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Thème

**Optimization Of Mono Ethylene Glycol Consumption
in Hassi R'mel South Plant**

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DEDICATION

I dedicate this work to my Mother Messaouda,

my Father Mouhammed, My wife

my Brothers and Sisters,

my Sons Djaber, Zakaria

and Daughters Asma and Ferdous.

H·CHABANE

ACKNOWLEDGMENT

I have been blessed with so many wonderful people who have supported me through this journey. First of all, I thank Allah for keeping me in proper health and provided me with wisdom and knowledge. This enable me under take my Masters' degree and be able to complete it without any problems.

My bid of gratitude goes to my supervisor Dr.Farid TOUAITI who has tirelessly examined and corrected my work and gave me the courage to carry on this challenging but interesting research.

Last but not least many thanks to all my teachers who taught me during my studying years, advised, guided, and encouraged me to reach this level.

H.CHABANE

DEDICATION

I dedicate this work to my Grandmother Aisha,

my Father Babouhoun , and his wife

my Brothers Sallah edine, Idris and

Mehdi

and my little Sisters farah and Youcef,

my fiancée Amal

And all My friends

A·DAGHOR

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I have been blessed with so many wonderful people who have supported me through this journey. first of all, I thank Allah for watching over me and blessed me with health and provided me with wisdom and knowledge in order to under take this Masters' degree and be able to complete it without any problems.

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A.DAGHOR

Abstract

The presence of water in natural gas can cause many problems, among them the hydrates formation specific under certain condition of temperature and pressure which reign in the installation, Those hydrates can damage the process and lead to poor specification sales gas, to avoid these phenomena, it is necessary to reduce water rate content in natural gas using appropriate techniques such as injection of monoethylene glycol. (MEG)

In our study we look to optimize the amount of MEG to be injected in our process depending on newly adopted parameters of pressure and temperature to minimize the quantity of water in raw gas avoiding hydrate formation and assure high quality sales gas

Keyword: monoethylene glycol, natural gas, hydrates, sales gas.

Résumé

La présence d'eau dans le gaz naturel peut causer de nombreux problèmes, parmi lesquels la formation d'hydrates sous certaines conditions de température et de pression qui règnent dans les une installation : Ces hydrates peuvent endommager le processus et conduire à des gaz de ventes de mauvaise spécification, pour éviter ces phénomènes, il est nécessaire de réduire la teneur en eau du gaz naturel en utilisant des techniques appropriées telles que l'injection de monoéthylène glycol. (MEG)

Dans notre étude, nous cherchons à optimiser la quantité de MEG qui sera injectée dans notre procédé en fonction des paramètres nouvellement adoptés de pression, et de température pour minimiser la quantité d'eau dans le gaz brut en évitant la formation d'hydrates. Tores pour assures un ben qualité a notre gaz de vente

Mot clé : monoéthylène glycol, gaz naturel, hydrates, gaz de vente.

المخلص

يمكن أن يتسبب وجود الماء في الغاز الطبيعي في العديد من المشاكل ، من بينها تكوين الهيدرات تحت ظروف معينة من درجة الحرارة والضغط التي تسود في المنشأة ، ويمكن لهذه الهيدرات أن تتلف العملية وتؤدي إلى ضعف مواصفات الغاز المباع ، لتجنب هذه الظواهر ، يتوجب تقليل محتوى معدل الماء في الغاز الطبيعي باستخدام التقنيات المناسبة مثل حقن أحادي إيثيلين جلايكول

في دراستنا ، نتطلع إلى تحسين كمية أحادي إيثيلين جلايكول التي سيتم حقنها في عملياتنا اعتماداً على معايير الضغط ودرجة الحرارة المعتمدة حديثاً لتقليل كمية الماء في الغاز الخام وتجنب تكوين الهيدرات.

كلمات البحث : أحادي إيثيلين جلايكول، الغاز الطبيعي، الهيدرات، الغاز المباع .

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Abbreviation List

EJ : Exajoule
HR: Hassi R'Mel
RNG: Raw natural gas
Btu: British thermal unite
MPP2: Module process plant 2
CTH : Center de traitement d' huile
NGLs: Natural Gas Liquids
LPG: Liquefied petroleum gas
J.T: Joule Thompson
MEG: Mono ethylene glycol
DEG: Diethylene glycol
TEG : Triethylene glycol
PES : Polyurethane
PET: Terephthalate
LP : Low pressure
HP : High pressure
MEA : Monoethanolamine
S20/21/22 : Section 20/21/22
D 101: Drum 101
E-102 A/B : Exchanger 102 A/B
C401A/B : Compressor 401 A/B
Boost : Booster
IEA : international Energy Agency
GHG: Green house gas

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General Introduction

The nineteenth century is considered as the beginning of the gas industry. In the mid 1900's, enormous ungenerous reservoirs of natural gas were found in Texas and Oklahoma, it was the deficiencies of crude oil in the last part of the 1960's and mid 1970's that constrained major industrial countries to look for energy options.

Today, natural gas is quickly becoming critical as a concentrated, clean fuel for home heating and cooking and ..etc . It is therefore reaching an important position in energy market as crowd oil .

In 2009 Natural gas gave about 23% of the all out world energy supply. More significant, there are extremely huge deposits of natural gas on the planet far more than oil this will definitely increase the contribution of natural gas energy market .

Natural gas is a growing player in the global energy mix. In 1980, natural gas provided 57 EJ or 19% of the global total primary energy consumption where in 2010 it provided 124 EJ, representing 23% of global energy . Natural gas grew its proportion of primary total energy at a time when global energy consumption was itself rising rapidly. So natural gas demand grew at a faster rate than total energy demand—since 1980, average annual growth rate for natural gas has been 2.6%, compared to 2.0% growth for total energy.

This increase of its share in global and regional energy mixes by displacing oil products and, sometimes, each region uses differing amounts of oil products, natural gas and coal to supply its primary fossil fuel energy needs each year, and the balance of these energy sources changes over time. In the Middle East and North Africa and countries of the former Soviet Union, for example, natural gas has tended to supplant oil, while in North America and Europe it has taken some of coal's share. In general, the global trend has been toward natural gas consumption instead of oil with a parallel movement toward coal as well in some regions. Looking to the future, global energy demand will continue to grow, and demand for natural gas is expected to increase faster than demand for other fossil fuels, continuing the trend of recent years.

The IEA has noted that rapid population growth, increasing prosperity and improved access to reliable electricity are driving this trend.

Average annual growth rate for natural gas is generally forecast to be 2% from 2012 to 2040. The growth in natural gas demand in the period to 2040 is expected to be widely dispersed geographically, with Asia and the Americas playing an important role . Asia is expected to account for the largest proportion of global natural gas demand growth during this period (as well as production). In particular, natural gas demand in China is expected to grow by 5.2% a year, accounting for 56% of Asia's natural gas consumption growth. Natural gas demand is expected to grow steadily in other emerging economies as well, with India rising 4.6% a year and Brazil 4.0%. However, OECD member country growth should be slower, averaging about 1% a year. Power generation will play a significant role in increasing natural gas consumption, accounting for 36% of total growth from 2012 to 2040 Driven by

the petrochemical industry, the industrial sector is also expected to contribute strongly, with an annual growth rate reaching 1.9%. Although natural gas use in transportation is expected to grow strongly at 3.3% a year, this sector will still continue to account for only a small share of total demand, about 9% by 2040. During the same period, unconventional natural gas (such as shale natural gas) will come to account for an increased proportion of the overall supply mix.

Global natural gas resources are widely dispersed geographically, and at the current rate of production, there are 60 years of proven reserves. Even though US shale natural gas development has seen strong growth, there remain significant uncertainties about the development of shale natural gas in other regions. Currently, there are essentially no other regions outside of the United States that have successfully developed shale natural gas. In Poland, Sweden and Ukraine, resource discoveries have been disappointing, while developments in Algeria, France, South Africa and other countries have met with public opposition.

The huge economy behind this natural energy make it an important source of income to many countries like Algeria. However, this product should ensure a high level of purity and quality in order to remain a fruitful source of income. The main problems facing the exploitation of a high quality product is the formation of hydrates during production, this reduces the sales and rend its economical value poor.

The depletion of the Hassi R'mel (HR) South field is confirmed by the decrease in operating parameter (temperature and pressure) which led to an increase in the amount of water entrained with the gas during exploitation. Therefore, an increase in the quantity of dehydrating glycol agent (MEG) injected to hinder these formations is required. Under the current parameters of pressure and temperature, the current amount of MEG injected in the process is insufficient, since still a small quantity of hydrate kept forming. These species gather with time and block tubes of heat exchangers leading to an increase in the pressure and a decrease in gas flow rate inside these exchangers. This phenomenon occur two or three times in the year at the HR gas processing plant.

In this study, the HR gas plant was taken as a real case in order to conduct an optimization study on the amount of MEG to be injected in the process depending on the production parameters. This optimization aims to first evaluate the efficiency of the currently used process parameters used when designing this plant in terms of natural gas flow rate and EG injections quantities. After that, due to depletion, this study deduce the relationship between the required amount of MEG agent during the decrease of the production pressure at the HR plant in order to estimate the best parameters for efficient production of high quality sales gas in the future.

In the first chapter of our study, we gives the over view on natural gas, in the second chapter we present the Hassi R'mel South Plant ,in third chapter, we discuss the hydrate formation and dehydration of natural gas, while in the forth chapter, we present the glycols usage and choice, after that in the chapter five we illustrate the calculation method and in the chapter six we have the calculation part with results discussion, at the end we have conclusion.

Chapter I : The Over View on Natural Gas

Raw natural gas has to be treated in order to complete all the commercial and pipeline gas specifications. The configuration and complexity of the gas processing plant depends on the feed RNG compositions and the treating degree and processing required to have a product fulfilling all the environmental specifications.

RNG as it leaves the reservoir contains many impurities and water vapor. Hence, this natural gas delivered from wells have to be treated to satisfy the quality standards specified by pipeline organizations, which should be compatible with the pipeline design and the client's requirements.

If the raw gas impurities and corrosive gas content are low, the gas can be treated and dried at the wellhead then sent straight forward to the exporting gas pipeline. However, if the impurities levels are high and the gas is aggressive, then it is commonly gathered and sent to a processing plant where it is treated, and dried to meet product and pipeline specifications.

In general, these standards show how a commercially natural gas ought to be in terms of :

- Specific Btu content range.
- Specified hydrocarbon dew point temperature level. This would prevent formation of liquid slugs which damaging the pipeline.
- Trace of elements such as hydrogen sulfide, water vapor, mercaptans, carbon dioxide, nitrogen, and oxygen.
- The water vapor have to be removed (dehydrate the gas) sufficiently to prevent the hydrates formation and corrosion in the plant or in the pipelines.
- To remove all impurities

Therefore the motivation behind gas processing is to produce a natural gas with quantity that Meet sales specifications that include heating value and the recovery of maximum amount of NGLs. The processing of natural gas can be quite complex and generally involves many processes. that many in general include the fallowing operations .

The main steps of natural gas treatment are:

I.1. Natural gas and liquid separation

The removal of heavy hydrocarbons is important to guarantee pipeline transportation security and to meet the pipeline gas specifications such us heating value and the hydrocarbon dew point. The hydrocarbon liquids compose of two components, the natural gas liquids (NGLs) (C_2-C_4) and the natural gas condensate (C_5+).

The liquid separation is done by gradually lowering the temperature of the natural gas then thermal cooling processes. Refrigeration units are intended to meet the process cooling temperature prerequisites, In NGL recuperation or natural gas liquefaction plant, a three-stage propane blower is the most well-known, ordinarily intended to meet the temperature of about $-30\text{ }^\circ\text{C}$. In the event where lower temperatures are required, ethane refrigeration or blended refrigeration framework can be utilized. On the other hand, gas expander can likewise deliver profound refrigeration utilizing feed gas as the functioning liquid.

The high gas pressure can be used to generate cooling in J.T valve by enthalpic expansion. This cooling will cause heavy hydrocarbons to condense. Glycol injection is required to avoid hydrate formation due to the presence of water in the RNG.

The liquids will be collected in a three-phase separator from which the two liquid phases, (water/glycol phases and hydrocarbon condensate), the recovered condensate which is collected natural gas will be pumped without further processing but generally stabilized to produce a safe transportable liquid.

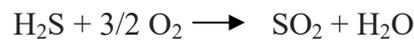
If the feed RNG is at low pressures, there will not be sufficient pressure to use the J–T process. In this case, the feed gas can be chilled at pressure by propane refrigeration. The propane refrigeration is a more efficient process than the J–T process to recover liquids. However, the two methods can be used to meet hydrocarbon dew point specification of the sales gas. The usage of turboexpander is a more efficient method of cooling instead of the J–T valve. The turboexpanders and the brazed aluminum exchangers are the important contributors to the success of NGL recovery plants.

I.2. Natural Gas Sweetening (Acid Gases Removal)

In this stage CO₂, and especially H₂S, must be removed before the gas is sent to sale.

When the quantity of H₂S in natural gas is above the acceptable industry limits this gas is called sour gas, while sweet gas means the natural gas has no H₂S. The process of removing H₂S is called natural gas sweetening. Based on published information (Ikoku, 1984; Leecraft, 1987; Campbell, 1997; GPSA, 1998; Mokhatab et al., 2006). there are enormous strategies that might be utilized to eliminate acidic components (essentially H₂S and CO₂) and different pollutants from hydrocarbon streams. The accessible techniques might be comprehensively arranged as those depending on chemical reaction, absorption, adsorption or permeation.

In the modified Claus sulfur recovery process, the reaction is completed in two phases. In the first phase (thermal section), enough air is added to oxidize only 33% of the incoming H₂S to SO₂. This reaction is exceptionally exothermic and is not restricted by equilibrium.



In the response heater, the unburned H₂S in the corrosive gas responds with the delivered SO₂ to yield natural sulfur fume. This reaction is endothermic and is limited by equilibrium.



Usually, the conversion of H₂S to elemental sulfur is achieved in the thermal stage with 70% Organic compounds such as Monoethanolamine (MEA), Diethanolamine (DEA), and Triethanolamine (TEA), must be planned for total acid-gases removal. Monoethanolamine (MEA), the common agent that it used in gas plant to eliminate H₂S and CO₂ from sour gas.

When low dew point is not required, a solution formed of 85% glycol, 10 wt % MEA, and 5% water for the simultaneous removal of water vapor, H₂S and CO₂. The process plant is essentially the same as that for MEA. One of disadvantage of this process is the losses of MEA due to vaporization in regeneration with high temperature.

I.3. Natural Gas Dehydration (Water Removal)

Water within natural gas can cause an incredible number of issues. One significant issue is that it could shape strong hydrates at specific pressures and temperatures, which can plug installations and pipelines. Likewise, water vapor condenses and can cause slug stream and possible erosion and corrosion in the framework, when pressures and temperature drop,

Particularly when corrosive gases are present. At last, water vapor increases the absolute volume and diminishes the heating value of gas, which in this manner, can't meet gas specifications.

Hence, water must be taken out from natural gas before it is transported. For cryogenic processing to produce natural gas liquids (NGLs) and LNG feed pretreatment, water removal level much seriously requesting, down to a few parts per million water and dew point of -101°C and below.

The large amount of free water is removed at the gas-liquid separation, but the small amount of water vapor content in a natural gas stream will be eliminated by several methods of dehydrating natural gas, counting absorption, adsorption, and direct cooling of the wet gas. Absorption using liquid (glycol) and the most common, when low water dew point gas is required for some specifications is adsorption using solid desiccants. For less dew point depression in production of pipeline gas The direct cooling method by expansion or refrigeration agent, with injection of hydrate inhibitors, is very common.

The selection of natural gas dehydration process is based on the water dew point requirements, any of the mentioned processes of dehydration can be applicable If it is only to meet the pipeline specification of 4–7 lb/MMscf. The glycol dehydration process is more economical than molecular sieves for meeting pipeline gas specification; as low as -40°C .

for deep dehydration to meet a low water dew point as to produce LNG or to recover NGL Solid desiccant dehydrators are chosen.

Determining the saturation water content of a gas is the first step in evaluating and designing a gas dehydration process, for the plant inlet separator design this data is so important. There are several methods available for determining water contents of natural gases.

McKetta and Wehe (1958) chart is very common, since it is used to estimate the water content of sweet gas, Wichert and Wichert (2003) introduced appropriate method to the equilibrium water vapor content of sour natural gas for a range of conditions.

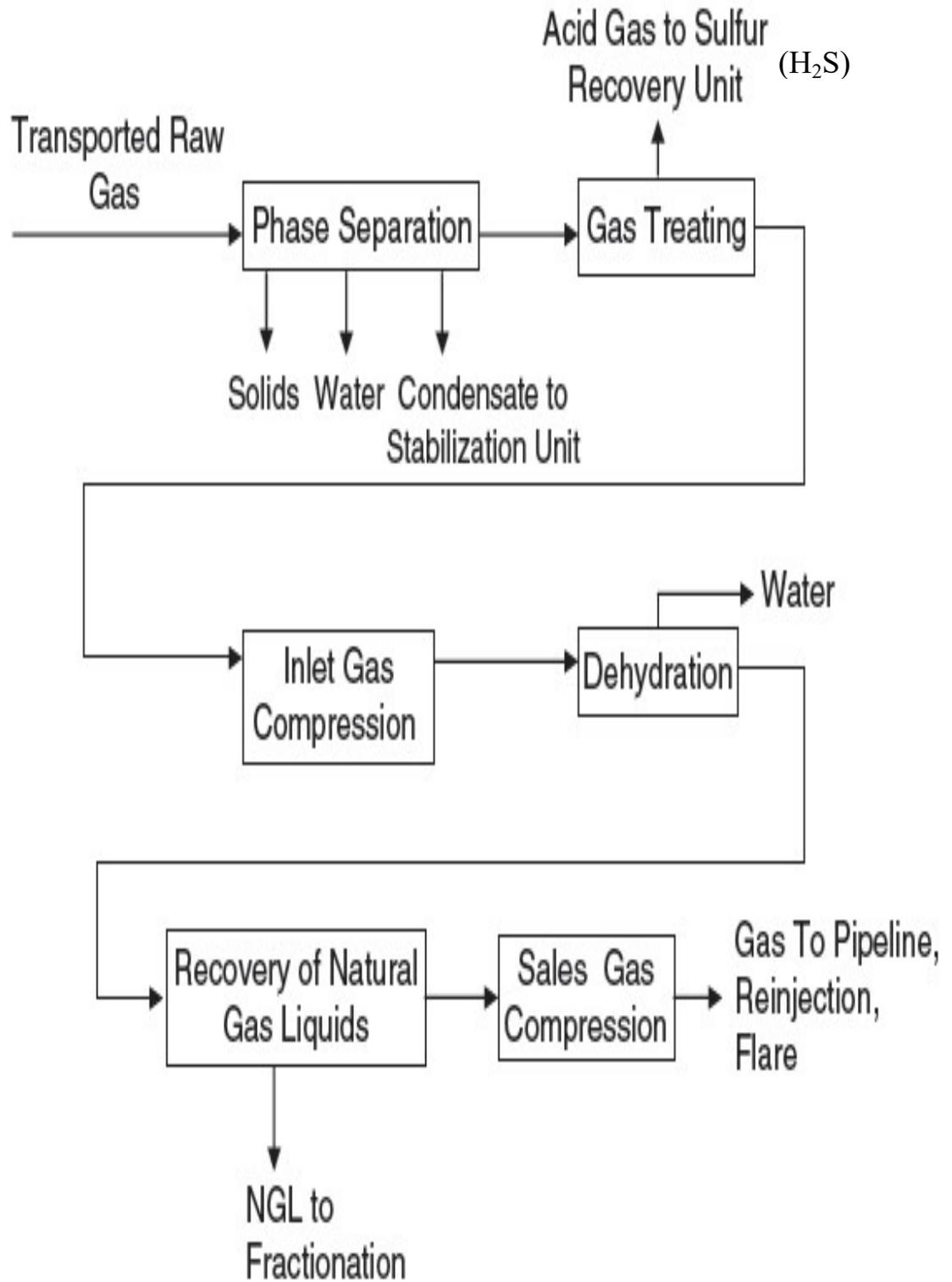


Figure I.1. Simplified typical onshore treatment process

(Handbook of Natural Gas Transmission and Processing)

Chapter II : The Hassi R'mel South Plant

Hassi R'Mel, is desert field, which is located 550 km south of Algiers, between the wilayas of Ghardaïa and Laghouat. In this relatively flat region of the Sahara, the average altitude is about 750 m. The Hassi R'mel field is one of the largest gas fields in the world, includes three sectors (HR North, HR Center and HR South) each sector is composed by several units of oil and gas plants accounts for 60% of the total primary production of natural gas in Algeria.



Figure II.1. Hassi R'mel gas field location

The HR South Plant is designed for the treatment of raw gas, ensuring a daily production of approximately 9 million Sm^3 / day of dry gas, 450 m^3 /day of unstabilized condensate and 1 million m^3 /day of LPG.

The treatment process for this feed is designed to recover the maximum amount of liquid hydrocarbons (condensate) and LPG. For this, the raw gas is first cooled by heat exchange through air coolers and core and shell heat exchangers, then undergoing expansion: from the inlet pressure up to 73 Kgf/Cm^2 through a valve of J.T (isenthalpic relaxation), The recovered liquid hydrocarbons (unstabilized condensate) are collected in the common section to be sent to the MPP2 module to be stabilized; While the associated gas LPG is sent to compression section (Boosting) to be compressed and sent to MPP2 module.

II.1. Plant Capacity and Feed Conditions:

Table 1. Gas processing plant characteristics

Gas Processing section Capacity	Feed Conditions
Train A : 5.0×10^6 m ³ /day	Pressure : 131 kgf/cm ²
Train B: 2.0×10^6 m ³ /day	Temperature : 65 °C
Train C: 2.0×10^6 m ³ /day	

Table 2. Raw gas factions and composition

Components	Mol %
N ₂	4.43
CO ₂	0.13
CH ₄	80.67
C ₂ H ₆	7.51
C ₃ H ₈	2.86
iC ₄ H ₁₀	0.59
nC ₄ H ₁₀	0.97
iC ₅ H ₁₂	0.26
nC ₅ H ₁₂	0.31
C ₆ H ₁₄	0.32
C ₇ H ₁₆	0.43
C ₈ H ₁₈	0.38
C ₉ H ₂₀	0.32
C ₁₀ H ₂₂	0.26
C ₁₁ H ₂₄	0.18
C ₁₂ ⁺	0.39
TOTAL	100

II.2. Product Specifications:

Firstly, we have Sales Gas which has a Pressure of 82.5 Kgf/Cm² and Dew point at this pressure is -5°C. Secondly, the produced Associated Gas has Pressure of 82.5 Kgf/Cm² and Temperature Max 65 °C. Concerning Unstabilized Condensate has no product specification exists such as Reid Vapor Pressure .

II.3. Main units that make up the plant :

The HR South Plant Consists of :

- 3 gas processing trains are (A,B,C) with total capacity of 9×10^6 m³/day.
- Associated gas compression of 10⁶ m³/day of associated gas from existing crude oil separation center (CTH-SOUTH).
- Unstabilized condensate section
- Glycol system
- Fuel gas system
- Flare system
- Instrument and service air system
- Blow Down system
- Electrical Distribution
- Fire Fighting system

II.3.1. Gas Processing Trains :

This section is provided to cool the well gas by J.T operation and resultantly, bring down the dew point of the sales gas. Gas processing section consists of three trains (A,B,C). Although the process configuration is identical for all trains, capacity of trains is different.

Inlet gas from six (6) wells is cooled to 39°C by inlet gas cooler S21/22/23-E101. Separated gas in the inlet separator S21/22/23-D-101 is cooled to -6.6°C by Gas/Gas exchangers S-21/22/23- E-102 A/B and Gas/Liquid exchanger S21/22/23-E-103.

Separated liquid in the inlet separator is introduced to the middle pressure separator S21/22/23-D103. The produced liquid and vapor are fed to the unstabilized condensate section and the 2nd stage associated gas compressor S20-C202 suction header respectively. Cooled vapor from the low temperature separator S21/22/23-D102 is heated up by S21/22/23-E102 A/B and sent to the existing module II sales gas line through sales gas pipeline which is in the scope of the company. Cooled liquid from the low temperature separator is heated up to 1.1°C and sent to unstabilized condensate section.

MEG (Mono Ethylene Glycol) is introduced to prevent hydrate formation in the gas before gas cooling. Recovered glycol solution from the low temperature separator is recycled to the glycol system via flushing oil cooler for S20-P001A/B/C where glycol is regenerated. Thus, closed circuit of glycol system is established.

II.3.2. Associated Gas Compression Section:

This section is installed to compress associated gas and provide a sufficient steam pressure for feed S-5 gathering header for module II. Associated gas from existing crude oil separation center (CTH-SOUTH) enters into the 1st stage compressor K.O drum S20-D201, Associated gas from S20-D201 is compressed to 52kgf/cm² by 1st stage compressor S20-C201. The compressed gas is cooled down to 65°C by 1st stage compressor after-cooler S20-E201 before it is combined with the gas from the unstabilized condensate section and middle pressure separator S21/22/23-D103 in the gas Processing trains.

After mixing of gas, the stream pressure is controlled by PIC-210 at 51.2kgf/cm² to maintain suction pressure of 2nd stage compressor, which gives stable operation for various operation conditions of this section. Pressure controlled gas is further compressed by the 2nd stage compressor and cooled down to 65°C. Compressed gas at pressure 148kgf/cm² is introduced to the associated gas pipeline and send to module II.

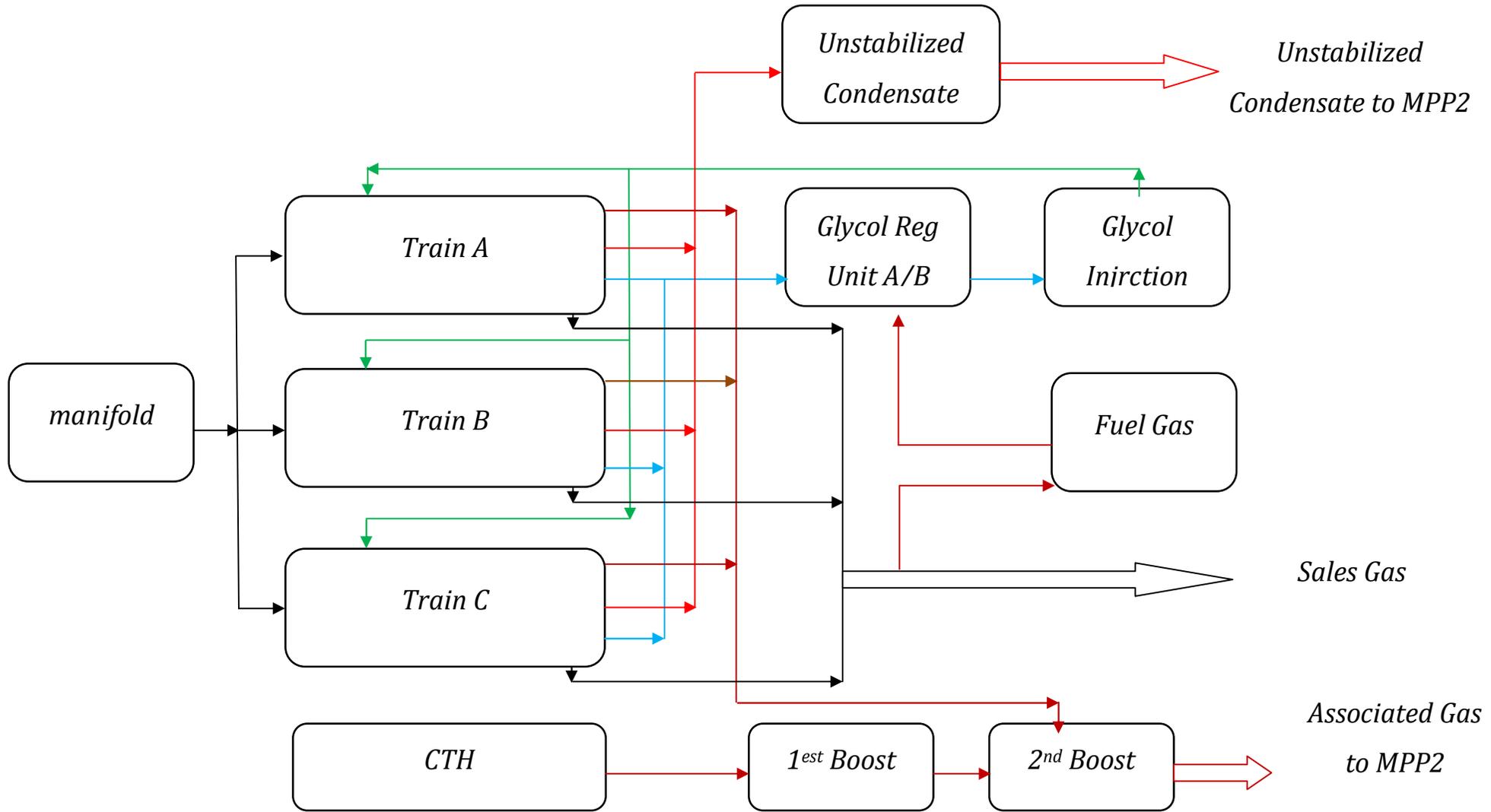


Figure II.2. General layout of HR South plant

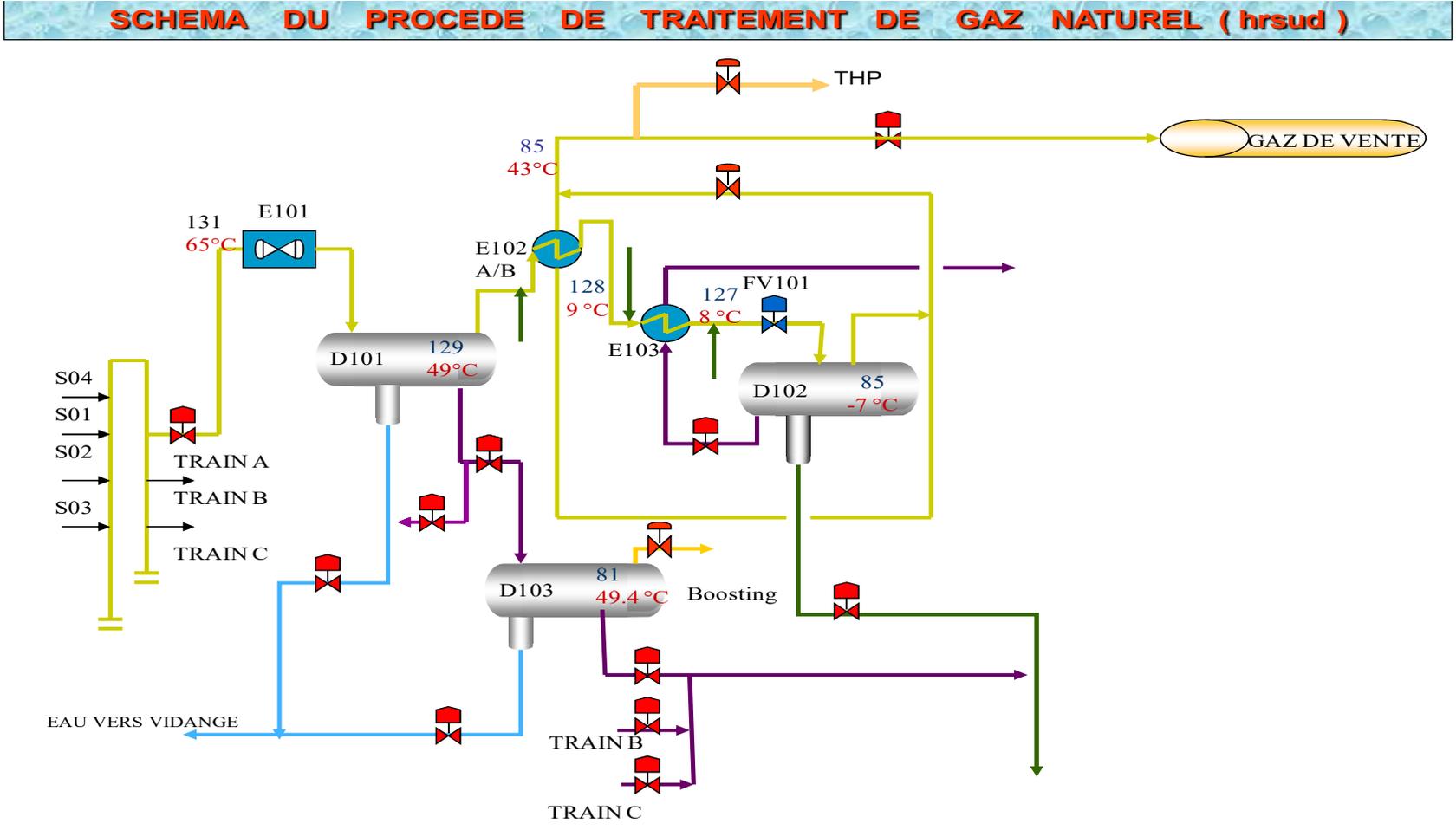


Figure II.3. Diagram of the natural gas treatment process (HR South Plant) showing the operating pressure (bleu) and temperature (red)

II.3.3.Unstabilized Condensate Section:

This unit is provided to recover the condensate from gas processing trains without stabilized facility. Liquid from the low temperature separator S21/22/23-D102 is flashed in the unstabilized condensate separator S20-D001, reducing the operating pressure to 56.1kg/cm². Produced liquid from unstabilized condensate separator and that from middle pressure separator S21/22/23-D103 in the gas processing trains are introduced to the surge drum S20-D002.

This two stage flash drum and hot liquid introduction from middle separator in the gas processing train results in a less lighter hydrocarbon content in the unstabilized condensate. The unstabilized condensate from surge drum is pumped up to the unstabilized condensate surge drum 20-D015 in module II.

II.3.4.Glycol System:

A closed glycol system is provided to prevent hydrate formation in the gas processing trains. A formulation made of 80 wt% of MEG (Mono Ethylene Glycol) solution is selected as dehydration agent in module II. Normal capacity of MEG injection is about 4310 kg/h and normal capacity of MEG regeneration package is about 4690 kg/h although design capacity of the regeneration package was set to 6330kg/h with a glycol concentration of 73.5 wt% in solution, whereas the regenerated glycol was set to 80wt%.

II.3.5.Fuel Gas System :

Fuel gas system is one of the important units since it feeds the flare pilot burner, heater of glycol regeneration package, blow down headers, it runs on low pressure fuel gas of about 3.5kgf/cm². Fuel gas from associated gas feed line is supplied to fuel gas drum S20-D401 during black start-up but in normal operation, fuel gas can be obtained from inlet of sales gas pipeline.

Provision is made on the supply of fuel gas in such a way that all flares are active during total shutdown of the plant for safety reasons.

II.3.6.Flare System :

This system consists of two HP flare systems and one LP flare system. LP flare system is provided for associated gas compressors de-pressuring, blanket gas relieving of glycol surge drum and pressure safety valve at fuel gas drum. The other flaring requirements are all handled by the two HP flare systems.

II.3.7.Instrument and Service Air System:

The instrument air system consists of two air compressors S20-(C401A/B). Air service is used for the various services in the module, such as cleaning the filters and the exchanger tubes. However, air instrument is used for regulation instruments. Part of the compressed air is fed into dryer to dehydrate air, whereas the remaining is used as service air. After

dehydration, the dry air is distributed to the instruments in all plant facilities. In this plant the stan-by compressor is automatically started when operating machine is in trouble.

II.3.8. Blow down System:

Closed drain system is provided for blow down of all vessels except glycol recovery system. Collected oily water and condensate are drained by gravity into blow down drum S20-D402 which is operated at atmospheric pressure.

II.3.9. Electrical Distribution:

Sonelgaz supplies electrical power of 60kV at 50Hz to HR South plant. Switchgear receives electricity from Sonelgaz and divided into two feeders to ensure continuous supply of electrical current to the plant .

II.3.10. Fire Fighting System:

The existing fire water system supplies water to South Plant fire water tank. The fire water pumps will be operated automatically fire water network pressure drops. In addition, these pumps will also be operated from Fire Alarm & Control Panel, in Security House. The water hydrants, fixed water monitors and hose reels are operated manually. CO₂ extinguishing systems installed in Control Building and Substation will be operated automatically by the fire alarm signals generated from smoke or heat detectors.

II.4. Safety and Environment

II.4.1. Introduction :

The treatment of high pressure gases and liquid hydrocarbons can be dangerous if safety rules are not strictly observed at all times. All the staff working at the plant have three main qualities:

- Thorough knowledge of plant operations
- Awareness of all the dangers that exist
- Deep knowledge of the existence, location and proper use of all safety equipment available at the factory

II.4.2. Safety rules :

The most common safety instructions are:

- Absolute ban on causing any kind of flame in the area
- Wearing a helmet is compulsory for everyone
- Avoid any concentration of gas that could cause suffocation and toxicity
- Obtain a work permit from the security services before carrying out any new activity

II.4.3. Handling chemicals:

The chemicals used in the HR South plant are monoethylene glycol (MEG), monoethanolamine (MEA) and anti-foam additive that are stored in a cold location for the safe use of these three products. All employees should avoid inhaling or contacting their vapors as much as possible, and wear goggles and gloves.

II.4.4. Fire network:

The main water collector which surrounds the plant is supplied from the raw water storage tank, it has a capacity of 10,000 m³, this collector is pressurized to 9.5 kgf/cm² by one of the two pumps called “Jokey” with a flow rate of 50 m³/h. In the event of a pressure drop in the network or an alarm signal is triggered, two pumps driven by an electric motor are started automatically bringing the pressure to 13.5 kg / cm². In the event of a power cut, two diesel-powered pumps are used.

II.4.5. Automatic trigger system:

Several self-triggering fire fighting systems are installed in different parts of the factory, these systems are based on flame, smoke and gas detectors. These detectors trigger water diffusers in unclosed installations using the CO₂ gas diffuser or halon

Real Photos in HR South Plant

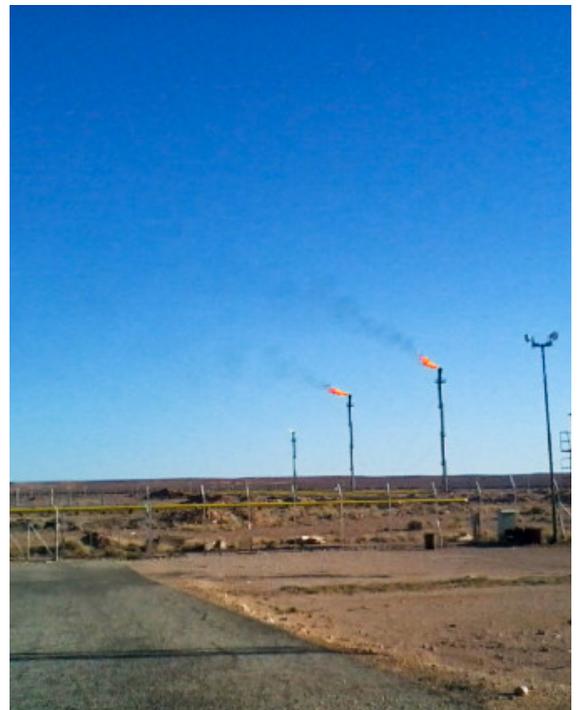


Figure II.4.Storage of MEG barrels at HR plant

Figure II.5. HP and BP flares at HR plant



Figure II.6. water tank for Fire fighting

II.4.6. Influence of natural gas on the environment :

The protection of the natural environment has become one of the main concerns of industrialized nations and even in developing countries and today constitutes an essential component in business strategy. The activity of certain chemical and petrochemical industries considered to be responsible for the degradation of the environment appears to be parasitic, undesirable and subversive in the light of the new social and ecological order. In this context, it is not the reputation of the company or its competitiveness in certain markets that is at stake, but its own survival in general. The issue of the environment is at the forefront of the fight in the next few years. The greenhouse effect is the direct result of the emission of gases on an industrial scale, this is the case in Hassi-Rmel where the emission of carbon dioxide is enormous at the reboiling furnaces and the various flares that operates all year around.

II.4.7. The Greenhouse effect :

II.4.7.1. Definition:

Solar energy reaching the ground heats the earth and turns into infrared rays. Like the windows of a greenhouse, hence the name given to this mechanism), the gases present in the atmosphere trap some of these rays which tend to heat it up. Thus, without the greenhouse effect, the average temperature on earth would be $-18\text{ }^{\circ}\text{C}$ and little water would be in liquid form. This effect therefore has a beneficial influence since it allows our planet to have an average temperature of $15\text{ }^{\circ}\text{C}$.

II.4.7.2. The mechanism of the greenhouse effect:

The ground re-emits infrared rays back into space that certain gases like the GHG intercept and push back towards the ground, thereby increasing the temperature. This is the greenhouse effect, a natural phenomenon. Without these gases, the global average temperature would be 35°C lower: -20 °C instead of + 15 °C. Analysis of gas bubbles contained in ice caps shows a striking parallelism between temperatures for 160,000 years and the levels of carbon dioxide and methane in the atmosphere. The most plausible explanation is that the alternation of ice ages and warmer periods triggered astronomical phenomena and that carbon dioxide and methane are accelerators of warming.

II.7.3. Greenhouse-effect gas :

The molecular structure of certain gases makes them capable of lowering infrared rays towards the ground. This ability is observed in Carbon dioxide (CO₂), Methane (CH₄), Chloro-fluoro-carbons and Ozone (O₃) as well as Nitrous oxide (N₂O). The concentrations of these gases are minimal around 0.035% by volume for the most abundant of them like CO₂ which is about 600 times less than oxygen. This explains why human activities can change these concentrations.

Chapter III: The Hydrate Formation and Dehydration of Natural Gas

III.1.Introduction:

Hydrates are a physical blend of water and other little particles of Gas when combined they create an ice-like solid.

III.2.Definition of hydrates:

Gas hydrates called clathrates are made up of a network of water molecules linked by hydrogen bonds, and whose cavities are occupied by various organic molecules. Hydrates under certain conditions are formed with very light hydrocarbons like CH₄, C₂H₆, C₃H₈, C₄H₁₀ and also CO₂, H₂S.

There are two forms of hydrates:

- Hydrates formed from short chain hydrocarbons (C₁, C₂, and CO₂).
- Hydrates formed from long chain hydrocarbons (C₃, C₄)

III.3.Clathrate hydrate crystal structure types and properties:

Clathrate hydrates are a nonstoichiometric solid lattice inclusion compounds having a crystalline water cage that enclathrates small gas molecules. Generally there are vacant cages in the clathrate hydrates, but a sufficient amount of gas molecules are needed inside the cages to stabilize the structure. Typically, there is one molecule per cage. However in a high pressure environment ($P > 10^8 \text{ Pa}$), it is possible for a cage to contain more than one gas molecule. Therefore, clathrates have similar physical properties as water including physical appearance, refractive index, and density. However, they differ from water when considering properties like mechanical strength, heat capacity, thermal conductivity.

In the 1950s, von Stackelberg and Muller were the first to discover a clathrate hydrate crystal structure using X-ray diffraction. They determined that CO₂ hydrates had the structure I (sI) crystal structure. Since then, three most common crystal structure types of clathrate hydrates, have been identified by X-ray diffraction this includes the structure I (sI), structure II (sII) and structure H (sH). The sI structure is a body-centered cubic structure and has two cage types - a small pentagonal dodecahedral cage (512) and a large tetrakaidecahedral cage (51262). The structure sII is a diamond lattice within a cubic framework and has two cage types - small cage (512) and a large hexacaidecahedral cage (51264). The sII structure fits molecules in natural gases or oils that are larger than ethane but smaller than pentane. The sI and sII

structures are of interest for gas companies because they form when natural gas molecules interact with water near gas pipelines or deep ocean areas.

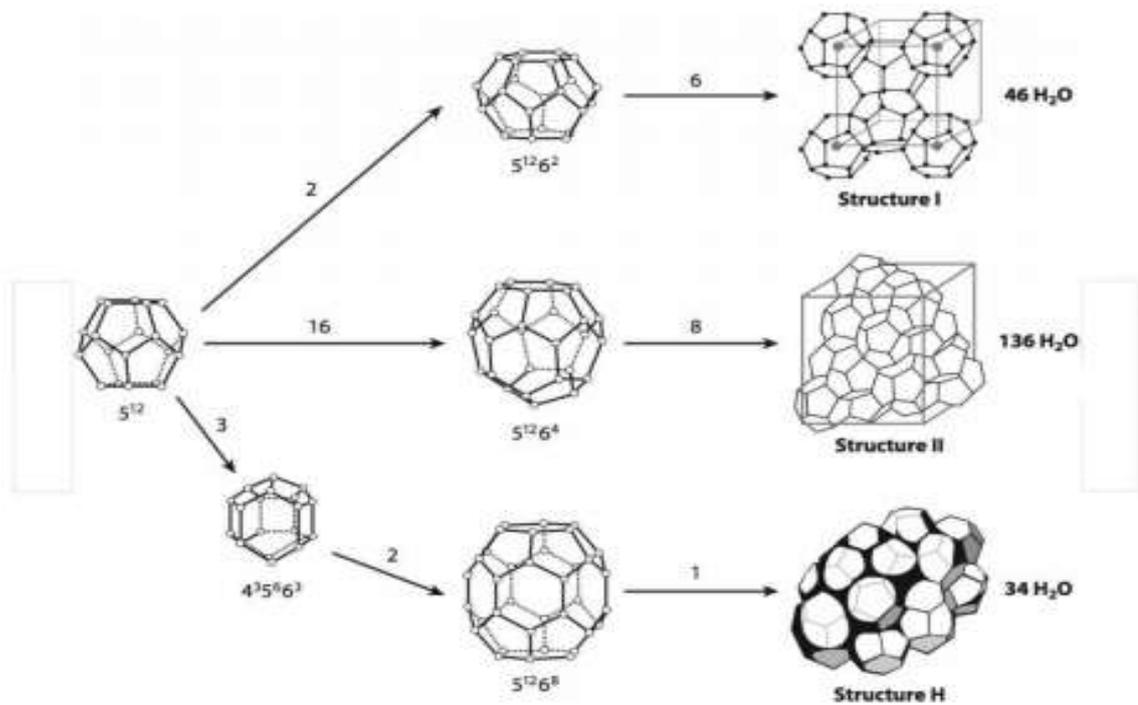


Figure III.1. Common clathrate hydrate structures [sI, sII, sH] [courtesy of Koh et al].

The sH structure has a hexagonal framework and three cage types: a small (5^{12}) cage, a mid-sized ($4^3 5^6 6^3$) cage, a large icosahedral cage ($5^{12}6^8$). Understanding of sH hydrate structure is particularly important for the oil industry because it is able to fit larger molecules contained in crude oils. The cage size is determined by the size of the largest guest molecule. For example, methane can fit into both the small and large cages of sI whereas other large hydrocarbon molecules such as propane are too large to fit into the large cage of sI. Instead, they can fit into the larger cages of sII. In fact, clathrate hydrates formed near oil and gas pipelines are mostly of sII structure because they contain larger hydrocarbon molecules like propane and isobutane. Spectroscopy has been used to analyze guest occupancy. It has been found that molecules below 0.35 nm will not stabilize sI and above 0.75 nm will not stabilize sII. When a large organic molecule is combined with a clathrate hydrate promoter, it is possible to form hydrates with atypical crystal structures. More new structures are being discovered as researchers produce clathrate hydrates with different types of gases in laboratory settings.

III.4. Conditions for hydrate formation:

Several factors control the hydrates formation but there are four main requirements that must be fulfilled for the hydrates to appear in the gas stream:

1. Free liquid water
2. Light hydrocarbon molecules (C_1 to C_4) or acid gas (CO_2 , H_2S) or nitrogen (N_2)
3. Sufficiently high pressure ($P > 10$ bars)
4. Sufficiently low temperature ($T < 25$ °C)

There are also other secondary conditions that promote the formation of hydrates:

- High flow velocity that induces flow turbulence like in fittings (elbow, orifice..)
- Pressure pulsation and all types of agitation
- The presence of fine particles assuring the heterogeneous crystallization where seeds are made of hydrates microcrystals and solid particles (dust, corrosion oxides)

All these conditions can be understood by studying four systems (type of mixtures) that exists in almost all the oil and gas plants. When oil and gas are produced into a flowline, they are invariably accompanied by water, so that three phases are commonly present as a liquid hydrocarbon, an aqueous liquid and a gas phase. Since a unified hydrate formation, Dendy Sloan et al. flow model does not exist, the problems will be described by breaking it into four end-member models (systems):

1. Oil-Dominated Systems where the oil holds more than 50% of the total volume of the mixture (gas, oil, and water). In this system, all of the existing water is emulsified as droplets in the oil phase due either to oil surfactants or shear.
2. Gas-Dominated Systems where in this system small amounts of liquid hydrocarbon or aqueous liquid are present.
3. Gas Condensate Systems which is similar to oil-dominated type since these systems also contain high level of oil. However, water cannot be dispersed in the liquid hydrocarbon phase. Condensate systems are defined here to have water dissolved in the condensate, or suspended as droplets in the condensate due to high shear.
4. High-Water-Cut (Volume) Systems. When the water content is very high (volume > 70%), water forms a separate continuous phase. These studies are limited to conditions below the inversion point; in systems that have water droplets suspended in the oil, and oil droplets suspended in a separate water phase. Actual phase inversion

has infrequently been observed in oil systems to date. In the maximum amount of water considered, there are two liquid phases, an oil phase with emulsified water droplets, and a water phase with emulsified oil droplets.

III.5. The water content in natural gas:

The water content in natural gas depends mainly on the operating temperature and the pressure. Salts in water solution reduce its partial pressure in the vapor phase and water content of the gas is therefore reduced.

III.6. Measurement of the water content:

The water vapor content can be measured by three methods mainly the dew point, the water retention on an adsorbent and through the adsorption in a liquid (Karl-Fisher method).

1. The dew point method consists in observing the condensation temperature of the water by means of a cooled mirror.
2. The water content can be measured after adsorption water on materials such as Chlorate or Magnesium. The amount of water adsorbed is determined by a gravimetric method.
3. Karl-fisher's method is a widely used method that consists of adsorbing water into methanol known as a Karl-Fisher reagent. The water content in the solution is measured by the quantity of gas necessary for neutralize the reagent (solution of iodine, pyridine and sulfur dioxide) in a controlled environment where the evolution of temperature and pressure conditions is monitored. Using the natural gas water dew curve, it is possible to determine the hydrate formation. The quantity of water deposited can then be calculated from the difference between the water content in the gas at saturation at the inlet and outlet respectively.

III.7. Dehydration of natural gas:

Natural gases either from natural creation or capacity repositories contain water, which consolidate to form strong gas hydrates to obstruct pipeline stream and particularly control frameworks. Natural gas on the way to market ought to be got dried out to a controlled water substance to evade hydrate just as to limit the erosion issues. Natural gas handling comprises of isolating the entirety of the different hydrocarbons and liquids from the unadulterated natural gas. Significant transportation pipelines normally force limitations eager for advancement up of the natural gas that is permitted into the pipeline. Which implies that

before the natural gas can be shipped it should be purged. While the ethane, propane, butane, and pentanes should be taken out from natural gas, this doesn't imply that they are all 'byproducts'.

The natural gas produced and transported by the major highway mainline transmission frameworks should fulfil the quality guidelines determined by pipeline organizations in the "General Terms and Conditions (GTC)". These quality standards change from one pipeline to another and are generally an element of a pipeline framework's plan, its downstream interconnecting pipelines, and its client base. In general, these standards ensure that the natural gas:

- be inside a particular Btu content territory (1,035 ±50 Btu for every cubic feet)
- be conveyed at a predetermined hydrocarbon dew point temperature level (beneath which any disintegrated gas fluid in the blend will in general consolidate at pipeline pressure)
- contain close to follow measures of components like hydrogen sulfide, carbon dioxide, nitrogen, water fume, and oxygen
- be liberated from particulate solids and fluid water that could be adverse to the pipeline or its auxiliary working gear.

Dehydration of natural gas is the evacuation of the water that is related with natural gases in fume structure. The natural gas industry has perceived that dehydration is important to guarantee smooth activity of gas transmission lines. Dehydration forestalls the development of gas hydrates and lessens consumption. Except if gases are got dried out, fluid water may gather in pipelines and aggregate at depressed spots along the line, decreasing its stream limit. A few strategies have been created to get dried out gases on a mechanical scale.

The three significant techniques for dehydration are direct cooling, absorption and adsorption. Molecular sieves (zeolites), silica gel, and bauxite are the desiccants utilized in adsorption process. In retention measures, the most regularly utilized desiccants are diethylene and triethylene glycols. Normally, the retention/stripping cycle is utilized for eliminating a lot of water, and adsorption is utilized for cryogenic frameworks to arrive at low dampness substance.

III.7.1-Direct Cooling :

The saturated vapor substance of natural gas diminishes with expanded pressing factor or diminished temperature. Subsequently, hot gases saturated with water might be somewhat dried out by direct cooling. Gases exposed to pressure are ordinarily after cooled, and this cooling may well eliminate water from the gas. The cooling interaction should decrease the temperature to the least worth that the gas will experience at the common strain to forestall further buildup of water.

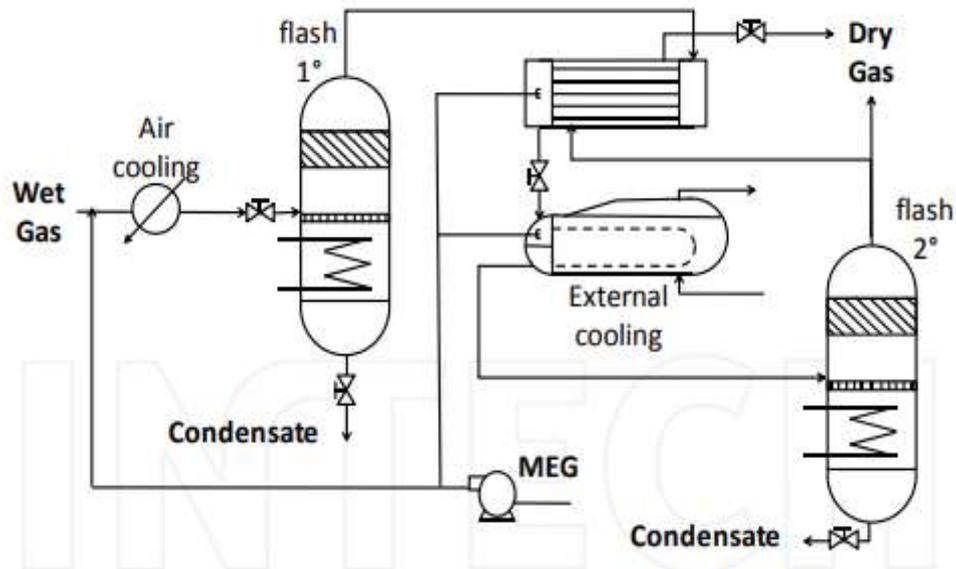


Figure III.2. Scheme of direct cooling unit

III.7.2.Absorption of Water in Glycols :

Absorption for dehydration includes the utilization of a fluid desiccant to eliminate water vapour from the gas. Albeit numerous fluids have the capacity to retain water from gas, the fluid that is generally alluring to use for business dehydration purposes ought to have the accompanying properties:

- High absorption efficiency.
- Simple and monetary recovery
- Non-destructive and non-poisonous
- Trouble less operations (no issues when utilized in high focuses)

- No communication with the hydrocarbon segment of the gas, and no pollution by corrosive gases.

The glycols, especially ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (T4EG) come to nearest to fulfilling these operations to shifting degrees. Water and the glycols show total common solvency in the fluid stage due to hydrogen interactions, and their very low water vapour pressures. One often utilized glycol for dehydration is triethylene glycol, or TEG which is excellent agent in absorption/stripping operations. The wet gas is dried out in the safeguard, and the stripping section recovers the water with TEG. The glycol stream ought to be re-energized continually on the grounds that some TEG may respond and frame substantial particles, which ought to be eliminated by the channel

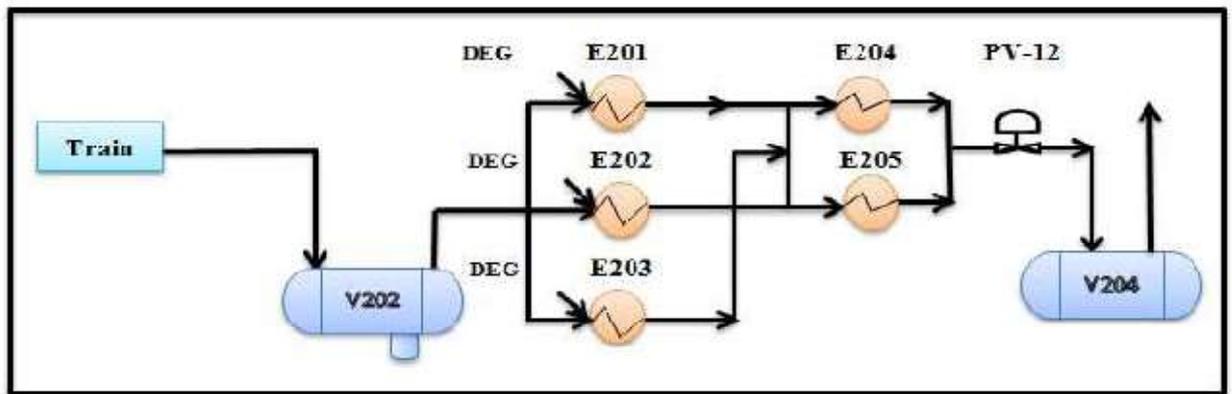


Figure III.3. Scheme DEG Glycol Injection

III.7.3. Adsorption of Water by a Solid :

Solid-desiccant dehydration is the essential means of getting dried out natural gas utilizing adsorption and ordinarily comprises of at least two adsorption towers, which are loaded up with a solid desiccant. Common desiccants incorporate enacted alumina, silica gel, and sub-atomic sifter. Wet natural gas is gone through these column and as it passes around the particles of desiccant material, water is held on the outside of these desiccant particles. Going through the whole desiccant bed, practically the entirety of the water is adsorbed onto the desiccant material, leaving the dry gas to leave the lower part of the tower.

Solid-desiccant dehydrators are regularly more successful than glycol dehydrators and are generally introduced where exceptionally dry gas is required, for example, upstream of a cryogenic expander, LPG, and LNG plants. These kinds of dehydration frameworks are most

appropriate for huge volumes of gas under extremely high tension and are in this manner typically situated on a pipeline downstream of a blower station.

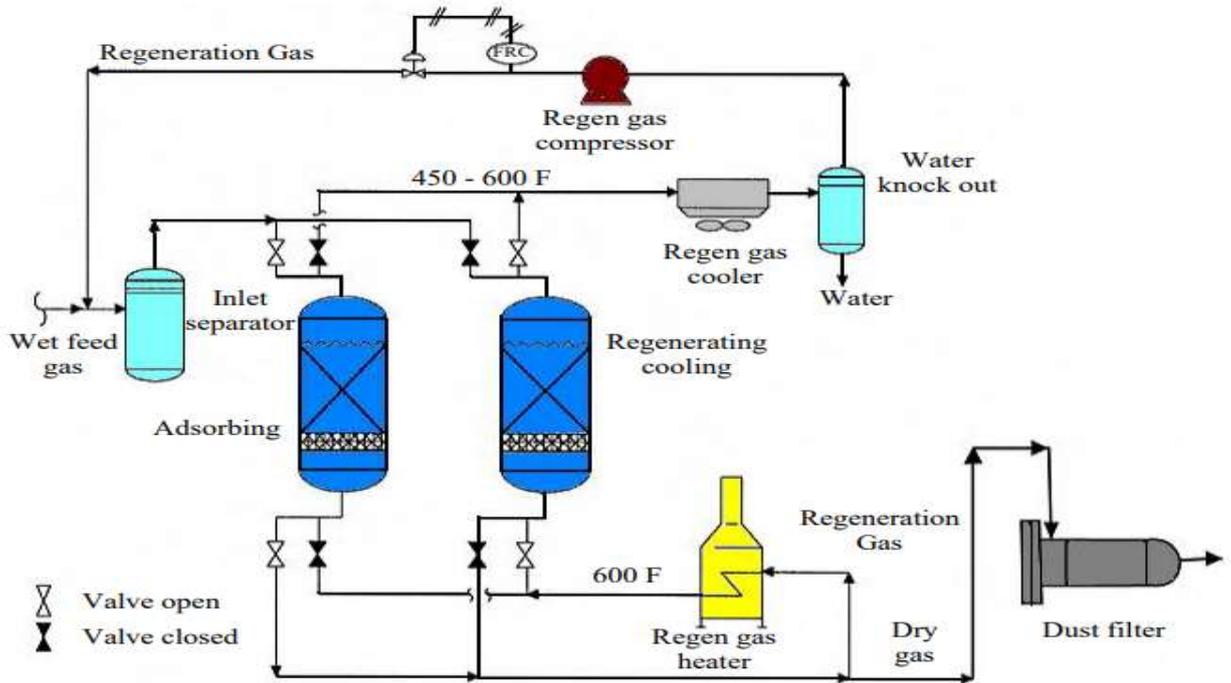


Figure III.4. Solid desiccant dehydrator twin tower system

Chapter IV : The Glycols Usage and Choice

The most desirable dehydrating agents that can be used for commercial dehydration purposes should possess the following important properties [Campbell, 1998]:

- High water absorption efficiency
- High decomposition temperature
- Low vaporization losses
- Easy and economic to be separated and regenerated
- Non-corrosive and non-toxic to the system

The commonly available glycols and their uses can be described as [Katz et al., 1959]:

1. Monoethylene glycol (MEG): high vapour equilibrium with gas so tend to lose to gas phase in contactor. Use as hydrate inhibitor where it can be recovered from gas by separation at temperatures below 10°C.
2. Diethylene glycol (DEG): high vapour pressure leads to high losses in contactor. Having a low decomposition temperature requires low reconcentrator temperature (157.2 to 171.1°C) and thus cannot get pure enough for most applications.
3. Triethylene glycol (TEG): the most common agent which reconcentrate at (171.1–204.4°C), for high purity. At contactor temperatures in excess of 48.89°C, there is a tendency to high vapour losses. Dew point depressions up to 65.6°C are possible with stripping gas.

IV.1. Physical Properties of Selected Glycols:

The physical properties of commonly used agents in the dehydration of natural gas are presented in the Table 3. This includes the different transition temperatures as well as structural characteristics.

Table 3. Physical Properties of Selected Glycols and Methanol [GPSA, 1998]

Compounds	Ethylene glycol	Diethylene Glycol	Triethylene glycol	Tetraethylene glycol	Methanol
Formula	C ₂ H ₆ O ₂	C ₄ H ₁₀ O ₃	C ₆ H ₁₄ O ₄	C ₆ H ₁₈ O ₅	CH ₃ OH
Molecular mass	62.1	106.1	150.2	194.2	32.04
Boiling point at 760 mm Hg (°C)	197.3	244.8	285.5	314	64.5
Vapor pressure at 25°C	0.12	0.01	0.01	0.01	120
Density at 25°C Kg/ m ³	1110	1113	1119	1120	790
Freezing point (°C)	-13	-8	-7	-5.5	-97.8
Flash point (°C)	116	124	177	204	12

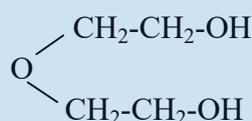
IV.2. The different types of glycol:

The glycols have many (OH) alcohol functional groups. These compounds are present in the form of (C₂H₄O)_n HOH. Due to these hydrogen interactions it is possible to water to stick strongly to these compounds which rend the gas stream dry.

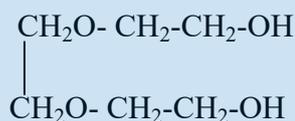
There are several types of glycol:

- Monoethylene glycol (MEG) : HO-CH₂-CH₂-OH

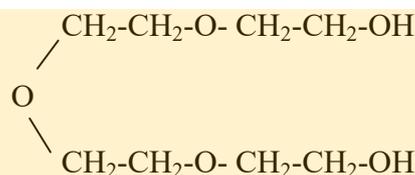
- Diethylene glycol (DEG) :



- Triethylene glycol (TEG)



- Tetra ethylene glycol (T4EG)



IV.3.The main uses of MEG :

The uses for ethylene glycol are numerous. Ethylene glycol is mostly used as a major component of antifreeze, heat transfer and coolant fluids in automobiles, aircraft anti-icing materials, chilled water air conditioning systems, and heat transport. Additionally, ethylene glycol is an important antecedent to produce polyesters, such as polyurethane (PES), and polyethylene terephthalate (PET).

The monoethylene glycol (MEG) is commonly used hydrate inhibition and in dehydration of natural gas because it could remove water and inhibit the formation of hydrates in natural gas and can be reused after purification.

IV.4.Choice :

The large usage of glycols in gas dehydration process is mainly due to their great hygroscopicity, excellent stability toward thermal and chemical decomposition, low vapor pressures, moderate cost and availability.

Mono ethylene glycol (MEG), diethylene glycol (DEG), and triethylene glycol (TEG) are the main products used for the dehydration of natural gas. The formulation made of 80% by weight aqueous MEG solutions are the best choice because of their affinity towards water.

This choice is related to:

- Tendency to absorb water which depends on its concentration
- Efficiency; Per unit mass ethylene glycol is more effective than DEG for inhibiting hydrates (its low molecular mass 62.1 g/ mol)
- Heat stability
- Freezing temperature which is around -13°C (Figure 12)
- Poor solubility in the liquid hydrocarbon phase.
- Lower viscosity; Ethylene glycol solution has a lower viscosity than other glycols.

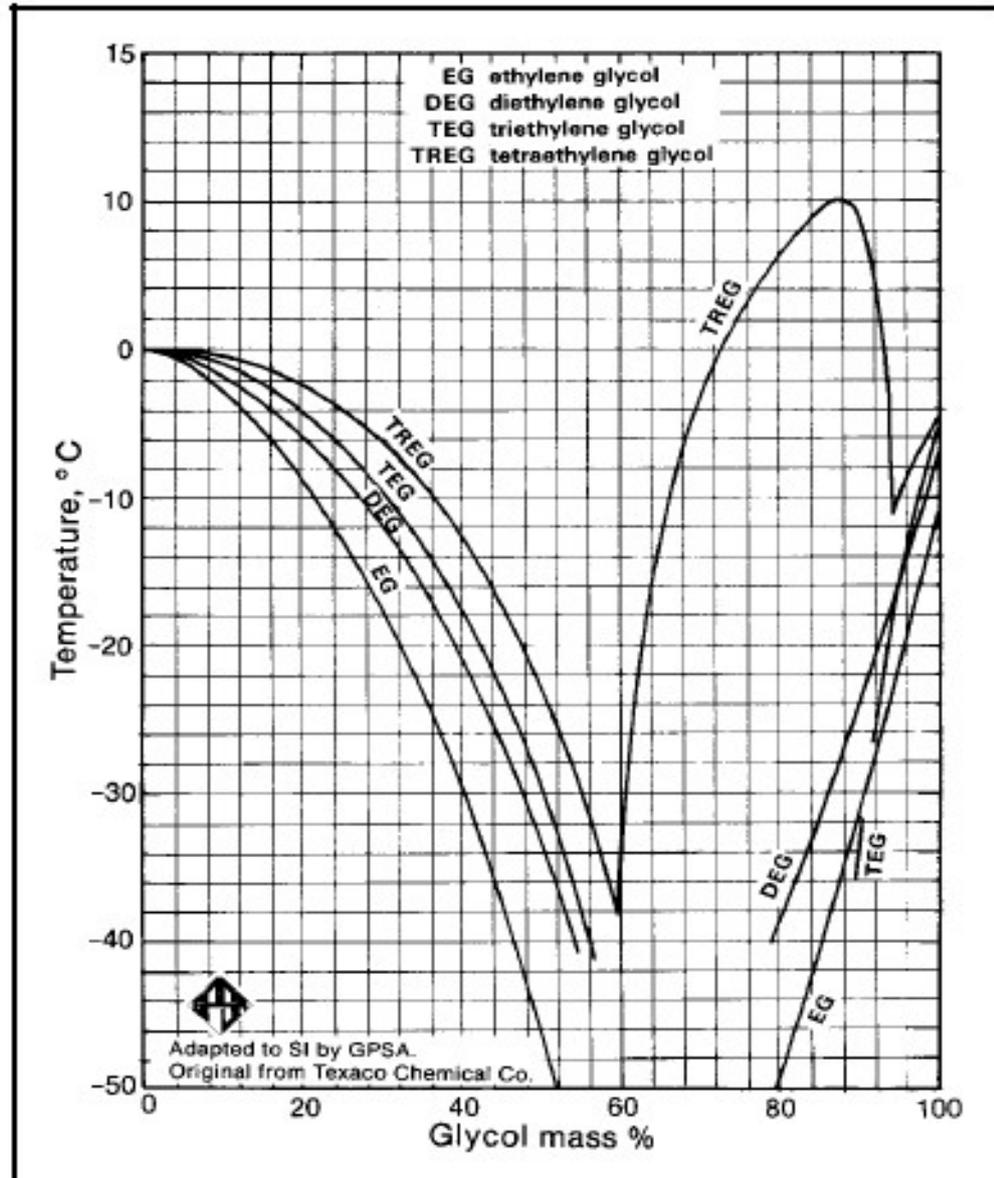


Figure IV.1. Freezing points aqueous glycol solutions

IV.5. Injection and regeneration of mono ethylene glycol (MEG):

The glycol is injected into all cold spots to prevent hydrate formation. These permanent injection are located in the following areas:

- At the inlet of the E102A / B raw gas exchangers (gas / gas) on the tube side.
- At the entrance of the E103 (gas / liquid) exchangers.
- At the entrance of J.T valve.

IV.6. Regeneration of monoethylene glycol (MEG):

After water absorption in the process, the hydrated glycol is collected from the bottom of the D102 separator then sent to the regeneration unit at a concentration of about 73.5% by weight.

The glycol generation unit is designed to regenerate hydrated glycol from 73% by mass concentration up to a 80% by mass concentration, removing the water in the glycol by heating. The hydrated glycol 73% by mass coming from the 3 trains arrives at the regeneration unit, at a temperature of about -6°C and at a pressure of $7\text{kg} / \text{cm}^2$. The hydrated glycol passes through a series of exchangers up to a temperature of 121.0°C by hot low water glycol (dehydrated glycol) from the bottom of the H301 boiler, these heat exchangers are intended to reduce the amount of heat required, by the H301 boiler.

The poor glycol which has a concentration of 80% by mass cooled to 37°C on the average of the rich glycol in the heat exchanger, then it is sent to the buffer tank D301 where it is sucked by the pump P301A / B, and C to be injected into train A, B and C in a closed circuit. There are two MEG regeneration units of the same capacity (U301A /B) one on work whereas, the second is on standby.



Figure IV.2. MEG regeneration unit(side A) **Figure IV.3.** MEG regeneration unit(side B)

Operational and corrosion problems usually appear when the circulating solution becomes dirty. So to achieve continuous, trouble-free operation and long glycol life, it is necessary to recognize these problems and know how to prevent them. Such as oxidation, thermal decomposition, PH, foaming and the presence of liquid hydrocarbons.

Glycol losses during process function generally are classified into :
process losses, mechanical losses and exceptional losses.

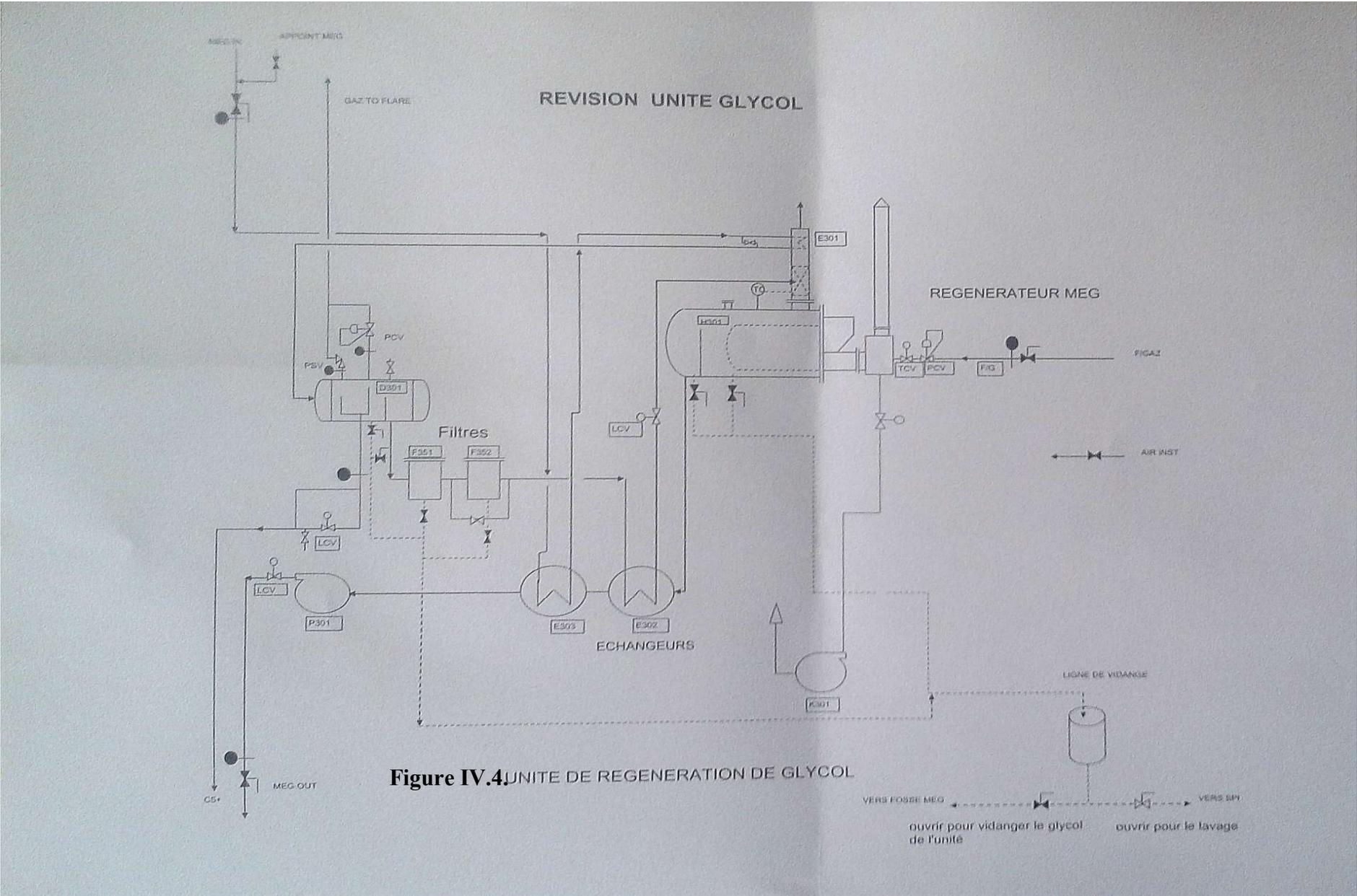


Figure IV.4. UNITE DE REGENERATION DE GLYCOL

Chapter V : The Calculation Method

In this chapter, the method for calculating the injection flow rate of MEG in heat exchangers will be explained.

The calculations based on the two diagrams presented in Figures 12 as well as Figure I and II in order to estimate the following parameters:

1. The hydrate formation temperature
2. The amount of water in natural gas
3. Water quantity to be eliminated
4. MEG solution injection flow rates
5. Absorption efficiency
6. Upstream pressure (decreasing due to depletion) on the MEG injection flow rate.

In the current study as explained previously, the flow circuit between the two separator D101 and D102 (injection section) as shown in this figure 16 is investigated.

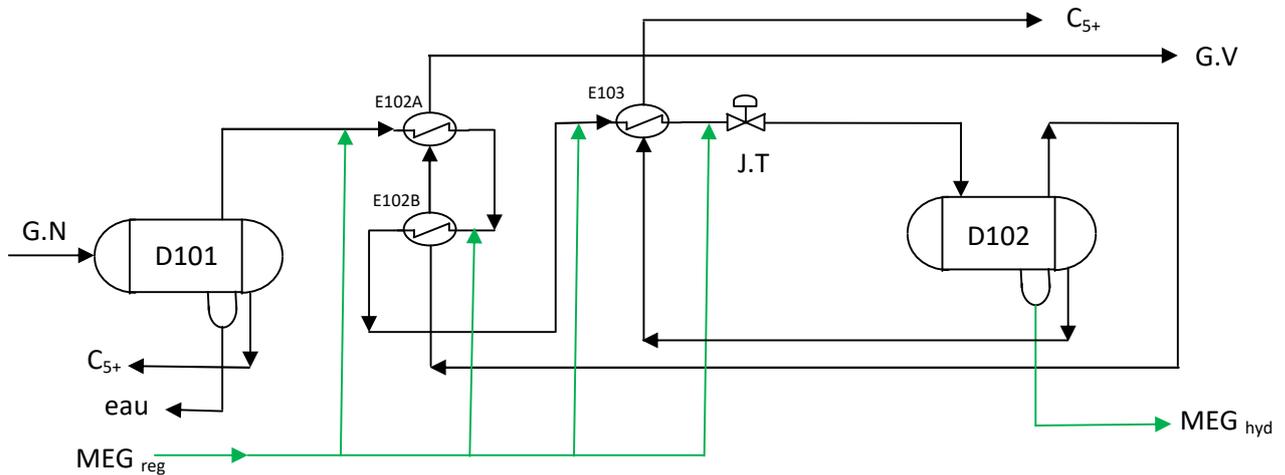


Figure V.1. Diagram glycol injection (A)

V.1.Determination of the hydrate formation temperature :

The hydrate formation temperature (TFH) is one of the most important criteria in the calculation of dehydration because below this temperature there is a risk of hydrate formation. To calculate this temperature, the method of Katz based on the chart presented in Figure 12 is used.

This chart is a set of curves giving the TFH as a function of the density of the feed gas and the operating pressure. The practical application of this method is based on the very low content of H₂S and CO₂, such as the case of natural gas in Hassi R'Mel.

V.2.Determination of the amount of water in natural gas :

When the molar concentration of the acid components (CO₂, H₂S) in the gas is low than (<5%) as is the case in Hassi R'Mel, the water content at saturation of natural gases can be

determined using graphical method directly. Some corrections are required as soon as the molar concentration of the acid constituents exceeds 5%.

V.2.1. Graphic method (Mcketta's abacus):

The Mcketta and Wehe chart (Figure II) is based on experimental data. It makes it possible to estimate the water content of sweet natural gas saturated with humidity, as a function of the pressure and the temperature (Figure I).

V.3. Calculation of water quantity to be eliminated :

The amount of water to be removed will be calculated by the following equation:

$$Q_{\text{water}} = Q_{\text{H}_2\text{O}}(\text{D101}) - Q_{\text{H}_2\text{O}}(\text{D102})$$

Q_{water} : Amount of water to eliminate.

$Q_{\text{H}_2\text{O}}(\text{D101})$: Water content of the vapors leaving the D101 separator.

$Q_{\text{H}_2\text{O}}(\text{D102})$: Water content of the vapors leaving the D102 separator.

V.4. Determination of MEG solution injection rates:

In order to calculate the quantity of MEG at 80% by weight solution that will be injected in exchangers ,it should be mentioned that the hydrated MEG solution recovered from regeneration is of the order 73% by weight, we must establish a material balance.

Material balance: $F_1 + Q_{\text{water}} = F_2$ (1) total balance.

$F_1 \cdot X_1 = F_2 \cdot X_2$ (2) partial balance compared to the MEG solution

F_1 : the injection rate in 80% by weight MEG solution.

F_2 : the flow rate of the hydrated MEG solution at 73% by weight recovered with D102.

Q_{water} : amount of water to absorb.

X_1 : mass fraction of the poor MEG solution (80%).

X_2 : mass fraction of the rich MEG solution (73%).

V.5. Calculation of absorption efficiency:

The absorption efficiency can be calculated through the mathematical formula:

$$R_{\text{absorption}} = (M_1/M_2) \times 100$$

M_1 : the amount of water absorbed in (train A + C)

M_2 : the amount of water in Raw Gas (train A + C)

V.6. Effect of upstream pressure (decrease) on MEG injection rate

For a fixed temperature $T = 60^\circ\text{C}$, the variation of injection flow as a function of the pressure ($P = 109 \text{ kgf/cm}^2$, $P = 105 \text{ kgf/cm}^2$, $P = 100 \text{ kgf/cm}^2$, $P = 95 \text{ kgf/cm}^2$ and $P = 90 \text{ kgf/cm}^2$) can be calculated.

Chapter VI :Calculation Part

VI.1.Starting Values : in Design (when the plant start):

Table 4. HR South Plant gas composition in design

Constituants	Mi(g/mole)	Yi
CH4	16	0,8067
C2H6	30	0,0751
C3H8	44	0,0285
i- C4H10	58	0,0059
n- C4H10	58	0,0097
i- C5H12	72	0,0026
n- C5H12	72	0,0031
C6H14	86	0,0032
C7H16	100	0,0043
C8H18	114	0,0038
C9H20	128	0,0032
C10H22	142	0,0083
N2	28	0,0443
CO2	44	0,0013
Total		1

Parameters in design :

$$P = 131 \text{ kgf/cm}^2 = 1863.25 \text{ psia} = 128.4 \text{ Bar}$$

$$T = 60 \text{ }^\circ\text{C}$$

Actual parameters used in production at HR South Plant:

Since the raw gas composition changes, the newly measured values at March 25th, 2021

$$P = 109 \text{ kgf/cm}^2 = 1550.34 \text{ psia}$$

$$T = 60 \text{ }^\circ\text{C}$$

$$d_{\text{gaz}} = 0.68$$

Operating ratio capacity between Train A and C (Train C / Train A) is 0.556

Table 5. Trains sales gas flow and MEG injection rate

	Train A	Train C
Sales gas flow m ³ /d	2870×10 ³	1597×10 ³
MEG injection rate m ³ /h	1.98	0.97

VI.2. Determination of the hydrate formation temperature

VI.2.1. Calculation of gas density:

The density of the gas (d_{gaz}) at constant volume is equal to the ratio of the molar mass of gas (M_g) to the molar mass of air (M_a) det to 28.97 g/mol:

$$d_{\text{gaz}} = M_g / M_a = \sum Y_i \cdot M_i / 28,97$$

Y_i : mole fraction of gas

M_i : molecular mass of the gas components.

Gas Composition in Design:

Table 6. Molecular mass of raw gas

Constituants	Mi(g/mole)	Yi	Mi × Yi
CH4	16	0,8067	12,9072
C2H6	30	0,0751	2,253
C3H8	44	0,0285	1,254
i- C4H10	58	0,0059	0,3422
n- C4H10	58	0,0097	0,5626
i- C5H12	72	0,0026	0,1872
n- C5H12	72	0,0031	0,2232
C6H14	86	0,0032	0,2752
C7H16	100	0,0043	0,43
C8H18	114	0,0038	0,4332
C9H20	128	0,0032	0,4096
C10H22	142	0,0083	1,1786
N2	28	0,0443	1,2404
CO2	44	0,0013	0,0572
Total		1	21,7536

$$d_{\text{gaz}} = \sum Y_i \cdot M_i / 28,966 = 21,7536 / 28,97 = 0.7509$$

$$d_{\text{gaz}} = 0.7509 \text{ in design}$$

$$P = 131 \text{ kgf/cm}^2 = 1863.25 \text{ psia}$$

With time actual parameters are:

$$d_{\text{gaz}} = 0.68$$

$$P = 109 \text{ kgf/cm}^2 = 1550.34 \text{ psia}$$

VI.2.2. The hydrate formation temperature : According to Figure I, hydrate formation prediction (GPSA, 2004) can give:

$$\left\{ \begin{array}{l} T_1 = 67 \text{ }^\circ\text{F for natural gas with a density of } d_1=0.6 \\ \text{TFH} = ? \text{ }^\circ\text{F for natural gas with a density of } d=0.68 \\ T_2 = 71 \text{ }^\circ\text{F for natural gas with a density of } d_2=0.7 \end{array} \right.$$

by graphical estimation we obtain:

$$\Delta T_1 = T_2 - \text{TFH} = 71 - \text{TFH} \quad \text{and} \quad \Delta d_1 = d_2 - d = 0.7 - 0.68$$

$$\Delta T_2 = T_2 - T_1 = 71 - 67 \quad \text{and} \quad \Delta d_2 = d_2 - d_1 = 0.7 - 0.6$$

$$\left. \begin{array}{l} \Delta T_1 \longrightarrow \Delta d_1 \\ \Delta T_2 \longrightarrow \Delta d_2 \end{array} \right\} \longrightarrow \Delta d_2 \times \Delta T_1 = \Delta d_1 \times \Delta T_2$$

$$\Delta T_1 = 4 \times 0.02 / 0.1 = 0.8 \quad \text{so TFH} = T_2 - \Delta T_1 = 71 - 0.8 = 70.2$$

$$\text{TFH} = 70.2 \text{ } ^\circ\text{F} = 20.77 \text{ } ^\circ\text{C}$$

From the results obtained, we can conclude that there is no risk of hydrate formation between the entry of the train and the separator tank D101 until the entry of the heat exchangers E102A / B since the operating temperature at these location in the level (36 to 60 °C) which is higher than that the hydrate formation temperature TFH = 21.22 °C. The hydrates formation at the level of the heat exchanger bank E102A / B, E103 and in the J.T valve up to the separator D102 is inevitable at the operating conditions of gas treatment P = 109 kgf/cm² and T = 36°C to - 6°C. So, to avoid the risk of hydrate formation, we have to move outside of the hydrate formation domain, for that glycol injection is necessary in sufficient quantity.

Pressure-Temperature Curves for Predicting Hydrate Formation

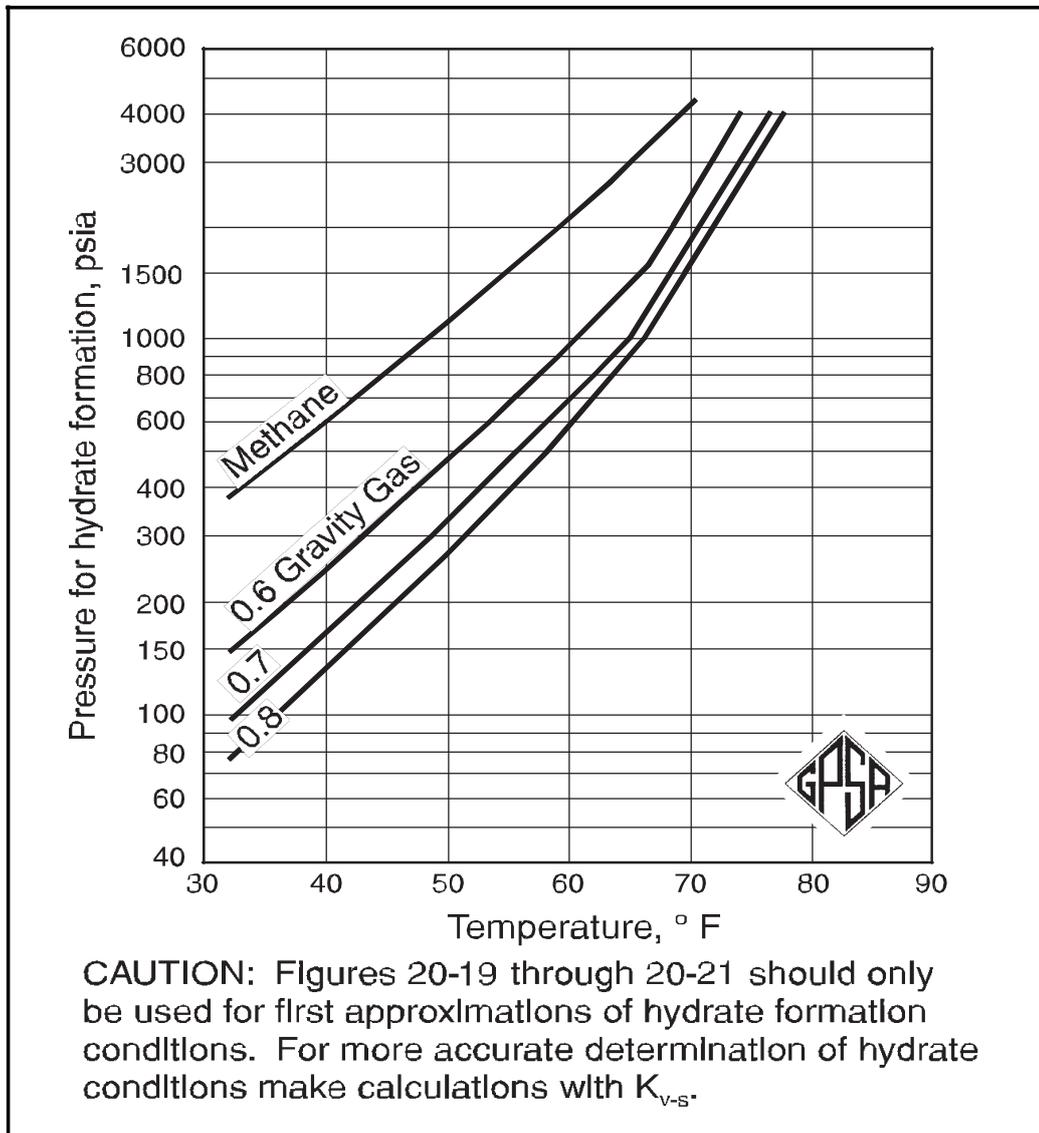


Figure V.2. Hydrate formation prediction (GPCSA, 2004)

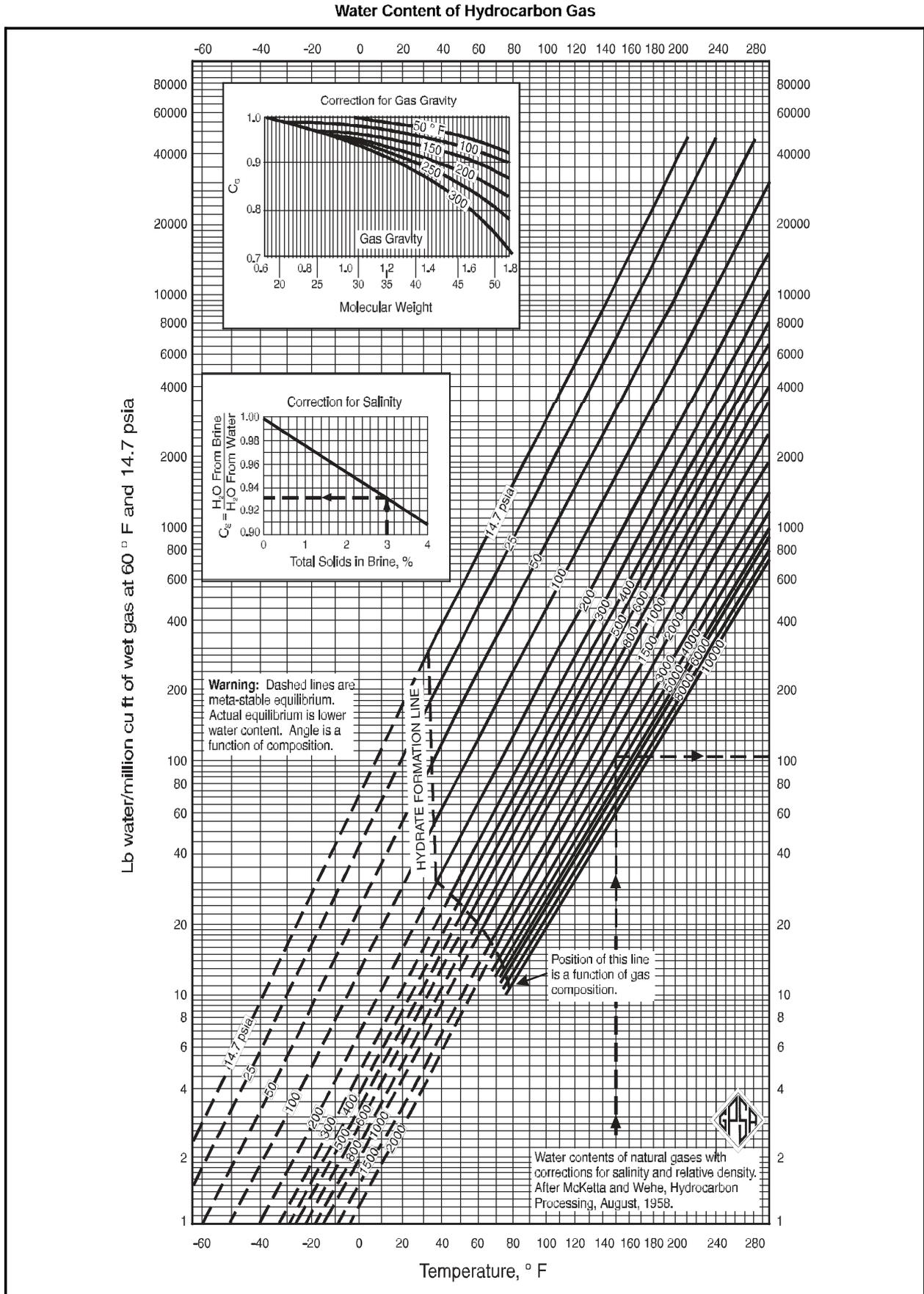


Figure V.3. Mc KETTA and WEHE chart (GPSA, 2004)

VI.3.Calculation of water quantity to be eliminated :

The amount of water to be eliminated will be calculated by the following equation:

$$Q_{\text{water}} = Q_{\text{H}_2\text{O}(\text{D101})} - Q_{\text{H}_2\text{O}(\text{D102})}$$

Q_{water} : Amount of water to be eliminated (dehydrated) .

$Q_{\text{H}_2\text{O}(\text{D101})}$: Water content of the vapors leaving the D101 separator.

$Q_{\text{H}_2\text{O}(\text{D102})}$: Water content of the vapors leaving the D102 separator.

VI.3.1.Water content of the vapors leaving the D101 separator : $Q_{\text{H}_2\text{O}(\text{D101})}$

$$\left\{ \begin{array}{l} P = 109 \text{ kgf/cm}^2 = 1550.34 \text{ psia} \\ T = 60^\circ\text{C} = 140^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart figure II we have :

$$T = 140^\circ\text{F} \longrightarrow \left\{ \begin{array}{ll} Q_1 = 130 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_1 = 1500 \text{ psia} \\ Q_{\text{H}_2\text{O}} = ? \text{ lb}/10^6\text{ft}^3 & \longrightarrow P = 1550.34 \text{ psia} \\ Q_2 = 105 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_2 = 2000 \text{ psia} \end{array} \right.$$

We have:

$$\begin{array}{ll} \Delta Q_1 = Q_2 - Q_{\text{H}_2\text{O}} = 105 - Q_{\text{H}_2\text{O}} & \text{and} \quad \Delta P_1 = P_2 - P = 2000 - 1550.34 = 449.66 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 105 - 130 & \text{and} \quad \Delta P_2 = P_2 - P_1 = 2000 - 1500 = 500 \text{ psia} \end{array}$$

So we obtain :

$$\left\{ \begin{array}{ll} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -25 \times 449.66 / 500 = -22.48 \text{ lb}/10^6\text{ft}^3, \text{ so we get } Q_{\text{H}_2\text{O}} = Q_2 - \Delta Q_1 = 105 + 22.48 = 127.48$$

$$Q_{\text{H}_2\text{O}} = 127.48 \text{ lb}/10^6\text{ft}^3 = 1.911 \times 10^{-3} \text{ kg/m}^3$$

$$\boxed{Q_{\text{H}_2\text{O}(\text{D101})} = 1.911 \times 10^{-3} \text{ kg/m}^3}$$

VI.3.2. Water content of the vapors leaving the D102 separator : $Q_{H_2O(D102)}$

$$\left\{ \begin{array}{l} P = 72 \text{ kgf/cm}^2 = 1024.08 \text{ psia} \\ T = -6 \text{ }^\circ\text{C} = 21.2 \text{ }^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart, figure II we have :

$$T = 21.2 \text{ }^\circ\text{F} \longrightarrow \left\{ \begin{array}{l} Q_1 = 4.5 \text{ lb}/10^6\text{ft}^3 \longrightarrow P_1 = 1000 \text{ psia} \\ Q_{H_2O} = ? \text{ lb}/10^6\text{ft}^3 \longrightarrow P = 1024.08 \text{ psia} \\ Q_2 = 3.2 \text{ lb}/10^6\text{ft}^3 \longrightarrow P_2 = 1500 \text{ psia} \end{array} \right.$$

We have:

$$\begin{array}{ll} \Delta Q_1 = Q_2 - Q_{H_2O} = 3.2 - Q_{H_2O} & \text{and} \quad \Delta P_1 = P_2 - P = 1500 - 1024.08 = 475.92 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 3.2 - 4.5 & \text{and} \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{array}$$

So we obtain :

$$\left\{ \begin{array}{l} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -1.3 \times 475.92 / 500 = -1.237 \text{ lb}/10^6\text{ft}^3 \quad \text{so we get} \quad Q_{H_2O} = Q_2 - \Delta Q_1 = 3.2 + 1.237 = 4.437$$

$$Q_{H_2O} = 4.437 \text{ lb}/10^6\text{ft}^3 = 0.0665 \times 10^{-3} \text{ kg/m}^3$$

$$Q_{H_2O(D102)} = 0.0665 \times 10^{-3} \text{ kg/m}^3$$

VI.3.3. The water quantity to be eliminated :

The amount of water to be removed will be calculated by the following equation:

$$Q_{\text{water}} = Q_{H_2O(D101)} - Q_{H_2O(D102)}$$

$$= 1.911 \times 10^{-3} - 0.0665 \times 10^{-3} = 1.8445 \times 10^{-3}$$

$$Q_{\text{water}} = 1.8445 \times 10^{-3} \text{ kg/m}^3$$

VI.3.4. Calculation of the total hourly water flow to be eliminated for train A :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}^A$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas}^A : gas flow train A

$$Q_{\text{gas}}^A = 2870 \times 10^3 \text{ m}^3/\text{d} = 119.583 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 1.8445 \times 10^{-3} \times 119.583 \times 10^3 = 220.57 \text{ kg/h}$$

$Q_{\text{Total water}} = 220.57 \text{ kg/h}$
--

VI.3.5. Calculation of the total hourly water flow to be eliminated for train C :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}^C$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas}^C : gas flow train C

$$Q_{\text{gas}}^C = 1597 \times 10^3 \text{ m}^3/\text{d} = 66.541 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 1.8445 \times 10^{-3} \times 66.541 \times 10^3 = 122.73 \text{ kg/h}$$

$Q_{\text{Total water}} = 122.73 \text{ kg/h}$
--

VI.4. Determination of MEG solution injection flow rates :**VI.4.1. The concentration of hydrated MEG:**

The glycol regeneration unit is designed to regenerate hydrated glycol from 73% by mass concentration up to a 80% by mass concentration, whereas the absorbed water in the glycol is removed by heating.

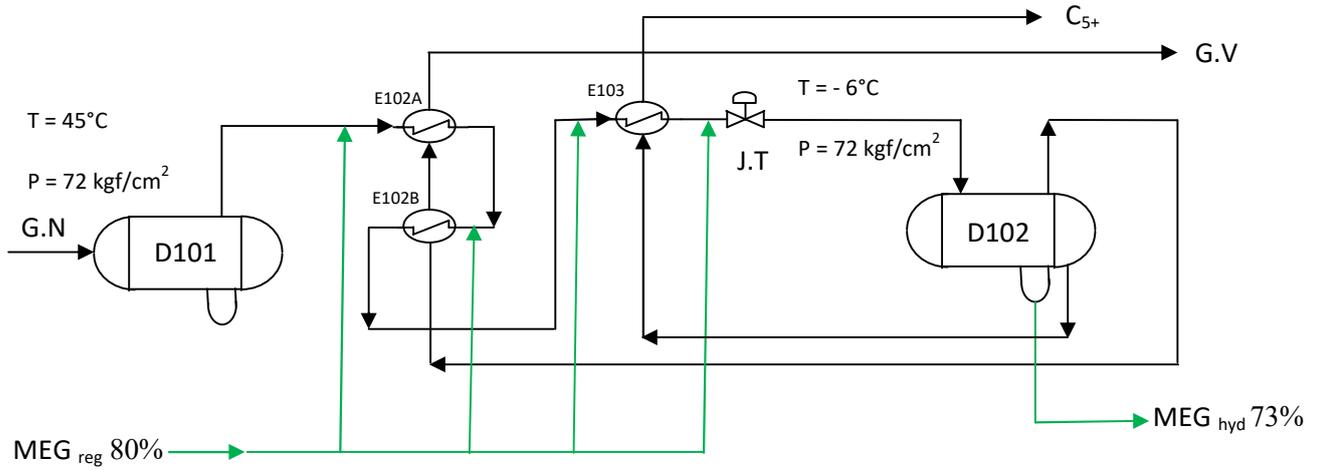


Figure VI.1. Detailed Diagram Glycol Injection (B)

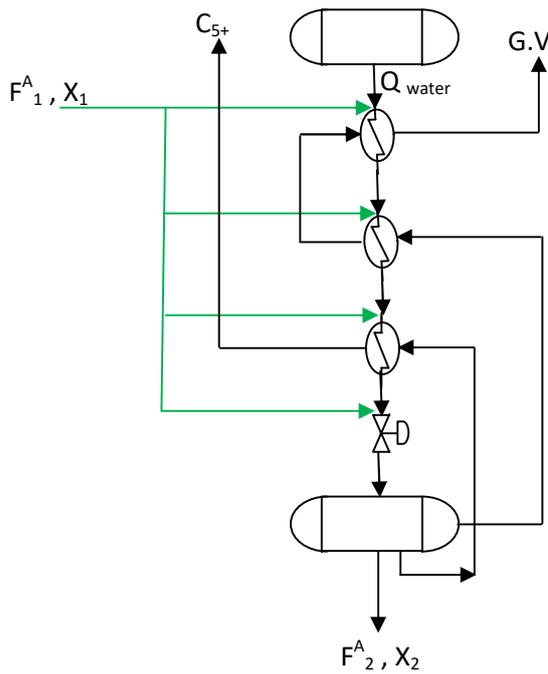


Figure VI.2. Diagram for MEG Material balance Train A

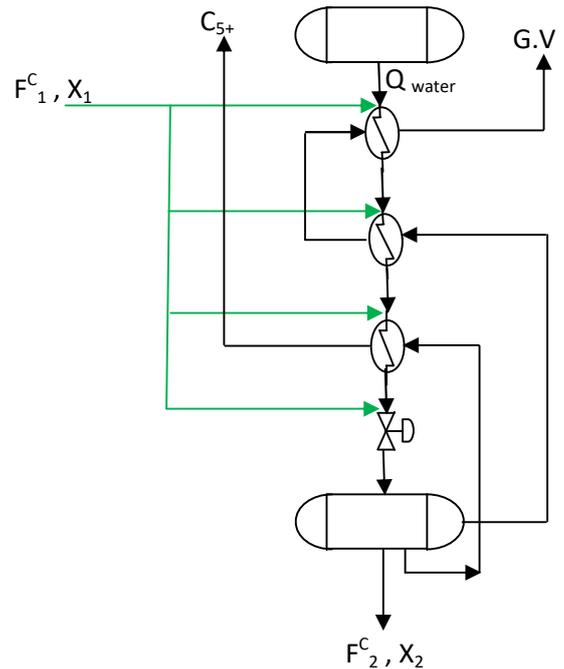


Figure VI.3. Diagram for MEG Material balance Train C

VI.4.2.MEG solution injection flow rates in train A

We have to establish a material balance.

Material balance:

$$F^A_1 + Q_{\text{water}} = F^A_2 \dots\dots\dots (1) \text{ total balance.}$$

$$F^A_1 \cdot X_1 = F^A_2 \cdot X_2 \dots\dots\dots(2) \text{ partial balance compared to the MEG solution}$$

From (1) and (2) we obtain :

$$F^A_1 = Q_{\text{Totalwater}} \cdot X_2 / (X_1 - X_2) \quad \text{Kg MEG /h}$$

$$F^A_2 = F^A_1 \cdot X_1 / X_2 \quad \text{Kg MEG}_{\text{hydr}}/\text{h}$$

Q_{water} : amount of water to absorb.

F^A_1 : the injection rate in 80% by weight MEG solution.

X_1 : mass fraction of the poor MEG solution (80%).

F^A_2 : the flow rate of the hydrated MEG solution at 73% by weight recovered with D102.

X_2 : mass fraction of the rich MEG solution (73%).

Knowing that we have:

$$F^A_1 = Q_{\text{Totalwater}} \cdot X_2 / (X_1 - X_2)$$

$$F^A_2 = F^A_1 \cdot X_1 / X_2$$

We have : $Q_{\text{Totalwater}} = 220.57 \text{ kg/h}$

$X_1 = 80\%$ in weight , $X_2 = 73\%$ in weight.

So : $F^A_1 = (220.57 \times 73) / (80 - 73) = 2300.23 \text{ kg MEG/h.}$

$F^A_1 = 2300.23 \text{ kg MEG /h}$

$$F^A_2 = F^A_1 (X_1 / X_2) = 2300.23 \times (80 / 73) = 2520.81 \text{ Kg MEG}_{\text{hyd}} / \text{h}$$

$F^A_2 = 2520.81 \text{ Kg MEG}_{\text{hyd}} / \text{h}$
--

VI.4.3. Determination of the minimum volume flow of MEG to be injected in Train A

We have :

$$F_1^A = 2300.23 \text{ kg}_{\text{MEG}}/\text{h} \quad \text{and} \quad \rho_m = ? \text{ kg}/\text{m}^3 \text{ in } 80\% \text{ in weight at } 25^\circ\text{C}$$

Determination of average density ρ_m :

$$\rho_m = 1 / \sum x_i / \rho_{m_i} = 1 / (x_1 / \rho_{\text{MEG}} + x_2 / \rho_{\text{water}})$$

$$\rho_{\text{MEG}} = 1110 \text{ kg}/\text{m}^3 \quad \text{and} \quad \rho_{\text{water}} = 998 \text{ kg}/\text{m}^3$$

$$\text{So, } \rho_m = 1 / (0.8 / 1110 + 0.2 / 998) = 1085.63 \text{ kg}/\text{m}^3$$

$$\rho_m = 1085.63 \text{ kg}/\text{m}^3$$

$$\text{So, } F_1^A = 2300.23 / 1085.63 = 2.11 \text{ m}^3_{\text{MEG}}/\text{h}$$

$$F_1^A = 2.11 \text{ m}^3_{\text{MEG}}/\text{h}$$

VI.4.4. Determination of the minimum volume flow of MEG_{hyd} to be obtained from Train A :

$$\text{We have : } F_2^A = 2520.81 \text{ kg}_{\text{MEG}}/\text{h} \quad \text{and} \quad \rho_m = 1017 \text{ kg}/\text{m}^3 \text{ in } 73\% \text{ in weight at } -6^\circ\text{C}$$

$$\text{So, } F_2^A = 2520.81 / 1017 = 2.48 \text{ m}^3_{\text{MEG}}/\text{h}$$

$$F_2^A = 2.48 \text{ m}^3_{\text{MEG}}/\text{h}$$

VI.4.5. MEG solution injection flow rates in train C

We have to establish a material balance.

Material balance:

$$F_1^C + Q_{\text{water}} = F_2^C \dots\dots\dots(1) \text{ total balance.}$$

$$F_1^C \cdot X_1 = F_2^C \cdot X_2 \dots\dots\dots (2) \text{ partial balance compared to the MEG solution}$$

From (1) and (2) we obtain :

$$F_1^C = Q_{\text{Totalwater}} \cdot X_2 / (X_1 - X_2) \quad \text{Kg MEG / h}$$

$$F_2^C = F_1^C \cdot X_1 / X_2 \quad \text{Kg MEG}_{\text{hydr}}/\text{h}$$

F_1^C : the injection rate in 80% by weight MEG solution.

F^C_2 : the flow rate of the hydrated MEG solution at 73% by weight recovered with D102.

Q_{water} : amount of water to absorb.

X_1 : mass fraction of the poor MEG solution (80%).

X_2 : mass fraction of the rich MEG solution (73%).

Knowing that we have:

$$F^C_1 = Q_{\text{Totalwater}} \cdot X_2 / (X_1 - X_2)$$

$$F^C_2 = F^C_1 \cdot X_1 / X_2$$

And $Q_{\text{Totalwater}} = 122.73 \text{ kg/h}$, $X_1 = 80\% \text{ in weight}$, $X_2 = 73\% \text{ in weight}$.

So : $F^C_1 = (122.73 \times 73) / (80 - 73) = 1279.95 \text{ kg MEG/h}$.

$$F^C_1 = 1279.95 \text{ kg MEG/h}$$

$$F^C_2 = F^C_1 (X_1 / X_2) = 1279.95 \times (80 / 73) = 1402.68 \text{ Kg MEG hyd / h}$$

$$F^C_2 = 1402.68 \text{ Kg MEG hyd / h}$$

VI.4.6. Determination of the minimum volume flow of MEG to be injected in Train C :

We have : $F^C_1 = 1279.94 \text{ kg MEG/h}$ and $\rho_m = ? \text{ kg/m}^3$ in 80% in weight at 25°C

Determination of average density ρ_m : $\rho_m = 1 / \sum x_i / \rho_m = 1 / (x_1 / \rho_{\text{MEG}} + x_2 / \rho_{\text{water}})$

$$\rho_{\text{MEG}} = 1110 \text{ kg/m}^3 \text{ and } \rho_{\text{water}} = 998 \text{ kg/m}^3$$

$$\text{So, } \rho_m = 1 / (0.8 / 1110 + 0.2 / 998) = 1085.63 \text{ kg/m}^3$$

$$\rho_m = 1085.63 \text{ kg/m}^3$$

$$\text{So, } F^C_1 = 1279.94 / 1085.63 = 1.18 \text{ m}^3_{\text{MEG}}/\text{h}$$

$$F^C_1 = 1.18 \text{ m}^3_{\text{MEG}}/\text{h}$$

VI.4.7. Determination of the minimum volume flow of MEG_{hyd} to be obtained from Train C :

We have : $F^C_2 = 1402.68 \text{ kg MEG/h}$ and $\rho_{\text{MEG}} = 1017 \text{ kg/m}^3$ in 73% in weight at -6°C

$$\text{So, } F_2^C = 1402.68 / 1017 = 1.38 \text{ m}^3_{\text{MEG}}/\text{h}$$

$$F_2^C = 1.38 \text{ m}^3_{\text{MEG}}/\text{h}$$

In this table we will summarize our main results,

Table 7. Summary of current and calculated MEG injection flow

MEG inject m ³ /h	Train A	Train C	Total
Current values	1.98	0.97	2.95
Calculated values	2.11	1.18	3.29

The total quantity of MEG currently injected into the A and C train of the HR South plant (2.95 m³/h) is lower than the calculated amount of MEG injected (3.29 m³/h), since we observe the formation of hydrates in our installation (heat exchanger bank and the J.T valve). So, clearly which necessitate according to our calculation to increase in the MEG injection rate by 0.34 m³/h which is about 11.5% of the current value to avoid hydrate formation.

VI.5. Calculation of absorption efficiency:

However, it should be noted that at the level of the separator D102, the hydrated MEG solution is recovered at a concentration in the order of 73% by weight, which gives an idea on the quantity of water actually absorbed by the MEG at 80% by weight.

The absorption efficiency:

$$R_{\text{absorption}} = (M_1/M_2) \times 100$$

M₁ : the total amount of water absorbed by MEG (train A + C)

M₂ : the total amount of water in Raw Gas (train A + C)

$$M_1 = F_1 (X_i - X_f)$$

F₁: the total quantity of poor MEG to inject in [kg/h]

X_i: the initial concentration of MEG

X_f: the final concentration of MEG

Current case :

$$\left\{ \begin{array}{l} F_1: 3202.617 \\ X_i: 0.8 \\ X_f: 0.73 \end{array} \right. \longrightarrow M_1 = 3202.617 (0.8 - 0.73) = 224.18$$

$$M_1 = 224.18 \text{ kg/h}$$

$$M_2 = (Q_{\text{gas A}} + Q_{\text{gas C}}) \times Q_{\text{H}_2\text{O}}(\text{D101})$$

$$Q_{\text{gas A}} : \text{gas flow train A [Sm}^3/\text{h]}$$

$$Q_{\text{gas C}} : \text{gas flow train C [Sm}^3/\text{h]}$$

$$Q_{\text{H}_2\text{O}}(\text{D101}) : \text{Water content in Raw Gas [kg/Sm}^3\text{]}$$

$$Q_{\text{gas A}} : 119583 \text{ Sm}^3/\text{h}$$

$$Q_{\text{gas C}} : 66541 \text{ Sm}^3/\text{h}$$

$$Q_{\text{H}_2\text{O}}(\text{D101}) : 1.911 \times 10^{-3} \text{ kg/Sm}^3$$

$$\text{So, } M_2 = (119583 + 66541) \times 1.911 \times 10^{-3} = 355.68 \text{ kg/h}$$

$$M_2 = 355.68 \text{ kg/h}$$

Now, we can calculate $R_{\text{absorption}}$

$$R_{\text{absorption}} = (M_1/M_2) \times 100 = (224.18/355.68) \times 100 = 63.03\%$$

$$R_{\text{absorption}} = 63.03\%$$

Calculated case:

$$\left\{ \begin{array}{l} F_1: 3580.188 \\ X_i: 0.8 \\ X_f: 0.73 \end{array} \right. \longrightarrow M_1 = 3580.188 (0.8 - 0.73) = 250.61$$

$$M_1 = 250.61 \text{ kg/h}$$

$$M_2 = 355.68 \text{ kg/h}$$

Now, we can calculate $R_{\text{absorption}}$

$$R_{\text{absorption}} = (M_1/M_2) \times 100 = (250.61/355.68) \times 100 = 70.46\%$$

$$R_{\text{absorption}} = 70.46\%$$

From the results of absorption efficiency in current and calculated cases. We see clearly that the value of absorption efficiency in calculated case is higher than current case, we can conclude that just with the increase of MEG injection with $0.34 \text{ m}^3/\text{h}$ which is about 11.5% of the current value, as a result the absorption efficiency increased from 63.03% to 70.46% which means more water absorbed (eliminated) from raw natural gas to avoid hydrate formation.

VI.6. Effect of upstream pressure on MEG injection rate

VI.6.1. 1st case $P = 105 \text{ kgf/cm}^2$:

VI.6.1.1. Water content of the vapors leaving the D101 separator : $Q_{\text{H}_2\text{O}}(\text{D101})$

$$\left\{ \begin{array}{l} P = 105 \text{ kgf/cm}^2 = 1493.45 \text{ psia} \\ T = 60^\circ\text{C} = 140^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart, figure II we have :

$$T = 140^\circ\text{F} \longrightarrow \left\{ \begin{array}{ll} Q_1 = 170 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_1 = 1000 \text{ psia} \\ Q_{\text{H}_2\text{O}} = ? \text{ lb}/10^6\text{ft}^3 & \longrightarrow P = 1493.45 \text{ psia} \\ Q_2 = 130 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_2 = 1500 \text{ psia} \end{array} \right.$$

We have:

$$\begin{array}{ll} \Delta Q_1 = Q_2 - Q_{\text{H}_2\text{O}} = 130 - Q_{\text{H}_2\text{O}} & \text{and} \quad \Delta P_1 = P_2 - P = 1500 - 1493.45 = 56.55 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 130 - 170 & \text{and} \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{array}$$

So we obtain :

$$\left\{ \begin{array}{ll} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -40 \times 56.55 / 500 = -4.52 \text{ lb}/10^6\text{ft}^3, \text{ so we get } Q_{\text{H}_2\text{O}} = Q_2 - \Delta Q_1 = 130 + 4.52 = 134.52$$

$$Q_{\text{H}_2\text{O}} = 134.52 \text{ lb}/10^6\text{ft}^3 = 2.01 \times 10^{-3} \text{ kg/m}^3$$

$$Q_{\text{H}_2\text{O}}(\text{D101}) = 2.01 \times 10^{-3} \text{ kg/m}^3$$

VI.6.1.2. Water content of the vapors leaving the D102 separator : $Q_{\text{H}_2\text{O}}(\text{D102})$

$$\left\{ \begin{array}{l} P = 72 \text{ kgf/cm}^2 = 1024.08 \text{ psia} \\ T = -6^\circ\text{C} = 21.2^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart , figure II we have :

$$T = 21.2^\circ\text{F} \longrightarrow \left\{ \begin{array}{ll} Q_1 = 4.5 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_1 = 1000 \text{ psia} \\ Q_{\text{H}_2\text{O}} = ? \text{ lb}/10^6\text{ft}^3 & \longrightarrow P = 1024.08 \text{ psia} \\ Q_2 = 3.2 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_2 = 1500 \text{ psia} \end{array} \right.$$

We have:

$$\begin{aligned} \Delta Q_1 = Q_2 - Q_{H_2O} = 3.2 - Q_{H_2O} \quad \text{and} \quad \Delta P_1 = P_2 - P = 1500 - 1024.08 = 475.92 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 3.2 - 4.5 \quad \text{and} \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{aligned}$$

So we obtain :

$$\left\{ \begin{array}{l} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -1.3 \times 475.92 / 500 = -1.237 \text{ lb}/10^6 \text{ft}^3 \quad \text{so we get} \quad Q_{H_2O} = Q_2 - \Delta Q_1 = 3.2 + 1.237 = 4.437$$

$$Q_{H_2O} = 4.437 \text{ lb}/10^6 \text{ft}^3 = 0.0665 \times 10^{-3} \text{ kg}/\text{m}^3$$

$$Q_{H_2O(D102)} = 0.0665 \times 10^{-3} \text{ kg}/\text{m}^3$$

VI.6.1.3 The water quantity to be eliminated at 105 kgf/cm² :

The amount of water to be removed will be calculated by the following equation:

$$Q_{\text{water}} = Q_{H_2O(D101)} - Q_{H_2O(D102)}$$

$$= 2.01 \times 10^{-3} - 0.0665 \times 10^{-3} = 1.94 \times 10^{-3}$$

$$Q_{\text{water}} = 1.94 \times 10^{-3} \text{ kg}/\text{m}^3$$

VI.6.1.4 Calculation of the total hourly water flow to be eliminated for train A and C :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas} : gas flow train A and C

$$Q_{\text{gas}} = 186.124 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 1.94 \times 10^{-3} \times 186.124 \times 10^3 = 361.08 \text{ kg}/\text{h}$$

$$Q_{\text{Total water}} = 361.08 \text{ kg}/\text{h}$$

VI.6.1.5. Determination of MEG solution injection rates in Train A and C :

We have : $Q_{\text{Total water}} = 361.08 \text{ kg}/\text{h}$

$X_1 = 80\%$ in weight , $X_2 = 73\%$ in weight.

In the same way as before : $F = Q_{\text{Totalwater}} \cdot X_2 / (X_1 - X_2)$

So : $F = (361.08 \times 73) / (80 - 73) = 3765.54 \text{ kg MEG/h.}$

$$F = 3765.54 \text{ kg MEG/h}$$

VI.6.1.6. Determination of the volume flow of MEG to be injected in Train A and C :

We have : $F = 3765.54 \text{ kg MEG/h}$ and $\rho_m = 1085.63 \text{ kg/m}^3$ in 80% in weight at 25°C

So, $F = 3765.54 / 1085.63 = 3.46 \text{ m}^3_{\text{MEG/h}}$

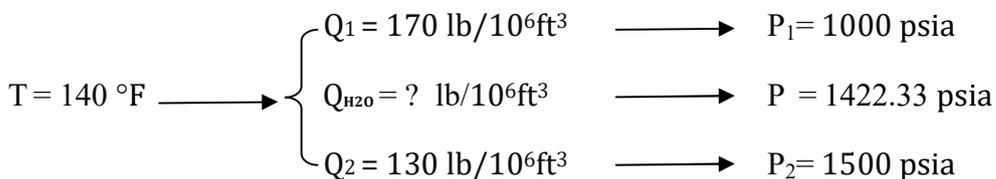
$$F_1 = 3.46 \text{ m}^3_{\text{MEG/h}}$$

VI.6.2. 2nd case $P = 100 \text{ kgf/cm}^2$:

VI.6.2.1. Water content of the vapors leaving the D101 separator : $Q_{\text{H}_2\text{O(D101)}}$

$$\left\{ \begin{array}{l} P = 100 \text{ kgf/cm}^2 = 1422.33 \text{ psi} \\ T = 60^\circ\text{C} = 140^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart, figure II we have :



We have:

$$\begin{aligned} \Delta Q_1 &= Q_2 - Q_{\text{H}_2\text{O}} = 130 - Q_{\text{H}_2\text{O}} & \text{and} & \quad \Delta P_1 = P_2 - P = 1550 - 1422.33 = 127.67 \text{ psia} \\ \Delta Q_2 &= Q_2 - Q_1 = 130 - 170 & \text{and} & \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{aligned}$$

So we obtain :

$$\left\{ \begin{array}{l} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -40 \times 127.67 / 500 = -10.21 \text{ lb}/10^6\text{ft}^3, \text{ so we get } Q_{\text{H}_2\text{O}} = Q_2 - \Delta Q_1 = 130 + 10.21 = 140.21$$

$$Q_{\text{H}_2\text{O}} = 140.21 \text{ lb}/10^6\text{ft}^3 = 2.10 \times 10^{-3} \text{ kg/m}^3$$

$$Q_{\text{H}_2\text{O(D101)}} = 2.10 \times 10^{-3} \text{ kg/m}^3$$

VI.6.2.2. The water quantity to be eliminated at 100 kgf/cm² :

The amount of water to be removed will be calculated by the following equation:

$$Q_{\text{water}} = Q_{\text{H}_2\text{O}(D101)} - Q_{\text{H}_2\text{O}(D102)}$$

$$= 2.10 \times 10^{-3} - 0.0665 \times 10^{-3} = 2.03 \times 10^{-3}$$

$$Q_{\text{water}} = 2.03 \times 10^{-3} \text{ kg/m}^3$$

VI.6.2.3. Calculation of the total hourly water flow to be eliminated for train A and C :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas} : gas flow train A and C

$$Q_{\text{gas}} = 186.124 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 2.03 \times 10^{-3} \times 186.124 \times 10^3 = 377.83 \text{ kg/h}$$

$$Q_{\text{Total water}} = 377.83 \text{ kg/h}$$

VI.6.2.4. Determination of MEG solution injection rates in Train A and C :

We have :

$$Q_{\text{Total water}} = 377.83 \text{ kg/h}$$

$$X_1 = 80\% \text{ in weight}, \quad X_2 = 73\% \text{ in weight.}$$

In the same way as before : $F = Q_{\text{Total water}} \cdot X_2 / (X_1 - X_2)$

$$\text{So : } F = (377.83 \times 73) / (80 - 73) = 3940.24 \text{ kg MEG/h.}$$

$$F = 3940.24 \text{ kg MEG/h}$$

VI.6.2.5. Determination of the volume flow of MEG to be injected in Train A and C :

We have :

$$F = 3940.24 \text{ kg MEG/h} \text{ and } \rho_m = 1085.63 \text{ kg/m}^3 \text{ in } 80\% \text{ in weight at } 25^\circ\text{C}$$

$$\text{So, } F = 3940.24 / 1085.63 = 3.62 \text{ m}^3_{\text{MEG}}/\text{h}$$

$$F_1 = 3.62 \text{ m}^3_{\text{MEG}}/\text{h}$$

VI.6.3. 3rd case : P= 95 kgf/cm² :

VI.6.3.1. Water content of the vapors leaving the D101 separator : Q_{H2O(D101)}

$$\left\{ \begin{array}{l} P= 95 \text{ kgf/cm}^2 = 1351.21 \text{ psia} \\ T= 60^\circ\text{C} = 140^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart , figure II we have :

$$T = 140^\circ\text{F} \longrightarrow \left\{ \begin{array}{ll} Q_1 = 170 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_1 = 1000 \text{ psia} \\ Q_{\text{H}_2\text{O}} = ? \text{ lb}/10^6\text{ft}^3 & \longrightarrow P = 1351.21 \text{ psia} \\ Q_2 = 130 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_2 = 1500 \text{ psia} \end{array} \right.$$

We have:

$$\begin{array}{ll} \Delta Q_1 = Q_2 - Q_{\text{H}_2\text{O}} = 130 - Q_{\text{H}_2\text{O}} & \text{and} \quad \Delta P_1 = P_2 - P = 1500 - 1351.21 = 198.79 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 130 - 170 & \text{and} \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{array}$$

So we obtain :

$$\left\{ \begin{array}{l} \Delta Q_1 \longrightarrow \Delta P_1 \\ \Delta Q_2 \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -40 \times 198.79 / 500 = -15.90 \text{ lb}/10^6\text{ft}^3, \text{ so we get } Q_{\text{H}_2\text{O}} = Q_2 - \Delta Q_1 = 130 + 15.90 = 145.90$$

$$Q_{\text{H}_2\text{O}} = 145.90 \text{ lb}/10^6\text{ft}^3 = 2.18 \times 10^{-3} \text{ kg/m}^3$$

$$Q_{\text{H}_2\text{O(D101)}} = 2.18 \times 10^{-3} \text{ kg/m}^3$$

VI.6.3.2. The water quantity to be eliminated in at 95 kgf/cm² :

The amount of water to be removed will be calculated by the following equation:

$$\begin{aligned} Q_{\text{water}} &= Q_{\text{H}_2\text{O(D101)}} - Q_{\text{H}_2\text{O(D102)}} \\ &= 2.18 \times 10^{-3} - 0.0665 \times 10^{-3} = 2.20 \times 10^{-3} \end{aligned}$$

$$Q_{\text{water}} = 2.11 \times 10^{-3} \text{ kg/m}^3$$

VI.6.3.3. Calculation of the total hourly water flow to be eliminated for train A and C :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas} : gas flow train A and C

$$Q_{\text{gas}} = 186.124 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 2.11 \times 10^{-3} \times 186.124 \times 10^3 = 392.72 \text{ kg/h}$$

$Q_{\text{Total water}} = 392.72 \text{ kg/h}$
--

VI.6.3.4. Determination of MEG solution injection rates in Train A and C :

We have : $Q_{\text{Total water}} = 392.72 \text{ kg/h}$

$X_1 = 80\%$ in weight , $X_2 = 73\%$ in weight.

In the same way as before :

$$F = Q_{\text{Total water}} \cdot X_2 / (X_1 - X_2)$$

So : $F = (392.72 \times 73) / (80 - 73) = 4095.50 \text{ kg MEG/h}$.

$F = 4095.50 \text{ kg MEG/h}$
--

VI.6.3.5. Determination of the volume flow of MEG to be injected in Train A and C :

We have :

$F = 4095.50 \text{ kg MEG/h}$ and $\rho_m = 1085.63 \text{ kg/m}^3$ in 80% in weight at 25°C

So, $F = 4095.50 / 1085.63 = 3.77 \text{ m}^3_{\text{MEG/h}}$

$F_1 = 3.77 \text{ m}^3_{\text{MEG/h}}$

VI.6.4. 4th case : P= 90 kgf/cm² :**VI.6.4.1. Water content of the vapors leaving the D101 separator : Q_{H2O(D101)}**

$$\left\{ \begin{array}{l} P= 90 \text{ kgf/cm}^2 = 1280.10 \text{ psia} \\ T= 60^\circ\text{C} = 140^\circ\text{F} \end{array} \right.$$

Based on Mc KETTA and WEHE chart , figure II we have :

$$T = 140^\circ\text{F} \longrightarrow \left\{ \begin{array}{ll} Q_1 = 170 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_1 = 1000 \text{ psia} \\ Q_{\text{H}_2\text{O}} = ? \text{ lb}/10^6\text{ft}^3 & \longrightarrow P = 1280.10 \text{ psia} \\ Q_2 = 130 \text{ lb}/10^6\text{ft}^3 & \longrightarrow P_2 = 1500 \text{ psia} \end{array} \right.$$

We have:

$$\begin{array}{ll} \Delta Q_1 = Q_2 - Q_{\text{H}_2\text{O}} = 130 - Q_{\text{H}_2\text{O}} & \text{and} \quad \Delta P_1 = P_2 - P = 1500 - 1280.10 = 269.9 \text{ psia} \\ \Delta Q_2 = Q_2 - Q_1 = 130 - 170 & \text{and} \quad \Delta P_2 = P_2 - P_1 = 1500 - 1000 = 500 \text{ psia} \end{array}$$

So we obtain :

$$\left\{ \begin{array}{ll} \Delta Q_1 & \longrightarrow \Delta P_1 \\ \Delta Q_2 & \longrightarrow \Delta P_2 \end{array} \right. \longrightarrow \Delta Q_1 \times \Delta P_2 = \Delta Q_2 \times \Delta P_1 \longrightarrow \Delta Q_1 = \Delta Q_2 \times \Delta P_1 / \Delta P_2$$

$$\Delta Q_1 = -40 \times 269.9 / 500 = -21.6 \text{ lb}/10^6\text{ft}^3, \text{ so we get } Q_{\text{H}_2\text{O}} = Q_2 - \Delta Q_1 = 130 + 21.6 = 151.6$$

$$Q_{\text{H}_2\text{O}} = 151.6 \text{ lb}/10^6\text{ft}^3 = 2.27 \times 10^{-3} \text{ kg/m}^3$$

$$Q_{\text{H}_2\text{O(D101)}} = 2.27 \times 10^{-3} \text{ kg/m}^3$$

VI.6.4.2. The water quantity to be eliminated in at 90 kgf/cm² :

The amount of water to be removed will be calculated by the following equation:

$$\begin{aligned} Q_{\text{water}} &= Q_{\text{H}_2\text{O(D101)}} - Q_{\text{H}_2\text{O(D102)}} \\ &= 2.27 \times 10^{-3} - 0.0665 \times 10^{-3} = 2.20 \times 10^{-3} \end{aligned}$$

$$Q_{\text{water}} = 2.20 \times 10^{-3} \text{ kg/m}^3$$

VI.6.4.3. Calculation of the total hourly water flow to be eliminated for train A and C :

$$Q_{\text{Total water}} = Q_{\text{water}} \times Q_{\text{gas}}$$

$Q_{\text{Total water}}$: total hourly water flow to be eliminated.

Q_{gas} : gas flow train A and C

$$Q_{\text{gas}} = 186.124 \times 10^3 \text{ m}^3/\text{h}$$

$$Q_{\text{Total water}} = 2.20 \times 10^{-3} \times 186.124 \times 10^3 = 409.47 \text{ kg/h}$$

$Q_{\text{Total water}} = 409.47 \text{ kg/h}$
--

VI.6.4.4. Determination of MEG solution injection rates in Train A and C :

We have :

$$Q_{\text{Total water}} = 409.47 \text{ kg/h}$$

$$X_1 = 80\% \text{ in weight} \quad , \quad X_2 = 73\% \text{ in weight.}$$

In the same way as before :

$$F = Q_{\text{Total water}} \cdot X_2 / (X_1 - X_2)$$

$$\text{So : } F = (409.47 \times 73) / (80 - 73) = 4270.18 \text{ kg MEG/h.}$$

$F = 4270.18 \text{ kg MEG/h}$
--

VI.6.4.5. Determination of the volume flow of MEG to be injected in Train A and C :

We have :

$$F = 4270.18 \text{ kg MEG/h} \quad \text{and} \quad \rho_m = 1085.63 \text{ kg/m}^3 \quad \text{in } 80\% \text{ in weight at } 25^\circ\text{C}$$

$$\text{So, } F = 4270.18 / 1085.63 = 3.93 \text{ m}^3_{\text{MEG}}/\text{h}$$

$F_1 = 3.93 \text{ m}^3_{\text{MEG}}/\text{h}$
--

We can summarize our results of upstream pressure on MEG injection flow rate in the following table, for a fixed temperature $T = 60^{\circ}\text{C}$, the variation in injection flow rate as a function of the pressure was calculated, the following results are obtained:

Table 8. Effect of upstream pressure on MEG injection flow rate

Pression in kg/cm^2	109	105	100	95	90
volume flow of MEG to be injected m^3/h	3.30	3.46	3.62	3.77	3.93

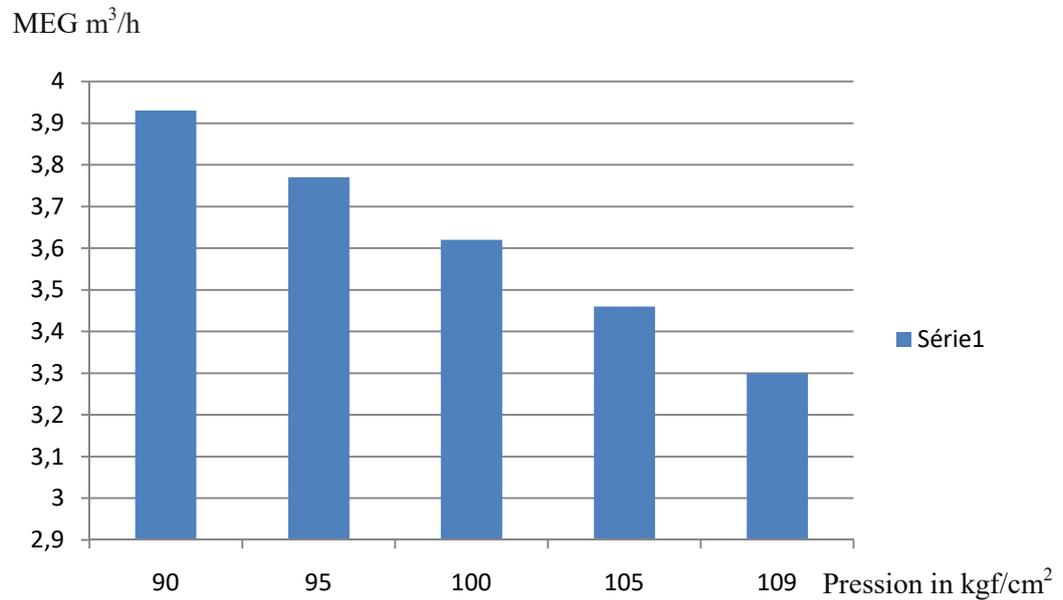


Figure VI.4. Variation of MEG injection flow rate as a function of pressure

For a fixed temperature $T = 60^{\circ}\text{C}$, we calculated the variation of injection flow as a function of the pressure, we noticed that the flow of MEG injected increases with the pressure drop because the quantity of water increases with the decrease of raw natural gas pressure.

Conclusion :

The presence of water in natural gas can cause several problems, among them the formation of hydrates under certain temperature and pressure conditions which can damage process installations and lead to poor specification sales gas, hence its elimination is required using appropriate techniques such as absorption through MEG injection.

Dehydration is carried out by injection of MEG, this injection will take place at any hydrate formation points and it mainly depends on: The nature of the natural gas in the injection point, the temperature and pressure conditions of the natural gas and the concentration of MEG injected and recovered.

The quantity of MEG currently injected into the HR South plant is lower than the calculated amount of MEG injected, for this sometimes, we have hydrate formation in our installation so, a slight increase in MEG injection from $2.95\text{m}^3/\text{h}$ to $3.29\text{m}^3/\text{h}$ is suggested to avoid hydrate formation and to have a good sales natural gas specification, add to this under the new flow of hydrated MEG our regeneration MEG unit will function properly.

Over time, we have the drop in reservoir pressure which implies an increase in the quantity of water entrained with the natural gas, therefore an increase in the amount of glycol that will be injected, this is verified by the calculation method that we had followed.

Dehydration of natural gas by glycol is an efficient process, its advantage lies mainly in the ease of regeneration of the glycol and the large amount of water that can be absorbed, but we have to use a sufficient amount of MEG in our process.

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