the hydrogen from the oil. This can also ensure that the method is safely executed, as it can allow for a reduced risk of explosion at the separation facility. The stabilized oil may have a temperature ranging from 15 °C to 25 °C, for example from 15 °C to 20 °C, for example from 15 °C to 16 °C, for example 15.8 °C or of such order. The stabilized oil may have a maximum pressure ranging from 80 kPa to 120 kPa, for example of the order of 100 kPa or of such order. The stabilized oil may have a temperature and pressure such that no gas may leave the oil.

The oil flowing from the oil source, before flowing through the pipeline, may have a concentration of up to 50 mol% of gases. In other words, the oil may have a concentration of up to 50 mol% of gas prior to flowing into the pipeline with the hydrogen. In other words, the multi-phase flow made of hydrogen and oil plus hydrocarbon gases may have a concentration of non-hydrogen gases which is at most 50 mol%. The separating may comprise separating the hydrogen from the gaseous part of the oil. This separating step may occur following the separating of the hydrogen from the liquid component of the oil. A membrane may separate the hydrogen from the gaseous part of the oil. Alternatively, a dedicated separator

or dedicated separator technologies may separate the hydrogen from the gaseous part of the oil.

The pipeline may be over-dimensioned for flowing the oil alone through the pipeline. In other words, the pipeline may no longer operate at full capacity for the transport of oil and therefore may have a geometry that is too large for the quantity of oil flowing through it alone. This may be because the oil source to which it is connected may be nearing depletion. The quantity of oil flowing through the pipeline may therefore become smaller over time. The pipeline may have been installed for a number of years prior to flowing hydrogen through the pipeline, for example for more than 10 years, or for example for more than 30 years. Therefore, flowing hydrogen through the pipeline can allow for making use of non-practicing volumes of the pipeline.

The multi-phase flow may flow at a minimum speed of 0.1 m/s, or of such order, within the pipeline (where the expression “of such order” after a given value refers in the present disclosure to any value equal to the given value within a 10% error). In this way, the multi-phase flow can move through the pipeline with a reduced risk of slugging.

The multi-phase flow may flow at a maximum speed 10 m/s, or of such order, within the pipeline. In the way, the multi-phase flow can move through the pipeline rapidly while also reducing risk of having a dispersed flow, which may in turn facilitate removal of hydrogen from the oil at the separation facility.

The multi-phase flow may be a concentric flow. In other words, the hydrogen may flow along a longitudinal axis of the pipeline (i.e. through a center point of the pipeline) and the oil may flow along or be dragged along walls of the pipeline (i.e. around the longitudinal axis of the pipeline). This can allow for a flow behavior that results in no slugging, or minimal slugging, or the production of only very small slugs (i.e. slugs that do not result in a significant flow disruption, for example those that do not result in a reduce in flow speed that drops below 0.1 m/s, or of such order). The installation may nevertheless have at least one slug catcher to reduce the presence of slugs along the pipeline. The pipeline may be bisymmetric so as to reduce the risk of slugging.

The hydrogen may have a minimum concentration of 2 wt % and/or a maximum concentration of 80 wt % (percentage in weight), in the multi-phase flow. Therefore, the oil pipeline can always carry a quantity of hydrogen that can result in a recovered quantity of hydrogen (i.e. at the separating), that is justifiable, or for example economically viable. The pipeline can therefore allow for an efficient use of the available space in the pipeline, especially if the pipeline is a

retiring pipeline (i.e. is approaching the end of oil transport from an oil source, due to for example oil depletion from the oil source).

The method may comprise simultaneously flowing the oil into the pipeline and flowing the hydrogen into the pipeline. This can allow for avoiding any flow instability as the multi-phase flow moves through the pipeline. The hydrogen and oil may flow simultaneously into the pipeline at the same location of the pipeline, for example at an end of the pipeline. The hydrogen and oil may each flow into the pipeline via a respective inlet. The hydrogen may flow through a first inlet of the pipeline fluidically connected to the hydrogen source and the oil may flow through a second inlet of the pipeline fluidically connected to the oil source.

The method may comprise varying the flow (i.e. flowrate) of hydrogen and/or of oil into the pipeline depending on the ratio of hydrogen to oil in the pipeline. This can allow for ensuring flow stability in the pipeline (i.e. avoiding the likes of slugs and pressure drops). The method may comprise varying the flow rate in a manner that ensures that the design pressure of the pipeline is not exceeded during the supplying of hydrogen to the pipeline (and flowing of the multi-phase flow through the pipeline). The maximum pressure of the pipeline at which it can operate may be the design pressure. The design pressure may be that of a standard (classic, conventional) oil pipeline. The method may comprise supplying a quantity of hydrogen to the pipeline that is specific to the oil pipeline itself, for example according to the age of the pipeline and/or the geometry of the pipeline.

The method may comprise taking measurements of the flowrate of the oil after flowing from the oil source and before flowing the oil into the pipeline. A flowmeter located between the oil source and before the pipeline may take the measurements. The method may comprise taking measurements of the flowrate of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline. A flowmeter located between the hydrogen source and before the pipeline may take the measurements. The flowmeter may be located along the hydrogen pipeline. By obtaining both the flowrate of the flowing oil and the flowing hydrogen, the method may adjust hydrogen flow rate so as to match the flow rate of the oil. Therefore, as each fluid enters the pipeline, their flowrate can be synchronized, resulting in a more stable flow of the multi-phase flow.

The method may comprise pumping the oil from the oil source into the pipeline. The installation may comprise a pump located between the oil source and the pipeline to execute the pumping. The pump may increase the flow rate of the oil as a result of the measurements of the oil flow rate taken by the flowmeter.

The method may comprise taking pressure measurements of the oil after flowing from the oil source and before flowing the oil into the pipeline. One or more pressure sensors located between the oil source and before the pipeline may take the pressure measurements. The one or more pressure sensors may be located
5 after the pump and so may take pressure measurements of the oil at its increased flow rate. Additionally or alternatively, the method may comprise taking temperature measurements of the oil after flowing from the oil source and before flowing the oil into the pipeline. One or more temperature sensors located between the oil source and before the pipeline may take the temperature
10 measurements. The one or more temperature sensors may be located after the pump and so may take temperature measurements of the oil at its increased flow rate. Taking pressure and/or temperature measurements can allow for ensuring that the oil is at a desired pressure and/or temperature for forming a multi-phase flow with the hydrogen. The method may comprise adjusting the pressure of the
15 pump as a result of these measurements, so as to better achieve a desired oil pressure and/or temperature.

The method may comprise compressing the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline. A compressor located between the hydrogen source and the pipeline
20 may compress the hydrogen as it flows toward the pipeline. The compressor may be located along the hydrogen pipeline. The method may comprise cooling the hydrogen after the compressing and before flowing the hydrogen into the pipeline. Alternatively, the method may comprise cooling the hydrogen if the hydrogen is produced under pressure, by high-pressure electrolysis (HPE), *i.e.* in this case,
25 the method may comprise the cooling without the compressing. Alternatively, the method may comprise both compressing and then cooling the hydrogen prior to producing the hydrogen under pressure.

A heat exchanger located after the compressor and before the pipeline may cool the hydrogen. The heat exchanger may be located along the hydrogen
30 pipeline. The method may comprise taking pressure measurements of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline. One or more pressure sensors located between the hydrogen source and the pipeline may take the pressure measurements. The one or more pressure sensors may be located after the cooler and so may take
35 pressure measurements of the hydrogen after both the compressing and the cooling. The one or more pressure sensors may be located along the hydrogen pipeline. Additionally or alternatively, the method may comprise taking temperature measurements of the hydrogen after flowing the hydrogen from the

hydrogen source and before flowing the hydrogen into the pipeline. One or more temperature sensors located between the hydrogen source and the pipeline may take the temperature measurements. The one or more temperature sensors may be located after the cooler and so may take temperature measurements of the hydrogen after both the compressing and the cooling. The one or more temperature sensors may be located along the hydrogen pipeline. Taking pressure and/or temperature measurements can allow for ensuring that the hydrogen is at a desired pressure and/or temperature for forming a multi-phase flow with the oil. The method may comprise adjusting the compression of the hydrogen and/or of the cooling by the heat exchanger as a result of these measurements, so as to better achieve a desired hydrogen pressure and/or temperature.

The method may comprise flowing the hydrogen into the pipeline at a first inlet of the pipeline and flowing the oil into the pipeline at a second inlet of the pipeline. The first inlet and second inlet may both be located at the same position on the pipeline, for example at one end of the pipeline (the end of the pipeline may in such a case be considered to be the entry to the pipeline). The first inlet and the second inlet may be the same inlet, or two different inlets located so close together that they can be considered to form one inlet. In other words, the hydrogen and oil may flow into the pipeline at the same point on the pipeline. A mixer may optionally be located at the entry of the pipeline, for example just after the first inlet and second inlet so as to mix the hydrogen and oil together as they enter the pipeline to form the multi-phase flow. But alternatively the method and installation may form the multi-phase flow without use or even presence of such a mixer.

The hydrogen source may be fluidically connected to the first inlet of the pipeline by the hydrogen pipeline. The oil source may be fluidically connected to the pipeline by an additional (intermediary) oil flowline. The additional oil flowline may be a separate oil pipeline fluidically to the pipeline. In this case, the additional oil flowline may be fluidically connected to the second inlet of the pipeline. Alternatively, the additional oil flowline may be an extension of the pipeline. In this case, the pipeline may not comprise a second inlet for flowing oil into the pipeline, the additional flowline simply acting as a continuation of the (main) oil pipeline.

At least part of the pipeline may be offshore. At least part of the pipeline may be onshore. The pipeline may have a length higher than 50 km and/or lower than 500 km, for example 100 km or of such order. The pressure in the pipeline may be higher than 1000 kPa and/or lower than 25000 kPa, for example 200 kPa

or of such order. The temperature in the pipeline may range from 3 °C to 30 °C, for example from 3 °C to 20 °C, for example 5 °C or of such order.

The method may comprise taking pressure measurements of the multi-phase flow at the first inlet and second inlet of the pipeline. One or more pressure sensors located at the first inlet and/or second inlet of the pipeline may take the pressure measurements. Additionally or alternatively, the method may comprise taking temperature measurements of the multi-phase flow at the first inlet and second inlet of the pipeline. One or more temperature sensors located at the first inlet and/or second inlet of the pipeline may take the temperature measurements.

The method may comprise adjusting the flowing of hydrogen into the pipeline according to a flow behavior of the oil flowing into the pipeline so that minimal slugging occurs as the multi-phase flow flows through the pipeline. The flow behavior of the oil flowing into the pipeline may be characterized by the pressure and temperature measurements after flowing the oil from the oil source and before flowing the oil into the pipeline.

The method may comprise determining a flow schedule for the oil flowing into the pipeline and adjusting the flowing of hydrogen into the pipeline according to the schedule. The flow schedule may comprise a predetermined quantity of oil planned to flow in the pipeline over time. For example, the schedule may provide information regarding a respective quantity of oil to flow to the pipeline for each of one or more period of times. Each period of time may be defined by a starting date and/or an ending date, and/or comprise one or more (consecutive) years, one or more (consecutive) months, one or more (consecutive) weeks, one or more (consecutive) days, one or more (consecutive) hours, one or more (consecutive) minutes, and/or one or more (consecutive) seconds. The flow schedule may account for variations in the oil flow over time. In other words, the flow schedule may indicate a reduced oil quantity for a certain duration and an increased oil quantity for another duration. The method may comprise increasing the flow of hydrogen to the pipeline for each reduction in oil flow to the pipeline. The method may comprise decreasing the flow of hydrogen to the pipeline for each increase in oil flow to the pipeline. The method may comprise executing flow assurance work to optimize the schedule over time. This can account for any variations in the oil production over time.

The flow schedule may optionally comprise two schedule types. The first schedule type may be a constant flow type wherein the schedule plans for a continuous flow of hydrogen into the oil pipeline. For example, this may be implemented if there is a lower ratio of hydrogen to oil in the pipeline (e.g. as low as 2 wt %), or an equal ratio of hydrogen to oil in the pipeline, or a close to equal

ratio of hydrogen to oil in the pipeline (for example, within 10% of being an equal ratio of hydrogen to oil in the pipeline). Therefore, a larger volume of hydrogen can be provided in one batch to the separation facility. The second schedule type may be a patch injection type wherein the schedule plans for a sequential flow of hydrogen into the oil pipeline. The second type of flow schedule may depend on the ratio of hydrogen to oil. For example, this may be implemented if there is a higher ratio of hydrogen to oil in the pipeline (e.g. up to 80 wt %). Therefore, a larger volume of hydrogen can be provided in one batch to the separation facility. The decision to implement one schedule type versus another schedule type may depend on, for example, the flowrate of the each of the two fluids (hydrogen and oil), the length of the oil pipeline, the diameter of the oil pipeline and/or the pressure conditions inside the pipeline.

The method may comprise adjusting the flowing of hydrogen so that a maximum quantity of hydrogen flows into the pipeline. This may apply for both the first schedule type and the second schedule type. The method may comprise adjusting the flow of hydrogen so that, regardless as to the quantity of oil flowing through the pipeline, the remaining available space within the pipeline can be accurately filled with hydrogen. In this way, the oil pipeline can be made more efficient than if it were carrying just oil, or even a multi-phase flow made of oil and a less than maximum quantity of hydrogen.

In an example, the flow schedule for the oil flowing into the pipeline may comprise a number of hours per day for oil flow (with a starting time and/or an ending time) and no oil flow the rest of the day, or alternatively the date of days for oil flow and no oil flow the other days. In other words, the oil is scheduled to flow intermittently. In such an example, the hydrogen may be scheduled to flow when the oil flow is interrupted. In other words, the oil and hydrogen are flowed alternatively into the pipeline.

The pipeline being an oil pipeline, it may be configured to receive one or more pigs (devices for inspecting and/or cleaning the pipeline), and the method may comprise such reception (e.g. and actions of the pigs described herein below). The one or more pigs may each be up to 3m long. The one or more pigs may clean the inside of the pipeline. At least one of the one or more pigs may be an intelligent pig. The one or more pigs may comprise sensors to measure corrosion in the pipeline. The one or more pigs may be sent inside the pipeline to scrape the inside of the pipeline, for example to remove water gathering in a lower part of the pipeline. The method may comprise operational pigging wherein the one or more pigs carry out such scraping every number of days, for example every 1 to 7 days, for example every 2 days. The method may comprise intelligent

pigging (with one or more intelligent pigs) every number of months, for example once a year.

The method may comprise a prior study to determine a quantity of hydrogen to flow into the pipeline. For example, the method may comprise forming a graph based on oil flow parameters and using the graph to determine a quantity of hydrogen to flow into the pipeline. The oil flow parameters may include parameters such as, but not limited to, oil type, oil viscosity, solution gas oil ratio, density, oil pipeline geometry (e.g. pipeline length, pipeline internal diameter, pipeline material, pipeline wall thickness), oil pressure, oil flowrate, oil temperature. The method may comprise using the graph to determine the maximum quantity of hydrogen to flow into the pipeline. One or more sections of the pipeline may be vertical (i.e. perpendicular or substantially perpendicular to the earth's surface). For one or more such vertical sections, the graph may represent a flow regime map for vertical flow of the hydrogen and oil together (i.e. a multi-phase hydrogen-oil fluid). The graph may for example present a gas (hydrogen) volumetric flux (e.g. in m/s) as a function of liquid (oil) volumetric flux (e.g. in m/s). The graph may describe any one or more of the following flow behaviors of the multi-phase flow: bubbly flow, slug flow, churn flow, annular flow, disperse flow. One or more sections of the pipeline may be horizontal. For one or more such horizontal sections, the graph may represent a flow regime for horizontal flow of the hydrogen and oil together. The graph may for example present a mass flux of hydrogen (e.g. in kg/sm²) as a function of mass flux of oil (e.g. in kg/sm²). The graph may describe any one or more of the following flow behaviors of the multi-phase flow: bubble flow, plug flow, stratified flow, wavy flow, slug flow, annular flow, disperse flow.

The multi-phase flow flows to the separation facility fluidically connected to the pipeline. The pipeline may be fluidically connected to the separation facility at the opposite end of the pipeline. The pipeline may be fluidically connected to the separation facility by an intermediate flow line between an outlet of the pipeline and the separation facility. Alternatively, the pipeline may be directly connected (i.e. without need for an intermediate flowline connecting the pipeline to the separation facility) to the separation facility. In such a case, the multi-phase flow may flow directly from an outlet of the pipeline into the separation facility.

Separating the multi-phase flow at the separation facility to recover the hydrogen may comprise separating the hydrogen to a purity of ranging from 50 mol% to 100 mol%, for example from 60 mol% to 100 mol%, for example from 70 mol% to 100 mol%, for example from 80 mol% to 100 mol%, for example from 90 mol% to 100 mol%, for example from 95 mol% to 100 mol%. Separating the

hydrogen to such a purity can allow for the hydrogen to be immediately available for further use, for example as an energy fuel.

The separating may comprise separation by gravity in a settling tank. This can allow for a simple method for recovering the hydrogen while also allowing for the recovery of hydrogen of a high purity. The settling tank may operate at atmospheric pressure. The separating may take place over a duration ranging from 30 s to 5 mins, for example 1 min, or of such order. The separating can therefore not only result in a high purity of hydrogen, but can result in recovery of a high purity of hydrogen in a short amount of time. The separating time may depend on the quantity of the multi-phase flow provided to the settling tank and on the dimensions of the settling tank.

The hydrogen may lie (or float) above the oil in the separation facility. The separation facility may comprise an evacuation line dedicated to the hydrogen (hydrogen evacuation line) and an evacuation line dedicated to the oil (oil evacuation line). The hydrogen evacuation line may be fluidically connected to an upper part of the settling tank, the upper part of the tank being the part of the tank occupied by the hydrogen. The hydrogen evacuation line may transport the separated hydrogen from the settling tank to a temporary storage unit, from which the hydrogen may be transported for its intended application. The oil evacuation line may be fluidically connected to a lower part of the settling tank, the lower part of the tank being fluidically being the part of the tank occupied by the oil. The oil evacuation line may transport the oil from the settling tank to another unit of the separation facility for further treatment. The oil evacuation line may transport the oil to an oil treatment unit. The method may comprise further separating water from the oil after separating the multi-phase flow. In this way, the method can allow for not only the recovery of hydrogen but the recovery of oil and water also.

The method may comprise recovering the oil from the separating of the multi-phase flow and transporting the recovered oil to an oil refinery (for example to remove components such as C5, C6). The method can therefore allow for the recovery of oil and for refining the oil, for example to form a petrol or diesel fuel amongst other products. The oil refinery may be the same oil refinery to which the oil was transported previously when the oil pipeline was used for oil transport only, i.e. before the flowing of hydrogen through the pipeline. The oil refinery may be downstream of the separation facility. In this way, the method can comprise first separating the multi-phase flow before sending the oil to the oil refinery.

Further examples are now described with reference to the figures.

FIG. 1 shows an example of a schematic implementation of the installation. Oil flows from an oil field 106 serving as an oil source. The oil flows through a

flowline 110 connected to the plant 106 and reaches one end of an oil pipeline 100. Meanwhile, hydrogen flows from a hydrogen production plant 104 serving as a hydrogen source. The hydrogen flows through a hydrogen pipeline 112 and reaches the same end of the oil pipeline 100 as the oil flowline 110. The hydrogen may flow into the pipeline via a first inlet of the pipeline and the oil may flow into the pipeline via a second inlet of the pipeline (not shown in the figure). The hydrogen and oil form a multi-phase flow in the pipeline, as indicated by the lines 102. The multi-phase flow flows through the pipeline until it arrives at a separation facility 116. A flowline 114 is indicated to communicate the multi-phase flow from the pipeline 100 to the separation facility 116. Alternatively, the pipeline 100 may be connected directly (i.e. without need for an intermediate flowline 114) to the separation facility 116. The separation facility 116 may comprise a settling tank 117. The multi-phase flow flows into the settling tank 117. Once in the settling tank, the multi-phase flow may begin to separate into hydrogen and oil by gravity. The hydrogen 122 is easily separated from the oil 124 within the settling tank 117 as the hydrogen is significantly lighter than the oil. Therefore, the oil 124 settles to the bottom of the settling tank 117 and the hydrogen occupies the top of the settling tank 117. Once the hydrogen 122 and oil 124 separate from one another inside the settling tank 117, the hydrogen flows to a flow line 118 fluidically connected to the top of the settling tank 117, through the flow line 118 and to a hydrogen storage unit or hydrogen recovery unit 120. The hydrogen may then be transported for use as a source of energy. Meanwhile, the oil 124 flows to a flow line 128 connected to the bottom of the settling tank 117. The oil 124 flows through the flow line 128 until it reaches an oil refinery 126. The oil refinery 126 may treat the oil to form a useful product for further use, for example petrol or diesel.

FIG. 2 provides a schematic example of flowing oil and hydrogen to the pipeline 100. Hydrogen flows from the hydrogen production plant 104 through the hydrogen pipeline 112, the hydrogen pipeline 112 being fluidically connected at one end of the hydrogen pipeline 112 to the hydrogen production plant. Oil flows from the oil refinery 106 through the flow line 110, the flow line 110 being fluidically connected at one end of the flow line 110 to the oil refinery 106. The flow line 110 and the hydrogen pipeline 112 are both fluidically connected to the pipeline 100, for example the hydrogen pipeline 112 via a first inlet and the oil pipeline 110 via a second inlet.

A flowmeter 138a is located along the flow line 110. The flowmeter 138a is located between the oil refinery 106 and the pipeline 100. The flowmeter 138a measures the flow rate of the oil flowing from the refinery 106. A pump 136 is located along the flow line 110. The pump 136 is also located between the oil

refinery 106 and the pipeline 100, and is located after the flowmeter 138a. Measurements of the flow rate taken by the flowmeter 138a may allow for determining the extent to which the pump 136 may pump the flowing oil along the flow line 110 to the pipeline 100. The pump 136 increases the flow rate of the flowing oil. A temperature sensor 140a and a pressure sensor 142a lie along the flow line 110, between the oil refinery 106 and the pipeline 100. The sensor 140a and the sensor 142a lie after the pump 136 and at the entrance to the pipeline 100. The temperature sensor 140a takes measurements of the temperature of the oil and the pressure sensor 142a takes measurements of the pressure of the oil.

A flowmeter 138b is located along the hydrogen pipeline 112. The flowmeter 138b is located between the hydrogen production plant 104 and the pipeline 100. The flowmeter 138a measures the flow rate of the hydrogen flowing from the plant 104. A compressor 132 is located along the hydrogen pipeline 112. The compressor 132 is also located between the hydrogen pipeline 112 and the pipeline 100, and is located after the flowmeter 138b. Measurements of the flow rate taken by the flowmeter 138b may allow for determining the extent to which the compressor 132 may compress the flowing hydrogen along the flow hydrogen pipeline 112 to the pipeline 100. The compressor 132 brings the hydrogen to a vapor state. A heat exchanger 134 is located along the pipeline 112. The heat exchanger 134 is located along the pipeline 112 after the compressor and before the pipeline 100. A temperature sensor 140b and a pressure sensor 142a lie along the flow line 110, between the oil refinery 106 and the pipeline 100. The sensor 140b and the sensor 142b lie after the compressor 132 and before the entrance to the pipeline 100. The temperature sensor 140b takes measurements of the temperature of the hydrogen and the pressure sensor 142b takes measurements of the pressure of the hydrogen.

The hydrogen and the oil both flow from the hydrogen pipeline 112 and oil flow line 110 respectively to the pipeline 100 to form a multiphase flow 102 at the entry to the pipeline 100. A temperature sensor 140c and a pressure sensor 142c are located at or just after an entry to the pipeline 100. The temperature sensor 140c takes temperature measurements of the multi-phase flow. The pressure sensor 142c takes pressure measurements of the multi-phase flow.

FIG. 3 shows a schematic example of the installation. The figure also represents an example of a schematic representation of a simulation of the method. As indicated by arrow 111, oil flows from an oil source into the flow line 110. The oil source in this example is offshore and the pipeline 100 is at least partly onshore. Arrow 101 indicates an energy exchange between the pipeline 100 and surrounding seawater (i.e. an energy flow to and from the seawater). The

oil has a standard ideal liquid volume flow of 192.0 m³/h. The oil has a liquid volume flow at standard conditions of 192.1 m³/h. The oil has a molar flow of 1148 kgmole/h.

5 As indicated by arrow 113, hydrogen flows from a hydrogen source into a hydrogen pipeline 112. The hydrogen flows through the hydrogen pipeline at a temperature of 20 °C. The hydrogen flows through the hydrogen pipeline 112 at a pressure of 9620 kPa. The hydrogen has a molar flow of 7440 kgmole/h.

10 The flow line 110 and the hydrogen pipeline 112 are both fluidically connected to a mixer 144. The mixer 144 may mix the hydrogen and the oil together to form a multi-phase flow. However, it is also possible for the hydrogen and oil to flow into the pipeline 100 and form a multi-phase flow without need for a mixer 144 to mix the fluids together. The multi-phase flow enters the pipeline 100 and flows through the pipeline 100 before flowing out of the pipeline 100 and into a flowline 114. A valve 146a is located along the flowline 114. The multi-phase
15 fluid enters the separation facility 116. The multi-phase flow is separated at the separation facility 116 to recover the hydrogen. Hydrogen may flow along the flowline 118 fluidically connected to the separation facility 116. Oil flows along a flowline 128 fluidically connected to the separation facility 116. A valve 146b lies along the flowline 118. The hydrogen flows into a condenser/membrane 149. The
20 condenser/membrane 149 purifies the hydrogen by removing remaining hydrocarbons that may be mixed in with the hydrogen. Line 148 indicates an energy supply connected to the condenser 149. The condenser 149 partially condenses the hydrogen so that hydrocarbons mixed in with the hydrogen are condensed and can be separated from the hydrogen. Alternatively, the hydrogen
25 may flow into another type of condenser or into a membrane for purification. The hydrogen can then be recovered as pure hydrogen, flowing through flowline 150b and to a hydrogen collection facility or storage unit, as indicate by arrow 151. A valve 146d is located along the flowline 150b. The pure hydrogen has a temperature of 20 °C. The pure hydrogen has a pressure of 3856 kPa. The pure
30 hydrogen has a molar flow of 7413 kgmole/h.

The separated hydrocarbons, or HC (hydrocarbon) carryover (i.e. hydrogen dissolved in the gas flow), flow through flowline 150a. A valve 146e is located along the flowline 150a.

35 The HC carryover has a temperature of 20.03 °C. The HC carryover has a pressure of 3856 kPa. The HC carryover has a molar flow of 101.0 kgmole/h.

Upon separation of the multi-phase flow, oil flows along the flowline 128 fluidically connected to the separation facility 116. A valve 146c lies along the flowline 128. The flowline 128 is fluidically connected to a separation unit 154. The

oil may flow into the separation unit 154. The separation unit 154 may be part of an oil refinery. Alternatively, the separation unit 154 may be part of the separation facility 116 (even though not depicted as such in FIG. 3). The separation unit 154 separates water (e.g. in the form of gas carryover) from the oil. The water flows
5 through a flow line 152b fluidically connected to the other separation facility 154. The water may be stored or put to a further use.

The gas carryover has a temperature of 20.33 °C. The gas carryover has a temperature of 20.33 °C. The gas carrier over has a pressure of 200.00 kPa. The gas carryover has a molar flow of 33.69 kgmole/h.

10 The separated oil meanwhile flows from the separation facility through a flowline 152a fluidically connected to the separation facility 154. The oil may be stored or put to a further use.

The oil has a temperature of 20.33 °C. The oil has a pressure of 200 kPa. The oil has a molar flow of 1041 kgmole/h.

15 The hydrogen in the hydrogen pipeline 112 has a hydrogen concentration of 100 mol%. The hydrogen recovered after the separation of hydrocarbons (the pure hydrogen) has a hydrogen concentration of >99.5 mol%. The gas carryover has a hydrogen concentration of <0.5 mol%. The oil separated from the gas carryover in the separation facility has a hydrogen concentration of <0.01 mol%.

Claims

1. A method for hydrogen transport, the method comprising:
 - flowing oil from an oil source into an oil pipeline and through the oil pipeline;
 - flowing hydrogen from a hydrogen source into the oil pipeline and through the oil pipeline, the hydrogen and the oil forming a multi-phase flow;
 - flowing the multi-phase flow to a separation facility fluidically connected to the pipeline;
 - separating the multi-phase flow at the separation facility to recover the hydrogen.
2. The method according to claim 1, wherein the oil is a low gas-oil-ratio (GOR) oil or a stabilized oil.
3. The method according to claim 1 or 2, wherein the oil from the oil source, before flowing through the pipeline, has a concentration of up to 50 mol% of gases.
4. The method according to any one of claims 1 to 3, wherein the method comprises simultaneously flowing the oil into the pipeline and flowing the hydrogen into the pipeline.
5. The method according to any one of claims 1 to 4, wherein the pipeline is over-dimensioned for flowing the oil alone through the pipeline.
6. The method according to any one of claims 1 to 5, comprising recovering the oil from the separating of the multi-phase flow and transporting the recovered oil to an oil refinery.
7. The method according to any one of claims 1 to 6, comprising adjusting the flowing of hydrogen into the pipeline according to a flow behavior of the oil flowing into the pipeline so that minimal slugging occurs as the multi-phase flow flows through the pipeline.
8. The method according to any one of claims 1 to 7, comprising determining a flow schedule for the oil flowing into the pipeline and adjusting the flowing of hydrogen into the pipeline according to the schedule.

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9. The method according to any one of claims 1 to 8 comprising adjusting the flowing of hydrogen so that a maximum quantity of hydrogen flows into the pipeline.
 10. The method according to any one of claims 1 to 9, comprising forming a graph based on oil flow parameters and using the graph to determine a quantity of hydrogen to flow into the pipeline.
 11. The method according to claim 9 and 10, comprising using the graph to determine the maximum quantity of hydrogen to flow into the pipeline.
 12. The method according to any one of claims 1 to 11, wherein the multi-phase flow is a concentric flow, the hydrogen flowing along a longitudinal axis of the pipeline and the oil flowing along walls of the pipeline.
 13. The method according to any one of claims 1 to 12, wherein the hydrogen has a maximum concentration of 80 wt % in the multi-phase flow.
 14. The method according to any one of claims 1 to 13, wherein the hydrogen has a minimum concentration of 2 wt % in the multi-phase flow.
 15. The method according to any one of claims 1 to 14, comprising taking measurements of the flowrate of the oil after flowing from the oil source and before flowing the oil into the pipeline.
 16. The method according to any one of claims 1 to 15, comprising pumping the oil from the oil source into the pipeline.
 17. The method according to any one of claims 1 to 16, comprising taking pressure measurements and/or temperature measurements of the oil after flowing from the oil source and before flowing the oil into the pipeline.
 18. The method according to any one of claims 1 to 17, comprising taking measurements of the flowrate of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline.
 19. The method according to any one of claims 1 to 18, comprising compressing the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline.

20. The method according to any one of claims 1 to 19, comprising cooling the hydrogen before flowing the hydrogen into the pipeline.
- 5 21. The method according to any one of claims 1 to 20, comprising taking pressure measurements and/or temperature measurements of the hydrogen after flowing the hydrogen from the hydrogen source and before flowing the hydrogen into the pipeline.
- 10 22. The method according to any one of claims 1 to 21, comprising flowing the hydrogen into the pipeline at a first inlet of the pipeline and flowing the oil into the pipeline at a second inlet of the pipeline.
- 15 23. The method according to any one of claims 1 to 22, wherein the hydrogen source is fluidically connected to the pipeline by a hydrogen pipeline, the hydrogen pipeline having a length ranging from 50 km to 500 km.
- 20 24. The method according to claim 22 and 23, wherein the hydrogen source is fluidically connected to the second inlet of the pipeline by the hydrogen pipeline.
- 25 25. The method according to any one of claims 22 to 24, comprising taking pressure measurements and/or temperature measurements of the multi-phase flow at the first inlet and second inlet of the pipeline.
- 30 26. The method according to any one of claims 22 to 25, wherein the first inlet and the second inlet are both located at the same position on the pipeline, for example at one end of the pipeline.
- 35 27. The method according to any one of claims 1 to 26, wherein the length of the pipeline ranges from 50 km to 500 km, for example 100 km, or of such order.
28. The method according to any one of claims 1 to 27, wherein the separating comprises separation by gravity in a settling tank.
29. The method according to any one of claims 1 to 28, wherein the separating takes place over a duration ranging from 30 s to 5 mins, for example 1 min, or of such order.

30. The method according to any one of claims 1 to 29, comprising further separating water from the oil after separating the multi-phase flow.
- 5 31. The method according to any one of claims 1 to 30, wherein the multi-phase flow flows at a minimum speed of 0.1 m/s within the pipeline.
32. The method according to any one of claims 1 to 31, wherein the multi-phase flow flows at a maximum speed 10 m/s.
- 10 33. The method according to any one of claims 1 to 32, wherein the pressure in the pipeline ranges from 1000 kPa to 25000 kPa, for example 200 kPa, or of such order.
- 15 34. The method according to any one of claims 1 to 33, wherein the temperature in the pipeline ranges from 3 °C to 30 °C, for example from 3 °C to 20 °C, for example 5 °C, or of such order.
- 20 35. The method according to any one of claims 1 to 34, wherein the hydrogen source is a hydrogen production facility.
36. The method according to any one of claims 1 to 35, comprising treating seawater to produce the hydrogen.
- 25 37. The method according to any one of claims 1 to 36, wherein at least part of the pipeline is offshore.
38. The method according to any one of claims 1 to 37, wherein at least part of the pipeline is onshore.
- 30 39. The method according to any one of claims 1 to 38, wherein the separated hydrogen has a purity ranging from 50 mol% to 100 mol%.
- 35 40. An installation configured for hydrogen transport according to the method of any one of claims 1 to 39, the installation comprising:
- the oil source;
 - the hydrogen source;
 - the oil pipeline, the oil pipeline being fluidically connected to the oil source and to the hydrogen source;

- the separation facility fluidically connected to the oil pipeline.

41. The installation according to claim 40 wherein the pipeline is over-dimensioned for flowing oil alone through the pipeline.

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42. The installation according to claim 40 or 41, comprising an oil refinery downstream of the separation facility.

43. The installation according to any one of claims 40 to 42, comprising a flowmeter between the oil source and before the pipeline.

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44. The installation according to any one of claims 40 to 43, comprising a pump between the oil source and the pipeline.

45. The installation according to any one of claims 40 to 44, comprising one or more pressure sensors and/or one or more temperature sensors between the oil source and before the pipeline.

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46. The installation according to any one of claims 40 to 45, comprising a flowmeter between the hydrogen source and before the pipeline.

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47. The installation according to any one of claims 40 to 46, comprising a compressor between the hydrogen source and the pipeline.

48. The installation according to any one of claims 40 to 47, comprising a heat exchanger after the compressor and before the pipeline.

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49. The installation according to any one of claims 40 to 48, comprising one or more pressure sensors and/or one or more temperature sensors between the hydrogen source and the pipeline.

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50. The installation according to any one of claims 40 to 49, comprising a first inlet of the pipeline fluidically connected to the hydrogen source and a second inlet of the pipeline fluidically connected to the oil source.

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51. The installation according to claim 40 to 50, wherein the hydrogen source is fluidically connected to the pipeline by a hydrogen pipeline, the hydrogen pipeline having a length ranging from 50 km to 500 km.

52. The installation according to claim 50 and 51, wherein the hydrogen source is fluidically connected to the second inlet of the pipeline by the hydrogen pipeline.
- 5 53. The installation according to any one of claims 50 to 52, comprising one or more pressure sensors and/or one or more temperature sensors at the first inlet and/or second inlet of the pipeline.
- 10 54. The installation according to claim any one of claims 50 to 53, wherein the first inlet and the second inlet are located at one end of the pipeline.
55. The installation according to any one of claims 40 to 54, wherein the length of the pipeline ranges from 50 km to 500 km, for example 100 km, or of such order.
- 15 56. The installation according to any one of claims 40 to 55, wherein the separation facility comprises a settling tank.
57. The installation according to any one of claims 40 to 56, wherein the pressure in the pipeline ranges from 1000 kPa to 25000 kPa, for example 200 kPa.
- 20 58. The installation according to any one of claims 40 to 57, wherein the temperature in the pipeline ranges from 3 °C to 30 °C, for example from 3 °C to 20 °C, for example 5 °C.
- 25 59. The installation according to any one of claims 40 to 58 wherein the hydrogen source is a hydrogen production facility.
- 30 60. The installation according to any one of claims 40 to 59, wherein at least part of the pipeline is offshore.
61. The installation according to any one of claims 40 to 60 wherein at least part of the pipeline is onshore.
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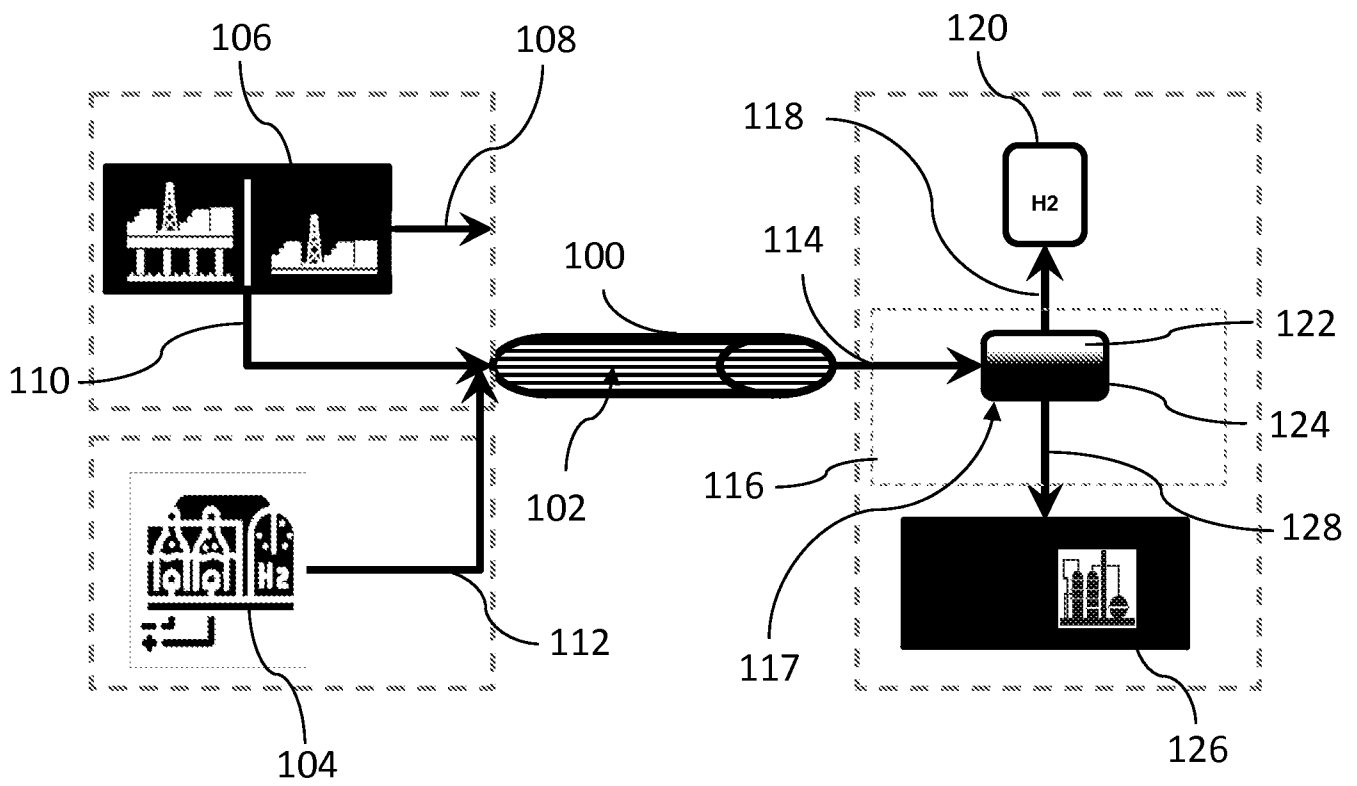
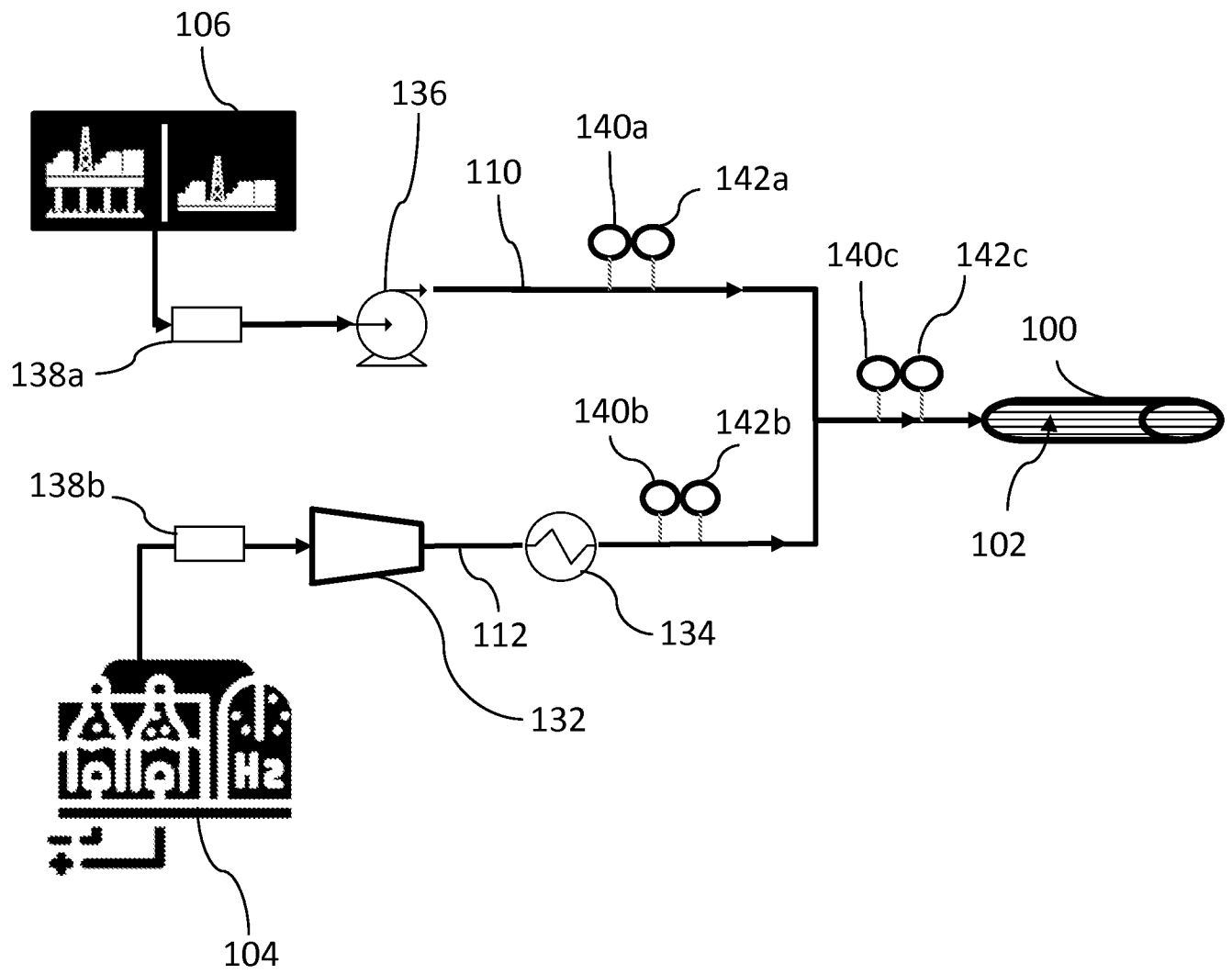


FIG. 1

FIG. 2

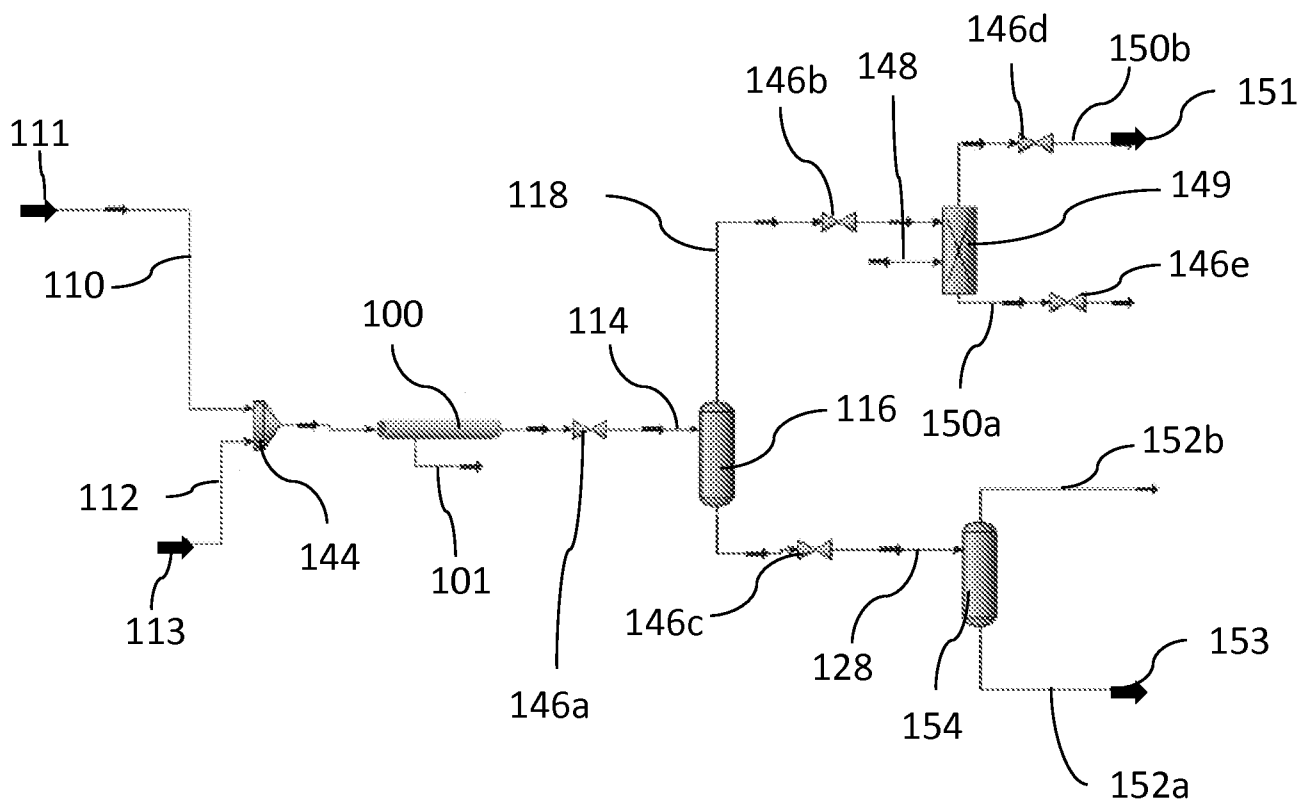


FIG. 3

INTERNATIONAL SEARCH REPORT

International application No

PCT/IB2023/000448

A. CLASSIFICATION OF SUBJECT MATTER

INV. F17D3/05 F17D1/17

ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

F17D

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	CN 107 314 242 A (HEPU TECH DEVELOPMENT BEIJING CO LTD) 3 November 2017 (2017-11-03) the whole document -----	1-61
X	CN 107 448 775 A (HEMPEL TECH DEVELOPMENT BEIJING CO LTD) 8 December 2017 (2017-12-08) the whole document -----	1-61
A	IT 2021 0002 9993 A1 (ENI SPA [IT]) 26 May 2023 (2023-05-26) the whole document -----	1-61
A	WO 2021/198102 A1 (BASF SE [DE]) 7 October 2021 (2021-10-07) the whole document ----- -/-	1-61



Further documents are listed in the continuation of Box C.



See patent family annex.

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"X" document of particular relevance;; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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Date of the actual completion of the international search

12 February 2024

Date of mailing of the international search report

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INTERNATIONAL SEARCH REPORT

International application No

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C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT		
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