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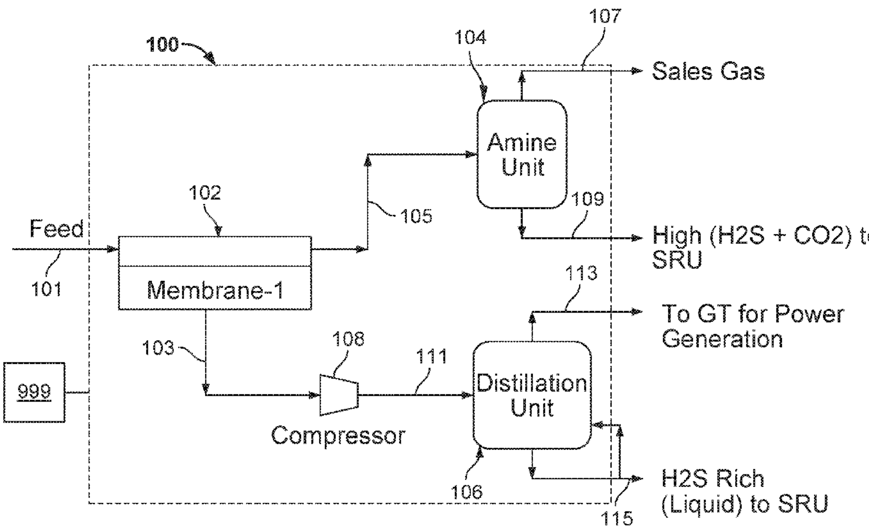

FIG. 1A

(57) Abstract: Techniques for treating a natural gas feed stream include receiving a natural gas feed stream that includes one or more acid gases, one or more hydrocarbon fluids, and one or more non-hydrocarbon fluids; circulating the natural gas feed stream to a membrane module; separating, with the membrane module, at least a portion of the one or more acid gases into a permeate stream and at least a portion of the one or more hydrocarbon fluids into a reject stream; circulating the permeate stream to a distillation unit; and separating, in the distillation unit, the one or more acid gases from the one or more non-hydrocarbon fluids.

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[Continued on next page]

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METHODS AND APPARATUSES FOR TREATING RAW NATURAL GAS COMPRISING A MEMBRANE UNIT AND A DISTILLATION

CLAIM OF PRIORITY

[0001] This application claims priority to U.S. Provisional Patent Application No. 62/521,654, filed on June 19, 2017, and U.S. Utility Patent Application No. 16/007,585, filed on June 13, 2018, the entire contents of which are incorporated by reference herein.

TECHNICAL FIELD

[0002] The present disclosure relates to systems and methods for treating raw natural gas and, more particularly, treating raw natural gas to, for example, separate acid gases, helium, or both.

BACKGROUND

[0003] Natural gas production can often include sour, or acid, gas, which may difficult to treat with existing technologies such as an amine sweetening unit. For instance, for raw natural gas feeds that include a particularly high acid gas content, amine may degrade quickly and generate heat stable salts. Such salts are corrosive and also may cause foaming. Furthermore, raw natural gas feeds that include such high acid gas contents may require more energy for solvent circulation and regeneration (for example, reboiling).

SUMMARY

[0004] In a general implementation, a method of treating a natural gas feed stream includes receiving a natural gas feed stream that includes one or more acid gases, one or more hydrocarbon fluids, and one or more non-hydrocarbon fluids; circulating the natural gas feed stream to a membrane module; separating, with the membrane module, at least a portion of the one or more acid gases into a permeate stream and at least a portion of the one or more hydrocarbon fluids into a reject stream; circulating the permeate stream to a distillation unit; and separating, in the distillation unit, the one or more acid gases from the one or more non-hydrocarbon fluids.

[0005] An aspect combinable with the general implementation further includes circulating the permeate stream through a compressor fluidly positioned between the membrane module and the distillation unit; and circulating the reject stream to an amine unit.

[0006] Another aspect combinable with any one of the previous aspects further includes separating the one or more hydrocarbon fluids in the reject stream from another portion of the one or more acid gases in the amine unit; and circulating the one or more hydrocarbon fluids to a sales gas pipeline, and circulating the other portion of the one or more acid gases to a sulfur recovery unit (SRU).

[0007] In another aspect combinable with any one of the previous aspects, the membrane module includes an acid gas selective membrane that includes at least one of a poly-imide (PI) membrane, a cellulose acetate (CA) membrane, or an amorphous perfluoropolymer membrane.

[0008] In another aspect combinable with any one of the previous aspects, the distillation unit includes a bottom output that outputs the portion of the one or more acid gases and an overhead output that outputs the one or more non-hydrocarbon fluids.

[0009] Another aspect combinable with any one of the previous aspects further includes circulating the one or more non-hydrocarbon fluids to a power generation unit, and circulating the portion of the one or more acid gases to the SRU; and circulating the one or more non-hydrocarbon fluids to a second membrane module fluidly coupled between the overhead output and the amine unit.

[0010] In another aspect combinable with any one of the previous aspects, the second membrane module includes another acid gas selective membrane that includes at least one of a PI membrane, a CA membrane, or an amorphous perfluoropolymer membrane.

[0011] Another aspect combinable with any one of the previous aspects further includes separating, with the second membrane module, another portion of the one or more acid gases entrained in the one or more non-hydrocarbon fluids; circulating the separated portion of the one or more acid gases to the SRU, and circulating the one or more non-hydrocarbon fluids to at least one of the amine unit or the power generation unit; and circulating the separated one or more non-hydrocarbon fluids to a third membrane module.

[0012] In another aspect combinable with any one of the previous aspects, the third membrane module includes a helium selective membrane that includes a PI helium selective membrane.

[0013] Another aspect combinable with any one of the previous aspects further includes separating a helium fluid from the one or more non-hydrocarbon fluids with the third membrane module; and recovering the separated helium fluid in a helium recovery unit that is fluidly coupled to the third membrane module.

[0014] In another aspect combinable with any one of the previous aspects, the distillation unit includes a hydrogen sulfide (H_2S) distillation unit.

[0015] Another aspect combinable with any one of the previous aspects further includes separating, in the H_2S distillation unit, a stream of H_2S from the one or more acid gases; and circulating the stream of H_2S to the SRU, and circulating an H_2S-lean stream of the one or more acid gases to another distillation unit.

[0016] In another aspect combinable with any one of the previous aspects, the other distillation unit includes a carbon dioxide (CO_2) distillation unit.

[0017] Another aspect combinable with any one of the previous aspects further includes separating, in the other distillation unit, a stream of CO_2 from the H_2S-lean stream; circulating the stream of CO_2 away from the other distillation unit, and circulating a CO_2-lean stream from the other distillation unit to a second membrane module; separating, in the second membrane module, at least a portion of a helium fluid from the CO_2-lean stream; circulating the portion of the helium fluid to a third membrane module, and circulating a helium-lean stream from the second membrane module; and separating another portion of the helium fluid, in the third membrane module.

[0018] In another aspect combinable with any one of the previous aspects, the one or more acid gases includes at least one of H_2S or CO_2.

[0019] In another general implementation, a natural gas processing system includes a first membrane module positioned to receive a natural gas feed stream that includes one or more acid gases, one or more hydrocarbon fluids, and one or more non-hydrocarbon fluids, the first membrane module configured to separate at least a portion of the one or more acid gases into a permeate stream and at least a portion of the one or more hydrocarbon fluids into a reject stream; a distillation unit in fluid communication with the first membrane; and a control system configured to perform operations. The operations include circulating the natural gas feed stream to the first membrane module; circulating the permeate stream separated by the first membrane module to the distillation unit; and operating the distillation unit to separate, in the distillation unit, the one or more acid gases from the one or more non-hydrocarbon fluids.

[0020] In an aspect combinable with the general implementation, the control system is configured to perform operations further including circulating the permeate stream through a compressor fluidly positioned between the membrane module and the distillation unit; and circulating the reject stream to an amine unit.

[0021] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including separating the one or more hydrocarbon fluids in the reject stream from another portion of the one or more acid gases in the amine unit; circulating the one or more hydrocarbon fluids to a sales gas pipeline; and circulating the other portion of the one or more acid gases to a sulfur recovery unit (SRU).

[0022] In another aspect combinable with any one of the previous aspects, the first membrane module includes an acid gas selective membrane that includes at least one of a poly-imide (PI) membrane, a cellulose acetate (CA) membrane, or an amorphous perfluoropolymer membrane.

[0023] In another aspect combinable with any one of the previous aspects, the distillation unit includes a bottom output and an overhead output.

[0024] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including circulating the portion of the one or more acid gases from the bottom output; circulating the one or more non-hydrocarbon fluids from the overhead output; circulating the one or more non-hydrocarbon fluids to a power generation unit; circulating the portion of the one or more acid gases to the SRU; and circulating the one or more non-hydrocarbon fluids to a second membrane module fluidly coupled between the overhead output and the amine unit.

[0025] In another aspect combinable with any one of the previous aspects, the second membrane module includes another acid gas selective membrane that includes at least one of a PI membrane, a CA membrane, or an amorphous perfluoropolymer membrane.

[0026] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including operating the second membrane module to separate another portion of the one or more acid gases entrained in the one or more non-hydrocarbon fluids; circulating the separated portion of the one or more acid gases to the SRU; circulating the one or more non-hydrocarbon fluids to at least one of the amine unit or the power generation unit; and circulating the separated one or more non-hydrocarbon fluids to a third membrane module.

[0027] In another aspect combinable with any one of the previous aspects, the third membrane module includes a helium selective membrane that includes a PI helium selective membrane.

[0028] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including operating the third membrane module to separate a helium fluid from the one or more non-hydrocarbon fluids with the third membrane module; and recovering the separated helium fluid in a helium recovery unit that is fluidly coupled to the third membrane module.

[0029] In another aspect combinable with any one of the previous aspects, the distillation unit includes a hydrogen sulfide (H_2S) distillation unit.

[0030] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including operating the H_2S distillation unit to separate a stream of H_2S from the one or more acid gases; and circulating the stream of H_2S to the SRU; and circulating an H_2S-lean stream of the one or more acid gases to another distillation unit.

[0031] In another aspect combinable with any one of the previous aspects, the other distillation unit includes a carbon dioxide (CO_2) distillation unit.

[0032] In another aspect combinable with any one of the previous aspects, the control system is configured to perform operations further including operating the other distillation unit to separate a stream of CO_2 from the H_2S-lean stream; circulating the stream of CO_2 away from the other distillation unit; circulating a CO_2-lean stream from the other distillation unit to the second membrane module; operating a second membrane module to separate at least a portion of a helium fluid from the CO_2-lean stream; circulating the portion of the helium fluid to a third membrane module; circulating a helium-lean stream from the second membrane module; and operating the third membrane module to separate another portion of the helium fluid.

[0033] In another aspect combinable with any one of the previous aspects, the one or more acid gases includes at least one of H_2S or CO_2.

[0034] Implementations according to the present disclosure may include one or more of the following features. For example, implementations according to the present disclosure may facilitate the separation of acid gases (for example, hydrogen sulfide (H_2S) and carbon dioxide (CO_2)) from a raw natural gas feed stream while minimizing slippage of heavy hydrocarbons (HHC), a loss of methane, and energy use. As another example, implementations according to the present disclosure may minimize the HHC content of a feed of a reaction furnace of a sulfur recovery unit (SRU). Also, implementations according to the present disclosure may upgrade sour gas through a utilization of membranes of different selectivity, which can be advantageously utilized upstream of one or more distillation units to concentrate the acid gas percentage being fed to the distillation unit in order to maximize separation efficiency. As another example, implementations according to the present disclosure may increase an efficiency of a Claus unit through higher H_2S concentration in feed to an SRU and smoother operability of the SRU. Further, implementations according to the present disclosure may avoid or help avoid Carsul formation due to an absence or reduction of HHC in a feed to the SRU. Further, implementations according to the present disclosure may route rich H_2S from the distillation unit to a reservoir for re-injection. Also, implementations according to the present disclosure may allow for the recovery of HHC while still separating acid gases, unlike conventional techniques.

[0035] Implementations according to the present disclosure may also include one or more of the following features. For example, implementations according to the present disclosure may recovery helium from sour natural gas that can be further monetized after enrichment steps. For example, helium can be further concentrated and recovered by membranes and a helium recovery unit. As another example, implementations according to the present disclosure may reduce acid gases to an amine unit while preventing HHC to be in the bottoms of distillations. Thus, bottoms of distillation units can be directly sent to a reaction furnace of an SRU with a reduced risk of contamination of catalytic beds. As another example, additional revenues may be realized by recovery of HHC according to the described implementations. Further, present implementations may avoid circulating the HHC to the SRU or for reinjection.

[0036] The details of one or more implementations of the subject matter described in this disclosure are set forth in the accompanying drawings and the description. Other features, aspects, and advantages of the subject matter will become apparent from the description, the drawings, and the claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0037] FIG. 1A shows a schematic illustration of an example implementation of a hybrid raw natural gas treatment system and process that uses a membrane and a distillation unit to separate acid gases from natural gas according to the present disclosure.

[0038] FIGS. 1B-1C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more poly-imide (PI) membranes.

[0039] FIGS. 1D-1E illustrate results of another simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more cellulose acetate (CA) membranes.

[0040] FIGS. 1F-1G illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more Hyflon AD-80 (amorphous perfluoropolymers) membranes.

[0041] FIG. 2A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system and process that uses two membranes and a distillation unit to separate acid gases from natural gas according to the present disclosure.

[0042] FIGS. 2B-2C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 2A.

[0043] FIG. 3A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system and process that uses two membranes and a distillation unit to separate acid gases from natural gas according to the present disclosure.

[0044] FIGS. 3B-3C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 3A.

[0045] FIG. 4A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system and process that uses two membranes and a distillation unit to separate acid gases from natural gas, as well as a membrane and a helium recovery unit to capture helium from natural gas according to the present disclosure.

[0046] FIGS. 4B-4D illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 4A.

[0047] FIG. 5A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system and process that uses one or more membranes and cascading distillation units to separate acid gases from natural gas and capture helium according to the present disclosure.

[0048] FIGS. 5B-5Q illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 5A.

DETAILED DESCRIPTION

[0049] The present disclosure describes example implementations of a raw natural gas treatment system and process in which membrane and distillation processes are combined to minimize slippage of heavy hydrocarbons (HHC) while separating acid gases (for example, H_2S and CO_2) from a raw natural gas stream. In some aspects, acid gas selective membranes are implemented for bulk removal of acid gases from raw natural gas. The output of implementing the membrane system and process may include two streams: a reject stream that has a relatively high concentration of HHC and a relatively low concentration of acid gases, and a permeate stream that has a relatively low concentration of HHC and a relatively high concentration of acid gases. The reject stream may be routed to an amine unit and subsequently to a refrigeration unit to recover the HHC after gas sweetening and dehydration. The permeate stream may be compressed and circulated to one or more a distillation units where acid gas removal is implemented leaving other gases (for example, methane, helium, and nitrogen) in an overhead of the distillation column. Thus, a membrane system and process and a distillation system and process may be combined to generate an acid gas stream depleted in HHC. The acid gases can be separated from the acid gas stream by distillation, while the HHC can be recovered using refrigeration after gas sweetening and dehydration.

[0050] In some aspects, by combining membrane and distillation sub-processes in the hybrid raw natural gas treatment system and process, lowering acid gases in a stream that enters an amine unit may also minimize HHC loss in the distillation bottom stream, which in turn may reduce HHC in the feed of a sulfur recovery unit (SRU). Further, in some aspects, helium in the stream may be concentrated in the distillation unit overhead, which may be economically recovered as pure helium in a dedicated unit after enrichment steps. In some aspects, an outlet temperature of the one or more distillation units may be about -30°C, which may enable higher selectivity for the membrane(s) to separate compounds from the overhead of the distillation column.

[0051] In example implementations, two membrane stages may be used to reduce a content of the acid gases in the raw natural gas stream. Further, implementations according to the present disclosure may include a reduced temperature of a stream circulated to a second stage membrane section to provide for increased selectivity for the second stage or subsequent membrane section. Additionally, the example implementations of the raw natural gas treatment system and process may include the recovery and enrichment of helium in the overhead of the distillation unit(s). Also, such implementations may generate an increased nitrogen content than the feed in the overhead of the distillation unit.

[0052] In some aspects, bulk removal of acid gas from raw natural gas can be performed with the help of acid gas selective membrane. For example, example processes may include one or multiple stages of membrane separation, as well as one or more distillation stages. In some aspects, glassy polymeric membranes are utilized to separate raw natural gas components from a high pressure acid gas stream into two streams: one at high pressure stream (or reject) and one at low pressure stream (or permeate). For glassy polymers, small molecules are faster than bigger molecules to permeate; separation is mainly due to size of molecules. Hence, helium, water, hydrogen sulfide, carbon dioxide, and nitrogen will permeate faster than C2+. Therefore, the permeate gas stream, depleted in HHC, can be routed to a distillation unit, where acid gas removal is carried out, while methane, helium and nitrogen remain in the overhead of the distillation unit.

[0053] In example implementations, the permeate stream (low pressure stream) is concentrated in acid gas while depleted in HHC so it can be liquefied without significant loss of HHC. A reject stream (high pressure stream) is depleted in acid gas. This high pressure stream can be treated in an existing or new high pressure amine unit. Subsequently, HHC can be recovered from this high pressure stream with the help of a refrigeration unit after gas sweetening and dehydration steps. The permeate stream at low pressure (for example, between 50-250 pounds per square inch (psi)), which may contain relatively small amounts of HHC, can be efficiently treated in a high pressure distillation column to concentrate acid gas in the bottom and recover methane and other gases from the overhead. Acid gases and water are concentrated in the bottom of the distillation column and can be routed to the reaction furnace of the SRU. The overhead product, which may be mainly methane, could be used as fuel or directed to a master gas system after a final sweetening step if necessary depending on the distillation performance and gas composition.

[0054] In some aspects, the example processes may produce an acid gas stream depleted in HHC that can be directly routed to the reaction furnace of the SRU and avoid the loss of valuable HHC. In contrast to conventional techniques, the example implementations may facilitate a large fraction of acid gases being separated from a natural gas feed with minimal loss of HHC. Further, implementations that include helium recovery, for example, with helium selective membrane(s) installed downstream of one or more distillation units such membranes receive a gas containing a much lower content of acid gas and HHC, which results in longer lifetime and improved separation performance of the membranes.

[0055] FIG. 1A shows a schematic illustration of an example implementation of a hybrid raw natural gas treatment system 100 that uses a membrane and a distillation unit to separate acid gas from natural gas. In this illustrated implementation, the system 100 includes a membrane 102 that receives a raw natural gas feed stream 101. In some aspects, the natural gas feed stream 101 is at a flow rate of between 5 and 500 million standard cubic feet per day (MMscfd). The membrane 102 separates the natural gas feed stream 101 into a permeate stream 103 that flows through a compressor 108 to a distillation unit 106 and a reject stream 105 that flows to an amine unit 104. The permeate stream 103 has a relatively low concentration of HHC and a relatively high concentration of acid gases compared to the reject stream 105, which has a relatively low concentration of acid gases and a relatively high concentration of HHC. The membrane 102 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the membrane 102 may be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the membrane 102).

[0056] The permeate stream 103, which may be at a lower pressure than the reject stream 105, is compressed into a compressed permeate stream 111 that is circulated to the distillation unit 106, in which the acid gases (and possibly a small portion of HHC not separated in the membrane 102) are separated in a bottom stream 115 of the distillation unit 106 from other gases (for example, helium (He), water (H_2O) and nitrogen (N_2)) in an overhead stream 113 of the unit 106. The other gases may be circulated to the gas turbine (GT) for power generation, while the acid gases (and portion of HHC) may be circulated to the SRU.

[0057] The reject stream 105, which may be at a higher pressure than the permeate stream 103, is circulated to the amine unit 104, in which sales gas 107 is separated from the remaining acid gases 109 in the reject stream 105. The separated acid gases 109 may also be circulated to the SRU. In some aspects, the sales gas 107 may be circulated to a refrigeration unit for recovery of the HHC.

[0058] FIGS. 1B-1C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more poly-imide (PI) membranes. The simulation from which the results shown in FIGS. 1B-1C (as well as the other simulations shown and described in the present disclosure) were performed using PRO II and HYSIS modeling software, as well as data available for the particular types of membranes and distillation units described in the disclosure. FIGS. 1B-1C show simulations of the system 100 in which the membrane 102 is a PI membrane, as well as mass balance (dry basis) for the system 100. FIGS. 1B-1C also show data regarding the membrane 102, permeation constant for the membrane 102, the acid gases removed by the membrane 102, and the power production using the overhead stream from distillation unit 106.

[0059] FIGS. 1D-1E illustrate results of another simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more cellulose acetate (CA) membranes. FIGS. 1D-1E show simulations of the system 100 in which the membrane 102 is the CA membrane, as well as mass balance (dry basis) for the system 100. FIGS. 1D-1E also show data regarding the membrane 102, permeation constant for the membrane 102, the acid gases removed by the membrane 102, and the power production using the overhead stream from distillation unit 106.

[0060] FIGS. 1F-1G illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 1A that uses one or more Hyflon AD-80 (amorphous perfluoropolymers) membranes. FIGS. 1F-1G show simulations of the system 100 in which the membrane 102 is the Hyflon AD-80 membrane, as well as mass balance (dry basis) for the system 100. FIGS. 1F-1G also show data regarding the membrane 102, permeation constant for the membrane 102, the acid gases removed by the membrane 102, and the power production using the overhead stream from distillation unit 106.

[0061] FIG. 2A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system 200 that uses two membranes and a distillation unit to separate acid gases from natural gas. In this illustrated implementation, the system 200 includes a first membrane 202 that receives a raw natural gas feed stream 201. In some aspects, the natural gas feed stream 201 is at a flow rate of between 5 and 500 MMscfd. The first membrane 202 separates the natural gas feed stream 201 into a permeate stream 203 that flows through a compressor 210 to a distillation unit 204 and a reject stream 205 that flows to an amine unit 208. The permeate stream 203 has a relatively low concentration of HHC and a relatively high concentration of acid gases compared to the reject stream 205, which has a relatively low concentration of acid gases and a relatively high concentration of HHC. The first membrane 202 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the first membrane 202 may be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the membrane 202).

[0062] The permeate stream 203, which may be at a lower pressure than the reject stream 205, is compressed into a compressed permeate stream 211 and circulated to the distillation unit 204, in which the acid gases (and possibly a small portion of HHC not separated in the first membrane 202) are separated in a bottom stream 215 of the distillation unit 204 from other gases (for example, He, H_2O andN_2) in an overhead stream 213 of the unit 204.

[0063] As illustrated, the system 200 includes a second membrane 206 fluidly coupled to the overhead stream 213 of the distillation unit 204. The second membrane 206 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the second membrane 206 may also be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the second membrane 206). Thus, the second membrane 206 may further separate acid gases 219 from the overhead stream 213 (for example, from the He, H_2O, and N_2) and route the further separated acid gases 219 to the output of the bottom stream 215 of the distillation unit. The other gases 217 may be circulated to the amine unit 208 (to join the reject stream 205), while the acid gases from the distillation unit 204 and the second membrane 206 (and portion of HHC) may be circulated to the SRU.

[0064] The reject stream 205, which may be at a higher pressure than the permeate stream 203, is circulated to the amine unit 208, in which sales gas 207 is separated from the remaining acid gases 209 in the reject stream 205 (combined with the other gases 217). The separated acid gases 209 may also be circulated to the SRU. In some aspects, the sales gas 207 may be circulated to a refrigeration unit for recovery of the HHC.

[0065] FIGS. 2B-2C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 2A. FIGS. 2B-2C show simulations of the system 200 in which the first membrane 202 is an H_2S and CO_2 selective PI membrane and the second membrane 206 is an H_2S and CO_2 selective PEBAX membrane. FIGS. 2B-2C show simulations of the system 200 for mass balance (dry basis) as well as data regarding the membranes 202 and 206, permeation constant for the membrane 202, the acid gases removed by the membrane 202, and the power production using the overhead stream from distillation unit 204.

[0066] FIG. 3A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system 300 that uses two membranes and a distillation unit to separate acid gases from natural gas. In this illustrated implementation, the system 300 includes a first membrane 302 that receives a raw natural gas feed stream 301. In some aspects, the natural gas feed stream 301 is at a flow rate of between 5 and 500 MMscfd. The first membrane 302 separates the natural gas feed stream 301 into a permeate stream 303 that flows through a compressor 310 to a distillation unit 304 and a reject stream 305 that flows to an amine unit 308. The permeate stream 303 has a relatively low concentration of HHC and a relatively high concentration of acid gases compared to the reject stream 305, which has a relatively low concentration of acid gases and a relatively high concentration of HHC. The first membrane 302 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the first membrane 302 may be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the first membrane 302).

[0067] The permeate stream 303, which may be at a lower pressure than the reject stream 305, is compressed into a compressed permeate stream 311 and circulated to the distillation unit 304, in which the acid gases (and possibly a small portion of HHC not separated in the first membrane 302) are separated in a bottom stream 315 of the distillation unit 304 from other gases (for example, He, H_2O and N_2) in an overhead stream 313 of the unit 304.

[0068] As illustrated, the system 300 includes a second membrane 306 fluidly coupled to the overhead stream 313 of the distillation unit 304. The second membrane 306 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the second membrane 306 may further separate acid gases 319 from the overhead stream 313 (for example, from the He, H_2O, and N_2) and route the further separated acid gases 319 to the output of the bottom stream 315 of the distillation unit. The other gases 317 may be circulated to the amine unit 308 or to the GT for power generation (or both), while the acid gases (combined 319 and 315) from the distillation unit 304 and the second membrane 306 (and portion of HHC) may be circulated to the SRU.

[0069] The reject stream 305, which may be at a higher pressure than the permeate stream 303, is circulated to the amine unit 308, in which sales gas 307 is separated from the remaining acid gases 309 in the reject stream 305. The separated acid gases 309 may also be circulated to the SRU. In some aspects, the sales gas 307 may be circulated to a refrigeration unit for recovery of the HHC.

[0070] FIGS. 3B-3C illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 3A. FIGS. 3B-3C show simulations of the system 300 in which the first membrane 302 is an H_2S and CO_2 selective PI membrane and the second membrane 306 is an H_2S and CO_2 selective PEBAX membrane. FIGS. 3B-3C show simulations of the system 300 for mass balance (dry basis) as well as data regarding the membranes 302 and 306, permeation constant for the membrane 302, the acid gases removed by the membrane 302, and the power production using the other gases from the second membrane 306.

[0071] FIG. 4A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system 400 that uses two membranes and a distillation unit to separate acid gases from natural gas, as well as a membrane and a helium recovery unit to capture helium from natural gas. In this illustrated implementation, the system 400 includes a first membrane 402 that receives a raw natural gas feed stream 401. In some aspects, the natural gas feed stream 401 is at a flow rate of between 5 and 500 MMscfd. The first membrane 402 separates the natural gas feed stream 401 into a permeate stream 403 that flows through a compressor 414 to a distillation unit 404 and a reject stream 405 that flows to an amine unit 412. The permeate stream 403 has a relatively low concentration of HHC and a relatively high concentration of acid gases compared to the reject stream 405, which has a relatively low concentration of acid gases and a relatively high concentration of HHC. The first membrane 402 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the first membrane 402 may be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the first membrane 402).

[0072] The permeate stream 403, which may be at a lower pressure than the reject stream 405, is compressed into a compressed permeate stream 411 and circulated to the distillation unit 404, in which the acid gases (and possibly a small portion of HHC not separated in the first membrane 402) are separated in a bottom stream 415 of the distillation unit 404 from other gases (for example, He, H_2O and N_2) in an overhead stream 413 of the unit 404.

[0073] As illustrated, the system 400 includes a second membrane 406 fluidly coupled to the overhead stream 413 of the distillation unit 404. The second membrane 406 may be or include, for example, an H_2S and CO_2 selective PEBAX membrane. Thus, the second membrane 406 may further separate acid gases 419 from the overhead stream 413 (for example, from the He, H_2O and N_2) and route the further separated acid gases 419 to the output of the bottom stream 415 of the distillation unit 404.

[0074] In this example implementation, the other gases 421 may be circulated to a third membrane 408, in which helium (He) 423 is separated from the other gases 421 (for example, separated from H_2O, N_2). In this example, the third membrane 408 may be or include a PI helium selective membrane. The separated He 423 is routed to a helium recovery unit 410 from which the He 423 may be enriched for economic efficiencies into an enriched He stream 425.

[0075] The other gases 417 from which the He 423 is separated in the third membrane 408 may be routed from the third membrane 408 to the amine unit 412, while the acid gases (combined 415 and 419) from the distillation unit 404 and the second membrane 406 (and portion of HHC) may be circulated to the SRU. The reject stream 405, which may be at a higher pressure than the permeate stream 403, is circulated to the amine unit 412, in which sales gas 407 is separated from the remaining acid gases 409 in the combined reject stream 405 and gases stream 417. The separated acid gases 409 may also be circulated to the SRU. In some aspects, the sales gas 407 may be circulated to a refrigeration unit for recovery of the HHC.

[0076] FIGS. 4B-4D illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 4A. FIGS. 4B-4D show simulations of the system 400 in which the first membrane 402 is an H_2S and CO_2 selective PI membrane, the second membrane 406 is an H_2S and CO_2 selective PEBAX membrane, and the third membrane is a PI helium selective membrane. FIGS. 4B-4D show simulations of the system 400 for mass balance (dry basis) as well as data regarding the membranes 402, 406, and 408, permeation constant for the membrane 402, and the acid gases removed by the membrane 402.

[0077] As further shown in FIG. 4C, power production using the distillation stream may be realized in the example implementations of the system 400. For example, although not specifically shown in FIG. 4A, the gases separated from the helium in the third membrane 408 may be routed to produce power.

[0078] FIG. 5A shows a schematic illustration of another example implementation of a hybrid raw natural gas treatment system 500 that uses three membranes and two cascading distillation units to separate acid gases from natural gas and capture helium. In this illustrated implementation, the system 500 includes a first membrane 502 that receives a raw natural gas feed stream 501. In some aspects, the natural gas feed stream 501 is at a flow rate of between 5 and 500 MMscfd. The first membrane 502 separates the natural gas feed stream 501 into a permeate stream 503 that flows through a compressor 514 to a distillation unit 504 and a reject stream 505 that flows to an amine unit 512. The permeate stream 503 has a relatively low concentration of HHC and a relatively high concentration of acid gases compared to the reject stream 505, which has a relatively low concentration of acid gases and a relatively high concentration of HHC. The first membrane 502 may be or include, for example, a PI membrane, a CA membrane, or a Hyflon AD-80 (amorphous perfluoropolymers) membrane. Thus, the first membrane 502 may be selected to ensure that acid gases (for example, H_2S and CO_2) are separated from HHC (for example, due to a material of the first membrane 502).

[0079] The permeate stream 503, which may be at a lower pressure than the reject stream 505, is compressed and a compressed permeate stream 511 is circulated to the distillation unit 504. In this example, the distillation unit 504 is an H_2S selective distillation unit, in that H_2S is routed to a bottom stream 515 of the distillation unit 504 in an H_2S-rich stream, which is routed to the SRU. An overhead stream 513 of the distillation unit 504, which may contain acid and other gases, including CO_2, He, H_2O and N_2 (and is an H_2S-lean stream), is routed to distillation unit 506.

[0080] In this example, the distillation unit 506 is a CO_2 selective distillation unit, in that CO_2 is routed to the bottom stream 519 of the distillation unit 506 in a CO_2-rich stream. An overhead stream 517 of the distillation unit 506, which may contain other gases such as helium (He), H_2O and N_2 (and is a CO_2-lean stream), is routed to a second membrane 508. In this example, the second membrane 508 may be or include a PI helium selective membrane. The separated He 523 (in a He-rich stream) is routed through another compressor 516 and to a third membrane 510. A He-lean stream 521 is routed away from the second membrane 508 and may contain, for example, H_2O, N_2, and other gases.

[0081] In this example implementation, a compressed He-rich stream 529 is circulated to the third membrane 510. Like the second membrane 508, the third membrane 510 may be or include a PI helium selective membrane, which separates the incoming stream 529 from the second membrane 508 into a He-rich stream 531 (which can be enriched or recirculated to the third membrane 510) and a He-lean stream 525.

[0082] The reject stream 505, which may be at a higher pressure than the permeate stream 503, is circulated to the amine unit 512, in which sales gas 507 is separated from the remaining acid gases 509 in the reject stream 505. The separated acid gases 509 may be circulated to the SRU. In some aspects, the sales gas 507 may be circulated to a refrigeration unit for recovery of the HHC.

[0083] FIGS. 5B-5Q illustrate results of a simulation of the hybrid raw natural gas treatment system and process shown in FIG. 5A. FIGS. 5B-5Q show simulations of the system 500 in which the first membrane 502 is an H_2S and CO_2 selective membrane and the second and third membranes 508 and 510 are PI helium selective membranes. FIGS. 5B-5Q show simulations of the system 500 for mass balance (dry basis) as well as data regarding the membranes 502, 508, and 510, permeation constant for the membrane 502, and the acid gases removed by the membrane 502. More specifically, FIGS. 5B-5I illustrate an effect of permeate pressure on the third membrane helium stream (for example, FIGS. 5B-5E illustrate a low pressure and FIGS. 5F-5I illustrate a high pressure). FIGS. 5B-5I illustrate an effect of permeate pressure on the third membrane recycle stream (for example, FIGS. 5J-5M illustrate a low pressure and FIGS. 5N-5Q illustrate a high pressure).

[0084] As shown, each of systems 100, 200, 300, 400, and 500 includes a control system 999 that is communicably coupled (wired or wirelessly) to one or more components of the respective systems. Systems 100, 200, 300, 400, or 500 may be controlled (for example, control of temperature, pressure, flowrates of fluid, or a combination of such parameters) to provide for a desired output given particular inputs. In some aspects, a flow control system for systems 100, 200, 300, 400, or 500 can be operated manually. For example, an operator can set a flow rate for a pump or transfer device and set valve open or close positions to regulate the flow of the process streams through the pipes in the flow control system. Once the operator has set the flow rates and the valve open or close positions for all flow control systems distributed across the system, the flow control system can flow the streams under constant flow conditions, for example, constant volumetric rate or other flow conditions. To change the flow conditions, the operator can manually operate the flow control system, for example, by changing the pump flow rate or the valve open or close position.

[0085] In some aspects, a flow control system for systems 100, 200, 300, 400, and 500 can be operated automatically. For example, control system 999 is communicably coupled to the components and sub-systems of systems 100, 200, 300, 400, and 500. The control system 999 can include or be connected to a computer or control system to operate systems 100, 200, 300, 400, and 500. The control system 999 can include a computer-readable medium storing instructions (such as flow control instructions and other instructions) executable by one or more system and processors to perform operations (such as flow control operations). An operator can set the flow rates and the valve open or close positions for all flow control systems distributed across the facility using the control system 999. In such embodiments, the operator can manually change the flow conditions by providing inputs through the control system 999. Also, in such embodiments, the control system 999 can automatically (that is, without manual intervention) control one or more of the flow control systems, for example, using feedback systems connected to the control system 999. For example, a sensor (such as a pressure sensor, temperature sensor or other sensor) can be connected to a pipe through which a process stream flows. The sensor can monitor and provide a flow condition (such as a pressure, temperature, or other flow condition) of the process stream to the control system 999. In response to the flow condition exceeding a threshold (such as a threshold pressure value, a threshold temperature value, or other threshold value), the control system 999 can automatically perform operations. For example, if the pressure or temperature in the pipe exceeds the threshold pressure value or the threshold temperature value, respectively, the control system 999 can provide a signal to the pump to decrease a flow rate, a signal to open a valve to relieve the pressure, a signal to shut down process stream flow, or other signals.

[0086] Control system 999 can be implemented in digital electronic circuitry, or in computer hardware, firmware, software, or in combinations of them. The apparatus can be implemented in a computer program product tangibly embodied in an information carrier, for example, in a machine-readable storage device for execution by a programmable processor; and method steps can be performed by a programmable processor executing a program of instructions to perform functions of the described implementations by operating on input data and generating output. The described features can be implemented advantageously in one or more computer programs that are executable on a programmable system including at least one programmable processor coupled to receive data and instructions from, and to transmit data and instructions to, a data storage system, at least one input device, and at least one output device. A computer program is a set of instructions that can be used, directly or indirectly, in a computer to perform a certain activity or bring about a certain result. A computer program can be written in any form of programming language, including compiled or interpreted languages, and it can be deployed in any form, including as a stand-alone program or as a module, component, subroutine, or other unit suitable for use in a computing environment.

[0087] Suitable processors for the execution of a program of instructions include, by way of example, both general and special purpose microprocessors, and the sole processor or one of multiple processors of any kind of computer. Generally, a processor will receive instructions and data from a read-only memory or a random access memory or both. The essential elements of a computer are a processor for executing instructions and one or more memories for storing instructions and data.

Generally, a computer will also include, or be operatively coupled to communicate with, one or more mass storage devices for storing data files; such devices include magnetic disks, such as internal hard disks and removable disks; magneto-optical disks; and optical disks. Storage devices suitable for tangibly embodying computer program instructions and data include all forms of non-volatile memory, including by way of example semiconductor memory devices, such as EPROM, EEPROM, and flash memory devices; magnetic disks such as internal hard disks and removable disks; magneto-optical disks; and CD-ROM and DVD-ROM disks. The processor and the memory can be supplemented by, or incorporated in, ASICs (application-specific integrated circuits).

[0088] To provide for interaction with a user, the features can be implemented on a computer having a display device such as a CRT (cathode ray tube) or LCD (liquid crystal display) monitor for displaying information to the user and a keyboard and a pointing device such as a mouse or a trackball by which the user can provide input to the computer. Additionally, such activities can be implemented via touchscreen flat-panel displays and other appropriate mechanisms.

[0089] The features can be implemented in a control system that includes a back-end component, such as a data server, or that includes a middleware component, such as an application server or an Internet server, or that includes a front-end component, such as a client computer having a graphical user interface or an Internet browser, or any combination of them. The components of the system can be connected by any form or medium of digital data communication such as a communication network. Examples of communication networks include a local area network (“LAN”), a wide area network (“WAN”), peer-to-peer networks (having ad-hoc or static members), grid computing infrastructures, and the Internet.

[0090] While this specification contains many specific implementation details, these should not be construed as limitations on the scope of what may be claimed, but rather as descriptions of features specific to particular implementations. Certain features that are described in this specification in the context of separate implementations can also be implemented in combination in a single implementation. Conversely, various features that are described in the context of a single implementation can also be implemented in multiple implementations separately or in any suitable subcombination. Moreover, although features may be described above as acting in certain combinations and even initially claimed as such, one or more features from a claimed combination can in some cases be excised from the combination, and the claimed combination may be directed to a subcombination or variation of a subcombination.

[0091] Similarly, while operations are depicted in the drawings in a particular order, this should not be understood as requiring that such operations be performed in the particular order shown or in sequential order, or that all illustrated operations be performed, to achieve desirable results. In certain circumstances, multitasking and parallel processing may be advantageous. Moreover, the separation of various system components in the implementations described above should not be understood as requiring such separation in all implementations, and it should be understood that the described program components and systems can generally be integrated together in a single software product or packaged into multiple software products.

[0092] A number of implementations have been described. Nevertheless, it will be understood that various modifications may be made without departing from the spirit and scope of the disclosure. For example, example operations, methods, or processes described herein may include more steps or fewer steps than those described. Further, the steps in such example operations, methods, or processes may be performed in different successions than that described or illustrated in the figures. Accordingly, other implementations are within the scope of the following claims.

WHAT IS CLAIMED IS:

1. A method of treating a natural gas feed stream, comprising:

receiving a natural gas feed stream that comprises one or more acid gases, one or more hydrocarbon fluids, and one or more non-hydrocarbon fluids;

circulating the natural gas feed stream to a membrane module;

separating, with the membrane module, at least a portion of the one or more acid gases into a permeate stream and at least a portion of the one or more hydrocarbon fluids into a reject stream;

circulating the permeate stream to a distillation unit; and

separating, in the distillation unit, the one or more acid gases from the one or more non-hydrocarbon fluids.

2. The method of claim 1, further comprising:

circulating the permeate stream through a compressor fluidly positioned between the membrane module and the distillation unit; and

circulating the reject stream to an amine unit.

3. The method of claim 1, further comprising:

separating the one or more hydrocarbon fluids in the reject stream from another portion of the one or more acid gases in the amine unit; and

circulating the one or more hydrocarbon fluids to a sales gas pipeline, and circulating the other portion of the one or more acid gases to a sulfur recovery unit (SRU).

4. The method of claim 1, wherein the membrane module comprises an acid gas selective membrane that comprises at least one of a poly-imide (PI) membrane, a cellulose acetate (CA) membrane, or an amorphous perfluoropolymer membrane.

5. The method of claim 1, wherein the distillation unit comprises a bottom output that outputs the portion of the one or more acid gases and an overhead output that outputs the one or more non-hydrocarbon fluids, the method further comprising:

circulating the one or more non-hydrocarbon fluids to a power generation unit, and circulating the portion of the one or more acid gases to the SRU; and

circulating the one or more non-hydrocarbon fluids to a second membrane module fluidly coupled between the overhead output and the amine unit.

6. The method of claim 5, wherein the second membrane module comprises another acid gas selective membrane that comprises at least one of a PI membrane, a CA membrane, or an amorphous perfluoropolymer membrane.

7. The method of claim 5, further comprising:

separating, with the second membrane module, another portion of the one or more acid gases entrained in the one or more non-hydrocarbon fluids;

circulating the separated portion of the one or more acid gases to the SRU, and circulating the one or more non-hydrocarbon fluids to at least one of the amine unit or the power generation unit; and

circulating the separated one or more non-hydrocarbon fluids to a third membrane module.

8. The method of claim 7, wherein the third membrane module comprises a helium selective membrane that comprises a PI helium selective membrane.

9. The method of claim 8, further comprising:

separating a helium fluid from the one or more non-hydrocarbon fluids with the third membrane module; and

recovering the separated helium fluid in a helium recovery unit that is fluidly coupled to the third membrane module.

10. The method of claim 1, wherein the distillation unit comprises a hydrogen sulfide (H_2S) distillation unit, the method further comprising:

separating, in the H_2S distillation unit, a stream of H_2S from the one or more acid gases; and

circulating the stream of H_2S to the SRU, and circulating an H_2S-lean stream of the one or more acid gases to another distillation unit.

11. The method of claim 10, wherein the other distillation unit comprises a carbon dioxide (CO_2) distillation unit.

12. The method of claim 11, further comprising:

separating, in the other distillation unit, a stream of CO_2 from the H_2S-lean stream;

circulating the stream of CO_2 away from the other distillation unit, and circulating a CO_2-lean stream from the other distillation unit to a second membrane module;

separating, in the second membrane module, at least a portion of a helium fluid from the CO_2-lean stream;

circulating the portion of the helium fluid to a third membrane module, and circulating a helium-lean stream from the second membrane module; and

separating another portion of the helium fluid, in the third membrane module.

13. The method of claim 1, wherein the one or more acid gases comprises at least one of H_2S or CO_2.

14. A natural gas processing system, comprising:

a first membrane module positioned to receive a natural gas feed stream that comprises one or more acid gases, one or more hydrocarbon fluids, and one or more non-hydrocarbon fluids, the first membrane module configured to separate at least a portion of the one or more acid gases into a permeate stream and at least a portion of the one or more hydrocarbon fluids into a reject stream;

a distillation unit in fluid communication with the first membrane; and

a control system configured to perform operations comprising:

circulating the natural gas feed stream to the first membrane module;

circulating the permeate stream separated by the first membrane module to the distillation unit; and

operating the distillation unit to separate, in the distillation unit, the one or more acid gases from the one or more non-hydrocarbon fluids.

15. The natural gas processing system of claim 14, wherein the control system is configured to perform operations further comprising:

circulating the permeate stream through a compressor fluidly positioned between the membrane module and the distillation unit; and

circulating the reject stream to an amine unit.

16. The natural gas processing system of claim 14, wherein the control system is configured to perform operations further comprising:

separating the one or more hydrocarbon fluids in the reject stream from another portion of the one or more acid gases in the amine unit;

circulating the one or more hydrocarbon fluids to a sales gas pipeline; and

circulating the other portion of the one or more acid gases to a sulfur recovery unit (SRU).

17. The natural gas processing system of claim 14, wherein the first membrane module comprises an acid gas selective membrane that comprises at least one of a poly-imide (PI) membrane, a cellulose acetate (CA) membrane, or an amorphous perfluoropolymer membrane.

18. The natural gas processing system of claim 14, wherein the distillation unit comprises a bottom output and an overhead output, the control system configured to perform operations further comprising:

circulating the portion of the one or more acid gases from the bottom output;

circulating the one or more non-hydrocarbon fluids from the overhead output;

circulating the one or more non-hydrocarbon fluids to a power generation unit;

circulating the portion of the one or more acid gases to the SRU; and

circulating the one or more non-hydrocarbon fluids to a second membrane module fluidly coupled between the overhead output and the amine unit.

19. The natural gas processing system of claim 18, wherein the second membrane module comprises another acid gas selective membrane that comprises at least one of a PI membrane, a CA membrane, or an amorphous perfluoropolymer membrane.

20. The natural gas processing system of claim 18, wherein the control system is configured to perform operations further comprising:

operating the second membrane module to separate another portion of the one or more acid gases entrained in the one or more non-hydrocarbon fluids;

circulating the separated portion of the one or more acid gases to the SRU;

circulating the one or more non-hydrocarbon fluids to at least one of the amine unit or the power generation unit; and circulating the separated one or more non-hydrocarbon fluids to a third membrane module.

21. The natural gas processing system of claim 20, wherein the third membrane module comprises a helium selective membrane that comprises a PI helium selective membrane.

22. The natural gas processing system of claim 21, wherein the control system is configured to perform operations further comprising:

operating the third membrane module to separate a helium fluid from the one or more non-hydrocarbon fluids with the third membrane module; and

recovering the separated helium fluid in a helium recovery unit that is fluidly coupled to the third membrane module.

23. The natural gas processing system of claim 14, wherein the distillation unit comprises a hydrogen sulfide (H_2S) distillation unit, the control system configured to perform operations further comprising:

operating the H_2S distillation unit to separate a stream of H_2S from the one or more acid gases;

circulating the stream of H_2S to the SRU; and

circulating an H_2S-lean stream of the one or more acid gases to another distillation unit.

24. The natural gas processing system of claim 23, wherein the other distillation unit comprises a carbon dioxide (CO_2) distillation unit.

25. The natural gas processing system of claim 24, wherein the control system is configured to perform operations further comprising:

operating the other distillation unit to separate a stream of CO_2 from the H_2S-lean stream;

circulating the stream of CO_2 away from the other distillation unit;

circulating a CO_2-lean stream from the other distillation unit to the second membrane module;

operating a second membrane module to separate at least a portion of a helium fluid from the CO_2-lean stream;

circulating the portion of the helium fluid to a third membrane module;

circulating a helium-lean stream from the second membrane module; and

operating the third membrane module to separate another portion of the helium fluid.

26. The natural gas processing system of claim 14, wherein the one or more acid gases comprises at least one of H_2S or CO_2.

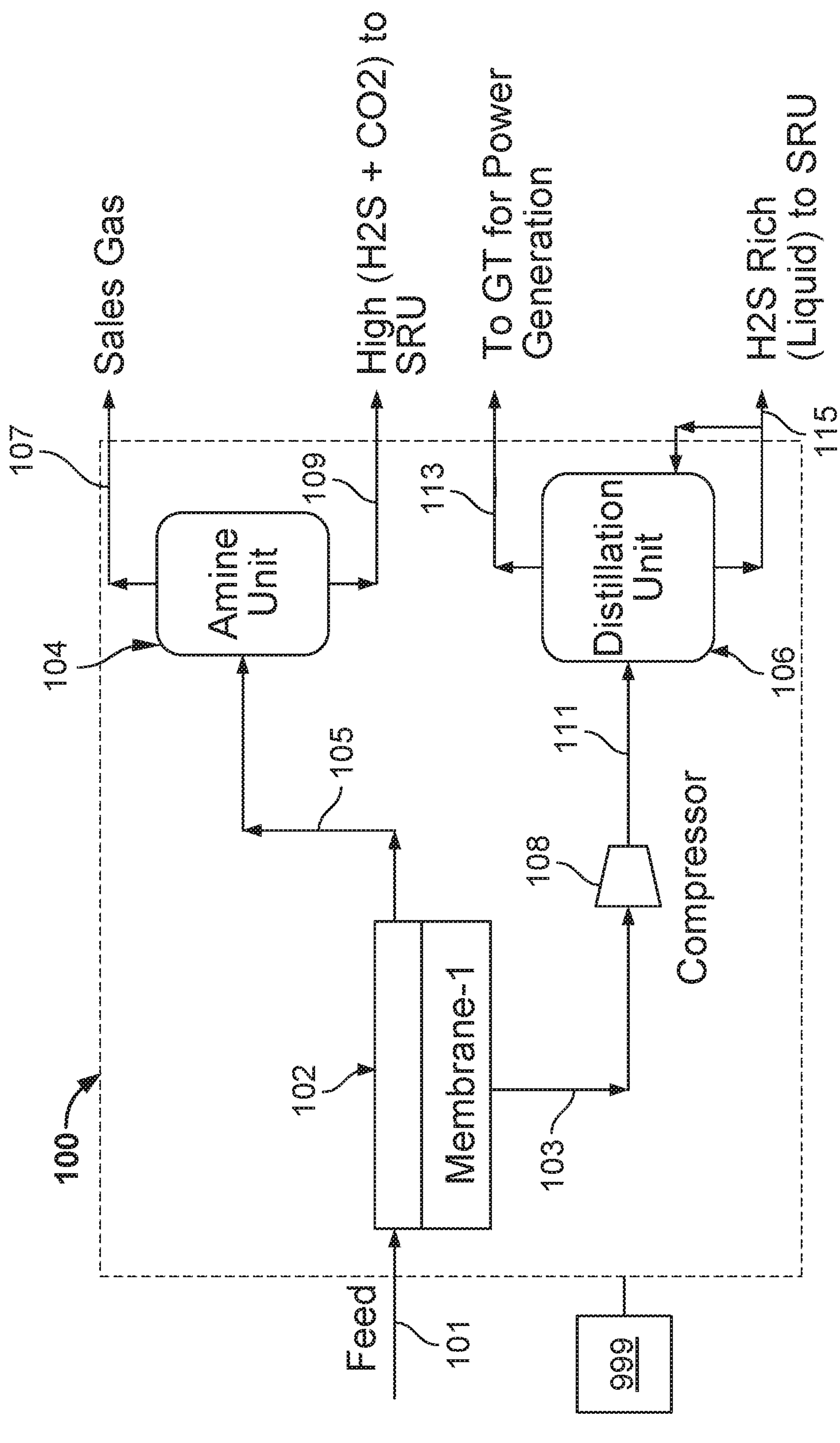
Sales Gas
High (H2S + CO2) to SRU
To GT for Power Generation
H2S Rich (Liquid) to SRU
107
109
113
115
Amine Unit
Distillation Unit
104
105
106
111
108
Compressor
Membrane-1
102
103
100
Feed
101
999

FIG. 1A

Stream Name	psig	FEED	MEM1-PERM	MEM1-REJECT	AMIN _H2S	AMIN_CLN GAS	DIST_H2S SOUP	DIST_CLN GAS
Temperature	C	48.889	37.064	37.064	48.889	46.116	62.812	-34.593
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304	885.304
Stream #		101	103	105	109	107	115	113
Total Adj. Std. Vapor Rate	MMft3/ day	199.389	59.205	140.157	15.142	127.344	34.892	24.288
Bulk stream Ideal LHV	BTU /ft3	723.915	497.184	819.936	410.894	851.920	515.537	470.673
Composition								
CO2		0.071	0.194	0.019	0.175	0.000	0.124	0.295
HYSULFID		0.208	0.521	0.076	0.699	0.000	0.874	0.010
METHANE		0.550	0.207	0.695	0.001	0.764	0.000	0.505
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001	0.003
PROPANE		0.007	0.000	0.010	0.000	0.011	0.000	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000	0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.074	0.147	0.000	0.162	0.000	0.180
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000	0.006

FIG. 1B

Membrane # 1		
Area	510000	sq ft
Area	47398	sq m
stage cut	0.30	
perm pressure	100	Psia

FEED		
Flow	200	MMSCFD
Temperature	37.78	C
Pressure	900	psia

C1 in feed	109.6	MMSCFD
C1 loss Dist	0.0	MMSCFD
C1 loss Amin	0.0	MMSCFD
Total C1 loss	0.02	%

Permeation constant for PI

Gas	GPU
CO2	90
H2S	60
Methane	3
Ethane	0.5
Propane	0.2
i-Butane	0.1
n-Butane	0.1
i-Pentane	0.05
n-Pentane	0.02
n-Hexane	0.02
Heptane	0.02
H2O	100
MEA	0
AIR	0
Nitrogen	5
Helium	300

Acid gas removal in Membrane		
Acid gas in feed	55.7	MMSCFD
Acid gas in perm	42.3	MMSCFD
Acid gas removal	75.9	%

CO2 to SRU	6.98	MMSCFD
CO2 reduction to SRU	49.45	% (wrt feed)
H2S to SRU	41.09	MMSCFD

Power production using Distillation Stream		
Total flow rate	24.3	MMSCFD
Energy content	470.7	btu/scf
Efficiency	0.50	
Power produced	69.8	MW

Compressor Name		C1
Actual Work	HP	11,486
	kW	8,729

FIG. 1C

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLN GAS	DIST_H2S SOUP	DIST_CLN GAS
Temperature	C	48.889	36.753	36.753	48.889	46.118	65.073	-36.475
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	199.389	59.802	139.558	15.032	126.699	35.465	24.311
Bulk stream Ideal LHV	BTU/ft3	723.915	531.545	806.571	370.471	842.322	531.100	532.198
Stream #		101	103	105	109	107	115	113
Composition								
CO2		0.071	0.175	0.026	0.244	0.000	0.104	0.279
HYSULFID		0.208	0.535	0.068	0.629	0.000	0.892	0.010
METHANE		0.550	0.231	0.687	0.001	0.755	0.000	0.571
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001	0.005
PROPANE		0.007	0.001	0.010	0.000	0.011	0.001	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000	0.000
BUTANE		0.004	0.000	0.005	0.000	0.006	0.000	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.053	0.156	0.000	0.172	0.000	0.130
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000	0.006

FIG. 1D

Membrane # 1					
Area	175000	sq ft			
Area	16264	sq m			
stage cut	0.30				
perm pressure	100	Psia			
FEED			C1 in feed	109.6	MMSCFD
Flow	200	MMSCFD	C1 loss Dist	0.007	MMSCFD
Temperature	37.78	C	C1 loss Amin	0.015	MMSCFD
Pressure	900	psia			
			Total C1 loss	0.02	%
Permeation constant for PI membrane			Acid gas removal in Membrane		
Gas	GPU		Acid gas in feed	55.7	MMSCFD
CO_2	170		Acid gas in perm	42.5	MMSCFD
H_2S	200		Acid gas removal	76.2	%
Methane	10				
Ethane	2		CO_2 to SRU	7.37	MMSCFD
Propane	2		CO_2 reduction to SRU	52.16	% (wrt feed)
i-Butane	1		H_2S to SRU	41.11	MMSCFD
n-Butane	1				
i-Pentane	1		Power production using Distillation Stream		
n-Pentane	1		Total flow rate	24.3	MMSCFD
n-Hexane	1		Energy content	532.2	btu/scf
Heptane	1		Efficiency	0.50	
H_2O	170		Power produced	79.0	MW
MEA	0				
AIR	0		Compressor Name		C1
Nitrogen	10		Actual Work	HP	11,561
Helium	400			kW	8,786

FIG. 1E

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLN GAS	DIST_H2S SOUP	DIST_CLN GAS
Temperature	°C	48.889	35.848	35.848	48.890	46.121	62.463	-61.071
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304	885.304
Stream #		101	103	105	109	107	115	113
Total Adj. Std. Vapor Rate	MMft3/day	199.389	95.835	103.550	18.588	87.370	30.746	65.049
Bulk stream Ideal LHV	BTU/ft3	723.915	550.288	884.624	461.933	946.480	534.268	557.907
Composition								
CO2		0.071	0.131	0.016	0.088	0.000	0.125	0.134
HYSULFID		0.208	0.280	0.142	0.786	0.000	0.862	0.004
METHANE		0.550	0.392	0.696	0.001	0.822	0.000	0.578
ETHANE		0.026	0.014	0.037	0.000	0.044	0.006	0.019
PROPANE		0.007	0.002	0.012	0.000	0.014	0.005	0.000
IBUTANE		0.002	0.000	0.003	0.000	0.003	0.001	0.000
BUTANE		0.004	0.000	0.007	0.000	0.008	0.001	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.003	0.000	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEXANE		0.001	0.000	0.002	0.000	0.003	0.000	0.000
HEPTANE		0.002	0.000	0.005	0.000	0.005	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.179	0.076	0.000	0.089	0.000	0.263
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000	0.002

FIG. 1F

Membrane # 1					
Area	157000	sq ft			
Area	14591	sq m			
stage cut	0.40				
perm pressure	100	Psia			
FEED			C1 in feed	109.6	MMSCFD
Flow	200	MMSCFD	C1 loss Dist	0.007	MMSCFD
Temperature	37.78	C	C1 loss Amin	0.015	MMSCFD
Pressure	900	psia			
			Total C1 loss	0.02	%
Permeation constant for PI membrane			Acid gas removal in Membrane		
Gas	GPU		Acid gas in feed	55.7	MMSCFD
CO2	190		Acid gas in perm	33.8	MMSCFD
H2S	70		Acid gas removal	60.6	%
Methane	25				
Ethane	18		CO2 to SRU	6.39	MMSCFD
Propane	7		CO2 reduction to SRU	45.15	% (wrt feed)
i-Butane	3		H2S to SRU	41.07	MMSCFD
n-Butane	3				
i-Pentane	2		Power production using Distillation Stream		
n-Pentane	1		Total flow rate	52.9	MMSCFD
n-Hexane	0.5		Energy content	535.3	btu/scf
Heptane	0.5		Efficiency	0.50	
H2O	1000		Power produced	172.8	MW
MEA	0				
AIR	0		Compressor Name		C1
Nitrogen	80		Actual Work	HP	15,469
Helium	1200			kW	11,756

FIG. 1G

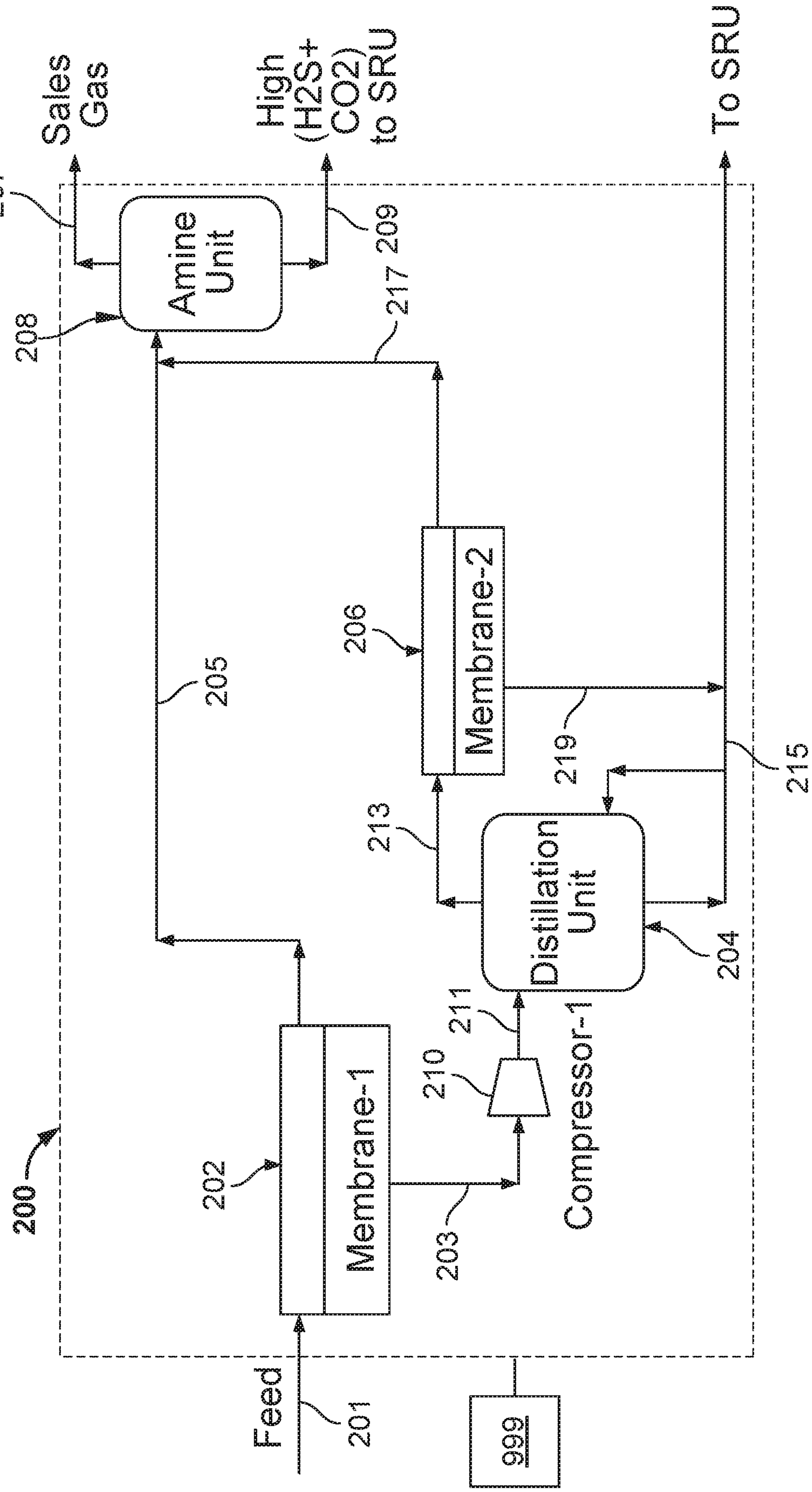
Sales Gas
High (H2S+ CO2) to SRU
To SRU
207
208
Amine Unit
209
217
205
206
Membrane-2
219
215
213
Distillation Unit
204
211
210
Compressor-1
Membrane-1
202
203
200
Feed
201
999

FIG. 2A

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLN GAS	DIST_H2S SOUP	DIST_CLN GAS	MEM2-SRU	MEM2-AMIN
Stream Description										
Temperature	C	48.889	36.839	36.839	48.889	46.124	62.903	-35.274	33.310	33.310
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304	885.304	7.304	885.304
Stream #		201	203	205	209	207	215	213	219	217
Total Adj. Std. Vapor Rate	MMft3/day	199.389	60.569	138.793	19.868	143.656	35.447	25.096	2.592	22.503
Bulk Stream Ideal LHV	BTU/ft3	723.915	498.901	822.360	286.906	830.023	516.061	474.531	222.667	503.612
Composition										
CO2		0.071	0.192	0.018	0.386	0.000	0.124	0.290	0.723	0.240
HYSULFID		0.208	0.518	0.073	0.489	0.000	0.875	0.010	0.024	0.008
METHANE		0.550	0.211	0.698	0.000	0.759	0.000	0.510	0.224	0.543
ETHANE		0.026	0.002	0.037	0.000	0.036	0.001	0.003	0.003	0.003
PROPANE		0.007	0.000	0.010	0.000	0.010	0.000	0.000	0.000	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000
BUTANE		0.004	0.000	0.006	0.000	0.005	0.000	0.000	0.000	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000	0.000	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.003	0.000	0.000	0.000	0.000
H2O		0.000	0.000	0.000	0.125	0.006	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.075	0.147	0.000	0.173	0.000	0.181	0.025	0.199
HELIUM		0.001	0.002	0.000	0.000	0.001	0.000	0.006	0.001	0.006

FIG. 2B

Membrane # 1		
Area	530000	sq ft
Area	49257	sq m
stage cut	0.30	
perm pressure	100	Psia

FEED		
Flow	200	MMSCFD
Temperature	48.89	C
Pressure	900	psia

Permeation constant for membrane	PI	Pebax
Gas	GPU	GPU
CO2	90	360
H2S	60	360
Methane	3	53
Ethane	0.5	106
Propane	0.2	106
i-Butane	0.1	106
n-Butane	0.1	106
i-Pentane	0.05	106
n-Pentane	0.02	106
n-Hexane	0.02	106
Heptane	0.02	106
H2O	100	500
MEA	0	0
AIR	0	0
Nitrogen	5	16
Helium	300	21.2

Membrane # 2 PEBAX		
Area	1600	sq ft
Area	149	sq m
stage cut	0.10	
perm pressure	22.004	Psia

C1 in feed	109.6	MMSCFD
C1 loss in Mem2 to SRU	0.6	MMSCFD
C1 loss Amin to SRU	0.003	MMSCFD
C1 loss H2S Soup	0.007	MMSCFD
Total C1 loss	0.54	%

Acid gas removal in Membrane # 1		
Acid gas in feed	55.7	MMSCFD
Acid gas in perm	43.0	MMSCFD
Acid gas removal	77.1	%

CO2 to SRU	9.54	MMSCFD
H2S % to SRU	98.15	% (wrt feed)
H2S to SRU	40.79	MMSCFD

Power production using Distillation Stream		
Total flow rate	0.0	MMSCFD
Energy content	0.0	btu/scf
Efficiency	0.50	
Power produced	0.0	MW

Compressor Name		C1
Actual Work	HP	11,744
	kW	8,925

FIG. 2C

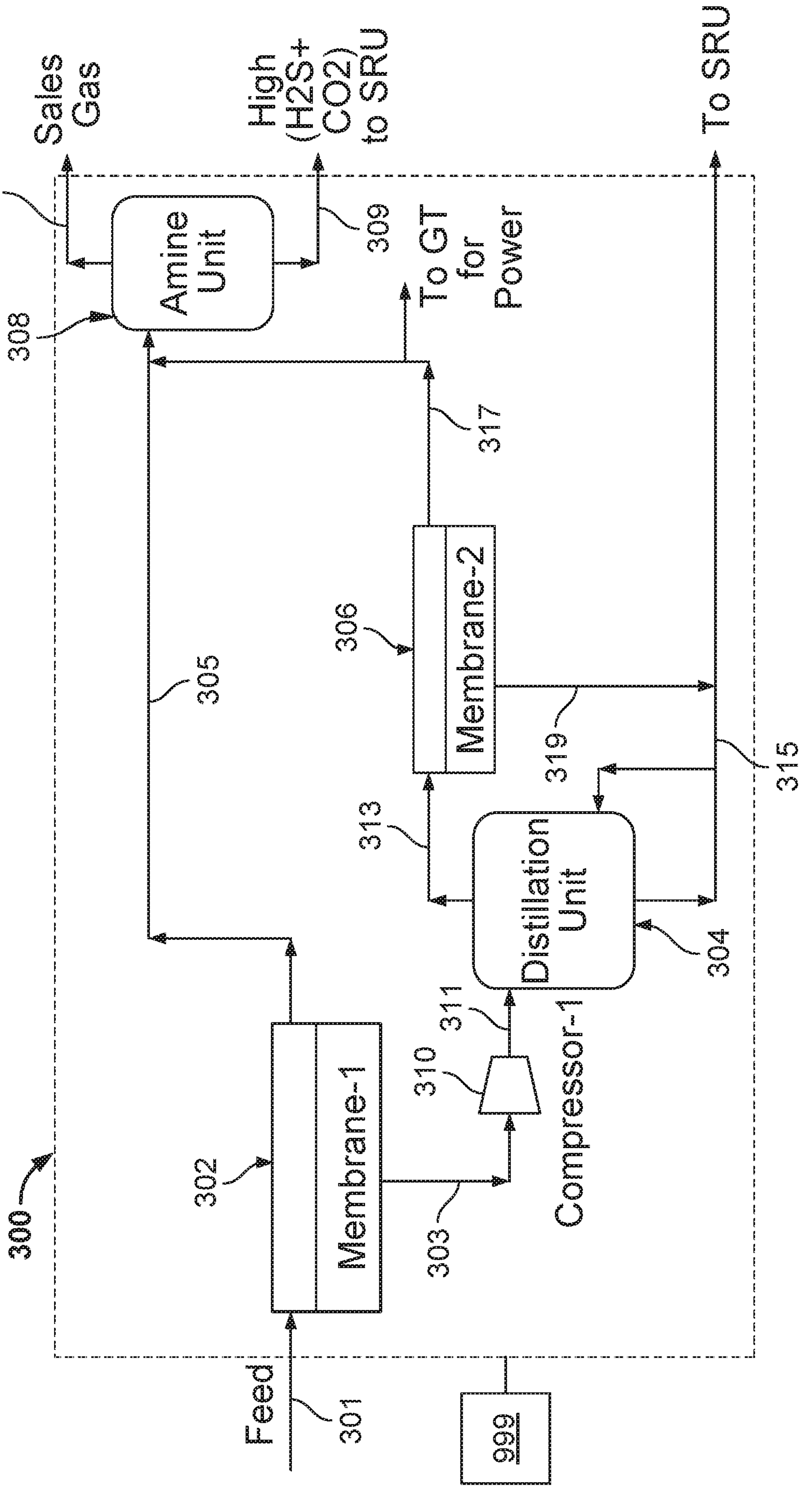
300
Feed
301
302
Membrane-1
303
Compressor-1
310
311
Distillation Unit
304
313
Membrane-2
306
317
319
315
305
To GT for Power
Amine Unit
308
307
309
Sales Gas
High (H2S+ CO2) to SRU
To SRU
999

FIG. 3A

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN _H2S	AMIN_CLN GAS	DIST_H2S SOUP	DIST_CLN GAS
Stream Description								
Temperature	C	48.889	36.839	36.839	48.889	46.117	62.903	-35.274
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304	885.304
Stream #		301	303	305	309	307	315	313
Total Adj. Std. Vapor Rate	MMft3/day	199.389	60.569	138.793	18.165	136.402	35.447	25.096
Bulk Stream Ideal LHV	BTU/ft3	723.915	498.901	822.360	326.604	839.167	516.061	474.531
Composition								
CO2		0.071	0.192	0.018	0.318	0.000	0.124	0.290
HYSULFID		0.208	0.518	0.073	0.556	0.000	0.875	0.010
METHANE		0.550	0.211	0.698	0.000	0.761	0.000	0.510
ETHANE		0.026	0.002	0.037	0.000	0.038	0.001	0.003
PROPANE		0.007	0.000	0.010	0.000	0.010	0.000	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000	0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000	0.000
H2O		0.000	0.000	0.000	0.125	0.006	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.075	0.147	0.000	0.168	0.000	0.181
HELIUM		0.001	0.002	0.000	0.000	0.001	0.000	0.006

FIG. 3B

MEM2-SRU	MEM2-REJECT
34.370	34.370
7.304	885.304
319	317
1.976	23.119
217.887	496.516
0.729	0.253
0.025	0.009
0.219	0.535
0.003	0.003
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.000	0.000
0.024	0.195
0.001	0.006

FIG. 3B (Cont.).

Membrane # 1		
Area	530000	sq ft
Area	49257	sq m
stage cut	0.30	
perm pressure	100	Psia

FEED		
Flow	200	mmscfd
Temperature	48.89	C
Pressure	900	psia

Permeation constant for membrane	PI	Pebax
Gas	GPU	GPU
CO2	90	360
H2S	60	360
Methane	3	53
Ethane	0.5	106
Propane	0.2	106
i-Butane	0.1	106
n-Butane	0.1	106
i-Pentane	0.05	106
n-Pentane	0.02	106
n-Hexane	0.02	106
Heptane	0.02	106
H2O	100	500
MEA	0	0
AIR	0	0
Nitrogen	5	16
Helium	300	21.2

Membrane # 2 PEBAX		
Area	1200	sq ft
Area	112	sq m
stage cut	0.08	
perm pressure	22.004	Psia

C1 in feed	109.6	MMSCFD
C1 loss in Mem2 to SRU	0.4	MMSCFD
C1 loss Amin to SRU	0.007	MMSCFD
C1 loss H2S Soup	0.007	MMSCFD
Total C1 loss	0.41	%

Acid gas removal in Membrane # 1		
Acid gas in feed	55.7	MMSCFD
Acid gas in perm	43.0	MMSCFD
Acid gas removal	77.1	%

CO2 to SRU	7.22	MMSCFD
H2S % to SRU	99.05	% (wrt feed)
H2S to SRU	41.17	MMSCFD

Power production using Distillation Stream		
Total flow rate	10.0	MMSCFD
Energy content	496.5	btu/scf
Efficiency	0.50	
Power produced	30.3	MW

Compressor Name		C1
Actual Work	HP	11,744
	kW	8,925

FIG. 3C

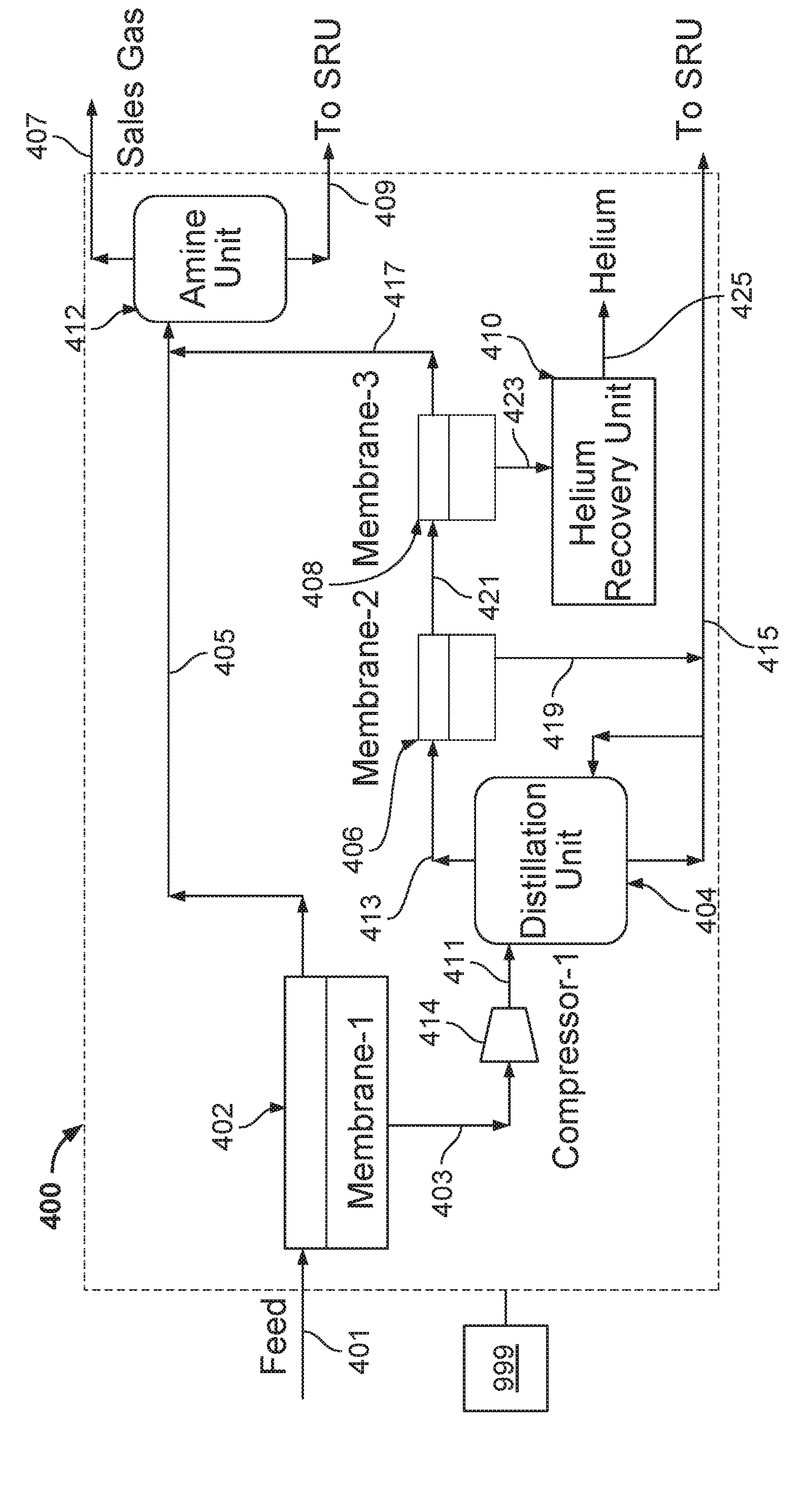
400
Feed
401
999
Membrane-1
402
403
Compressor-1
414
411
Distillation Unit
413
404
406
Membrane-2
419
421
408
Membrane-3
423
405
417
412
Amine Unit
407
Sales Gas
409
To SRU
410
Helium Recovery Unit
Helium
425
415
To SRU

FIG. 4A

Stream Name		FEED	MEM1-PERM	MEM1-REJECT		AMIN_H2S	AMIN_CLNGAS	DIST_H2SSOUP	DIST_CLNGAS	MEM2-TOMEM3	MEM2-TO SRU	MEM3-2AMIN	MEM3-2HELIUM
Stream #		401	403	405		409	407	415	413	421	419	417	423
Temperature	C	48.889	35.051	35.051		48.889	46.116	64.028	40.615	43.955	43.955	32.631	32.631
Pressure	psig	885.304	85.304	885.304		-1.196	235.304	885.304	885.304	885.304	85.304	885.304	7.304
Std. Vapor Rate	MMft3/day	149.542	54.561	94.960		9.280	104.966	29.535	25.001	21.322	3.675	14.110	7.210
Ideal LHV	BTU/ft3	723.915	515.113	844.161		300.217	837.767	522.596	506.221	539.701	312.327	680.505	264.631
Composition													
CO2		0.071	0.175	0.011		0.364	0.000	0.113	0.249	0.186	0.614	0.005	0.540
HYSULFID		0.208	0.485	0.049		0.509	0.000	0.885	0.010	0.007	0.024	0.000	0.021
METHANE		0.550	0.249	0.723		0.001	0.763	0.000	0.544	0.582	0.321	0.738	0.277
ETHANE		0.026	0.002	0.040		0.000	0.037	0.001	0.004	0.004	0.004	0.006	0.000
PROPANE		0.007	0.000	0.011		0.000	0.010	0.000	0.000	0.000	0.000	0.000	0.000
IBUTANE		0.002	0.000	0.003		0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
BUTANE		0.004	0.000	0.006		0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.000
IPENTANE		0.001	0.000	0.002		0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
PENTANE		0.001	0.000	0.002		0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
HEXANE		0.001	0.000	0.002		0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
HEPTANE		0.002	0.000	0.004		0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000
H20		0.000	0.000	0.000		0.125	0.005	0.000	0.000	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.086	0.147		0.000	0.168	0.000	0.189	0.216	0.036	0.251	0.147
HELIUM		0.001	0.002	0.000		0.000	0.000	0.000	0.005	0.005	0.001	0.000	0.015

FIG. 4B

Membrane # 1		
Area	550000	sq ft
Area	51115	sq m
stage cut	0.36	
perm pressure	100	Psia

FEED		
Flow	150	mmscfd
Temperature	48.89	C
Pressure	900	psia

C1 in feed	82.2	MMSCFD
C1 loss to Helium str	2.0	MMSCFD
C1 loss Amin	0.0	MMSCFD
C1 loss H2S Soup	0.007	MMSCFD
Total C1 loss	2.45	%

Permeation constant for membrane	PI	Pebax
Gas	GPU	GPU
CO2	90	360
H2S	60	360
Methane	3	53
Ethane	0.5	106
Propane	0.2	106
i-Butane	0.1	106
n-Butane	0.1	106
i-Pentane	0.05	106
n-Pentane	0.02	106
n-Hexane	0.02	106
Heptane	0.02	106
H2O	100	500
MEA	0	0
AIR	0	0
Nitrogen	5	16
Helium	300	21.2

Acid gas removal in Membrane # 1		
acid gas in feed	41.8	MMSCFD
Acid gas in perm	36.0	MMSCFD
Acid gas removal	86.2	%

CO2 to SRU	3.38	MMSCFD
CO2 reduction to SRU	36.87	% (wrt feed)
H2S to SRU	26.14	MMSCFD

Power production using Distillation Stream		
Total flow rate	0.0	MMSCFD
Energy content	0.0	btu/scf
Efficiency	0.50	
Power produced	0.0	MW

FIG. 4C

Helium recovery		
Helium in Feed	0.120	MMSCFD
Helium in recovery stream	0.111	MMSCFD
Helium Recovery	92.7	%

Membrane # 2 PEBAX		
Area	3,200	sq ft
Area	297	sq m
stage cut	0.56	
perm pressure	100.004	Psia

Membrane # 3 PI		
Area	221,000	sq ft
Area	20,539	sq m
stage cut	0.34	
perm pressure	22.004	Psia

Compressor Name		C1
Actual Work	HP	19,022
	kW	14,457

Compressor Name		C2
Actual Work	HP	664
	kW	505

FIG. 4D

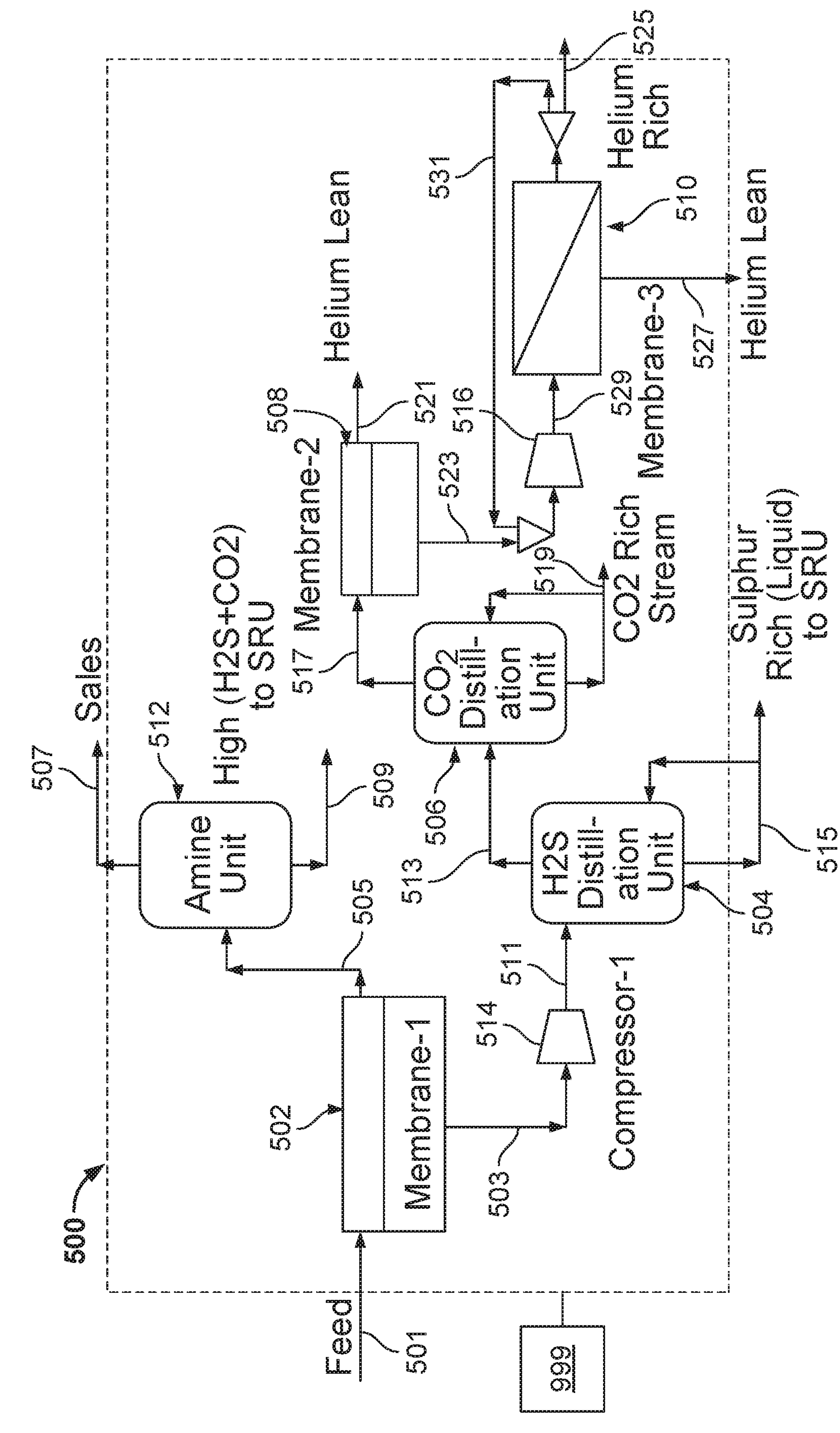
500
Feed
501
999
Membrane-1
502
503
Compressor-1
514
511
505
Amine Unit
512
507
Sales
509
High (H2S+CO2) to SRU
H2S Distill-ation Unit
504
513
515
Sulphur Rich (Liquid) to SRU
506
CO2 Distill-ation Unit
517
Membrane-2
508
521
Helium Lean
523
519
CO2 Rich Stream
516
529
Membrane-3
510
527
Helium Lean
531
525
Helium Rich

FIG. 5A

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLNGAS	DIST_H2SSOUP
Stream Description							
Stream #		501	503	505	509	507	515
Temperature	C	48.889	37.064	37.064	48.889	46.116	62.812
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	199.389	59.205	140.157	15.142	127.344	34.892
Bulk Stream Ideal LHV	BTU/ft3	723.915	497.184	819.936	410.894	851.920	515.537
Composition							
CO2		0.071	0.194	0.019	0.175	0.000	0.124
HYSULFID		0.208	0.521	0.076	0.699	0.000	0.874
METHANE		0.550	0.207	0.695	0.001	0.764	0.000
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001
PROPANE		0.007	0.000	0.010	0.000	0.011	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000
H20		0.000	0.000	0.000	0.125	0.006	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.074	0.147	0.000	0.162	0.000
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000

FIG. 5B

Stream Name		FEED2_CO2_DI	CO2COL_BOTM	CO2COL_OHEAD	HE_LEAN_1	RECYCLE	CONC_HE	HE_LEAN
Stream Description								
Stream #		513	519	517	521	531	525	527
Temperature	C	36.667	-29.482	-90.387	23.669	23.669	23.669	3.103
Pressure	psig	885.304	885.304	885.304	885.304	7.304	7.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	28.158	9.700	18.449	16.893	0.567	1.235	0.321
Bulk Stream Ideal LHV	BTU/ft3	507.466	264.740	635.468	642.287	479.751	479.751	875.555
Composition								
CO2		0.241	0.699	0.000	0.000	0.000	0.000	0.000
HYSULFID		0.009	0.025	0.000	0.000	0.000	0.000	0.000
METHANE		0.553	0.275	0.699	0.707	0.528	0.528	0.963
ETHANE		0.002	0.000	0.000	0.000	0.000	0.003	0.000
PROPANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IBUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
BUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IPENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
PENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEXANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEPTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
H20		0.000	0.000	0.000	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.192	0.001	0.293	0.293	0.369	0.369	0.037
HELIUM		0.005	0.000	0.008	0.001	0.103	0.103	0.000

FIG. 5C

Membrane # 1		
Area	510000	sq ft
Area	47398	sq m
stage cut	0.30	
perm pressure	100	Psia

FEED		
Flow	200	MMSCFD
Temperature	37.78	C
Pressure	900	psia

Permeation constant for PI membrane

Gas	GPU
CO2	90
H2S	60
Methane	3
Ethane	0.5
Propane	0.2
i-Butane	0.1
n-Butane	0.1
i-Pentane	0.05
n-Pentane	0.02
n-Hexane	0.02
Heptane	0.02
H2O	100
MEA	0
AIR	0
Nitrogen	5
Helium	300

C1 in feed	109.6	MMSCFD
C1 loss Dist	0.0	MMSCFD
C1 loss Amin	0.0	MMSCFD
Total C1 loss	0.02	%

Acid gas removal in Membrane		
Acid gas in feed	55.7	MMSCFD
Acid gas in perm	42.3	MMSCFD
Acid gas removal	75.9	%

CO2 to SRU	6.98	MMSCFD
CO2 reduction to SRU	49.45	% (wrt feed)
H2S to SRU	41.09	MMSCFD

Power production using Distillation Stream		
Total flow rate	24.3	MMSCFD
Energy content	470.7	btu/scf
Efficiency	0.50	
Power produced	69.8	MW

Compressor Name		C1
Actual Work	HP	11,486
	kW	8,729

FIG. 5D

Helium in feed	0.159	MMSCFD
Feed to CO2 Distill Unit	0.146	MMSCFD
From CO2 dist unit	0.141	MMSCFD
Helium conc stream	0.127	MMSCFD
Helium REC from CO2 dist feed	87%	
overall Helium recovery	80%	
Compressor duty	1,832	HP
	1,392	kW
Membrane # 3		
Area	415,000	sq ft
Area	38,569	sq m
perm pressure	85	Psia

FIG. 5E

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLNGAS	DIST_H2SSOUP		CO_2 rich stream
Stream Description									
Stream #		501	503	505	509	507	515		519
Temperature	C	48.889	37.064	37.064	48.889	46.116	62.812		-30.765
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304		885.304
Total Adj. Std. Vapor Rate	MMft3/day	199.389	59.205	140.157	15.142	127.344	34.892		9.700
Bulk stream Ideal LHV	BTU/ft3	723.915	497.184	819.936	410.894	851.920	515.537		265.337
Composition									
CO2		0.071	0.194	0.019	0.175	0.000	0.124		0.699
HYSULFID		0.208	0.521	0.076	0.699	0.000	0.874		0.025
METHANE		0.550	0.207	0.695	0.001	0.764	0.000		0.276
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001		0.000
PROPANE		0.007	0.000	0.010	0.000	0.011	0.000		0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000		0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000		0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000		0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000		0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000		0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000		0.000
H2O		0.000	0.000	0.000	0.125	0.006	0.000		0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000		0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000		0.000
N2		0.125	0.074	0.147	0.000	0.162	0.000		0.000
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000		0.000

FIG. 5F

Stream Name		CO2_LEAN_1	HE_LEAN_1	RECYCLE	CONC_HE	HE_LEAN
Stream Description						
Stream #		517	521	531	525	527
Temperature	C	-90.408	20.187	20.187	20.187	12.547
Pressure	psig	885.304	885.304	85.304	85.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	18.452	9.576	1.471	3.205	5.667
Bulk Stream Ideal LHV	BTU/ft3	635.153	642.700	487.456	487.456	736.344
Composition						
CO2						
HYSULFID		0.000	0.000	0.000	0.000	0.000
METHANE		0.000	0.000	0.000	0.000	0.000
ETHANE		0.699	0.687	0.536	0.536	0.810
PROPANE		0.000	0.000	0.000	0.000	0.000
IBUTANE		0.000	0.000	0.000	0.000	0.000
BUTANE		0.000	0.000	0.000	0.000	0.000
IPENTANE		0.000	0.000	0.000	0.000	0.000
PENTANE		0.000	0.000	0.000	0.000	0.000
HEXANE		0.000	0.000	0.000	0.000	0.000
HEPTANE		0.000	0.000	0.000	0.000	0.000
H20		0.000	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000
N2		0.294	0.312	0.422	0.422	0.190
HELIUM		0.008	0.001	0.041	0.041	0.000

FIG. 5G

Membrane # 1		
Area	510000	sq ft
Area	47398	sq m
stage cut	0.30	
perm pressure	100	Psia

FEED		
Flow	200	MMSCFD
Temperature	37.78	C
Pressure	900	psia

C1 in feed	109.6	MMSCFD
C1 loss Dist	0.0	MMSCFD
C1 loss Amin	0.0	MMSCFD
Total C1 loss	0.02	%

Permeation constant for PI membrane

Gas	GPU
CO2	90
H2S	60
Methane	3
Ethane	0.5
Propane	0.2
i-Butane	0.1
n-Butane	0.1
i-Pentane	0.05
n-Pentane	0.02
n-Hexane	0.02
Heptane	0.02
H2O	100
MEA	0
AIR	0
Nitrogen	5
Helium	300

Acid gas removal in Membrane		
Acid gas in feed	55.7	MMSCFD
Acid gas in perm	42.3	MMSCFD
Acid gas removal	75.9	%

CO2 to SRU	6.98	MMSCFD
CO2 reduction to SRU	49.45	% (wrt feec
H2S to SRU	41.09	MMSCFD

Power production using Distillation Stream		
Total flow rate	24.3	MMSCFD
Energy content	470.7	btu/scf
Efficiency	0.50	
Power produced	69.8	MW

Compressor Name		C1
Actual Work	HP	11,486
	kW	8,729

FIG. 5H

Helium in feed	0.159	MMSCFD
Feed to CO2 Distill Unit	0.146	MMSCFD
From CO2 dist unit	0.141	MMSCFD
Helium after membrane-2	0.133	MMSCFD
Helium REC from CO2 dist feed	91%	
overall Helium recovery	83%	
Compressor duty	1,832	HP
	1,392	kW
Membrane #3		
Area	415,000	sq ft
Area	38,569	sq m
perm pressure	85	Psia

FIG. 5I

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN_H2S	AMIN_CLNGAS	DIST_H2SSOUP
Stream Description							
Stream #		501	503	505	509	507	515
Temperature	C	48.889	37.064	37.064	48.889	46.116	62.812
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	199.389	59.205	140.157	15.142	127.344	34.892
Bulk stream Ideal LHV	BTU/ft3	723.915	497.184	819.936	410.894	851.920	515.537
Composition							
CO2		0.071	0.194	0.019	0.175	0.000	0.124
HYSULFID		0.208	0.521	0.076	0.699	0.000	0.874
METHANE		0.550	0.207	0.695	0.001	0.764	0.000
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001
PROPANE		0.007	0.000	0.010	0.000	0.011	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000
H2O		0.000	0.000	0.000	0.125	0.006	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.074	0.147	0.000	0.162	0.000
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000

FIG. 5J

Stream Name		FEED2_CO2_DI	CO2COL_BOTM	CO2COL_OHEAD	HE_LEAN_1	RECYCLE	CONC_HE	HE_LEAN
Stream Description								
Stream #		513	519	517	521	531	525	527
Temperature	C	36.667	-29.482	-90.387	23.131	23.131	23.131	3.103
Pressure	psig	885.304	885.304	885.304	885.304	7.304	7.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	28.158	9.700	18.449	16.473	0.759	1.655	0.321
Bulk Stream Ideal LHV	BTU/ft3	507.466	264.740	635.468	645.188	491.903	491.903	875.555
Composition								
CO2		0.241	0.699	0.000	0.000	0.000	0.000	0.000
HYSULFID		0.009	0.025	0.000	0.000	0.000	0.000	0.000
METHANE		0.553	0.275	0.699	0.710	0.541	0.541	0.963
ETHANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
PROPANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IBUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
BUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IPENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
PENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEXANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEPTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
H20		0.000	0.000	0.000	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.192	0.001	0.293	0.290	0.377	0.377	0.037
HELIUM		0.005	0.000	0.008	0.000	0.082	0.082	0.000

FIG. 5K

Membrane # 1					
Area	510000	sq ft			
Area	47398	sq m			
stage cut	0.30				
perm pressure	100	Psia			
FEED			C1 in feed	109.6	MMSCFD
Flow	200	MMSCFD	C1 loss Dist	0.0	MMSCFD
Temperature	37.78	C	C1 loss Amin	0.0	MMSCFD
Pressure	900	psia			
			Total C1 loss	0.02	%
Permeation constant for PI membrane			Acid gas removal in Membrane		
Gas	GPU		acid gas in feed	55.7	MMSCFD
CO2	90		Acid gas in perm	42.3	MMSCFD
H2S	60		Acid gas removal	75.9	%
Methane	3				
Ethane	0.5		CO2 to SRU	6.98	MMSCFD
Propane	0.2		CO2 reduction to SRU	49.45	% (wrt feed)
i-Butane	0.1		H2S to SRU	41.09	MMSCFD
n-Butane	0.1				
i-Pentane	0.05		Power production using Distillation Stream		
n-Pentane	0.02		Total flow rate	24.3	MMSCFD
n-Hexane	0.02		Energy content	470.7	btu/scf
Heptane	0.02		Efficiency	0.50	
H2O	100		Power produced	69.8	MW
MEA	0				
AIR	0		Compressor Name		C1
Nitrogen	5		Actual Work	HP	11,486
Helium	300			kW	8,729

FIG. 5L

Helium in feed	0.159	MMSCFD
Feed to CO2 Distill Unit	0.146	MMSCFD
From CO2 dist unit	0.141	MMSCFD
Helium conc stream	0.136	MMSCFD
Helium REC from CO2 dist feed	93%	
overall Helium recovery	85%	
Compressor duty	1,832	HP
	1,392	kW
Membrane # 3		
Area	415,000	sq ft
Area	38,569	sq m
perm pressure	85	Psia

FIG. 5M

Stream Name		FEED	MEM1-PERM	MEM1-REJECT	AMIN _H2S	AMIN_CLN GAS	DIST_H2S SOUP
Stream Description Stream #		501	503	505	509	507	515
Temperature	C	48.889	37.064	37.064	48.889	46.116	62.812
Pressure	psig	885.304	85.304	885.304	-1.196	235.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	199.389	59.205	140.157	15.142	127.344	34.892
Bulk Stream Ideal LHV	BTU/ft3	723.915	497.184	819.936	410.894	851.920	515.537
Composition							
CO2		0.071	0.194	0.019	0.175	0.000	0.124
HYSULFID		0.208	0.521	0.076	0.699	0.000	0.874
METHANE		0.550	0.207	0.695	0.001	0.764	0.000
ETHANE		0.026	0.002	0.036	0.000	0.040	0.001
PROPANE		0.007	0.000	0.010	0.000	0.011	0.000
IBUTANE		0.002	0.000	0.002	0.000	0.002	0.000
BUTANE		0.004	0.000	0.006	0.000	0.006	0.000
IPENTANE		0.001	0.000	0.002	0.000	0.002	0.000
PENTANE		0.001	0.000	0.002	0.000	0.002	0.000
HEXANE		0.001	0.000	0.002	0.000	0.002	0.000
HEPTANE		0.002	0.000	0.003	0.000	0.004	0.000
H2O		0.000	0.000	0.000	0.125	0.006	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000
N2		0.125	0.074	0.147	0.000	0.162	0.000
HELIUM		0.001	0.002	0.000	0.000	0.000	0.000

FIG. 5N

Stream Name		FEED2_CO2_DI	CO2COL_BOTM	CO2COL_OHEAD	HE_LEAN_1	RECYCLE	CONC_HE	HE_LEAN
Stream Description								
Stream #		513	519	517	521	531	525	527
Temperature	C	36.667	-29.482	-90.387	22.425	22.425	22.425	3.103
Pressure	psig	885.304	885.304	885.304	885.304	7.304	7.304	885.304
Total Adj. Std. Vapor Rate	MMft3/day	28.158	9.700	18.449	15.933	1.007	2.195	0.321
Bulk Stream Ideal LHV	BTU/ft3	507.466	264.740	635.468	648.856	503.070	503.070	875.555
Composition								
CO2		0.241	0.699	0.000	0.000	0.000	0.000	0.000
HYSULFID		0.009	0.025	0.000	0.000	0.000	0.000	0.000
METHANE		0.553	0.275	0.699	0.714	0.553	0.553	0.963
ETHANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
PROPANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IBUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
BUTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
IPENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
PENTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEXANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
HEPTANE		0.000	0.000	0.000	0.000	0.000	0.000	0.000
H20		0.000	0.000	0.000	0.000	0.000	0.000	0.000
MEA		0.000	0.000	0.000	0.000	0.000	0.000	0.000
AIR		0.000	0.000	0.000	0.000	0.000	0.000	0.000
N2		0.192	0.001	0.293	0.286	0.383	0.383	0.037
HELIUM		0.005	0.000	0.008	0.000	0.064	0.064	0.000

FIG. 5O

Membrane # 1					
Area	510,000	sq ft			
Area	47,398	sq m			
stage cut	0.30				
perm pressure	100	Psia			
FEED			C1 in feed	109.6	MMSCFD
Flow	200	MMSCFD	C1 loss Dist	0.0	MMSCFD
Temperature	37.78	C	C1 loss Amin	0.0	MMSCFD
Pressure	900	psia			
			Total C1 loss	0.02	%
Permeation constant for PI membrane			Acid gas removal in Membrane		
Gas	GPU		Acid gas in feed	55.7	MMSCFD
CO2	90		Acid gas in perm	42.3	MMSCFD
H2S	60		Acid gas removal	75.9	%
Methane	3				
Ethane	0.5		CO2 to SRU	6.98	MMSCFD
Propane	0.2		CO2 reduction to SRU	49.45	% (wrt feed)
i-Butane	0.1		H2S to SRU	41.09	MMSCFD
n-Butane	0.1				
i-Pentane	0.05		Power production using Distillation Stream		
n-Pentane	0.02		Total flow rate	24.3	MMSCFD
n-Hexane	0.02		Energy content	470.7	btu/scf
Heptane	0.02		Efficiency	0.50	
H2O	100		Power produced	69.8	MW
MEA	0				
AIR	0		Compressor Name		C1
Nitrogen	5		Actual Work	HP	11,486
Helium	300			kW	8,729

FIG. 5P

Helium in feed	0.159	MMSCFD
Feed to CO2 Distill Unit	0.146	MMSCFD
From CO2 dist unit	0.141	MMSCFD
Helium conc stream	0.140	MMSCFD
Helium REC from CO2 dist feed	95%	
overall Helium recovery	88%	
Compressor duty	1,832	HP
	1,392	Kw

Membrane # 3		
Area	415,000	sq ft
Area	38,569	sq m
perm pressure	85	Psia

FIG. 5Q

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2018/038076

A. CLASSIFICATION OF SUBJECT MATTER
INV. B01D53/14 B01D53/22 B01D53/30 C01B23/00 C10L3/10
B01D71/06
ADD.

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
B01D C01B C10L

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	US 2012/111051 A1 (KULKARNI SUDHIR S [US] ET AL) 10 May 2012 (2012-05-10)	1,2,4, 13-15, 17,26
Y	figure 2A paragraphs [0002], [0033], [0034], [0061], [0068] -----	3,4,16, 17
Y	US 2012/168154 A1 (CHINN DANIEL [US] ET AL) 5 July 2012 (2012-07-05)	3,4,16, 17
A	figure 2 paragraphs [0030], [0032], [0036], [0070] -----	1,2, 13-15,26

☐ 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 September 2018	28/11/2018

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	Pöhlmann, Robert

1

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2018/038076

Box No. II Observations where certain claims were found unsearchable (Continuation of item 2 of first sheet)

This international search report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:

2. ☐ Claims Nos.:
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:

3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box No. III Observations where unity of invention is lacking (Continuation of item 3 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

see additional sheet

1. ☐ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.

2. ☐ As all searchable claims could be searched without effort justifying an additional fees, this Authority did not invite payment of additional fees.

3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:

4. ☒ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

2-4, 13, 15-17, 26(completely); 1, 14(partially)

Remark on Protest

☐ The additional search fees were accompanied by the applicant's protest and, where applicable, the payment of a protest fee.

☐ The additional search fees were accompanied by the applicant's protest but the applicable protest fee was not paid within the time limit specified in the invitation.

☐ No protest accompanied the payment of additional search fees.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/US2018/038076

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2012111051 A1	10-05-2012	EP 2624935 A1	14-08-2013
		US 2012111051 A1	10-05-2012
		WO 2012048078 A1	12-04-2012
US 2012168154 A1	05-07-2012	CA 2823242 A1	05-07-2012
		EA 201390991 A1	30-12-2013
		US 2012168154 A1	05-07-2012
		WO 2012092040 A2	05-07-2012

FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. claims: 2-4, 13, 15-17, 26(completely); 1, 14(partially)

   A method and apparatus for treating a natural gas stream by using a membrane contactor to separate acid gases from the feed stream into a the permeate wherein the acid gases are separated from non-hydrocarbons in a distillation unit further comprising the retentate stream to an amine unit

   ---

2. claims: 5-9, 18-22(completely); 1, 14(partially)

   A method and apparatus for treating a natural gas stream by using a membrane contactor to separate acid gases from the feed stream into a the permeate wherein the acid gases are separated from non-hydrocarbons in a distillation unit, further comprising a additional membrane units for further separating the non-hydrocarbon overhead stream of the distillation unit.

   ---

3. claims: 10-12, 23-25(completely); 1, 14(partially)

   A method and apparatus for treating a natural gas stream by using a membrane contactor to separate acid gases from the feed stream into a the permeate wherein the acid gases are separated from non-hydrocarbons in a distillation unit, further comprising an additional distillation unit in order to selectively separate H2S and other acid gases from the permeate stream

   ---