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College of Engineering
Department of Petroleum

Thermodynamic simulation for plant design of gas dehydration process

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Prepared by:

- Muntadhar Saadoon Sayyed Ubaid
- Mohammed Qasim Lazim Ajeel
- Jabbar Abdulrahim Fayyadh Labees
- Zahraa Jasim Jariyo Hasoun

Supervised By

Assist. Lect. Jaafar Chasib Ors

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بِسۡمِ ٱللَّهِ ٱلرَّحۡمَٰنِ ٱلرَّحِيمِ

"يَرْفَعِ اللَّهُ الَّذِينَ آمَنُوا مِنكُمْ
وَالَّذِينَ أُوتُوا الْعِلْمَ دَرَجَاتٍ"

المجادلة: 11

صَدَقَ اللَّهُ العَظِيمُ

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Abstract

Gas dehydration is widely used in natural gas treatment plant as a common process, because water and hydrocarbon can form hydrates [ice formation] which may block valve and pipelines. Water also can cause corrosion in the presence of acid gas component in natural gas. The produced natural gas from a well normally contains: free and/or vapor water, hydrogen sulfide, carbon dioxide and other solid materials. These are considered as impurities that should be removed as much as possible in order to meet the requirement of marketable gas. The process of natural gas dehydration is very important in: gaspipelines, -storage, and –marketing.

Natural gas often contains water vapor which must be removed to prevent operational issues such as hydrate formation, corrosion, and reduced heating value. This study presents a detailed examination of natural gas dehydration processes with a particular focus on triethylene glycol (TEG) systems. Theoretical foundations, industrial practices, types of desiccants, simulation methodologies, and challenges are discussed. A case study of the Jubilee Field in Ghana is presented using Aspen HYSYS to simulate and optimize the TEG dehydration process. Key variables such as glycol flow rate, number of contactor stages, and reboiler temperature were analyzed for their impact on water content in the gas stream. Results showed that a balanced flow rate and proper design parameters are essential to meeting pipeline specifications while maintaining economic feasibility.

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Chapter One

Introduction and Overview

1.1 Background

Natural Gas is a gaseous fossil fuel consisting primarily of methane but including small quantities of ethane, propane, butane, pentane and any heavier hydrocarbon; element sulfur; and sometimes helium and nitrogen [3]. Natural gas can be discovered in the wellhead. It comes from the three types of well such as oil wells, condensate wells and gas wells. This gas are exists separate from the oil (free gas) or dissolved in the crude oil (dissolved gas) [4]. Before natural gas can be used as a fuel, it must undergo extensive processing to remove almost all materials other than methane. The by-products of that processing include ethane, propane, butanes, pentanes and higher molecular weight hydrocarbons, elemental sulfur, and sometimes helium and nitrogen. To get the higher impurities of methane, there are several process need to be done such as oil and condensate removal, separations of natural gas liquid, sulfur and carbon dioxide removal and water removal.

Natural gas contains many contaminants, of which the most common undesirable impurity is water. Most natural gas will be near water saturation at the temperature and pressure of production. Process that involved removing all the water content in the natural gas can be known as a dehydration process. This dehydration process is needed to reduce the potential for corrosion in the presence of acid gas, hydrate formation, and freezing in the pipeline stream. Water is also removed to meet a water dew point requirement [5]. The dehydration process can be done into many different types of process. But, only two process that widely use which is an absorption process and adsorption process.

Gas dehydration is widely used in natural gas treatment plant as a common process and it removes water that is associated with natural gases in vapor form.

The natural gas industry has recognized that dehydration is necessary to ensure smooth operation of gas transmission lines as water and hydrocarbon can form gas hydrates which may block valves and pipelines.

Several methods have been developed to dehydrate gases on an industrial scale. The three major methods of dehydration are direct cooling, absorption of water in glycol, and adsorption of water by solid. In absorption processes, the absorption/stripping cycle is used for removing large amounts of water, and adsorption is used for cryogenic systems to reach low moisture contents and does not involve any chemical reaction. For commercial dehydration purpose, high absorption efficiency, and easy and economic regeneration should be possessed by those dehydrating agent. They should be noncorrosive and non-toxic, no operation problems when used in high concentration, no interaction with the hydrocarbon portion of the gas, and no contamination by acid gases. When optimizing the design of dehydration facilities, the impact of number of trays in the contactor, liquid desiccant circulation rate through the contactor, temperature of the reboiler in the regenerator, amount of stripping gas used, and operating pressure of the regenerator should be considered.

The theme of natural gas (NG) dehydration is closely linked with storage of natural gas. There are two basic reasons why NG storage is important. Firstly, it can reduce dependency on NG supply. Secondly, NG storage enables the maximum capacity of distribution lines to be exploited. NG is stored in summer periods, when there is lower demand for it, and is withdrawn in the winter periods, when significant amounts of NG are used for heating. Underground Gas Storages (UGS) are the most advantageous option for storing large volumes of gas. Nowadays there are approximately 135 UGSs inside the European Union. Their total maximum technical storage capacity is around 109 ms3. [1]. There are three types of UGSs: (1) Aquifers, (2) Depleted oil/gas fields, and (3) Cavern reservoirs (salt or hard rock). Each of these types possesses distinct physical characteristics.

The important parameters describing the appropriateness of UGS use are storage capacity, maximum injection/withdrawal performance, and gas contamination during storage. Generally, the allowable pressure of stored gas inside a UGS is up to 20 MPa. The pressure inside increases as the gas is being injected, and decreases when gas is withdrawn. The output gas pressure depends on further distribution. The temperature of the gas usually ranges from 20 - 35°C.

1.2. Water in the gas

A disadvantage of UGSs is that during storage the gas become saturated by water vapors. In the case of depleted oil field UGSs, vapors of higher hydrocarbons also contaminate the stored gas. The directive for gas distribution sets the allowable concentration of water and concentration of higher hydrocarbons. In the US and Canada, the amount of allowable water in the gas is specified in units: pounds of water vapor per million cubic feet (lbs/MMcft). This amount should be lower than 7 lbs/MMcft [2]. In Europe, the concentration of water and higher hydrocarbons is specified by their dew point temperature (Tdew). Tdew for water is -7°C for NG at 4 MPa, and Tdew for hydrocarbons is 0°C for NG at the operating pressures [3]. As was stated above, the distribution specifications depend on the geographic region in which they are applied. For example, in Nigeria water Tdew should be below 4°C for NG at 4 MPa, which means that the NG can contain more than twice as much water vapors as in Europe. The water content of NG at saturation is dependent on temperature and pressure. With increasing pressure of the gas the water content decreases, and with increasing temperature the water content in the gas increases. This is well presented in Figure No. 20, Chapter 20, in the GPSA Data Book, 12th Edition. The water content of the gas can be calculated using the following equation [4, 5]:

$$w_{water} = 593{,}335 \cdot exp(0.05486 \cdot t_G) \cdot {P_G}^{-0.81462} \tag{1}$$

Where W_{water} is in kilograms of water per 10^6 ms^3 of NG, tG is temperature of NG in °C, and PG is pressure of NG in MPa. The average value of water in NG withdrawn from UGS is 2 - 5 times higher than required. An NG dehydration step is therefore essential before further distribution.

1.3. Problems with water in the gas

If the temperature of pipeline walls or storage tanks decreases below the Tdew of the water vapors present in the gas, the water starts to condense on those cold surfaces, and the following problems can appear.

- NG in combination with liquid water can form methane hydrate. Methane hydrate is a solid in which a large amount of methane is trapped within the crystal structure of water, forming a solid similar to ice. The methane hydrate production from a unit amount of water is higher than the ice formation. The methane hydrates formed by cooling may plug the valves, the fittings or even pipelines.
- NG dissolved in condensed water is corrosive, especially when it contains CO_2 or H_2S.
- Condensed water in the pipeline causes slug flow and erosion.
- Water vapor increases the volume and decreases the heating value of the gas.
- NG with the presence of water vapor cannot be operated on cryogenic plants.

1.4 PROBLEM STATEMENT

Natural gas is a mixture of many components which is classified into 3 major groups, that is hydrocarbons containing Hydrogen and Carbon, inert elements and trace compounds. Natural gas hydrates are solids that formed from natural gas hydrocarbons and water. The water molecules have a honeycomb structure with a molecule of one of the natural gas components occupying each void. Since these solids are denser than water ice, their formation is favored at higher pressure. Natural gas hydrates may form and interfere with the passage of natural gas through valves and pipes. These may block pipeline flow and control systems. Natural gas in transit needs to be dehydrated to a controlled water content in order to avoid gas hydrates and to minimize corrosion.

1.5 RESEARCH OBJECTIVES

The goal of this study is to remove the water component in natural gas by using dehydration process and to treat the natural gas.

1.6 SIGNIFICANCE OF STUDY

Dehydration to the gas will be subjected to prevent hydrate formation and corrosion from condensed water. The latter consideration is especially important in gas streams containing CO2 or H2S where the acid gas components will form an acid with the condensed water.

Natural gases either from natural production or storage reservoirs contain water, which condense and form solid gas hydrates to block pipeline flow and especially control systems. Natural gas in transit to market should be dehydrated to a controlled water content to avoid hydrate as well as to minimize the corrosion problems.

Chapter Two

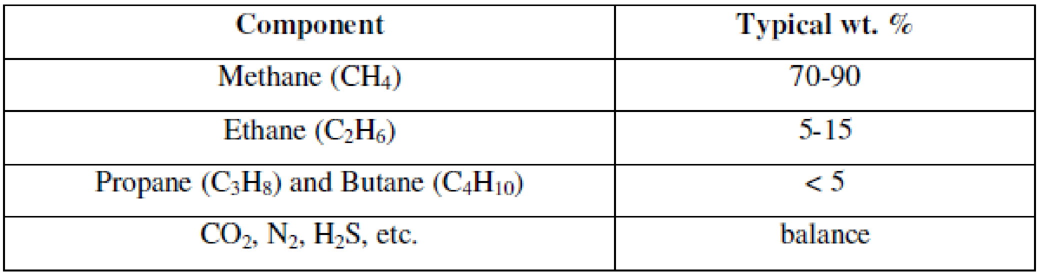
Literature Review

2.1 Natural Gas

Natural gas is a gaseous fossil fuel that commercially produce from oil fields(associated gas) either dissolved or isolated in natural gas fields(non-associated gas) , and in coal beds. Natural gas is not a pure product underground. Since natural gas is not a pure product, when non-associated gas is extracted from a field under supercritical (pressure/temperature) conditions, it may partially condense upon isotherm depressurizing.. The liquids thus formed may get trapped by depositing in the pores of the gas reservoir. One method to deal with this problem is to reinject dried gas free of condensate to maintain the underground pressure and to allow Re-evaporation and extraction of condensates [8]. Natural gas are produced from the plants and animal decayed and built up in thick layer about millions years ago. This decayed matter from plants and animals is called organic material. Over time, the mud and soil changed to rock, covered the organic material and trapped it beneath the rock. Pressure and heat changed some of this organic material into coal, some into oil (petroleum), and some into natural gas [9].

Methane is primary component in natural gas which is the shortest and lightest hydrocarbon molecule. Natural gas also contains many heavy hydrocarbons such as ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}) and also have other gases such as helium, nitrogen, sulfur, carbon dioxide and water vapor. Natural gas that contains hydrocarbons other than methane is called wet natural gas. Natural gas consisting only of methane is called dry natural gas [10].

Table 2.1: Component of natural gas



Component	Typical wt. %
Methane (CH_4)	70-90
Ethane (C_2H_6)	5-15
Propane (C_3H_8) and Butane (C_4H_{10})	< 5
CO_2, N_2, H_2S, etc.	balance

2.2 Gas Dehydration

Under normal production condition, the natural gas is saturated with water vapor Water vapor components in natural gas can cause many problems especially in the pipeline stream. Process that involved removing the water content can be known as dehydration process. This dehydration process is a important process in operate the natural gas. The purpose of dehydration process is to prevent gradual plugging of the pipeline by ice formation, to avoid the formation of liquid slugs, to avoid risk of condensation of water in pipeline and to maximize pipeline efficiency. Water is also removed to meet a water dew point requirement of a sales gas contract specification range from 32.8 to 117 kg/10^6 std m^3 [11].

2.3 Hydrates

Having accumulated in the gas pipeline, they can choke or completely block the pipe and cause damage to the system's operating conditions [4].

If the temperature of pipeline walls or storage tanks decreases below the dew point of the water vapors present in the gas, the water starts to condense on those cold surfaces, and the following problems can appear [5]:

- Natural gas in combination with liquid water can form methane hydrate that may plug the valves, the fittings or even pipelines
- Natural gas dissolved in condensed water is corrosive, especially when it contains CO_2 or H_2S
- Condensed water in the pipeline causes slug flow and erosion

- Water vapor increases the volume and decreases the heating value of the gas
- Natural gas with the presence of water vapor cannot be operated on cryogenic plants

2.4 Gas Dehydration Processing

Under normal production condition, the natural gas is saturated with water vapor Water vapor components in natural gas can cause many problems especially in the pipeline stream. Process that involved removing the water content can be known as dehydration process. This dehydration process is a important process in operate the natural gas. The purpose of dehydration process is to prevent gradual plugging of the pipeline by ice formation, to avoid the formation of liquid slugs, to avoid risk of condensation of water in pipeline and to maximize pipeline efficiency. Water is also removed to meet a water dew point requirement of a sales gas. When large gas volumes are transported, dehydration is the most efficient and economical means of preventing the hydrate formation in the trunk pipeline. The existing methods for gas dehydration in the field fall into two main groups :

- Absorption (dehydration by liquid media)
- Adsorption (dehydration by solid media), [6]. The dehydration is aimed at the depression of the water dew point below the minimal temperature that can be expected in the gas pipeline.

Gas dehydration by liquid media is most widely used in the gas industry. The liquid sorbents used for the dehydration of natural and petroleum gases should have [4]: o high solubility in water, o low cost, o high corrosion resistance. o chemically neutral towards the gas components, and o easily regenerated. Diethylene glycol (DEG), triethylene glycol (TEG) and, to a lower extent, monoethylene glycol (MEG) satisfy most of these requirements. Advantages of dehydration by means of liquid sorbents [4]:

- relatively small capital expenditure and operating costs,
- small pressure differentials in the dehydration system,
- ability to dehydrate gases containing substances poisoning solid sorbents
- continuous processes. Disadvantages of dehydration by means of liquid sorbents [5]:
    - smaller depression of the dew point (compared to solid sorbents),
    - foaming of glycols when the gas contains lighter hydrocarbons. Glycol dehydration units are of two types [4]:
    - ❖ absorption units
    - ❖ glycol injection into the gas stream, [7]. Advantage of the absorption scheme (glycol concentration is 9699%) is minimal glycol losses, but it is difficult to reach the water dew point of the dehydrated gas. The glycol injection scheme (glycol concentration is 70-80%), the dew point is depressed as the gas cools down, and not only the gas is dehydrated, but also the condensate which has dropped out of the cooled gas. Disadvantage of the glycol injection is glycol losses due to its solubility in the hydrocarbon condensate.

2.5 Dehydration Processes in the Gas Plant:

There are two different dehydration processes in the gas plant.

- ❖ Mono- Ethylene Glycol (MEG) is used to remove water from the wet gas,
- ❖ Tri-Ethylene Glycol (TEG), which is used in all production fields.

The specifications of both Glycols are summarized in table 2.

Table 2.1: Comparison of Mono- and Tri- Ethylene Glycol properties

Property	MEG	TEG
Formula	$HO(C_2H_4O)H$	$HO(C_2H_4O)3H$
Flash point (° F)	240	330
boiling point (° F)	387	549

2.6 Gas hydrates

Gas hydrates are crystals of natural gas and water which can appear fare above the temperature where ice is formed. Gas hydrates are a caged structure containing a gas molecule like methane, the cage is formed by water through hydrogen bonding, as illustrated in Figure 2-1. Because the gas hydrate crystals are similar to ice crystals, the problems with gas hydrates are similar to those with ice, although gas hydrates are more troublesome because of the higher formation temperature.

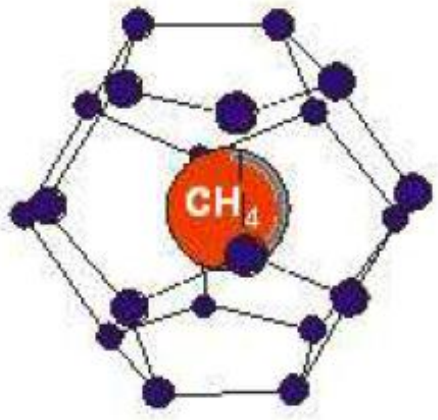


Figure 2.1: Gas hydrate [W2].

Because hydrates can form in pipelines, large amounts of hydrates can be in the gas simultaneously; this can create plugs in the pipeline. Because of the potentially high hydrate contents in the gas the blockage can arise within minutes without any prior warning.

2.6.1 Prevention

Because of the potential dangers from gas hydrates they must be prevented. There are several methods to prevent gas hydrate formation, they are:

- Gas dehydration
- Raising the temperature
- Reducing the pressure
- Adding inhibitors

Gas dehydration is the most efficient way to prevent hydrate formation, but there may be practical limitation to the use of dehydration, e.g. one central dehydration unit. Gas dehydration will be treated further in section 3. If the gas stream can not be dehydrated, one of the other prevention methods must be used. Raising the temperature of a pipeline is very impractical, likewise is reducing the pressure, because such a reduction will reduce the pipeline flow. The only practical solution is therefore to ad inhibitors to the gas. Inhibitors Inhibitors acts as antifreeze in the gas, the usual inhibitors are:

- Alcohols
- Glycols

Methanol and monoethylene glycol (MEG) are the most commonly used inhibitors, low doses are often injected continuously in pipeline where hydrate formation is a problem. Higher doses of especially methanol are used temporally to dissolve hydrate plugs. MEG is more viscous than methanol, but has the advantage of being easier to regenerate from the gas than methanol, because methanol regeneration is usually not feasible.

MEG is the most commonly used glycol, because it is more efficient at a given mass concentration than diethylen glycol (DEG). DEG may nevertheless be used as inhibitor in the pipeline, but only if DEG also is the glycol used in the dehydration process afterwards.

There are other possible inhibiters that prevent hydrate formation they are:

- Salts
- Ammonia
- Monoethanolamine

Salts are very rarely used because of the risk of corrosion and deposits. Ammonia is corrosive, toxic and can form solid deposits of carbonates obtained with carbon dioxide and water. Monoethanolamine is only attractive if it after pipe transport is used (and thereby recovered) for gas sweetening [11].

2.7 Processes in offshore production

On the process platforms the main purpose is to process the reservoir fluid into oil, gas and water. This has to be done in such a manor that oil, gas and water meets the requirements before oil and gas can be exported and the water released into the sea. Demands on oil may be the vapour pressure, to insure that no vapour is produced in the pipeline during transport to shore. Likewise a demand for gas may be no water dew in the pipeline; other gas demands may be the methane contents or heating value. For the oil and gas it is also a demand that the pipeline pressure is reached, before it can be exported from the platform. Water is a by-product, which needs to be cleaned before it can be disposed off. To divide the reservoir fluid and insure that the requirements for the three phases are meet the reservoir fluid is processed. The process equipment can be divided into three parts [12].

1. Separation, including oil treatment and export
2. Gas treatment, including gas export
3. Water purification

The processes associated with these three systems may differ for different composition of reservoir fluid, especially for the gas treatment.

2.7.1 Separation

The first task when the reservoir fluid enters the process equipment is to separate it into its three phases. This is done in a series of three-phase separators, the number of which depends upon the inlet pressure of the reservoir fluid. The first separator divides the reservoir fluid into its three phases. Subsequent separators are used to improve the purity of the oil and increase the gas recovery. When the first separation is completed there will still be gas dissolved in the oil, and probably also some water if the retention time is too small to ensure total separation between the two liquid phases. Before the next separation, the pressure of the oil is lowered; this releases more of the dissolved gas. In case of additional water this will be separated off in the subsequent separators. This continues until the oil has the required purity, often two or three separators are enough. When the quality is as desired it is pumped to the pipeline pressure, before it is exported of the platform and to shore. The gas released from the oil in the subsequent separators needs to be recompressed before it can be send to the gas treatment system. Figure 2.2 illustrates a separation system with two separators and gas recompression [12].

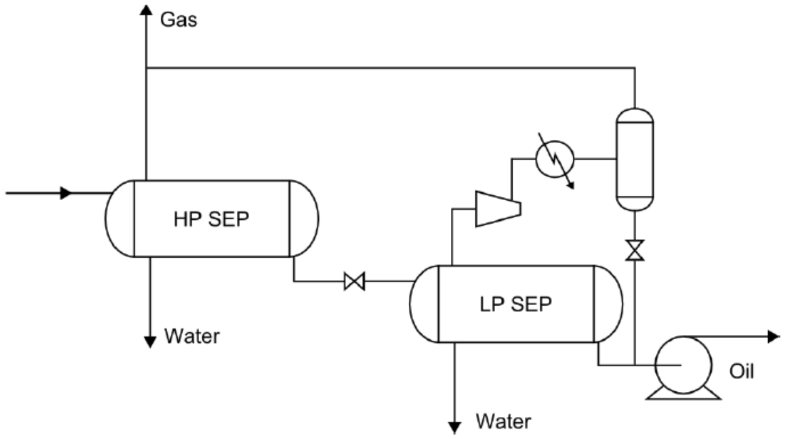


Figure 2.2: Separation and oil export

When gas is compressed, it is necessary to cool the gas and separate off any condensed liquid. In case of more separators than in Figure 1-4, each new separator will also be equipped with a compressor. There will also be some liquid recycled from the gas treatment and the water purification system, but these streams have been excluded here for simplicity [13].

2.7.2 Gas treatment

The purpose of gas treatment is to clean the gas for unwanted impurities and get it to the desired condition before it is exported. The composition of the gas is the decisive factor for which gas treatment procedures that are used. The most common cleaning procedures are gas sweetening, dehydration and hydrocarbon recovery; more seldom treatments can be removal of inorganic elements. The purpose of cleaning the gas of its impurities is to improve the gas quality, avoid dangers to the process plant or pipeline from e.g. corrosion or enable the gas to be brought to the desired export condition. After purification usually only compression is required, for the gas to reach its desired export condition. In rare cases the desired export condition could require liquefaction of the gas[13].

a. Gas sweetening

To minimize corrosion it is often necessary to remove acid components in the gas. It is manly CO2 and H2S that are removed, although in some cases other sulphur components are present in the gas and must therefore also be removed. The most common sweetening procedure is absorption of the acid, with amines in an aqueous solution. Afterwards the rich amine solution is regenerated before it can be reused. Because the amines are in an aqueous solution, the sweet gas will be water saturated. Amine sweetening must therefore be conducted before gas dehydration. Absorption is the most common procedure, but other procedures can also be used. E.g. membrane processes if only carbon dioxide are to be removed [14].

b. Dehydration

Where dehydration was deemed to be the most efficient way to solve the problems associated with wet gas. Dehydration is usually done by absorption, although other processes like adsorption, membrane processes and refrigeration may be used.

c. Hydrocarbon recovery

In gas with a high content of C2+ components, there is a risk of NGL (Natural Gas Liquids) formation. NGL may be removed from the gas to avoid liquid in the pipeline or to sell the more expensive NGL separately, instead of as a part of the gas. Hydrocarbon recovery is preformed by cooling the gas below its dew point temperature, condensing the more heavy hydrocarbons in the gas, the condensed liquid is then removed in a separator. The easiest way to cool the gas is in heat exchangers; this is most efficient at high pressure. Hydrocarbon recovery by cooling with heat exchangers may not yield the desired gas purity depending on the initial composition. In these cases the temperature can be lowered further by flashing the gas in a Jules-Thompson valve or in a turbo-expander. Because of the low temperatures achieved by flashing the gas, low water content is essential to prevent ice formation. Further improvements in hydrocarbon recovery can be achieved by distilling the liquid from the NGL recovery, thus recovering the methane condensed in this treatment[14].

d. Inorganic contents

If the gas quality is below pipeline quality because of contamination by inorganic elements, it is necessary to remove these impurities. Some of the inorganic components are only present in trace amounts, but can none the less create problems. The most common inorganic component is nitrogen, the nitrogen contents might be high, either naturally or if nitrogen is used for injection into the reservoir to improve hydrocarbon recovery. Nitrogen can be recovered by cryogenic distillation, adsorption or membrane separation. Radon may be present in the gas, it is radioactive, but with a half-life of 3.8 days the health problems from radon is minimal. The problem is that it decays into radioactive lead, which eventually will turn into non-radioactive lead. The result is that low-level radioactive materials will sediment in the process equipment and pipes; this constitutes a problem because cleaning produces radioactive waste.

e. Other contaminants

Benzene, Toluene, Ethylbenzene and Xylene (BTEX) are a problem because of environmental concerns. BTEX is removed from the gas during glycol dehydration, a smaller amount BTEX may also be removed during gas sweetening. When the glycol is regenerated the BTEX will be removed with the water, and thereby be vented to the atmosphere. BTEX are also a problem in cryogenic gas treatment because they can freeze like water. BTEX can not be removed from the gas before the dehydration. The BTEX problem can be reduced by using a light glycol, because BTEX is more solvable in larger glycols. Alternatively the vented gas from the glycol regenerator can be flared or treated to remove the BTEX before it is vented to the atmosphere [14].

f. Compression

The gas is compressed from the process pressure to the pipeline pressure in one or more steps, depending on the pressure difference. After each compression the gas is cooled and condensed liquids are separated off.

g. Liquefaction of the gas

Liquefied natural gas is an advantage when gas is stored or transported by non pipeline transport. Liquefaction of methane requires extensive refrigeration to temperatures as low as -161 °C (-258 °F). A very low water contents are therefore required.

2.7.3 Water treatment

Unlike oil and gas treatment, water treatment is an environmental issue. Water is a waste product in oil and gas production; therefore it is released into the sea or used for well injection. When water is separated off in the three-phase separation it still has a small hydrocarbon contents. This hydrocarbon contents constitutes no problem when the water is used for well injection, only when it is released into the sea. Because of environmental concerns the hydrocarbons needs to be removed from the water so the contents is below the threshold limit value for water released into the sea. The hydrocarbons in the water are oil that did not separate off in the separators and dissolved gas. First the oil is removed using hydro cyclones; the oil is lead back to the separator system. The gas is removed from the water by decreasing the pressure thus decreasing the solvability in the water. The gas is separated off before the water is released into the sea [15].

Chapter Three

Design and Theoretical consideration

3.1 Dehydration Methods of Natural Gas

Dehydration of natural gas is the process 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.

3.1.1 Direct Cooling

The ability of natural gas to contain water vapor decreases as the temperature is lowered at constant pressure. During the cooling process, the excess water in the vapor state becomes liquid and is removed from the system. Natural gas containing less water vapor at low temperature is output from the cooling unit. The gas dehydrated by cooling is still at its water dew point unless the temperature is raised again or the pressure is decreased. It is often a good practice that cooling is used in conjunction with other dehydration processes. Glycol may be injected into the gas upstream ahead of the heat exchanger to reach lower temperatures before expansion into a low temperature separator [16].

3.1.2 Indirect Cooling

Expansion is a second way of natural gas cooling. It can be achieved by the expander or Joule.Thomson valve. These processes are characterized by a temperature drop to remove condensed water to yield dehydrated natural gas. The principal is similar to the removal of humidity from outside air as a result of air conditioning. Gas is forced through a constriction called an expansion valve into space with a lower pressure. As a gas expands, the average distance between molecules increase. Because of intermolecular attractive forces, expansion causes an increase in the potential energy of the gas. If no external work is extracted in the process and no heat is transferred, the total energy of the gas remains the same. The increase in potential energy thus implies a decrease in kinetic energy and therefore in temperature [16].

3.1.3 Dehydration by Absorption

The basis for gas dehydration using absorption is the absorbent; there are certain requirements for absorbents used in gas treating.

● Strong affinity for water to minimize the required amount of absorbent [liquid solvent].

● Low potential for corrosion in equipments, low volatility at the process temperature to minimize vaporization losses.

● Low affinity for hydrocarbons to minimize their loss during the process.

● Low solubility in hydrocarbons to minimize losses during treating.

● Low tendency to foam and emulsify to avoid reduction in gas handling capacity and minimize losses during regeneration.

● Good thermal stability to prevent decomposition during regeneration and low viscosity for easily pumping and good contact between gas and liquid phases. Off course, the major critical property for a good absorbent is the high affinity for water. The others are used to evaluate potential absorbents practical applicability in the industry [17].

There are numbers of liquids that can be used to absorb water from natural gases such as calcium chloride, lithium chloride and glycols. 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 [16] . There are a few types of glycol usually used in industry with their advantages and disadvantages like ethylene glycol [EG], diethylene glycol [DEG], triethyleneglycol [TEG], and tetraethylene glycol [TREG]. Glycols typically seen in industry include monoethylene glycol [MEG] Table[2.1] shows the properties of the glycols [16] .The commonly available glycol and their uses are described as follows.

1. Monoethylene glycol [MEG];high vapor equilibrium with gas so tend to lose Monoethylene glycol to gas phase in contactor. Use as hydrate inhibitor where it can be recovered from gas by separation at temperature below 50ºF.

2. Diethylene glycol [DEG]; high vapor pressure leads to high losses in contactor. Low decomposition temperature requires low reconcentrator temperature [315 to 340ºF] and thus cannot get pure enough for most applications. [Show table 3.1]

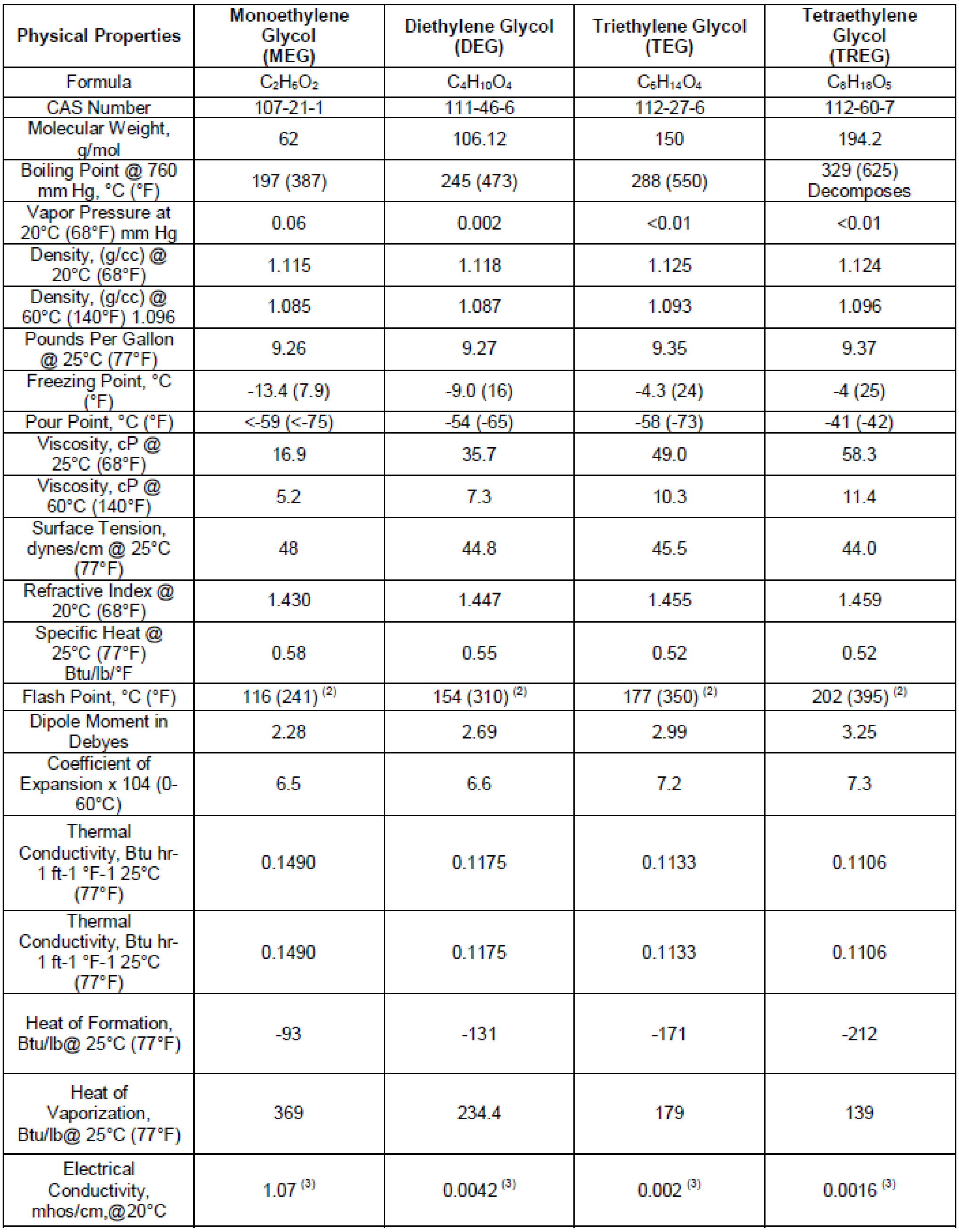
3.Triethylene glycol [TEG]; most common. Reconcentrate at 340.400ºF,for high purity. At contactor temperatures in excess of 120ºF, there is a tendency to high vapor losses. Dew point depressions up to 150ºF are possible with stripping gas.

4. Tetraethylene glycol [TREG]; more expensive than TEG but less loss at high gas contact temperatures. Reconcentrate at 400 to 430ºF. TEG is by far the most common liquid desiccant used in natural gas dehydration. It exhibits most of the desirable criteria of commercial suitability listed here. 1.TEG is regenerated more easily to a concentration of 98.99% in an atmospheric stripper because of its high boiling point and decomposition temperature. 2. TEG has an initial theoretical decomposition temperature of 404ºF, whereas that of diethylene glycol is only 328ºF.

5. Vaporization losses are lower than monoethylene glycol or diethylene glycol. Therefore, the TEG can be regenerated easily to the high concentrations needed to meet pipeline water dew point specifications.

6. Capital and operating costs are lower [18] .

Table[3.1]: Shows the properties of the glycols



Physical Properties	Monoethylene Glycol (MEG)	Diethylene Glycol (DEG)	Triethylene Glycol (TEG)	Tetraethylene Glycol (TREG)
Formula	$C_2H_6O_2$	$C_4H_{10}O_4$	$C_6H_{14}O_4$	$C_8H_{18}O_5$
CAS Number	107-21-1	111-46-6	112-27-6	112-60-7
Molecular Weight, g/mol	62	106.12	150	194.2
Boiling Point @ 760 mm Hg, °C (°F)	197 (387)	245 (473)	288 (550)	329 (625) Decomposes
Vapor Pressure at 20°C (68°F) mm Hg	0.06	0.002	<0.01	<0.01
Density, (g/cc) @ 20°C (68°F)	1.115	1.118	1.125	1.124
Density, (g/cc) @ 60°C (140°F) 1.096	1.085	1.087	1.093	1.096
Pounds Per Gallon @ 25°C (77°F)	9.26	9.27	9.35	9.37
Freezing Point, °C (°F)	-13.4 (7.9)	-9.0 (16)	-4.3 (24)	-4 (25)
Pour Point, °C (°F)	<-59 (<-75)	-54 (-65)	-58 (-73)	-41 (-42)
Viscosity, cP @ 25°C (68°F)	16.9	35.7	49.0	58.3
Viscosity, cP @ 60°C (140°F)	5.2	7.3	10.3	11.4
Surface Tension, dynes/cm @ 25°C (77°F)	48	44.8	45.5	44.0
Refractive Index @ 20°C (68°F)	1.430	1.447	1.455	1.459
Specific Heat @ 25°C (77°F) Btu/lb/°F	0.58	0.55	0.52	0.52
Flash Point, °C (°F)	116 (241) (2)	154 (310) (2)	177 (350) (2)	202 (395) (2)
Dipole Moment in Debyes	2.28	2.69	2.99	3.25
Coefficient of Expansion x 104 (0-60°C)	6.5	6.6	7.2	7.3
Thermal Conductivity, Btu hr-1 ft-1 °F-1 25°C (77°F)	0.1490	0.1175	0.1133	0.1106
Thermal Conductivity, Btu hr-1 ft-1 °F-1 25°C (77°F)	0.1490	0.1175	0.1133	0.1106
Heat of Formation, Btu/lb@ 25°C (77°F)	-93	-131	-171	-212
Heat of Vaporization, Btu/lb@ 25°C (77°F)	369	234.4	179	139
Electrical Conductivity, mhos/cm,@20°C	1.07 (3)	0.0042 (3)	0.002 (3)	0.0016 (3)

The rational of using TEG or advantages of TEG is ease of regeneration and operation, minimal losses of drying agent during operation, high affinity for water [this may be attributed to hydrogenoxygen bonds which are set up between atoms of the hydroxyl groups and those of water], chemical stability, high hygroscopicity and low vapor pressure at the contact temperature [16] . TEG, or triethyleneglycol is a colorless, odourless viscous liquid with molecular formula C6H14O4 and molecular structure as shown in Figure [2.1].

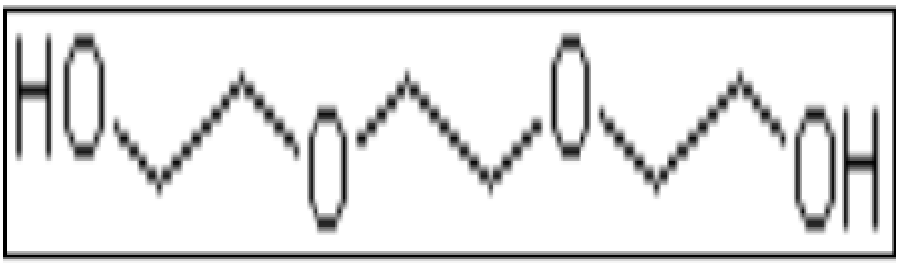


Figure [3.1]: Molecular structure of triethylene glycol [TEG]

Essentially, Dehydration of natural gas by TEG is first outlined by summarizing the flow paths of natural gas and glycol . Then the individual components of a typical TEG unit are described in detail. shown in Figure [2.2], wet natural gas first typically enters an inlet separator to remove all liquid hydrocarbons from the gas stream. Then the gas flows to an absorber [contactor] where it is contacted countercurrently and dried by the lean TEG. TEG also absorbs volatile organic compounds [VOCs²] that vaporize with the water in the reboiler. Dry natural gas exiting in the absorber passes through a gas/glycol heat exchanger and then into the sales line.

The wet or "rich" glycol exiting the absorber flows through a coil in the accumulator where it is preheated by hot lean glycol. After the glycolglycol heat exchanger, the rich glycol enters the stripping column and flows down the packed bed section in to the reboiler . Steam generated in the reboiler strips absorbed water and VOCs out of the glycol as it rises up the packed bed. The water vapor and desorbed natural gas are vented from the top of the stripper. The hot regenerated lean glycol flows out of the reboiler into the accumulator [surge tank] where it is cooled via cross exchanger with returning rich glycol; it is pumped to a glycol/gas heat exchanger and back to the top of the absorber. Glycol unit decreases the water content to 60 ppm [18] .

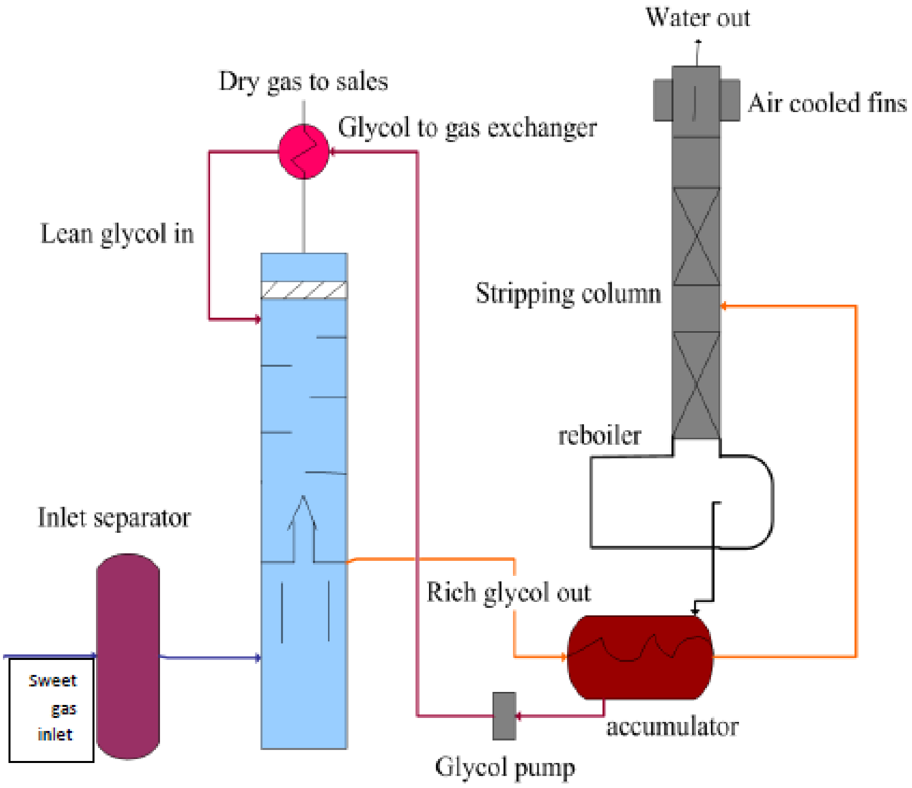


Figure [3.2]: Flow diagram for TEG dehydration

3.1.4 Dehydration by Adsorption (Solid Desiccant)

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] .

1. Large surface area for high capacity. Commercial adsorbents have a surface area of 500.800 m^2 /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[16 . 21].

The most widely used adsorbents today are activated alumina, silica gel, molecular sieves [zeolites] [16]

3.2 Types of Adsorbents

3.2.1 Alumina

A hydrated form of aluminum oxide [Al2O3], alumina is the least expensive adsorbent. It is activated by driving off some of the water associated with it in its hydrated form [[Al2O3.3H2O] by heating. It produces an excellent dew point depression values as low as .100 ºF, but requires much more heat for regeneration. Also, it is alkaline and cannot be used in the presence of acid gases, or acidic chemicals used for well treating. The tendency to adsorb heavy hydrocarbons is high, and it is difficult to remove these during regeneration. It has good resistance to liquids, but little resistance to disintegration due to mechanical agitation by the flowing gas [21]

3.2.2 Silica Gel and Silica.Alumina Gel

Gels are granular, amorphous solids manufactered by chemical reaction. Gels manufactured from sulfuric acid and sodium silicate reaction are called silica gels, and consist almost solely of silicon dioxide [$SiO2$]. Alumina gels consist primarily of some hydrated form of $Al2O3$. Silicaalumina gels are a combination of silica and alumina gel. Gels can dehydrate gas to as low as 10 ppm, and have the greatest ease of regeneration of all desiccants. They adsorb heavy hydrocarbons, but release them relatively more easily during regeneration. Since they are acidic, they can handle sour gases, but not alkaline materials such as caustic or ammonia. Although there is no reaction with $H2S$, sulfur can deposit and block their surface. Therefore, gels are useful if the $H2S$ content is less than (5.6%) [21] .

3.2.3 Molecular Sieves

Molecular Sieves are crystalline alkali metal alumino silicates comprising a three dimensional interconnecting network of silica and alumina tetrahedral [18]. These tetrahedras are the basic building blocks for various zeolite structures, such as zeolites A and X, the most common commercial adsorbents [figure.2.3]. [22] Molecular sieve is the most versatile adsorbent because it can be manufactured for a specific pore size, depending on the application. It is:

- Capable of dehydration to less than 0.1 ppm water content.
- The overwhelming choice for dehydration prior to cryogenic processes [especially true for LNG].
- Excellent for $H2S$ removal, $CO2$, dehydration, high temperature dehydration, heavy hydrocarbon liquids, and highly selective removal.

- More expensive than silica gel ,but offers greater dehydration.


Molecular Sieve Type A
Molecular Sieve Type X

Figure [3.3]: Zeolite structure

Requires higher temperatures for regeneration, thus has a higher operating, cost [18]. The water adsorption in zeolites functions on the basis of physisorption. the main driving force for adsorption is the highly polar surface within the pores. This unique characteristic distinguishes zeolites from other commercially available adsorbents, enabling an extremely high adsorption capacity for water and other polar components even at very low concentrations (figure 3.4) [22].

The structure of molecular sieve is an array of cavities connected by uniform pores with diameters ranging from about 3 to 10ºA, depending on the sieve type. In addition, the pore size plays a significant role, allowing or prohibiting the entrance of molecules to the pore system [16] .Some types of molecular sieves and it application in table (3.2).

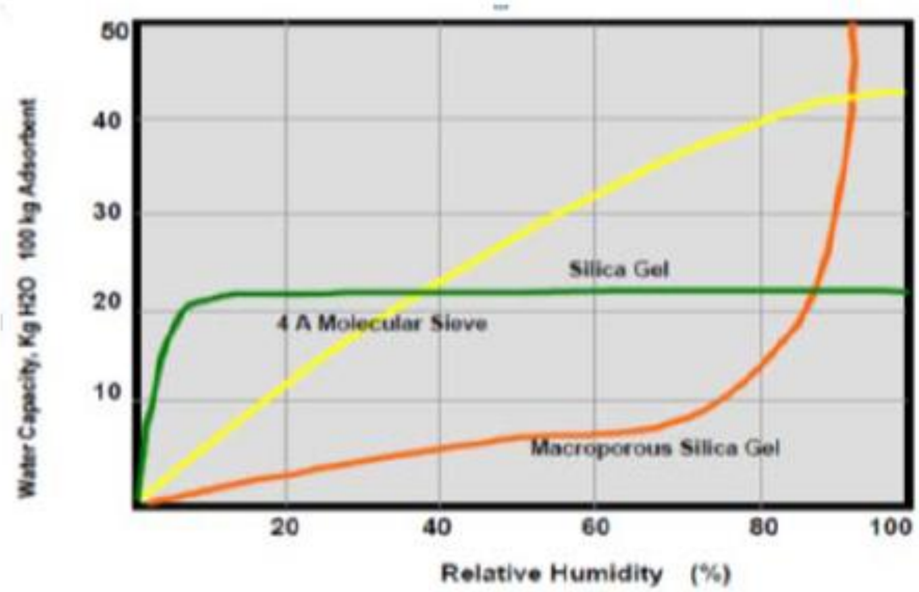
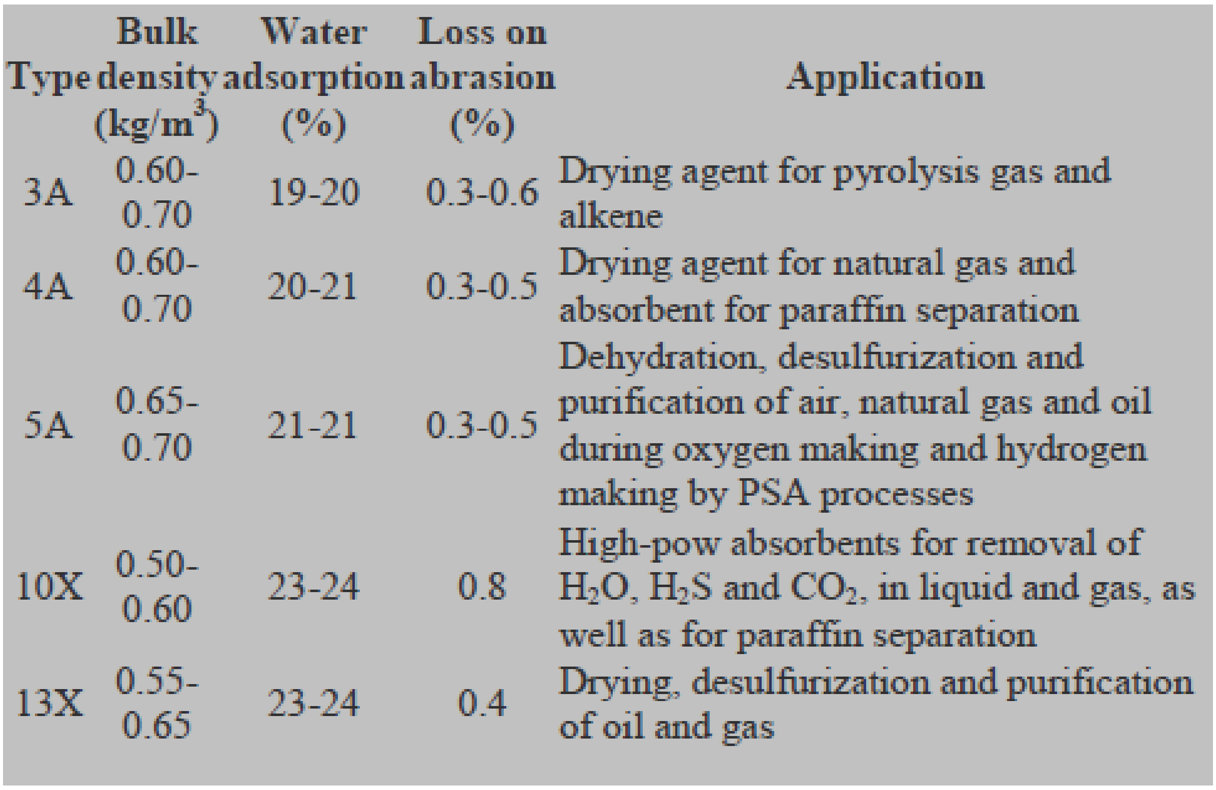


Figure [3.4]Water adsorption curve versus relative humidity.

Table[3.2] Technical data & application of some kind of molecular sieve.



Type	Bulk density (kg/m^3)	Water adsorption (%)	Loss on abrasion (%)	Application
3A	0.60-0.70	19-20	0.3-0.6	Drying agent for pyrolysis gas and alkene
4A	0.60-0.70	20-21	0.3-0.5	Drying agent for natural gas and absorbent for paraffin separation
5A	0.65-0.70	21-21	0.3-0.5	Dehydration, desulfurization and purification of air, natural gas and oil during oxygen making and hydrogen making by PSA processes
10X	0.50-0.60	23-24	0.8	High-pow absorbents for removal of H_2O, H_2S and CO_2, in liquid and gas, as well as for paraffin separation
13X	0.55-0.65	23-24	0.4	Drying, desulfurization and purification of oil and gas

3.3 Some Types of Molecular Sieves

3.3.1 3A Molecular Sieve

The pore size of 3A molecular sieve is 3A. It does not adsorb any molecular larger than 3A. According to the industrial application specialties, 3A molecular sieves have the characters of higher adsorption speed, stronger crushing and anti.contaminative resistance, more cyclic times and longer work.span. All these advantages have made it come to be the most essential and necessary desiccant in the fields of the deep drying, refinery polymerization for cracked gases [pyrolysis gas], ethylene, propylene and any other non.acidic gasses of liquids in petroleum and chemical industrials.

Formula : $0.4K_2O \cdot 0.6Na_2O \cdot Al_2O_3 \cdot 2.0SiO_2 \cdot 4.5H_2O$

Applications: Dehydration of many kinds of liquids [such as ethanol], dehydration of air, dehydration of refrigerant, dehydration of natural gas or methane, dehydration of cracked gas [pyrolysis gas], ethylene, propylene or butadiene[8]. .

3.3.2 4A Molecular Sieve

is set up considering the features of target material and processing environment.The general revival temperature of Molecular Sieve 4A is about200.300°C [23].

Formula: $Na_2O . Al_2O_3 . 2SiO_2 . 4.5 H_2O$

Applications

Deep drying of air, Natural gas, alkane and refrigerant. Generation and purification of argon. Static dehydration of electronic element, pharmaceutical and unstable materials. Desiccant for paint, dope and foul etc. Type 4A molecular sieve is typically used in regenerable drying systems to remove water vapor or contaminants which have a smaller critical diameter than four angstroms.

3.3.3 5A Molecular Sieve

Molecular Sieve type 5A is an alkali alumino silicate; it is the calcium form of the Type A crystal structure. The pore size of 5A molecular sieve is about 5 Å . It can adsorb all kinds of molecular smaller than this size, it is mainly used in separation of the normal and isomerous alkane,pressure swing adsorption [PSA] for gases,co.adsorption of moisture and carbon dioxide.Regeneration: molecular sieve Type 5A can be regenerated by pressure swing or purging, usually at elevated temperatures. The purge gas temperature must be sufficiently high to bring the molecular sieve to a level of 200°C . 350°C [22] .

Formula: $0.75\ CaO \cdot 0.25\ Na_2O \cdot Al_2O_3 \cdot 2\ SiO_2 \cdot 4.5H_2O$

Applications

Oxygen/hydrogen PSA [Pressure Swing Adsorption] process for removal of

water and carbon dioxide from air. Type 5A separates normal paraffins from branched.chain and / cyclic hydrocarbons through a selective adsorption process. Ethanol refinement [moisture, CO_2, etc.].

3.3.4 13X Molecular Sieve

Molecular Sieve 13X is the sodium form of the type X crystal and has a much larger pore opening than the type A crystals.The pore size 13X molecular sieve is about 10 Å . It can adsorb any molecular smaller than 10 Å , mainly used as catalyst carrier, co.adsorption of CO_2 and H_2O, H_2O and H_2S, as desiccant for medical and air compressor system, and can also be adjusted to fit other various applications. Regeneration : molecular sieve Type 13X can be regenerated by evacuating or purging, usually at elevated temperatures. The purge gas temperature must be sufficiently high to bring the molecular sieve to a level of 250°C . 350°C [22] .

Formula: Na_2O . Al_2O_3 . [2.8±0.2] SiO_2 . [6~7]H_2O.

Applications

Air refining [removing CO_2 and H_2O] removal of mercaptans and hydrogen sulphide from natural gas, removal of mercaptans and hydrpogen sulphide from hydrocarbon liquid streams [LPG, butane, propane etc.] , oxygen PSA [Pressure Swing Adsorption] process special double glass [removing solvent and grease].

3.4 Solid Desiccant Adsorption Kinetics

Figure [2.5] illustrates the movement of an adsorption zone front as a function of time. In a dry desiccant bed, the adsorbtcate components are adsorbed at different rates. A short while after the process has begun, a series of adsorption zones appear, as shown in Figure [2.5]b. The distance between successive adsorption zone fronts is indicative of the length of the bed involved in the adsorption of a given component. Behind the zone, all of the entering component is removed from the gas; ahead of the zone, the concentration of that component is zero. Note the adsorption sequence: C1 and C2 are adsorbed almost instantaneously, followed by the heavier hydrocarbons, and finally by water that constitutes the last zone. Almost all the hydrocarbons are removed and dehydration begins. Water displaces the hydrocarbons on the adsorbent surface if enough time is allowed. At the start of dehydration cycle, the bed is saturated with methane as the gas flows through the bed. Then ethane replaces methane, and propane is adsorbed next. Finally, water will replace all the hydrocarbons. For good dehydration, the bed should be switched to regeneration just before the water content of outlet gas reaches an unacceptable level. The regeneration of the bed consists of circulating hot dehydrated gas to strip the adsorbed water, then circulating cold gas to cool the bed down [21].

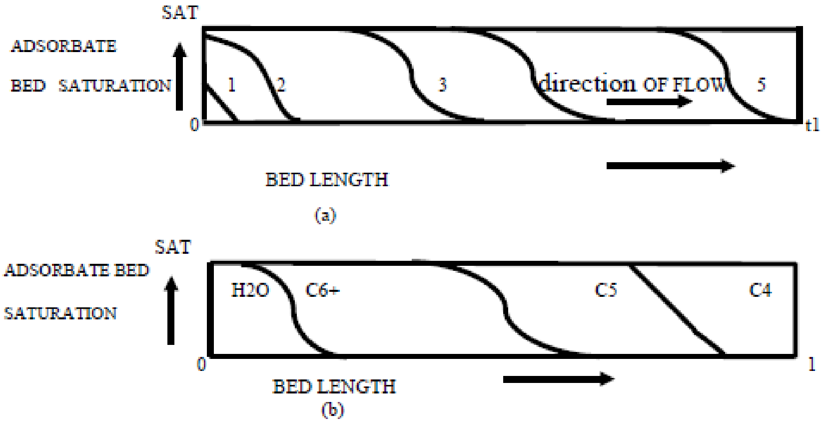


Figure [3.5] Schematic representation of the adsorption process

3.5 Fundamentals of Adsorption

The adsorption process, takes place in four more or less definable steps.

1.Bulk solution transport.

2.Film diffusion transport. 3.Pore transport. 4.Adsorption [or sorption].

Bulk solution transport involves the movement of the organic material to be adsorbed through the bulk liquid to the boundary layer of fixed film of liquid surrounding the adsorbent, typically by advection and dispersion in adsorbent contactors. Film diffusion transport involves the transport by diffusion of the organic material through the stagnant liquid film to the entrance of the pores of the adsorbent. Pore transport involves the transport of the material to be adsorbed through the pores by a combination of molecular diffusion through the pore liquid and/or by diffusion along the surface of the adsorbent. Adsorption involves the attachment of the material to be adsorbed to adsorbent at an available adsorption site. Because the adsorption process occurs in a series of steps, the slowest step in the series is identified as the rate limiting step. In general, if physical adsorption is the principal method of adsorption, one of the diffusion transport steps will be the rate limiting, because the rate of physical adsorption is rapid. Where chemical adsorption is the principal method of adsorption, the adsorption step has often been observed to be rate limiting. When the rate of sorption equals the rate of desorption, equilibrium is achieved and the capacity of the adsorbent is reached. The theoretical adsorption capacity of the molecular sieve for a particular contaminant can be determined by developing its adsorption isotherm as described below [23].

3.6 TEG Dehydration Process

In the oil and gas manufacturing industry, plant operators constantly have to figure out how to remove contaminants and deliver the best purity products. A major undesirable contaminant associated with natural gas is water vapor. To eliminate unwanted moisture from recovered natural gas, industrial manufacturers utilize various gas dehydration methods, including triethylene glycol processes.

3.6.1 TEG Gas Dehydration Unit

A triethylene glycol [TEG] gas dehydration system is a setup used to eliminate water vapor from newly recovered natural gas. This drying equipment utilizes liquid triethylene glycol as its dehydrating agent to pull out water from a stream of natural gas flowing over it. A major benefit of using a TEG dehydration unit is the ability to recycle the drying fluid multiple times before replacement.

3.6.1.1 Components of a Glycol Dehydration Unit

To properly conduct its function of drying natural gas, a glycol dehydration unit must possess some critical components.

These key parts of a glycol drying setup include [25]:

- Inlet scrubbers
- Contact towers
- Reboilers
- Surge tanks
- Flash separator

While the first two components are crucial to natural gas drying, the latter three are primarily used to regenerate the glycol to aid further cycles of gas dehydration.

A TEG dehydration unit integrated natural gas drying phases with glycol regeneration processes. To begin with, natural gas mixed with water vapor is channeled through a feed gas inlet on the gas scrubber, eliminating free water associated with it. This removes most of the water suspended in the gas stream as well as particulate impurities and free hydrocarbons. However, the natural gas at this point is still considered “moist” and must undergo further drying.

Next, the gas is passed through connecting channels to a contact tower, where the final stage of drying occurs. A typical contact tower is made up of carefully arranged levels containing moisture.free or “lean” liquid glycol. Natural gas is typically introduced via an inlet at the bottom of the contact tower and rises through it while being in constant contact with glycol fluid at various levels. Any residual moisture within the gas is pulled out of it as it rises to the top of the column, where an outlet channel awaits to conduct the newly dried gas to storage tanks or other processing. While this occurs, the glycol solution contained within the contact tower becomes “rich” as it absorbs moisture necessitating its regeneration. While dry glycol is being fed into the process by one inlet, wet glycol is being removed via another outlet and channeled to a regeneration process [25].

The process of reformulating lean glycol begins when “wet” glycol is channeled into a three.stage flash separator which removed accumulated water vapor, particulate impurities, and oils. These contaminants are channeled to storage tanks for later discharge impurity.free glycol is moved to a reboiler unit.

The reboiler separates the absorbed water from the glycol by distillation. Water boils at 212oF, while the boiling point of glycol is 550oF. Ethylene glycol will begin to degrade at 404oF, so most operators maintain their distillation processes between 212°F and 400°F. Any residual water within the glycol is eliminated as steam, and the “lean” or dry glycol is now ready to be returned to the contact tower for further natural gas dehydration cycles [25].

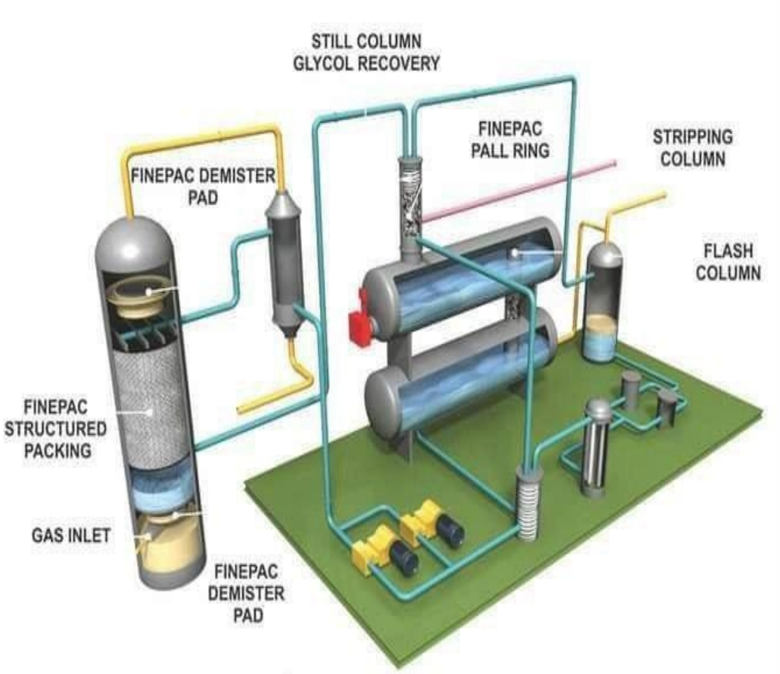


Figure [3.6]: Parts of TEG dehydration process

3.7 Operational Problems

3.7.1 Solid Desiccant Dehydration

Operational problems that may occur because of poor design, operation, and maintenance in a solid desiccant unit are described in this section.

3.7.1.1 Bed Contamination

The most frequent cause is incomplete removal of contaminants in the inlet gas separator. Also, if the regeneration gas leaving the separator is commingled with the feed gas to the dehydrators,then a separator malfunction can dump liquid hydrocarbons and water onto the desiccant regenreration separators should usually be equipped with filtration levels similar to the inlet gas to prevent recontamination [3] .

3.7.1.2 High Dew Point

High dew point is one of the two common problems that can cause operating trouble. Possible causes include the following.

1."wet" inlet gas bypasses the dehydrator through cracks in the internal insulation. Cracks in a liner or in sprayed.on insulation can be detected by "hot spots" and peeling paint on the outer shell. Other symptoms are fast water breakthrough and an unusually rapid rise in the effluent gas temperature during regeneration.

2.Leaking valves also permit wet gas to bypass the dehydrators. Even a slight leak of hot gas usually produces a detectable temperature rise in what should be the cold side of the valve. Ultrasonic translators are also useful.

3.Incomplete desiccant regeneration will lead to a sudden loss in adsorption capacity and a significantly premature breakthrough. To be sure to well regenerate the adsorbents the inlet and outlet temperatures of the adsorber in regeneration should be analyzed. At the end of the heating step the outlet temperature should be almost contact during a certain time [30 minutes to 2 hours] depending on the design of the adsorber,and the temperature difference between inlet and outlet should not be more than 59.68ºF depending on the quality of the heat insulation.

4.Excessive water content in the wet feed gas due to increased flow rate,higher temperatures,and lower pressure. It is very important to respect the inlet temperature [feed temperature] of the adsorbers in case of saturated gas. Small variations in temperature will lead to significant increases in the water content [3]

3.7.1.3 Premature Breakthrough

Satisfactory dew points are observed at the beginning but not for the entire duration of the drying cycle. Desiccant capacity should decrease with use but should stabilize at 55.70% of the initial capacity Ballard, [24].However, premature symptoms of "old gas" are caused by an unrecognized increase in inlet water loading, an increase in heavy hydrocarbons [C4+] in feed gas, methanol vapor in feed, desiccant contamination, or incomplete regeneration.

3.7.1.4 Hydrothermal Damaging

Heating up the adsorber without using a heating ramp or an intermediate heating step leads to a strong temperature difference in the vessel. At the bottom, the molecular sieve will be very hot and will desorb rapidly the adsorbed water while the layers at the top of the adsorber will be still at adsorption temperature. The water desorber in the bottom layer will condense in the top layer. Hydrothermal damaging will appear in consequence, which is different depending on the type of molecular sieve. In order to prevent hydrothermal damaging of molecular sieves it is not only important to choose the right formulation of the molecular sieve [binder and zeolite] but the operating conditions; the regeneration conditions should be determined carefully. In fact, the higher the regeneration temperature and the higher the amount of liquid water present on the sieves, the heavier the damaging of the molecular sieves. In an industrial unit it is also important to limit the quantity of water appearing in liquid phase [condensing water due to oversaturation of the gas phase], as this decreases the temperature where hydrothermal destruction may occur with water acting as a stabilizer for intermediates formed by dissolution of the zeolites.

3.7.1.5 Liquid Carryover

Liquid [particularly amines] carryover in the molecular sieve bed has a bad effect on the drying process. In order to reduce the liquid carryover in adsorbers, separators must be modified to improve their efficiency. The regeneration procedure should also be changed so as to have a moderate temperature increase to avoid water recondensation. Although on.site mechanical changes of the drying unit can improve the performance, however, the right corrective action can be found by using a more resistant molecular sieve, SRA. The SRA adsorbent offers a better mechanical resistance than the regular one to severe operating conditions simulating the thermal regeneration step of a natural gas purification unit.

3.7.1.6 Bottom Support

Sometimes operators have problems with the support grid and leakage of molecular sieves through the support grid. As a result, they have to replace the whole bed. Important point here is the good mechanical design of the support bed, putting three wire mesh on the support grid (4, 10,20 mesh) and installing the correct quantity and size of ceramic balls.

3.7.2 Glycol Dehydration

The operating problems associated with each equipment in the TEG dehydration unit are described individually in the following sections.

3.7.2.1.1 Absorber

The main operating problems associated with the absorber are insufficient dehydration, foaming and hydrocarbon solubility in glycol, which are discussed next.

Insufficient Dehydration Causes of insufficient dehydration [i,e, wet sales gas] include excessive water content in the lean glycol, inadequate absorber design, high inlet gas temperature, low lean glycol temperature, and overcirculation /undercalculation of glycol [3] .

3.7.2.1.2 Foaming

Foaming causes glycol to be carried out of the absorber top with the gas stream, resulting in large glycol losses and decreased glycol unit efficiency. Foaming can normally be traced to mechanical or chemical causes. High gas velocity is usually the source of mechanical entrainment. Chemical foaming is caused by contaminants in the glycol, liquid hydrocarbons, well.treating chemicals, salts, and solid. Adequate inlet separation and filtration system [cartridge filter and activated carbon bed] are therefore needed to prevent foaming due to chemical contamination.

3.7.2.1.3 Hydrocarbon solubility in TEG solution

Aromatic hydrocarbon solubility in glycol is a significant issue in gas dehydration technology due to the potential release of aromatics to the atmosphere at the regenerator.

3.7.2.2 Still (Stripper)

Excessive glycol vaporization is more of a problem for finned atmospheric condensers than for water.cooled or glycol.cooled condensers. Although finned atmospheric condensers are simple and inexpensive, they are sensitive to extremes in ambient temperature. For example, during cold winter periods, a low temperature at the top of the still column causes excessive condensation and floods the reboiler. This prevents adequate regeneration of the glycol and reduces the potential dew point depression of the glycol causing insufficient dehydration in the absorber. Also, excessive glycol losses may occur as the reboiler pressure increases and blows the liquids out the top of the column. During the summer months, inadequate cooling may allow excessive glycol vaporization losses.

3.7.2.3 Reboiler: Operational problems associated with the reboiler include salt contamination, glycol degradation, and acid gas.related problems.

3.7.2.3.1 Salt Contamination

Carry over of brine solution from the field can lead to salt contamination in the glycol system. Sodium salt[typically sodium chloride, NaCl] are a source of problems in the reboiler, as NaCl is less soluble in hot TEG than in cool TEG; NaCl will precipitate from the solution at typical reboiler temperature of 350.400ºF. The salt can deposit on the fire tube, restricting heat transfer. If this occurs,the surface temperature of the fire tube will increase,causing hot spots and increased thermal degradation of the glycol. The deposition of salt may also result in corrosion of the fire tube. Dissolved salt cannot be removed by filtration. As a general rule, when the salt content reaches 1%, the glycol should be drained and reclaimed. If the level of salts is allowed to increase beyond 1% both severe corrosion and thermal degradation threaten the system.

3.7.2.3.2 Glycol Dehydration

Glycol degradation is caused primarily by either oxidation or thermal degradation. Glycol readily oxidizes to form corrosive acid. Oxygen can enter the system with incoming gas, from unblanketed storage tanks or sumps, and through packing glands. Although oxidation inhibitors [such as a 50.50 blend of monoethanolamine [MEA] and 33% hydrazine solution] can be used to minimize corrosion, a better approach to controlling oxidation is blanketing the glycol with natural gas, which can be applied to headspace in storage tank and any other area where glycol may contact oxygen. Thermal degradation of the glycol results from the following conditions: high reboiler temperature, high heat flux rate, and localized overheating. The reboiler temperature should always be kept below 402ºF to prevent degradation, and a good fire tube design should inherently prevent a high heat flux rate. In addition, thermal degradation of the glycol produces acid degradation products that lower the PH and increase the rate of degradation, creating a destructive cycle.

3.7.2.3.3 Acid Gas

Some natural gas contains H2S and/or CO2, and these acid gases may be absorbed in the glycol. Acid gases can be stripped in the reboiler and still. Mono.,di., or triethanolamine may be added to the glycol to provide corrosion protection from the acid gases[3] .

3.7.2.3.4 Surge Tank

When surge tanks also serve as glycol/glycol heat exchanger, the level must be monitored to ensure that the lean glycol covers the rich glycol coil. Otherwise, inadequate heat exchange will occur, and the lean glycol will enter the absorber at an excessively high temperature.

3.7.2.3.5 Heat Exchanger

The primary operational problem with heat exchangers is poor heat transfer, which results in lean glycol that is too warm. When this occurs, poor dehydration and insufficient dew point depression can result. Also, glycol vaporization losses to the product gas may be higher with increased lean glycol temperature. Poor heat transfer and the resulting high lean glycol temperature are usually caused by fouled heat exchangers. Exchangers may be fouled by deposits such as salt, solids,coke,or gum. Corrosion of the coil in surge tank heat exchangers can also present operating problems, as it can lead to cross.contamination of rich and lean glycol.

3.7.2.3.6 Phase Separator [Flash Tank]

Inadequate residence time in the phase separator may result in a large quantity of glycol being included in the hydrocarbon stream and vice versa.

3.7.2.3.7 Glycol Circulation Pump

Major problems associated with the circulation pump and rates are related to reliability, pump wear, and over circulation or under circulation [3] .

Chapter Four

Natural Gas Dehydration Process Simulation and Optimization: A Case Study of Jubilee Field[26]

4.Preface

This case study about gas dehydration simulation and optimization of Jubilee field/Ghana by researcher S. A. Marfo[26].

4.1 Background of the Study Area

Jubilee oil Field is located in deep-water of about 1100 - 1700 m depth and an approximate distance of 60 km from the nearest coast in the Western Region of Ghana. The field covers an area of 109 265 220 gross sq. m and a total gross resource of 600 MMbbl with upside. The production from the field averaged approximately 102 000 bopd. The field underlies portions of the West Cape Three Point and Deep-water Tano License Blocks. The field start-up occurred on November 28, 2010 and production has continued to ramp up as additional phase one wells has been brought online. The phase 1 development program consists of 17 wells, 9 producers, 6 water injectors, and 2 gas injectors which target the lower and upper Mahogany reservoirs [27]. Figure 4.1 shows the location of the Jubilee Field.

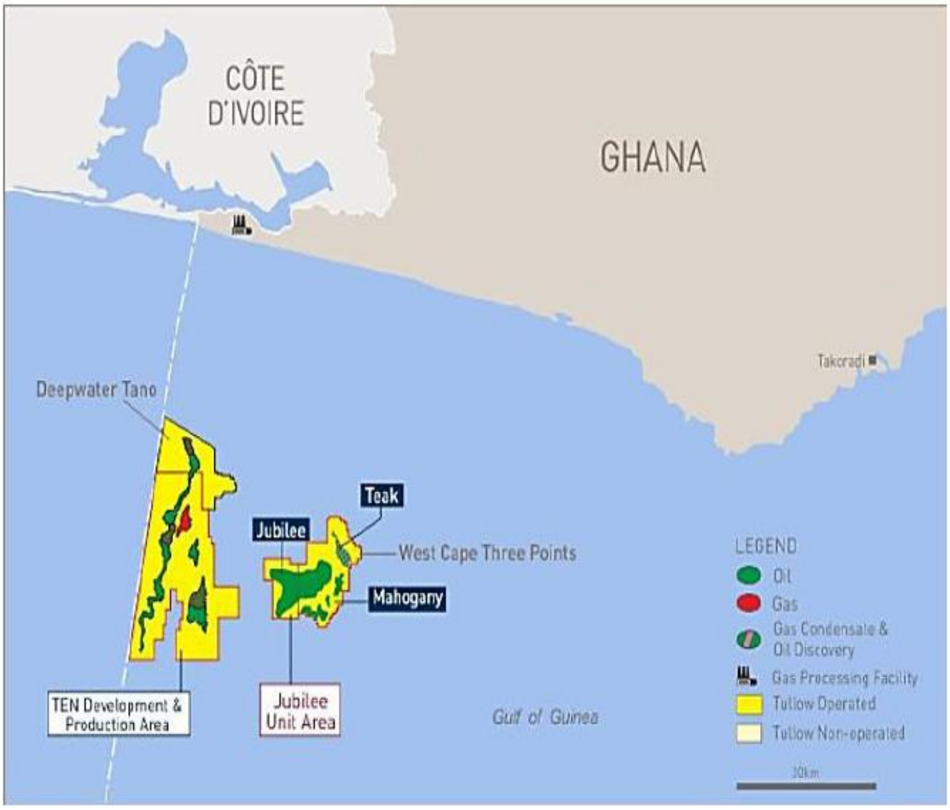


Figure 4.1: Location of the Jubilee Fields

4.2 Resources and Methods Used

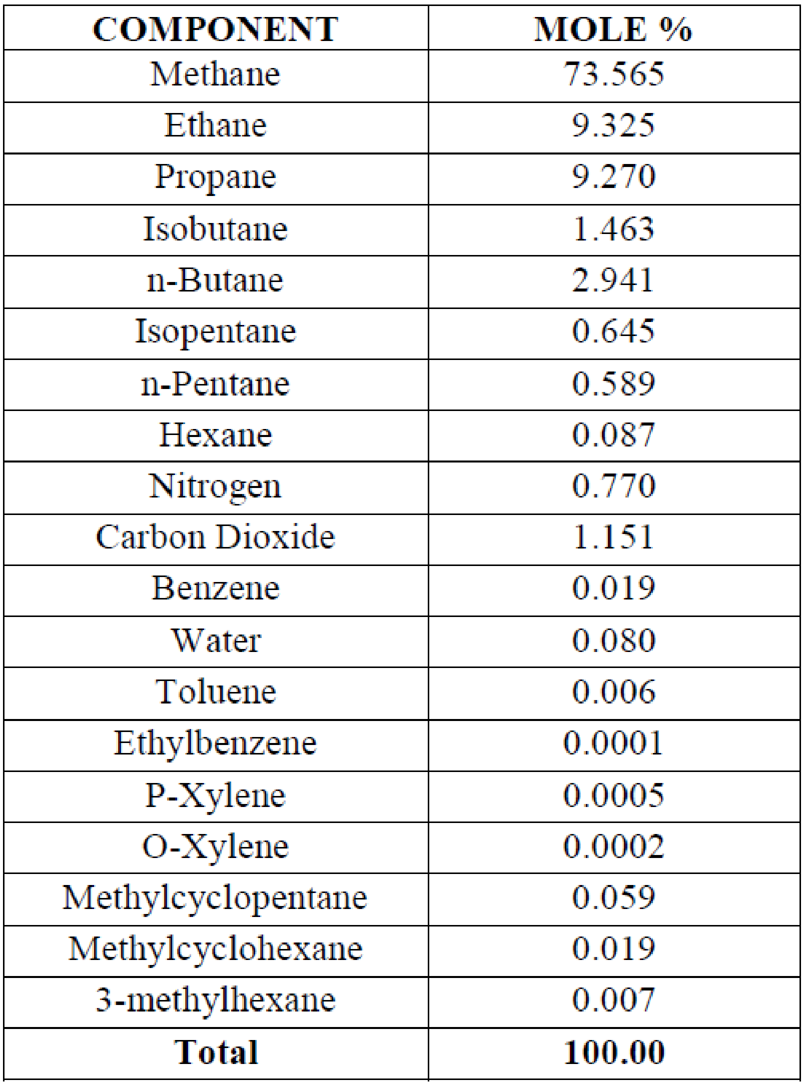
4.2.1 Data Acquisition

The basic parameters required for simulation of TEG dehydration of natural gas in Aspen HYSYS are:

- Composition and feed stream conditions of raw natural gas coming from the well;
- Required purity and operating conditions of lean TEG
- Design and operating conditions of the plant. Secondary data on these parameters were obtained from different sources for the purposes of this study.

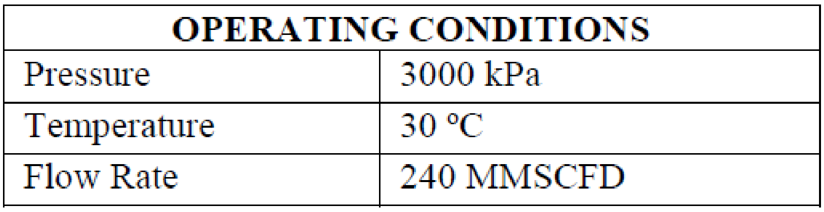
Data on gas composition and feed stream composition from the Jubilee Field were obtained from the Tullow Ghana Limited website. Data on glycol purity is a general standard which must be equal to or higher than 99.5 wt%, and was obtained from literature. Tables 4.1 and 4.2 show data on gas composition and operating conditions from the Jubilee Field.

Table 4.1: Jubilee Field Gas Composition



COMPONENT	MOLE %
Methane	73.565
Ethane	9.325
Propane	9.270
Isobutane	1.463
n-Butane	2.941
Isopentane	0.645
n-Pentane	0.589
Hexane	0.087
Nitrogen	0.770
Carbon Dioxide	1.151
Benzene	0.019
Water	0.080
Toluene	0.006
Ethylbenzene	0.0001
P-Xylene	0.0005
O-Xylene	0.0002
Methylcyclopentane	0.059
Methylcyclohexane	0.019
3-methylhexane	0.007
Total	**100.00**

Table 4.2: Jubilee Field Gas Operating Conditions



OPERATING CONDITIONS	
Pressure	3000 kPa
Temperature	30 ºC
Flow Rate	240 MMSCFD

2.2 Resources Used

The Aspen HYSYS software was utilised in the simulation of the TEG dehydration process. Aspen HYSYS is a user friendly, industry-standard simulation program used by researchers, process engineers and engineering companies. Version 8.8 of the software was used for the simulation.

4.2.3 Methods Used

4.2.3.1 Process Simulation of the Gas Dehydration Plant

Process simulation is a model-based representation of technical processes and unit operations in software and it can be used for the design, development, analysis and optimisation of processes such as the TEG dehydration plant. Process simulation software describes processes in flow diagrams and solves mass and energy balance equations to find optimal conditions for processes.

4.2.3.2 Gas Compositional Model

For the purposes of this study, a steady state simulation of the dehydration plant was carried out. The software requires the input of the pure gas components. Therefore, in the first step of the simulation process, the main components of the gas were defined by adding the data on gas stream compositions of this case study.

4.2.3.3 Selection of fluid package

Following the selection of gas components, a fluid package was selected. The fluid package is the equation of state used by the software to calculate gas stream properties and it is carefully selected depending on the process type and its pressure and temperature range. The fluid package selected in this case is the Glycol Package because it is applicable over the range of temperatures, pressures and component concentrations encountered in a typical TEG dehydration system. The Glycol Package is based on the Twu-Sim-Tasson (TST) equation of state and according to Aspen Technologies, the TST equation of state is suitable for TEG dehydration systems and can accurately predict;

- Activity coefficients of the TEG-water solutions within the absolute deviation of 2%.
- Dew point temperatures within an average error of positive or negative 1 °C.
- Water content of gas within the average absolute deviation of 1%.

4.2.3.4 Design of Process Flow Diagram

After the fluid package selection was successfully done, the simulation environment was entered. The simulation environment consists of a plain flowsheet where the flow diagram can be designed. The design of the dehydration plant flow diagram was completed sequentially using an available model palette on the flowsheet tab. The built-in model palette is used to select blocks of equipment and stream types to add to the flowsheet. There are two stream types available in Aspen HYSYS, the material stream and the energy stream. Material streams are used to show the travelling of material or fluids between different units of operations and the energy streams are used to show the energy travelling between different units of operations.

The design of the process flow diagram was based on the typical TEG dehydration plant described in Figure 4.2. The various equipment needed for the dehydration process, including the scrubber, absorber, flash separator, heat exchanger, reboiler, regenerator and pump were selected from the palette and connected by their respective material streams. It is important to define the composition and conditions of the feed stream. In this paper, the feed stream is named inlet gas and its molar composition and conditions are based on the data obtained. The input conditions required are the flow rate, temperature and pressure. HYSYS calculates all other conditions using the selected property package.

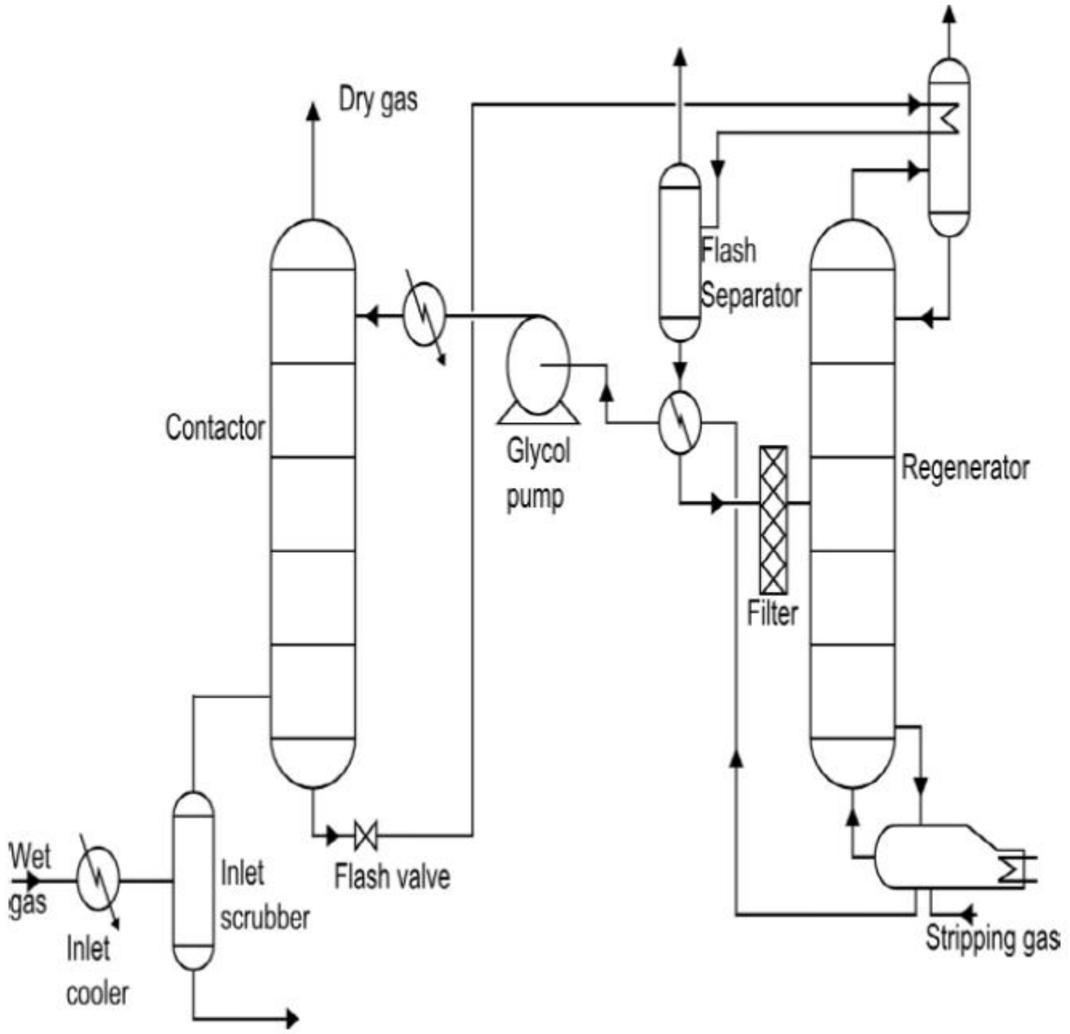
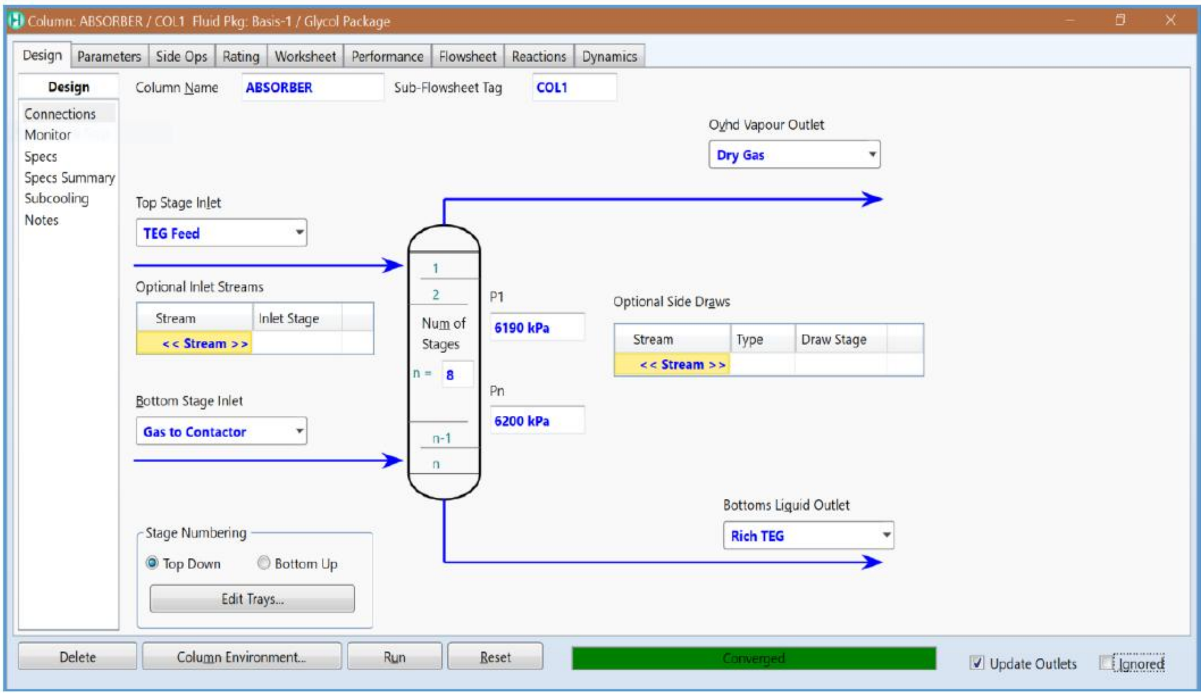


Figure 4.2 Typical Glycol Dehydration Process

It is also necessary to specify certain operating conditions of the various equipment. With this information, HYSYS solves all the mass and energy equilibrium equations taking into consideration the specified design parameters for the unit to produce a product stream. The converged sign indicates that the absorber has been simulated successfully. Figure 4.3 shows the menu for the absorber unit specified with eight contacting stages.

The converged sign indicates that the absorber has been simulated successfully. Figure 4 shows the complete process flow diagram.


Column: ABSORBER / COL1 Fluid Pkg: Basis-1 / Glycol Package

Column Name: ABSORBER

Sub-Flowsheet Tag: COL1

Ovhd Vapour Outlet: Dry Gas

Top Stage Inlet: TEG Feed

Bottom Stage Inlet: Gas to Contactor

P1: 6190 kPa

Pn: 6200 kPa

Num of Stages n = 8

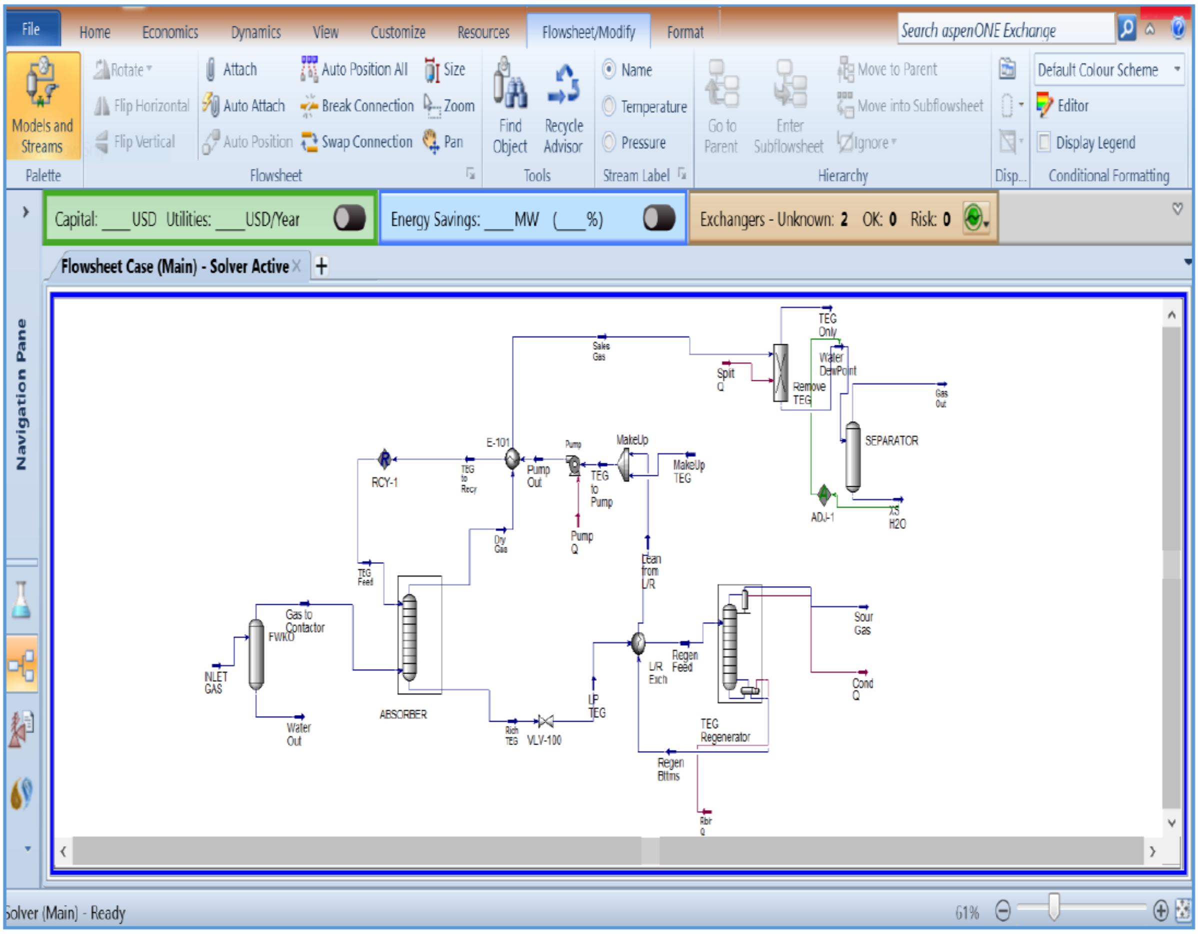
Bottoms Liquid Outlet: Rich TEG

Stage Numbering: ● Top Down ○ Bottom Up

Converged

☑ Update Outlets ☐ Ignored

Figure 4.3: Glycol Contactor Menu


Capital: ___USD Utilities: ___USD/Year

Energy Savings: ___MW (___%)

Exchangers - Unknown: 2 OK: 0 Risk: 0

Flowsheet Case (Main) - Solver Active

Solver (Main) - Ready

61%

Figure 4.4: Complete Process Flow Diagram

4.2.3.5 Simulation Procedure

After the design of the process flow diagram, a simulation process was carried out in which the inlet gas was first passed through a separator to remove any liquid water from the gas stream. The gas was then routed into an absorption column with eight theoretical equilibrium stages. Lean TEG was injected into the contactor at 0.5 m^3/hr and 30 °C to flow counter current to the inlet gas and absorb water from the gas. After the dehydration of the gas and further removal of any entrained TEG in a splitter column, the dry gas stream was found to be composed of 4.840 lb/MMSCFD of water at a gas flow rate of 236 MMSCFD. Although this value is within the range of specifications for pipeline quality natural gas and indicates that the processed gas can be transported through pipeline without hydrate forming in the line, it is necessary to investigate the most effective and economical parameters on gas dehydration. Consequently, design and operational variables that affect the gas dehydration process are of utmost importance.

The following parameters were therefore varied to observe their effect on outlet gas water content:

- TEG flow rate;
- Number of equilibrium stages of contactor; and
- Reboiler temperature.

4.3 Results and Discussion

Pipeline specifications indicate that water content in a processed natural gas stream should be below 7 lb/MMSCFD. The raw unprocessed natural gas stream obtained from the Jubilee Fields contained 0.08 mole percentage of water and at a gas flow rate of 240 MMSCFD and pressure of 3000 kPa, water content translates to 37.988 lb/MMSCF. This is far above the pipeline specification of water in natural gas and therefore necessitated dehydration of the gas stream. Thus, a simulation process was carried out in Aspen HYSYS to dehydrate the natural gas stream. The resulting outlet dry gas stream composed of 4.840 lb/MMSCFD of water at a gas flow rate of 236 MMSCFD. However, TEG flow rate, number of equilibrium stages of contactor and reboiler temperature were varied to investigate their effect on the water content of the outlet dry gas stream.

TEG was flowed at different rates to determine the effect of different flow rates on water content in the processed natural gas stream as shown in Table 4.3.

With the reboiler temperature fixed at 204 °C, gas pressure at 3000 kPa and TEG temperature of 30 °C, the number of equilibrium stages in the absorption column were varied along with TEG flow rates to observe their effects on outlet gas water content. Table 4 indicates the resulting values for water content with varying number of contractor stages and varying TEG circulation rates.

Based on the research conducted by Arubi and Duru [28], it has been established that increasing reboiler temperature above 204 °C would result in the thermal decomposition of TEG. Reboiler temperature was therefore simulated between 180 to 204 °C as shown in Figure 5 and 6. Keeping all other operating parameters constant, a simulation was carried out to determine the effect of stripping gas rate on lean TEG purity. Figure 7 shows the relationship between stripping gas flow rate and glycol purity. A stream analysis was therefore conducted to ascertain the possibility of hydrate formation in the stream. Figure 8 indicates the results obtained.

Table 4.3: Obtained Values for Water Content Using 8 Contactor Stages and Varying TEG Circulation Rates

TEG Flow Rate (m^3/hr)	Outlet Gas Water Content (lb/MMSCFD)
0.2	10.156
0.5	4.849
1.0	3.644
3.0	3.618
5.0	3.659
10.0	3.764
15.0	3.871

Table 4.4: Resulting Values for Water Content with Varying Number of Contactor Stages and Varying TEG Circulation Rates

Number of Contacting Stages	TEG Flow Rate (m^3/hr)	Outlet Gas Water Content (lb/MMSCFD)
4	0.2	12.168
	0.5	6.655
	1.0	4.351
	3.0	3.645
	5.0	3.664
10	0.2	9.778
	0.5	4.521
	1.0	3.599
	3.0	3.617
	5.0	3.659
12	0.2	9.537
	0.5	4.324
	1.0	3.584
	3.0	3.617
	5.0	3.659

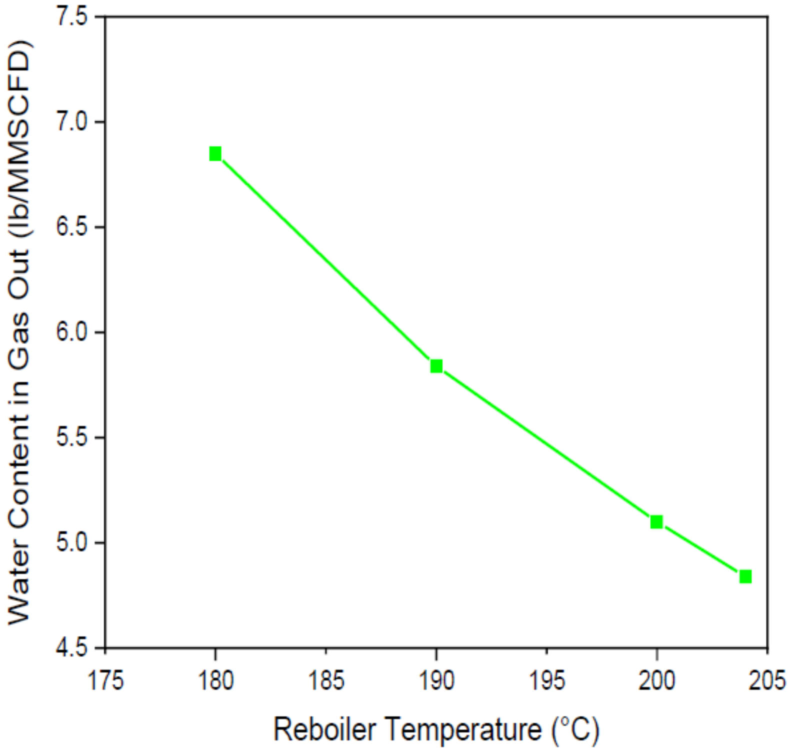


Figure 4.5 Outlet Gas Water Content against Reboiler Temperature at 8 Contactor Stages and TEG Flow Rate of 0.5 m³/hr

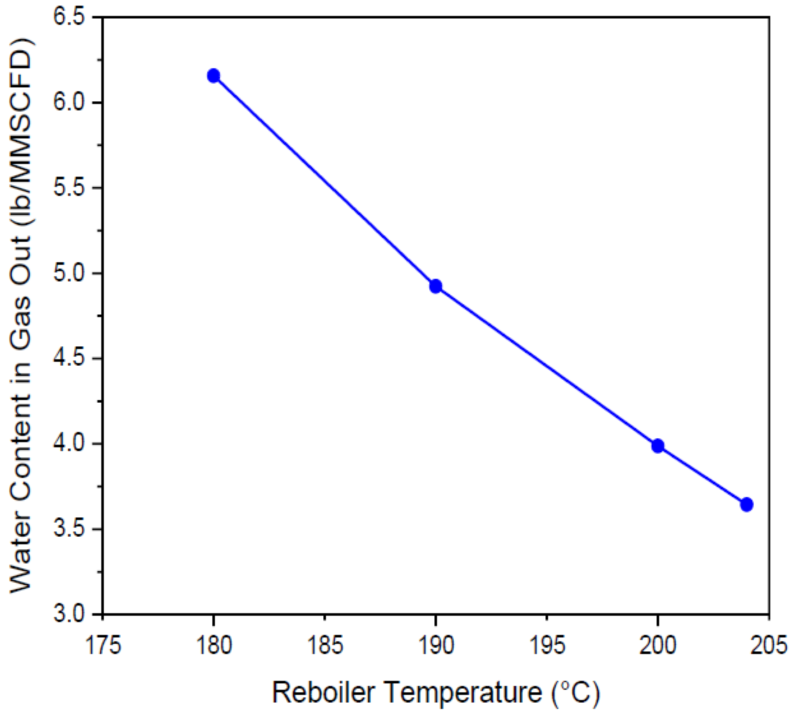


Figure 4.6 Outlet Gas Water Content against Reboiler Temperature at 8 Contactor Stages and TEG Flow Rate of 1m³/hr.

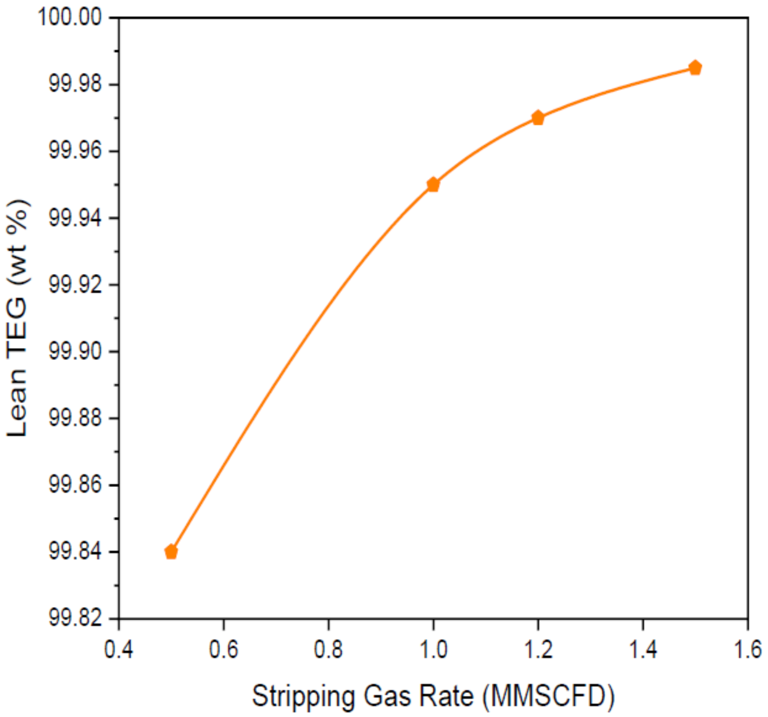
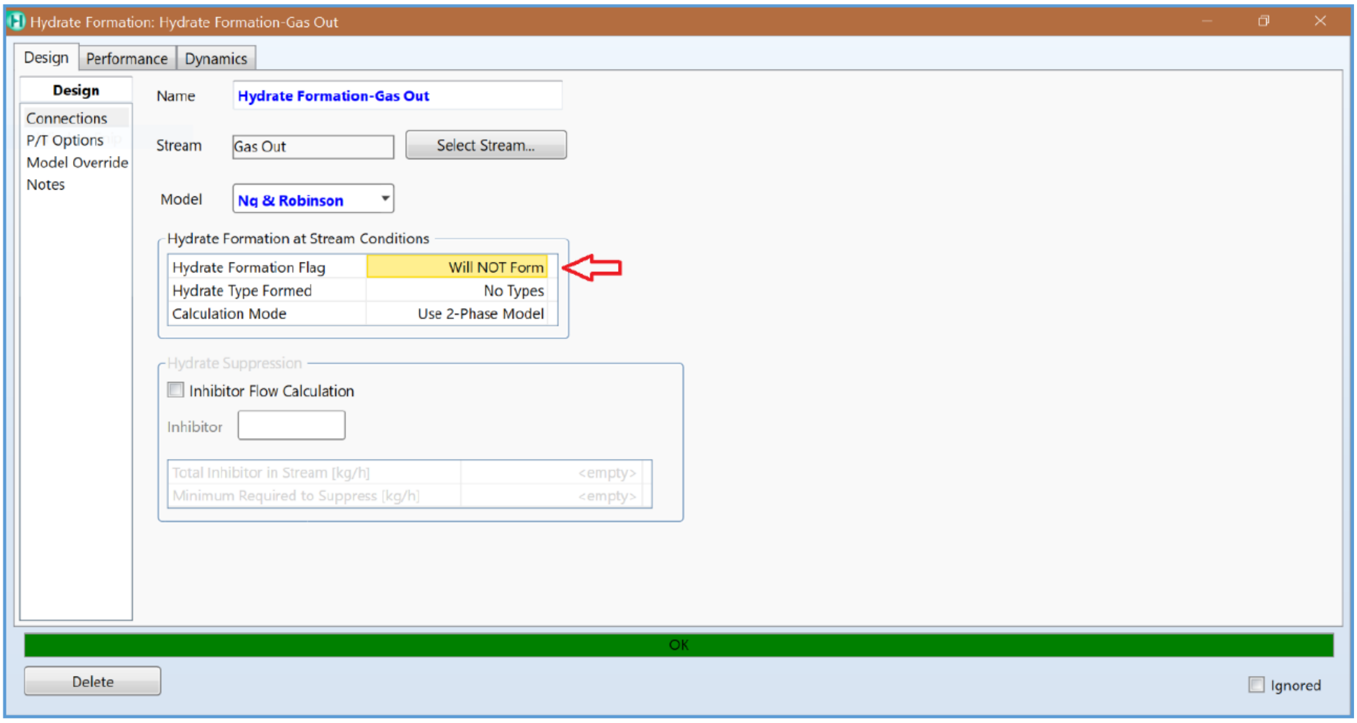


Figure 4.7 Lean TEG against Stripping Gas Flow Rate



Name: Hydrate Formation-Gas Out

Stream: Gas Out

Model: Nq & Robinson

Hydrate Formation at Stream Conditions

Hydrate Formation Flag	Will NOT Form
Hydrate Type Formed	No Types
Calculation Mode	Use 2-Phase Model

Hydrate Suppression

☐ Inhibitor Flow Calculation

Inhibitor:

Total Inhibitor in Stream [kg/h]	<empty>
Minimum Required to Suppress [kg/h]	<empty>

Figure 4.8 Hydrate Formation Possibility of Gas Outlet Stream

From Table 4.3, it can be observed that outlet gas water content reduces with high TEG flow rate and increases with low flow rates. However, between a TEG flow rate of 0.5 m^3/hr and 3 m^3/hr, water content is well within pipeline specifications. It can also be recognised that high TEG flow rates of 5 m^3/hr and above do not further decrease water content in the outlet gas stream significantly. Anyadiegwu *et al.* (2014) reported that flooding the contactor with such high amounts of TEG could rather result in a phenomenon called liquid carryover where the excess TEG becomes entrained in the gas stream causing an increase in the hydrate formation temperature. It would therefore not be economical to flow TEG beyond 1 m^3/hr given the processing conditions obtained from the Jubilee Field. Similarly, a low TEG flow rate of 0.2 m^3/hr would result in water content which do not fall within the range for pipeline quality natural gas and therefore cannot be used.

Table 4.4 indicates that, increasing numbers of theoretical equilibrium stages of the contactor results in reduced water content of outlet gas regardless of the TEG flow rate. A TEG flow rate of 1 m^3/hr for example, results in 4.351 lb/MMSCFD of water in the outlet gas stream at 4 contacting stages, 3.644 lb/MMSCFD at 8 contacting stages (Table 4.3), 3.599 lb/MMSCFD and 3.584 lb/MMSCFD at 10 and 12 stages respectively. Thus, as expected, a greater number of contactor stages indicates a larger surface area for effective transfer of water from the gas to the glycol. Also, a greater number of trays indicates that the gas would have a higher contacting time in the vessel and would as such lead to more effective dehydration. These results are corroborated by researches conducted by other authors [29]. It can also be noticed that a TEG flow rate of above 3 m^3/hr is uneconomical and leads to liquid loading in the gas because of excessive TEG in the contactor.

From Figures 4.5 and 4.6, it can be realised that although the TEG flow rate also determines the extent of dehydration, water content of outlet gas reduces with increasing reboiler temperature. This is because the reboiler temperature largely determines the purity to which the glycol is regenerated. However, reboiler temperature must not be raised beyond 204 °C to prevent breakdown of glycol molecules. This temperature limit also affects the purity of glycol that can be regenerated to less than 98.5%. For this simulation, a glycol temperature of 180 °C resulted in a TEG purity of 96.02%. Operating the reboiler temperature at 190 °C led to a TEG regeneration of 96.96%. Finally, 97.64 and 97.88% of lean TEG were obtained for reboiler temperatures of 200 °C and 204.4 °C respectively.

Chapter Five

Conclusion

5.1 Conclusion

A natural gas dehydration unit was designed with the use of HYSYS software using Jubilee Field gas with compositions and conditions as shown in Tables 1 and 2 to simulate and evaluate the effect of various operating parameters on natural gas dehydration. From the results obtained, it can be concluded that:

a. A natural gas dehydration process has been successfully simulated using Aspen HYSYS and the simulation was efficient as it reduced water content to meet pipeline specifications of 4 – 7 lb/MMSCFD.

b. Different water contents in the final dry gas stream have been obtained for different operating parameters. The TEG flow rate, the number of contacting stages and the reboiler temperature were varied to obtain different dry gas water content that meets pipeline specifications. The ultimate combination to be chosen depends on the most economical option.

c. Based on the simulation conducted, the optimal design is to consider a flow rate of 0.5 m^3/hr of TEG at eight contactor stages and a reboiler temperature of 204 °C. This reduces the water content of the gas stream flowing at 240 MMSCFD from 37.988 lb/MMSCFD to 4.849 lb/MMSCFD, which is within the limit of 4 – 7 lb/MMSCFD.

d. Flow rate of TEG at or below 0.2 m^3/hr will not reduce water content to specified limit and can lead to hydrate formation during pipeline transportation of the gas.

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