Natural Gas Dehydration Optimization

by

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Dissertation submitted in partial fulfillment of
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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
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Approved by,

(Dr Usama Mohamed Nour El Demerdash)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOHD FAHDI BIN MOHD GHAZALI

ABSTRACT

Natural Gas is a vital component of the world's supply of energy. It is one of the cleanest, safest, and most useful of all energy sources. Under normal production conditions, it saturated with water vapor. Water vapor increases natural gas corrosivity especially when acid gases are present. This report discusses the research done and basic understanding of the chosen topic, which is natural gas dehydration optimization. The objectives of this project are to do the comparison between different types of Natural Gas dehydration technology on the basis of efficiency and capacity and to do the simulation to optimize operating condition of gas dehydration technology. The current technologies used to dehydrating gas have some weaknesses in term of efficiency, capacity, cost effectiveness and are harmful to environment. As for this study, gas dehydration using solid desiccant is being considered. It is a common technology used widely in the world especially in oil and gas industries. In order to optimize this technology, a simulation model base on the actual dehydration unit in the liquefied natural gas (LNG) plant is used. The optimization is base on manipulating temperature and pressure to see the effect to the adsorption capacity and later, from the manipulated pressure, the hydrate formation temperature can be predicted. From this, the optimum temperature and pressure of operating the dehydration unit can be known. Furthermore, a study of increasing the moisture removal by adding pre-dehydration unit is also discussed in this study.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

Natural Gas is a vital component of the world's supply of energy. It is one of the cleanest, safest, and most useful of all energy sources. Unlike other fossil fuels, natural gas is clean burning and emits lower levels of potentially harmful byproducts into the air.

Table 1.1 : Typical natural gas composition

Components	IUPAC	Percentage (mol %)
Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	0-20%
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Natural gas under normal condition is saturated with water vapour. The gas usually contains water, in liquid and/or vapour form as source and/or as a result if sweetening with an aqueous solution. It is necessary to reduce and control the water content of gas to ensure safe processing and transmission. The major reasons for removing the water from the natural gas are as follow:

1. Natural gas in the right conditions can combine with liquid or free water to form solid hydrates that can plug valves fittings or even pipelines.
2. Water can condense in the pipelines, causing slug flow and possible erosion and corrosion.
3. Water vapour increases the volume and decreases the heating value of the gas
4. Sales gas contracts and/or pipeline specification often have to meet the maximum water content of 7 lb H_2O per MMscf.
5. It can cause erratic operation of gas burners.

There are several methods of dehydrating natural gas. Until today, the most popular dehydration technology remains absorption with liquid desiccant, solid desiccant and the latest technology is by using membrane. However, in a typical gas drying and solution regeneration system, some of the problems can arise such as pump failures, leaks, maintaining regeneration temperatures, flooding of the dehydrators, inefficient glycol compositions, plugged trays, and these existence technologies are also need high capital investment and perhaps need more experts to operate it. Due to these, a more environmentally acceptable gas drying medium and process is needed and the water absorption medium should be efficient and readily regenerable with a minimum of maintenance. Thus, for this present study, solid desiccant is chosen to be optimized.

1.2 PROBLEM STATEMENT

1.2.1 Problem Identification

Liquefied natural gas or LNG plant need to be operated at low water content. Due to this, dehydration unit is very essential in removing the water composition. Among the different gas drying processes, absorption is the most common technique where water vapour in the gas stream becomes absorbed in a liquid solvent stream. Glycols are the most widely used absorption liquid as they approximate the properties that meet commercial application criteria. In this process, glycols absorb water vapour from the gas stream. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. However, this technology has certain disadvantages:

1. Water dew points below -25°F require stripping gas
2. Glycol is susceptible to contamination
3. Glycol is corrosive when contaminated or decomposed.
4. Loss of methane
5. Foaming
6. Burping
7. Frequent pump failure

Meanwhile, solid desiccant dehydration system works on the principle of adsorption. Wet natural gas is passed through towers, from top to bottom. Water is retained on the surface of desiccant particles as the gas passes and almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower. Somehow, the technology appears to have disadvantages such as;

1. Higher capital cost and higher pressure drop
2. Desiccant poisoning by heavy hydrocarbons, H_2S, CO_2
3. Mechanical breaking of desiccant particles
4. High generation heat requirement and high utility cost

1.2.2 Significant of the project

Using conventional drying process, it can contribute to too many problems such as problem to the environment. Due to this reason, study need to be carried out in order to identified the root cause of the problems and in the same time to optimize the performance of the current gas dehydration technique so that it can be more reliable and most important safe for the environment.

Literature shown by using solid desiccant is seems better compare to liquid desiccant in many ways especially in term of environmental acceptance and it can give lower dew point over a wide range of operating condition. Although involve larger cost to install the dehydration unit using this method, it is still the best way to remove hydrates in the natural gas. Thus for this research, it will study on how to optimize operating condition for gas dehydration technology using solid desiccant.

1.3 OBJECTIVE AND SCOPE OF STUDY

The objectives of this study are:

1. To do a comparison between different types of Natural Gas dehydration technology on the basis of efficiency and capacity
2. To do simulation to optimize operating condition for gas dehydration technology

CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

Moisture is one of the impurities and contaminated present in natural gas. Even though the concentration of the moisture is natural gas is traceable and very low, it is able to provide a higher effect to the pipelines specification and it lowers the quality of natural gas. Thus, the natural gas must be upgraded by removing the moisture and other impurities content, by going through the purification process.

The present of moisture can detract from the heating value and properties of natural gas that directly will lower the quality of natural gas. The hydration of natural gas is concern as for preventing the hydrated formation. The hydrates formation is the crystallization of the reaction between free water vapour and any hydrocarbon that smaller than normal butane. Gas dehydration also important consideration especially in gas streams containing CO_2 or H_2S where the acid gas components will form an acid with the condensed water.

Different techniques can be applied for gas dehydration but the most common and current used in industry today are absorption by using liquid desiccants and adsorption by solid desiccant.

2.2 HYDRATE FORMATION CONDITION

The first step in evaluating and/or designing a gas dehydration system is to determine the water content of the gas and the conditions that promote hydrate formation. It is a pre requirement that need to be understood in order to design and optimize the natural gas dehydration.

There are three conditions that will contribute to the formation of hydrates from the natural gas and it can be divided into three main categories, present of free water and natural gas components, temperature and pressure.

1. *In order to form hydrates, free water and natural gas components need to be* present. Gas molecules ranging from methane to butane are typical hydrates components including CO_2,N_2, and H_2S. The water in the hydrates can come from free water produces from the reservoir or water condensed by cooling the hydrocarbon fluid. [9]

2. Low temperature operates at the plant or inside the pipeline also will contribute to the formation of hydrates. Although hydrate is 85% mol water, the system does not need to be 0°C to form ice. Offshore however, below approximately 3000ft of water depth, the ocean bottom temperature is remarkably uniform at 3 °C -4°Cand pipelined gas has already cooled to this temperature within a few miles from the well head.

3. High pressure will lead to formation of hydrates. At 3 °C, natural gas form hydrates at pressure as low as 100psig and at 19 °C, hydrate form at 1500psig. [9]

2.2.1 Water specification

The hydrate composition contents of 6 volumes of methane molecules to 1 molecules of moisture. To be more specific, a typical water specification is 112mg of water per standard m^3 of gas (7 lb/mmscf) in many jurisdiction in the United States and 64mg/Sm3 (4 lb/mmscf) in many jurisdiction in Canada. In other jurisdictions, other specifications are employed. [1] It is also common to refer to the water content of a gas in term of water dewpoint, the dewpoint being the temperature at which the water just begins to condense. Thus another common specification is a -10°C (14°F) water dewpoint. However this method must be used with some caution because dewpoints at temperatures below 0°C (32°F) represent a metastable condition. At temperature below 0°C, a true liquid dewpoint does not exist because the stable form of water at this temperature is a solid phase, either ice or hydrate. [1]

A study done by Durham, 1999 analyzed that the natural gas pipelines with moisture content 7 lbs/mmscf , when compressed to 3600psig, it has a dew point of 52 °F /11°C, and when compressed natural gas is subjected to temperatures below the 52 °F /11°C, the moisture begins to condense. If the temperature falls below 32 °F /0°C, the moisture will freeze and form crystal [2]

2.2.2 Hydrate formation prediction

The first problem when dealing with gas processing plant and dehydration unit is to predict the condition of temperature and pressure at which hydrates will form [1]. In general, there are computerized method and also hand calculation using an appropriate hydrate prediction correlation.

Two methods are commonly employed for rapidly estimating the ordinations at which the hydrate will form. Both are contributed to Katz and co-worker [1]. The methods are gas gravity method and K-Factor method.

2.2.2.1 Gas gravity method

This gas gravity method which had been developed by Professor Katz and co-workers in 1940s is a simple yet can give good prediction on the hydrate formation in the natural gas with respect to pressure and temperature condition. It involve only a single chart with pressure, temperature plot and specific gravity of the gas as a third parameters. The chart is developed in two type, one is in SI unit and another one is using American Engineering Unit.

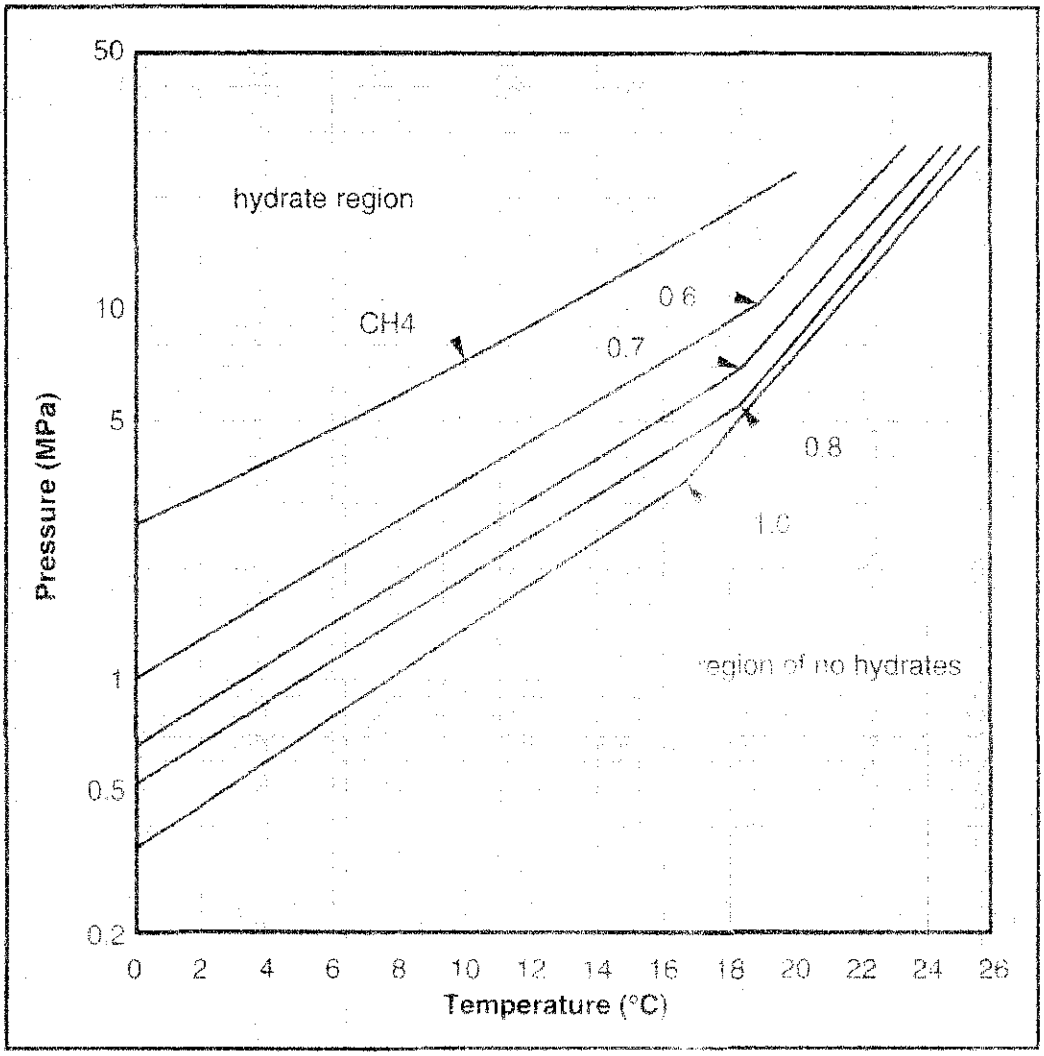

Figure 2.1 : Hydrate locus for sweet natural gas using gas gravity method (SI Unit) [1]

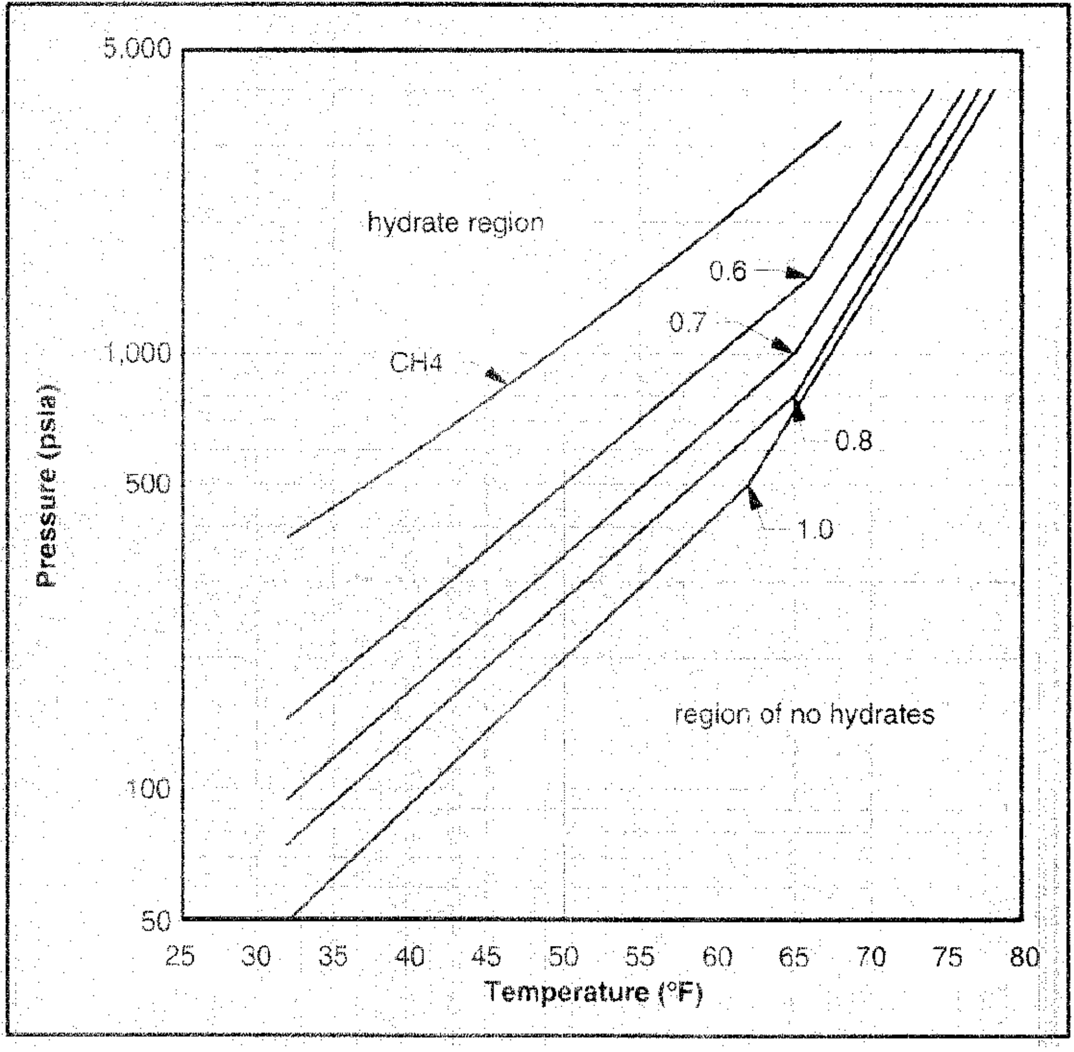

Figure 2.2: Hydrate locus for sweet natural gas using the gas gravity method (American Unit)[1]

To use the chart, specific gravity or relative density of the gas needs to be known. If the molar mass of the gas, M, the gas gravity γ can be calculated using this formula:

$$\gamma = \frac{M}{28.966} \quad (2.1)$$

Where;

28.966 is the standard molar mass of air.

M = molecular weight

It is a very simple-to-use chart in order to predict the hydrate formation. The first method is to predict whether the hydrate will form or not with availability of temperature, pressure and gas gravity. It is simple as if the point plot of the graph is left and above the appropriate gravity curve, then it is a hydrate forming region. If the plot is at right and below, the hydrate will not formed.

Another method is to find at which temperature or pressure will hydrate form base on the temperature/pressure condition. For example, if people want to know at what temperature a hydrate will form, just simply enter the chart on x-axis at the specific temperature. Go up until reaching appropriate gas gravity curve. At this point, interpolation is needed. Next, go left and read the temperature on y-axis.

2.2.2.2 K-Factor method

The second method is named with K-factor method. It is developed by Katz (gas gravity method) with Carson in 1942. The K-factor method is defined as the distribution of the component between hydrate and the gas:

$$K = \frac{yi}{si} \quad (2.2)$$

Where;

y_i = mole fraction of component i in vapour

s_i = mole fraction of component i in hydrate

Charts are available for each of components commonly encountered in natural gas that is a hydrate former: methane, ethane, propane, isobutene, n butane, hydrogen sulphide and carbon dioxide [1]. Version of these chart are available in the appendix.

This K-Factor chart usually used in three methods [1]:

1. Given the temperature and pressure, calculate the composition of the coexisting phases
2. Given the temperature, calculate the pressure at which the hydrate will forms and the composition of the hydrate
3. Given the pressure, calculate the temperature at which the hydrate forms and the composition of the hydrate.

2.2.2.2.1 Flash calculation

Flash calculation is basically the first calculation. The objective of this calculation is to calculate the amount of phases present in equilibrium mixture and to determine the composition of the coexisting phases. The temperature, pressure and composition are the input parameters. The objective function to be solve in the Rachford-Rice form is; [1]

$$f(V) = \sum \frac{Zi\,(1-Ki)}{1+V\,(Ki-1)} \quad (2.3)$$

where Zi is the composition of the feed on a water free basis. An iterative procedure is used to solve for vapour phase fraction, V, such that the function equals zero.

Once the phase fraction is calculated, the vapour phase composition can be calculated as follows:

$$Yi = \frac{ZiKi}{1+V\,(Ki-1)} \quad (2.4)$$

The composition of solid is calculated from:

$$K = \frac{yi}{Ki} \quad (2.5)$$

2.2.2.2.2 Incipient solid formation

The purpose of this calculation is to know the exact temperature and composition, at which pressure will hydrate formed.

The objective functions are:

$$f_1(T) = 1 - \sum yi/ Ki \ (2.6)$$

$$f_2(P) = 1 - \sum yi/Ki \ (2.7)$$

2.2.2.2.3 Liquid hydrocarbon

The K-Factor method is design for calculations involving a gas and a hydrate. In order to extend this method to liquid hydrocarbons, the vapour-liquid K-factor should be incorporated. For the purposes of this book, these K-factors will be denoted Kv to distinguish from the K-factor defined earlier. [1] Therefore;

$$Kvi = \frac{yi}{Xi} \ (2.8)$$

Where the Xi is the mole fraction of component i in the nonaqueous liquid.

If the there are present of gas, hydrate and nonaqueous liquid, the following equation should be solved to find the phase fraction, L and V:

$$f_1(V,L) = \sum \frac{Zi\ (1-Kvi)}{L(1-V)+(1-V)(1-L)\left(\frac{Kvi}{Ki}\right)+VKvi} \ (2.9)$$

$$f_2(V,L) = \sum \frac{Zi\ (1-\frac{Kvi}{Ki})}{L(1-V)+(1-V)(1-L)\left(\frac{Kvi}{Ki}\right)+VKvi} \ (2.10)$$

The equilibria involving a hydrate and a nonaqueous liquid, the K-factors are as follows:

$$K_{Li} = \frac{Kvi}{Ki} = \frac{Si}{Xi} \ (2.11)$$

For solid incipient formation point determination, this function need to be satisfied:

$$\sum \frac{Kvi\ Xi}{Ki} = 1 \ (2.12)$$

2.3 COMMON GAS DEHYDRATION TECHNOLOGY

2.3.1 Glycol dehydration

Absorption dehydration involves the use of a liquid desiccant to remove water vapor from the gas and the most common organic used is known as Glycol. In this process, a liquid desiccant dehydrator serves to absorb water vapour from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will absorb the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG) or triethylene glycol (TEG). Triethylene glycol (TEG) is by far the most used in natural gas dehydration. It exhibit most of the desirable characteristic listed earlier and has other advantages compared to other glycols. Comparisons of glycols are as follows:

Table 2.1 : Glycol types comparison

	MEG	DEG	TEG	TREG
Cost	1	2	3	4
Vapor pressure	4	3	2	1
Losses	4	3	2	1
Affinity to water	4	3	2	1
Viscosity	1	2	3	4

(Note: 4= highest, 3 = higher, 2 = high, 1= low)

By referring to the chart above, by comparison, MEG is marginally lower cost than other glycol types. However, it has high vapour pressure and because of that, it has larger losses. For affinity to water, TEG has less affinity to water and thus has less dew point depression. TREG is seen the best option but the price is considered too high and the viscosity of this type of glycol is high. High viscosity translates into higher pumping costs.

2.3.1.1 Glycol dehydration process description

As for the process involve, the glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it be reused in the dehydration process.

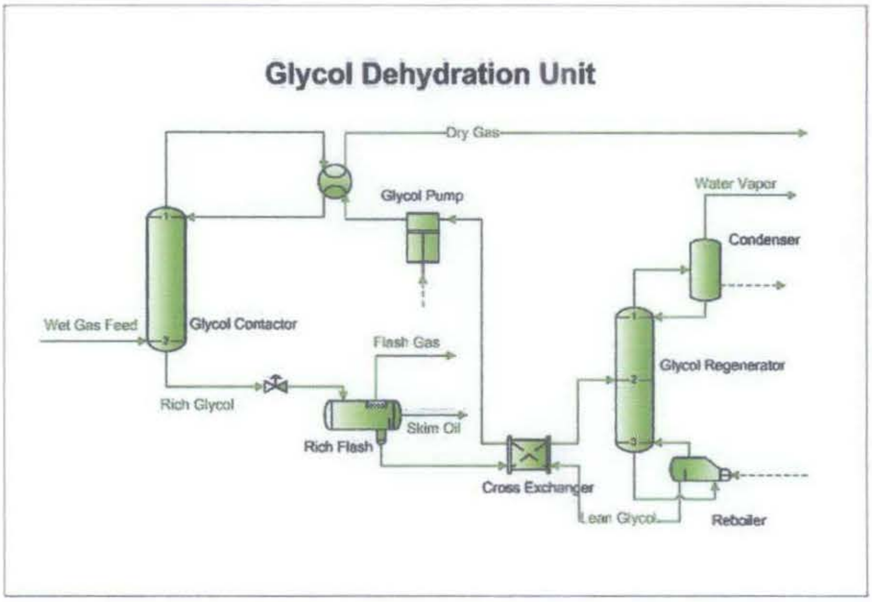

Figure 2.3 : Typical flow diagram for glycol dehydration unit

2.3.1.2 Problems encountered in a glycol plant

Glycol dehydration plant always encounter frequent problem and these problems are common when operating this type of dehydration. Among of the problems are:

Table 2.2: Glycol dehydration problems

Types of problem	Description
Foaming	Glycol is fairly viscous liquid and will foam readily if a small quantity of liquid hydrocarbon or dirt is in the solution. Foaming usually occurs in the contractor. It is characterized by an abnormally high glycol lost, which result in a reduction in level in the glycol surge tank. In some dehydration plant foaming is a problem even though the glycol solution is appears clean, and there is no apparent entry of liquid hydrocarbon into the contractor with the inlet gas stream. In this situation, a foam inhibitor is often added to the glycol stream to prevent foaming.
Burping	Burping or puking is usually a problem in the stripper. It is usually caused from a sludge or liquid hydrocarbon entering the stripper . The hydrocarbon will flow down the stripper as a liquid and when they reach the reboiler, they will vaporized almost instantaneously. The vapors flow up the stripper with sufficient velocity to carry out most of the liquid in the tower. The level in the surge tank will drop. Liquid hydrocarbons should be removed from the rich glycol in the flash tank or a similar vessel.
Corrosion	When the inlet gas contained hydrogen sulphide, H2S or carbon dioxide, the glycol solution will absorb some of these gases and become corrosive. Scale or other corrosion product will form which will contaminate the system. Frequent filter element change out is required to keep the glycol clean. When the corrosive gases (H2S and CO2) are absorb in the glycol, the liquid become acidic. It is confirmed by measuring the pH of the solution. A PH of 7 is neutral and pH of 6to 8 is usually not corrosive. Corrosion will

	only occur if the pH falls below 6. The quantity of amine which is be added to prevent corrosion will depend upon the concentration of H2S and CO2 in the inlet gas and the operating temperature and pressure of the contractor. A typical plant require weekly additional of one litre of amine for each 1000liter of glycol contained in the system.
High moisture content of outlet gas	High moisture content is almost due to a low flow rate of a low concentration. Failure of the glycol pump is a frequent cause of low flow. Low concentration results from low temperature in the stripper reboiler or low stripping fluid rate.
Frequent pump failure	Pump failure usually happen when pumps have a number of small passageways. This passageway can be restricted if the lean glycol or drive fluid contained solid particles. Also, the temperature of lean glycol entering the pump is usually about 95°C. If the temperature rise above 105 °C, it can cause pump problems due to thermal expansion at higher temperature.
Concentrated glycol	High concentrated glycol solution tent to become viscous at low temperature and therefore re hard to pump. Glycol lines may solidify completely at low temperature when the plant is not operating.
Environmental problems	There are substantial environmental problems due to fugitive emission, soil contamination and fluid disposal problems.

2.3.2 Membrane technology

Membrane technology promises lower methane and hydrocarbon losses, lower emissions, lower energy consumption, and reduced maintenance costs from the use of fewer components. In addition membrane dehydration does not produce spent wastes such as glycol. [5]

A membrane is a layer of material which serves as a selective barrier between two phases and remains impermeable to specific particles, molecules, or substances when exposed to the action of a driving force. Some components are allowed passage by the membrane into a permeate stream, whereas others are retained by it and accumulate in the retentate stream.

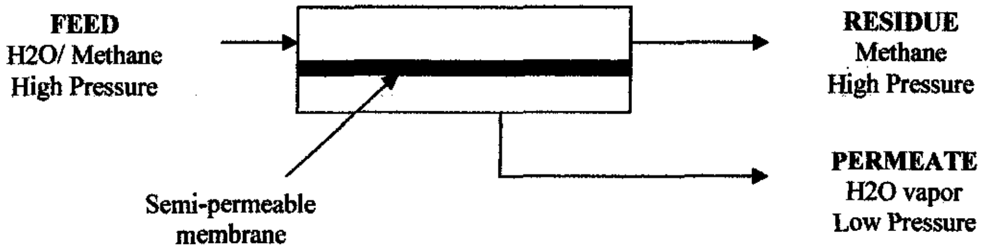

Figure 2.4 : Schematic of a membrane-based separation of dehydration

Base on figure 2, the feed mixture consist of mixture of natural gas and moisture is later being separate into residue (methane) and permeate (H_2O vapour). The method used in this process is by using single stage membrane where it is a concentration driven process. It is directly related to the partial pressure of the gas species and differential pressure between the feed and product stream.

At the incoming stream, the feed is compress at high pressure to create driving force for the separation so that, the Natural Gas (methane) can be separated from moisture. As for the membrane, it is more permeable to the water vapour thus the moisture permeate to the low pressure permeate side, due to the size of the water molecules is smaller than methane. The remaining stream is enriched in methane and exits as the high pressure residue stream.

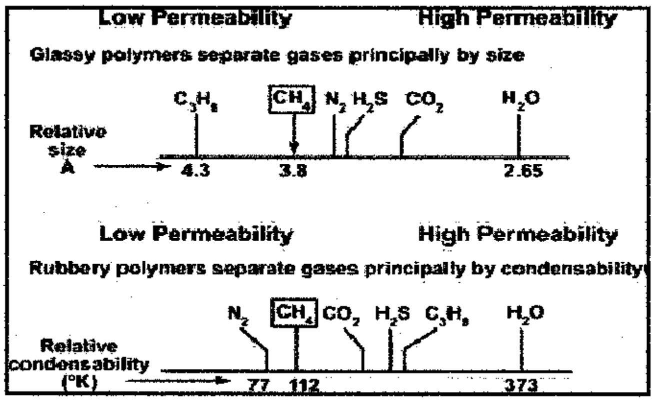

Figure 2. 5: The relative size (kinetic diameter) and condensability (boiling point) of the principle component of natural gas.

Membrane separation processes require large membrane areas, which are generally expressed in thousands of square meters. The membrane surface is dependent on the amount of gas permeating through it. Compact permeation modules with a high membrane area are therefore needed (Rojey A. et. al., 1997). The most widely used idustrial modules belong to two types are (Figure 2.3):

1. Modules with plane membranes wound spirally around a collector tube
2. Modules with a bundle of hollow fibers

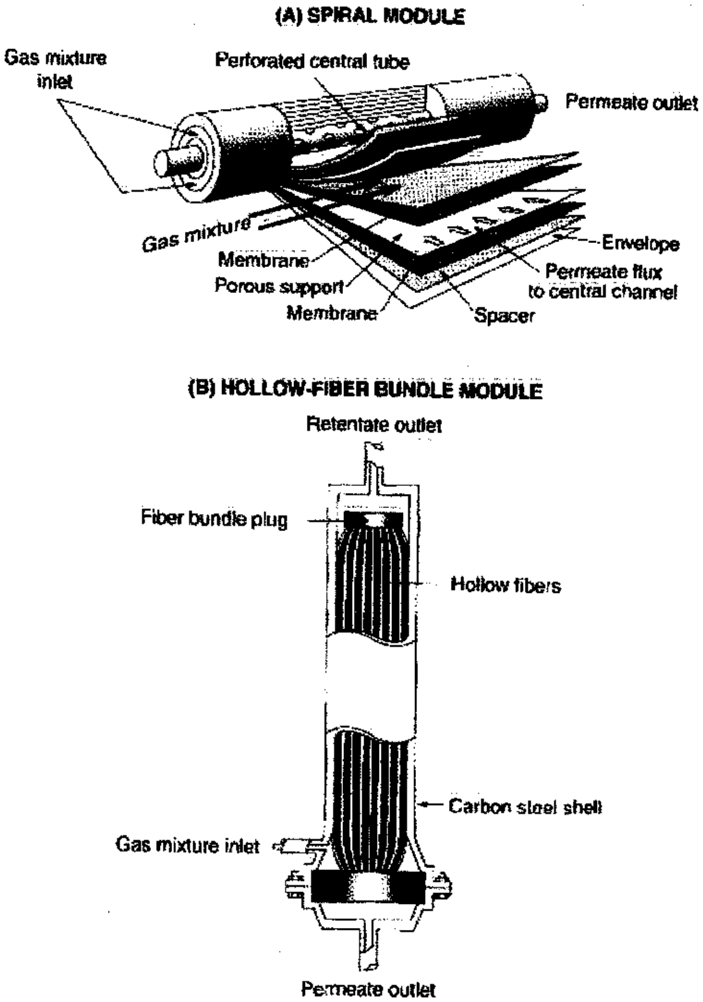

Figure 2.6: Gas Permeation Modules

2.3.2.1 Membrane separation problems

The dehydration of natural gas which is very common natural gas treatment process has proven disappointing for membrane technology. A handful of systems that are based on membranes and process designed developed for air dehydration have been installed. However, current membrane technology cannot compete with glycol and solid desiccant except in few offshore operations where size and weight considerations favour membrane solution. Therefore, the dehydration of natural gas using membranes is likely to remain niche application.

2.4 SOLID DESICCANT DEHYDRATION

As dehydration using solid desiccant will be the main focus of this study, the author will describe in detailed of this type of gas dehydration. The intention is to give more understanding and information regarding this solid desiccant dehydration before any work of optimization can be done.

2.4.1 Introduction of solid desiccant dehydration

The general term for sorption is selective transfer to insoluble rigid particles. One or more components of gas or liquid stream are adsorbed on the surface of a solid adsorbent and separation occurs. In adsorption technology, there are two different approaches on how the adsorbent (the material that need to be removed) is attached to the absorbent (small particles in fixed that will adsorb the adsorbate); Physical adsorption and chemisorptions. Physical adsorption is the adsorptions process accordingly to the van the waals bonding. The intermolecular forces between molecules of a solid (adsorbent) and the gas (adsorbante) are greater than those between molecules (adsorbate) itself. Chemisorption attached is base on the activated carbon where the separation occurred caused by the formation of chemical bonds between adsorbate and adsorbent.Adsorption is purely a surface phenomenon. The degree of adsorption is a function of operating temperature and pressure; adsorption increases with pressure increase and decreases with temperature increase. [7]

Natural gas dehydration using solid desiccants has several advantages over liquid desiccant dehydration system;

1. Lower dew point can be obtained over a wide range of operating condition using solid desiccant dehydrator
2. Dehydration of very small quantities of natural gas at low cost can be achieved and the unit is insensitive to moderate changes in the gas temperature, flow rate and pressure.
3. They are relatively free from problems such as corrosion and foaming [7]

2.4.2 Water adsorption mechanism

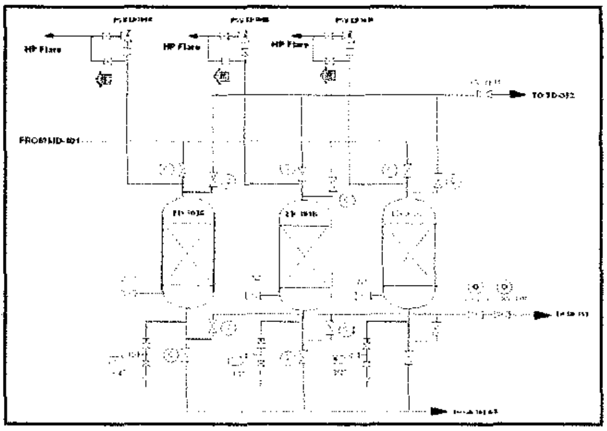

Figure 2.7: Schematic of a solid desiccant gas dehydration system

The schematic flow of solid desiccant is shown in figure 4. During adsorption process, the rich gas will be passed through absorbent bed which selectively retrains the water. When the bed is saturated, it will be regenerated by using hot gas. In this case, hot gas will be passed through the column of solid desiccant. After heating and before the adsorption step, the bed must be cooled. This is achieved by passing through cold gas. In real practise, two to four beds are needed and this cyclic operation to dry gas are on a continuous basis.

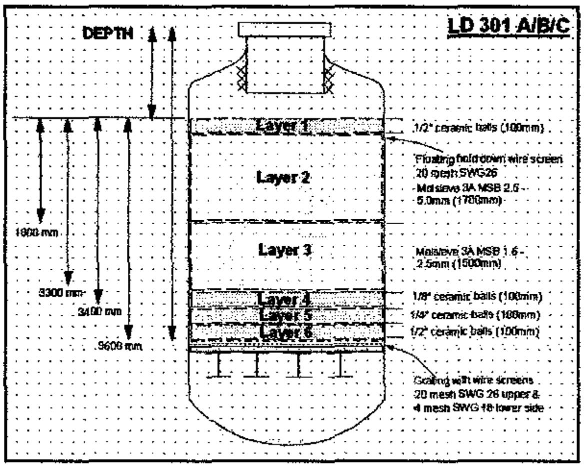

Figure 2.8: Schematic diagram of PETRONAS Gas Berhad (GPPA) gas dehydration column.

2.4.3 Properties of solid desiccant

The selection of adsorbent is depending on what type of separation takes place and mostly the criteria of adsorbent are based on;

1. High selectivity to enable sharp separations
2. Large surface area for high capacity and high mass transfer
3. High bulk density and activity for the components to be removed
4. Small resistance to gas flow through the desiccant bed
5. Favourable kinetic and transport properties for rapid sorption
6. Chemical and thermal stability to preserve the amount and its properties
7. Hardness and mechanical strength – to resist crushing and dust formation
8. High fouling resistance
9. Capability of being regenerated easily at relatively low cost
10. The adsorbent must be fairly cheap, non-corrosive, non-toxic and chemically inert.

In addition to the previous criteria of adsorbent selection for natural gas dehydration, there are another three main consideration need to be considered;

1. Pressure drop: Particles size is inversely proportional with pressure drop per unit length of packed bed. Thus, the pressure drop can be reduced by selecting the larger particle size.
2. Mass transfer rate: Adsorbent size can also behave inversely proportional to the mass transfer rate to a power less than unity. In this case, high size of the packed bed can be reduced by selecting the smaller particles size.
3. Shape: Shape can affect both pressure and mass transfer resistance.

2.4.3.1 Types of adsorbents solid desiccant

Solid particle offered by most of vendor usually in particle sizes that range from a 100x200 mesh screen analysis to ¼ in (0.64 cm) size. The smaller sizes of the particle are usually irregular while for larger size are regular in size such as spheres and cylinder.

Table 2.3: Commercial adsorbent for adsorption technology [8]

Commercial adsorbents	Description
Activated carbon	Made by thermal decomposition of wood
Silica gel	Acid treatment of sodium silicate solution
Activated alumina	Hydrated aluminium activated by heating to dry off water
Molecular sieve zeolites	Porous crystalline aluminosilicates

Table 3 describe the composition of the given adsorbent. Alumina in this case is the cheapest compared to the other three but for given water load, alumina needs larger tower and this will involve larger capital cost. Another disadvantages using this type of adsorbent is it co-adsorption of hydrocarbons which will lead to hydrocarbon loss and rehydration which destroy its activity. As for molecular sieve, it is the most expensive among those four types of adsorbent. However, it can give higher adsorption design loadings, greater resistance to fouling and coking and high removal of impurities from the process stream.

Silica gel which is produce by acid treatment of sodium silicate solution has high capacity for water, can be generated at low temperature and are not catalytic for sulphur conversion reaction. It also has high capacity for pentane and higher hydrocarbons and can be used for combined dehydration/hydrocarbon process. [7]. Instead of the advantages, silica gel has a few weaknesses such as tendency to shatter when contacted with liquid water. This can be avoided by installing water-resistance layer at the top of the bed as a preventive measure to avoid water from coming into the bed and damage the adsorbent.

Table 2.4 : Summary of typical desiccant properties

	Bulk Density (kg/m3)	Surface area (m^2/g)	Specific Heat (kJ/kg ^oC)	Regeneration Temperature (^oC)
Activated Carbon	320	1500	11.09	130 – 250
Silica Gel	721	750-830	0.92	121- 260
Alumina	801-881	210	0.24	121- 260
Molecular sieve zeolites (4Å to 5Å)	689-721	650-800	1.0	230-290

2.4.3.2 Adsorbent shape

Adsorbent commercially available in a variety of geometrics shapes such as beads (sphere), pellets (cylinder), granular, and extended surface. This shape can affects both pressure and mass transfer resistance.

Figure 2.9: Granular activated carbon

Granular materials are irregular in shape and may vary from platelet to spheroid to cubic. They derive their irregularity from the manufacturing process where the desired-size particles result from crushing larger materials. Typical sizes for granules are 100x200 to 4x8 mesh screen analysis. This irregularity of shape can also be describe using shape factor ϕ, which define as the ratio of the surface area of a sphere with the volume equivalent to the particle divided by actual surface area of the particle. Published value of ϕ for granules ranged from 0.45 to 0.65.

Figure 2.10: Silica gel beads

Beads are also usually denoted by their screening analysis because the manufacturing techniques cannot make a single uniform size. This type of adsorbent usually has size ranged from 16x40 to 4x8 screen. Although they are not totally spherical, commercial beads can have shape to the factor of 1.

Figure 2.11: Pallets adsorbents

Pellets adsorbents are produced by extrusion trough dies and therefore have a uniform diameter but a range of length to diameter ratio. Typical commercial particles size range from 1/32 in to ¼ in (0.08 – 0.64 cm) in diameter and posses a shape factor of about 0.63.

Figure 2.12: molecular sieves

In addition, as being used in many gas dehydration plant, molecular sieves provide a unique combination of mass transfer and pressure drop performance in one particle.

CHAPTER 3

METHODOLOGY/PROJECT WORK

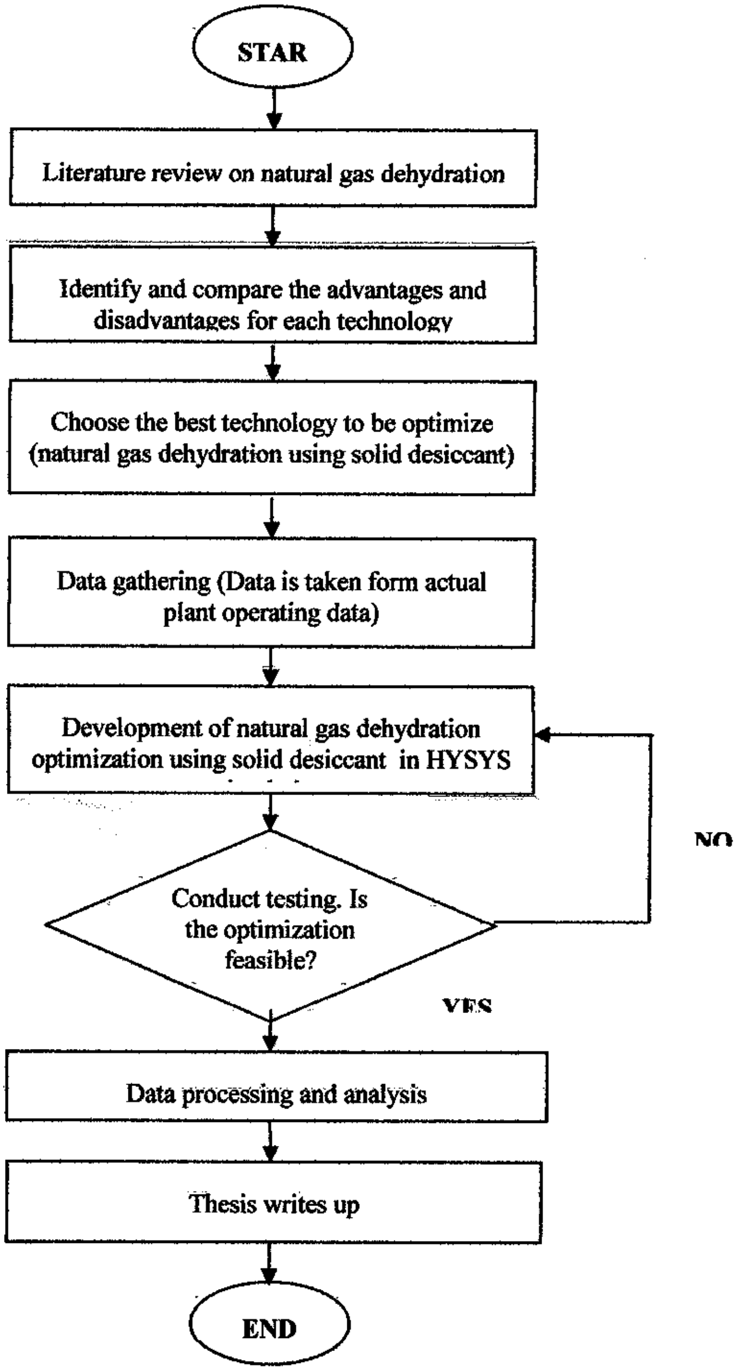

Figure 3.1: Project methodology

3.1 PROJECT METHODOLOGY

In order to optimize the gas dehydration using solid desiccant, the author needs to get a clear overview on how natural gas is being dehydrated by using solid desiccant dehydrator and also to learn how regeneration affect the adsorption process. Thus, a simulation using HYSYS will be constructed. It is a basic approach before optimization of the solid desiccant unit can be done.

3.1.1 Data collection

In this stage, actual data from process plant will be obtained. It will be extract from actual gas processing plant in Malaysia and by using this data, it will help a lot to develop flowsheet in later stage. For some reason, data taken might not be accurate all the time. Its due to the plant condition where there are always sudden problems occur or there might be shutdown process going on.

Table 3.1: Sample of actual dehydration unit data collected

T/H	DEG C	KPAG	T/H	T/H
Flow inlet DHU	Temperature inlet bed	Common bed dp	Hot regen flow	Cold regen flow
285.6280212	19.65385437	33.01881409	7.028180122	4.531960487
249.0326843	19.57505035	26.22424316	4.093060493	4.678452015
259.7215881	19.44704437	28.92930984	6.441766739	3.453466892
274.4064636	19.3569603	30.86968422	7.290332317	4.486448288
249.1088867	19.10934639	26.10346031	7.335764408	4.142158031
282.1249695	19.79619408	32.7244606	6.899541855	4.377542973
278.1717834	19.99786186	33.72343445	3.627982616	3.572258234
260.3218384	19.96850777	27.58623123	7.175979614	4.210882664
280.3170776	19.87239456	31.90444374	7.222902298	4.156164169
283.3424988	19.88269997	33.15811157	6.334057331	4.598501682
239.5596161	19.82997704	23.96570778	6.190636635	4.762344837
277.5119934	20.11195183	31.21685219	6.45874548	4.814775467
249.1926117	19.61646461	25.01482582	7.30594635	4.044626713
243.5502014	19.67575073	24.70503807	7.100651741	4.133811951
276.6520386	19.95911217	31.49053764	6.549534321	4.819450378

262.1685181	20.00130272	27.73995399	6.561894894	4.697604656
267.3648071	19.73636818	28.89634895	6.86478281	4.726782799
247.9937897	19.56664276	26.13385582	6.884967804	4.276237011
201.0322876	18.85371399	16.485672	7.377949715	4.094201088
194.1821594	18.91290092	15.21907234	6.264643669	4.645704269
210.7707062	19.08631706	18.39589119	6.797727585	4.651820183
207.5722961	18.87639427	18.28185272	6.841817856	4.76204443
128.3497009	17.65979767	10.85300064	5.354321957	3.247327566
208.7458038	19.08409882	25.01837158	7.522019863	4.189260483
267.1127319	19.88386726	28.70818901	6.684571266	4.668279171
259.2969666	19.66725922	27.81591415	6.883564472	4.808364868

3.1.2 Development of dehydration unit (DHU) flowsheet

The flowsheet of the dehydration unit will give information for author on how the dehydration unit works. It covers the operating condition such as pressure, temperature and flow rate in and out of the unit. It will also show the equipment needed in the DHU plant. From this, simulation development of DHU unit can be done using HYSYS software.

The following assumptions are made to dry natural gas from the AGRU (Acid gas removal unit):

1. The average DHU (dehydration unit) load is 250 tonne per hour
2. The pressure drop of each packed bed is 33 kPag
3. The outlet moisture content leaving the dehydration is 1ppm (0.0000625 mol)
4. The operating condition of the dehydration unit is 60- 70 bar and the temperature operating temperature is 20-30 °C
5. The adsorbent used in this simulation is molsieve 3A (according to PETRONAS Gas Bhd) molsieve specification.

3.2 OPTIMIZATION STRATEGIES

There are two key strategies that can be implemented in order to optimize this natural gas dehydration unit. The first one is to manipulate pressure and temperature and compare it with the outlet moisture content. From this, the relationship between the temperature and pressure towards the moisture removed can be found. It also to ensure that moisture content that is leaving the DHU unit is below than 1 ppm (0.0000625mol) in order to ensure the hydrate will not formed. As from the literature, adsorption favours high pressure, low temperature.

The second part of the optimization strategies is to get a good prediction whether the hydrates will form after leaving the gas dehydration unit or not with the respective to temperature, pressure and also the molecular weight of the natural gas. By using a relationship developed from the literature, the hydrate formation is so much dependent toward temperature and pressure condition. Thus, it plays an important role towards hydrates formation prediction.

3.2.1 Temperature and pressure relationship toward outlet moisture content

This part is basically to see the effect of operating pressure and temperature to the outlet moisture content of the dehydration unit. From this, the trend or the relationship between temperature with moisture removal and pressure with moisture removal can be understood.

For this case, the temperature is varied between 20 to 30 °C and pressure between 60 to 70 bar. This value is exactly according to the operational data obtained from actual plant.

3.2.2 Hydrate formation prediction

From the journal publish by Alireza and Hari [14], Katz (1946) gravity chart can be used for predicting approximate temperature and pressure for hydrate formation in natural gas system. But somehow, the author had find a new simple – to – used correlation base on Katz and this correlation in order to predict the temperature and pressure relationship for the hydrates to form. This correlation is developed based on newly proposed numerical model from Alireza and Hari [14], This method is promising and easy to use as it has been simplified from the previous gravity chart and will be use to determine the hydrate formation pressure and temperature for this study.

Correlation developed by Alireza and Hari [14];

$$\text{In}\,(T) = a + b\left(\frac{1}{p}\right) + c\left(\frac{1}{p}\right)^2 + d\left(\frac{1}{p}\right)^3 \text{-----} (3.1)$$

$$\text{In}\,(P) = a + b\left(\frac{1}{T}\right) + c\left(\frac{1}{T}\right)^2 + d\left(\frac{1}{T}\right)^3 \text{-----} (3.2)$$

Where;

$$a = A_1 + B_1M + C_1M^2 + D_1M^3 \text{-----} (3.3)$$

$$b = A_2 + B_2M + C_2M^2 + D_2M^3 \text{-----} (3.4)$$

$$c = A_3 + B_3M + C_3M^2 + D_3M^3 \text{-----} (3.5)$$

$$d = A_4 + B_4M + C_4M^2 + D_4M^3 \text{-----} (3.6)$$

The coefficient (3.1) and (3.2) shown above are correlated as a function of molecular weight (M) in equation (3.3) to (3.6). The optimum derived coefficients used in the equation (3.3) to (3.6) are given in table 3.2 and 3.3. These optimum tuned coefficient help to cover data from Katz (1945) gravity chart in temperature variation of 260K to 298L as well as the gas molecular weight within the range of 16 to 29. [14]

Table 3.2: Tuned coefficient used in equation 3.2 to 3.5 to predict hydrate formation pressure in kPa (given temperature K) by equation 2 [14]

Coefficient	Natural gas with molecular weight less than 23 265 K <Temperature <298 K	Natural gas with molecular weight more than 23 265 K <Temperature <298 K
A_1	$-2.8375555003183 \times 10^5$	$9.6485148281011 \times 10^4$
B_1	$4.188723721533 \times 10^4$	$-1.2987255223562 \times 10^4$
C_1	$-2.0426785680161 \times 10^3$	$5.6943123183493 \times 10^2$
D_1	$3.2999427860007 \times 10^1$	-8.0291736544591
A_2	$2.3518577113598 \times 10^8$	$-8.3851942305767 \times 10^7$
B_2	$-3.470311070979 \times 10^7$	$1.1292443545403 \times 10^7$
C_2	$1.6921307674758 \times 10^6$	$-4.9481203210497 \times 10^5$
D_2	$-2.7331526571044 \times 10^4$	$6.9743729419639 \times 10^3$
A_3	$-6.4899035506028 \times 10^{10}$	$2.4283950487232 \times 10^{10}$
B_3	$9.5728921505256 \times 10^9$	$-3.2713325876178 \times 10^9$
C_3	$-4.667233443707 \times 10^8$	$1.4325969896394 \times 10^8$
D_3	$7.5373257072387 \times 10^6$	$-2.018536147544 \times 10^6$
A_4	$5.9653477415552 \times 10^{12}$	$-2.3430538061379 \times 10^{12}$
B_4	$-8.796372864875 \times 10^{11}$	$3.1570181175788 \times 10^{11}$
C_4	$4.2881972248701 \times 10^{10}$	$-1.3818050947490\!8 \times 10^{10}$
D_4	$-6.924141404623\!5 \times 10^8$	$1.9463506733398 \times 10^8$

Table 3.3: Tuned coefficient used in equation 3.2 to 3.5 to predict hydrate formation temperature in K (given pressure in kPa) by equation 1 [14]

Coefficient	Natural gas with molecular weight more than 23 and pressure 1200 kPa $< P <$ 40000 kPa	Natural gas with molecular weight less than 23 and pressure 1200 kPa $< P <$ 5000 kPa	Natural gas with molecular weight less than 23 and pressure range 5000 kPa $< P <$ 40000 kPa
A_1	6.4185071105353	-4.1812132784232	7.0959703947586
B_1	$-8.8017107875666\times10^{-2}$	1.472639349108	$-2.1806030070795\times10^{-1}$
C_1	$3.5573429357137\times10^{-3}$	$-7.2745386271251\times10^{-2}$	$1.1305933439794\times10^{-2}$
D_1	$-4.7499843881244\times10^{-5}$	$1.1897795879884\times10^{-3}$	$-1.927203195626\times10^{-4}$
A_2	$-8.6426289139868\times10^{3}$	$4.5284975000181\times10^{4}$	$-1.2584649421592\times10^{5}$
B_2	$1.0243307852297\times10^{3}$	$-6.8628124449813\times10^{3}$	$1.8993111766336\times10^{4}$
C_2	$-4.0966392546509\times10^{1}$	$3.4240721860406\times10^{2}$	$-9.5260058127234\times10^{2}$
D_2	$5.4450050757729\times10^{-1}$	-5.642533019	$1.5806820089029\times10^{1}$
A_3	$1.159643030462\times10^{7}$	$-8.317075073225\times10^{7}$	$9.219038228315\times10^{8}$
B_3	$-1.3859027774109\times10^{6}$	$1.2604810249225\times10^{7}$	$-1.403041056748\times10^{8}$
C_3	$5.5353148270822\times10^{4}$	$-6.3018579466138\times10^{5}$	$7.0820417989994\times10^{6}$
D_3	$-7.339994547645\times10^{2}$	$1.0408848430973\times10^{4}$	$-1.1818763471949\times10^{5}$
A_4	$-4.0200951475377\times10^{9}$	$5.8589773993386\times10^{9}$	$-2.1053548626211\times10^{12}$
B_4	$4.791331833062\times10^{8}$	$-9.6634962535354\times10^{8}$	$3.213992597219\times10^{11}$
C_4	$-1.9036325296009\times10^{7}$	$5.1347314224130\times10^{7}$	$-1.627476726273\times10^{10}$
D_4	$2.5113297404156\times10^{5}$	$-8.878185886492\times10^{5}$	$2.724884324573\times10^{8}$

The relationship requires molecular weight of the natural gas in order to select suitable coefficient. Due to many outlet composition of the outlet gas, and in order to get the overall molecular weight, apparent molecular weight is calculated. The AMW (apparent molecular weight) is defined as;

$$M_a = \sum_I y_i M_i$$

Where;

Ma = Apparent molecular weight

y_i = mol fraction of each species

M_i = Molecular weight for each species

3.2.3 Installation of cooler and knock-up drum

This cooler and knock-up drum can act like pre dehydration before entering the gas dehydration unit. As the gas is coming from the Acid gas removal unit (AGRU), the temperature is slightly higher and this will make the gas is in vapour condition. Thus, the installation of the cooler will make sure the temperature of the gas become less, and it will eventually condense the moisture into liquid so that is can be easily separated from the sales gas.

Later, after the gas is cooled, the knock – up drum or a separator is installed in between the cooler and the inlet of the dehydration unit. The purpose of this is to provide a separation environment for the gas after it being condense previously after passing through the cooler. Due to this, dehydration unit will have higher efficiency to remove the unwanted moisture inside gas and to achieve the objective of removing the hydrate formation major contributor that is water.

CHAPTER 4

RESULT AND DICUSSION

This section is the result after running and testing the HYSYS simulation. The simulation is used as a tool to evaluate and simulate the dehydration unit in the actual gas dehydration plant and to do a study and improvement toward the efficiency of the dehydration unit. For the record, the data used to construct the simulation are the actual plant data taken from one of the gas processing plant in Malaysia. Thus the real dehydration unit behaviour can be known. It also used to observe the behaviour of natural gas dehydration unit towards manipulation of temperature and pressure.

4.1 HYSYS SIMULATION

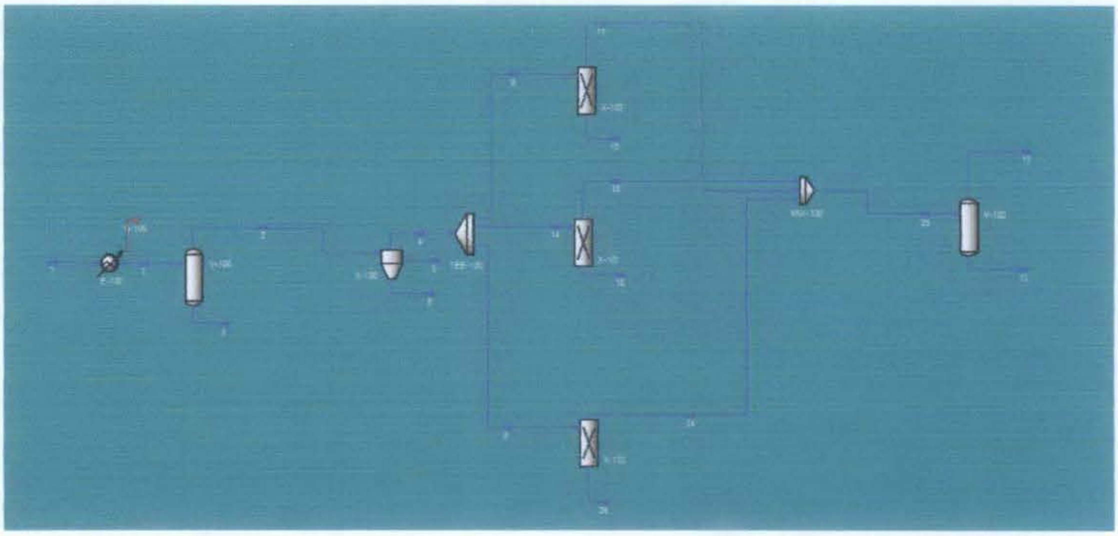

Figure 4.1: Flow sheet of natural gas dehydration developed using HYSYS

This dehydration process takes place when the wet gas enters the DHU (dehydration unit) from the Acid gas removal unit. In this unit, gas will further treated to remove water vapour that contained inside the gas. It is to avoid any hydrates formation along the pipelines that will cause serious damage as being discuss in the earlier chapter of this research report.

The dehydration unit is designed to reduce the feed gas water content below 1ppm v/v and the mercury content to 0.1 ppb w/w. Thus, upon reaching DHU, gas will be passing through the heat exchanger to remove heat from the gas. Due to this, some water droplets will form out of the gas. A separator is place after the heat exchanger in order to separate the gas and the water droplets.

Later, the gas is further treated by the inlet filter separator. This is important to remove all the liquid mist, down to 1 micron particles size that can be found in the gas stream. If these mists are not being removed before they enter into the packed bed, it will damage the adsorbent inside it. The cost to replace the adsorbent it self is expensive. Due to this, this step is one the proven way to prolong the adsorbent lifetime.

The gas goes forward to the dryers bed which operate with two in parallel service while one under regeneration. The dryers are packed with adsorbent. It can be silica gel, activated carbon or molecular sieve. Most of gas dehydration plant nowadays use molecular sieve as the adsorbent to serve this purpose (to dehydrate gas) and to achieve outlet moisture content in the gas to below 1ppm. Later the gas is pass through mercury removal filter to remove deposited mercury that left in the gas.

4.2 EFFECT OF PRESSURE AND TEMPERATURE VARIATION TOWARD WATER MOISTURE COMPOSITION AT THE OUTLET OF DEHYDRATION UNIT

Table 4.1 : Natural gas composition with changes of temperature

Natural Gas Composition	**Temperature**											
	30	**29**	**28**	**27**	**26**	**25**	**24**	**23**	**22**	**21**	**20**	**19**
C1	0.973449980	0.973758254	0.974062468	0.974362765	0.974659289	0.974952178	0.975241567	0.975527591	0.975810379	0.976090059	0.976366754	0.976640587
C2	0.017414775	0.017325482	0.017235124	0.017143676	0.017051113	0.016957410	0.016862542	0.016766483	0.016669209	0.016570694	0.016470912	0.016369837
C3	0.001245064	0.001226740	0.001208447	0.001190186	0.001171962	0.001153776	0.001135632	0.001117532	0.001099481	0.001081480	0.001063534	0.001045646
i-C4	0.003619744	0.003523278	0.003428829	0.003336369	0.003245869	0.003157301	0.003070636	0.002985847	0.002902905	0.002821785	0.002742458	0.002664898
n-C4	0.003128192	0.003025878	0.002926682	0.002830510	0.002737270	0.002646876	0.002559243	0.002474288	0.002391934	0.002312102	0.002234718	0.002159712
CO2	0.000758202	0.000756989	0.000755747	0.000754474	0.000753169	0.000751831	0.000750459	0.000749053	0.000747611	0.000746132	0.000744616	0.000743060
O2	0.000008088	0.000008096	0.000008104	0.000008113	0.000008121	0.000008130	0.000008139	0.000008147	0.000008156	0.000008165	0.000008174	0.000008183
Ni	0.000205666	0.000206025	0.000206386	0.000206750	0.000207116	0.000207485	0.000207858	0.000208234	0.000208613	0.000208997	0.000209385	0.000209777
H2S	0.000170205	0.000169176	0.000168137	0.000167086	0.000166024	0.000164951	0.000163866	0.000162768	0.000161659	0.000160538	0.000159404	0.000158257
H2O	0.000000085	0.000000080	0.000000075	0.000000071	0.000000067	0.000000063	0.000000059	0.000000056	0.000000052	0.000000049	0.000000046	0.000000043

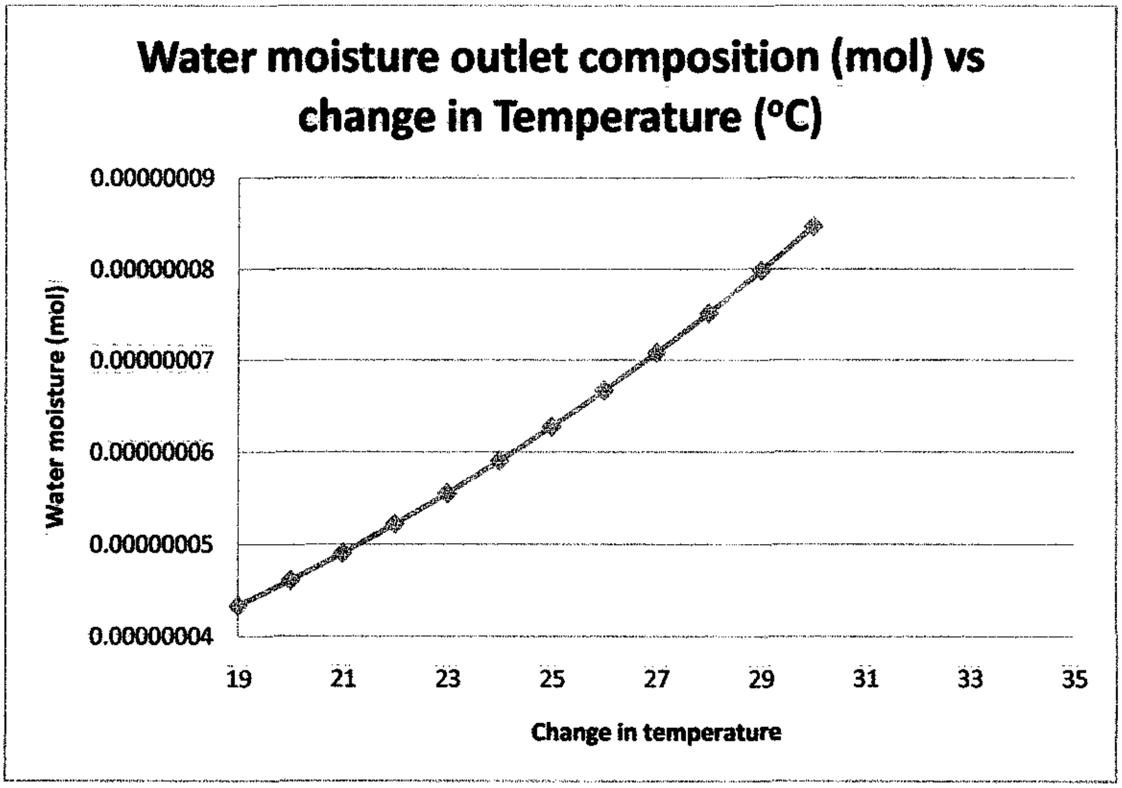

Figure 4.2: Water moisture outlet composition (mol) versus change in temperature (°C)

From the graph above, it is showing that as the operating temperature increase, the water moisture content in the natural gas leaving the dehydration increase. The lowest temperature that being record in the simulation is 19 °C with the moisture composition of 0.000000043 mol and the highest is 30 °C with composition of outlet moisture of 0.000000085 mol. This condition satisfy the relationship of temperature and moisture content leaving the dehydration unit, where for gas dehydration, it favour lower temperature in order to get high adsorption in the packed bed column. This is because, in low temperature, the moisture will easily be condensed and from this, it can be easily adsorb by the adsorbent inside the packed bed. Plus, an increase in temperature reduces the adsorption capacity of adsorbent as the adsorption of water is exothermic. Thus, in order to increase the efficiency of the dehydration unit, it need to be run and operated at low temperature to ensure the moisture can be separated from the gas much more easier.

Table 4.2 : Natural gas composition with changes of pressure

Natural Gas	Pressure (bar)										
	60	61	62	63	64	65	66	67	68	69	70
C1	0.973449980	0.973490478	0.973526559	0.973558270	0.973585650	0.973608727	0.973627521	0.973642042	0.973652291	0.973658259	0.973659929
C2	0.017414775	0.017398422	0.017383144	0.017368966	0.017355914	0.017344016	0.017333300	0.017323796	0.017315535	0.017308549	0.017302872
C3	0.001245064	0.001242464	0.001240121	0.001238036	0.001236208	0.001234636	0.001233321	0.001232263	0.001231463	0.001230923	0.001230642
i-C4	0.003619744	0.003608934	0.003599596	0.003591698	0.003585213	0.003580118	0.003576392	0.003574018	0.003572983	0.003573275	0.003574889
n-C4	0.003128192	0.003117825	0.003109052	0.003101829	0.003096118	0.003091887	0.003089107	0.003087755	0.003087809	0.003089256	0.003092081
CO2	0.000758202	0.000757936	0.000757682	0.000757441	0.000757212	0.000756997	0.000756796	0.000756610	0.000756440	0.000756286	0.000756149
O2	0.000008088	0.000008089	0.000008091	0.000008092	0.000008094	0.000008095	0.000008096	0.000008098	0.000008099	0.000008100	0.000008100
Ni	0.000205666	0.000205748	0.000205827	0.000205902	0.000205974	0.000206042	0.000206106	0.000206165	0.000206221	0.000206272	0.000206318
H2S	0.000170205	0.000170019	0.000169845	0.000169684	0.000169536	0.000169402	0.000169281	0.000169175	0.000169083	0.000169005	0.000168942
H2O	0.000000085	0.000000084	0.000000083	0.000000082	0.000000081	0.000000080	0.000000079	0.000000078	0.000000078	0.000000077	0.000000076

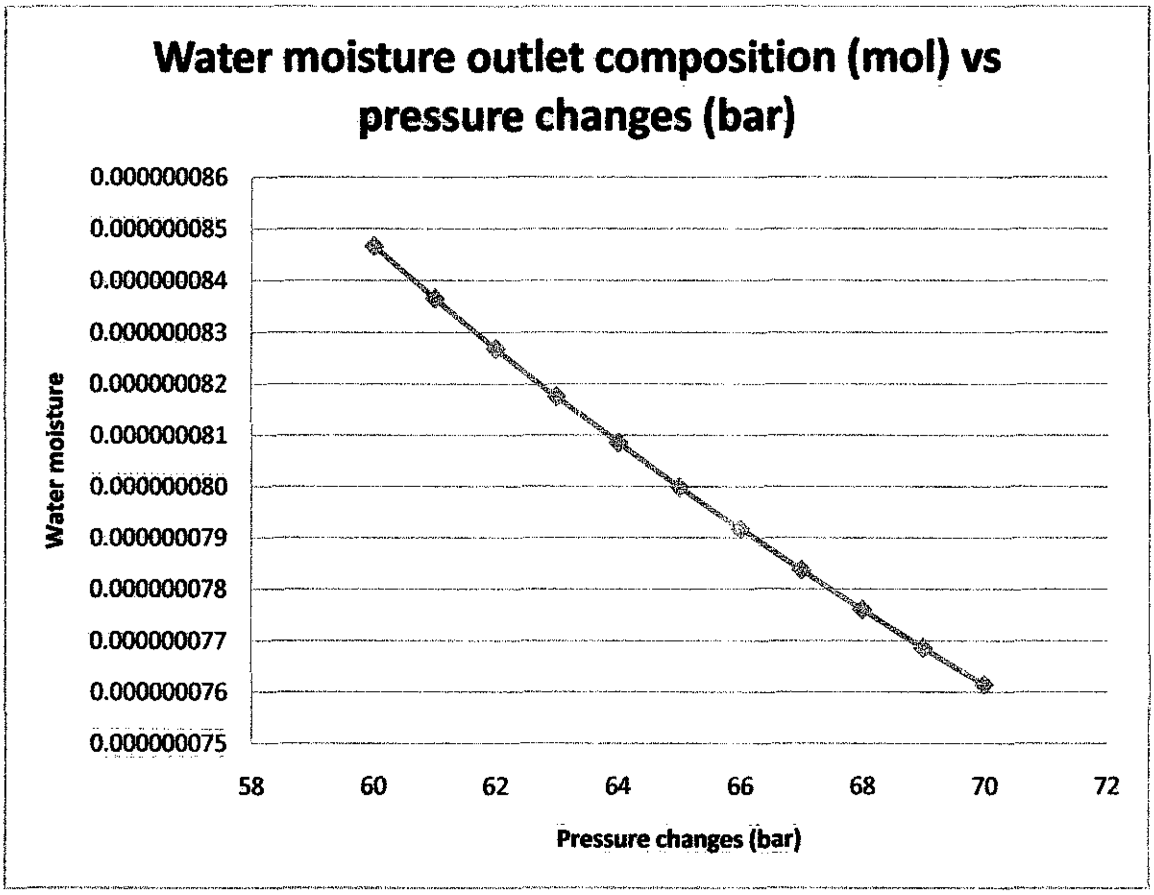

Figure 4.3: Water moisture outlet composition (mol) versus pressure (bar) change

Figure 4.3 shows the trend of water moisture outlet composition (mol) against pressure changes (bar) raging from 60 to 70 bar . From the trend, it is clearly showing that as the pressure increase, the water moisture composition at the outlet of dehydration unit is decrease (high moisture removing capacity). Generally, when a gas is compressed, the partial pressure of the water present increases. At a constant temperature the adsorptive capacity for water increases with increasing water partial pressure. Due to this, high pressure can give high moisture removal capacity form the gas.

4.3 HYDRATE FORMATION PREDICTION

To predict the hydrate formation of natural gases with respect to the temperature and pressure, a few steps of calculation need to be done. For the initial work to use the method developed by Alireza and Hari [14],, the molecular weight of the gas is taken from the HYSYS simulation. This, molecular weight of the gas is needed in order to calculate the temperature and pressure relation toward the hydrate formation.

Table 4.3 : Molecular weight of natural gas for each pressure and temperature

Pressure (bar)	MW
60	23.4791795
61	22.28248487
62	21.93968171
63	21.78581992
64	21.7756557
65	21.90065546
66	22.17772933
67	22.69110874
68	22.56982315
69	22.95874132
70	22.32741566

By using the molecular weight in table 4.3, it is assume that average molecular weight for all pressure is around 22.5 lb mol/mol.

It is understandable that, the MW of the gas is less than 23. Thus, referring to the table 4.4 , (tuned coefficient used in equation 3.2 to 3.5 to predict hydrate formation temperature in K (given pressure in kPa) by equation 1), the values of coefficient a, b, c and d from equation 3,4,5,6 can be found.

The region of the table is divided into to part for natural gas with molecular weight less than 23. The first part is pressure between 1200 kPa to 5000kpa and second one is pressure range 5000 kPa to 40,000 kPa.

Table 4.4: Tuned coefficient used in equation 2 to 5 to predict hydrate formation temperature in K (given pressure in kPa) by equation 1 [14]

Coefficient	Natural gas with molecular weight more than 23 and pressure 1200 kPa$<P<$ 40000 kPa	Natural gas with molecular weight less than 23 and pressure 1200 kPa$<P<$ 5000 kPa	Natural gas with molecular weight less than 23 and pressure range 5000 kPa$<P<$40000 kPa
A_1	6.4185071105353	-4.1812132784232	7.0959703947586
B_1	$-8.8017107875666\times10^{-2}$	1.472639349108	$-2.1806030070795\times10^{-1}$
C_1	$3.5573429357137\times10^{-3}$	$-7.2745386271251\times10^{-2}$	$1.1305933439794\times10^{-2}$
D_1	$-4.7499843881244\times10^{-5}$	$1.1897795879884\times10^{-3}$	$-1.927203195626\times10^{-4}$
A_2	$-8.6426289139868\times10^{3}$	$4.5284975000181\times10^{4}$	$-1.258464942159 2\times10^{5}$
B_2	$1.0243307852297\times10^{3}$	$-6.8628124449813\times10^{3}$	$1.8993111766336\times10^{4}$
C_2	$-4.0966392546550 9\times10^{1}$	$3.4240721860406\times10^{2}$	$-9.5260058127234\times10^{2}$
D_2	$5.4450050757729\times10^{-1}$	-5.642533019	$1.5806820089029\times10^{1}$
A_3	$1.159643030462\times10^{7}$	$-8.3170750732 25\times10^{7}$	$9.2190382283151\times10^{8}$
B_3	$-1.3859027774109\times10^{6}$	$1.2604810249225\times10^{7}$	$-1.4030410567488\times10^{8}$
C_3	$5.5353148270822\times10^{4}$	$-6.3018579466138\times10^{5}$	$7.0820417989994\times10^{6}$
D_3	$-7.3399945476 45\times10^{2}$	$1.0408848430973\times10^{4}$	$-1.1818763471949\times10^{5}$
A_4	$-4.0200951475377\times10^{9}$	$5.8589773993386\times10^{9}$	$-2.1053548626211\times10^{12}$
B_4	$4.791331833062\times10^{8}$	$-9.663496253535 4\times10^{8}$	$3.213992597219\times10^{11}$
C_4	$-1.9036325296009\times10^{7}$	$5.1347314224130 7\times10^{7}$	$-1.627476726273 9\times10^{10}$
D_4	$2.5113297404156\times10^{5}$	$-8.8781858649 2\times10^{5}$	$2.7248843245 73\times10^{8}$

Correlation developed by Alireza and Hari [14];

$$a = A_1 + B_1M + C_1M^2 + D_1M^3 \text{--} (3.3)$$

$$b = A_2 + B_2M + C_2M^2 + D_2M^3 \text{--} (3.4)$$

$$c = A_3 + B_3M + C_3M^2 + D_3M^3 \text{--} (3.5)$$

$$d = A_4 + B_4M + C_4M^2 + D_4M^3 \text{--} (3.6)$$

In order to find the a, b, c and d values, the M is the molecular weight of the gas in inserted into equation (3.3) to (3.6) while A,B,C,D values can be identified at table 4.4 based on the pressure range that is 5000 kPa < P < 40000 kPa

The a, b, c, and d values obtained;

Table 4.5: Calculated value for a,b,c and d

5000 kPa < P < 40000 kPa			
a	b	c	d
5.72	-705.97	4114081.00	-9158929570.00

To find the temperature at which the hydrates formed, equation 3.1 [14] is used.

$$\text{In}\ (T) = a + b\left(\frac{1}{p}\right) + c\left(\frac{1}{p}\right)^2 + d\left(\frac{1}{p}\right)^3 \tag{3.1}$$

Thus;

Table 4.6: Calculated value of temperature from equation 3.1

Pressure	In (T)	T (K)	T (^oC)
60000	5.6742	291.2552	18.10524
61000	5.6745	291.3426	18.19263
62000	5.6747	291.4009	18.25091
63000	5.6749	291.4592	18.30919
64000	5.6752	291.5466	18.39664
65000	5.6754	291.605	18.45496
66000	5.6756	291.6633	18.51328
67000	5.6758	291.7216	18.57162
68000	5.676	291.78	18.62997
69000	5.6762	291.8383	18.68833
70000	5.6764	291.8967	18.74671

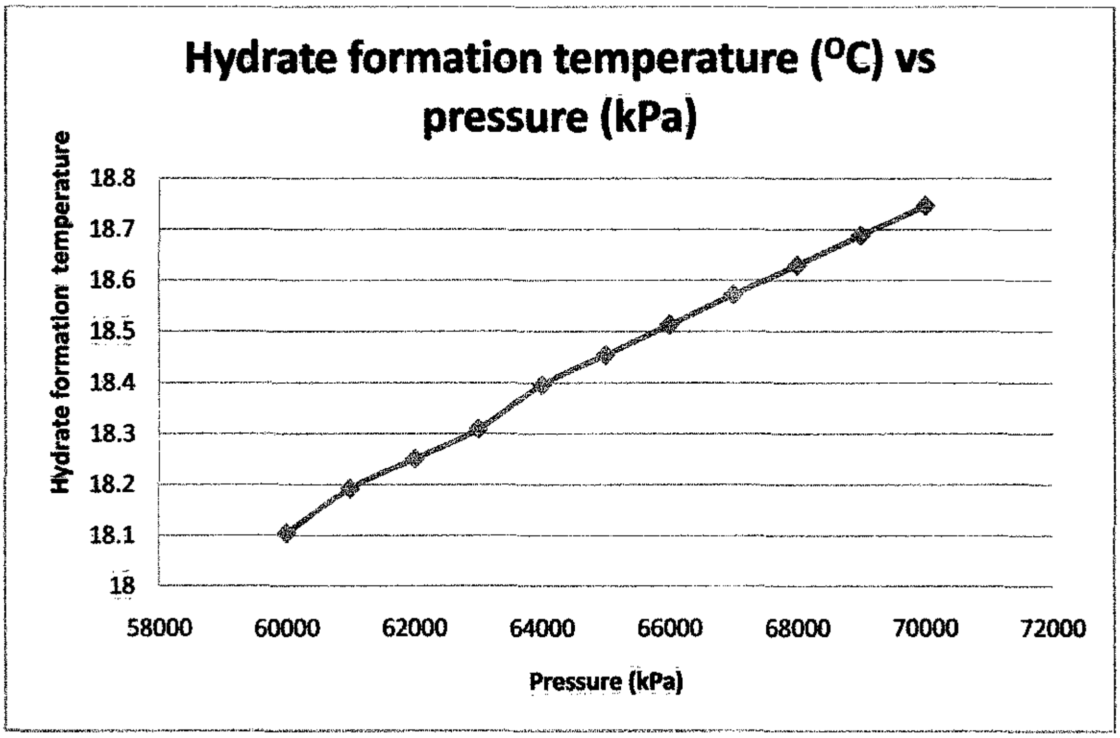

Figure 4.4: Hydrate formation temperature (^{O}C) vs pressure (kPa)

From figure 4.4, it is clearly observed that the higher the pressure, the higher the hydrate formation temperature. From the calculation and base on the dehydration unit and gas processing plant average pressure that is 60 bar, the hydrate will formed when the temperature is about 18^{O}C.

As the plant it self is operated at normal temperature range of 19-30 ^{O}C (discussed in 4.2), which is slightly higher then the hydrate formation temperature of 18^{O}C, it can be conclude that the potential of hydrate to form in the process stream is very high. Thus, the dehydration unit need to be operated at temperature slightly lower in order to prevent the hydrates formation after the gas leaving the dehydration unit. So, base on the hydrate prediction, the optimum temperature of dehydration unit can be assume 18-21 ^{O}C.

4.4 INSTALLATION OF COOLER AND KNOCK-UP DRUM

Installation of the cooler and knock- up drum (separator) before the gas enters into the dehydration unit can increase the efficiency to remove moisture from the gas. As the gas is coming from the acid gas removal unit (AGRU) that operates at high temperature, it need be cooled first and separate possible water moisture that available inside the gas. Thus, cooler and knock-up drum suit this purpose.

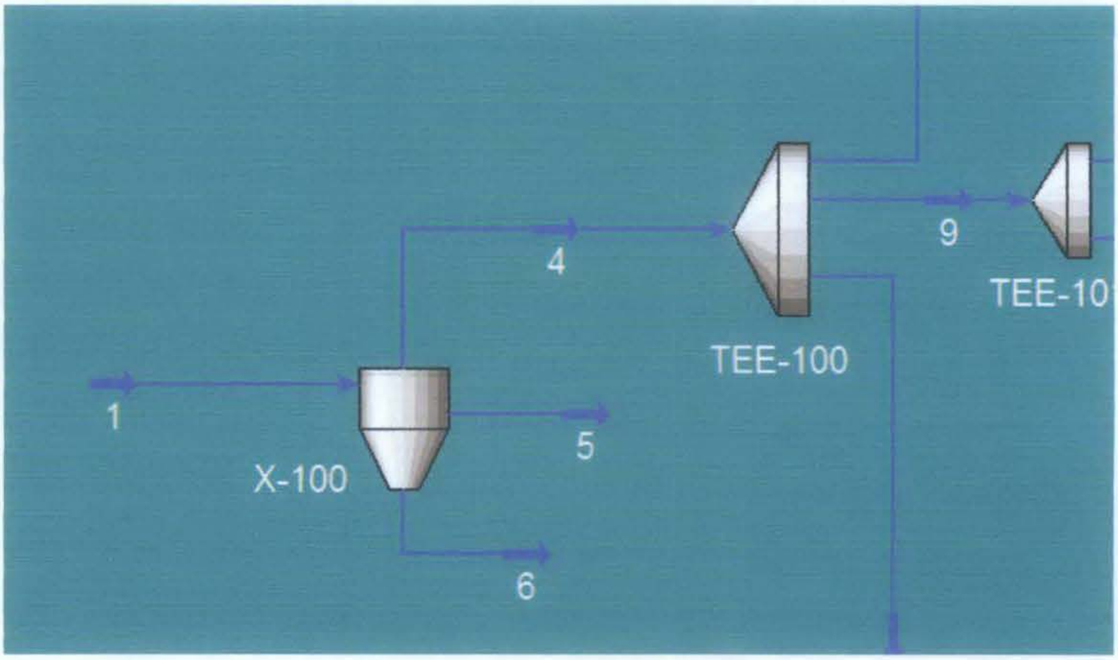

Figure 4.5: Hysys simulation without pre-dehydration of the gas before entering the dehydration unit.

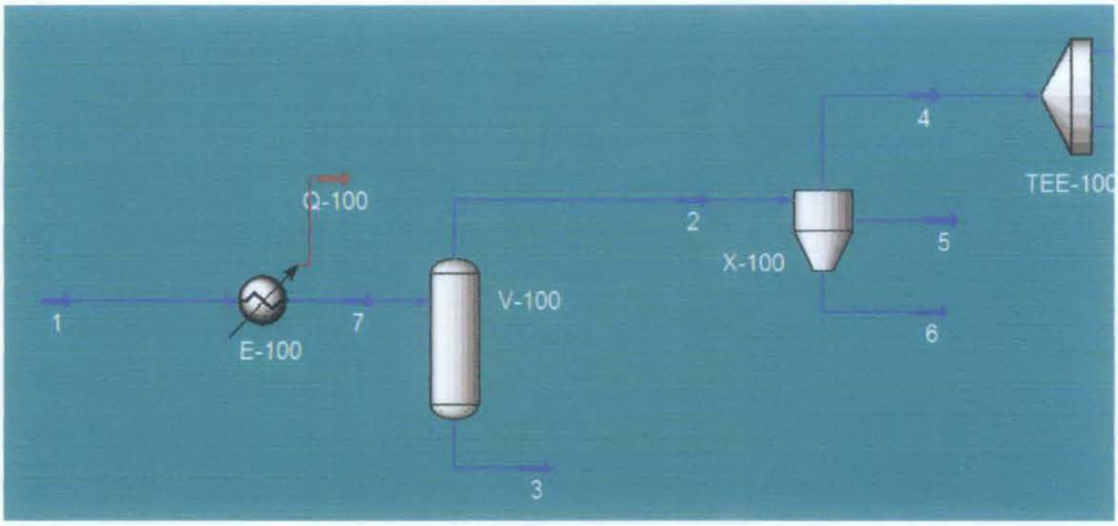

Figure 4.6: Hysys simulation with pre-dehydration of the gas before entering the dehydration unit.

From hysys simulation, the changes of efficiency of the dehydration unit before and after the installation of cooler and knock –up drum can be observed. The data taken is plotted into graph for further discussion.

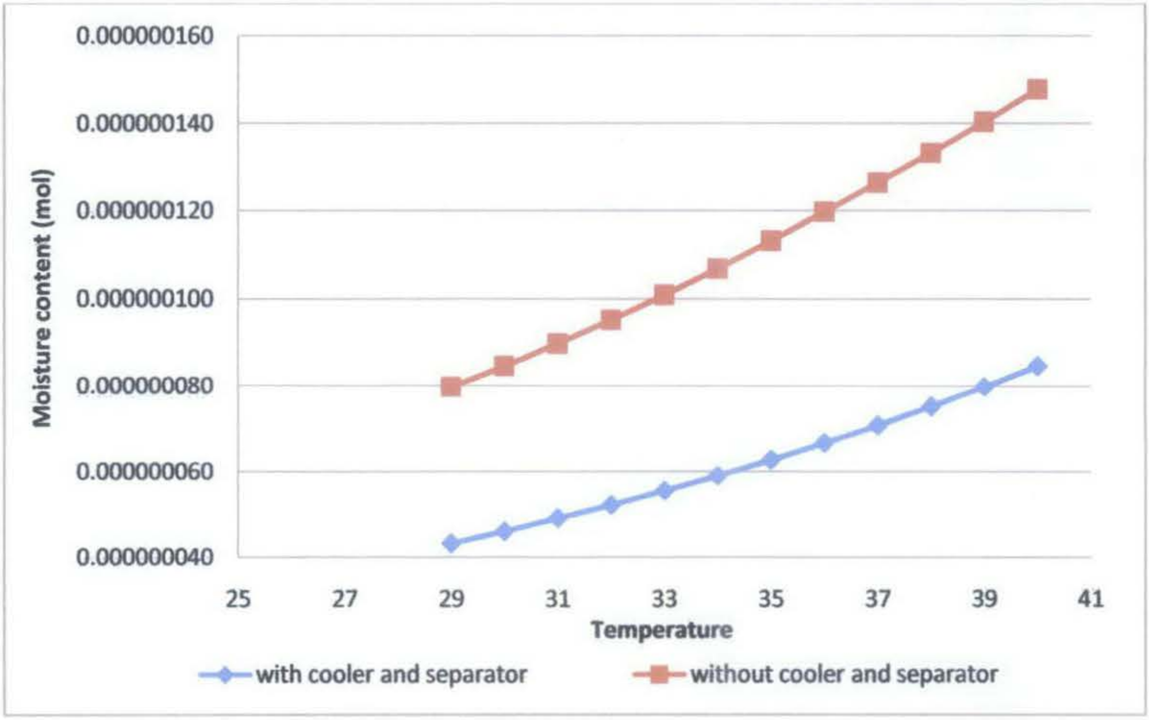

Figure 4.7: Moisture content versus temperature with and without cooler and separator

Table 4.7 : Natural gas composition without cooler and phase separator

Natural Gas Composition	Temperature											
	40	39	38	37	36	35	34	33	32	31	30	29
C1	0.971412989	0.971413001	0.971413012	0.971413022	0.971506448	0.971842346	0.972173234	0.972499280	0.972820646	0.973137494	0.973449980	0.973758254
C2	0.017952320	0.017952320	0.017952320	0.017952320	0.017929508	0.017846104	0.017761777	0.017676504	0.017590262	0.017503027	0.017414775	0.017325482
C3	0.001360604	0.001360604	0.001360604	0.001360604	0.001355517	0.001337059	0.001318617	0.001300195	0.001281794	0.001263416	0.001245064	0.001226740
i-C4	0.004273012	0.004273012	0.004273012	0.004273012	0.004242549	0.004133359	0.004026365	0.003921537	0.003818844	0.003718256	0.003619744	0.003523278
n-C4	0.003847829	0.003847829	0.003847830	0.003847830	0.003813227	0.003690044	0.003570616	0.003454827	0.003342564	0.003233721	0.003128192	0.003025878
CO2	0.000765180	0.000765177	0.000765174	0.000765172	0.000764886	0.000763838	0.000762765	0.000761665	0.000760539	0.000759385	0.000758202	0.000756989
O2	0.000008035	0.000008035	0.000008035	0.000008035	0.000008037	0.000008046	0.000008054	0.000008062	0.000008071	0.000008079	0.000008088	0.000008096
Ni	0.000203455	0.000203455	0.000203455	0.000203455	0.000203551	0.000203900	0.000204250	0.000204602	0.000204955	0.000205310	0.000205666	0.000206025
H2S	0.000176429	0.000176427	0.000176426	0.000176424	0.000176158	0.000175191	0.000174214	0.000173227	0.000172230	0.000171223	0.000170205	0.000169176
H2O	0.000000148	0.000000140	0.000000133	0.000000126	0.000000120	0.000000113	0.000000107	0.000000101	0.000000095	0.000000090	0.000000085	0.000000080

Table 4.8 : Natural gas composition with cooler and phase separator

Natural Gas Composition	Temperature											
	40	39	38	37	36	35	34	33	32	31	30	29
C1	0.973449980	0.973758254	0.974062468	0.974362765	0.974659289	0.974952178	0.975241567	0.975527591	0.975810379	0.976090059	0.976366754	0.976640587
C2	0.017414775	0.017325482	0.017235124	0.017143676	0.017051113	0.016957410	0.016862542	0.016766483	0.016669209	0.016570694	0.016470912	0.016369837
C3	0.001245064	0.001226740	0.001208447	0.001190186	0.001171962	0.001153776	0.001135632	0.001117532	0.001099481	0.001081480	0.001063534	0.001045646
i-C4	0.003619744	0.003523278	0.003428829	0.003336369	0.003245869	0.003157301	0.003070636	0.002985847	0.002902905	0.002821785	0.002742458	0.002664898
n-C4	0.003128192	0.003025878	0.002926682	0.002830510	0.002737270	0.002646876	0.002559243	0.002474288	0.002391934	0.002312102	0.002234718	0.002159712
CO2	0.000758202	0.000756989	0.000755747	0.000754474	0.000753169	0.000751831	0.000750459	0.000749053	0.000747611	0.000746132	0.000744616	0.000743060
O2	0.000008088	0.000008096	0.000008104	0.000008113	0.000008121	0.000008130	0.000008139	0.000008147	0.000008156	0.000008165	0.000008174	0.000008183
Ni	0.000205666	0.000206025	0.000206386	0.000206750	0.000207116	0.000207485	0.000207858	0.000208234	0.000208613	0.000208997	0.000209385	0.000209777
H2S	0.000170205	0.000169176	0.000168137	0.000167086	0.000166024	0.000164951	0.000163866	0.000162768	0.000161659	0.000160538	0.000159404	0.000158257
H2O	0.000000085	0.000000080	0.000000075	0.000000071	0.000000067	0.000000063	0.000000059	0.000000056	0.000000052	0.000000049	0.000000046	0.000000043

Figure 4.6 show the moisture content versus temperature at different condition, with and without cooler and separator. Generally, the gas from the process stream before it enters into dehydration unit is in high temperature. To be exacts, the gas is having high temperature because of the temperature at the acid gas removal unit (AGRU). Due to this, the moisture that contained inside the gas which is in gas form can only be removed when it is condensed properly. Because of this, pre-dehydration treatment which is by using cooler and separator is needed before the gas enters dehydration.

As the hot gas enters into the cooler, it will cool down and the water vapour will condense to form liquid with higher density compare to the density of the gas. For this HYSYS simulation, the temperature drop is set to 10 ^{O}C after the gas enters cooler. The water liquid is later transferred into the separator to be separated form the gas stream. From the graph, it can be observe that, by placing cooler and separator, it will increase the moisture removal up to 44%.

CHAPTER 5

CONCLUSION

Liquefied natural gas or LNG need to be operated at low water moisture content to avoid any hydrate formation problem during the cryogenic production processes. Due to this, dehydration method is very essential. The research and analysis are conducted based on actual industrial application of natural gas dehydration. Dehydrating moisture in natural gas by conventional method such as dehydration by using glycol (liquid desiccants) is proven to give problems such as pump failures, leaks, and these existence technologies also need high capital investment and perhaps need more experts to operate it. As for this project, it covers on optimization of natural gas dehydration using solid desiccant. Literatures have shown, by using solid desiccant is seems better compare to liquid desiccant in many ways especially in term of environmental acceptance and it can give lower dew point over a wide range of operating condition. Although involve larger cost to install the dehydration unit using this method, it is still the best way to remove hydrates in the natural gas. That is why, optimization of dehydration using solid desiccant is choosed.

One of the ways to evaluate and optimize natural dehydration unit using solid desiccant is by using simulation and in this case HYSYS software is used. The process data is taken from the actual plant data as the basis of the development of the plant flowsheet in order to simulate the real process in the gas dehydration unit.

Optimization is done base on the flow sheet developed. From observation, the water moisture adsorption increase when there is increase in pressure and decrease in temperature. As for the study that had been conducted, the optimum temperature that the dehydration unit should be operated at the pressure of 60 – 70 bar is 21 ^{O}C.

This optimum operating temperature of 21 ^{O}C has been identified is proven by using a correlation developed by Alireza and Hari. This correlation can be use to determine the relationship between pressure and temperature at which hydrate will formed and in this case, the temperature of hydrates formation is at 18 ^{O}C. Thus, it is proved that the optimum temperature is about 21 ^{O}C

Another method to optimize the natural gas dehydration unit is by using cooler and separator to be as a pre-dehydration unit. This is because, the gas from the process before DHU is in high temperature. Thus, cooler can condense the water moisture that contained in the gas and the separator will separate between liquid and gas phase. From the calculation and observation of HYSYS data, 44% of moisture removal can be increase by installing cooler and separator.

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APPENDICES

APPENDIX A:

MOLECULAR SIEVE APPLICATION

	Molecular Sieve		
Application	Type	Grade	Comments
Natural Gas Dehydration	4A	MS 513 / 514	Dehydration to less than 0.1 ppm(v) prior to liquefaction or Natural Gas liquids extraction
Natural Gas Dehydration	3A	MS 562 / 564	Dehydration to less than 0.1 ppm(v) while minimizing methanol and / or propane co-adsorption; reduces regeneration heating requirements and improves yields with less hydrocarbon hold up
Natural Gas Dehydration with min. COS formation	3A	MS 562 / 564 MS 562 CS / 564 CS	Dehydration to less than 0.1 ppm(v); H_2S conversion to COS is less than 0.25%
Desulfurization of Natural Gas / NGL / LPG	5A	MS 521 / 522	Removal of H_2S, COS, and light Mercaptans to pipeline specifications
Desulfurization & COS Min. Natural Gas / NGL / LPG	5A	SZ - 5	Special COS minimizing 5A sieve for H_2S removal; H_2S conversion to COS is less than 4%
CO_2 Removal & Dehydration before Liquefaction	4A	MS 514 - LNG	High capacity Type 4A molecular sieve for removal ofCO_2 and water to less than 1 ppm(v) prior to liquefaction.
Condensate Drying	4A	MS 513 / 514	Dehydration to less than 1.0 ppm(w)
NGL / LPG Sweetening	13X	MS 542HP / 544HP SZ - 9	Removal of H_2S, COS, Mercaptans and high MW Sulfur compounds to maintain 1A copper strip LPG / NGL specifications

APPENDIX B:
KATZ K-FACTOR CHARTS