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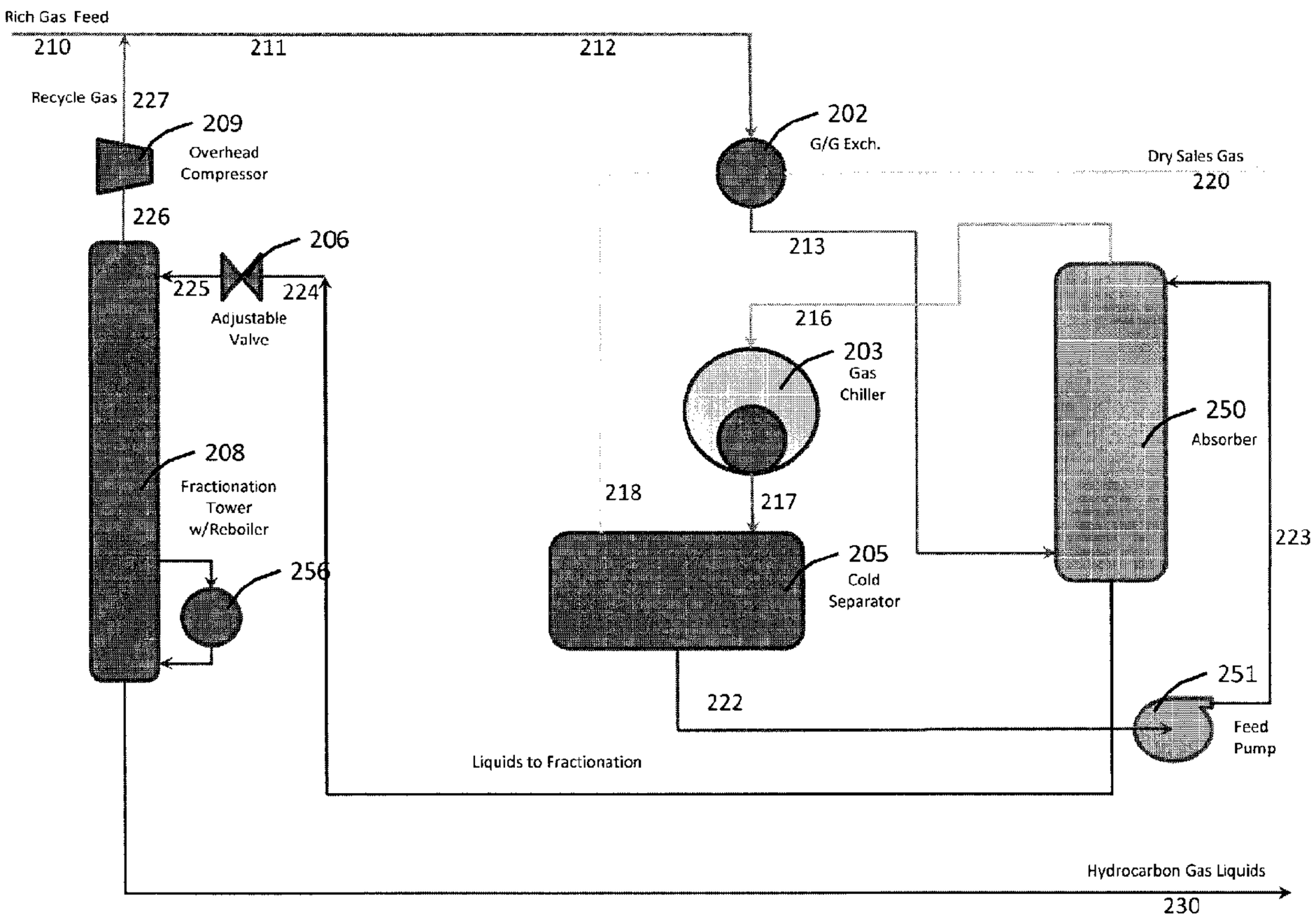
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(54) **Titre : PROCEDE ET APPAREIL DE TRAITEMENT D'UN FLUX DE GAZ D'HYDROCARBURE**
(54) **Title: PROCESS AND APPARATUS FOR PROCESSING A HYDROCARBON GAS STREAM**



(57) **Abrégé/Abstract:**
A process for separating a mixed or raw gas feed to produce a dry gas product and a hydrocarbon liquid product is provided. The process comprises scrubbing heavier hydrocarbon components from the gas feed to produce a lighter ends gas stream and a heavier ends liquid stream; cooling the lighter ends gas stream and separating the cooled lighter ends gas stream into a cold liquid stream and the dry gas product; and using the cold liquid stream to assist in scrubbing the heavier hydrocarbon components from the gas feed.

ABSTRACT

A process for separating a mixed or raw gas feed to produce a dry gas product and a hydrocarbon liquid product is provided. The process comprises scrubbing heavier hydrocarbon components from the gas feed to produce a lighter ends gas stream and a heavier ends liquid stream; cooling the lighter ends gas stream and separating the cooled lighter ends gas stream into a cold liquid stream and the dry gas product; and using the cold liquid stream to assist in scrubbing the heavier hydrocarbon components from the gas feed.

PROCESS AND APPARATUS FOR PROCESSING A HYDROCARBON GAS STREAM

FIELD OF THE INVENTION

The present invention is directed to a process and apparatus for processing a mixed hydrocarbon gas stream such as natural gas, refinery gas, and synthetic gas streams. More particularly, the present process and apparatus provide an enhanced and sharper separation of hydrocarbon mid-components (i.e., C_3 and/or C_4 hydrocarbons) from a mixed hydrocarbon gas stream. The present invention further provides the capability to direct a desired portion of the mid-components to either a gaseous product comprising the majority of C_1, C_2, hydrocarbons or a liquid product comprising the majority of C_5 and C_6+ hydrocarbons, or a chosen amount to both gas and liquid products in order to maximize profitability at any time.

BACKGROUND OF THE INVENTION

Raw or mixed hydrocarbon gas consists primarily of methane (CH_4) but also includes heavier gaseous hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), butanes (C_4H_{10}), pentanes (C_5H_{12}), higher molecular weight hydrocarbons (C_6+), and other hydrocarbon species and non-hydrocarbons associated with the raw gas source.

The relative amount of the heavier gaseous hydrocarbons, or richness, can be expressed in terms of gallons per mcf (thousand cubic feet), abbreviated as GPM. In this embodiment, GPM includes all hydrocarbon components heavier than methane and represents the total volume, in liquid gallons, contained in one thousand cubic feet of a particular gas at standard conditions.

The raw gas must be purified to produce a gas product that meets the quality standards specified by a particular gas transmission pipeline ("sales gas"). Typically, one of the objectives of gas processing is to remove liquefiable

hydrocarbons commonly referred to as hydrocarbon gas liquids (HGL) comprised of propane, butanes, pentanes and higher molecular weight C_{6+} hydrocarbons to meet the pipeline gas quality specification desired. A second objective is often then to remove further HGL (deeper cut, e.g., incremental $C_{3+}$and perhaps even ethane, C2) for economic gain. If the raw gas stream contains objectionable quantities of non-hydrocarbon compounds such as sulphur compounds or carbon dioxide, these are typically removed by pre-treatment processes not shown or discussed here. Similarly, excess water vapor in the raw gas stream is removed through dehydration.

A conventional approach to removing the HGL is to use the straight refrigeration process as described in the Gas Processors Suppliers Association Engineering Data Book, Chapter 16, 13th Edition. While there are several configurations known in the art for the straight refrigeration process, **Figure 1** (Prior Art) depicts a configuration that is commonly used in the industry and is hereinafter referred to as "conventional refrigeration process". In the conventional refrigeration process shown in Fig. 1, a rich gas feed (stream **110**) is combined with recycle gas (stream **127**) to produce stream **111**. Stream **111** is then separated into two steams, stream **112** and stream **114**, where stream **114** enters a gas-to-liquid heat exchanger **101** and stream **112** enters a gas-to-gas heat exchanger **102**. The heat exchangers reduce the temperature of the gas streams **112** and **114**, which streams exit as cooled gas stream **113** and cooled gas stream **115**, respectively. Streams **113** and **115** are then combined and combined cool gas stream (stream **116**) is further chilled in a second heat exchanger (gas chiller **103**), which uses mechanical refrigeration, typically using propane as the refrigerant, but could use any refrigerant type, and could include using Joule-Thompson expansion cooling. The desired temperature of the cold gas **117** produced is dependent on the raw gas composition, the pressure of the raw gas stream, the gas quality specification desired, and the economics of recovering additional liquids.

The cold gas **117** is sent to a cold gas separator (cold separator **105**), which is also referred to in the literature as a low temperature separator or LTS, where the condensed liquids **122** are separated from gas. The residual gas stream **118** from the cold separator **105** is returned to the gas-to-gas heat exchanger **102**, and is warmed by the incoming raw gas stream **112**. The warmed residual gas **119** is dry relative to the rich gas feed stream **110** and is often intended to be conveyed to the gas transmission pipeline for sale (dry sales gas 1**20**).

Liquids **122** from the cold separator **105** are warmed in the gas-to-liquid exchanger **101** and the warmed liquids **124** are then expanded through adjustable valve **106** which functions to hold a constant liquid level in the cold separator **105** and reduce the liquid stream pressure (stream **125**) before stream **125** enters the fractionation column or tower **108**. Heat exchangers **101** and **102** reduce the energy requirement in gas chiller **103**, by utilizing the energy already expended to chill the cold gas stream and transferring energy from warm to cold streams.

The fractionation tower **108** comprises a reboiler **156**, which provides heat and generates vapors to drive the distillation or fractionation process. The fractionation tower **108** distills the co-absorbed light components (primarily C_1, C_2, and sometimes C_3, and C_4 hydrocarbons) from the liquid stream to meet the HGL quality specifications of a liquids transporter and downstream refinery or fractionation facility. The fractionation tower may further comprises a reflux condenser (not shown) to improve separation of the light hydrocarbon components from the heavier ends liquid stream.

However, the composition of the HGL from the conventional refrigeration process is somewhat inflexible as discussed later,

The overhead gas stream **126** from the fractionation tower **108** is then compressed in overhead compressor **109** to produce recycle gas **127**. Recycle

gas **127** is recycled by combining with the rich gas feed **110** and reprocessed. The bottom liquids product **130** contains the HGL extracted from the gas stream. In one alternative, the overhead compressor gas **109** can be added as gas **128** to residual gas **119** to produce dry sales gas **120**.

In the conventional refrigeration process, the "mid-components", which are defined herein as C_3 and C_4 hydrocarbons, are extracted from the rich gas feed as liquid product and are therefore found in the HGL product. However, there may be times when market demand and product pricing does not economically support the extraction of the propane and butane from the raw gas, and, therefore, rejection of these constituents from the HGL product to the gas product is desired. In other words, there is more value for these mid-components to remain in the gas stream rather than be recovered as HGL product, provided gas transmission pipeline specifications are met.

There may also be times where the extraction of the heavier hydrocarbons is desired close to the source of the raw gas, and the extraction of the mid-components is desired at an alternate downstream gas processing plant, generally distant from the source and which feedstock often comprises an aggregation of several residue gas streams, to achieve economies of scale and close proximity to consumer markets.

To maintain these mid-components in the residue gas steam in a conventional refrigeration process, conventional practice has been to: adjust the temperature in gas chiller **103** to a higher temperature so as to reduce the amount of these constituents condensed and separated in cold separator **105** as liquid stream **122**; and/or adjust the operating conditions in the fractionation tower **108** and reboiler **156** in order to reject the co-absorbed mid components into stream **126** and recycle stream **127** back into the rich gas feed stream **110**; and in very rich raw gas feed streams, conventional practice is to re-direct the fractionation overhead gas stream **127** from combining with the raw gas feed

stream **110**, to combining with the residue gas stream **119**, via stream **128**, to form dry Sales Gas **120**.

However, the above practices to maintain mid-components in the dry sales gas stream **120** can result in low recoveries of the constituents that are desirable in the HGL product stream **130**. In other words, economic value is lost because a portion of the heavier hydrocarbons such as C_{6+}, pentanes, and sometimes butanes remain in the dry sales gas stream **120**. Therefore, there is a need in the industry for a process and apparatus that is capable of customizing the amount of propane and butane retained in a sales gas product from a raw gas stream without compromising the recovery of valuable heavy hydrocarbons such as C_5 and C_6+ components (HGL products) from the raw gas stream.

SUMMARY OF THE INVENTION

The present invention is directed to a process and apparatus for purifying a mixed hydrocarbon gas stream by removing hydrocarbon gas liquids (HGL) therefrom to produce a gas product that meets the sales gas quality standards intended. The present invention may be used to purify a variety of gases such as natural gas, refinery gas, and synthetic gas streams. In particular, the present invention is directed to a process and apparatus with the flexibility to direct mid-component hydrocarbons (i.e., C_3 and C_4 hydrocarbons) contained in a mixed hydrocarbon gas stream (C_1 to C_{6+}) to produce a gas product comprising the majority of C_1 and C_2 components and having a desired proportion of mid-components (i.e., C_3 and C_4 hydrocarbons) and a liquid product comprising the majority of C_5 and C_6+ hydrocarbons and having a desired proportion of mid-components. In other words, the present invention provides the versatility to produce either: a C_{3+} rich HGL stream, with a very high percentage recovery of the C_{4+} components; or a high recovery C_{4+} HGL stream; or strictly a very high recovery C_{5+} HGL stream; with all other components remaining in the sales gas stream.

In one aspect, the present invention provides a process and apparatus that enhances hydrocarbon gas liquids (HGL) recovery from mixed hydrocarbon gas streams when compared to a conventional refrigeration process. More particularly, a process and apparatus is provided which includes the addition of an absorber between a gas/gas heat exchanger and a gas chiller of a conventional refrigeration process. Cold separator liquids are pumped to the top of the absorber as a rectifying solution. The enhancement results in very high recovery of heavy hydrocarbons such as C_5+ components from the gas stream, with the potential to direct a desired proportion of mid-components to the gas product or the HGL product. Furthermore, the enhancement often results in lower utility loads for very rich gas streams as compared to the conventional refrigeration process.

Thus, in one aspect, a process is provided for separating a mixed or raw gas feed such as natural gas, refinery gas and synthetic gas, the gas feed containing methane, C_2 components, C_3 components, C_4 components and heavier hydrocarbon components (C_5+), into a dry gas product containing a portion of C_3 and C_4 components, comprising:

- scrubbing heavier hydrocarbon components from the gas feed to produce a lighter ends gas stream and a heavier ends liquid stream;
- cooling the lighter ends gas stream and separating the lighter ends gas stream into a cold liquid stream and the dry gas product; and
- using the cold liquid stream to assist in scrubbing the heavier hydrocarbon components from the cooled gas feed.

In one embodiment, the process includes cooling the gas feed prior to scrubbing to reduce energy consumption required for cooling the lighter ends gas stream. In another embodiment, the process further comprises flash distillation and/or fractionating the heavier ends liquid stream to form a hydrocarbon gas

liquid product and an overhead gas stream. In one embodiment, the overhead gas stream is compressed and the compressed gas stream is combined with the mixed or raw gas feed. In one embodiment, the hydrocarbon gas liquid product comprises the majority of C5+ hydrocarbon components from the mixed or raw gas feed.

In another aspect, an apparatus is provided for separating a mixed or raw gas feed such as natural gas, refinery gas and synthetic gas, the gas feed containing methane, C_2 components, C_3 components, C_4 components and heavier hydrocarbon components (C_5+) into a dry gas product containing a portion of C_3 and C_4 components, comprising:

- an absorber for receiving the gas feed and scrubbing heavier hydrocarbon components from the gas feed to form a lighter ends gas stream and a heavier ends liquid stream;

- a first cooling device for receiving the lighter ends gas stream and cooling the lighter ends gas stream; and

- a cold separator for receiving the cooled lighter ends gas stream and removing condensed liquids from the cooled lighter ends gas stream to form the dry gas product.

In one embodiment, the apparatus further comprises at least one second cooling device for cooling the gas feed prior to sending it to the absorber. In another embodiment, the apparatus further comprises a feed pump for pumping the condensed liquids to the absorber to assist in scrubbing heavier hydrocarbon components from the gas feed. In another embodiment, the apparatus further comprises a flash separator and/or a fractionation tower for receiving the heavier ends liquid stream from the absorber and fractionating the heavier ends liquid stream to form hydrocarbon gas liquids and an overhead gas stream. In another embodiment, the apparatus further comprises an overhead gas compressor to

increase the pressure of the overhead gas stream to form a recycle gas stream for reprocessing. In one embodiment, the recycle gas stream is added to the mixed or raw gas feed prior to further processing.

In another aspect, an improved apparatus is provided for separating a mixed or raw gas feed including natural gas, refinery gas, and synthetic gas, the gas feed containing methane, C_2 components, C_3 components, C_4 components and heavier hydrocarbon components (C_5+), into a dry gas product containing a portion of C_3 and C_4 components, said apparatus comprising in series at least one heat exchanger, a gas chiller, a cold separator and a gas/liquid fractionator, said improvement comprising:

- an absorber operably connected to the at least one heat exchanger for receiving a cooled gas feed from the at least one heat exchanger and scrubbing heavier hydrocarbon components from the cooled gas feed in the absorber to form a lighter ends gas stream and a heavier ends liquid stream prior to sending the lighter ends gas stream to the gas chiller.

Other features will become apparent from the following detailed description. It should be understood, however, that the detailed description and the specific embodiments, while indicating preferred embodiments of the invention, are given by way of illustration only, since various changes and modifications within the spirit and scope of the invention will become apparent to those skilled in the art from this detailed description.

BRIEF DESCRIPTION OF THE DRAWINGS

Referring to the drawings wherein like reference numerals indicate similar parts throughout the several views, several aspects of the present invention are illustrated by way of example, and not by way of limitation, in detail in the following figures. It is understood that the drawings provided herein are for illustration purposes only and are not necessarily drawn to scale.

Figure 1 is a schematic depiction of a conventional refrigeration process and apparatus of the prior art.

Figure 2 is a schematic depiction of one embodiment of the process and apparatus of the present invention.

Figure 3 is a schematic depiction of another embodiment of the process and apparatus of the present invention as an addition or retrofit to an existing conventional refrigeration process.

Figure 4 is a graph showing the % recovery of C_4, C_5 and C_6+ hydrocarbons in a HGL stream from a hydrocarbon gas stream when using the process of the present invention (Enhanced) to effectively direct all the C_3 to the sales gas stream over a feed gas richness ranging from 1 to 9 GPM, (gal/mcf) in comparison to the conventional refrigeration process of the prior art.

Figure 5 is a graph showing the % recovery of C_6+, C_5, C_4, C_3, from a hydrocarbon gas stream having a richness of 5 GPM at a constant cold separator pressure of 600 Psig, and at various cold separator temperatures ranging between -40 °F and 20 °F, using the process of the present invention (Enhanced) when directing effectively all the C_3 to the sales gas stream, in comparison to the conventional refrigeration process of the prior art.

Figure 6 is a graph showing the % recovery of C_5, and C_4, from a hydrocarbon gas stream having a richness of 5 GPM at a constant cold separator temperature of 13 °F, and at various cold separator pressures between 200 Psig and 1200 Psig, using the process of the present invention (Enhanced) when directing effectively all the C_3 to the sales gas stream, in comparison to the conventional refrigeration process of the prior art.

Figure 7 is a graph showing the C_4 recovery versus refrigeration power for a hydrocarbon gas stream having a richness of 5 GPM using the process of the

present invention (Enhanced) in comparison to the conventional refrigeration process of the prior art.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The detailed description set forth below in connection with the appended drawings is intended as a description of various embodiments of the present invention and is not intended to represent the only embodiments contemplated by the inventor. The detailed description includes specific details for the purpose of providing a comprehensive understanding of the present invention. However, it will be apparent to those skilled in the art that the present invention may be practiced without these specific details.

The purpose of gas processing such as natural gas processing is to convert raw natural gas into sales gas and HGL which can be delivered to end user markets. In other words, gas processing conditions gas to commercial specifications, e.g., hydrocarbon dew point (HCDP), water content, heating value, and other qualities as specified by a particular gas transmission or distribution company. Further, gas processing allows for the recovery of higher value liquefied products such as C_2, C_3, C_4, and C_5+ hydrocarbons, processed by one or more fractionation steps to meet commercial specifications such as hydrocarbon component content, vapor pressure, and density. As used herein "rich gas" means a gas which contains heavier hydrocarbons and is typically between temperatures of 30 °F and 120 °F, and is typically provided at pressures between 200 Psig and 1000 Psig.

Figure 2 shows one embodiment of a hydrocarbon gas processing plant of the present invention. In particular, rich gas feed **210** is combined with recycle gas (stream **227**) to produce stream **211**, which stream **211** can be further processed in at least one heat exchanger. In the embodiment shown in **Figure 2**, stream **211** is only fed to a single heat exchanger as stream **212**. Stream **212** is fed into a gas/gas heat exchanger **202** and is cooled in heat exchanger **202** by

heat exchange with cool stream **218**. It is understood, however, that stream **212** can be cooled in one or more of any cooling device, for example, such as a cooling tower, evaporative cooler, water chiller, gas chiller, waste heat exchanger, Joule-Thompson expansion valve, and the like.

However, unlike in the conventional refrigeration process shown in **Figure 1** (Prior Art), cooled gas stream **213** is directed to the bottom of heavy ends absorber tower **250**, where the heavy ends are scrubbed out. Thus, in this embodiment, the flow of cooled gas stream **213** does not go to gas chiller **203** (as is the case in the conventional refrigeration process) and, instead, is directed to absorber **250**. The absorber may be filled with suitable packing or trays. In absorber **250**, the heavy ends are scrubbed out and are removed from the bottom of absorber **250** as liquids **224**. The remaining scrubbed gas stream **216** is removed from the top of the absorber **250** and directed into gas chiller **203** for further cooling. It is understood, however, that stream **216** can be cooled in one or more of any cooling device, for example, such as a Joule-Thompson expansion valve, gas chiller, waste heat/cold exchanger, and the like. Gas chiller **203** commonly uses propane as the refrigerant but other refrigerants known in the art can also be used. Temperatures in the chiller typically range between -40 °F and 25 °F.

The cold gas **217** is then fed to a cold gas separator **205**, where the condensed liquids **222** are separated from the gas stream. The dry residue gas stream **218** that is produced in cold gas separator **205** is directed to gas/gas heat exchanger **202** and is used to cool gas stream **212**. It is understood that heat exchanger **202** aids in reducing the energy requirement in gas chiller **203**, and elevates the temperature of the sales gas stream **220** for further processing or transmission. The warmed sales gas **220** is dry relative to the rich gas feed stream **210**, and is often intended to be conveyed to the gas transmission pipeline for sale (dry sales gas **220**). It is understood, however, that warming the sales gas stream may not be necessary if the sales gas stream is intended to go

to further cryogenic processing, for example, ethane production or liquefied natural gas (LNG) production.

Condensed liquids **222** produced in cold separator **205** are then pumped via feed pump **251** and returned to the top of absorber **250** as liquid stream **223**. The counter-current flow of cooled gas stream **213** and liquid stream **223** allow the two streams to contact one another in the absorber **250** and, thus, provides multiple stages of contact to alter the composition of both the gas stream produced (gas stream **216**) and the liquid stream **224**. In particular, liquid stream **224** will contain fewer light hydrocarbons (e.g., C_1 and C_2 hydrocarbons) than in stream 223 and additional heavy hydrocarbons (e.g., C_5+ hydrocarbons), which have been removed (scrubbed) from the cooled gas stream **213**. Hence, the heavy hydrocarbons are scrubbed from the cooled gas stream **213** and the light hydrocarbons are stripped from light liquid stream **223**. Thus, the absorber **250**, gas chiller **203** and cold separator **205**, in combination, operate as a rectifier column, reducing the light end components and increasing the heavier components in the absorber **250** bottom liquid product stream **224**, thereby providing sharp separation between light key components and heavy key components.

The liquid stream **224** is removed from the bottom of absorber **250** and flash expanded through expansion (adjustable) valve **206** to the operating pressure of fractionation tower **208**. During expansion a portion of the stream is vaporized, resulting in cooling of the total stream. The expanded stream **225** leaving expansion valve **206** is sent to fractionating tower **208** to distill the light ends (e.g. methane, ethane and propane) from the liquid, resulting in heavy liquid product **230** and light ends gaseous stream **226**. The fractionation tower **208** comprises a reboiler **256**, which provides heat and generates vapors to drive the distillation or fractionation process. The fractionation tower pressure typically ranges between 80 Psig to 350 Psig and reboiler temperatures range may from 140 °F to 320 °F. The fractionation tower provides the versatility and ability to reject the

desired proportion of mid-components from the heavy liquid product stream **225**, back into the raw gas as the overhead gas stream **226**. The selected operating pressure and temperature is dependent in part on what portions of mid-components are to be rejected, and the composition of the heavy liquid stream. In one embodiment, the fractionation tower **208** may further comprises a reflux condenser (not shown) to improve separation of the mid-components from the heavier ends liquid stream.

The overhead gas stream **226** from the fractionation tower **208** is then compressed in overhead compressor **209** to produce recycle gas **227**. Recycle gas **227** is recycled by combining with the rich gas feed **210** and reprocessed. The bottom heavy liquids product **230** contains the HGL extracted from the gas stream.

In comparison to the conventional refrigeration process shown in **Figure 1**, the HGL **230** produced by the process shown in **Figure 2** of the present invention significantly increases the volume of C_5 recovered from rich gas streams having greater than 2 GPM, and significantly improves the propane rejection to the residue stream (sales gas). For example, with certain rich gas streams, i-pentane recovery in the HGL may be increased from 84.74% to 99.52%. Further, C_3 rejection from HGL **230** may increase from 76.60% to 97.22%. Consequently, the dry sales gas **220** can be tailored to contain more propane and butane, thereby maximizing value from the raw gas stream for specific economic conditions.

In one embodiment, the conventional refrigeration process equipment shown in **Figure 1** can be retrofitted with an absorber to achieve similar benefits as realized when practicing the process shown in **Figure 2** and described above. With reference now to **Figure 3**, in this embodiment, rich gas feed (stream **310**) is combined with recycle gas (stream **327**) to produce stream **311**. Stream **311** is then separated into two steams, stream **312** and stream **314**, where stream **314** enters a gas-to-liquid heat exchanger **301** and stream **312** enters a gas-to-gas

heat exchanger **302**. The heat exchangers reduce the temperature of the gas streams **312** and **314**, which streams exit as cooled gas stream **315** and cooled gas stream **313**, respectively. Streams **313** and **315** are then combined and, when block valve 352 is in the closed position, the combined cool gas stream (stream **331**) is directed to the bottom of heavy ends absorber tower **350**, where the heavy ends are scrubbed out. The flow of both cooled gas stream **313** and cooled gas stream **315** is controlled by block valve **352**. In absorber **350**, the heavy ends are scrubbed out and are removed from the bottom of absorber **350** as liquids **332**. The remaining scrubbed gas stream **316** is removed from the top of the absorber **350** and directed into gas chiller **303** for further cooling. It is understood, however, that stream **316** can be cooled in one or more of any cooling device, for example, such as a Joule-Thompson expansion valve, gas chiller, waste heat/cold exchanger, and the like. Gas chiller **303** commonly uses propane as the refrigerant but other refrigerants known in the art can also be used. Temperatures in the chiller typically range between - 40 °F and 25 °F.

The cold gas **317** is then fed to a cold gas separator **305**, where the condensed liquids **322** are separated from the gas stream. The dry residue gas stream **318** that is produced in cold gas separator **305** is directed to gas/gas heat exchanger **302** and is used to cool gas stream **312**. It is understood that heat exchangers **301** and **302** aid in reducing the energy requirement in gas chiller **303**, and elevate the temperature of the sales gas stream **320** for further processing or transmission. The warmed sales gas **320** is dry relative to the rich gas feed stream **310**, and is often intended to be conveyed to the gas transmission pipeline for sale (dry sales gas **320**). It is understood, however, that warming the sales gas stream may not be necessary if the sales gas stream is intended to go to further cryogenic processing, for example, ethane production or liquefied natural gas (LNG) production.

When block valve **353** is in the closed position, condensed liquids **322** produced in cold separator **305** are pumped via feed pump **351** and returned to

the top of absorber **350** as liquid stream **323**. The counter-current flow of combined cool gas stream **331** and liquid stream **323** allow the two streams to contact one another in the absorber **350** and, thus, provides multiple stages of contact to alter the composition of both the gas stream produced (gas stream **316**) and the liquid stream **332**. In particular, liquid stream **332** will contain fewer light hydrocarbons (e.g., C_1 and C_2 hydrocarbons) than in stream 323 and more heavy hydrocarbons (e.g., C_5+ hydrocarbons), which have been removed (scrubbed) from the combined cool gas stream **331**. Hence, the heavy hydrocarbons are scrubbed from the combined cool gas stream **331** and the light hydrocarbons are stripped from the liquid. Thus, in this embodiment, the absorber **350**, gas chiller **303** and cold separator **305**, in combination, also operate as a rectifier column, reducing the light end components and increasing the heavier components in the absorber **350** bottom liquid product stream **332**, thereby providing sharp separation between light key components and heavy key components.

The liquid stream **332** is removed from the bottom of absorber **350** and passes into Gas/Liquid heat exchanger **301**, being warmed by the raw gas stream **314**. Stream **324** exits Gas/Liquid heat exchanger **301** and is flash expanded through expansion (adjustable) valve **306** to the operating pressure of fractionation tower **308**. During expansion a portion of the stream is vaporized, resulting in cooling of the total stream. The expanded stream **325** leaving expansion valve **306** is sent to fractionating tower **308** to distill the light ends (e.g. methane, ethane and propane) from the liquid, resulting in heavy liquid product **330** and light ends gaseous stream **326**. The fractionation tower **308** comprises a reboiler **356**, which provides heat and generates vapors to drive the distillation or fractionation process. In one embodiment, the fractionation tower **308** may further comprises a reflux condenser (not shown) to improve separation of the light ends (e.g. methane, ethane and propane) from the heavier ends liquid stream.

The overhead gas stream **326** from the fractionation tower **308** is then compressed in overhead compressor **309** to produce recycle gas **327**. Recycle gas **327** is recycled by combining with the rich gas feed **310** and reprocessed. The bottom heavy liquids product **330** contains the HGL extracted from the gas stream.

Thus, in the embodiment shown in FIG. **3**, the hydrocarbon gas processing plant can operate either as a conventional refrigeration processing plant or as a hydrocarbon gas processing plant of the present invention. When blocking valves **352**, **353** are in the closed position, the plant operates as a hydrocarbon gas processing plant of the present invention. However, when block valves **352**, **353** are in the open position, the plant will operate as a conventional refrigeration processing plant. The present invention is adaptable to existing gas processing plants already employing the prior art, or a version thereof.

Example 1

A comparison of the composition of the sales gas produced from the conventional refrigeration process (**Figure 1** (Prior Art)) and the sales gas of the present invention (**Figure 2**) when targeting a sales gas hydrocarbon dew point (HCDP) of 23 °F at 800 Psig is shown in Table 1 below.

Table 1

Component – mol fraction	Rich Gas Feed	Conventional Sales Gas	Enhanced Sales Gas
Helium	0.000993	0.001043	0.001029
Nitrogen	0.008428	0.008856	0.008737
CO2	0.007692	0.008044	0.007973
H2S	0.000002	0.000002	0.000002
Methane	0.721123	0.757708	0.747454
Ethane	0.144403	0.151728	0.149624
Propane	**0.073780**	**0.059381**	**0.073939**
i-Butane	0.011130	0.004904	0.005582
n-Butane	0.021026	0.007102	0.005637
i-Pentane	0.004011	0.000643	0.000021
n-Pentane	0.003884	0.000476	0.000004
Hexane	0.001685	0.000072	**0.000000**
Heptane	0.001176	0.000034	**0.000000**
Octane	0.000574	0.000008	**0.000000**
Nonane	0.000078	**0.000000**	**0.000000**
Decane +	0.000014	**0.000000**	**0.000000**
	1.000000	1.000000	1.000000

It can be seen from Table 1 that when using the present invention (Enhanced), much more propane and i-butane report to the sales gas and much less C_5+ hydrocarbons (i.e., i-pentane, n-pentane, n-hexane, n-heptane, n-octane, n-nonane and n-decane) are present therein when compared to the sales gas of the Prior Art (Conventional). Further, essentially no heavy hydrocarbons (C_5+ components) were found in the sales gas. Hence, the enhancement of the present invention results in high recovery (removal) of heavy hydrocarbons (C_5+ components) from the rich gas feed and more rejection of lighter hydrocarbons such as C_3 and i-C_4 to the sales gas product. Yet, both conventional and enhanced sales gas streams achieve the same HCDP.

Thus, under prescribed conditions, the present invention (Enhanced) produces a more valuable HGL stream per unit of volume than when using the Prior Art conventional refrigeration process. This can be seen more clearly in Table 2.

Table 2

Process		**Conventional**	**Enhanced**	
Parameter	Units			
Rich Gas Feed Rate	MMscfd	26.3	26.3	
Sales Gas HCDP	°F at 800 Psig	**Target 23°**	**Target 23°**	
Cold Sep. Temperature	°F	-4.0	11.1	
Cold Sep. Pressure	Psig	490	480	
Chiller duty	MMbtu/hr	3.09	2.46	
Refridge Compressor Load	HP	788	569	-27.8%
HC liq to Fractionator	bbl/day	2140	1874	
Fractionator Pressure	Psig	270	270	
Fractionator Ovhd. Vol.	MMscfd	2.49	1.93	
Overhead Compressor Load	HP	84	65	-22.6%
Fractionator Reboiler Temperature	°F	204	252	
Fractionator Reboiler Duty	MMbtu/hr	1.89	2.04	7.9%
HGL Product Volume	bbl/day	942	729	
Sales Gas Volume	MMscfd	25.02	25.37	1.4%
Higher Heating Value	btu/scf	1219	1234	1.2%
Propane Recovery	% of Feed	23.40	2.78	
i-Butane Recovery	% of Feed	58.07	51.68	
n-Butane Recovery	% of Feed	67.85	74.55	
i-Pentane Recovery	% of Feed	84.74	99.52	
n-Pentane Recovery	% of Feed	88.33	99.91	
Hexane Recovery	% of Feed	95.93	100.00	
Heptane Recovery	% of Feed	98.55	100.00	
Propane Yield	bbl/day	293.3	38.7	
Butanes Yield	bbl/day	408.4	422.4	
C5+ Yield	bbl/day	240.7	267.8	
HGL-Product:Feed Ratio	bbl/MMscf	37.68	29.14	

In particular, when targeting a sales gas HCDP of 23°F at 800 Psig, it can be seen from Table 2 that the HGL stream produced using the Conventional process yields 293.3 bbl/d propane, 408.4 bbl/d of butanes and 240.7 bbl/d of pentanes+ (C_{5+}). On the other hand, when using the Enhanced process of the present invention, only 38.7 bbl/d of propane are yielded in the HGL stream. This results in a marginally higher sales gas volume with slightly higher heating value due to more propane (C3) being directed to the sales gas stream, which may be favorable for specific economic conditions. Further, 267.8 bbl/d of pentanes+ (C_{5+}) are yielded in the HGL stream (as compared to 240.7 bbl/d in Conventional), resulting in better recovery of heavy hydrocarbons in the HGL product.

Furthermore, Table 2 shows that when using the Enhanced process of the present invention the refrigeration compressor load decreases 27.8%, and the overhead compressor load decreases 22.6%, resulting in significantly lower utility requirements and slightly smaller equipment having lower capital costs, when comparing to the conventional refrigeration process (Prior Art). Further, the cold separator can be operated at a much higher temperature, i.e., 11.1°F versus -4.0°F with the conventional refrigeration process.

Table 3 below further illustrates the difference in intermediate liquid streams compositions generated in the conventional refrigeration of the prior art as compared to the present invention (Enhanced). Specifically, in the present invention, stream **222**, which is the liquid stream produced in the cold separator **205**, contains much less C_{5+} (heavy ends) as compared to stream **122** in the conventional refrigeration process. This is because the C_{5+} (heavy ends) have already been stripped out of the raw gas in the absorber **250**, and, thus, a much lighter liquid product is produced in cold separator **205** to send to the absorber **250** as a scrubbing fluid.

Thus, liquid streams **224**, **225,** which are produced in the absorber **250** and fed to the fractionation tower **208**, respectively, will contain higher volume flows of C_4 (and C_{5+} heavier components) and much less C_3 and lighter components when compared to liquid streams **122**, **124** and **125** of the conventional art, which streams are produced in the cold separator **105**, cooled in gas/liquid exchanger **101**, and fed into fractionation tower **108**, respectively.

Table 3

Component - bbl/d	Stream 122 & 125 **Conventional** Cold Sep. Liquid & Liq. To Frac.	Stream 222 **Enhanced** Cold Sep. Liquid	Stream 225 **Enhanced** Liq. To Frac.
Helium	0	0	0
Nitrogen	1	1	1
CO2	9	6	4
H2S	0	0	0
Methane	358	234	190
Ethane	555	396	286
Propane	670	693	531
i-Butane	168	147	177
n-Butane	333	198	410
i-Pentane	84	2	103
n-Pentane	82	0	97
Hexane	42	0	45
Heptane	29	0	30
Octane	7	0	7
Nonane	11	0	11
Decane +	1	0	1
	2349	1678	1892

Example 2

Table 4 below shows the flexibility of the present invention using the same rich gas feed as in Example 1. In this example, the objective is to obtain the maximum liquids possible, including propane and butanes, while the refrigeration

compressor load is limited to 1151 HP for both the Conventional and Enhanced process.

Table 4

Component – mol fraction	Rich Gas Feed	**Conventional** Sales Gas	**Enhanced** Sales Gas
Helium	0.000993	0.001081	0.001085
Nitrogen	0.008428	0.009176	0.009212
CO2	0.007692	0.008321	0.008407
H2S	0.000002	0.000002	0.000002
Methane	0.721123	0.784952	0.788098
Ethane	0.144403	0.156153	0.156904
Propane	0.073780	0.034538	0.036099
i-Butane	0.011130	0.002296	0.000159
n-Butane	0.021026	0.003042	0.000034
i-Pentane	0.004011	0.000237	**0.000000**
n-Pentane	0.003884	0.000166	**0.000000**
Hexane	0.001685	0.000022	**0.000000**
Heptane	0.001176	0.000010	**0.000000**
Octane	0.000574	0.000002	**0.000000**
Nonane	0.000078	**0.000000**	**0.000000**
Decane +	0.000014	**0.000000**	**0.000000**
	1.000000	1.000000	1.000000

Process Parameter	Units	**Conventional**	**Enhanced**	
Rich Gas Feed Rate	MMscfd	26.3	26.3	
Sales Gas HCDP	°F at 800 Psig	-5.8	-18.0	
Cold Sep. Temperature	°F	-13.0	-29.2	
Cold Sep. Pressure	Psig	490	480	
Chiller duty	MMbtu/hr	4.35	3.61	
Refridge Compressor Load	HP	**1151**	**1154**	0.3%
HC liq to Fractionator	bbl/day	8416	2679	
Fractionator Pressure	Psig	300	300	
Fractionator Ovhd. Vol.	MMscfd	4.28	2.11	
Overhead Compressor Load	HP	144	63	-56.3%
Frationator Reboiler Temp.	°F	188	192	
Fractionator Reboiler Duty	MMbtu/hr	2.49	2.27	-8.8%

HGL Product Volume	bbl/day	1521	1599	
Sales Gas Volume	MMscfd	24.14	24.05	-0.4%
Higher Heating Value	btu/scf	1167	1157	-0.9%
Propane Recovery	% of Feed	57.00	55.23	
i-Butane Recovery	% of Feed	81.05	98.69	
n-Butane Recovery	% of Feed	86.71	99.85	
i-Pentane Recovery	% of Feed	94.56	100.00	
n-Pentane Recovery	% of Feed	96.07	100.00	
Hexane Recovery	% of Feed	98.80	100.00	
Heptane Recovery	% of Feed	99.61	100.00	
Propane Yield	bbl/day	713.0	690.4	
Butanes Yield	bbl/day	536.6	628.6	
C5+ Yield	bbl/day	257.8	266.9	
		1,507	1,586	5.2%
HGL-Product:Feed Ratio	bbl/MMscf	60.82	63.93	5.1%

Under the prescribed conditions, the present invention (Enhanced) is capable of achieving a lower Cold Separator temperature and consequently recovering higher amounts of HGL than when using the conventional refrigeration process (Conventional). Once again, the sales gas composition of the Enhanced process contains a lesser amount of butanes (C_4) and pentanes+ (C_{5+}) than does the Conventional process. As well, the utility requirements for the Overhead compressor load and Fractionation Reboiler Duty are significantly less.

Examples 3 and 4

Table 5 further shows the flexibility of the Enhanced process of the present invention using the same rich gas feed as in Example 1 and Example 2 above. Example 3 reflects the ability to reject propane into the sales gas stream, yet with high butane recovery in the HGL stream. Example 4 reflects the ability to direct both propane and butane into the sales gas stream to produce a de-butanized condensate (C_{5+}) product stream.

Table 5

Component – mol fraction	Rich Gas Feed	**Example 3 Enhanced Propane Rejection** Sales Gas	**Example 4 Enhanced Butane Rejection** Sales Gas
Helium	0.000993	0.001038	0.001005
Nitrogen	0.008428	0.008817	0.008537
CO2	0.007692	0.008043	0.007789
H2S	0.000002	0.000002	0.000002
Methane	0.721123	0.754234	0.730304
Ethane	0.144403	0.150850	0.146128
Propane	0.073780	0.074884	0.074431
i-Butane	0.011130	0.001593	0.011147
n-Butane	0.021026	0.000538	0.020250
i-Pentane	0.004011	0.000001	0.000324
n-Pentane	0.003884	**0.000000**	0.000084
Hexane	0.001685	**0.000000**	**0.000000**
Heptane	0.001176	**0.000000**	**0.000000**
Octane	0.000574	**0.000000**	**0.000000**
Nonane	0.000078	**0.000000**	**0.000000**
Decane +	0.000014	**0.000000**	**0.000000**
	1.000000	1.000000	1.000000

Process

Parameter	Units		
Rich Gas Feed Rate	MMscfd	26.3	26.3
Sales Gas HCDP	°F at 800 Psig	10.4	48.0
Cold Sep. Temperature	°F	-2.2	36.0
Cold Sep. Pressure	Psig	480	480
Chiller duty	MMbtu/hr	3.46	2.12
Refridge Compressor Load	HP	864	449
HC liq to Fractionator	bbl/day	3234	2233
Fractionator Pressure	Psig	270	100
Fractionator Ovhd. Vol.	MMscfd	3.89	2.94
Overhead Compressor Load	HP	128	262
Fractinoator Reboiler Temp.	°F	248	248
Fractionator Reboiler Duty	MMbtu/hr	3.51	2.55

HGL Product Volume	bbl/day	895	274
Sales Gas Volume	MMscfd	25.13	25.95
Higher Heating Value	btu/scf	1216	1279
Propane Recovery	% of Feed	2.99	0.41
i-Butane Recovery	% of Feed	86.32	1.15
n-Butane Recovery	% of Feed	97.56	4.94
i-Pentane Recovery	% of Feed	99.99	92.02
n-Pentane Recovery	% of Feed	100.00	97.86
Hexane Recovery	% of Feed	100.00	100.00
Heptane Recovery	% of Feed	100.00	100.00
Propane Yield	bbl/day	29.8	0.0
Butanes Yield	bbl/day	596.6	13.2
C5+ Yield	bbl/day	268.3	261.2
		895	274
HGL-Product:Feed Ratio	bbl/MMscf	35.77	10.97

In Example 3, the results show a sharp separation between C_3 (propane) recovery at 2.99% and i-C_4 (i-butane) recovery at 86.32%. Example 4, under different operating conditions, shows a sharp distinction between n-C_4 (n-butane) recovery of 4.94%, and iC_5 (i-pentane) recovery of 92.02%.

Examples 1 to 4 demonstrate the flexibility of the present invention and enable one to respond to market conditions to maximize the profitability from a raw gas stream.

Example 5

In Example 5, the process of the present invention is used (Enhanced refrigeration) to recover sales gas and HGL product. The cold separator is operated at -13°F and 600 Psig and various gas feeds of varying richness were contemplated. The relative richness or amount of the heavier gaseous hydrocarbons, can be expressed in terms of gallons per mcf (thousand cubic feet), abbreviated as GPM. In this embodiment, GPM includes all hydrocarbon components heavier than methane and represents the total volume, in liquid

gallons, contained in one thousand cubic feet of a particular gas at standard conditions.

Recovery of C_6+ (heavy hydrocarbons), C_5 (pentane) and C_4 (butane) in the HGL product were determined and the results are shown in **Figure 4**. It can be seen from the graph in **Figure 4** that, in both the present invention (Enhanced) and the conventional process (Conventional), the component recoveries gradually increase with increasing gas richness. However, component recoveries in the present invention (Enhanced) exceed the component recoveries in the conventional process (Conventional) when using raw gas feed streams having richness of about 2 GPM and higher. It can be seen that for 4 GPM gas, very high recoveries, approaching 100% of C_5 and C_6+, can be recovered in the HGL stream (i.e., removed from the raw gas feed stream).

Also significant is the fact that, when using the present invention (Enhanced) with any of the raw gas feed richness examined, essentially no propane is recovered in the HGL product. Thus, when using the present invention (Enhanced), essentially the total amount of propane can report to the sales gas stream under selected conditions. However, as demonstrated in Example 2, a significant amount of propane recovery is possible.

Example 6

In Example 6, the cold separator was operated at 600 Psig and various operating temperatures of the cold separator were contemplated using a raw gas feed stream having a richness of 5 GPM employing both the conventional prior art process (Conventional) and the process of the present invention (Enhanced). The graph in **Figure 5** shows that the cold separator can be operated at much higher temperatures in the present invention (Enhanced) for recovery of 100% of the C_5 and C_6+ hydrocarbons (in the HGL product) than when using the conventional refrigeration process (Conventional). In particular, at about -13°F,

100% of C_5 was recovered in the present invention (Enhanced) whereas only about 92% of the C_5 was recovered using conventional refrigeration process (Conventional). In fact, even at -25°F, only about 95% of the C_5 was recovered in the conventional refrigeration process (Conventional). Also at the -25°F cold separator temperature, the present invention (Enhanced) is capable of recovering 100% of the butane, whereas about only 80% of the C_4 will also be removed by the conventional refrigeration process (Prior Art).

Figure 5 also shows that, when it is desirable for butane to report to the sales gas stream and be rejected from the HGL stream, 97.4% C_5 recovery can be achieved at only 14°F cold separator temperature. Further, it can be seen that for all temperature ranges, very little C_3 (propane) can be directed to the HGL product when using the present invention (Enhanced).

Example 7

In Example 7, the cold separator was operated at -13 °F and various operating pressures between 200 and 1200 Psig of the cold separator were contemplated, using a raw gas feed stream having a richness of 5 GPM. In this example, it was desirable to have all of the C_3 report to the sales gas stream and the majority of the C_4 and C_5 report to the HGL stream. Both the conventional prior art process (Conventional) and the process of the present invention (Enhanced) were investigated. The graph in **Figure 6** shows that the cold separator can be operated at a much broader range of pressures in the present invention (Enhanced) for recovery of 100% of the C_5 and C_6+ hydrocarbons (in the HGL product) than when using the conventional refrigeration process (Conventional). In particular, between 400 Psig and 1000 Psig, 100% of C_5 was recovered in the present invention (Enhanced) whereas only between 80% and 92% of the C_5 was recovered using the conventional refrigeration process (Prior Art).

Figure 6 also shows that, when the pressure exceeds 500 Psig, that butane recovery in the Present Invention exceeds that of the conventional refrigeration process (Prior Art). In fact, the maximum butane recovery for the Present Invention (Enhanced) is about 84% and occurs at about 800 Psig, as compared to the Prior Art (Conventional) butane recovery at about 69%.

The present invention provides the potential to produce a sales gas stream meeting pipeline specifications at a higher pressure when compared to the Prior Art (Conventional). This may be an advantage when the gas transmission pipeline operates at pressures between 900 and 1200 Psig.

Example 8

In Example 8, a gas feed stream having a richness of 5 GPM was used. The cold separator was operated at 600 Psi and various operating temperatures of the cold separator were tested using both the conventional prior art process (Conventional) and the process of the present invention (Enhanced). The butane recovery (%) versus refrigeration load (HP/MMscf) was determined. It can be seen in graph shown in **Figure 7** that when using and operating the cold separator over a range of temperatures, the refrigeration load for the present invention (Enhanced) becomes less than the refrigeration load for the conventional refrigeration process (Conventional) for equivalent butane recoveries (in the sales gas) greater than about 62%. In particular, at a target of 80% butane recovery in the sales gas, the refrigeration load for the process of the present invention (Enhanced) was only about 23 HP/MMscf of raw gas feed, as compared to about 32 HP/MMscf when using conventional refrigeration process (Conventional).

The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole.

WE CLAIM:

1. A process for separating a mixed or raw gas feed including natural gas, refinery gas, and synthetic gas, the gas feed containing methane, C_2 components, C_3 components, C_4 components and heavier hydrocarbon components (C_5+) into a dry gas product containing a desired portion of C_3 components and/or C_4 components, comprising:

(a) scrubbing heavier hydrocarbon components from the gas feed to produce a lighter ends gas stream and a heavier ends liquid stream;

(b) cooling the lighter ends gas stream and separating the cooled lighter ends gas stream into a cold liquid stream and the dry gas product containing the desired portion of C_3 components and/or C_4 components;

(c) using the cold liquid stream to assist in scrubbing the heavier hydrocarbon components from the gas feed in step (a);

(d) distilling and/or fractionating the heavier ends liquid stream to form a hydrocarbon gas liquid product and an overhead gas stream; and

(e) combining the overhead gas stream with the gas feed.

2. The process as claimed in claim 1, further comprising cooling the gas feed prior to step (a) to reduce energy required in step (b).

3. The process as claimed in claim 1, wherein the overhead gas stream is compressed prior to combining it with the gas feed.

4. The process as claimed in claim 1, wherein the hydrocarbon gas liquid product comprises the majority of the C_5+ hydrocarbon components present in the gas feed.

5. The process as claimed in claim 1, wherein the hydrocarbon gas liquid product comprises greater than 95% of the C_5+ hydrocarbon components present in the gas feed.

6. The process as claimed in claim 1, wherein the hydrocarbon gas liquid product comprises greater than 99% of the C_5+ hydrocarbon components present in the gas feed.

7. The process as claimed in claim 1, wherein when the gas feed has a richness greater than 2 GPM, the hydrocarbon gas liquid product comprises about 100% of the C_5 and C_{6+} hydrocarbon components present in the raw gas stream.

8. The process as claimed in claim 7, wherein when the raw gas feed has a richness between 2 GPM and 9 GPM, the raw gas feed pressure ranges between 200 and 1050 Psig, and the light ends gas stream are cooled and separated at a temperature between -40 °F and +25 °F, the hydrocarbon gas liquid product comprises substantially all the C_5+ hydrocarbon components and a portion of C_3 and C_4 components necessary to achieve a desired hydrocarbon dew point.

9. The process as claimed in claim 1, wherein the heavier ends liquid stream are fractionated in a fractionation tower operated at a range between 80 Psig to 350 Psig.

10. The process as claimed in claim 1, wherein the heavier ends liquid stream are flash distilled in a flash separator.

11. The process as claimed in claim 9, wherein the fractionation tower further comprises a reboiler and the reboiler temperature is selected in a range from 140 °F to 320 °F, to reject C_3 and/or C_4 components from the heavier ends liquid stream to the overhead gas stream.

12. The process as claimed in claim 11, wherein the fractionation tower further comprises a reflux condenser to achieve higher recovery and better separation of C_3 and/or C_4 components from the heavier ends liquid stream.

13. The process as claimed in claim 12, wherein the overhead gas stream is compressed and the compressed gas stream is combined with the gas feed for further processing.

14. The process as claimed 13, wherein the operating pressure and temperature of the fractionation tower is dependent in part on what portion of the C_3 and C_4 components are to be directed to the overhead gas stream.

15. The process as claimed in claim 2, wherein the gas feed is cooled in at least one heat exchanger.

16. The process as claimed in claim 1, wherein the heavier hydrocarbon components are scrubbed from the gas feed in an absorber to produce the lighter ends gas stream and the heavier ends liquid stream.

17. The process as claimed in claim 1, wherein the lighter ends gas stream is cooled in a gas chilling device.

18. The process as claimed in claim 1, wherein the cooled lighter ends gas stream are separated into the cold liquid stream and the dry gas product in a cold separator.

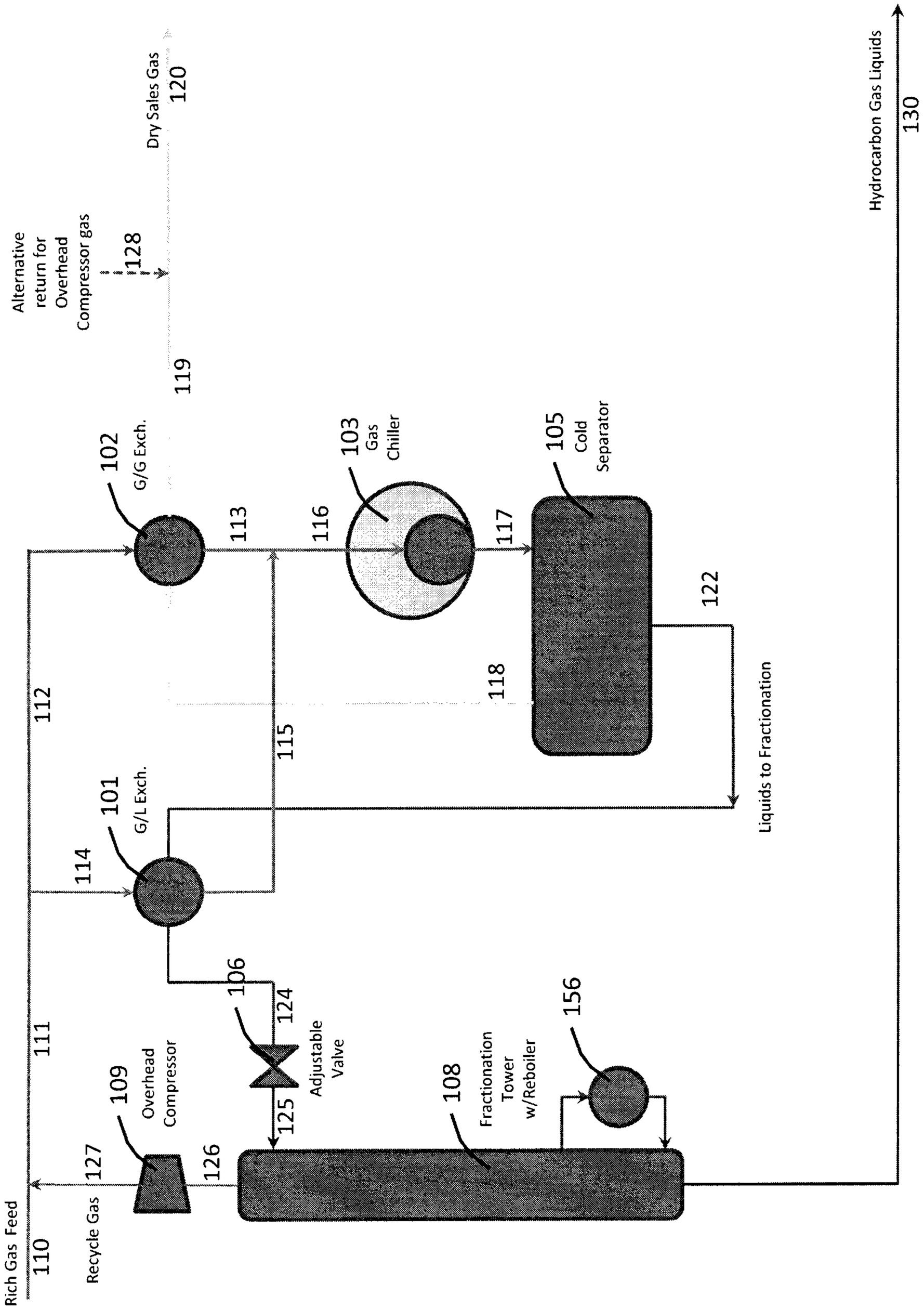


Figure 1 (Prior Art)

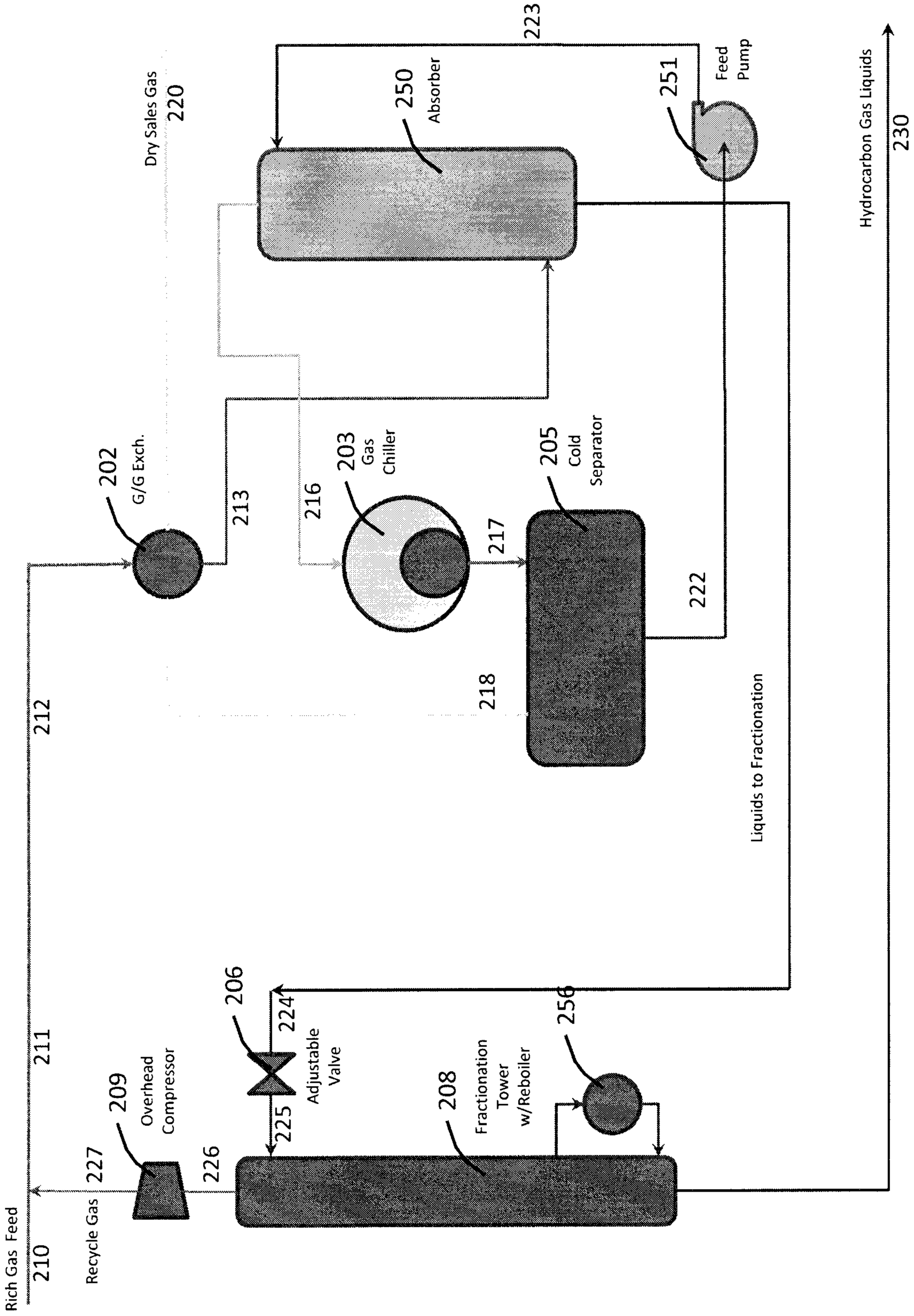

Dry Sales Gas
220
223
250
Absorber
251
Feed
Pump
Hydrocarbon Gas Liquids
230
202
G/G Exch.
213
216
203
Gas
Chiller
205
Cold
Separator
217
222
218
212
211
209
Overhead
Compressor
207
206
Adjustable
Valve
224
225
208
Fractionation
Tower
w/Reboiler
256
Liquids to Fractionation
227
226
Recycle Gas
Rich Gas Feed
210

Figure 2

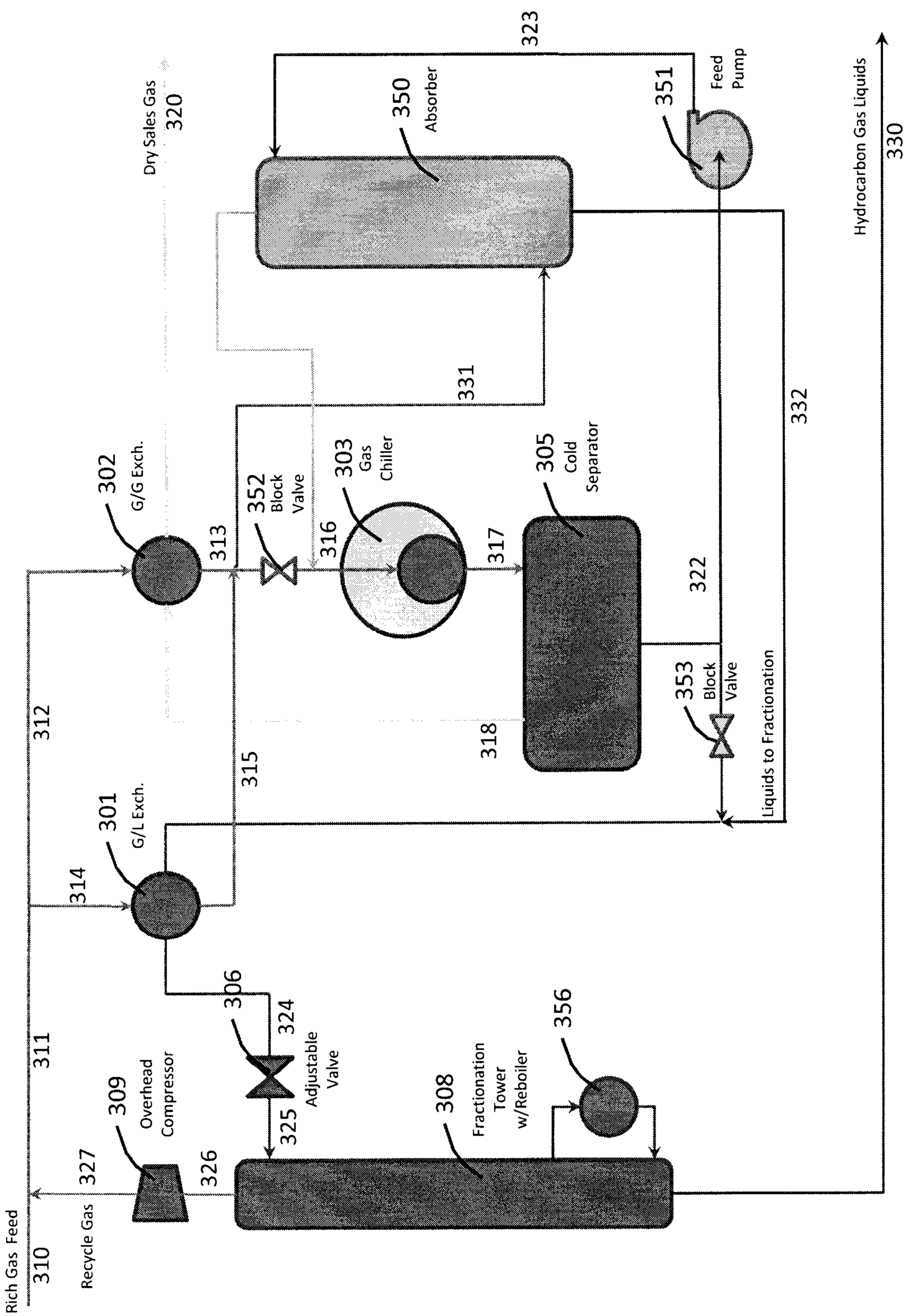


Figure 3 [Retrofit]

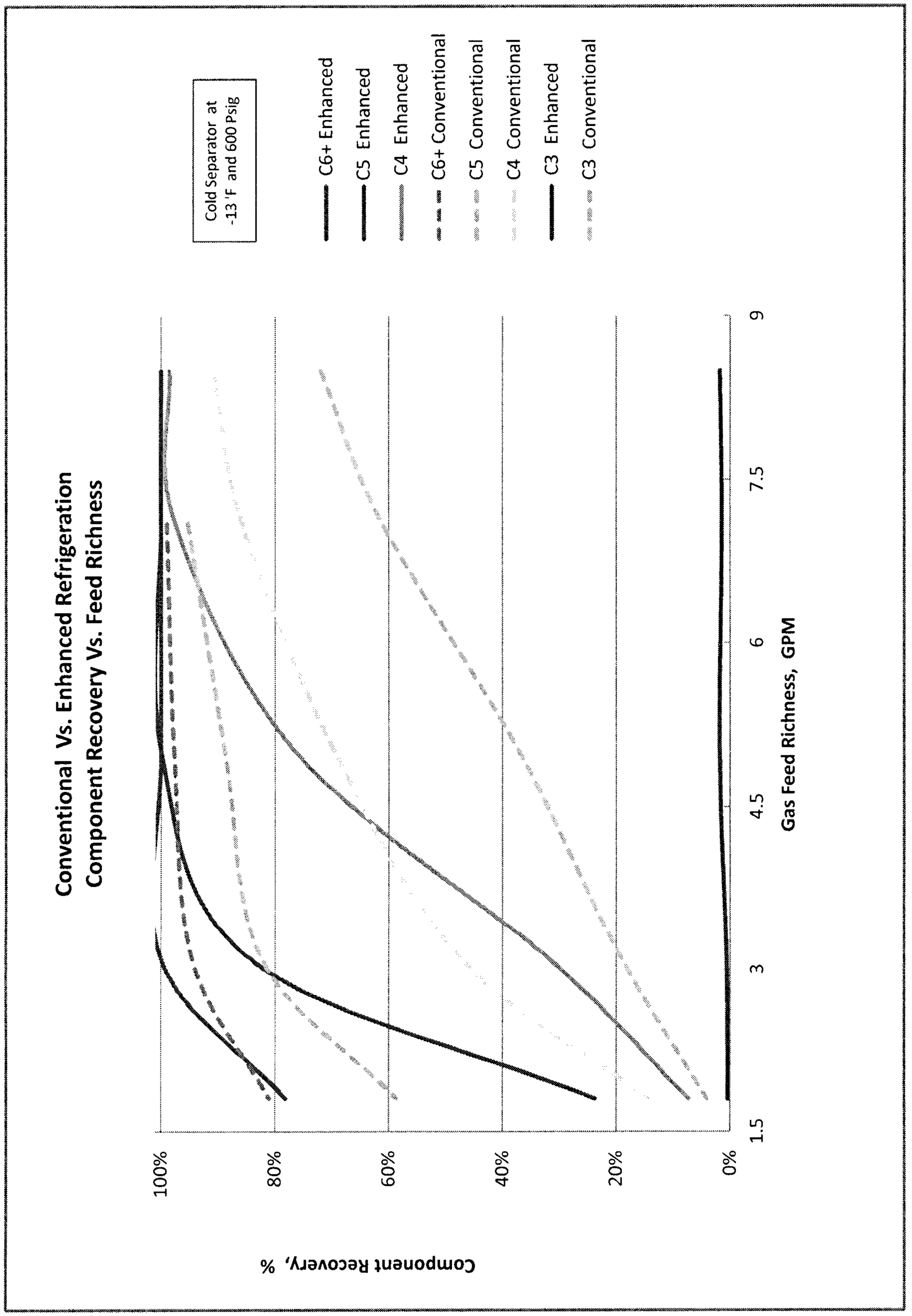

Conventional Vs. Enhanced Refrigeration
Component Recovery Vs. Feed Richness
Cold Separator at
-13 'F and 600 Psig
C6+ Enhanced
C5 Enhanced
C4 Enhanced
C6+ Conventional
C5 Conventional
C4 Conventional
C3 Enhanced
C3 Conventional
100%
80%
60%
40%
20%
0%
Component Recovery, %
1.5
3
4.5
6
7.5
9
Gas Feed Richness, GPM

Figure 4

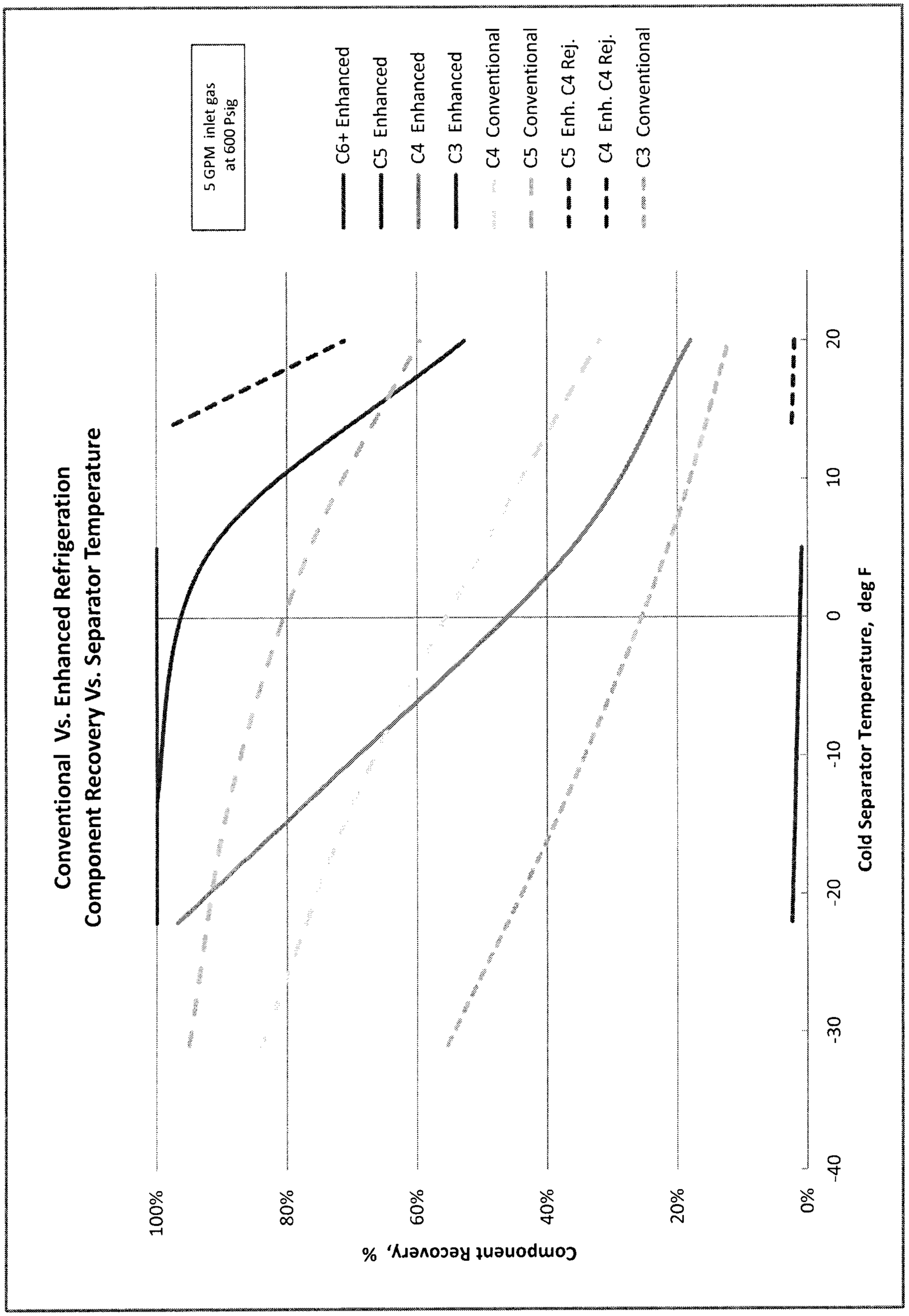

5 GPM inlet gas
at 600 Psig
C6+ Enhanced
C5 Enhanced
C4 Enhanced
C3 Enhanced
C4 Conventional
C5 Conventional
C5 Enh. C4 Rej.
C4 Enh. C4 Rej.
C3 Conventional
Conventional Vs. Enhanced Refrigeration
Component Recovery Vs. Separator Temperature
100%
80%
60%
40%
20%
0%
Component Recovery, %
20
10
0
-10
-20
-30
-40
Cold Separator Temperature, deg F

Figure 5

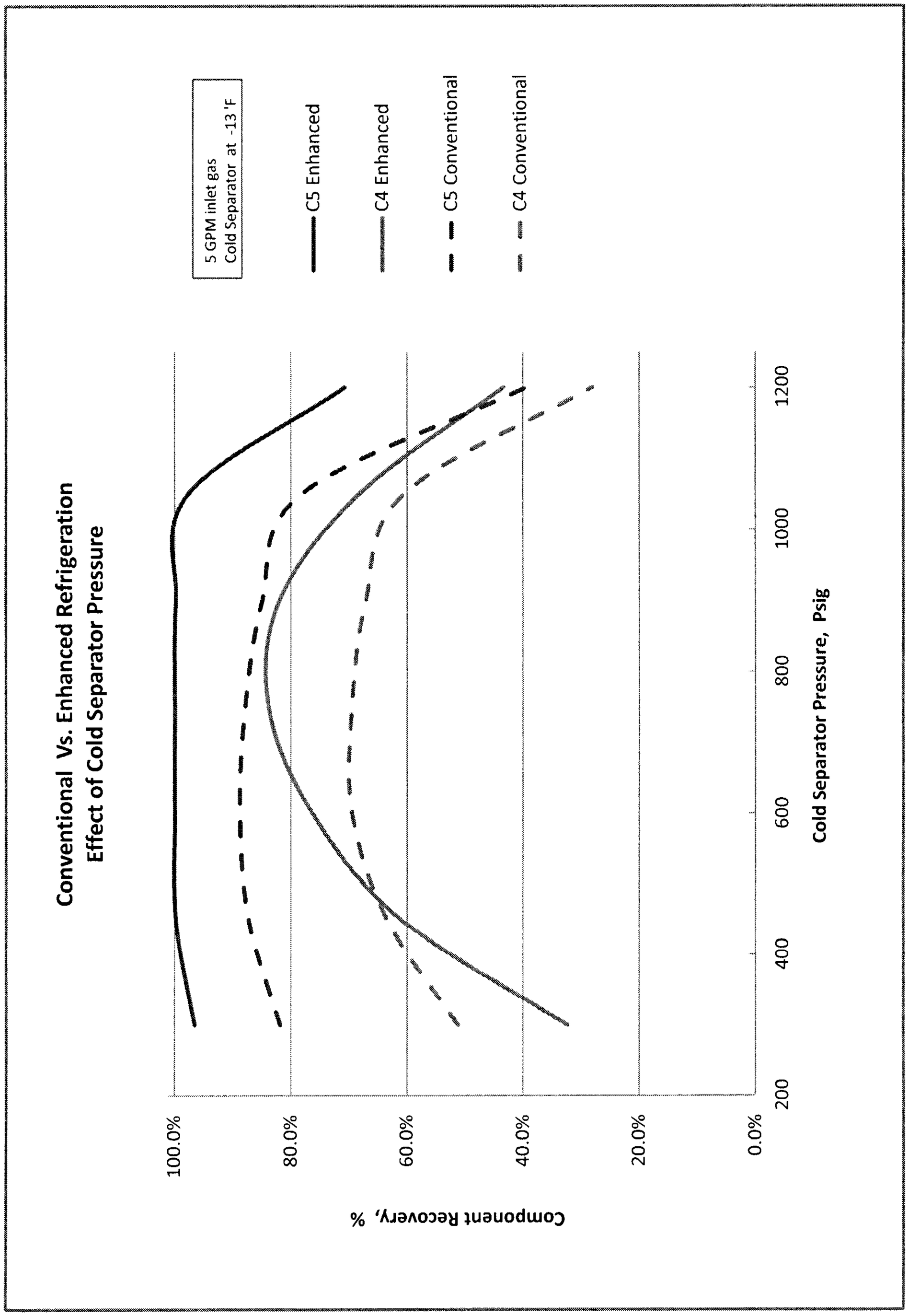

5 GPM inlet gas
Cold Separator at -13 'F
C5 Enhanced
C4 Enhanced
C5 Conventional
C4 Conventional
Conventional Vs. Enhanced Refrigeration
Effect of Cold Separator Pressure
Component Recovery, %
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
200
400
600
800
1000
1200
Cold Separator Pressure, Psig

Figure 6

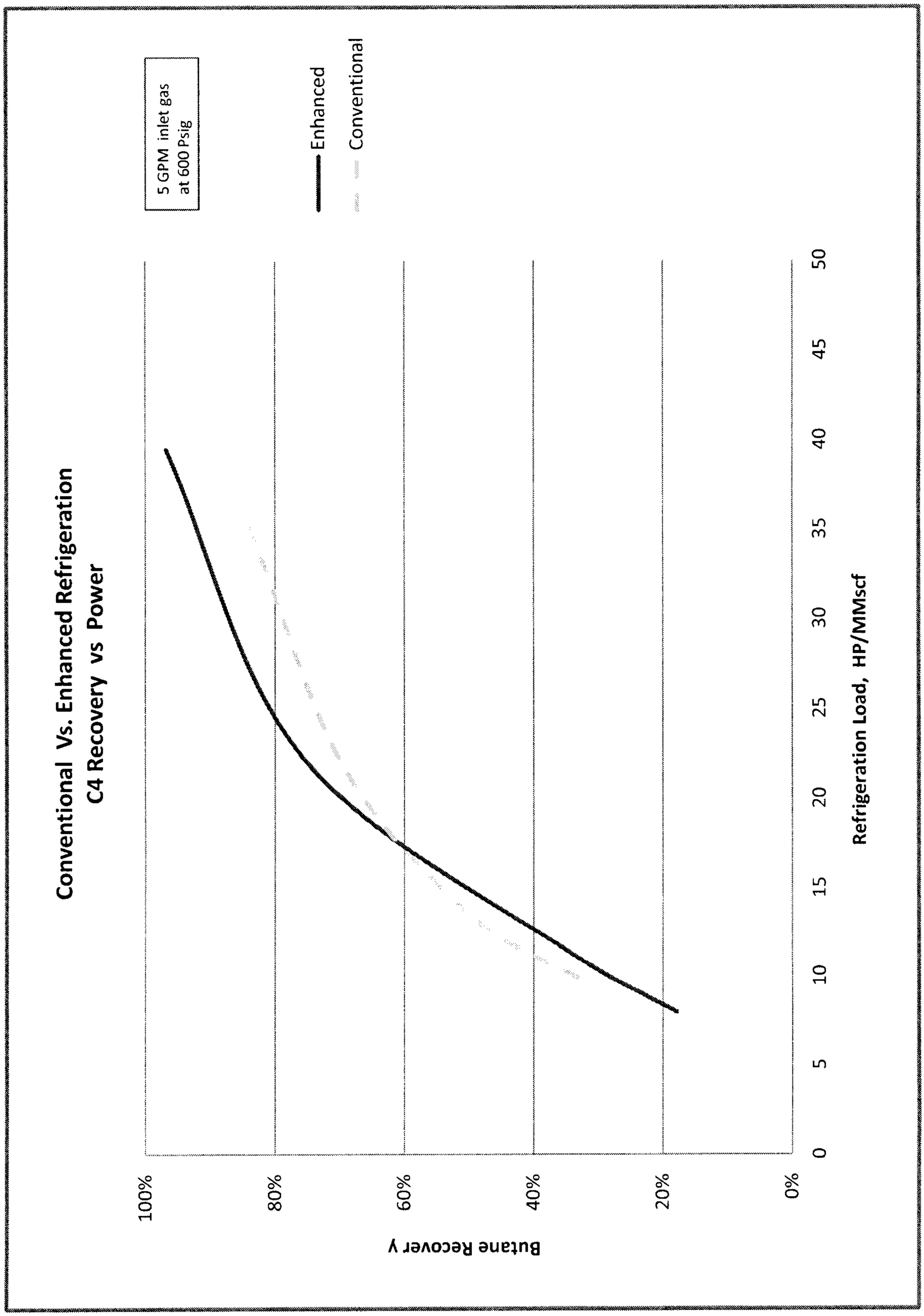
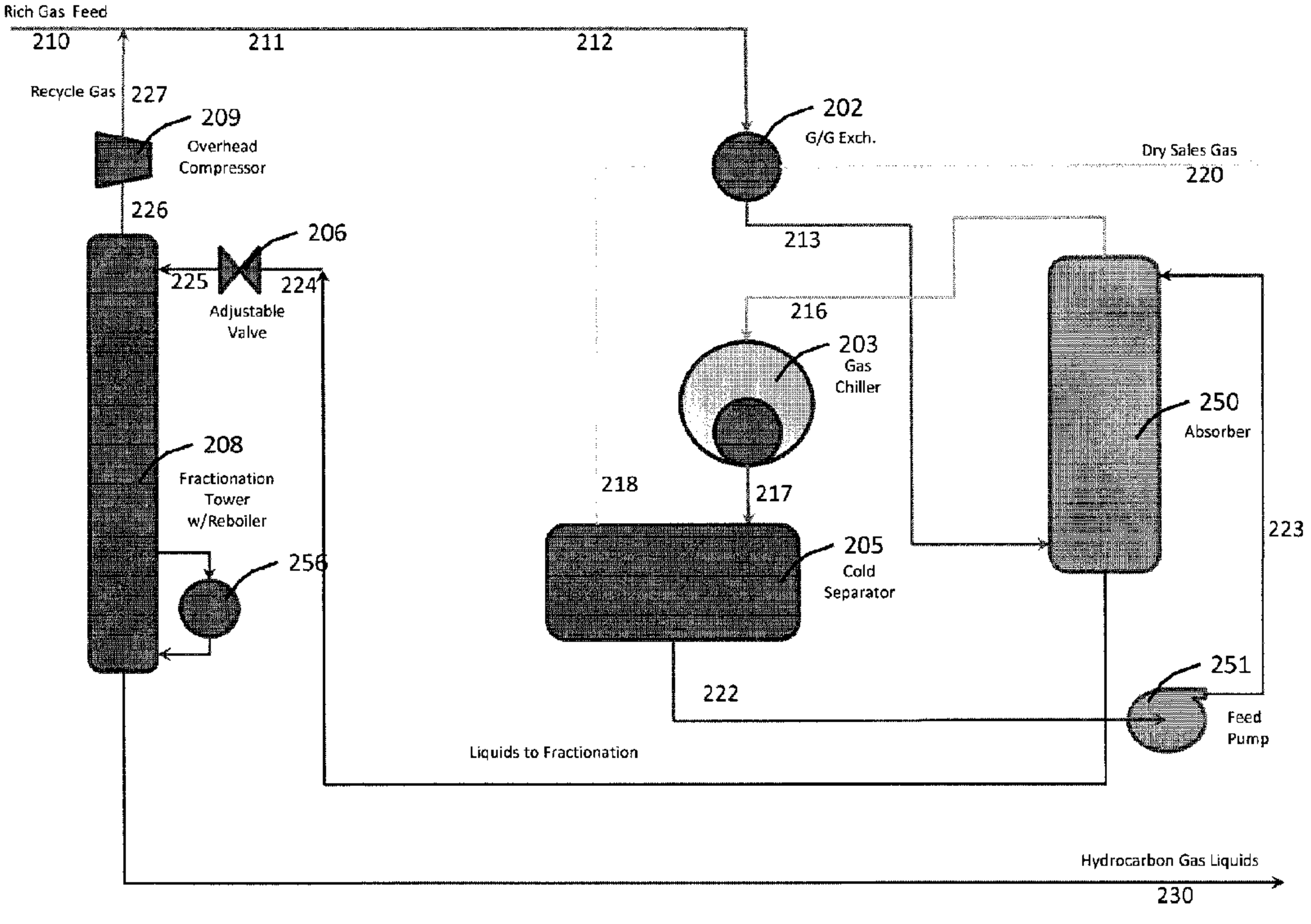

5 GPM inlet gas
at 600 Psig
Enhanced
Conventional
Conventional Vs. Enhanced Refrigeration
C4 Recovery vs Power
Butane Recovery
100%
80%
60%
40%
20%
0%
0
5
10
15
20
25
30
35
40
45
50
Refrigeration Load, HP/MMscf

Figure 7


Rich Gas Feed
210
211
212
Recycle Gas
227
209
Overhead
Compressor
202
G/G Exch.
Dry Sales Gas
220
226
206
225
224
Adjustable
Valve
213
216
203
Gas
Chiller
250
Absorber
208
Fractionation
Tower
w/Reboiler
218
217
223
256
205
Cold
Separator
251
222
Feed
Pump
Liquids to Fractionation
Hydrocarbon Gas Liquids
230