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RECOVERY OF NATURAL GAS LIQUIDS AND PRODUCE LIQUIFIED PETROLEUM GAS FROM ASSOCIATED NATRAL GAS

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الآية :

قال تعالى :-

(أَمَّنْ هُوَ قَانُثُ آنَاءَ اللَّيْلِ سَاجِدًا وَقَائِمًا يَحْذَرُ الْآخِرَةَ وَيَرْجُو
رَحْمَةَ رَبِّهِ قُلْ هَلْ يَسْتَوِي الَّذِينَ يَعْلَمُونَ وَالَّذِينَ لَا يَعْلَمُونَ إِنَّمَا
يَتَذَكَّرُ أُولُو الْأَلْبَابِ)

صدق الله العظيم

(39 الزمر آية 9)

Dedication

This project is dedicated to our families, teachers, guiders, friends and colleagues with love and respect. We are very thankful for all the people that supported us with their attitude and unlimited help.

Abstract

The major source of producing LPG in Sudan is from oil refining. The objective of this work is to Recover natural gas liquids and produce LPG from associated gas produced . The unit will consist of two parts: refrigeration unit, fractionation unit. The study is carried out following standard scientific approach of theoretical study and computer simulations. Associated gas flow rate, composition.. Material and energy balance are made for the process to determine the total energy and flow. A simulation for the process will be created in HYSYS V8.0, and studies are made to determined optimum operating pressures and temperatures.

The optimum temperature and pressure is -110c and 1atm respectively.

المستخلص

في السودان يتم حرق الغاز المصاحب في حقول النفط أو إعادة حقنه في الحقول في عام 2010 في السودان الموحد تم حرق حوالي 11.8 مليار قدم مكعب من الغاز المصاحب وفقاً لأحدث البيانات من إدارة المحيطات والغلاف الجوي الوطنية (NOAA)) هذه النسبة تمثل حوالي 0.2% من إجمالي الغاز المشتعل عالمياً .

يمثل الغاز الطبيعي المصاحب مصدر غني بالإنتاج غاز البترول المسال بالإضافة لتكرير النفط الذي يمثل المصدر الرئيسي لإنتاج غاز البترول المسال في السودان .

في هذا العمل تمت دراسة الجدوى الفنية لاستخلاص سوائل الغاز الطبيعي وذلك لإنتاج غاز البترول المسال .

الهدف من هذا العمل هو تصميم وحدة استخلاص سوائل الغاز الطبيعي المصاحب وانتاج غاز البترول المسال .

تم تنفيذ هذه الدراسة علي نهج علمي وبواسطة برنامج المحاكاة حيث أخذت تركيب الغاز المصاحب المثالي والخصائص الكيميائية أساس لهذا البحث .

يتكون المشروع من جزئين رئيسيين وحدة التبريد ووحدة التجزئة , تم عمل موازنات للمواد والطاقة للعملية لتحديد تدفقات المواد والطاقة مع إنشاء محاكاة للعملية في برنامج المحاكاة HYSYS V8 لتحديد ضغوط التشغيل ومرجات الحرارة المثلى -110م و 1م ضغط جوي .

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Chapter One

Introduction

1.1 Introduction:

Natural gas industry is expected to grow substantially and occupy the same importance as the international crude oil industry. Natural gas is a subcategory of petroleum that is a naturally occurring, complex mixture of hydrocarbons, with a minor amount of inorganic compounds. It consists primarily of methane as the prevailing element but it also contains considerable amount of light and heavier hydrocarbons as well as containing compounds of CO_2 , N_2 , H_2S , He, Hg and etc. thus, the impurities must be removed to meet quality standard specifications.

1.1.1 Natural gas history:

The discovery of natural gas dates from ancient times in the Middle East. Thousands of years ago, it was noticed that natural gas seeps ignited by lightning created burning springs. In Persia, Greece, or India, people built temples around these eternal flames for their religious practices. However, the energy value of natural gas was not recognized until approximately 900 BC in China, and the Chinese drilled the first known natural gas well in 211 BC. In Europe, natural gas was unknown until it was discovered in Great Britain in 1659, although it was not commercialized until about 1790. In 1821 in Fredonia, United States, residents observed gas bubbles rising to the surface from a creek. William Hart, considered as America's father of natural gas, dug the first natural gas well in North America (Speight, 1993). Throughout the 19th century, natural gas was used almost exclusively as a source of light and its use remained localized because of lack of transport structures, making it difficult to transport large quantities of natural gas long distances. There was an important change in 1890 with the invention of leak-proof pipeline couplings, but transportation of natural gas to long distance customers did not become practical until the 1920s as a result of technological advances in pipelines. Moreover, it was only after World War II that the use of natural gas grew rapidly because of the development of pipeline networks and storage systems.

1.2 Uses of natural gas :

Natural gas is used primarily as a fuel and as a raw material in manufacturing. It is used in home furnaces, water heaters, and cooking stoves. As an industrial fuel, it is used in brick, cement, and ceramic-tile kilns; in glass making; for generating steam in water boilers; and as a clean heat source for sterilizing instruments and processing foods. As a raw material in petrochemical manufacturing, natural gas is used to produce hydrogen, sulfur, carbon black, and ammonia. Ethylene, an important petrochemical, is also produced from natural gas.

Natural gas is yet another fossil fuel resource that will continue making significant contribution to the world energy economy. It is considered as an environmentally friendly clean fuel, offering important environmental benefits when compared to other fossil fuels. The superior environmental qualities over coal or crude oil are that emissions of sulfur dioxide are negligible or that the levels of nitrous oxide and carbon dioxide emissions are lower. This helps to reduce problems of acid rain, ozone layer, or greenhouse gases. Natural gas is also a very safe source of energy when transported, stored, and used.

1.2.1 Natural gas as a clean source compare with other source

As its name indicates, natural gas is not highly processed after extraction; at the start it is colourless and odourless. It is “odorised”, though, for safety.

Burning natural gas produces little apart from water vapour and carbon dioxide: it gives off no smoke, no particles.

Natural gas generates half as much nitrogen oxide as coal or heating oil to produce the same amount of energy, and nearly 30% less carbon dioxide.

By comparison with other non-renewable sources of energy, natural gas gives off the least CO₂ (55kg per gigaJoule of heat, against 75kg for crude oil and nearly 100kg for coal). Likewise, any condensing boiler using natural gas will give off half the CO₂ of newly-installed direct electric heating.

Natural gas is often used nowadays in low-energy buildings to supplement renewable energy sources.

Clean-burning natural gas is a safe and abundant source of energy that has been used for power generation and home heating across North America for generations.

As the cleanest-burning hydrocarbon, natural gas reduces greenhouse gas (GHG) and other emissions when it replaces other fossil fuels as a necessary source of energy for electrical power generation, heating and transportation. For example, latest-generation natural gas power generation plants are highly efficient and produce 50 percent fewer GHG emissions than coal-generated plants. For more information see [CAPP Upstream Dialogue, The Facts On Natural Gas, 2012](#)

Significant reductions in greenhouse gas emissions since the early 2000's in Canada and the United States are widely attributed to using natural gas as a replacement for coal in electrical power generation plants in North America (Environment Canada, IEA).

1.2.2 Abundant natural gas is a viable, clean alternative to other sources of energy

Recent advances in drilling and completion technologies dramatically increased the size of the commercially viable natural gas resource in North America, positioning natural gas as the best available alternative to coal-fired electrical generation not only in North America but around the world.

Large liquefied natural gas (LNG) export facilities, some of which are close to final investment decisions, are designed to export abundant Western Canadian natural gas. Most of this exported gas would be used to displace coal as a fuel for power generation in other parts of the world. Natural gas accounted for around 23% of global electricity production in 2012, an increase of 5% of the total share since 2000 while the use of nuclear for power generation decreased by 6% over the same period. In 2012 at least 40% of global power generation used coal as a fuel and it is widely believed that rising access to natural gas will displace coal as a fuel for power generation.

Since it is such an abundant and relatively inexpensive source of power, natural gas also has the potential to propel a renaissance of environmentally responsible manufacturing.

Low-emission CNG (Compressed Natural Gas) and LNG (Liquefied Natural Gas) engine technologies have been successfully deployed as economically viable fuels for transportation. Natural gas engines have 15 to 30 percent fewer GHG emissions than diesel-powered trucks and buses. The City of Calgary's public bus system has committed to [building a fleet of CNG-powered buses](#) after its successful pilot program.

1.2.3 Production & Consumption

Driven by surging natural gas consumption in Asia and the United States, global use of this form of fossil fuel rebounded 7.4 percent from its 2009 slump to hit a record 111.9 trillion cubic feet in 2010, according to a new Vital Signs Online report from the World watch Institute. This increase puts natural gas's share of total energy consumption at 23.8 percent, a reflection of new pipelines and natural gas terminals in many countries.

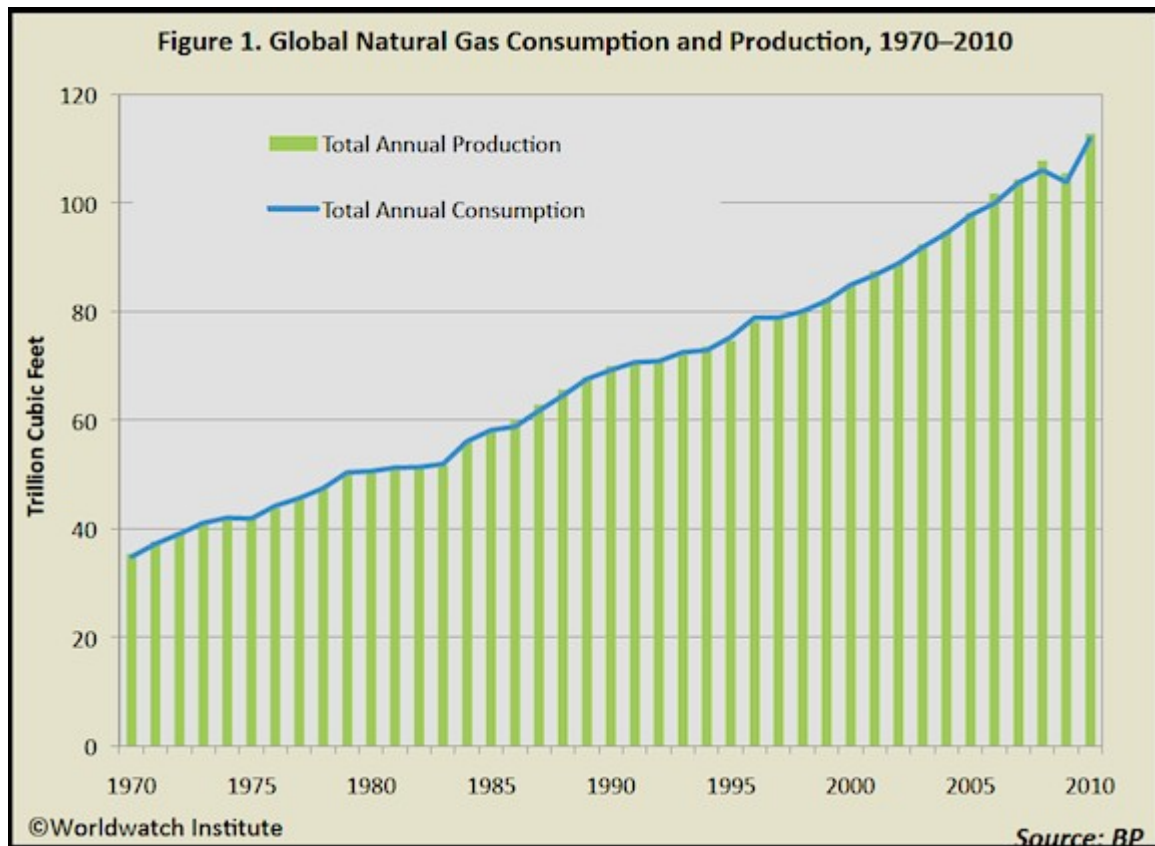


Figure 1.2 : The World watch Institute of Washington D.C. report 2010

1.3 Composition of natural gas:

The natural gas processed at the wells will have different range of composition depending on type, depth, and location of the underground reservoirs of porous sedimentary deposit and the geology of the area. Most often, oil and natural gas are found together in a reservoir.

Natural gas is a mixture of methane, ethane, propane and butane with small amounts of heavier hydrocarbons and some impurities, notably nitrogen and complex sulphur compounds, water, carbon dioxide and hydrogen Sulphide. Methane is by far the major component, usually, though not always, over 84% by volume. Table 1 below outlines the typical composition of natural gas before it is refined.

Table 1.3 : Typical Composition of Natural Gas:

Name	Formula	Volume%
Methane	CH ₄	>85
Ethane	C ₂ H ₆	3-8

Propane	C ₃ H ₈	1-2
Butane	C ₄ H ₁₀	<1
Pentane	C ₅ H ₁₂	<1
Carbon dioxide	CO ₂	1-2
Hydrogen sulphide	H ₂ S	<1
Nitrogen	N ₂	1-5
Helium	He	<0.5

1.4 Gas sources:

Natural gas produced from geological formations comes in a wide array of compositions. The varieties of gas compositions can be broadly categorized into three distinct groups:

1. Non-associated gas that occurs in conventional gas fields.
2. Associated gas that occurs in conventional oil fields.
3. Continuous (or unconventional) gas.

1.4.1 Non-associated gas:

(Sometimes called “gas well gas”) is produced from geological formations that typically do not contain much, if any, high boiling hydrocarbons (gas liquids) than methane.

Non-associated gas can contain non-hydrocarbon gases such as carbon dioxide and hydrogen sulfide.

Table 1.4.1
Composition of some nonassociated gases
(volume %)

	gronng en {nld}	Lacq {FRA}	Frigg {NOR}	HassiRm el {DZA}	Urengoy {CIS}	Uch {PAK}	Kapuni {NZL}	Type Average
C1	81.3	69.0	95.7	83.7	85.3	27.3	45.6	98 to 95
C2	2.9	3.0	3.6	6.8	5.8	0.7	5.8	1 to 3
C3	0.4	0.9	€	2.1	5.3	0.3	2.9	0.5 to 1
C4	0.1	0.5	€	0.8	2.1	0.3	1.1	0.2 to 0.5
C5	0.1	0.5	€	0.4	0.2		0.8	0.2 to 0.5
N ₂	14.3	1.5	0.4	5.8	0.9	25.2		
H ₂ S		15.3						

Co2	0.9	9.3	0.3	0.2	0.4	46.2	43.8	
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proportion for a dry gas without contaminate.

source: valais. 1983.

TYPICAL COMPOSITIONS OF A DRY GAS AND A WET GAS
OR A CONDENSATE GAS
(mol %)

Component	Dry gas	Wet gas or condensate gas
Hydrocarbons		
Methane	70 to 98	50 to 92
Ethane	1 to 10	5 to 15
Propane	traces to 5	2 to 14
Butane	traces to 2	1 to 10
Pentane	traces to 1	traces to 5
Hexane	traces to 0.5	traces to 3
Heptane+	0 to traces	traces to 15
Nonhydrocarbons		
Nitrogen	traces to 15	traces to 10
Carbon dioxide	traces to 1	traces to 4
Hydrogen sulfide	0 to traces	0 to 6
Helium	0 to 5	0

1.4.2 Associated petroleum gas (APG), or associated gas

Is a form of [natural gas](#) which is found with deposits of [petroleum](#), either dissolved in the oil or as a free "gas cap" above the oil in the reservoir. Historically, this type of gas was released as a waste product from the petroleum extraction industry. It may be a [stranded gas reserve](#) due to the remote location of the oil field, either at sea or on land, this gas is simply burnt off in [gas flares](#). When this occurs the gas is referred to as flare gas.

The gas can be utilized in a number of ways after processing: be sold and included in the natural gas distribution networks, used for on-site electricity generation with

[engines](#) or [turbines](#), reinjected for [enhanced oil recovery](#), be converted from [gas to liquids](#) producing [synthetic fuels](#) or used as feedstock for the [petrochemical industry](#).

Russia is the world leader in the flaring of APG, and flares 30 per cent of the total APG flared globally.

The flaring of APG is controversial as it is a pollutant, a source of global warming and is a waste of a valuable fuel source. APG is flared in many countries where there are significant power shortages. In the [United Kingdom](#), gas may not be flared without written consent from the UK Government in order to prevent unnecessary wastage and to protect the environment.

The [World Bank](#) estimates that over 150 billion cubic metres of natural gas are flared or vented annually. This amount of gas is worth approximately 30.6 billion dollars and is equivalent to 25 percent of the United States's yearly gas consumption or 30 percent of the European Union's annual gas consumption.

1.4.2.1 Approximate APG composition :

Component	Chemical formula	Volume fraction (%)	Weight fraction (%)
Methane	CH 4	81	60
Ethane	C 2H 6	5.5	7.7
Propane	C 3H 8	6.6	13.5
Butane	C 4H 10	4.0	10.8
Pentane	C 5H 12	1.4	4.8
Nitrogen	N 2	1.0	1.3
Carbon dioxide	CO ₂	0.17	0.33

1.5 Gas treatment:

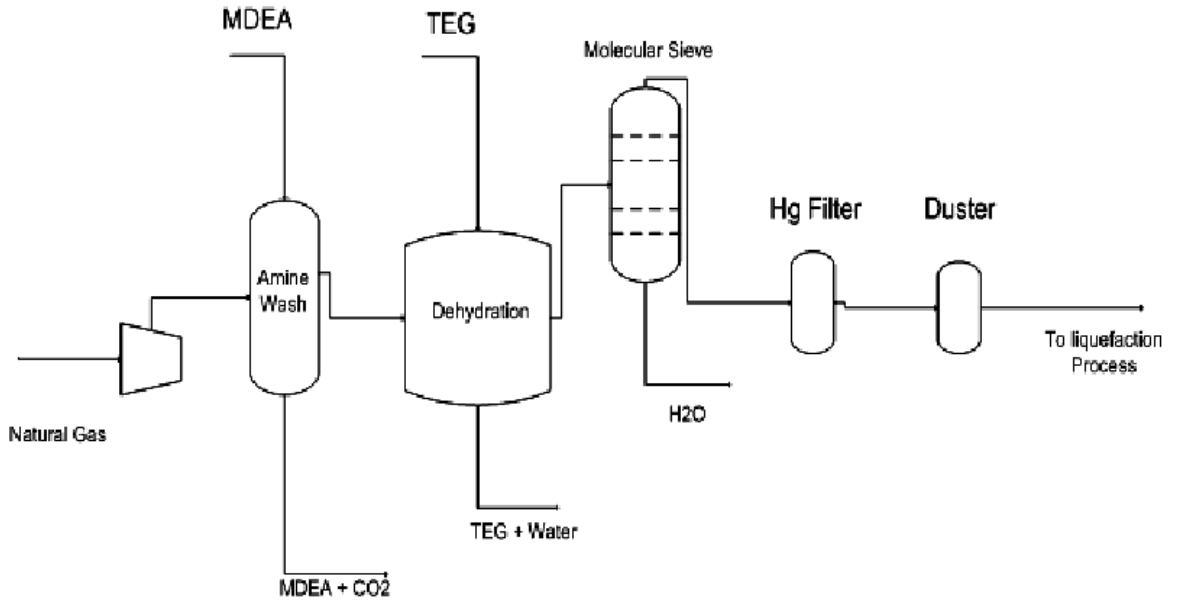


Figure 1.2 Pretreatment schematic

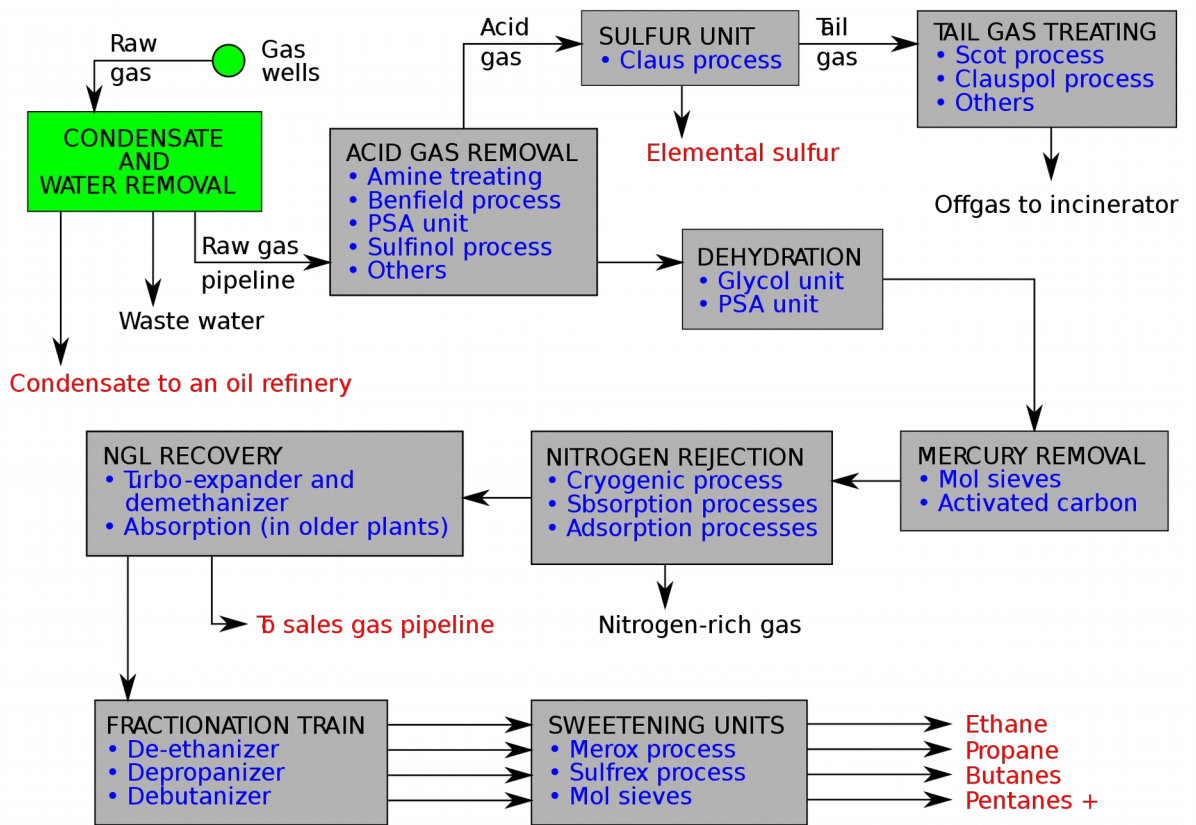


Figure 1.3 typical natural gas processing plant

1.5.1 Removal of Acid Gases

In addition to heavy hydrocarbons and water vapor, natural gas often contains other contaminants, which may have to be removed. Carbon dioxide (CO₂), hydrogen sulfide (H₂S), and other sulfur compounds, such as mercaptans may require complete or partial removal for acceptance by a gas purchaser. These contaminants are known as "acid gases" because they form acids or acidic solutions in the presence of water. They have no heating value but cause problems to systems and the environment.

H₂S is a toxic, poisonous gas and cannot be tolerated in gases that may be used for domestic fuels. H₂S in the presence of water is extremely corrosive and can cause premature failure of valves, pipeline, and pressure vessels. It can also cause catalyst poisoning in refinery vessels and requires expensive precautionary measures. Most pipeline specifications limit H₂S content to 0.25 g/100 ft³ of gas (about 4 ppm). Carbon dioxide is not as bad as H₂S and its removal is not always required. Removal of CO₂ may be required in gas going to cryogenic plants to prevent CO₂ solidification. Carbon dioxide is also corrosive in the presence of water. Most treating processes that remove H₂S will also remove CO₂. Therefore, the volume of CO₂ in the well stream is added to the volume of H₂S to arrive at the total acid-gas volume to be removed. The term sour gas refers to the gas containing H₂S in amounts above the acceptable industry limits. A sweet gas is a non- H₂S-bearing gas or gas that has been sweetened by treating. There are many processes for acid gas removal, the most common include :

1.5.1.1 Solid bed processes

Fixed bed of solid particles can be used to remove acid gases either through chemical reactions or ionic bonding. Typically, in solid bed processes the gas stream must flow through a fixed bed of solid particles, which remove the acid gases and hold them in the bed. When the bed is spent, the vessel must be removed from service and the bed regenerated or replaced. Since the bed must be removed from service to be regenerated, some spare capacity is normally provided. There are four commonly used processes under this category: Iron Sponge Process, Sulfa-Treat, Molecular Sieve Process, and Zinc Oxide Process.

1.5.1.2 Iron Sponge Process

The iron sponge process utilizes the chemical reaction of ferric oxide with H₂S to Sweet gas streams. This process is economically applied to gases containing small amounts of H₂S. This process does not remove carbon dioxide.

1.5.1.3 Sulfa-Treat Process

process is similar to the iron sponge process utilizing the chemical reaction of ferric oxide with H₂S to sweet gas streams. This process is economically applied to gases containing small amounts of H₂S. Carbon dioxide is not removed in the process.

1.5.1.4 Molecular Sieve Process

Molecular sieve processes use synthetically manufactured crystalline solids in a dry bed to remove gas impurities. The crystalline structure of the solids provides a very

porous material having uniform pore size. Within the pores the crystalline structure creates a large number of localized polar charges called active sites. Polar gas molecules such as H₂S and water vapor, which enter the pores, form weak ionic bonds at the active sites. Non-polar molecules such as paraffin hydrocarbons will not bond to the active sites.

Molecular sieves are generally limited to small gas streams operating at moderate pressures. Due to these operating limitations, molecular sieve units have seen limited use for gas sweetening operations. They are generally used for polishing applications following one of the other processes.

1.5.1.5 Zinc Oxide Process

This process is similar to the iron sponge process in the type of equipment used. The process has seen decreasing use due to increasing disposal problems with the spent bed, which is classified as a heavy metal salt.

1.5.1.6 Chemical Solvent Processes

Chemical solvent processes use an aqueous solution of a weak base to chemically react with and absorb the acid gases in the natural gas stream. The absorption driving force is a result of the partial pressure differential between the gas and the liquid phases. The reactions involved are reversible by changing the system temperature or pressure, or both. Therefore, the aqueous base solution can be regenerated and circulated in a continuous cycle. The majorities of chemical solvent processes utilize either an amine or carbonate solution.

1.5.1.7 Amine processes

The most widely used for sweetening of natural gas are aqueous solutions of alkanol amines. They are generally used for bulk removal of CO₂ and H₂S. The low operating cost and flexibility of tailoring solvent composition to suit gas compositions make this process one of most commonly selected. These amines can be categorized by the number of organic groups bonded to the central nitrogen atom, as primary, secondary or tertiary.

Primary amines form stronger bases than secondary amines, which form stronger bases than tertiary amines. Amines with stronger base properties will be more reactive toward CO₂ and H₂S gases and will form stronger chemical bonds. This implies that the acid gas vapor pressure will be lower for a given loading as amine reactivity increases and a higher equilibrium loading may be achieved.

1.5.1.8 Mono ethanol amine

Mono ethanol amine (MEA) is a primary amine, which has had widespread use as a gas sweetening agent. This process is well proven, can meet pipeline specifications, and has more design/operating data available than any other system. MEA is a stable compound and in the absence of other chemicals suffers no degradation or decomposition at temperatures up to its normal boiling point.

A disadvantage of MEA is that it also reacts with carbonyl sulfide (COS) and carbon disulfide (CS₂) to form heat stable salts, which cannot be regenerated at normal stripping column temperatures. At temperatures above 118°C (245°F) a side reaction with

CO₂ exists which produces oxazolidone-2, a heat stable salt, which consumes MEA from the process.

MEA is usually circulated in a solution of 15 percent to 20 percent MEA by weight in water. That the solution loading should not be greater than 0.3 to 0.4 moles of acid gas per mole of MEA. Both the solution strength and the solution loading are limited to avoid excessive corrosion.

The solution concentration and loading is largely determined by the H₂S/CO₂ ratio. The greater the ratio the higher the allowable loading and amine concentration.

MEA has the lowest boiling point and the highest vapor pressure of the amines. This results in MEA losses of 16 to 48 kg/MMm³ (1 to 3 lbs / MMSCF) of inlet gas.

In summation, MEA systems can effectively treat sour gas to pipeline specifications. However, care in the design and material selection of MEA systems is required to minimize equipment corrosion.

1.5.1.9 Di ethanol amine Process

Di ethanol amine (DEA) is a secondary amine also used to treat natural gas to pipeline specifications. As a secondary amine, DEA is less alkaline than MEA. DEA systems do suffer the same corrosion problems, but not as severely as those using MEA. Solution strengths are typically from 25 to 35 percent DEA by weight in water.

DEA has significant advantages over MEA when COS or are present. DEA reacts with COS and to form compounds which can be regenerated in the stripping column. Therefore, COS and CS₂ are removed without a loss of DEA. High CO₂ levels have been observed to cause DEA degradation to oxazolidones.

The stoichiometry of the reactions of DEA and MEA with CO₂ and H₂S are the same. The molecular weight of DEA is 105 compared to 61 for MEA. The combination of molecular weights and reaction stoichiometry means that approximately 0.77 kg (1.7 lbs) of DEA must be circulated to react with the same amount of acid gas as 0.45 kg (1.0 lbs) of MEA. The solution strength of DEA ranges up to 35 percent by weight compared to 20 percent for MEA. Loadings for DEA systems range from 0.35 to 0.65 moles of acid gas per mole of DEA without excessive corrosion. The result of this is that the circulation rate of a DEA solution is slightly less than in a comparable MEA system.

1.5.1.10 Methyl die ethanol amine

Methyldiethanolamine is a tertiary amine, which like the other amines, is used to treat acid gas streams. The major advantage, which MDEA offers over other amine processes, is its selectivity for H₂S in the presence of CO₂. In cases where a high CO₂/H₂S ratio is present, MDEA can be used to improve the quality of the acid gas stream to a Claus recovery plant, but the higher CO₂ content of the treated residue gas must be tolerated.

Solution strengths typically range from 40 to 50 percent MDEA by weight. Acid gas loading varies from 0.2 to 0.4 or more moles of acid gas per mole of MDEA depending on supplier. MDEA has a molecular weight of 119. Higher allowable MDEA concentration and acid gas loading results in reduced circulation flow rates. Significant capital savings are realized due to reduced pump and regeneration requirements. MDEA has a lower heat requirement due to its low heat of regeneration. applications, energy requirements for gas treating can be reduced as much as 75 percent by changing from DEA to MDEA.

1.5.1.11 Carbonate Processes

Carbonate processes generally utilize hot potassium carbonate to remove CO₂ and H₂S. As a general rule, this process should be considered when the partial pressure of the acid gas is 138 kPa (abs) (20 psia) or greater. It is not recommended for low pressure absorption, or high pressure absorption of low concentration acid gas.

When crude oil is brought to the surface, it releases gas of different hydrocarbons, which is known as associated gas. Associated gas with oil consists mainly of methane. In Sudan the associated gas is about 297 MMSCFD (7.811 Million Nm³ per day). This is equivalent to power production of 1.2 GW, almost similar to power production of Merowe Dam. This associated gas is currently flared generating about 1.5 million ton per year of CO₂. The associated gas can be utilized in power generation or LPG production or combination of both.

Raw natural gas must be processed before it can be moved into long-distance pipeline systems for use by consumers. The objective of gas processing is to separate natural gas, condensate, non-condensable, acid gases, and water from a gas-producing well and condition these fluids for sale or disposal.

1.5.2 Dehydration

Dehydration of natural gas is the process of removal of the water that is associated with natural gases. The natural gas industry has recognized that dehydration is necessary to ensure smooth operation of gas transmission lines. Several methods have been developed to dehydrate gases on an industrial scale. The four major methods of dehydration are absorption, adsorption, gas permeation and refrigeration.

Among the different gas drying processes, absorption and adsorption are the most common techniques. These techniques are discussed below:

1.5.2.1 Absorption Dehydration

There are numbers of liquids that can be used to absorb water from natural gas. Glycol dehydration is a liquid desiccant system for the removal of water from natural gas. It is the most common and economic means of water removal from these streams. Glycol, the principal agent in this process, has a chemical affinity for water. The liquid glycol will absorb the water content in the natural gas. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. This operation is called absorption.

There are a few types of glycol usually used in industry with their advantages and disadvantages like ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG). One of the best glycol frequently used in industry is TEG. Essentially, glycol dehydration involves using a glycol solution, usually either DEG or TEG, which is brought into contact with the wet gas stream in what is

called the 'contactor' or dehydration unit. The process function of glycol is absorbing the water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. Glycols typically seen in industry include monoethylene glycol (MEG).

Although many liquids possess the ability to absorb water from gas, the liquid that is most desirable to use for commercial dehydration purposes should possess the following properties:

- 1) Strong affinity for water.
- 2) High boiling points.
- 3) Low cost.
- 4) Noncorrosive.
- 5) Low affinity for hydrocarbons and acid gases.
- 6) Thermal stability.
- 7) Easy regeneration.
- 8) Low viscosity.
- 9) Low vapor pressure at the contact temperature.
- 10) Low solubility in hydrocarbon.
- 11) Low tendency to foam and emulsify.

Usually, TEG is used because it is the most commonly used glycol in industry. TEG, or triglycol is a colorless, odorless viscous liquid with molecular formula $C_6H_{14}O_4$ and molecular structure. The rationale of using TEG or advantages of TEG is ease of regeneration and operation, minimal losses of drying agent during operation, high affinity for water, chemical stability, high hygroscopicity and low vapor pressure at the contact temperature.

1.5.2.2 Adsorption dehydration

Adsorption (or solid bed) dehydration is the process where a solid desiccant is used for the removal of water content from a gas stream. The solid desiccants commonly used for gas dehydration are those that can be regenerated and, consequently, used over several adsorption-desorption cycles. The mechanisms of adsorption on a surface are of two types; physical and chemical. The latter process, involving a chemical reaction, is termed "chemisorption". Chemical adsorbents find very limited application in gas processing. Adsorbents that allow physical adsorption hold the adsorbate on their surface by surface forces. For physical adsorbents used in gas dehydration, the following properties are desirable:

- 1) Large surface area for high capacity. Commercial adsorbents have a surface area of 500-800 m²/g.
- 2) Good "activity" for the components to be removed and good activity retention with time/use.
- 3) High mass transfer rate or high rate of removal.
- 4) Easy, economic regeneration.
- 5) Small resistance to gas flow, so that the pressure drop through the dehydration system is small.
- 6) High mechanical strength to resist crushing and dust formation. The adsorbent also must retain enough strength when "wet".
- 7) Cheap, non-corrosive, non-toxic, chemically inert, high bulk density and small volume changes upon adsorption and desorption of water.

The most widely used adsorbents today are activated alumina, silica gel, molecular sieves (zeolites).

1.5.2.2.1 Activated alumina

A hydrated form of aluminum oxide (Al_2O_3), alumina is the least expensive adsorbent. It is activated by driving off some of the water associated with it in its hydrated form ($(\text{Al}_2\text{O}_3 \cdot 3\text{H}_2\text{O})$) by heating. It produces an excellent dew point depression values as low as -100°F , but requires much more heat for regeneration.

1.5.2.2.2 Silica gel

Gels are granular, amorphous solids manufactured by chemical reaction. Gels manufactured from sulfuric acid and sodium silicate reaction are called silica gels, and consist almost solely of silicon dioxide (SiO_2). Silica gel has many other properties that recommend it as a desiccant.

It will adsorb up to one third of its own weight of water content in natural gas. This adsorption efficiency is approximately 35% greater than that of typical desiccant clays, making silica gel the preferred choice where weight or efficiency are important factors. It also has an almost indefinite shelf life if stored in airtight conditions. It can be regenerated and reused if required. Gently heating silica gel will drive off the adsorbed water content and leave it ready for reuse. It is a very inert material, it will not normally attack or corrode other materials and with the exception of strong alkalis and hydrofluoric acid is itself resistant to attack. It is non-toxic and non-flammable. It is most frequently and conveniently used packed in a breathable sachet or bag. These are available in a wide range of sizes suitable for use with a wide range of applications.

1.5.2.2.3 Molecular sieves

Molecular sieves are a crystalline form of alkali metal (calcium or sodium) alumina-silicates, very similar to natural clays. Molecular sieves are used to obtain very low water levels in the processed gas (down to 0.03 ppm vol). They are highly porous, with a very narrow range of pore sizes, and very high surface area. Manufactured by ion exchange, molecular sieves are the most expensive adsorbents and must be replaced every three years. Thus for structure A sieves, depending on the compensation cation, the size of the access cavities maybe about 3A (3A sieves), 4A (4A sieves) or 5A (5A sieves). They possess highly localized polar charges on their surface that act as extremely effective adsorption sites for polar compounds such as water and hydrogen sulfide. Solid desiccants or absorbents are commonly used for dehydrating gases in cryogenic processes.

Gas processing in general is carried out for two main objectives:

1. The necessity to remove impurities from the gas.
2. The desirability to increase liquid recovery above that obtained by conventional gas processing.

1.5.3 Separation of Natural Gas Liquids

Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have a higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.

There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components.

1.5.3.1 NGL Extraction

There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process. According to the Gas Processors Association, these two processes account for around 90 percent of total natural gas liquids production.

1.5.3.1.1 The Absorption Method

The absorption method of NGL extraction is very similar to using absorption for dehydration. The main difference is that, in NGL absorption, an absorbing oil is used as opposed to glycol. This absorbing oil has an ‘affinity’ for NGLs in much the same manner as glycol has an affinity for water. Before the oil has picked up any NGLs, it is termed ‘lean’ absorption oil. As the natural gas is passed through an absorption tower, it is brought into contact with the absorption oil which soaks up a high proportion of the NGLs. The ‘rich’ absorption oil, now containing NGLs, exits the

absorption tower through the bottom. It is now a mixture of absorption oil, propane, butanes, pentanes, and other heavier hydrocarbons. The rich oil is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the NGLs, but below that of the oil. This process allows for the recovery of around 75 percent of butanes, and 85 – 90 percent of pentanes and heavier molecules from the natural gas stream.

The basic absorption process above can be modified to improve its effectiveness, or to target the extraction of specific NGLs. In the refrigerated oil absorption method, where the lean oil is cooled through refrigeration, propane recovery can be upwards of 90 percent, and around 40 percent of ethane can be extracted from the natural gas stream. Extraction of the other, heavier NGLs can be close to 100 percent using this process.

1.5.3.1.2 The Cryogenic Expansion Process

Cryogenic processes are also used to extract NGLs from natural gas. While absorption methods can extract almost all of the heavier NGLs, the lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, if it is economic to extract ethane and other lighter hydrocarbons, cryogenic

processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are a number of different ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine is able to convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated with extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

1.5.4 Natural Gas Liquid Fractionation

Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. That is, the mixed stream of different NGLs must be separated out. The process used to accomplish this task is called fractionation. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream. Essentially, fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. The particular fractionators are used in the following order:

1. **Deethanizer** – this step separates the ethane from the NGL stream.
2. **Depropanizer** – the next step separates the propane.
3. **Debutanizer** – this step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream.
4. **Butane Splitter or Deisobutanizer** – this step separates the iso and normal butanes.

By proceeding from the lightest hydrocarbons to the heaviest, it is possible to separate the different NGLs reasonably easily

1.6 Chemicals Based on Methane

Methane can be partially oxidized with a limited amount of oxygen or in presence of steam to a synthesis gas mixture. Many chemicals can be produced from methane via the more reactive synthesis gas mixture. Synthesis gas is the precursor for two major chemicals, ammonia and methanol. Both compounds are the hosts for many important

petrochemical products. Figure 5-1 shows the important chemicals based on methane, synthesis gas, methanol, and ammonia.

Methane CH₄

Ammonia	
NH ₃	
	<ul style="list-style-type: none"> - Carbon disulfide ▶ Chlorinated rrethanes ▶ Single cell protein <p>Urea</p> <ul style="list-style-type: none"> - Nitric acid . Hydrazine ▶ Alkanolairines Methylanines <p>Hexairethylene tetrarrine</p> <p>Methanol CH₃OH</p> <ul style="list-style-type: none"> - Ethylene glycol * FTS hydrocarbons - Oxo alcohols <p>Methanol</p> <p>Formaldehyde Acetic acid Methyl esters Methyl chloride Methyianines MTBE</p> <p>Gasoline (MTG)</p> <p>Figure 5-1. Important chemicals based on methane, synthesis gas, ammonia, and methanol.1</p>

1.7 Transportation of Natural Gas

Transporting natural gas thousands of miles through pipelines is the safest method of transportation. The transportation system for natural gas consists of a complex network of pipelines, designed to quickly and efficiently transport natural gas from its origin, to areas of high natural gas demand.

There are three major types of pipelines along the transportation route: the gathering system, the interstate pipeline system, and the distribution system. The gathering system consists of low pressure, small diameter pipelines that transport raw natural gas from the wellhead to the processing plant.

Pipelines are interstate or intrastate. Interstate pipelines are similar to the interstate highway system: they carry natural gas across state boundaries, and in some cases, across the country.

1.7.1 Pipeline Components

Interstate pipelines consist of a number of components that ensure the efficiency and reliability of a system that delivers an important energy source year-round, 24 hours a day. Transmission pipes can measure anywhere from 6 to 48 inches in diameter. The actual pipeline consists of a strong carbon steel material, engineered to meet vigorous standards. The pipe is also covered with a specialized coating to ensure that it does not corrode once placed in the ground. The purpose of the coating is to protect the pipe from moisture, which causes corrosion and rusting.

1.7.1.1 Compressor Stations

Natural gas is highly pressurized as it travels through an interstate pipeline. To ensure that the natural gas flowing through any one pipeline remains pressurized, compression of this natural gas is required periodically along the pipe. This is accomplished by compressor stations, usually placed at 40 to 100 mile intervals along the pipeline. The natural gas enters the compressor station, where it is compressed by either a turbine, motor, or engine.

1.7.1.2 Metering Stations

In addition to compressing natural gas to reduce its volume and push it through the pipe, metering stations are placed periodically along interstate natural gas pipelines. These stations allow pipeline companies to monitor the natural gas in their pipes.

1.7.1.3 Valves

Interstate pipelines include a great number of valves along their length. These valves work like gateways; they are usually open and allow natural gas to flow freely, or they can be used to stop gas flow along a certain section of pipe.

1.7.1.4 Control Stations and SCADA Systems

To ensure that all customers receive timely delivery of their portion of the gas, sophisticated control systems monitor the gas as it travels through all sections of what could be a very lengthy pipeline network. To accomplish the task of monitoring and controlling the natural gas that is traveling through the pipeline, centralized gas control stations collect, assimilate, and manage data received from monitoring and compressor stations along the pipe.

Chapter Two

Literature Review

2.1 Introduction:

Raw natural gas contains valuable heavier hydrocarbons such as ethane, propane, butane and fraction of higher hydrocarbons. These associated hydrocarbons, known as natural gas liquids (NGL), must be recovered from the gas in order to control the dew point of natural gas stream and to earn revenue by selling these components as products for different industries. Natural gas liquids are fractionated to produce LPG.

Natural gas is one of the world's favorite and promising fuels. Transportation of gas is not something easy therefore converting this gas into liquid simplifies and eases the transportation process. Liquefied Petroleum Gas, which is a super pressurized gas stored in a liquid form in tanks or canisters, is a known type of Natural gas that we are going to look very close into.

LPG is a flammable mixture of hydrocarbon gases used as a fossil fuel closely linked to oil, almost two third of the LPG that is used is extracted directly from the Earth in the same way as Natural gas. The rest is manufactured indirectly from petroleum drilled from the Earth in wells. (Crude oil) LPG is considered to be a mixture of two flammable nontoxic gases known as propane (C₃H₈) and butane (C₄H₁₀). Propylene and butylenes are present in small concentrations too. Mainly the LPG gas is of no odor which makes it hard for people to detect the leakage if it happens, so a small amount of a pungent gas such as ethanethiol are added to help people smell potentially dangerous gas leaks.

2.1.1 Properties of LPG

LPG is as twice as heavy as air and half as heavy as water and it is colorless and odorless. LPG can be compressed at a ratio of 1:250 which enables it to be marked in portable containers in liquid form as mentioned above. LPG also produces less air pollutants and carbon dioxide than most other fuels; it helps to reduce the emissions of the typical house Fractionation of NGL to produce LPG .

LPG has a high heating (the amount of heat released during combustion of a specified amount of it) of 12,467 kcal/m³ which is much higher than the average heat value of most Natural gas (9350 kcal/m³). Also LPG has a very high Wobbe index (an indicator of the interchangeability of fuel gases:) of 73.5-87.5 MJ/Sm³ which is a high combustion energy output. Gross Heat Value WI Specific Gravity

LPG can be used as an alternative fuel to natural gas (methane) in residential, commercial and industrial applications, as an alternative to gasoline for automotive fuel purposes, and as a feedstock in petrochemical applications. Both propane and butane are gaseous hydrocarbons at normal temperatures (15 degrees Celsius) and

atmospheric pressure. However, they can be stored and distributed in liquid form at temperatures of under -42 degrees and -2 degrees Celsius for propane and butane respectively. The Fig below shows the typical properties of LPG.

Table 1: Typical Properties of LPG

Property	Propane	butane
Liquid density	0.5-0.51	0.57-0.58
Conversion(ltr per ton)	1968	1732
Gas density/air	1.4-1.55	1.9-2.1
Boiling point	-45	-2
Latent heat of vaporization	358kj/kg	372kj/kg
Specific heat (as a liquid)	0.6btu/deg	0.57btu/deg
Sulfur content	0-0.02%	0-0.02%
Calorific value	2,500btu/ft3	3,270btu/ft3

2.2 Previous Studies :

Emtinan et al (2015) designed an associated natural gas treatment plant from associated gas produced at Alfula oil field; the associated gas currently available in Alfula Oil Field is estimated to be 40.00 MMSCFD. The plant will consist of four parts: pretreatment unit, Acid removal unit, dehydration unit and refrigeration unit.

The study is carried out following standard scientific approach of theoretical study and computer simulations. Associated gas flow rate, composition, and chemical properties are the basis for this investigation; the data collected from the field will be used to fulfill the objective requirement mentioned above.

Material and energy balance is made for the process to determine the total energy and flow. A simulation for the process will be created in HYSYS V8.0, and studies are made to determine optimum operating pressures and temperatures.

Ahmed et al (2008) model the auto thermal reformers by taking PETRONAS methanol Labuan company as a case study study the effect of varying process variables such as catalyst volume and composition temperature on the temperature profile of the auto thermal reformer as well as conversions of reactants and yield . and validate the developed model with auto thermal reforming plant data .

Mohammed et al (2015) Natural Gas (NG) is a viable energy source that is dependent on pipelines and other infrastructures to reach consumers. To overcome this problem, the gas

volume needs to be reduced so that it can be transported through Liquefied Natural Gas carriers and pipelines. Currently, the liquefaction process employed is energy intensive as NG needs to be cooled until it liquefies at -162°C and atmospheric pressure. Chemical and gas plants are energy-intensive facilities so that any enhancement of their efficiency will result in abundant reduction of energy consumption. Liquefied natural gas plants consume a great amount of energy.

In order to enhance LNG plant efficiency, the potential various options for improving liquefaction cycle efficiency is investigated in this study. After developing models for the LNG process using HYSYS software focusing on APCI C3MR cycle because it represent about 70% of the total LNG worldly produced . The simulation results show that the consumed energy decreased by replacing expansion valves with expanders from 1831KJ/Kg to 1478.33KJ/Kg.

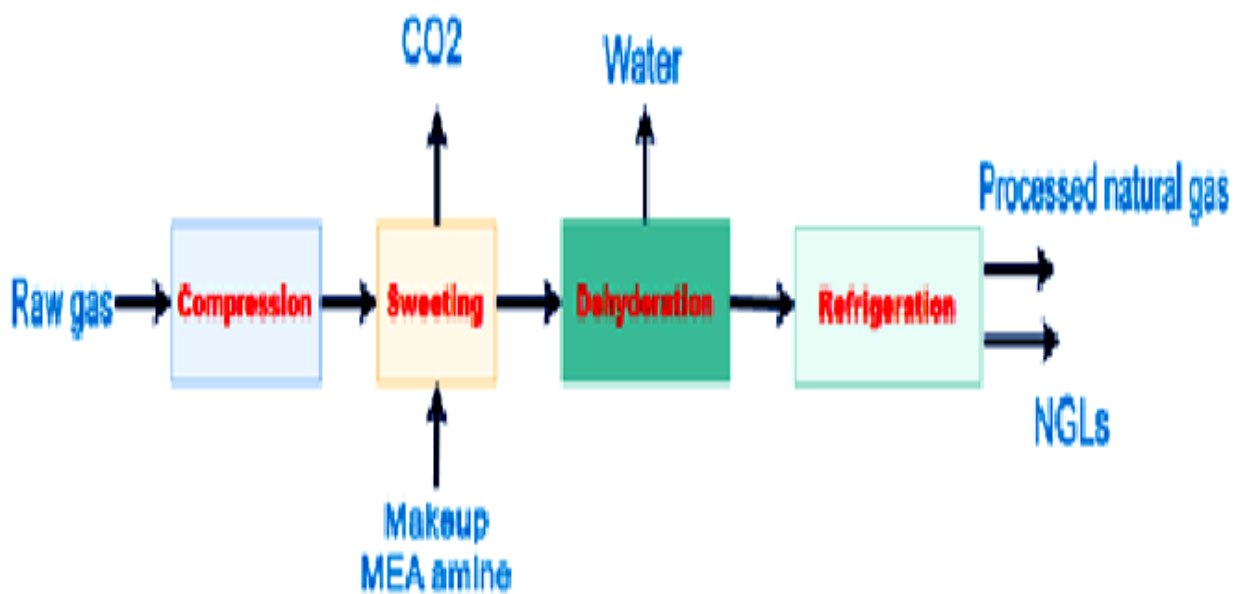
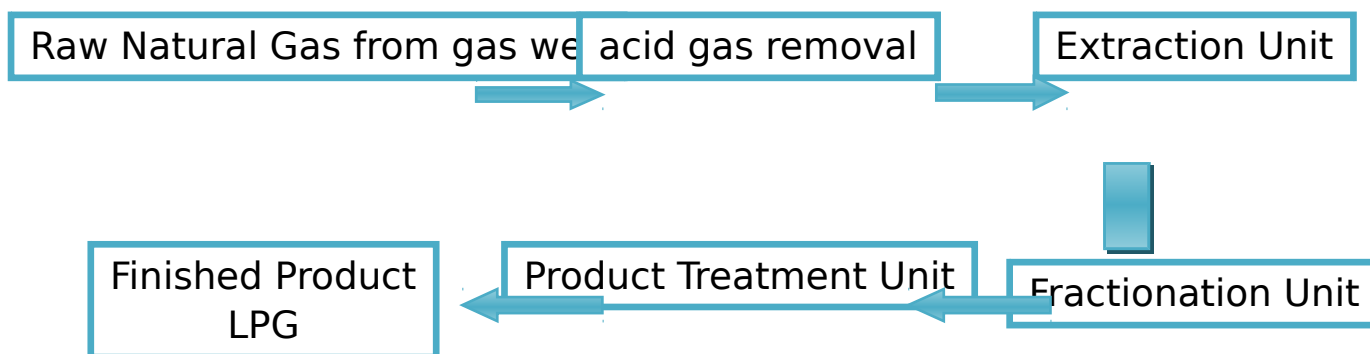


Figure 2.1 :Blockdiagram for LPG Manufacturing



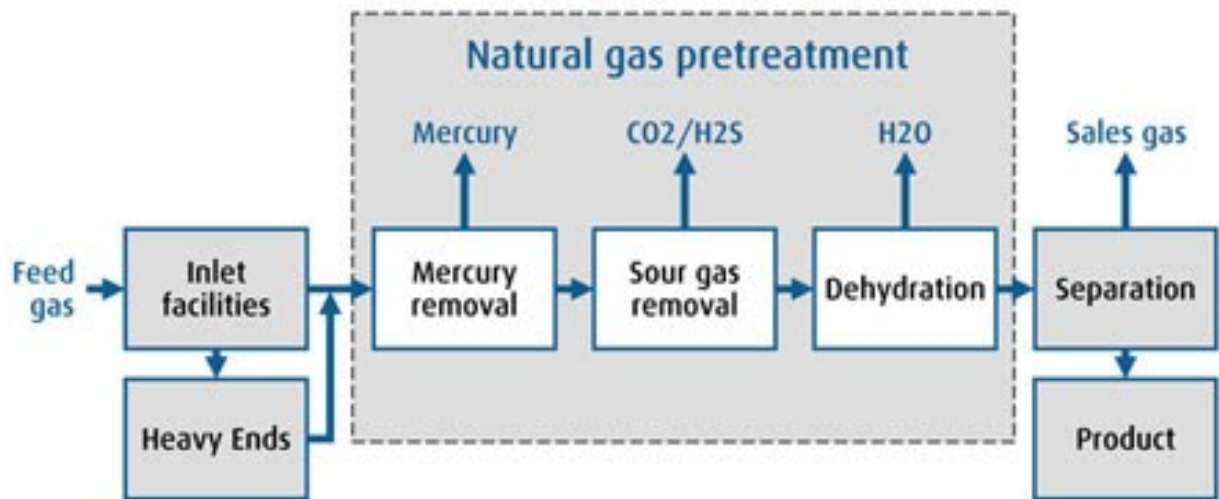


Figure 2.2 Natural gas pretreatment

Gas Treatment Plant Schematic

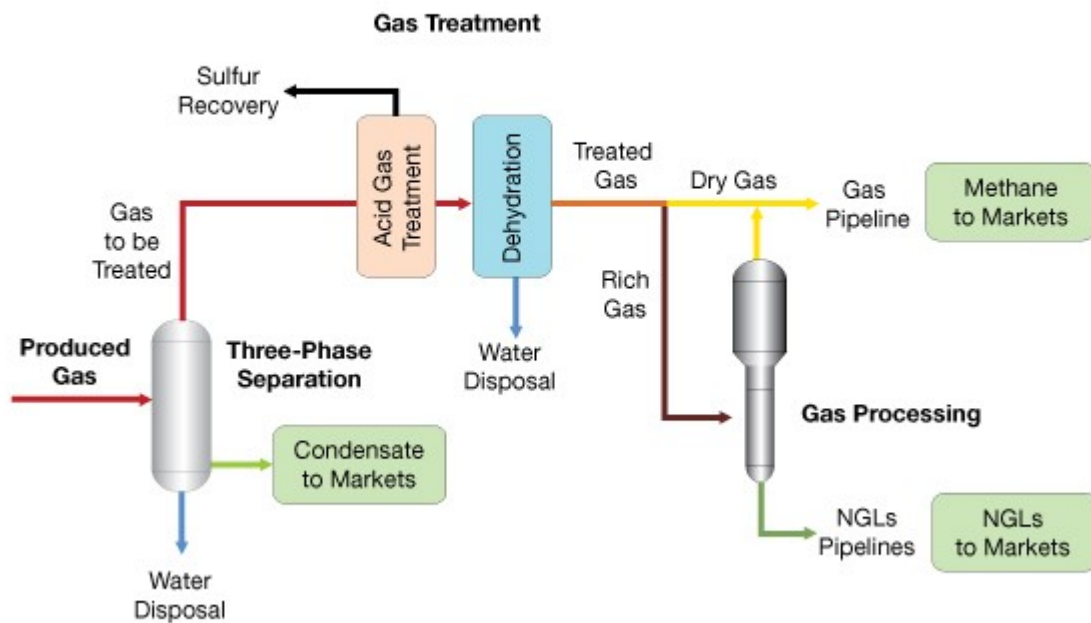


Figure 2.3 Gas treatment plant schematic

Chapter Three

Process Description

3.1 Introduction

First we assume the NG that we want to recover the NGLs from it is dry and sweet so that we will need the following processes to produce LPG :

- 1) Refrigeration unit .
- 2) Fractionation unit .

3.2 Refrigeration

It is required to reach a temperature of -110°C to be able to separate C3 from lighter components like C1 and C2 so the mechanical refrigeration using ethane and propane refrigerants I to be selected. A two stage method will be selected similar to the one shown in figure 3.1 where propane will be used for the first stage and ethylene for the second resulting in a more economic way to reach the target temperature.

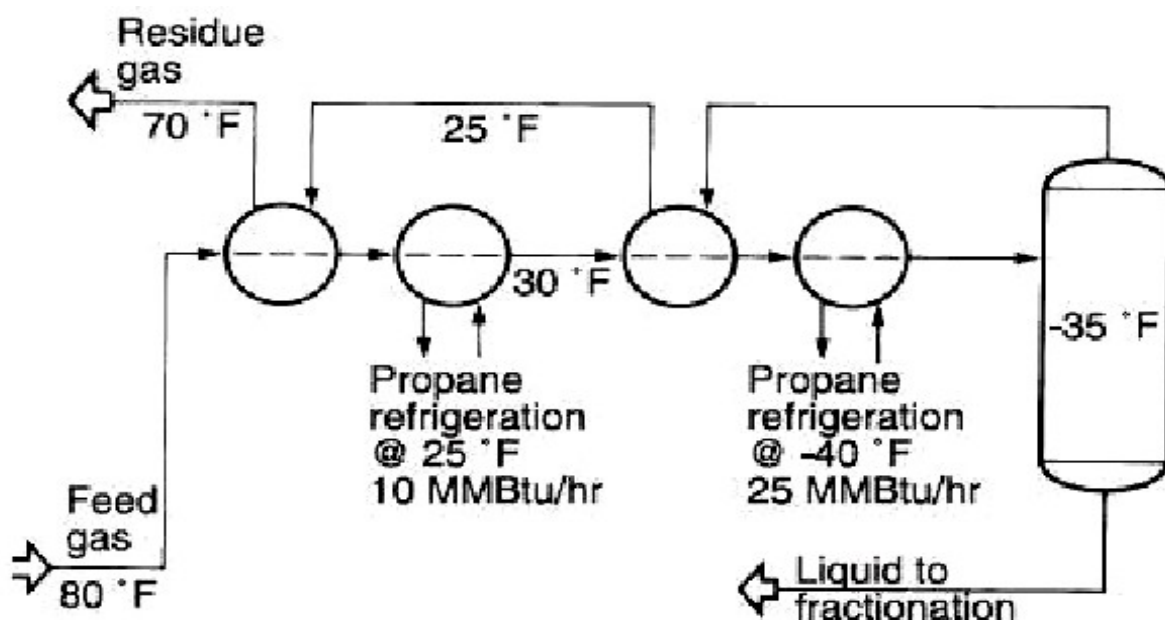


Figure 3.1 Refrigeration unit

As in figure 3.2 the stream feed (dry and sweet) is sent to a heat exchanger by the top stream of the flash separator V-100 to cool the stream before entering the chillers to partially liquefy the natural gas component. A cascade refrigeration is used where propane is used for the first stage and ethylene for the second stage, after the first heat exchanger E-100 the stream enter the first chiller E-101 using propane where it reaches a temperature up to -40°C then it enters the second heat exchanger E-102 to be cooled again before it enters the second chiller E-103 where it reaches a temperature up to -110°C using ethylene. Finally it is send to a flash separator to separate the light vapors (nitrogen, methane and ethane).

3.2.1 Heat Exchanger E-100:

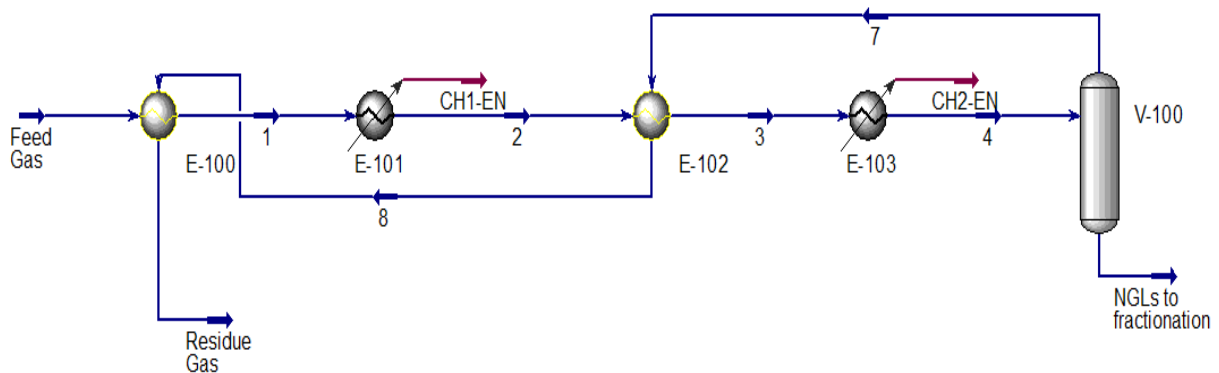


Figure 3.2 Refrigeration unit in hysys simulation

Tube Side Assumptions:

Tube in: Feed with $T=60\text{C}$, $P=1.013\text{bar}$, $M=2000\text{kgmole/hr}$

Tube out: Stream1 with $T=20\text{C}$, $P=1.013\text{bar}$, $M=2000\text{kgmole/hr}$, $\Delta T=-40\text{C}$

Shell side Assumption:

Shell in: Stream8 with $T=51.77\text{C}$, $P=1.013\text{bar}$, $M=1297\text{kgmole/hr}$

Shell out: Stream residue gas with $T=129.6\text{C}$, $P=1.013\text{bar}$, $M=1297\text{kgmole/hr}$, $\Delta T=77.78\text{C}$

3.2.2 Chiller E-101:

Inlet stream1, Outlet stream2 with $T=-40\text{C}$, $P=1.013\text{bar}$, $M=2000\text{kgmole/hr}$, $\Delta T=-60\text{C}$, $\Delta P=0\text{kpa}$, Duty=

3.2.3 Heat Exchanger E-102:

Tube side Assumption:

Tube in: Stream2 , Tube out: Stream3 with $T=-70\text{C}$, $P=1.013\text{bar}$, $M=2000\text{kgmole/hr}$, $\Delta T=-30\text{C}$

Shell side Assumption:

Shell in: Stream7 with $T=-110\text{C}$, $P=1.013\text{bar}$, $M=1297\text{kgmole/hr}$

Shell out: Stream8 with $T=51.77\text{C}$, $P=1.013\text{bar}$, $M=1297\text{kgmole/hr}$, $\Delta T=161.8\text{C}$, Duty=

3.2.4 Chiller E-103:

Inlet Stream3, Outlet Stream4 with $T=-110\text{C}$, $P=1.013\text{bar}$, $M=2000\text{kgmole/hr}$, $\Delta T=-40\text{C}$, $\Delta P=0\text{kpa}$, Duty=

Separator V-100 Assumption:

Inlet Stream4, Outlet in Top Stream7, Outlet in Bottom Stream NGLs to fractionation with $T=-110\text{C}$, $P=1.013\text{bar}$, $M=702.6\text{kgmole/hr}$, Liquid volume%=50%

3.3 Fractionation :

The gas stream from refrigeration unit, (NGLs to fractionation), is sent to the first distillation (De Ethanizer) column to remove ethane and the light components then the bottom stream is sent to the second distillation (De Propanizer) column where the propane is recovered in the top of the column then the bottom out stream is sent to third distillation column (De Butanizer) where the butane is recovered in the top of the column and other (C+) out from bottom .

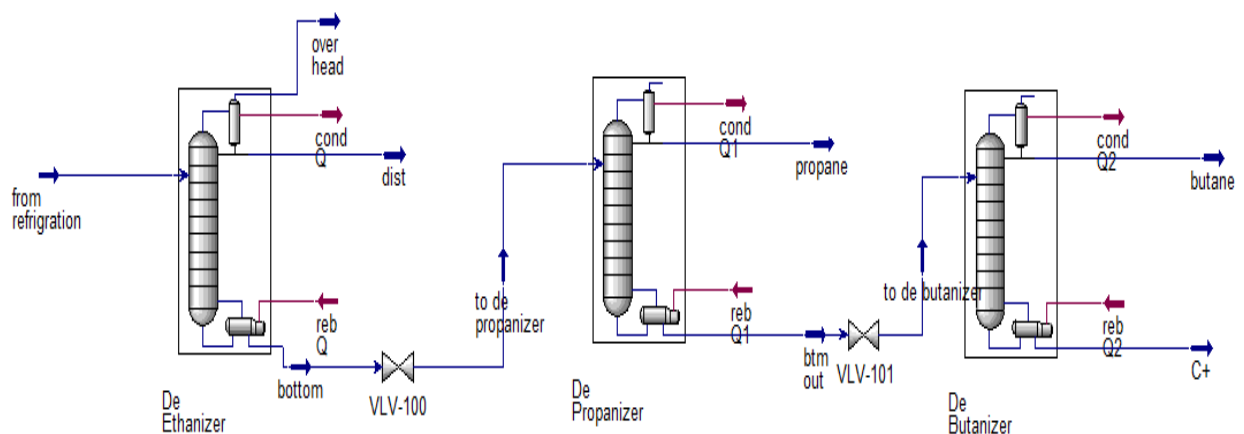


Figure 3.3 Fractionation unit in hysys simulation

3.3.1 De-Ethanizer column:

Inlet from refrigeration: $T=-110\text{c}$, $P=1.013\text{bar}$,
 $M=702.6\text{kgmole/hr}$.

Column assumptions:

Column outlet in Top=dist, in Bottom= bottom , Num of stage=12, Inlet stage=7,
Condenser $\Delta P=35\text{kpa}$, Reboiler $\Delta P=0\text{kpa}$, Pressure Condenser=2725kpa, Pressure
Reboiler=2792kpa, Stage Numbering=Top Down.

3.3.2 De-propaniser column:

Inlet Stream to depropaniser with T=83.22c, P=1690kpa, M=358kgmole/hr.

Column assumptions:

Column outlet in Top=propane, in Bottom= btm out , Num of stage=24, Inlet stage=11, Condenser Delta P=35kpa, Reboiler Delta P=0kpa, Pressure Condenser=1585kpa, Pressure Reboiler=1655kpa, Stage Numbering=Top Down.

3.3.3 Debutaniser column:

Inlet Stream to debutanizer with T=112.9c, P=1600kpa, M=187.5kgmole/hr.

Column assumptions:

Column outlet in Top=butane, in Bottom=C+ , Num of stages=24, Inlet stage=11, Condenser Delta P=0kpa, Reboiler Delta P=0kpa, Pressure Condenser=1163kpa, Pressure Reboiler=1204kpa, Stage Numbering=Top Down.

3.3.4 Valve VLV-100:

Inlet=bottom, Outlet=to de propaniser, Delta P=1102kpa, M=358kgmol/h, Percentage Open=50%.

3.3.5 Valve VLV-101:

Inlet=btm out, Outlet=to debutaniser , DeltaP=55kpa, M=187.5kgmol/h, Percentage Open=50%.

3.4 Material and Energy Balance

3.4.1 Introduction

Material and Energy balances are the basis of all process designs. A material balance will determine the quantities of raw materials and products. An Energy Balance will determine the heat, work, electric energy used in the process. The basic law for both material and energy balance is the conservation law, and it states simply that mass and energy cannot be created nor destroyed. This leads to the general equation:

$$\text{In} + \text{Generated} = \text{Out} + \text{Consumed} + \text{Accumulation} \quad (4.1)$$

The two terms In and Out represent the flow of material or energy past the boundary of the system. The Generated and Consumed terms are associated with reaction and the accumulation represents the unsteady state (dynamic or time depended) system. So for steady

state where no reaction occurs this equation can be simplified to the following from which is the basic equation that will be used in this chapter:

$$In = out \quad (4.2)$$

3.4.2 Material balance

3.4.2.1 Basic information

Feed is at a pressure of 1 atm and temperature of 60°C with the following composition:

Table 3.1: Feed composition

Gas	Mole fraction
C1	0.5268
C2	0.1427
C3	0.1225
i-C4	0.0180
n-C4	0.0435
i-C5	0.0099
n-C5	0.0128
C6	0.0091
CO2	0.1095
Nitrogen	0.0052

3.4.3 Energy Balance

3.4.3.1 Law of Conservation of Energy

$$E_{in} - E_{out} = E_{accumulated} \quad (4.3)$$

$$Q = m C_p \Delta T \quad (4.4)$$

Chapter Four
Results & Discussion

4.1 Material Balance

4.1.1 Refrigeration unit

We obtain the following results: Flash separator 1:

Table 4.1: Flash separator material balance results:

F	V/F	V	L
2000	0.6485	1297	702.6
Component	Zi	yi	Xi
Methane	0.5268	0.7912	0.0386
Ethane	0.1427	0.0765	0.2649
Propane	0.1225	0.0046	0.3403
i-Butane	0.0180	0.0001	0.0511
n-Butane	0.0435	0.0001	0.1237
i-Pentane	0.0099	0.0000	0.0282
n-Pentane	0.0128	0.0000	0.0364
n-Hexane	0.0091	0.0000	0.0259
Nitrogen	0.0052	0.0080	0.0000
CO2	0.1095	0.1196	0.0909

F, L, V are in kgmole/h.

From table above we got that the vapor phase is richer with light component (methane , ethane) and the liquid phase is richer with heavy component (propane and heavier)

4.1.2 Fractionation unit

For this unit the material balance is done for the three columns and results are obtained as follows:

Table 4.2: Distillation Column 1 material balance results

Kgmole/hr	F	B	D	
			Distilate	Over head
	702.6	358.0	8.094e-006	344.6
Component	XF	XB	XD	Xoverhead
Methane	0.0386	0.0000	0.0185	0.0787
Ethane	0.2649	0.0048	0.4557	0.5352
Propane	0.3403	0.4749	0.4446	0.2005
i-Butane	0.0511	0.1001	0.0009	0.0002
n-Butane	0.1237	0.2427	0.0005	0.0001
i-Pentane	0.0282	0.0553	0.0000	0.0000
n-Penane	0.0364	0.0714	0.0000	0.0000
n-Hexane	0.0259	0.0508	0.0000	0.0000
CO2	0.0909	0.0000	0.0799	0.1853
Nitrogen	0.0000	0.0000	0.0000	0.0000

In table above it is clear that the top of column (de-ethanizer) is richer with light component in distillate and over head and the bottom of column is richer with propane and heavier.

Table 4.3: Distillation Column 2 material balance results

Kgmole/hr	F	B	D
	358.0	187.5	170.5
Component	XF	XB	XD
Methane	0.0000	0.0000	0.0000
Ethane	0.0048	0.0000	0.0100
Propane	0.4749	0.0200	0.9749
i-Butane	0.1001	0.1801	0.0121
n-Butane	0.2427	0.4608	0.0029
i-Pentane	0.0553	0.1057	0.0000
n-Pentane	0.0714	0.1364	0.0000
n-Hexane	0.0508	0.0971	0.0000
Nitrogen	0.0000	0.0000	0.0001
CO2	0.0000	0.0000	0.0000

From table above we find that distillate of column (de-propanizer) is richer with propane, in the bottom of column richer with i-butane and heavier.

Table 4.4: Distillation Column 3 material balance results

Kgmole/hr	F	B	D
	187.5	62.77	124.7
Component	XF	XB	XD
Methane	0.0000	0.0000	0.0000
Ethane	0.0000	0.0000	0.0000
Propane	0.0200	0.0000	0.0301
i-Butane	0.1801	0.0000	0.2707
n-Butane	0.4608	0.0001	0.6927
i-Pentane	0.1057	0.3033	0.0062
n-Pentane	0.1364	0.4067	0.0004
n-Hexane	0.0971	0.2899	0.0000
Nitrogen	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.0000

From table above we find that distillate of column (de-butanizer) is richer with butane, in the bottom of column richer with heavier component.

4.2 Energy balance

The energy balance is done using the following equations :

$$E_{in} - E_{out} = E_{accumulated} \quad (4.3)$$

$$Q = m C_p \Delta T \quad (4.4)$$

The results are obtained from Excel as follows:

4.2.1 Refrigeration unit

4.2.1.1 Heat Exchangers

Table 4.5: Heat Exchanger 1 energy balance results

Component	Shell			Tube		
	Flow rate	Q _{in}	Q _{out}	Flow rate	Q _{in}	Q _{out}
	Kgmole/h	kw	Kw	Kgmole/h	Kw	kw
Methane	1026.4792	815.0946	4083.9208	1053.6000	2536.5631	2422.9337
Ethane	99.2950	538.4479	635.9011	285.4000	1052.1036	957.046
Propane	5.9209	45.4757	54.5553	245.0000	1283.1865	1149.6912
i-Butane	0.1087	1.1003	1.3255	36.0000	248.7492	221.6809
n-Butane	0.1043	1.0689	1.2736	87.0000	607.3992	546.7968
i-Pentane	0.0032	0.0399	0.0480	19.8000	168.6238	149.7809
n-Pentane	0.0017	0.02123	0.0253	25.6000	217.9258	195.9843
n-Hexane	0.0001	0.00148	0.0040	18.2000	183.8332	164.9333
Nitrogen	10.3797	29.4995	29.8771	10.4000	19.6382	19.6207
CO ₂	155.1435	582.2508	1412.0700	219.0000	552.3268	524.5232
Total	1297.43616	2013	6216	2000	6870.3494	6352.9907
Heat exchanger 1 Duty = 1148.14 kw						

From table above we find in the tube of heat exchanger the heat flow in of every component is higher than heat flow out due to the difference of temperature and specific heat .

In the shell of heat exchanger the heat flow in of every component is lower than heat flow out due to the difference of temperature and specific heat .

Table 4.6 : Heat Exchanger 2 energy balance results

Component	Shell			Tube		
	Flow rate	Qin	Qout	Flow rate	Qin	Qout
	Kgmole/h	Kw	kw	Kgmole/h	Kw	Kw
Methane	1026.4792	2145.4239	2458.6890	1053.6000	2406.8502	2321.0024
Ethane	99.2950	241.0521	360.3209	285.4000	866.1307	801.1512
Propane	5.9209	18.2984	30.4316	245.0000	1009.2304	910.0253
i-Butane	0.1087	0.4238	0.7363	36.0000	191.1313	171.4909
n-Butane	0.1043	0.4444	0.7153	87.0000	482.9998	440.4724
i-Pentane	0.0032	0.0407	0.0267	19.8000	126.9165	112.4066
n-Pentane	0.0017	0.0249	0.0142	25.6000	173.5054	158.4529
n-Hexane	0.0001	0.0006	0.0009	18.2000	145.6531	132.9169
Nitrogen	10.3797	19.6973	19.7406	10.4000	20.4473	20.4389
CO2	155.1435	301.2367	389.6332	219.0000	498.1249	473.2704
Total	1297.43616	2726.6428	3260.3091	2000	5929.9887	5541.6277
Heat exchanger 1 Duty = 2101.958 kw						

From table above we find in the tube of heat exchanger the heat flow in of every component is higher than heat flow out due to the difference of temperature and specific heat .

In the shell of heat exchanger the heat flow in of every component is lower than heat flow out due to the difference of temperature and specific heat .

Also the duty is increase in the second heat exchanger due to effeciency of refrigeration (we need more cooling).

4.2.1.2 Chillers

Table 4.7: Chiller 1 energy balance results:

Component	Flow rate	Qin	Qout
	Kgmole/h	Kw	kw
Methane	1053.6000	2214.9565	2109.7082
Ethane	285.4000	874.8962	759.2010
Propane	245.0000	1051.0052	884.6340
i-Butane	36.0000	202.6525	167.5348
n-Butane	87.0000	499.8614	423.3702
i-Pentane	19.8000	136.9242	111.2478
n-Pentane	25.6000	179.1616	152.085
n-Hexane	18.2000	150.7759	127.6809
Nitrogen	10.4000	17.9365	17.9229

CO2	219.0000	479.4998	414.8420
Total	2000	5807.6698	5168.2268
Chiller = 2049.972 kw			

From table above the heat flow in is higher than heat flow out due to temperature difference if we increase duty of cooler this will increase the cost.

Table 4.8: Chiller 2 energy balance results:

Component	Flow rate	Qin	Qout
	Kgmole/h	Kw	kw
Methane	1053.6000	2255.39	2185.5062
Ethane	285.4000	769.2602	687.6238
Propane	245.0000	872.5757	751.4587
i-Butane	36.0000	164.4337	139.3242
n-Butane	87.0000	422.346	367.9763
i-Pentane	19.8000	107.7808	89.2304
n-Pentane	25.6000	151.9322	132.8428
n-Hexane	18.2000	127.4470	111.1501
Nitrogen	10.4000	19.5978	19.5870
CO2	219.0000	453.7943	422.0188
Total	2000	5344.5577	4906.7183
Chiller = 2974.6 kw			

From table above the heat flow in is higher than heat flow out due to temperature difference here we increase duty of cooler to get more cooling for product.

Chapter Five
Conclusion & Recommendation

5.1 Conclusion and recommendations:

- Ethylene and propane could be used as a refrigerant to partially liquefy the natural gas components in the refrigeration unit.
- In the first distillation column the light component (Ethane) could be removed while the Liquefied Petroleum (LPG) Gas along with the heavy components are pumped to the second distillation column where the LPG gases could be recovered in the top of the column.
- The light components, after compressing it, could be used for well's reinjection to enhance oil production.
- Liquefied Petroleum Gas could be transported through pipeline safely due to its noncorrosive nature (gas free from water and carbon dioxide).
- LPG and light component could also be used for other major petrochemical treatment.
- The light components could be used as a fuel for power generation.

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