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(54) **Title**: COALESCER FOR CO-CURRENT CONTACTORS

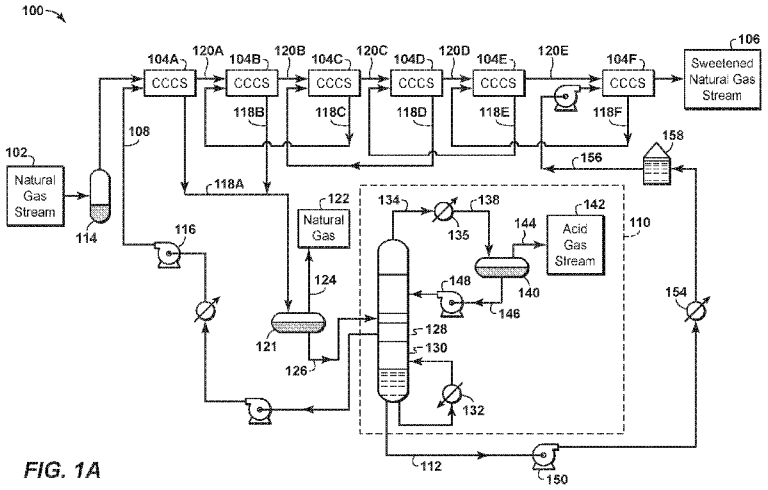


FIG. 1A

(57) **Abstract**: The disclosure includes a method, comprising passing a fluid into a co-current contactor, passing a solvent into the co-current contactor, dividing the solvent into solvent droplets having a first average droplet size, placing the fluid in contact with the solvent droplets to create a combined stream, coalescing at least a portion of the solvent droplets to create solvent droplets having a second average droplet size, wherein the second average droplet size is greater than the first average droplet size, and separating the fluid and the solvent.

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COALESCER FOR CO-CURRENT CONTACTORS

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the priority benefit of United States Patent Application 62/132,631 filed March 13, 2015 entitled COALESCER FOR CO-CURRENT CONTACTORS, the entirety of which is incorporated by reference herein.

BACKGROUND

[0002] The production of hydrocarbons from a reservoir oftentimes carries with it the incidental production of non-hydrocarbon gases. Such gases include contaminants such as hydrogen sulfide (H_2S) and carbon dioxide (CO_2). When H_2S or CO_2 are produced as part of a hydrocarbon stream (such as methane or ethane), the raw gas stream is sometimes referred to as "sour gas." The H_2S and CO_2 are often referred to together as "acid gases."

[0003] In addition to hydrocarbon production streams, acid gases may be associated with synthesis gas streams, or with refinery gas streams. Acid gases may also be present within so-called flash-gas streams in gas processing facilities. Further, acid gases may be generated by the combustion of coal, natural gas, or other carbonaceous fuels.

[0004] Gas and/or hydrocarbon fluid streams may contain not only H_2S or CO_2, but may also contain other "acidic" impurities. These include mercaptans and other trace sulfur compounds (SO_x). In addition, natural gas streams may contain water. Indeed, water is the most common contaminant in many natural gas streams. Such impurities should be removed prior to industrial or residential use.

[0005] Processes have been devised to remove contaminants from a raw natural gas stream. In the case of acid gases, cryogenic gas processing is sometimes used, particularly to remove CO_2 to prevent line freezing and plugged orifices. In other instances, particularly with H_2S removal, the hydrocarbon fluid stream is treated with a solvent. Solvents may include chemical solvents such as amines. Examples of amines used in sour gas treatment include monoethanol amine (MEA), diethanol amine (DEA), and methyl diethanol amine (MDEA).

[0006] Physical solvents are sometimes used in lieu of amine solvents. Examples include physical solvents currently marketed under the brand names Selexol® (comprising dimethyl ethers of polyethylene glycol) and Rectisol™ (comprising methanol). In some instances hybrid

solvents, meaning mixtures of physical and chemical solvents, have been used. An example of one such hybrid solvent is currently marketed under the brand name Sulfinol® (comprising sulfolane, water, and one or more amines). However, the use of amine-based acid gas removal solvents is most common.

[0007] Amine-based solvents rely on a chemical reaction with the acid gases. The reaction process is sometimes referred to as "gas sweetening." Such chemical reactions are generally more effective than the physical-based solvents, particularly at feed gas pressures below about 300 pounds per square inch absolute (psia) (about 20 bar). There are instances where special chemical solvents such as Flexsorb® (comprising hindered amine) are used, particularly for selectively removing H_2S from H_2S and CO_2-containing gas and/or hydrocarbon fluid streams.

[0008] As a result of the gas sweetening process, a treated or "sweetened" gas stream is created. The sweetened gas stream is substantially depleted of H_2S and/or CO_2 components. The sweetened gas can be further processed for liquids recovery, that is, by condensing out heavier hydrocarbon gases. The sweet gas may be sold into a pipeline or may be used for liquefied natural gas (LNG) feed. In addition, the sweetened gas stream may be used as feedstock for a gas-to-liquids process, and then ultimately used to make waxes, butanes, lubricants, glycols and other petroleum-based products. The extracted CO_2 may be sold, or it may be injected into a subterranean reservoir for enhanced oil recovery operations.

[0009] When a natural gas stream contains water, a dehydration process is usually undertaken before or after acid gas removal. This is done through the use of glycol or other desiccant in a water separator. The dehydration of natural gas is done to control the formation of gas hydrates and to prevent corrosion in distribution pipelines. The formation of gas hydrates and corrosion in pipelines can cause a decrease in flow volume as well as frozen control valves, plugged orifices and other operating problems.

[0010] Traditionally, the removal of acid gases or water using chemical solvents or desiccants involves counter-currently contacting the raw natural gas stream with the chemical. The raw gas stream is introduced into the bottom section of a contacting tower, or absorption tower. At the same time, the solvent solution is directed into a top section of the tower. The tower has trays, packing, or other "internals." As the solvent cascades through the internals, it absorbs the undesirable components, carrying them away through the bottom of the contacting tower as part of a "rich" solvent solution. At the same time, gaseous fluid that is largely depleted of the undesirable components exits at the top of the tower.

[0011] The rich solvent or rich glycol, as the case may be, that exits the contactor is sometimes referred to as an absorbent liquid. Following absorption, a process of regeneration (also called "desorption") may be employed to separate contaminants from the active solvent of the absorbent liquid. This produces a "lean" solvent or a "lean" glycol that is then typically recycled into the contacting tower for further absorption.

[0012] While perhaps capable of performing desired contacting for removal of contaminants from a gas and/or hydrocarbon-containing fluid stream, historic contactor designs have had difficulty scaling-up from lab and/or pilot-sized units to units capable of efficiently processing up to a billion standard cubic feet per day (BSFD) of gas. Past scale-up designs have high capital expenses (e.g., due to having larger and more pieces of equipment, more complicated transportation and installation, etc.) and high operational expenses (e.g., due to less reliability and/or operability, larger size and weight equipment, etc.). Consequently, a need exists for a contacting designs that is smaller, has fewer pieces of equipment, has improved operability and reliability, is easier to transport and install, and weighs less than traditional contacting equipment.

SUMMARY OF THE INVENTION

[0013] The disclosure includes a method, comprising passing a fluid into a co-current contactor, passing a solvent into the co-current contactor, dividing the solvent into solvent droplets having a first average droplet size, placing the fluid in contact with the solvent droplets to create a combined stream, coalescing at least a portion of the solvent droplets to create solvent droplets having a second average droplet size, wherein the second average droplet size is greater than the first average droplet size, and separating the fluid and the solvent.

[0014] The disclosure includes a co-current contactor apparatus, comprising a first inlet configured to receive a first fluid stream proximate to a first end of the co-current contactor, a second inlet configured to receive a second fluid stream proximate to the first end of the co-current contactor, an inlet section configured to atomize at least a portion of the second fluid stream, a mass transfer section configured to receive the first fluid stream and the atomized second fluid stream, and to pass the atomized second fluid stream and the the first fluid stream as a combined stream, a coalescer configured receive the combined stream, and to increase an average droplet size of the atomized second fluid stream, and a separator configured to separate at least a portion of the atomized second fluid stream from the combined stream.

[0015] The disclosure includes a co-current contacting system, comprising a plurality of

co-current contactors coupled in a counter-current configuration, wherein each co-current contactor comprises a first inlet configured to receive a first fluid stream proximate to a first end of the co-current contactor, a second inlet configured to receive a second fluid stream proximate to the first end of the co-current contactor, an inlet section configured to atomize at least a portion of the second fluid stream, a mass transfer section configured to receive the first fluid stream and the atomized second fluid stream, and to pass the atomized second fluid stream and the the first fluid stream as a combined stream, a coalescer configured to receive the combined stream, and to increase the average droplet size of the atomized second fluid stream, and a separator configured to separate at least a portion of the atomized second fluid stream from the combined stream.

[0016] It is understood that the methods above may be used to remove a contaminant, e.g., an acid gas component, a water component, etc., from other fluid streams. These separated fluid streams may include, for example, a sour water stream, a flash-gas stream, or a Claus tail gas stream.

DESCRIPTION OF THE DRAWINGS

[0017] So that the manner in which the present invention can be better understood, certain illustrations, charts and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[0018] FIG. 1A is a process flow diagram of a gas processing system that includes a co-current flow scheme.

[0019] FIG. 1B is a process flow diagram of another gas processing system that includes a co-current flow scheme.

[0020] FIG. 2 is a schematic diagram of a co-current contacting system comprising multiple co-current contactors.

[0021] FIG. 3 is a side view of an embodiment of a single stage multiple co-current contactor bundle configuration.

[0022] FIG. 4 is a schematic diagram of an embodiment of a co-current contactor having a coalescing section.

DETAILED DESCRIPTION

[0023] As used herein, an "acid gas" means any gas that dissolves in water producing an acidic solution. Non-limiting examples of acid gases include hydrogen sulfide (H_2S), carbon dioxide (CO_2), sulfur dioxide (SO_2), carbon disulfide (CS_2), carbonyl sulfide (COS), mercaptans, or mixtures thereof.

[0024] As used herein, the term "atomize" means to divide, reduce, or otherwise convert a liquid into minute particles, a mist, or a fine spray of droplets having an average droplet size within a predetermined range.

[0025] As used herein, the term "co-current contacting device" or "co-current contactor" means an apparatus, e.g., a pipe, a vessel, a housing, an assembly, etc., that receives (i) a stream of gas (or other fluid stream to be treated) and (ii) a separate stream of solvent (or other fluid treating solution) in such a manner that the gas stream and the solvent stream contact one another while flowing in generally the same direction within the contacting device.

[0026] As used herein, the term "contaminant" means an acid gas, water, another undesirable component, or a combination thereof absorbable by a selected solvent.

[0027] As used herein, the term "flue gas" means any gas stream generated as a by-product of hydrocarbon combustion.

[0028] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

[0029] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring, hydrocarbons including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[0030] As used herein, the term "industrial plant" refers to any plant that generates a stream containing at least one hydrocarbon or an acid gas. One non-limiting example is a coal-powered electrical generation plant. Another example is a cement plant that emits CO_2 at low pressures.

[0031] With respect to fluid processing equipment, the term "inline" may mean that two or more items are placed along a flow line such that a fluid stream undergoing fluid separation

moves from one item of equipment to the next while maintaining flow in a substantially constant downstream direction, and/or that the two or more items are connected sequentially or, more preferably, are integrated into a single tubular device.

[0032] As used herein, the terms "lean" and "rich," with respect to the absorbent liquid removal of a selected gas component from a gas stream, are relative, merely implying, respectively, a lesser or greater degree of content of the selected gas component. The respective terms "lean" and "rich" do not necessarily indicate or require, respectively, either that an absorbent liquid is totally devoid of the selected gaseous component, or that it is incapable of absorbing more of the selected gas component. In fact, it is preferred, as will be evident hereinafter, that the so called "rich" absorbent liquid produced in a first contactor in a series of two or more contactors retains significant or substantial residual absorptive capacity. Conversely, a "lean" absorbent liquid will be understood to be capable of substantial absorption, but may retain a minor concentration of the gas component being removed.

[0033] As used herein, the term "natural gas" refers to a multi-component gas obtained from a crude oil well (associated gas) or from a subterranean gas-bearing formation (non-associated gas). The composition and pressure of natural gas can vary significantly. A typical natural gas stream contains methane (C_1) as a significant component. The natural gas stream may also contain ethane (C_2), higher molecular weight hydrocarbons, one or more acid gases, and water. The natural gas may also contain minor amounts of contaminants such as nitrogen, iron sulfide, and wax.

[0034] As used herein, the term "non-absorbing gas" means a gas that is not absorbed by a solvent during a gas treating or conditioning process, e.g., during co-current contacting.

[0035] As used herein, the term "solvent" means a liquid phase fluid or a multiphase fluid (a fluid comprising both a liquid and gas phase) that preferentially absorbs one or more component over other components. For example, a solvent may preferentially absorb a contaminant, e.g., acid gas, thereby removing or "scrubbing" at least a portion of the contaminant from a contaminated stream, e.g., a contaminated natural gas stream.

[0036] As used herein, the term "sweetened gas stream" refers to a fluid stream in a substantially gaseous phase that has had at least a portion of acid gas components removed. Further, the term "sweetened" may also refer to a fluid stream that has been subjected to a dehydration or other conditioning process.

DESCRIPTION OF SPECIFIC EMBODIMENTS

[0037] FIG. 1A is a process flow diagram of a gas processing system **100** that includes a co-current flow scheme arranged in a counter current configuration. The gas processing system **100** may be used for the removal of H_2S or other acid gas components from a gas stream **102**. In addition, in some embodiments, the gas processing system **100** may be used for the removal of water or other impurities from the gas stream **102**.

[0038] The gas processing system **100** may employ a number of vertically oriented co-current contacting systems **104A-F**. In some embodiments, each vertically oriented co-current contacting system **104A-F** includes vertically oriented co-current contactor upstream of a separation system. In other embodiments, each vertically oriented co-current contacting system **104A-F** includes a number of vertically oriented co-current contactors upstream of a single separation system. As would be apparent to those of skill in the art, any or all of the co-current contacting systems **104A-F** may be either vertically oriented or horizontally oriented, depending on the details of the specific implementation, and such alternate embodiments are within the scope of this disclosure.

[0039] The gas stream **102** may be a natural gas stream from a hydrocarbon production operation. For example, the gas stream **102** may be a flue gas stream from a power plant, or a synthesis gas (syn-gas) stream. If the natural gas stream **102** is a syn-gas stream, the gas stream **102** may be cooled and filtered before being introduced into the gas processing system **100**. The gas stream **102** may also be a flash gas stream taken from a flash drum in a gas processing system itself. In addition, the gas stream **102** may be a tail gas stream from a Claus sulfur recovery process or an impurities stream from a regenerator. Furthermore, the gas stream **102** may be an exhaust emission from a cement plant or other industrial plant. In this instance, CO_2 may be absorbed from excess air or from a nitrogen-containing flue gas.

[0040] The gas stream **102** may include a non-absorbing gas, such as methane, and one or more impurities, such as an acid gas. For example, the gas stream **102** may include CO_2 or H_2S. The gas processing system **100** may convert the gas stream **102** into a sweetened gas stream **106** by removing the acid gases.

[0041] In operation, the gas stream **102** may be flowed into a first co-current contacting system **104A**, where it is mixed with a solvent stream **108**. If the gas processing system **100** is to be used for the removal of H_2S, or other sulfur compounds, the solvent stream **108** may include an amine solution, such as monoethanol amine (MEA), diethanol amine (DEA), or

methyldiethanol amine (MDEA). Other solvents, such as physical solvents, alkaline salts solutions, or ionic liquids, may also be used for H_2S removal. In embodiments used for other purposes, such as dehydration or reactions, other solvents or reactants, such as glycols, may be used. The solvent stream **108** may include a lean solvent that has undergone a desorption process for the removal of acid gas impurities. For example, in the gas processing system **100** shown in FIG. 1A, the solvent stream **108** introduced into the first co-current contacting system **104A** includes a semi-lean solvent that is taken from a central portion of a regenerator **110**. A lean solvent stream **112** taken from the regenerator **110** may also be directed into a final co-current contacting system **104F**.

[0042] In various embodiments, the gas processing system **100** employs a series of co-current contacting systems **104A-F**. In some embodiments, as shown in FIG. 1A, the co-current contacting systems **104A-F** may be arranged in a counter current configuration. Each co-current contacting system **104A-F** removes a portion of the acid gas content from the natural gas stream **102**, thereby releasing a progressively sweetened natural gas stream in a downstream direction. The final co-current contacting system **104F** provides the final sweetened natural gas stream **106**.

[0043] Before entering the first co-current contacting system **104A**, the natural gas stream **102** may pass through an inlet separator **114**. The inlet separator **114** may be used to clean the natural gas stream **102** by filtering out impurities, such as brine and drilling fluids. Some particle filtration may also take place. The cleaning of the natural gas stream **102** can prevent foaming of solvent during the acid gas treatment process.

[0044] As shown in FIG. 1A, the solvent stream **108** is flowed into the first co-current contacting system **104A**. Movement of the semi-lean solvent stream **108** into the first co-current contacting system **104A** may be aided by a pump **116**. The pump **116** may cause the semi-lean solvent stream **108** to flow into the first co-current contacting system **104A** at a suitable pressure, for example, of about 15 psig to about 1,500 psig.

[0045] Once inside the first co-current contacting system **104A**, the natural gas stream **102** and the solvent stream **108** move along the longitudinal axis of the first co-current contacting system **104A**. As they travel, the solvent stream **108** interacts with the H_2S, H_2O, and/or other impurities in the natural gas stream **102**, causing the H_2S, H_2O, and/or other impurities to chemically attach to or be absorbed by the amine molecules. A first partially-loaded, or "rich," gas solvent or treating solution **118A** may be flowed out of the first co-current contacting

system **104A**. In addition, a first partially-sweetened natural gas stream **120A** may be flowed out of the first co-current contacting system **104A** and into a second co-current contacting system **104B**. This general arrangement may be referred to as arranging co-current contactors in a counter current configuration.

[0046] As shown in the example illustrated in FIG. 1A, a third co-current contacting system **104C** may be provided after the second co-current contacting system **104B**, and a fourth co-current contacting system **104D** may be provided after the third co-current contacting system **104C**. In addition, a fifth co-current contacting system **104E** may be provided after the fourth co-current contacting system **104D**, and a final co-current contacting system **104F** may be provided after the fifth co-current contacting system **104E**. Each of the second, third, fourth, and fifth co-current contacting systems **104B**, **104C**, **104D**, and **104E** may generate a respective partially-sweetened natural gas stream **120B**, **120C**, **120D**, and **120E**. In addition, each of the second, third, fourth, fifth, and final co-current contacting systems **104B**, **104C**, **104D**, **104E**, and **104F** may generate respective partially-loaded gas treating solution **118B**, **118C**, **118D**, **118E**, and **118F**. If an amine is used as the solvent stream **108**, the partially-loaded gas treating solutions **118A-F** may include rich amine solutions. In the gas processing system **100**, the second loaded gas treating solution **118B** merges with the rich gas treating solution **118A** and goes through a regeneration process in the regenerator **110**.

[0047] As the progressively-sweetened natural gas streams **120A-E** are generated, the gas pressure in the gas processing system **100** will gradually decrease. As this occurs, the liquid pressure of the progressively-richer gas treating solutions **118A-F** may be correspondingly increased. This may be accomplished by placing one or more booster pumps (not shown) between each co-current contacting system **104A-F** to boost liquid pressure in the gas processing system **100**.

[0048] In the gas processing system **100**, solvent streams may be regenerated by flowing the partially-loaded gas treating solutions **118A** and **118B** through a flash drum **121**. Absorbed natural gas **122** may be flashed from the partially-loaded gas treating solutions **118A** and **118B** within the flash drum **121**, and may be flowed out of the flash drum **121** via an overhead line **124**.

[0049] The resulting rich solvent stream **126** may be flowed from the flash drum **121** to the regenerator **110**. The rich solvent stream **126** may be introduced into the regenerator **110** for desorption. The regenerator **110** may include a stripper portion **128** including trays or other

internals (not shown). The stripper portion **128** may be located directly above a heating portion **130**. A heat source **132** may be provided with the heating portion **130** to generate heat. The regenerator **110** produces the regenerated, lean solvent stream **112** that is recycled for re-use in the final co-current contacting system **104F**. Stripped overhead gas from the regenerator **110**, which may include concentrated H_2S (or CO_2), may be flowed out of the regenerator **110** as an overhead impurities stream **134**.

[0050] The overhead impurities stream **134** may be flowed into a condenser **135**, which may cool the overhead impurities stream **134**. The resulting cooled impurities stream **138** may be flowed through a reflux accumulator **140**. The reflux accumulator **140** may separate any remaining liquid, such as condensed water, from the impurities stream **138**. This may result in the generation of a substantially pure acid gas stream **142**, which may be flowed out of the reflux accumulator **140** via an overhead line **144**.

[0051] In some embodiments, if the initial natural gas stream **102** includes CO_2, and a CO_2-selective solvent stream **108** is used, the acid gas stream **142** includes primarily CO_2. The CO_2-rich acid gas stream **142** may be used as part of a miscible EOR operation to recover oil. If the oil reservoir to be flooded does not contain a significant amount of H_2S or other sulfur compounds, the CO_2 to be used for the EOR operation may not contain significant H_2S or other sulfur compounds. However, concentrated CO_2 streams from oil and gas production operations may be contaminated with small amounts of H_2S. Thus, it may be desirable to remove the H_2S from the CO_2, unless the acid gas stream **142** is to be injected purely for geologic sequestration.

[0052] While a gas stream **102** is discussed herein, those of skill in the art will appreciate that generally the same principles may be applied to any fluid stream, including with respect to liquid-liquid contacting. Consequently, use of the phrases "gas stream," "gas inlet," "gas outlet," etc. are to be understood as non-limiting and may optionally be replaced with "fluid stream," "fluid inlet," "fluid outlet," and so forth in various embodiments within the scope of this disclosure. Use of the phrases "gas stream," "gas inlet," "gas outlet," etc. are for the sake of convenience only.

[0053] In some embodiments, if the initial natural gas stream **102** includes H_2S, an H_2S-selective solvent stream **108** may be used to capture the H_2S. The H_2S may then be converted into elemental sulfur using a sulfur recovery unit (not shown). The sulfur recovery unit may be a so-called Claus unit. Those of ordinary skill in the art will understand that a "Claus process" is a process that is sometimes used by the natural gas and refinery industries to recover

elemental sulfur from H_2S-containing gas streams.

[0054] In practice, the "tail gas" from the Claus process, which may include H_2S, SO_2, CO_2, N_2, and water vapor, can be reacted to convert the SO_2 to H_2S via hydrogenation. The hydrogenated tail gas stream has a high partial pressure, a large amount of CO_2, e.g., more than 50%, and a small amount of H_2S, e.g., a few percent or less. This type of gas stream, which is typically near atmospheric pressure, is amenable to selective H_2S removal. The recovered H_2S may be recycled to the front of the Claus unit, or may be sequestered downstream. Alternatively, a direct oxidation of the H_2S to elemental sulfur may be performed using various processes known in the field of gas separation.

[0055] As shown in FIG. 1A, a residual liquid stream **146** may be flowed out of the bottom of the reflux accumulator **140**. The residual liquid stream **146** may be flowed through a reflux pump **148**, which may boost the pressure of the residual liquid stream **146** and pump the residual liquid stream **146** into the regenerator **110**. The residual liquid stream **146** may be flowed out of the regenerator **110**, for example, from the bottom of the heating portion **130** as part of the lean solvent stream **112**. Some water may be added to the lean solvent stream **112** to balance the loss of water vapor to the partially sweetened natural gas streams **120A-E**. This water may be added at an intake or suction of the reflux pump **148**.

[0056] The lean solvent stream **112** may be at a low pressure. Accordingly, the lean solvent stream **112** may be passed through a pressure boosting pump **150**. From the pressure boosting pump **150**, the lean solvent stream **112** may be flowed through a cooler **154**. The cooler **154** may cool the lean solvent stream **112** to ensure that the lean solvent stream **112** will absorb acid gases effectively. The resulting cooled lean solvent stream **156** is then used as the solvent stream for the final co-current contacting system **104F**.

[0057] In some embodiments, a solvent tank **158** is provided proximate the final co-current contacting system **104F**. The cooled lean solvent stream **156** may be flowed from the solvent tank **158**. In other embodiments, the solvent tank **158** is off-line and provides a reservoir for the lean solvent stream **156**.

[0058] The process flow diagram of FIG. 1A is not intended to indicate that the gas processing system **100** is to include all of the components shown in FIG. 1A. Further, any number of additional components may be included within the gas processing system **100**, depending on the details of the specific implementation. For example, the gas processing system **100** may include any suitable types of heaters, coolers, condensers, liquid pumps, gas

compressors, blowers, bypass lines, other types of separation and/or fractionation equipment, valves, switches, controllers, and pressure-measuring devices, temperature-measuring devices, level-measuring devices, or flow-measuring devices, among others.

[0059] FIG. 1B is a process flow diagram of another gas processing system **160** that includes a co-current flow scheme. Like numbered items are as described with respect to FIG. 1A. Operation of the gas processing system **160** of FIG. 1B is similar to that of the gas processing system **100** of FIG. 1A. However, in the gas processing system **160**, the first co-current contacting system **104A** receives the partially-loaded gas treating solution **118B** from the second co-current contacting system **104B**. Therefore, the gas processing system **160** does not include the semi-lean solvent stream **108**. In this example, the series of co-current contacting systems **104A-F** acts like a separation column, for example, wherein each stage corresponds to a packed stage.

[0060] Because the partially-loaded gas treating solution **118B** received by the first co-current contacting system **104A** in FIG. 1B has already been processed through the second co-current contacting system **104B**, the partially-loaded gas treating solution **118B** may be very rich. For this reason, it may be desirable to provide some level of intermediate processing of the partially-loaded gas treating solution **118B**.

[0061] Alternatively, a semi-lean liquid stream could be taken from other sweetening operations in the gas processing system **160** and used, at least in part, as an amine solution for the first or second co-current contacting system **104A** or **104B**. In this respect, there are situations in which a single type of solvent is used for more than one service in the gas processing system **160**. This is referred to as integrated gas treatment. For example, MDEA may be used both for high-pressure, H_2S-selective acid gas removal, as well as in a Claus tail gas treating (TGT) process. The rich amine stream from the TGT process is not heavily loaded with H_2S and CO_2, owing to the low pressure of the process. Thus, in some embodiments, the rich amine stream from the TGT process is used as a semi-lean stream for the first or second co-current contacting system **104A** or **104B**. The semi-lean stream (not shown) may be pumped to a suitable pressure and injected into the first or second co-current contacting system **104A** or **104B**, possibly along with the partially-loaded gas treating solution from the succeeding co-current contacting system.

[0062] Further, in the gas processing system **160** of FIG. 1B, the first partially-loaded treating solution **118A** is flowed through a heat exchanger **162** after being flowed through the

flash drum **121**. Within the heat exchanger **162**, the temperature of the first partially-loaded treating solution **118A** is increased via heat exchange with the lean solvent **112** taken from the regenerator **110**. This serves to heat the first partially-loaded treating solution **118A** before introduction into the regenerator **110**, while cooling the lean solvent stream **112**.

[0063] The process flow diagram of FIG. 1B is not intended to indicate that the gas processing system **160** is to include all of the components shown in FIG. 1B. Further, any number of additional components may be included within the gas processing system **160**, depending on the details of the specific implementation.

[0064] **FIG. 2** is a schematic diagram of a co-current contacting system **200**, e.g., any one of the co-current contacting systems **104A-F** of FIG. 1. The components of FIG. 2 may be the substantially the same as the corresponding components of FIG. 1 except as otherwise noted. The co-current contacting system **200** has four contacting units **202a-202d** separately supplied by a header **204** for a natural gas stream **102**. The contacting units **202a-202d** are separately supplied by a header carrying a lean solvent stream **206**, e.g., a semi-lean solvent stream **108** or any of the partially-loaded gas treating solutions **118A-F**, and received proximate to a first end of each each contacting unit **202a-202d**. Each contacting unit **202a-202d** has an inlet nozzle **208a-208d** (respectively) for atomizing and/or dividing the solvent into a large number of small droplets and introducing the lean solvent stream **206**. Atomizing the lean solvent stream **206** increases the surface area available for contact with the natural gas stream **102** and decreases the distances required for diffusion of acid gas components in both the vapor and liquid phases. Each contacting unit **202a-202d** has a recycle gas inlet **210a-210d** supplied by gas collected and returned from a seal pot or liquid boot **212a-212d**. As depicted, each recycle gas inlet **210a-210d** may include a swirl vane or equivalent structure to assist in separation. The seal pot or liquid boot **212a-212d** may provide residence time for process control and may seal the contacting units **202a-202d** to prevent gas bypass. Each contacting unit **202a-202d** has a treated gas outlet **214a-214d** and a rich solvent outlet **216a-216d**. The treated gas outlets **214a-214d** are depicted as comprising vortex tube finders, but alternate embodiments are well known in the art. Treated gas exiting the contacting units **202a-202d** via the treated gas outlets **214a-214d** may be combined and passed as the sweetened gas stream **106**, while rich solvent exiting the contacting units **202a-202d** via the rich solvent outlets **216a-216d** may be combined and passed as the rich solvent stream **136**.

[0065] In operation, each contacting unit **202a-202d** receives a natural gas stream **102** at

an inlet section **220a-220d**, where the inlet nozzles **208a-208d** atomize a lean solvent stream **206** and expose it to the natural gas stream **102**, creating a mixed, two-phase flow or combined stream (not depicted). The mixed, two-phase flow or combined stream passes through a mass transfer section **222** where absorption occurs. The mass transfer section **222** may comprise a tubular body having a substantially empty bore having one or more surface features, e.g., a hydrophobic surface, a superhydrophobic surface, a raised surface, a recessed surface, or any combination thereof, along an inner surface of the mass transfer section **222**. A separation section **224** follows the mass transfer section. In the separation section **224**, entrained liquid droplets are removed from the gas stream, e.g., using a cyclone inducing element, resulting in an at least partially dehydrated and/or decontaminated treated gas stream. In some embodiments, the inlet section **220** and the mass transfer section **222** may collectively be referred to as a contacting section. The length of the contacting section may be determined based on the residence time required to obtain a predetermined decontamination and/or dehydration level for the natural gas stream **102**, e.g., in view of the intended flow rate, pressure drop, etc. The treated gas stream exits the contacting units **202a-202d** through the outlet section **226**. The contacting units **202a-202d** may operate at about 400 psig to about 1,200 psig, or higher. Because the contacting units **202a-202d** must be individually constructed so as to tolerate these pressures, weight and/or footprint increases linearly as the number of contacting units **202a-202d** is increased.

[0066] As co-current contactors become more compact, both in length and diameter, it is important to ensure as much solvent as possible reacts in the increasingly shortened mixing and/or mass transfer section. The H_2S reaction is instantaneous relative to the CO_2 reactions, lowering the residence time, i.e., the contact time between the vapor and liquid phases, will result in less CO_2 being absorbed into the solvent. The design of the co-current contacting systems **104A-F** enhances selective H_2S removal due to the short contact time inherent in the equipment design. Disclosed herein are techniques for inhibiting or impeding an amount of liquid from propagating along a wall of the mass transfer section using a surface feature. By inhibiting or impeding liquid propagation along a wall of the mass transfer section, a comparatively greater amount of solvent is retained in the interior volume of the mass transfer section and, consequently, remains available for reaction.

[0067] FIG. 3 is a side view of an embodiment of a single stage multiple co-current contactor bundle configuration **300**. The components of FIG. 3 are substantially the same as the corresponding components of FIG. 2 except as otherwise noted. The single stage multiple

co-current contactor bundle configuration **300** is generally contained within a vessel **302** which may form a unitary (single and/or common) pressure boundary for the compact contacting occurring therein. The vessel **302** generally contains a single stage bundle of substantially parallel separation units or compact contactors comprising contacting units **202a-202n**, also referred to herein as separation units. Those of skill in the art will understand that the number of contacting units **202a-202n** in the bundle of compact contactors may be optionally selected based on the desired design characteristics, including desired flow rate, separation unit diameter, etc., and could number from anywhere between one to 300 or more units. The use of the letter nomenclature (i.e., 'a', 'b', 'n', etc.) in conjunction with the numerical reference characters is for ease of reference only and is not limiting. For example, those of skill in the art will understand that an illustrated set of contacting units **202a-202n** may, in various embodiments, comprise two, four, five, twenty, or several hundred contacting units. The vessel **302** comprises an inlet tubesheet **304** having inlet nozzles **208a-208n** in the inlet section **220**. The inlet section **220** is configured to receive the natural gas stream **102** in a common inlet plenum through which the natural gas stream **102** may be distributed substantially equally across the contacting units **202a-202n**. The contacting units **202a-202n** may be of a suitable size depending on the design requirements. For example, the contacting units **202a-202n** may have an individual diameter from about 2 inches (in) (about 5 centimeters (cm)) to about 24 in (about 61 cm), or any range there between. The inlet tubesheet **304** is configured to receive the lean solvent stream **206** and pass the lean solvent stream **206** to the inlet nozzles **208a-208n**, where the lean solvent stream **206** may be atomized. In some embodiments, the lean solvent stream **206** originates from a glycol supply system (not depicted) and the lean solvent stream **206** comprises glycol. The inlet nozzles **208a-208n** may serve to entrain the atomized solvent stream in the natural gas stream **102**, and the mixed stream of atomized solvent and natural gas may be passed to the mass transfer section **222** where absorption occurs. Each contacting unit **202a-202n** has a recycle gas inlet **210a-210n** supplied by recycle gas collected and returned, e.g., from a common boot **316**. The boot **316** may be optionally included in low liquid rate applications to improve liquid rate flow control. As depicted, the boot **316** may have an internal vortex breaker **317** or other appropriate internals. For ease of viewing, the recycle gas supply lines for each of the recycle gas inlets **210a-210n** are not depicted. As will be understood by those of skill in the art, the recycle gas inlets **210a-210n** are optional, and recycle gas may additionally or alternatively be sent downstream in other embodiments. Rich solvent exiting the contacting units **202a-202n** via the rich solvent outlets **306a-306n** may drain

into a common liquid degassing section or common contaminated liquid collection plenum **312**. The plenum **312** may provide sufficient residence time for desired degasing, may reduce liquid surges coming with the natural gas stream **102**, and may provide liquid seal to a cyclonic separation occurring in a contacting section of the separation device **202a-202n**. The residence time provided by the plenum **312** can vary from 5 seconds to 5 minutes, depending on the operation of the process, or from 30 seconds to 1 minute in various embodiments. The vessel **302** contains a mist eliminator **314**, e.g., a wire mesh, vane pack plates, baffles, or other internal devices to reduce liquid droplet carry over from degassing gas leaving the liquid phase of rich solvent in the plenum **312**. The mist eliminator **314** may also serve as a momentum breaker for the rich solvent liquid exiting the separation device **202a-202n** to minimize aeration of the liquid. In embodiments installed in offshore facilities or floating facilities or otherwise subject to motion, the mist eliminator **314** may mitigate wave motion effects in the bottom portion of the vessel **302**. Each contacting unit **202a-202n** has a treated gas outlet **214a-214n** and a rich solvent outlet **306a-306n**. The vessel **302** has a vent **318** for expelling degassing gas, e.g., gas degassed from rich solvent collected in the plenum **312** that may be fed upstream or downstream of the multiple co-current contacting unit, depending on the process configuration. The treated gas outlets **214a-214n** couple to an outlet tubesheet **310**. The treated gas exiting the contacting units **202a-202n** via the treated gas outlets **214a-214n** may be referred to as the dehydrated and/or decontaminated natural gas stream **102**. The vessel **302** also contains level control ports **320a** and **320b** for coupling a level control system (not depicted) and controlling the amount of rich solvent **326**, e.g., a semi-lean solvent stream **108** or any of the partially-loaded gas treating solutions **118A-F**, exiting the boot **316**. Rich solvent **326** exiting the boot **316** may be sent to a regeneration system for treatment or combined with streams in other processes.

[0068] FIG. 4 is a schematic diagram of a co-current contactor **400**, e.g., any of the co-current contacting units **202a-202d** of FIGS. 2-3, having a coalescing section **402**. The components of FIG. 4 are substantially the same as the corresponding components of FIGS. 2-3 except as otherwise noted. The co-current contactor **400** includes inlet section **220** and coalescing section **402** comprising one or more coalescer(s) **404**, e.g., an electrostatic coalescer, a mechanical coalescer, etc. Suitable electrostatic coalescers are well known in the art and are commercially available from a variety of vendors. Suitable mechanical coalescers are well known in the art, and include baffles, spiral baffles or swirl vanes, plates, plate packs, gauze, wire mesh, random or structured packing, fiber media, etc. Suitable mechanical coalescer

materials include austenitic steel, aluminum, copper, plastic, polytetrafluoroethylene (PTFE) or PTFE coated materials, polyvinylidene fluoride or polyvinylidene difluoride (PVDF), etc. Coalescer material selection decisions may consider the wettability of the material with the dispersed fluid. Coalescing media selection decisions may consider the desired coalescing efficiency with consideration to fouling and/or solids present in the system. In some embodiments, a pre-coalescer (not pictured) may be included, e.g., a pre-coalescer inline electrostatic coalescence device disposed immediately after the mass transfer section **222** and prior to a separation section **224**.

[0069] In operation, the solvent entering the coalescing section **402** may have an average droplet size in a range from a first average droplet size to a second average droplet size, wherein the first average droplet size is any of: less than about 1 micrometer (μm), about 1 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, or about 750 μm, and wherein the second average droplet size is any of: about 2 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, about 750 μm, or about 1000 μm. After passing through the one or more coalescer(s) **404**, the solvent may have an average droplet size in a range from a first average droplet size to a second droplet size, wherein the first average droplet size is any of: about 1 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, about 750 μm, about 1000 μm, about 2500 μm, about 5000 μm, about 7500 μm, or about 9000 μm, and wherein the second average droplet size is any of: about 2 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, about 750 μm, about 1000 μm, about 2500 μm, about 5000 μm, about 7500 μm, or about 10000 μm. In embodiments with a pre-coalescer, after passing through the pre-coalescer, the solvent may have an average droplet size in a range from a first average droplet size to a second droplet size, wherein the first average droplet size is any of: about 1 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, about 750 μm, about 1000 μm, about 2500 μm, about 5000 μm, about 7500 μm, or about 9000 μm, and wherein the second average droplet size is any of: about 2 μm, about 5 μm, about 10 μm, about 25 μm, about 50 μm, about 75 μm, about 100 μm, about 250 μm, about 500 μm, about 750 μm, about 1000 μm, about 2500 μm, about 5000 μm, about 7500 μm, or about 10000 μm.

[0070] The average residence time in the coalescer for a gas-liquid contacting system may be in a range from a first average residence time to a second average residence time, wherein

the first average residence time is any of: less than about 0.01 seconds (s), about 0.01 s, about 0.1 s, or about 0.2 s, and wherein the second average residence time is any of: about 0.01 s, about 0.1 s, or about 0.2 s. The average residence time in the coalescer for a liquid-liquid contacting system may be in a range from a first average residence time to a second average residence time, wherein the first average residence time is any of: less than about 0.1 seconds (s), about 1 s, about 5 s, or about 10 s, and wherein the second average residence time is any of: about 1 s, about 5 s, about 10 s, or about 15 s.

[0071] While it will be apparent that the invention herein described is well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the invention is susceptible to modification, variation and change without departing from the spirit thereof.

CLAIMS

What is claimed is:

1. A method, comprising:

passing a fluid into a co-current contactor;

passing a solvent into the co-current contactor;

dividing the solvent into solvent droplets having a first average droplet size;

placing the fluid in contact with the solvent droplets to create a combined stream;

coalescing at least a portion of the solvent droplets to create solvent droplets having a second average droplet size, wherein the second average droplet size is greater than the first average droplet size; and

separating the fluid and the solvent.

2. The method of claim 1, wherein the first average droplet size is between less than about 1 micrometer (μm) and about 1000 μm.

3. The method of claim 1, wherein the second average droplet size is between about 2 micrometers (μm) and about 10000 μm.

4. The method of claim 1 or any of claims 2-3, wherein coalescing comprises electrically inducing coalescence, mechanically inducing coalescence, or both.

5. The method of claim 1 or any of claims 2-4, wherein coalescing takes between less than about .01 seconds and about 15 seconds of residence time.

6. The method of claim 1 or any of claims 2-5, wherein coalescing comprises passing the combined stream through a pre-coalescer to create solvent droplets having a third average droplet size, wherein the third average droplet size is greater than the first average droplet size and less than the second average droplet size.

7. The method of claim 1 or any of claims 2-6, wherein the fluid and the solvent are liquids.

8. A co-current contactor apparatus, comprising:

a first inlet configured to receive a first fluid stream proximate to a first end of the co-current contactor;

a second inlet configured to receive a second fluid stream proximate to the first end of the co-current contactor;

an inlet section configured to atomize at least a portion of the second fluid stream;

a mass transfer section configured to receive the first fluid stream and the atomized second fluid stream, and to pass the atomized second fluid stream and the the first fluid stream as a combined stream;

a coalescer configured receive the combined stream, and to increase an average droplet size of the atomized second fluid stream; and

a separator configured to separate at least a portion of the atomized second fluid stream from the combined stream.

9. The co-current contactor of claim 8, wherein the coalescer is an electrostatic coalescer.

10. The co-current contactor of claim 8 or claim 9, wherein the coalescer comprises a plurality of extended vanes.

11. The co-current contactor of claim 8 or any of claims 9-10, wherein the first fluid stream comprises a hydrocarbon and a contaminant, and wherein the second fluid stream comprises a solvent selected to absorb the contaminant.

12. The co-current contactor of claim 8 or any of claims 9-11, wherein the inlet section is configured to create an average droplet size between less than about 1 micrometer (μm) and about 1000 μm.

13. The co-current contactor of claim 8 or any of claims 9-12, wherein the coalescer is configured to create an average droplet size between about 2 micrometers (μm) and about 10000 μm.

14. The co-current contactor of claim 8 or any of claims 9-13, further comprising a pre-coalescer inline between the mass transfer section and the separator.

15. A co-current conacting system, comprising:

a plurality of co-current contactors coupled in a counter-current configuration, wherein each co-current contactor comprises:

a first inlet configured to receive a first fluid stream proximate to a first end of the co-current contactor;

a second inlet configured to receive a second fluid stream proximate to the first end of the co-current contactor;

an inlet section configured to atomize at least a portion of the second fluid stream;

a mass transfer section configured to receive the first fluid stream and the atomized second fluid stream, and to pass the atomized second fluid stream and the the first fluid stream as a combined stream;

a coalescer configured receive the combined stream, and to increase an average droplet size of the atomized second fluid stream; and

a separator configured to separate at least a portion of the atomized second fluid stream from the combined stream.

16. The co-current contacting system of claim 15, wherein the first fluid stream comprises a hydrocarbon, an acid gas, water, or a combination thereof, and wherein the second fluid stream comprises a solvent selected to absorb the acid gas or the water.

17. The co-current contacting system of claim 16 or claim 17, wherein the first fluid stream comprises hydrogen sulfide (H_2S), carbon dioxide (CO_2), or both.

18. The co-current contacting system of claim 15 or any of claims 16-17, wherein at least one coalescer comprises a pre-coalescer.

19. The co-current contacting system of claim 15 or any of claims 16-18, wherein at least one of the co-current contactors is a multiple co-current contacting bundle, and wherein the multiple co-current contacting bundle comprises a plurality of contacting units.

20. The co-current contacting of claim 19, wherein the contacting units have an individual diameter from about 5 cm to about 61 cm.

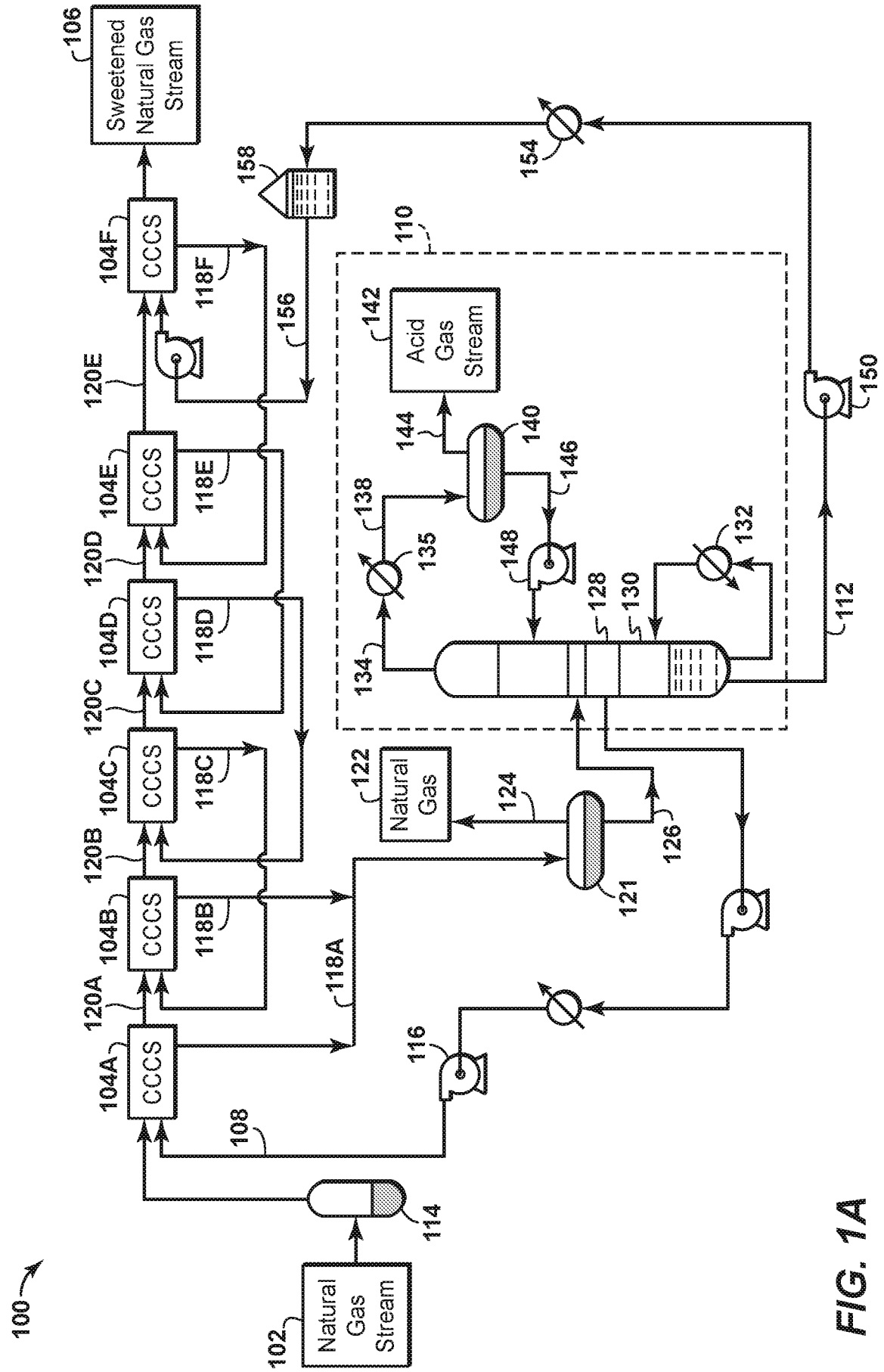

100
102
Natural Gas Stream
114
108
116
104A
CCCS
120A
104B
CCCS
120B
104C
CCCS
120C
104D
CCCS
120D
104E
CCCS
120E
104F
CCCS
106
Sweetened Natural Gas Stream
118A
118B
118C
118D
118E
118F
156
158
110
122
Natural Gas
124
121
126
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Acid Gas Stream
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148
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112
154
150

FIG. 1A

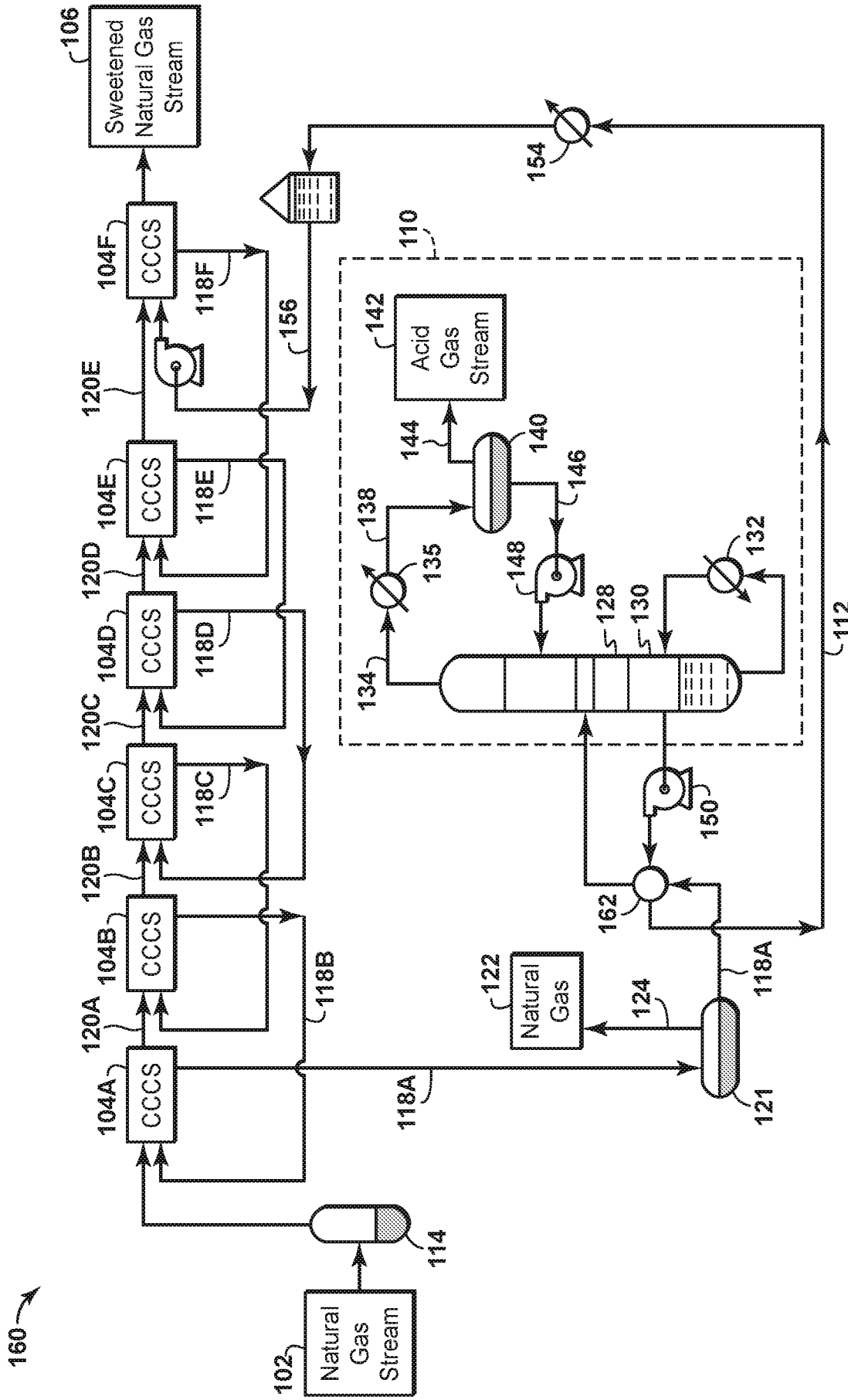

160
102
Natural Gas Stream
114
104A
104B
104C
104D
104E
104F
CCCS
120A
120B
120C
120D
120E
118A
118B
118C
118D
118E
118F
106
Sweetened Natural Gas Stream
156
154
110
142
Acid Gas Stream
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122
Natural Gas
124
121

FIG. 1B

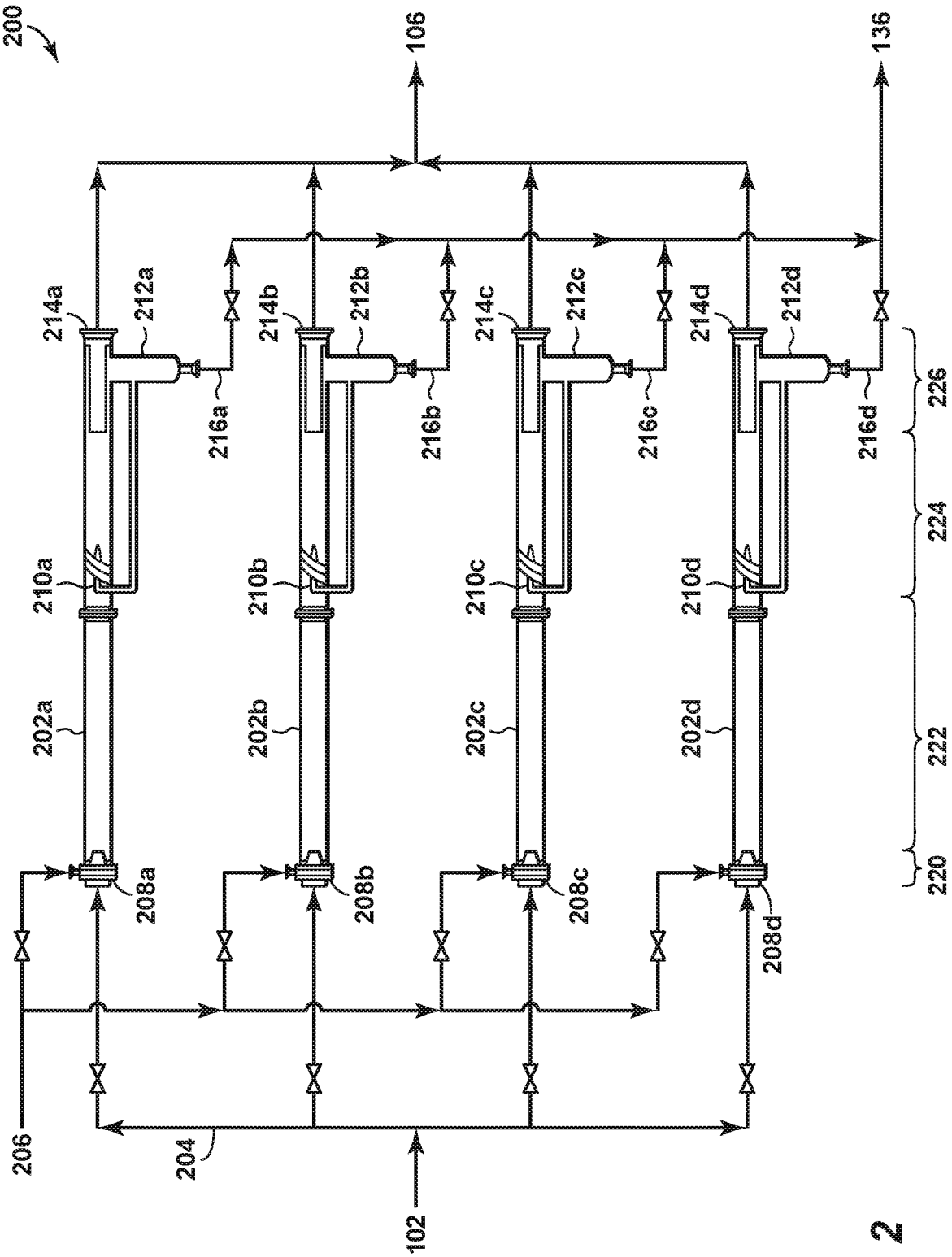

200
106
136
214a
212a
214b
212b
214c
212c
214d
212d
216a
216b
216c
216d
210a
210b
210c
210d
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208d
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220
222
224
226

FIG. 2

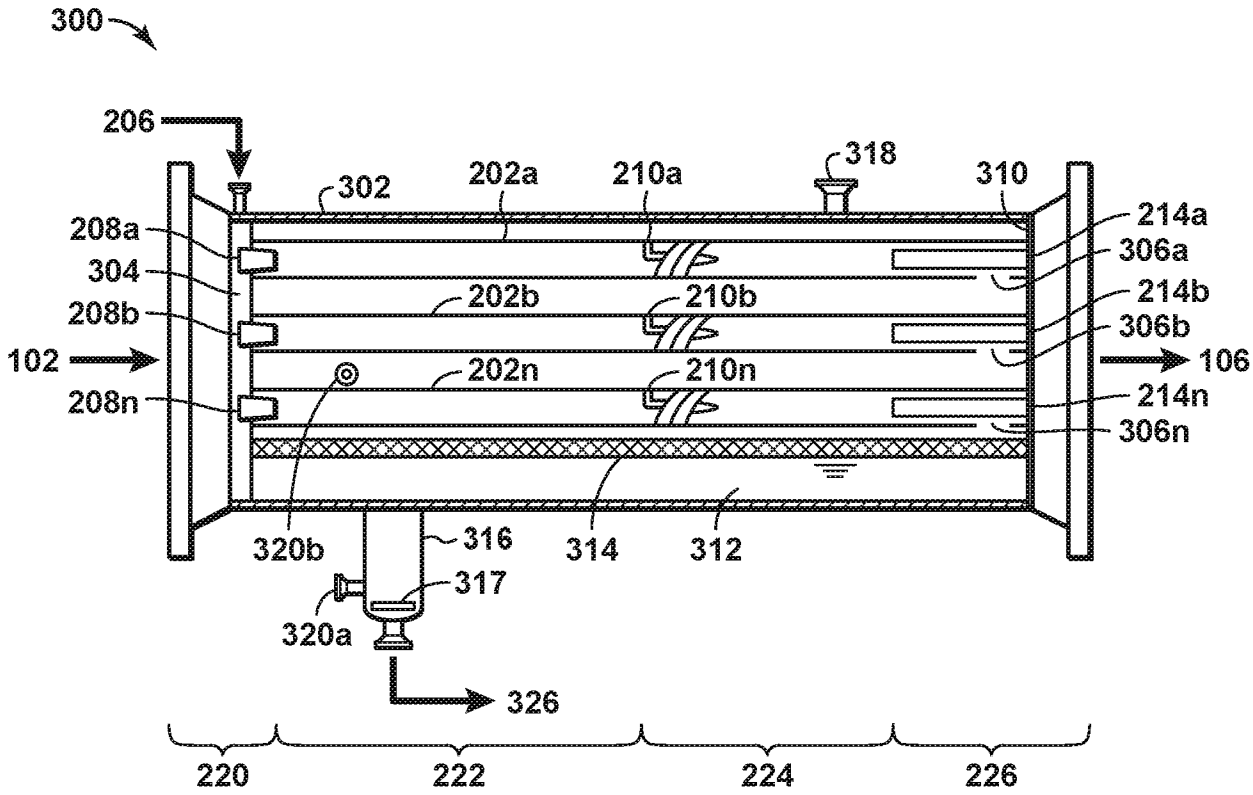

300
206
302
202a
210a
318
310
208a
304
208b
102
208n
202b
210b
202n
210n
214a
306a
214b
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306n
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314
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326
220
222
224
226

FIG. 3

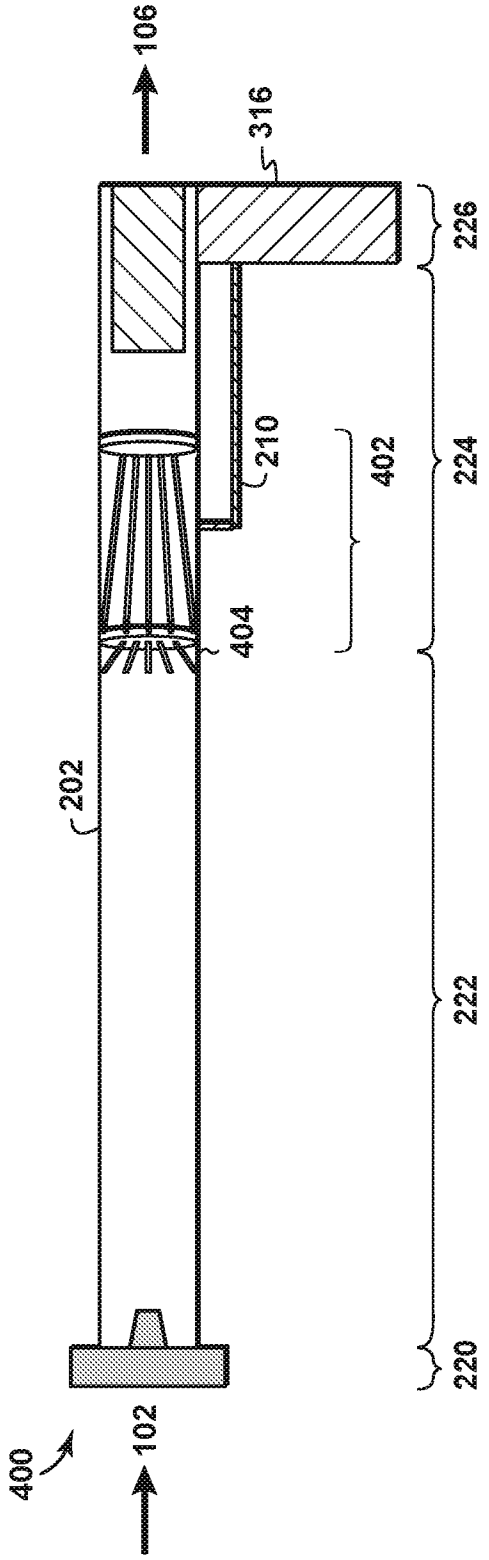


FIG. 4

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2016/015508

A. CLASSIFICATION OF SUBJECT MATTER
INV. B01F5/04 B01D53/18
ADD. B01F3/04 C10L3/10 C10G21/00

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)
B01F B01D C10L C10G

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	WO 2014/182563 A2 (EXXONMOBIL UPSTREAM RES CO [US]; CULLINANE J TIM [US]; GRAVE EDWARD J) 13 November 2014 (2014-11-13) paragraphs [0041], [0065]; claims; figures 6, 7a,7b,7c, 8 -----	1-20

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"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

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
18 April 2016	26/04/2016

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Serra, Renato

1

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/US2016/015508

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
WO 2014182563 A2	13-11-2014	AU 2014263002 A1	29-10-2015
		CA 2907953 A1	13-11-2014
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