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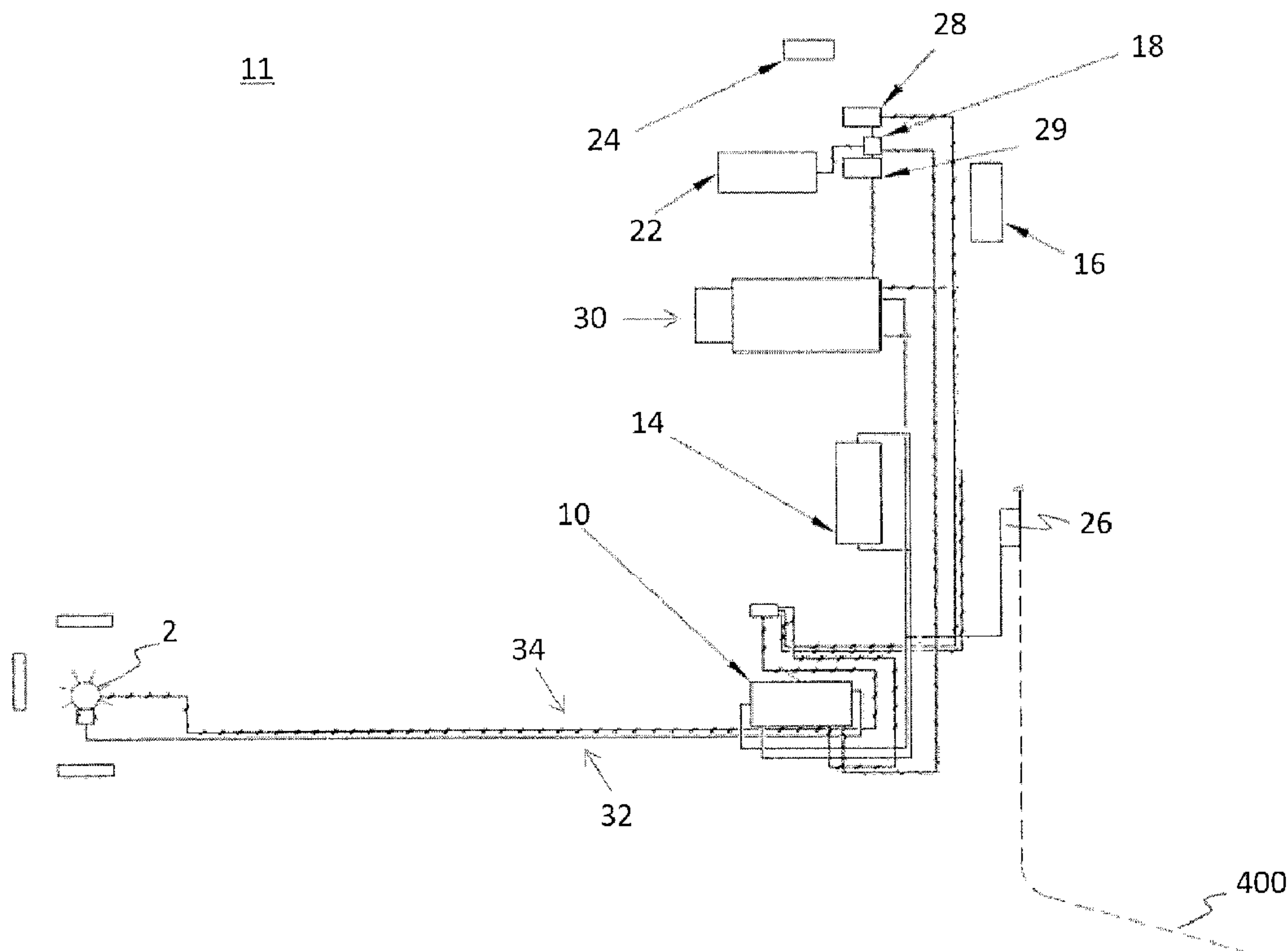
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(54) Title: A SYSTEM AND METHOD FOR WELL SITE PRODUCTIVITY TESTING AND PRODUCTION



(57) Abrégé/Abstract:

A mobile-skid based system is provided comprising a mobile skid, first separator, a second separator, a storage tank and a compressor unit. The compressor unit comprises a first compressor stage that is fluidly connectible to the storage tank for receiving

(57) **Abrégé(suite)/Abstract(continued):**

and pressurizing gas from the storage tank. The compressor unit also comprises a second compressor stage that is fluidly connectible to the second separator for receiving and pressurizing the second gas stream and the second compressor is fluidly connectible to the first compressor stage for receiving and further pressurizing the pressurized gas from the storage tank. All of the first separator, the second separator and the compressor unit are supported upon the mobile skid with all of the fluid connections therebetween pre- designed and installed before the mobile skid is deployed at a well site. A method of producing fluids from a well site and a well site system including surface- based equipment for producing fluids from a wellhead are also provided.

Abstract

[0066] A mobile-skid based system is provided comprising a mobile skid, first separator, a second separator, a storage tank and a compressor unit. The compressor unit comprises a first compressor stage that is fluidly connectible to the storage tank for receiving and pressurizing gas from the storage tank. The compressor unit also comprises a second compressor stage that is fluidly connectible to the second separator for receiving and pressurizing the second gas stream and the second compressor is fluidly connectible to the first compressor stage for receiving and further pressurizing the pressurized gas from the storage tank. All of the first separator, the second separator and the compressor unit are supported upon the mobile skid with all of the fluid connections therebetween pre-designed and installed before the mobile skid is deployed at a well site. A method of producing fluids from a well site and a well site system including surface-based equipment for producing fluids from a wellhead are also provided.

A SYSTEM AND METHOD FOR WELL SITE PRODUCTIVITY TESTING AND PRODUCTION**FIELD OF INVENTION:**

[001] This disclosure generally relates to the production of hydrocarbons. In particular, this disclosure relates to the production of hydrocarbons at a well site by using a system that provides prefabricated and pre-plumbed tanks and electronic controls.

BACKGROUND:

[002] Oil and gas wells require surface-based equipment to capture the hydrocarbon fluids that are produced at a well site from a wellhead that is fluidly connected to an underground reservoir. This equipment may collectively be referred to as a production facility. Selection of the equipment and how it is designed to be interconnected within the production facility is often dictated by the parameters of the fluids that are produced at the wellhead, the geographic location of the well site and the accessibility to means for moving the produced fluids from the well site to a processing facility.

[003] Some of the produced fluid parameters that dictate the selection of equipment include the composition and the flow parameters of the produced fluids. The produced fluid composition may comprise gas, light oil, heavy oil and water. The flow parameters of the produced fluid include volume, pressure, flow rate and temperature. Furthermore, some well sites are located relatively close to transportation infrastructure, such as oil or gas transmission pipelines, and some well sites are not. The availability of such infrastructure may also dictate what types of equipment are included within the production facility.

[004] Upon completion of the well, productivity testing provides information about the composition and flow parameters of the produced fluids. The productivity testing is often used in conjunction with information that is already known about produced fluids from a similar, or the same, underground reservoir to inform the selection of the equipment and the designing and building of the production facility. The applicant has observed that even when productivity testing information is used with known information, it can take many

months to design and build a production facility. This creates a time lag between when a completed well has to the potential to produce hydrocarbon fluids and when those produced hydrocarbon fluids can be captured and transported.

- [005] Advances in oil and gas drilling, such as completion and reservoir stimulation technologies, have improved the access to different types of underground reservoirs, including so called “tight reservoirs”. Due to this relatively newly acquired access, the information that is known about the composition and flow parameters of produced fluids from the different types of reservoirs is comparatively less than traditional reservoirs. One approach to overcome this knowledge deficiency, which is ultimately useful when designing the production facility, is to perform prolonged productivity testing. Prolonged productivity testing may increase the time lag between completing the well and producing hydrocarbon fluids. In applicant’s experience, the composition and flow parameters of the produced fluids from the different types of underground reservoirs also requires customization of the required equipment and the customization is often unique to each well site. Customization may further increase the lag time between completing the well and producing hydrocarbon fluids.
- [006] Figure 1 depicts an overview of an example oil and gas well site 11 that includes equipment that has been selected and whose interconnections have been designed and customized based upon the parameters of the fluids produced at a wellhead 2. The well site 11 includes a well head 2, a first separator 10, a second separator 14, and a chemical skid 16 for storing chemical additives that can be added into the wellhead 2 under control of a chemical skid control panel 18. The well site 11 may also include a power source 22 and, optionally, a fuel storage tank 24. The power source 22 may be a diesel-run generator, but in other embodiments the generator may run on other energy sources such as solar power, wind power, electricity, propane, gasoline or natural gas depending upon what is readily available at, or easily transported to, the well site 11. Figure 1 also depicts a pig housing and sender 26 for scrubbing a gas sales pipeline 400. The gas sales pipeline 400 is fluidly connected to a gas processing plant that may be many kilometers from the well site 11. Figure 1 depicts

the well site 11 as also including a drive means 29 for operating a vapor recovery unit 30. The well site 11 has various interconnections such as fluid conduits 32 for transporting fluids throughout the well site 11. The interconnections also include other conduits 34 that may, for example, be electrical conduits for providing electrical connections between different features of the well site 11 such as to convey electrical sensor information or electrical power.

SUMMARY:

[007] In one embodiment, the present invention provides a mobile-skid based system. The mobile-skid based system comprises a mobile skid, first separator, a second separator, a storage tank and a compressor unit. The first separator is fluidly connectible to a wellhead for receiving and separating produced fluids from the wellhead into a first gas stream and a first liquid stream. The second separator is fluidly connectible to the first separator for receiving the first liquid stream and separating the first liquid stream into a second gas stream and a second liquid stream. The storage tank is fluidly connectible to the second separator for receiving the second liquid stream. The compressor unit comprises a first compressor stage that is fluidly connectible to the storage tank for receiving and pressurizing gas from the storage tank. The compressor unit also comprises a second compressor stage that is fluidly connectible to the second separator for receiving and pressurizing the second gas stream and the second compressor is fluidly connectible to the first compressor stage for receiving and further pressurizing the pressurized gas from the storage tank. The compressor unit also comprises an output conduit that is fluidly connectible to the second compressor stage and that is fluidly connectible to a gas sales pipeline. The second compressor stage pressurizes the second gas stream and the further pressurized gas from the storage tank to substantially match a pressure requirement of the gas sales pipeline. All of the first separator, the second separator and the compressor unit are supported upon the mobile skid with all of the fluid connections therebetween pre-designed and installed before the mobile skid is deployed at a well site.

[008] In another embodiment, the present invention provides a method of producing fluids from a well site. The method comprises the steps of: separating fluids produced at a wellhead into a first gas stream and a first liquid stream; separating the first liquid stream into a second liquid stream and a second gas stream; directing the second liquid stream to a storage tank; collecting gas produced within the storage tank; directing the gas produced within the storage tank to a first stage of a compression unit; pressurizing the directed gas produced within the storage tank to a first predetermined pressure within the first stage of a compressor unit; directing the second gas stream to a second compression stage of the compression unit; pressurizing the second gas stream to a second predetermined pressure; directing the directed gas produced within the storage tank that is at the first predetermined pressure to the second compression stage of the compression unit; pressurizing the directed gas within the second compression stage of the compression unit to the second predetermined pressure; and directing the directed gas and the second gas stream that are at the second predetermined pressure to a gas sales pipeline. The second predetermined pressure is greater than the first predetermined pressure and the second predetermined pressure may substantially match a pressure requirement of the gas sales pipeline.

[009] In another embodiment, the present invention provides a well site system that includes surface-based equipment for producing fluids from a wellhead. The system comprises a first separator, a second separator and a compressor unit. The system may be supported by a mobile skid, or a trailer. The separators and the compressor unit may be fluidly connected by fluid conduits that are plumbed once and useful for a wide range of produced fluid parameters. The system may comprise further conduits for fluidly connecting the surface-based equipment with the equipment that is not on the mobile skid, such as the wellhead, flare systems, storage tanks and a gas sales pipeline. One or more of the conduits may further include valves, such as metering valves and flow control valves. The valves may be electronically controlled by a user or an electronic controller.

[0010] In another embodiment, the system can be fabricated before being deployed at the well site and this may be referred to as prefabricating the system. Prefabricating the system includes designing, engineering and fabricating all plumbing connections and electronic connections that are required to allow the system to operate once the system is deployed at a well site and fluidly connected to the wellhead and other parts of the production facility. Prefabricating the system reduces the time required to fluidly connect the wellhead to a production facility and to begin producing fluids. Prefabricating the system may also reduce the time to fluidly connect the system to any storage tanks, gas pipelines and flare systems, as may be required. Prefabricating the system also allows the system to operate under a range of well site operating conditions. For example, the system can operate under a range of wellhead output flow parameters, a range of produced fluid compositions and a range of gas sales pipeline pressure requirements. The flexibility in the system's operating ranges allows the system to be deployed and used at different well sites that each may have different well site operating conditions.

[0011] In another embodiment, the present invention comprises a multi-staged compressor unit that receives separate fluid inputs from a separator and from a storage tank. The separate input fluid flows into the multi-staged compressor unit may facilitate the present invention's broad operating ranges. For example, the separator may receive a fluid stream and separate that fluid stream into a gas stream and a liquid stream. The storage tank receives the liquid stream. While the liquid is in the storage tank, vapours can be released from the liquid. The vapours are collected and directed to the compression unit where a first two-compressive stages increase the pressure of the vapours to substantially the same pressure as the gas stream. The gas stream and the pressurized vapour stream are then fed into further compressive stages of the compressor unit. The compressor unit increases the pressure of the pressurized vapour and the gas stream so that they substantially match pressure requirements of a gas sales pipeline. Optionally, the compressor unit may be a reciprocating compressor with a single crankshaft that is operatively connected to all of the compressive stages within the multi-stage compressor unit. The crankshaft may be driven by an electric motor that is controlled by a variable frequency drive (VFD). The variable

frequency drive can change the rate at which the crankshaft and, therefore, the compressive stages operate to accommodate a variety of the fluid input parameters. For example, if the gas sales pipeline has a high-pressure requirement, then the VFD will set the operational rate of the compressor unit to produce a gas output that meets the gas sales pipeline requirement. However, the operational rate to provide the correct pressure for the gas sales pipeline pressure requirements may be too high for the first two-compressive stages that are receiving the vapor inputs from the lower pressure storage tanks. Alternatively, the liquid within the storage tanks may produce a relatively large volume of vapours that require an operational rate of the first two stages that is higher than what is required for a comparatively lower volume input from the gas stream. In either case, the compressor unit may be operating at an operational rate that is too high for one or more of the inputs into the compressor unit. In one embodiment, the compressor unit may include recirculation and make-up fluid input streams into one or more of the compressive stages to prevent gas starvation of the compressive stages. The recirculation and make-up gas input streams may allow the operational rate of the compressor unit to be set at one rate in spite of the different requirements of the separate fluid inputs from the separator and the storage tank.

[0012] The system may be deployed and fluidly connected to the wellhead shortly after the well is drilled and completed. The system can be used during productivity testing and remain in place at the well site, during production, until such time that a permanent production facility is designed and constructed. Once a permanent well facility is constructed, the system can be moved for use at another well site. Reducing the time between well completion, productivity testing and production of hydrocarbon fluids may provide a benefit of capturing commercially valuable produced fluids before the permanent well facility is built and installed. The applicant has observed that under typical circumstances many well sites experience a time lag of three to eighteen months to fluidly connect the wellhead to surface-based equipment before any fluids are produced from the underground reservoir. Applicants predict that the present invention could shorten this time lag from well completion to fluid production to between about three weeks to about six weeks.

[0013] In another embodiment, the system may be deployed at a multi-well pad. The system may be in fluid connection with more than one wellhead for productivity testing and production of fluids from more than one wellhead. Optionally, each wellhead may be fluidly connected to an individual first separator each of which is fluidly connected to the second separator of the system. Optionally, at least one of the wellheads that is fluidly connected to the system may be a newly completed well that may or may not have been subjected to productivity testing. Optionally, at least one of the wellheads may be a wellhead that has already completed productivity testing.

[0014] In another embodiment, the system may include one or more spill containment features so that fluid spills may be contained within the mobile skid.

[0015] In another embodiment, the system may enclose within an outer perimeter of the mobile skid all of the electronic connections, such as wires, that are required to provide electronic data collection and control over metering and flow control valves throughout the fluid conduits of the system. Enclosing the electronic wires upon the mobile skid may also reduce a time delay between when the system is deployed at a well site and when fluids will be produced from the wellhead at the well site. Furthermore, when the permanent production facility is completed and the system is moved to another well site, the electronic connections of the system will move with the mobile skid. This may reduce the cost and environmental impact of typical, temporary production facilities that often abandon the electronic connections when a permanent production facility is completed and installed.

BRIEF DESCRIPTION OF DRAWINGS:

[0016] Various examples of the apparatus are described in detail below, with reference to the accompanying drawings. The drawings may not be to scale and some features or elements of the depicted examples may purposely be embellished for clarity. Similar reference numbers within the drawings refer to similar or identical elements. The drawings are provided only as examples and, therefore, the drawings should be considered illustrative of

the present invention and its various aspects, embodiments and options. The drawings should not be considered limiting or restrictive as to the scope of the invention.

[0017] Figure 1 is a top plan view of an oil and gas well site.

[0018] Figure 2 is a top plan view of a hydrocarbon production well site in use with an example system of the present invention.

[0019] Figure 3 is a top plan, magnified view of the example system of Figure 2.

[0020] Figure 4 is a side elevation view of one example of a mobile skid with a sidewall removed.

[0021] Figure 5 is an isometric view of the mobile skid of Figure 4 with an upper support and sidewalls removed.

DETAILED DESCRIPTION:

[0022] Figure 2 depicts a top plan view of a well site 100 using an example system 108 that provides productivity testing and production of fluids from a wellhead 102. Figure 2 also depicts a first conduit 301 that fluidly connects the wellhead 102 to the system 108 and a second conduit 302 that fluidly connects the system 108 to a gas sales pipeline 400. The well site 100 may also include a chemical skid 104 for storing chemical additives that can be added into the wellhead 102 under control of a chemical skid control panel 106. The well site 100 may also include a power source 202 and, optionally, a fuel storage tank 204. The power source 202 may be a diesel-run generator, but in other embodiments the generator may run on other energy sources such as solar power, wind power, electricity, propane, gasoline or natural gas depending upon what is readily available at, or easily transported to, the well site 100. Figure 2 also depicts an optional pig housing and sender 206 for scrubbing the gas sales pipeline 400.

[0023] Figure 3 depicts a closer view of one embodiment of the system 108 that comprises a first separator 110, a second separator 114, a compressor unit 116 and a plurality of conduits 300 that are all supported by a skid 500. The skid 500 is defined by a perimeter 502. The

dimensions of the perimeter 502 accommodate all the system 108 and facilitate moving the system 108 to and from the well site 100. Optionally, the skid 500 can be a trailer that meets axle-loading regulations and standard dimensional tolerances so that the skid 500 can be transported along roads and highways. This avoids the necessity of using customized transportation equipment and, possibly, acquiring regulatory transportation permits. Alternatively, the skid 500 can be supported on a trailer as described above. For example the skid 500 can be moved by being placed on a trailer and pulled by a tractor trailer or truck. Additionally, the skid can be lifted by a crane, forklift, winch load, jack-and-roll methods or other means that are used to move heavy equipment to, from and within the well site 100. If the skid 500 is not a trailer, or supported on a trailer, at the well site 11, it may be supported on top of pilings or planks at the well site 11. In one embodiment, the skid 500 may have a length of between about 480 inches and about 720 inches (about 12 meters and about 18.25 meters) with a width of between about 180 inches and about 240 inches (about 3.4 meters and about 6 meters). In one preferred embodiment, the skid 500 has a length of about 588 $\frac{13}{16}$ inches (about 15 meters) and a width of about 218 inches (about 5.5 meters). These example lengths and widths may include any lugs that may extend beyond the perimeter 502 for fluidly connecting one or more conduits of the plurality of conduits 300 with equipment at the well site 100.

[0024] Figures 4 and 5, which are not intended to be limiting, depict one example of the skid 500. The skid 500 may include an enclosure with a lower support, a cover 504 and one or more sidewalls 506. In one embodiment, the cover 504 may be a peaked roof with a maximum height of between about 96 inches to about 144 inches (about 2.5 meters and about 3.6 meters) above the lower support. In a preferred embodiment, the cover 504 may have a height of about 129 $\frac{15}{16}$ inches (about 3.3 meters). The cover 504 may shelter the components of the system 108 from sometimes harsh weather conditions.

[0025] In one embodiment, the skid 500 may include one or more spill containment features so that fluid spills may be contained within the perimeter 502 of the mobile skid 500. For example, the spill containment features may include upturned flanges at the perimeter 502

for containing the spilled fluids. Additionally, the lower support may be shaped to direct spilled fluids to one or more drains, valves or pumps for removing the spilled fluids from the skid 500 by way of gravity drainage or pumping.

[0026] As depicted in Figures 4 and 5, the plurality of conduits 300 have been designed to utilize the space within the perimeter 502 and below the cover 504 so that all components of the system 108 fit upon the skid 500. As will be discussed further below, the system 108 may be engineered to provide components and fluid connections that have the capacity to work under a wide range of operational parameters of the fluids produced at the well site 100. The combination of the design and engineering allows the system 108 to be mobile and to provide surface equipment that has a capacity to process produced fluids from a variety of different wellheads 102, at single well pad, where each well head 102 may have a range of produced fluid parameters. The system 108 processes the produced fluids to produce a gas output that meets a range of pressure requirements for different gas sales pipelines 400. The first separator 110 is fluidly connected to the wellhead 102 by the first conduit 301. The first separator 110 separates the produced fluids that are received from the wellhead 102 into three separate fluid streams: a first gas stream, a first liquid stream and a produced water stream. The first gas stream may be of sufficiently high pressure so that it can be delivered to the gas sales pipeline 400 without requiring further pressurization by the compressor unit 116. The second conduit 302 fluidly connects the first separator 110 to the gas sales pipeline 440 for transporting the first gas stream to the gas sales pipeline 440. For the purposes of this disclosure, the term "transporting" is used in reference to moving or directing fluids through various parts of the system 108 by one or more conduits of the plurality of conduits 300. The transport of fluids through the plurality of conduits 300 may occur by pressure gradients within the plurality of conduits 300. The pressure gradients may be generated by the energy within the fluids produced at the wellhead 102, the compressor unit 116 and, optionally, other pumps within the system 108. A third conduit 303 fluidly connects the first separator 110 to the second separator 114 for transporting the first liquid stream to the second separator 114. The first liquid stream may comprise liquid hydrocarbons and gaseous hydrocarbons that are trapped within the liquid. The first liquid

stream may also comprise some produced water that is not separated out by the first separator 110. The liquid streams within the system 108 may also be referred to as condensate.

[0027] A fourth conduit 304 fluidly connects the first separator 110 to one or more water tanks for transporting the produced water stream to the one or more water tanks 404 from the first separator 110.

[0028] In one embodiment of the system 108, the first separator 110 is a high pressure separator, which may also be referred to as a test separator. The first separator 110 has an operating pressure in a range of about 517 to about 10342 kPag. In one embodiment of the system 108, any wellhead 102 that has an outlet pressure of produced fluids that is greater than about 9928 kPag (about 1440 psig), will include a choke means (not shown) in the first conduit 301 between the wellhead 102 and the first separator 110 so that the pressure of the produced fluids entering the first separator 110 is less than about 9928 kPag. The fluid outputs from the first separator 110 may be between about 50 to 150 $\text{e}^3\text{m}^3/\text{day}$ (d) for the first gas stream; between about 50 and 250 m^3/d for the first liquid stream; and between about 1 and 10 m^3/d for the produced water stream. In one embodiment the first separator 110 may receive the produced fluids from a single well that has already been through productivity testing, a period of production or a period of draw down, which may be referred to as a stabilized well. For example, when the first separator 110 receives produced fluids from a single stabilized well, the first gas stream may have a flow rate of about 75 $\text{e}^3\text{m}^3/\text{d}$; the first liquid stream may have a flow rate of about 85 m^3/d ; and the produced water stream may have a flow rate of about 4 m^3/d . In another embodiment, the first separator may receive the produced fluids from a single well that is new and has been completed more recently than a stabilized well. The produced fluid pressure and flow rates from a new well may be higher than a stabilized well. When the first separator 110 receives the produced fluids from a new well the first gas stream may have a flow rate of about 100 $\text{e}^3\text{m}^3/\text{d}$; the first liquid stream may have a flow rate of about 200 m^3/d ; and the produced water stream may have a flow rate of about 10 m^3/d . These flow parameters are based

upon assumed specific gravities of about 0.81 for the gas, about 0.77 for the liquids and about 1.0 for water from both of the new well and the stabilized well.

[0029] The second separator 114 separates the first liquid stream into a second liquid stream and a second gas stream. The second liquid stream may be transported from the second separator 114 to one or more storage tanks 402 by a sixth conduit 306. When compared with the first liquid stream, the second liquid stream may also comprise smaller amounts of trapped hydrocarbon gas. The second gas stream may be transported from the second separator to the compressor unit 116 by a fifth conduit 305. The compressor unit 116 and the fifth conduit 305 are also housed within the perimeter 502 of the skid 500. In one embodiment, the second separator 114 may have an operating pressure between about 300 and 1950 kPag. In one embodiment, the second separator 114 may receive the first liquid stream from the first separator 110, which in turn received the produced fluids from a single well.

[0030] In another embodiment, the system 108 may be fluidly connected to more than one well head. In this embodiment, the second separator 114 may also receive further liquid streams from a test separator 600 that receives produced fluids from a stabilized well. The test separator 600 separates the received produced fluids into a gas stream, a liquid stream and a produced water stream. The gas stream may be combined with the first gas flow via a conduit 316 that is fluidly connected to the second conduit 302. The liquid stream may be combined with the first liquid stream via a conduit 320 that is fluidly connected to the third conduit 303. The produced water stream may be combined with the produced water stream from the first separator 110 by a conduit 321 that fluidly communicates with the fourth conduit 304. In this embodiment, the flow rate of the second gas stream may be between about 2.0 and about 10 e³m³/d with a specific gravity of about 1.16. The flow rate of the second liquid stream may be between about 150 m³/d and 400 m³/d with a specific gravity of about 0.72. Optionally, the second separator 114 may also separate the first fluid stream into a second water stream. In this option, the second separator 114 may be fluidly connected to the fourth conduit 304 by a twelfth conduit 112 and the flow rate of the

second water stream may be between 0.1 m³/d and 0.5 m³/d with a specific gravity of about 1.0. In one embodiment, the system 108 is fluidly connected to at least two wellheads 102. In a preferred embodiment, the system 108 is fluidly connected to two stabilized wells and a new well, wherein the new well is fluidly connected to the first separator 110.

[0031] In one embodiment of the system 108, either or both of the water tanks 404 and the storage tanks 402 may be provided outside of the perimeter 502 of skid 500. The fourth conduit 304 and the sixth conduit 306 may terminate at or near the perimeter 502 of the skid 500. Further conduits 304A, 306A may be employed to fluidly connect the fourth and sixth conduits 304, 306 to the water tanks 404 and the storage tanks 402, respectively. For example, the conduits 304, 306 may comprise flanged end connections for fluidly connecting to the further conduits 304A, 306A.

[0032] The compressor unit 116 receives the second gas stream via the fifth conduit 305. The second gas stream may have a lower pressure than the first gas stream and, therefore, to meet the pressure requirements of the gas sales pipeline 400, the second gas stream may require pressurization. The compressor unit 116 pressurizes the second gas stream and the pressurized second gas stream may be transported, via a seventh conduit 307 to merge with the first gas stream within the second conduit 302 or the gas sales pipeline 400 or both.

[0033] In one embodiment, the compressor unit 116 comprises a multi-staged compressor 116A that comprises a two-staged, vapor recovery unit (VRU) 116B. The compressor unit 116 acts as both a booster compressor for the second gas stream and a VRU for vapours captured from either or both of the water tanks 404 and the storage tanks 402. In this description, the term "vapors" is used to refer to any gases that may or may not contain hydrocarbons and are released from liquids within the tanks 402, 404. The fifth conduit 305 conducts the second gas stream to the multi-staged compressor 116B. The multi-staged compressor 116A may comprise two or more compressor stages. Preferably, the multi-staged compressor 116A comprises three compressor stages and the multi-staged

compressor 116A is capable of compressing and pressurizing the second gas stream when more than one wellhead 102 contributes fluids to the first liquid stream, as discussed further below. The second gas stream passes through and is step-wise pressurized by each of the stages of the multi-staged compressor 116B. Upon leaving the multi-staged compressor 116A the second gas stream has a pressure that is substantially the same as the pressure of the fluids within the gas sales pipeline 400. The pressure of the fluids within the gas sales pipeline 400 may also be referred to as a pressure requirement of the gas sales pipeline 400. The pressure requirement of the gas sales pipeline 400 may be highly variable between different well sites. Some of the factors that influence this pressure requirement include the diameter of the gas sales pipeline 400, the distance that the gas has to travel before it reaches a commercial gas terminal, a gas storage facility or a booster compressor and the characteristics of the compressor or equipment at the end of the gas sales pipeline 400 that can be distant from the well site 11.

[0034] Either or both of the storage tanks 402 and the water tanks 404 may comprise a single or multiple tanks that can capture vapours that are produced from the liquids therewithin. The vapors are transported from the storage tanks 402 that are off the skid 500 via a further conduit 308A which may be fluidly connected to an eighth conduit 308 that transports the vapors from the perimeter 502 of the skid 500 to the VRU 116B. A further conduit 308B may fluidly connect the water tanks 404 to the eighth conduit 308 for transporting vapors that are collected from the produced water within the water tanks 404. The eighth conduit 308 may be a single conduit that is fluidly connected to one or both of the storage tanks 402 and the water tanks 404. Alternatively, the eighth conduit 308 may be split sections of conduit with each section fluidly connected to one of the storage tanks 402 or the water tanks 404 and the VRU 116B.

[0035] In one embodiment of the system 108, the compressor unit 116 is a reciprocating compressor with a single crankshaft that is operatively connected to an electric motor. The electric motor is controlled by a variable frequency drive (VFD) and a programmable logic (PLC) controller. The single crankshaft drives the operation of all of the compressive stages

within the compressor unit 116. The compressor unit 116 may have five total compressive stages, all of which are operatively connected to the single crankshaft. The first two compressive stages of the compressor unit 116 may form the VRU compressor 116B and the last three compressive stages may form the multi-staged compressor 116A. In an embodiment where the second separator 114 receives the second liquid stream from a new well and two other liquid streams from stabilized wells, the VRU compressor 116B may have a gas flow rate of between about 1.0 and about 10 e³m³/d with a gas specific gravity of about 1.63. The VRU compressor 116B may have an input pressure from the tanks 402, 404 of a vacuum pressure of about -101.3 kPag to about 138 kPag. Optionally, the VRU compressor 116B may produce a suction pressure of between about 1 to about 10 kPag and a discharge pressure of between about 300 and 400 kPag. The multi-staged compressor 116A may have an input suction pressure of between about 200 to about 300 kPag. The multi-staged compressor 116A produces the pressurized second gas stream with a flow rate of about 4 to about 10 e³m³/d with a specific gravity of about 1.16. The final discharge pressure of the pressurized second gas stream from the compressor unit 116 may be between about 1379 to about 9928 kPag.

[0036] One or more of the compressive stages may include an upstream suction scrubber. In one embodiment of the compressor unit 216, the stages 1, 2, 4 and 5 include an upstream suction scrubber that reduces the amount of liquid within the gas streams flowing into and through the compressive stages. The suction scrubbers that are upstream of stages 1, 2 and 4 may be fluidly connected to the storage tanks 402. The suction scrubber that is upstream of compressive stage 5 may be fluidly connected to a blow case, or pump, that is fluidly connected to the second conduit 302 and, optionally, the gas sales pipeline 400. The second separator 114 may act as a suction scrubber that is upstream of compressive stage 3.

[0037] In one embodiment, the compressor unit 116 may further comprise a cooler system for cooling the fluids within one or more of the compressive stages.

- [0038] In one embodiment, the compressor unit 116 may include a system of recirculation conduits and make-up fluid input streams into one or more of the compressive stages to prevent gas starvation of the compressive stages. The recirculation and make-up gas input streams may allow the operational rate of the compressor unit to be set at one rate in spite of the different requirements of the separate fluid inputs from the separator and the storage tank.
- [0039] Positioning the storage tanks 402 and the water tanks 404 off the skid 500 and collecting and transporting any gas or vapors that are collected in these tanks 402, 404 back to the skid, allows the liquid hydrocarbons and produced water to be transported off the well site 100 by truck or other vehicle. Because the most or all of the vapors that are collected in the tanks 402, 404 are directed to the VRU compressor 116B, the liquids within the tanks 402, 404 will have low or zero gas emissions when they are transported. By capturing and pressurizing the vapors from the tanks 402, 404, the system 108 may reduce a regulatory burden on a well site operator that would otherwise need to seek approvals for prolonged flaring and venting of hydrocarbon gases at the well site 100.
- [0040] In one embodiment of the system, the plurality of conduits 300 may comprise one or more fluid conducting pipes for directing fluids therethrough. One or more conduits of the plurality of conduits 300 may further comprise a flow control valve 320 and a metering valve 322. As depicted in Figure 3, which is not intended to be limiting, at least the second, third, fourth, fifth, sixth and twelfth conduits 302, 303, 304, 305, 306 and 312 include metering valves 322. Some conduits, for example the second conduit 302 may have orifice metering valves 322A and other types of metering valves 322 may be turbine-based.
- [0041] Figure 3 further depicts a fuel gas scrubber 112 that is fluidly connected with the second conduit 302 by a fourteenth conduit 314. The fuel gas scrubber 112 reduces the amount of liquids that may be entrained within the first gas stream. The fuel gas scrubber 112 may also reduce the amount of hydrogen sulfide gas (H₂S) that may be present in the first gas stream.

[0042] As depicted in Figure 3, the skid 500 may further comprise a master control center 501 that houses the PLC for monitoring, recording and archiving data captured from the metering valves 322 relating at least to the fluid parameters of: temperature, pressure and flow rate of the fluids that are being transported through the plurality of conduits 300. Additionally, the PLC may control remote opening and closing of one or more of the flow control valves 320. Operational parameters of the system 108, via the PLC, may be remotely monitored by a supervisory control and data acquisition (SCADA) system that provides remote reporting and control over operations of the system 108. In one embodiment, the system 108 may further comprise an emergency shut-down system that comprises combustible gas sensors and toxic gas sensors that are mounted on air intakes into the skid 500, when the skid 500 includes the cover 504 and sidewalls.

[0043] In one embodiment, the master control center 501 may also include compressed air powered display instruments 503. The system 108 may also include a compressor that is fluidly connected to at least one of the fifth conduit 305, the eighth conduit 308 or one of the tanks 402, 404 for drawing lower pressure gas into the compressor for powering one or more of the system's display instruments 503. The display instruments 503 may be located in the master control center 501 to provide a convenient location where the operational parameters, such as pressure, flow rates or fluid volumes can be viewed. Alternatively, the display instruments 503 may be positioned at various different positions upon the skid 500.

[0044] **EXAMPLES**

[0045] Case 1 provides fluid parameters of various produced fluid streams associated with the system 108 that have been modelled with standard computer well site fluid modelling software, as will be appreciated by one skilled in the art. The pressure requirement of the gas sales line 400 in Case 1 is about 1,380 kPag (about 200psig).

[0046] Table 1 provides example fluid parameters for a new well and a stabilized well.

Table 1.	Gas		Condensate		Water	
	e ³ sm ³ /d	MMSCFD	sm ³ /d	bb/d	sm ³ /d	bb/d

New Well	100	3.53	200	1258	10	62.9
Stabilized Wells (Each)	75	2.65	85	535	4	25.2

[0047] Table 2 provides example fluid parameters as modelled at the outlet for the first separator of three well sites: one well site has one single new well (well count 1), one well site has a new well and a stabilized well (well count 2) and one well site has a new well and two stabilized wells (well count 3).

Well Count	Pressure		Temperature		Gas			Condensate			Water	
	kPag	psig	°C	F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbbl/d	SG	sm ³ /d	bbbl/d
	1	350	50.8	33.9	93.1	4.0	0.14	1.14	199.0	1252	0.72	0.10
2	350	50.8	33.9	93.1	5.8	0.20	1.14	283.6	1784	0.72	0.10	0.6
3	350	50.8	33.9	93.1	7.5	0.26	1.14	368.1	2315	0.72	0.10	0.6

[0048] Table 3 provides example fluid parameters modelled at the outlet for the second separator 114 for the well sites of Table 2.

Well Count:	Pressure		Temperature		Gas			Condensate				Water		
	kPag	psig	°C	F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbbl/d	SG	RVP (kPa)	RVP (psia)	sm ³ /d	bbbl/d
	1	-5.5	-0.8	27	80.7	3.2	0.11	1.59	186.9	1175	0.74	85.0	12.33	-
2	-5.5	-0.8	27	80.7	4.6	0.16	1.59	266.3	1675	0.74	85.0	12.33	-	-
3	-5.5	-0.8	27.1	80.7	5.9	0.21	1.59	345.7	2175	0.74	85.0	12.33	-	-

[0049] Table 4 provides example fluid parameters modelled at the outlet for the water tanks 404.

Well Count:	Pressure		Temperature		Gas			Condensate			Water	
	kPag	psig	°C	F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbbl/d	SG	sm ³ /d	bbbl/d
	1	-5.5	-0.8	32.3	90.1	0.007	0.0003	1.06	-	-	-	10.0
2	-5.5	-0.8	32.3	90.1	0.010	0.0004	1.06	-	-	-	14.0	87.8
3	-5.5	-0.8	32.3	90.1	0.013	0.0005	1.06	-	-	-	17.9	112.8

[0050] Table 5 provides example fluid parameters modelled at the eighth conduit 308 that transports the vapors from the perimeter 502 of the skid 500 to the VRU 116B.

Well Count:	Flow		Pressure Drop		Length (2" S80)		Length (3" S40)		Length (4" S40)	
	e ³ sm ³ /d	MMSCFD	kPa	ozsi	m	ft	m	ft	m	ft
	1	3.2	0.11	2.6	6	16	53	155	509	606

2	4.6	0.16	2.6	6	8	26	79	259	311	1022
3	6.0	0.21	2.6	6	5	16	48	156	190	623

[0051] Table 6 provides example fluid parameters modelled at the inlet to the VRU 116B.

Well Count:	Table 6. VRU Inlet							
	Pressure		Temperature		Gas			
	kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG	
1	-5.5	-0.8	27.1	80.7	3.2	0.11	1.59	
2	-5.5	-0.8	27.1	80.7	4.6	0.16	1.59	
3	-5.5	-0.8	27.1	80.7	6.0	0.21	1.59	

[0052] Table 7 provides example fluid parameters modelled at the inlet to the multi-staged compressor 116A.

Table 7. Multi-staged Compressor Inlet						
Pressure		Temperature		Gas		
kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG
267.5	38.8	33.1	91.6	4.0	0.14	1.14
267.5	38.8	33.1	91.6	5.8	0.20	1.14
267.5	38.8	33.1	91.6	7.5	0.26	1.14

[0053] Table 8 provides the fluid parameters modelled at a blowcase that is positioned between a suction scrubber that is upstream of compressive stage 5 and the second conduit 302.

Well Count:	Table 8. Blowcase					
	Pressure		Temperature		Liquids	
	kPag	psig	°C	°F	sm ³ /d	bbbl/d
1	-5.5	-0.8	36.7	98.1	0.017	0.11
2	-5.5	-0.8	36.7	98.1	0.024	0.15
3	-5.5	-0.8	36.7	98.1	0.031	0.20

[0054] Table 9 provides the modelled injection rates of methyl alcohol (MeOH) to inhibit the formation of hydrates at each well site, as provided by the chemical skid 104.

Table 9. Hydrate Inhibition	
MeOH Inj. Rate	
sm ³ /d	bbbl/d
0.22	1.4
0.33	2.1
0.44	2.7

[0055] Case 2 provides the fluid parameters that have been modelled on standard computer well site fluid modelling software, as will be appreciated by one skilled in the art. The pressure requirement of the gas sales line 400 in Case 2 is about 9,650 kPag (about 1400psig).

[0056] Table 10 provides example fluid parameters for a new well and a stabilized well.

Table 10.	Gas		Condensate		Water	
	e ³ sm ³ /d	MMSCFD	sm ³ /d	bbl/d	sm ³ /d	bbl/d
New Well	100	3.53	200	1258	10	62.9
Stabilized Wells (Each)	75	2.65	85	535	4	25.2

[0057] Table 11 provides example fluid parameters as modelled at the outlet for the first separator of three well sites: one well site has one single new well (well count 1), one well site has a new well and a stabilized well (well count 2) and one well site has a new well and two stabilized wells (well count 3).

Well Count:	Table 11. First Separator Outlet											
	Pressure		Temperature		Gas			Condensate			Water	
	kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbl/d	SG	sm ³ /d	bbl/d
1	350	50.8	37.7	99.9	4.5	0.16	1.16	198.0	1246	0.72	0.10	0.6
2	350	50.8	37.7	99.9	6.4	0.23	1.16	282.2	1775	0.72	0.10	0.6
3	350	50.8	37.7	99.9	8.3	0.29	1.16	366.4	2304	0.72	0.10	0.6

[0058] Table 12 provides example fluid parameters modelled at the outlet for the second separator 114 for the well sites of Table 11.

Well Count:	Table 12. Second Separator Outlet													
	Pressure		Temperature		Gas			Condensate					Water	
	kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbl/d	SG	RVP (kPaa)	RVP (psia)	sm ³ /d	bbl/d
1	-5.5	-0.8	30.9	87.6	3.2	0.11	1.63	186.0	1170	0.74	78.9	11.44	-	-
2	-5.5	-0.8	30.9	87.6	4.5	0.16	1.63	265.1	1667	0.74	78.9	11.44	-	-
3	-5.5	-0.8	30.9	87.6	5.8	0.21	1.63	344.2	2165	0.74	78.9	11.44	-	-

[0059] Table 13 provides example fluid parameters modelled at the outlet for the water tanks 404

Well Count:	Table 13. Water Tank Outlet					
	Pressure	Temperature	Gas		Condensate	Water

	kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG	sm ³ /d	bbbl/d	SG	sm ³ /d	bbbl/d
1	-5.5	-0.8	34.1	93.5	0.009	0.0003	1.06	-	-	-	10.0	62.6
2	-5.5	-0.8	34.1	93.4	0.012	0.0004	1.06	-	-	-	13.9	87.7
3	-5.5	-0.8	34.1	93.4	0.015	0.0005	1.06	-	-	-	17.9	112.7

[0060] Table 14 provides example fluid parameters modelled at the eighth conduit 308 that transports the vapors from the perimeter 502 of the skid 500 to the VRU 116B.

Well Count:	Table 14. Conduit 308									
	Flow		Pressure Drop		Length (2" S80)		Length (3" S40)		Length (4" S40)	
	e ³ sm ³ /d	MMSCFD	kPa	ozsi	m	ft	m	ft	m	ft
1	3.2	0.11	2.6	6	15	50	156	510	607	1991
2	4.5	0.16	2.6	6	8	25	79	259	312	1024
3	5.9	0.21	2.6	6	4	15	48	157	190	624

[0061] Table 15 provides example fluid parameters modelled at the inlet to the VRU 116B.

Well Count:	Table 15. VRU Inlet						
	Pressure		Temperature		Gas		
	kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG
1	-5.5	-0.8	30.9	87.6	3.2	0.11	1.63
2	-5.5	-0.8	30.9	87.6	4.5	0.16	1.63
3	-5.5	-0.8	30.9	87.6	5.9	0.21	1.63

[0062] Table 16 provides example fluid parameters modelled at the inlet to the multi-staged compressor 116A.

Table 16. Multi-staged Compressor Inlet						
Pressure		Temperature		Gas		
kPag	psig	°C	°F	e ³ sm ³ /d	MMSCFD	SG
267.5	38.8	36.9	98.4	4.5	0.16	1.16
267.5	38.8	36.9	98.4	6.4	0.23	1.16
267.5	38.8	36.9	98.4	8.3	0.29	1.16

[0063] Table 17 the fluid parameters modelled at a blowcase that is positioned between a suction scrubber that is upstream of compressive stage 5 and the second conduit 302.

Well Count:	Table 17. Blowcase					
	Pressure		Temperature		Liquids	
	kPag	psig	°C	°F	sm ³ /d	bbbl/d
1	-5.5	-0.8	-27.2	-16.9	2.061	12.96
2	-5.5	-0.8	-27.2	-16.9	2.938	18.48
3	-5.5	-0.8	-27.2	-16.9	3.814	23.99

[0064] Table 18 provides the modelled injection rates of methyl alcohol (MeOH) to inhibit the formation of hydrates at each well site, as provided by the chemical skid 104.

Table 18. Hydrate Inhibition	
MeOH Inj. Rate	
sm ³ /d	bbl/d
0.27	1.7
0.43	2.7
0.59	3.7

[0065] While the above disclosure describes certain examples of the present invention, various modifications to the described examples will also be apparent to those skilled in the art. The scope of the claims should not be limited by the examples provided above; rather, the scope of the claims should be given the broadest interpretation that is consistent with the disclosure as a whole.

What is claimed is:

1. A mobile skid comprising:
 - a. a first separator that is fluidly connectible to a wellhead for receiving and separating produced fluids from the wellhead into a first gas stream and a first liquid stream;
 - b. a second separator that is fluidly connectible to the first separator for receiving the first liquid stream and separating the first liquid stream into a second gas stream and a second liquid stream;
 - c. a storage tank that is fluidly connectible to the second separator for receiving the second liquid stream;
 - d. a compressor unit comprising:
 - i. a first compressor stage that is fluidly connectible to the storage tank for receiving and pressurizing gas from the storage tank;
 - ii. a second compressor stage that is fluidly connectible to the second separator for receiving and pressurizing the second gas stream and the second compressor is fluidly connected to the first compressor stage for receiving and further pressurizing the pressurized gas from the storage tank;
 - iii. an output conduit that is fluidly connected to the second compressor stage and that is fluidly connectible to a gas sales pipeline,

wherein the second compressor stage pressurizes the second gas stream and the further pressurized gas from the storage tank to substantially match a pressure requirement of the gas sales pipeline.

2. The mobile skid of claim 1 wherein the first separator further separates the produced fluids into the first gas stream, the first liquid stream and a produced water stream, and wherein

the first separator is fluidly connectible to a water storage tank for receiving the produced water stream.

3. The mobile skid of either of claims 1 or 2, wherein the compressor unit comprises a single crankshaft that operates the first compressor stage and the second compressor stage.
4. The mobile skid of claim 3, wherein the first compressor stage comprises two stages.
5. The mobile skid of any one of claims 1, 2, 3 or 4, wherein the second compressor stage comprises at least two stages.
6. The mobile skid of claim 5, wherein the second compressor stage comprises three stages.
7. The mobile skid of any one of claims 1, 2, 3, 4, 5 or 6, wherein an operational rate of the compressor unit is controlled by a variable frequency drive.
8. The mobile skid of any one of claims 1, 2, 3, 4, 5, 6 or 7, wherein the first compressor stage and the second compressor stage both comprise separate fluid connections for recirculating fluids within each stage and fluid connections for providing make-up fluids.
9. The mobile skid of any one of claims 1, 2, 3, 4, 5, 6, 7 or 8, wherein the mobile skid is fluidly connectible to more than one well head.
10. The mobile skid of claim 9, wherein the more than one well head is a new well head and at least one stabilized well head.
11. The mobile skid of any one of claims 1, 2, 3, 4, 5, 6, 7, 8, 9 or 10, further comprising a gas compressor for powering one or more display instruments upon the mobile skid.
12. The mobile skid of any one of claims 1, 2, 3, 4, 5, 6, 7, 8, 9, 10 or 11, further comprising a spill containment means.
13. A method of producing fluids from a wellhead comprising steps of:

- a. separating fluids produced at the wellhead into a first gas stream and a first liquid stream;
- b. separating the first liquid stream into a second liquid stream and a second gas stream;
- c. directing the second liquid stream to a storage tank;
- d. collecting gas produced within the storage tank;
- e. directing the gas produced within the storage tank to a first stage of a compression unit;
- f. pressurizing the directed gas produced within the storage tank to a first predetermined pressure within the first stage of a compressor unit;
- g. directing the second gas stream to a second compression stage of the compression unit;
- h. pressurizing the second gas stream to a second predetermined pressure;
- i. directing the directed gas produced within the storage tank that is at the first predetermined pressure to the second compression stage of the compression unit;
- j. pressurizing the directed gas within the second compression stage of the compression unit to the second predetermined pressure;
- k. directing the directed gas and the second gas stream that are at the second predetermined pressure to a gas sales pipeline,

wherein the second predetermined pressure is greater than the first predetermined pressure and the second predetermined pressure substantially matches a pressure requirement of the gas sales pipeline.

14. The method of claim 13, further comprising a step of providing a mobile skid and performing at least steps (a), (b), (f), (g), (h), (i), (j) and (k) upon the mobile skid.
15. The method of claim 14, further comprising steps of fluidly connecting a plurality of conduits upon the mobile skid to the well head for receiving the produced fluids and fluidly connecting the mobile skid to the gas sales pipeline.
16. The method of either of claim 14 or claim 15, further comprising a step of fluidly connecting the plurality of conduits upon the mobile skid to more than one well head.
17. The method of claim 16, wherein the more than one well head comprise a new well and at least one stabilized well.
18. The method of any one of claims 14, 15, 16 or 17, further comprising a step of directing the first gas stream to the gas sales pipeline.
19. The method of any one of claims 14, 15, 16, 17 or 18, further comprising a step of separating at least one further first liquid stream that is received from at least one further wellhead and a step of combining the at least one further first liquid stream with the first liquid stream prior to or during step (b).
20. The method of any one of claims 14, 15, 16, 17, 18 or 19, further comprising a step of receiving fluids produced at a second wellhead and performing steps (a) through (k) on a stream of fluids that is combined from the fluids produced at the wellhead and the second wellhead.
21. The method of any one of claims 14, 15, 16, 17, 18, 19 or 20 further comprising a step of moving the mobile skid to another wellhead and performing the steps (a) through (k) on fluids produced from the another wellhead.

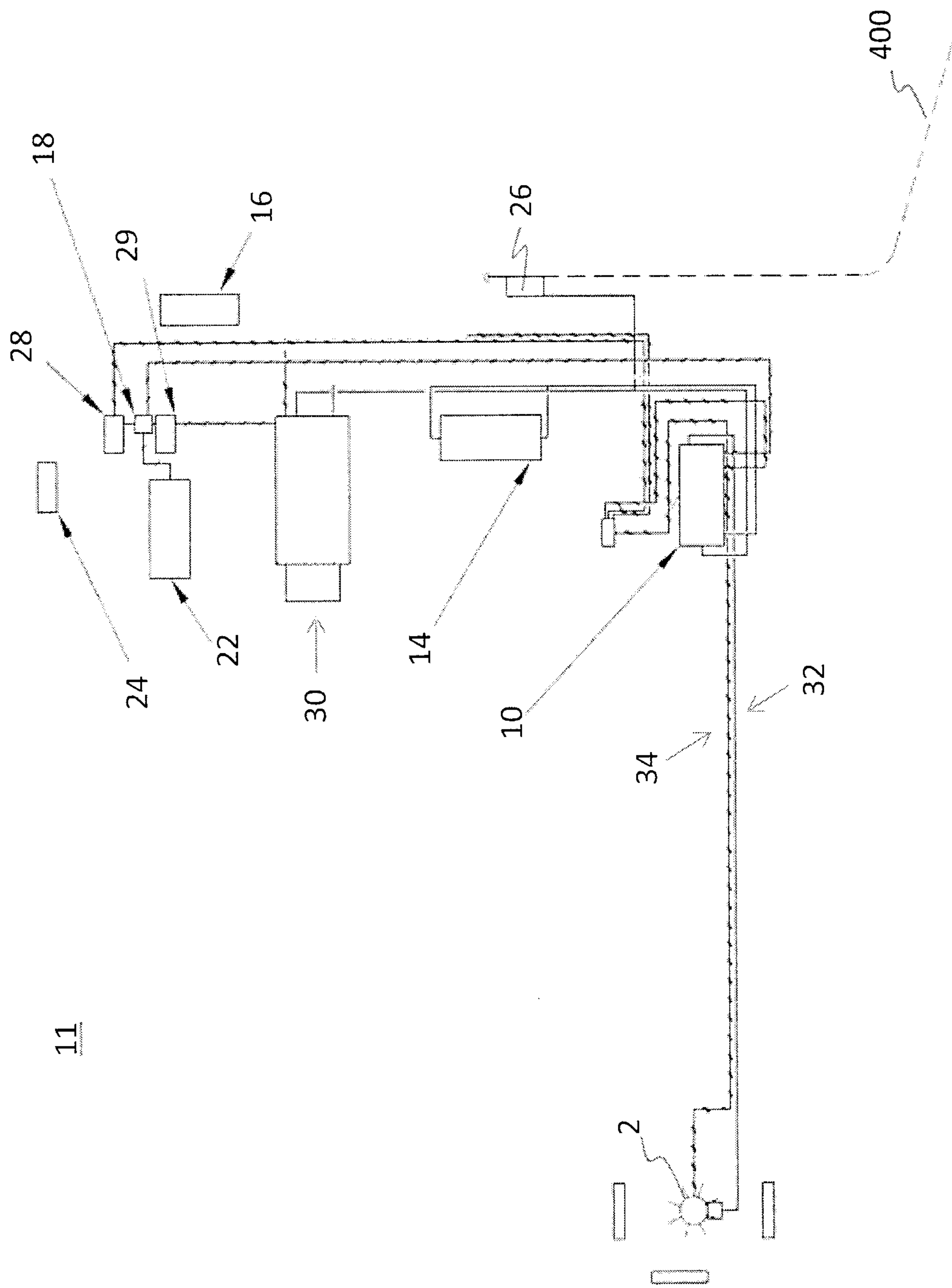


Figure 1

100

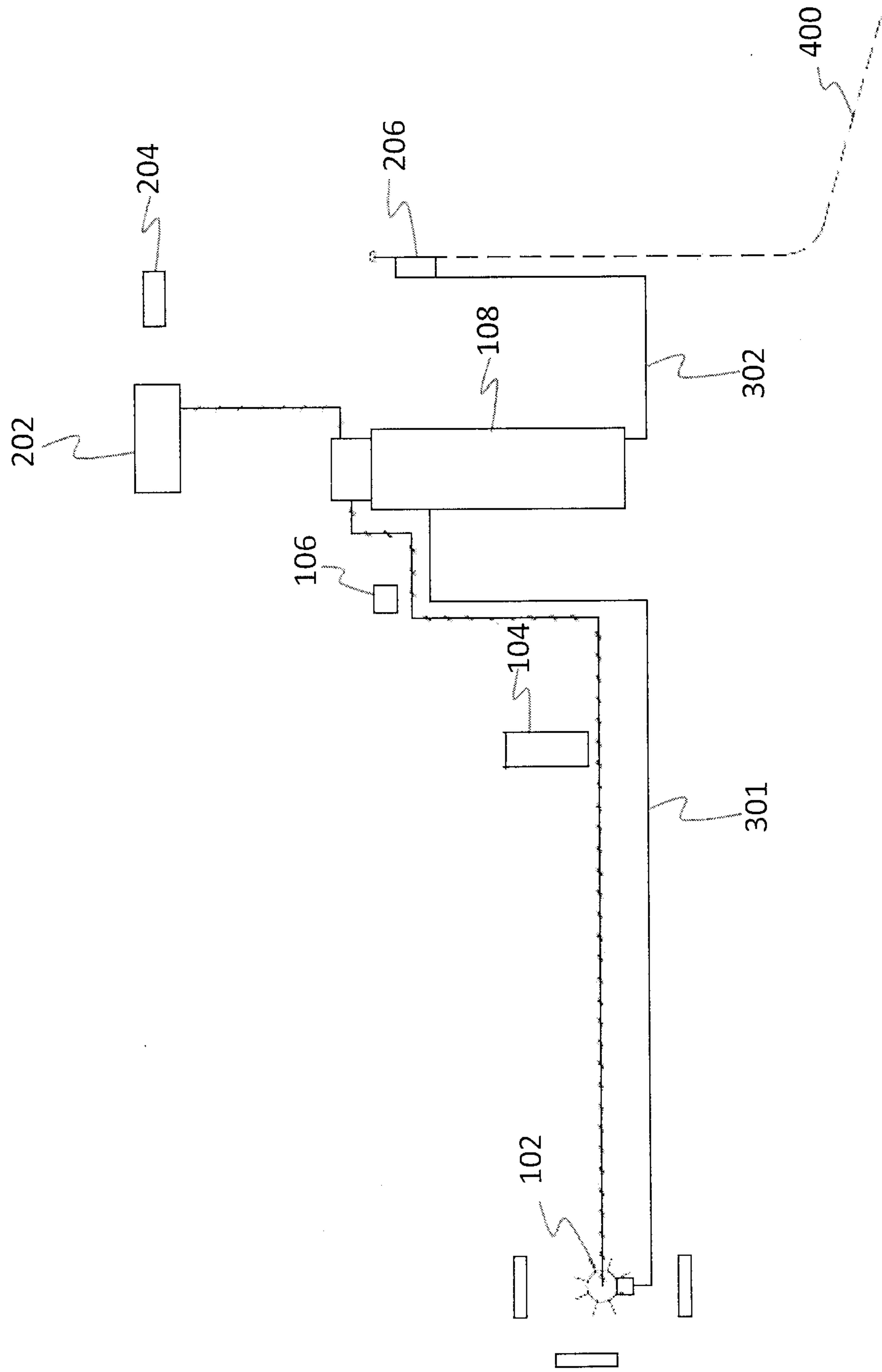


Figure 2

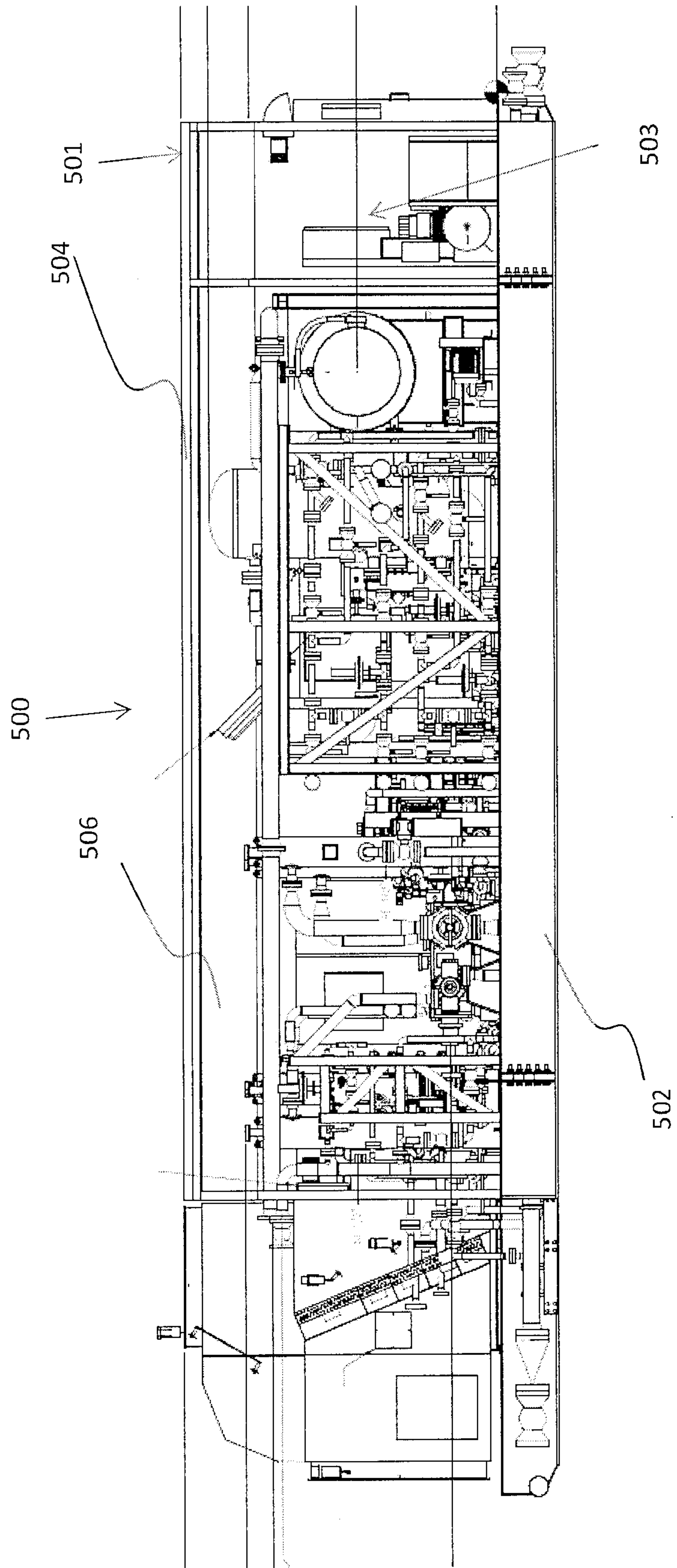


Figure 4

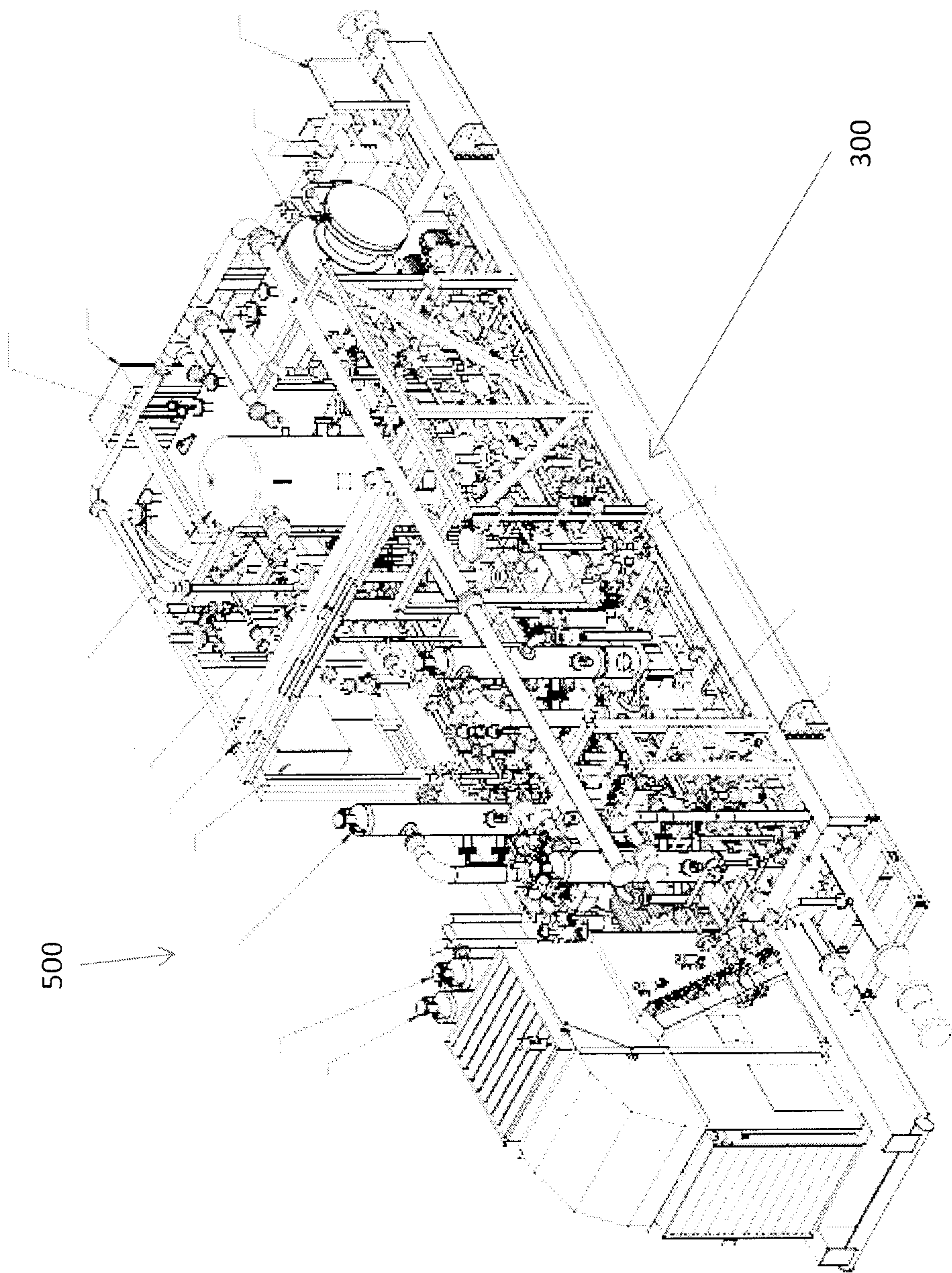


Figure 5

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