NATURAL GAS DEHYDRATION USING TRIETHYLENE GLYCOL (TEG)

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Abstract

Water vapour in natural gas stream, poses threat to process facilities if the dew point temperature is not properly controlled. Hydrate formation is imminent at temperatures below the dew point. It becomes very important to reduce the water content in the gas stream to below or within the tolerated limit of 6-7lb/MMSCFD. This work "Dehydration of Natural Gas Using Triethylene Glycol (TEG)" as the dehydrating agent, examined the amount of water removed from the natural gas stream when the dehydrating agent and the gas, flow in counter current manner in a contacting column. Adsorption and absorption are methods use to reduce the water content in a natural gas stream, in this work absorption was employed. Natural gas dehydrating plant was designed and simulated using HYSYS software. Process conditions of 92bar and 30°C and gas flow rate of 10MMSCFD, were inputted into the software and simulated. Six different TEG flowrates were used for the simulation. Results obtained show that for a TEG flow rate of 25.47m^3/h, the water content was reduced to 4.783lb/MMSCF from an initial value of 19.84lb/MMSCF. This value is well below the tolerated limit. The percentage composition of methane recovered at this flow rate was 82%. For a TEG flow rate of 3.5m^3/h, 6.8lb/MMSCF of water was obtained in the processed gas stream. Again, this value is within the tolerated limit. The hydrate formation temperature of the dry gas stream was tested with the hydrate utility in the software, which was -18.663^{o}C at the stream pressure of 92bar. This value is well below the dry gas stream temperature of 37.96^{o}C. This means that the dry gas can be transported to region of temperature not below the hydrate formation temperature.

Keywords: Dehydration; TEG; natural gas; absorption; hydrate; Counter-current; water vapour; reservoir; fossil fuel.

1. Introduction

Presently, about 20 percent of all of the primary energy requirements of the world are provided by natural gas; though it was once an unwanted by-product of crude oil production. This development has been recorded in only a few years with the increased availability of the gas resources from different countries [6]. Today, natural gas is one of the most important fuels in our life and one of the principle sources of energy for many of our day-to-day needs and activities. It is an important factor for the development of countries that have strong economy because it is a source of energy for household, industrial and commercial use, as well as to generate electricity. Natural gas, in itself, might be considered a very uninteresting gas - it is colorless, shapeless, and odorless in its pure form, but it is one of the cleanest, safest, and most useful of all energy sources [1]. Natural gas is the gas obtained from natural underground reservoirs either as free gas or gas associated with crude oil. It generally contains large amounts of methane along with decreasing amounts of other hydrocarbons [5]. Natural gas is a gaseous fossil fuel. Fossil fuels are essentially, the remains of plants and animals and microorganisms that lived millions and millions of years ago. It consists primarily of methane but including significant quantities of ethane, propane, butane, and pentane. Methane is a molecule made up of one carbon atom and four hydrogen atoms, and is referred to as CH$_4$. Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is 'wet' .The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means a pure gas. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in

the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed non-associated gas. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil it commonly exists in raw natural gas or sour gas The raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds as shown in figure 1 [1]. The properties of natural gas include gas-specific gravity, pseudocritical pressure and temperature, viscosity, compressibility factor, gas density, and gas compressibility. Knowledge of these property values is essential for designing and analyzing natural gas production and processing systems. Because natural gas is a complex mixture of light hydrocarbons with a minor amount of inorganic compounds, it is always desirable to find the composition of the gas through measurements. Once the gas composition is known, gas properties can usually be estimated using established correlations with confidence [3].

Table1 Compositions of raw natural gas [1]

Methane	CH_4	70-90%
Ethane	C_2H_6	
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	
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

In order to meet the requirements for a clean, dry, wholly gaseous fuel suitable for transmission through pipelines and distribution for burning by end users, the gas must go through several stages of processing, including the removal of entrained liquids from the gas, followed by drying to reduce water content. In order to remove water content, dehydration process is used to treat the natural gas. The types of dehydration process used are absorption, adsorption, gas permeation and refrigeration. The most widely dehydration processes used are those which usually involve one of two processes: either absorption, or adsorption. Absorption occurs when the water vapour is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface [9]. Gas dehydration is one of the most prominent unit operations in the natural gas industry. In this operation water content is removed from natural gas streams to meet sales specifications or other downstream gas processes such as gas liquid recovery. In particular, water content level in natural gas must be maintained below a certain threshold so as to prevent hydrate formation and minimize corrosion in transmission pipelines. The lifetime of a pipeline is governed by the rate at which corrosion occurs which is directly linked with the present of water content in gas and causes the formation of hydrates which can reduce pipeline flow capacities, even leading to blockages, and potential damage to process filters , valves and compressors [1]. There are three major methods of dehydration are (1) direct cooling, (2) adsorption, and (3) absorption [10]. For the purpose of this project work, only absorption process will be discussed which is the process used in the plant as case study.

Absorption is the transfer of a component from the gas phase to the liquid phase, and is more favorable at a lower temperature and higher pressure. Water vapor is removed from the gas by intimate contact with a hygroscopic liquid desiccant in absorption dehydration. The contact is usually achieved in packed or trayed towers. Glycols have been widely used as effective liquid desiccants. Dehydration by absorption with glycol is usually economically more attractive than dehydration by solid desiccant, though both processes are capable of meeting the required dew point [3].

2. Dehydration by Using Triethylene Glycol (TEG)

There are numbers of liquids that can be used to absorb water from natural gases such as calcium chloride, lithium chloride and glycols. Glycol dehydration is a liquid desiccant system for the removal of water from natural gas. It is the most common and economic

means of water removal from these streams. Glycol, the principal agent in this process, has a chemical affinity for water. The liquid glycol will absorbs the water content in the natural gas. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. This operation is called absorption [1]. Glycols used for dehydrating natural gas are ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG). Normally a single type of pure glycol is used in a dehydrator, but sometimes a glycol blend is economically attractive. TEG has gained nearly universal acceptance as the most cost effective of the glycols due to its superior dew point depression, operating cost, and operation reliability [7]. The Physical form of TEG is a colorless, odorless and stable liquid with high viscosity and a high boiling point. It is also soluble in ethanol, acetone, acetic acid, glycerin, pyridine and aldehydes; slightly soluble in diethyl ether; and insoluble in oil, fat and hydrocarbons. The physical and chemical properties of triethylene glycol are shown in Table 2.

Table 2 Physical and chemical properties of triethylene glycol [9]

Parameter	Unit	Properties
Common name	-	Triethylene Glycol
Chemical name	-	Triethylene Glycol
CAS registry number	-	112-27-6
Empirical formula	-	C6H14O4
Molecular weight	g/mol	150.17
Density	g/cm3	1.10
Flash point (PMCC)	°C (°F)	176 (350)
Ignition point, °C (°F)	°C (°F)	371 (700)
Distillation range at 760mmHg	°C (°F)	
Initial boiling point		278 (532)
Dry point		300 (572)
Boiling point at 760 mm Hg	°C (°F)	287.8 (550)
Freezing point	°C (°F)	-7.2 (19)
Coefficient of expansion per °C at 20°C	-	0.00068
Surface tension at 20°C	dyne/cm	45.2
Vapor pressure at 20°C	mm Hg	less than 0.01
Specific Gravity	-	1.1274
Solubility	-	Highly miscible in water

TEG, or triglycol is an odourless viscous liquid with molecular formula $C_6H_{14}O_4$. Although many liquids possess the ability to absorb water from gas, the liquid that is most desirable to use for commercial dehydration purposes should possess the following properties: (i) Strong affinity for water (ii) High boiling points (iii) Low cost (iv)Noncorrosive (v) Low affinity for hydrocarbons and acid gases (vi) Thermal stability (vii) Easy regeneration (viii) Low viscosity (ix) Low vapor pressure at the contact temperature (x) Low solubility in hydrocarbon (Xi) Low tendency to foam and emulsify. The rational of using TEG or advantages of TEG is ease of regeneration and operation, minimal losses of drying agent during operation, high affinity for water, chemical stability, high hygroscopicity and low vapor pressure at the contact temperature [1]. Triethylene glycol has been successfully used to dehydrate sweet and sour natural gases over wide ranges of operating conditions. Dew point depression of 40°F to 140°F can be achieved at a gas pressure ranging from 25 psig to 2500 psig and gas temperature between 40°F and 160°F. The dew point depression obtained depends on the equilibrium dew point temperature for a given TEG concentration and contact temperature. Increased glycol viscosity may cause problems at lower contact temperature. Thus, heating of the natural gas may be desirable. Very hot gas streams are often cooled prior to dehydration to prevent vaporization of TEG. The feeding-in gas must be cleaned to remove all liquid water and hydrocarbons, wax, sand, drilling mud, and other impurities. These substances can cause severe foaming, flooding, higher glycol losses, poor efficiency, and increased maintenance in the dehydration tower or absorber. These impurities can be removed using an efficient scrubber, separator, or even a filter separator for very contaminated gases [3].

3. Methodology

The design and simulation of the natural gas dehydration plant, using HYSYS was utilized in this work to achieve the desired objectives. A case study package of the software

was used in the analysis; such that different quantity and flow rate of TEG was imposed on the plant to determine the various quantity of water removed.

3.1 Process Overview of OVP Gas Treatment Plant

The OVP Gas treatment plant is operated by Total Exploration and Production [11]. It is situated in the South-South of Nigeria, the Niger Delta rich Oil region of the Country. The inlet raw high pressure (HP) gas to the OVP treatment plant from 15 wells and OVEH flow station is routed through high pressure separators, vessel 301 / vessel 302 and cooled inside cooler fans, EB 301. The vessel 301 inlet separator, is to separate the mixed gas received from the manifolds and routed to the cooling unit, cooler EB 301. The condensate recovered is routed to OVEH Flow Station. The gas stream, coming from the vessel 301, goes through the air Cooler (EB 301) in order to reach a temperature close to 45^0C. The outlet line has an automatic temperature monitor, control by the Process control system, (PCS). This Air Cooler is composed of 10 fans capable of being manually and independently controlled via the operator stations. The High pressure gas is then routed to the heaters. The heaters, EC 601 A and B, are based on heat exchanged between two gas streams: the treated gas stream coming from the Export gas drum, vessel 602, and the raw gas stream from high pressure gas separator, vessel 302. The gas stream from the export gas drum is heated while the raw gas from the high pressure separator is cooled to a temperature close to 25°C. The gas coming from EC 601 is routed to the dehydration separator vessel 601. The treated gas is sent to be exported via the metering unit. A methanol injection point is provided on the raw gas stream before cooling. The HP gas is routed to the dehydration unit for treatment and then to the refrigeration unit. The dry gas obtained is routed to the export line to BONNY, through the metering unit. All the condensates recovered from the gas are channeled to OVEH flow station for treatment [2].

3.2 Brief Description of OVP Glycol Dehydration Process Flow

Glycol dehydration units are typically represented by a contactor, a flash drum, heat exchangers, and a regenerator, as shown in Figure 1. The TEG enters at the top of the contactor and as it progresses toward the bottom of the column, it absorbs the water contained in the wet gas which is entering from the bottom. The dry gas exits at the top of the contactor at the required water dew point. The rich TEG flows from bottom of the contactor to a TEG/condensate separator, where TEG, condensates and gas are separated. From the TEG/condensate separator, the rich TEG passes through a heat exchanger (shell and tube exchanger) to raise the temperature up, then goes to the flash drum, where the low pressure and high temperature enhances the removal of a portion of absorbed light ends components, mainly C1 and C2. Here condensates are also skimmed out by means of a condensate collecting bucket. The rich TEG leaving the flash drum is filtered in a rich TEG cartridge filters to eliminate solid particles. The filtered rich TEG then flows through a plate-type heat exchanger where its temperature is further raised up closer to the boiling point of the rich TEG. The hot rich TEG leaving the exchanger finally enters the TEG still column and it flows downward to the glycol reboiler where it is concentrated. The hot lean glycol from the reboiler overflows into the stripping column through distributor at the top of the packing, here it comes in contact with preheated stripping fuel gas which enters at the bottom of a structure packing through a distributor and removes the remaining water in order to achieve a required lean TEG concentration of 99.7%. From the stripping column, the lean TEG flows to the receiving surge drum. The surge drum acts as a buffer to collect lean TEG from regeneration system and supply for injection to TEG contactor. The lean TEG is then sent to the TEG circulation pumps, which pumps the TEG to the contactor through an air cooler and rich/lean glycol heat exchangers. Chemical provision is given to the suction line of the pumps to control the pH of lean glycol by injecting a base and / or a corrosion inhibitor and to stop foaming in the contactor [11].

4. The Design and Simulation

Process variables of the plant is used to design and simulate the gas plant using HYSYS Simulation software and the plant will include TEG recycling unit. The process conditions used in this simulation are those obtained from the Statistic/Reporting department of the OVP natural gas dehydration plant and they include: Inlet gas temperature to contactor, Lean TEG temperature to contactor, Reboiler temperature, Outlet gas from contactor dew point temperature, Lean glycol flow rate to contactor,

Lean glycol concentration and Gas flow rate to contactor. Each process unit is designed and simulated according to the process condition, as shown in figure 2.
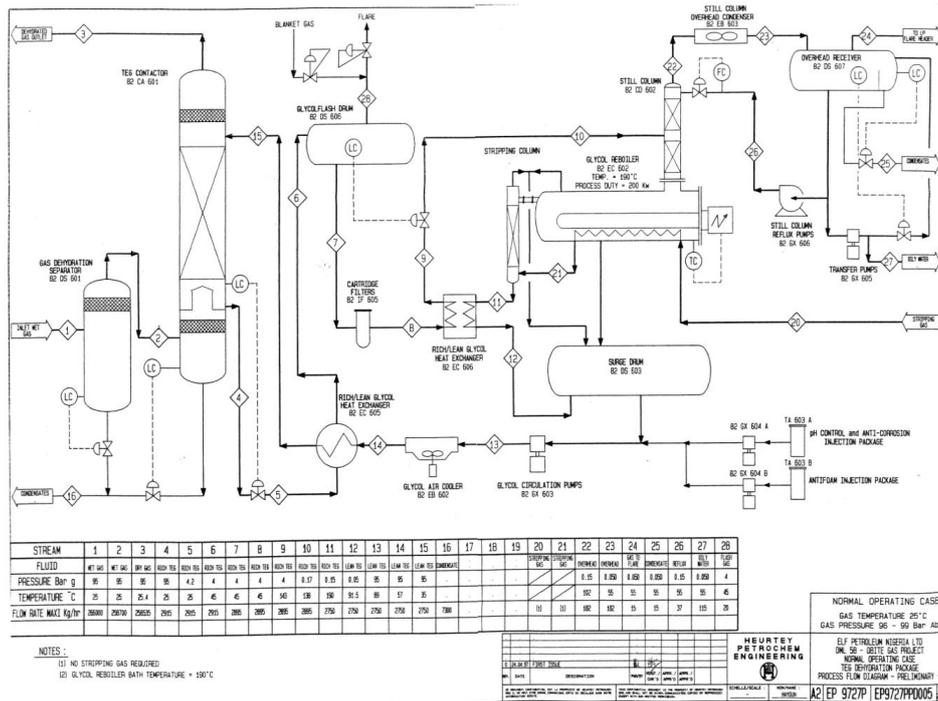
Figure 1 Glycol Dehydration Unit [11]

Table 3 Feed Gas Composition and Process Conditions

Components	Compositions	Process Conditions	Value
C_1	0.8042	Temperature	30°C
C_2	0.082	Pressure	92bar
C_3	0.0248	Flow rate	10MMSCFD
$i\text{-}C_4$	0.0085		
$n\text{-}C_4$	0.005	**Water Composition and Condition**	
C_5^+	0.014	Temperature	30°C
N_2	0.015	Pressure	92bar
H_2S	0.0165	Mole Fraction	1.000
CO_2	0.03	Flow rate	0.5kgmole/h
Total	1.0000		

The composition of the natural gas stream is saturated with water, prior to entering the Contactor. This is to demonstrate the effectiveness of the TEG in the contactor. The gas compositions and conditions are inputted into the software and simulated. The Process Flow Diagram and the generated production streams are shown in figure 2 below.
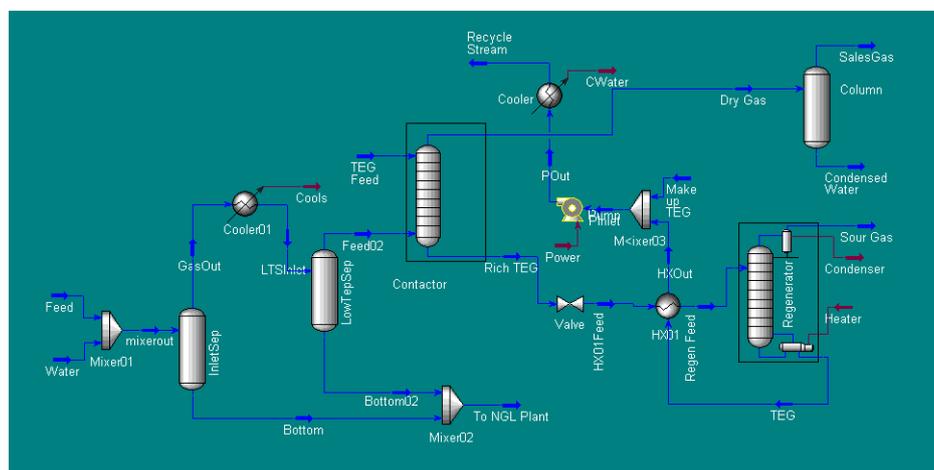
Figure 2 Process Flow Diagram of Natural gas Dehydration Unit

4.1 Compositions of Feed and Product

The pipeline specification of water content in a processed natural gas stream that can be tolerated is 6-7lb/MMSCF (that is 6lb to 7lb of water per million standard cubic feet of processed natural gas). The mixerOut stream has a flow rate of 500.5kgmole/h (10360 kg/h), of which the water content is 9.008kg/h (19.84lb/h). This value is far above the specification for water content in natural gas, therefore, the gas needs to be treated so as to reduce the water content in the strea [11]. 25.47m^3/h of TEG was injected into the contactor to counter mix with the natural gas in the contactor. The gas exit stream "Dry gas" has a flow rate of 487.6693kgmole/h (9974.6kg/h), of which methane has a flow rate of 398.335 kgmole/h (6390.446kg/h) and that of water is 0.005kgmole/h (0.0905kg/h). The recovery of methane is 98.9244% and its percentage composition in the dry gas stream is approximately 82%.

The pounds per million standard cubic feet of water in the dry gas stream can be calculated as follows:

$$\frac{0.0905kg}{MMSCF} = \frac{0.0905kg}{MMSCFh} \cdot \frac{1lb}{0.454kg} \cdot \frac{24h}{1\ day} = 4.783\frac{lb}{MMSCFD} \quad \ldots\ldots.. \quad\quad (1)$$

Although, this value is well below the water content specification, but was achieved for a TEG flow rate of 25.47m^3/h. For a flow rate of 3.5m^3/h, the percentage of methane in the dry gas stream remains at approximately 82% and its flow rate is 401.651kgmol/h (6443.651kg/h). The water content in the dry gas stream is 0.007144kgmol/h (0.1286kg/h). Following the same conversion above the water content is 6.8 lb/MMSCFD in the dry gas stream. These value are within the limit of water content in natural gas stream that can be tolerated, and indicate that the processed gas can be transported through pipeline without hydrate forming in the line, as will be seen later in this work. The TEG was flowed at different rate to determine the water content in the processed natural gas stream, as shown in the table and curve below.

Table 4 TEG Rate and Water Content

TEG Rate (m^3/hr)	Water content (lb/MMSCFD)
3.5	6.800
5.0	6.645
10	6.544
15	5.968
20	5.910
25.47	4.783
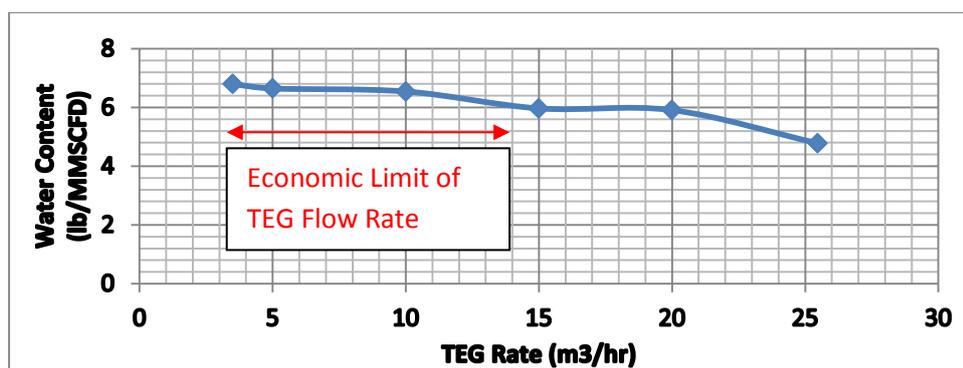
Figure 3 Plots of TEG Rate and Water Content

The curve of figure 3, shows an inverse relationship between the TEG rate and the water content. As it is expected, high flow rate of TEG will absorb more of the water present in the natural gas stream and low flow rate will absorb less water from the gas stream. Between a TEG rate of 3.5m^3/hr and 14m^3/hr, the water content is between 6lb/MMSCFD-7lb/MMSCFD, which is the water content limit in natural gas. Therefore, using a flow rate as high as 25m^3/hr may not add significant financial value to the revenue derived from the sales of the gas. However, it is important for the process engineer to know the minimum tolerated limit of water in the gas stream and what flow rate of TEG to use in order not to exceed

the water content limit, so as not to flood the contactor with TEG (which can cause liquid carryover) and still not add any significant financial value to the processed gas.

4.2 Hydrate Formation Analysis

Hydrate formation in process units and in pipelines can be within minutes without prior warning to the process engineer, and it can impact negatively on production (frequent production shutdown, loss of production time, corrosion and increase in operating cost). To avoid these negative impacts, it is necessary to test natural gas streams to determine at what temperature will hydrate form and then carryout operation above this temperature [8]. To do this, the Hydrate Utility Package in the software was used to carryout test on the dry gas stream to determine the possibility of hydrate formation in the stream. The following results were obtained:

- Hydrate calculation model: Vapour Model Only
- Equilibrium Phase: Vapour Phase
- Hydrate Formation Type: No type form
- Hydrate Formation Flag: Will Not Form

This is because the dry gas stream temperature is 37.96^{o}C and the hydrate formation temperature is -18.663^{o}C at the stream pressure of 9200KPa (92bar), which is far below the stream temperature. The critical properties of the dry gas stream are: Critical temperature T_{cr} = -46.48^{o}C, Critical Pressure P_{cr} = 8328KPa (83.26bar), Cricondentherm = 26.0^{o}C, Cricondenbar = 10910KPa (109.1bar). These values can be located in Figure 4.1.

The hydrate formation phase diagram is shown in figure 4. On the phase diagram, the hydrate formation line, intercept the dew point line at temperature of -18.663^{o}C. This means that the dry gas stream can be transported safely at temperatures above this value, without water condensing out of the stream. Temperatures at this value and below will cause hydrate to form. Again, this is because, the water content is very low. Other phase diagrams also generated are shown below.
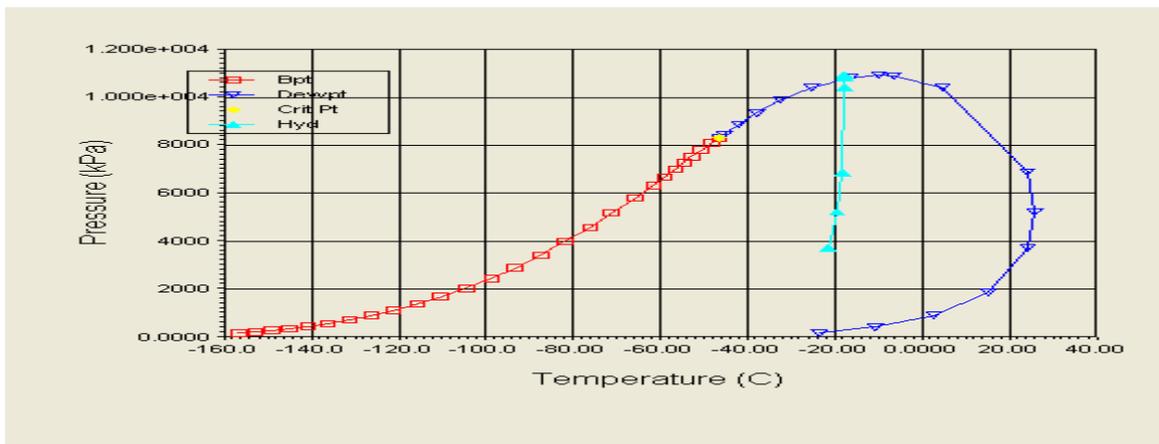
Figure 4 Hydrate Formation Phase Diagram for TEG rate of 25.47m^3/h
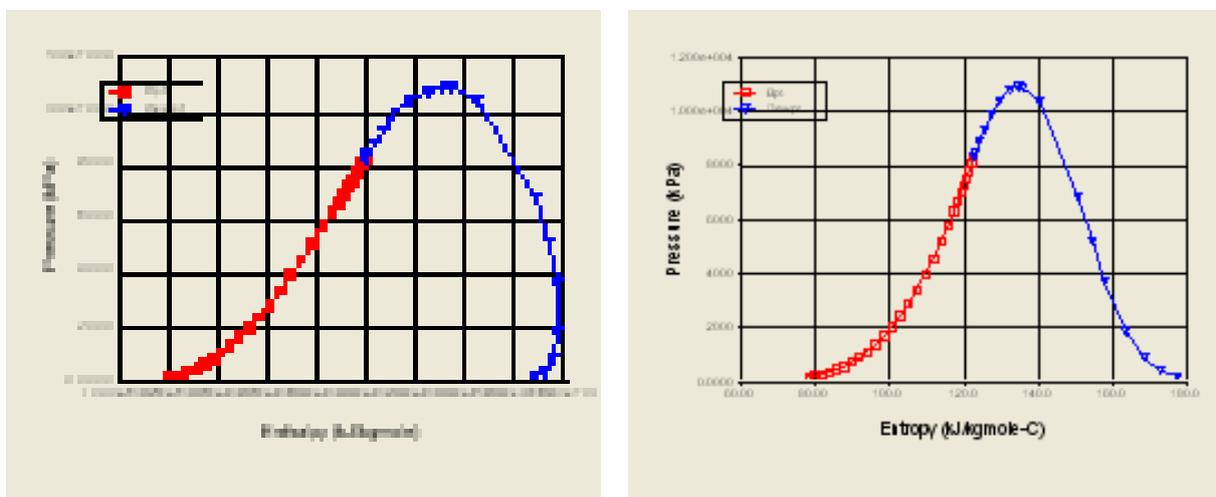
Figure 5 Pressure vs Enthalpy and Entropy Phase Diagram
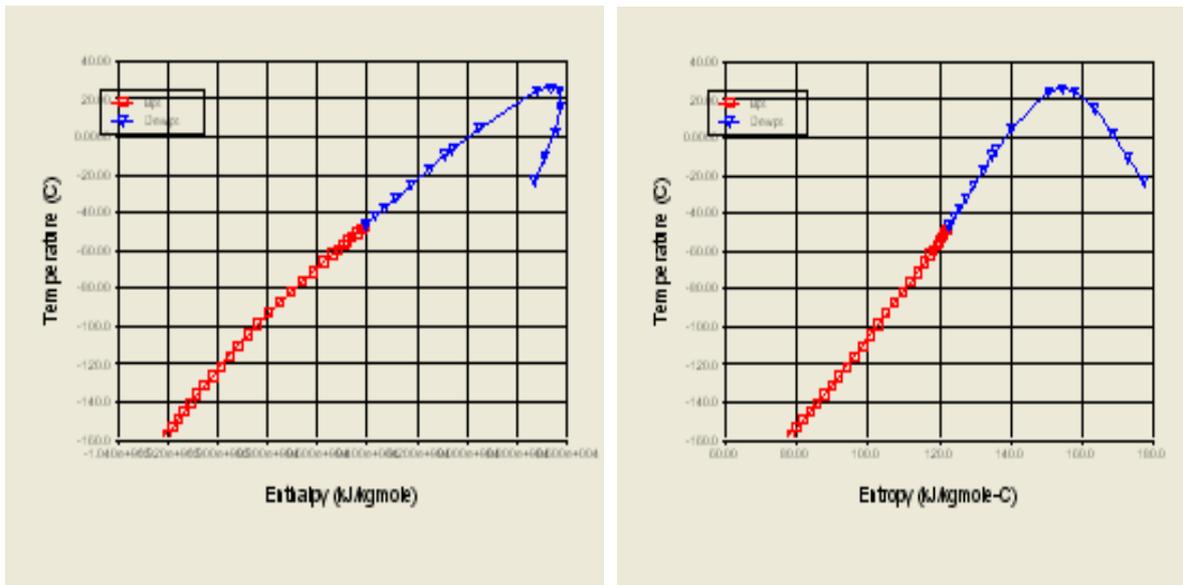
Figure 6 Temperature vs enthalpy and Entropy Phase Diagram

The phase diagrams and hydrate formation temperature of the different TEG flow rates are shown. For a TEG rate of 20m³/h, hydrate formation temperature is -24.99°C at stream pressure of 9190KPa.
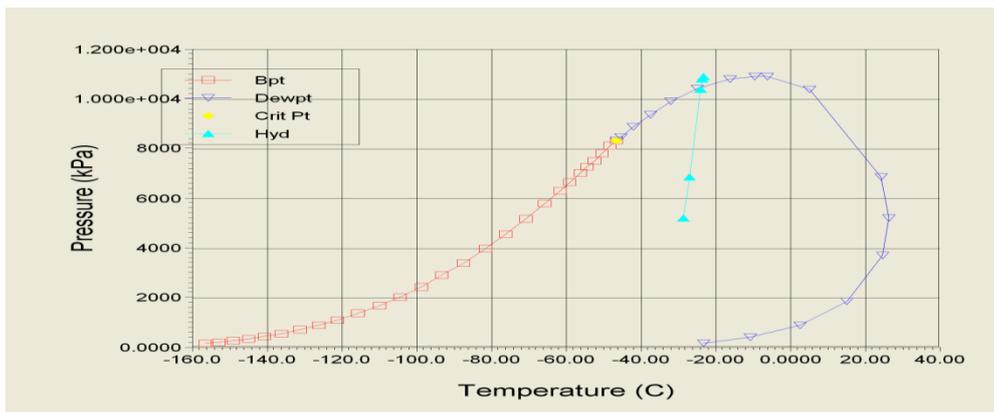
Figure 7 Hydrate Formation Temperature for TEG rate of 20m³/h

For a TEG rate of 15m³/h, hydrate formation temperature is -29.40°C at stream pressure of 9190KPa and for TEG rate of 10m³/h, hydrate formation temperature is -29.95°C at stream pressure of 9190KPa.
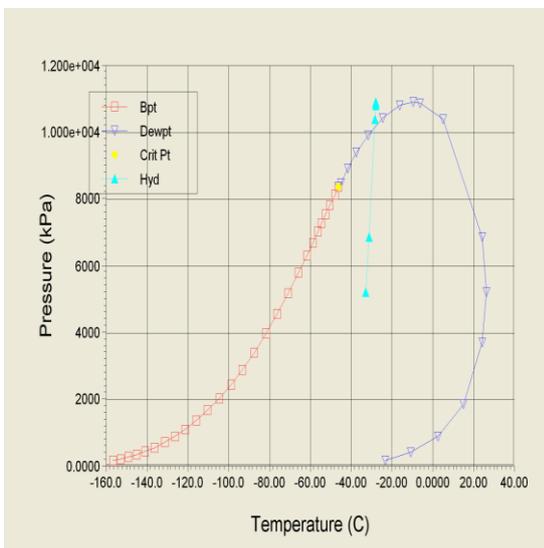
Fig. 8 Hydrate Formation Tempt. for TEG rate of 15m³/h
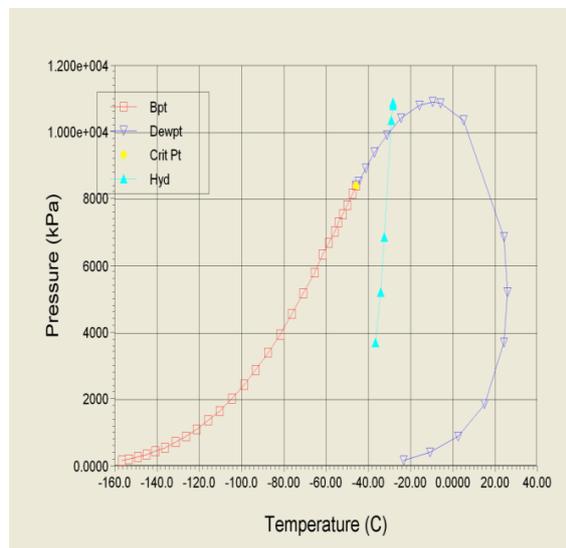
Fig. 9 Hydrate Formation Temperature for TEG rate of 10m³/h

For a TEG rate of 5m³/h, hydrate formation temperature is -32.97°C at stream pressure of 9190KPa. and for a TEG rate of 3.5m³/h, hydrate formation temperature is -33.96°C at the stream pressure.
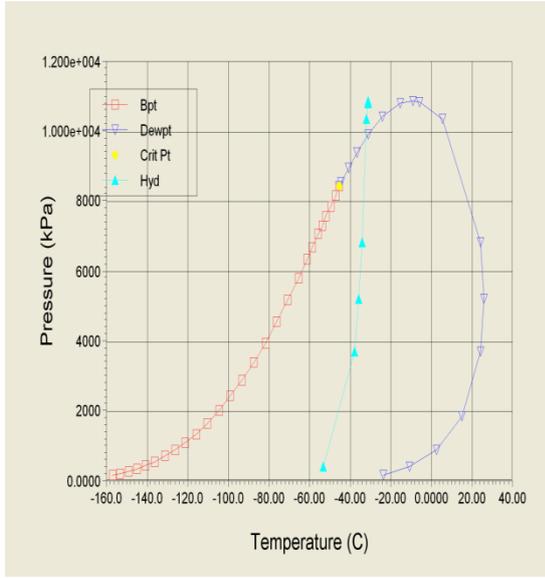
Fig. 10 Hydrate Formation Tempt. for TEG rate of 5m³/h
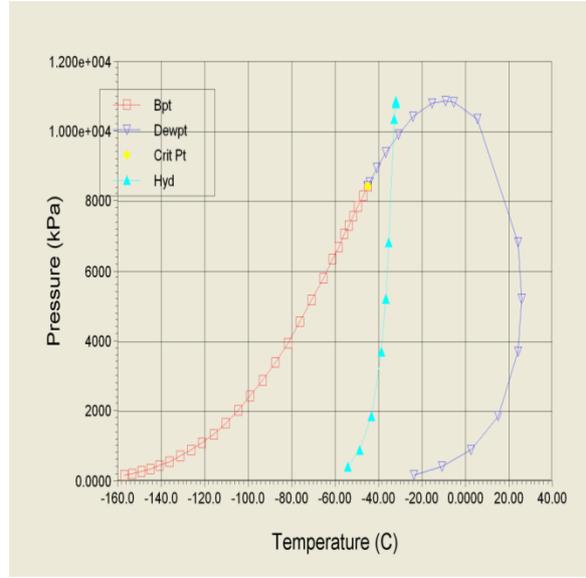
Fig. 11 Hydrate Formation Tempt. for TEG rate of 3.5m³/h

4.3 Contactor Column Profile Analysis

The contactor is designed such that the maximum pressure (92bar) of the streams is within the working pressure (98bar) of the OVP natural gas dehydration plant. During the simulation process, the column profile was generated for 25.47m³/h of TEG flow rate, as shown in table 5.

Table 5 Contactor column profile (TEG rate of 25.47m³/h)

Stages	Pressure (Kpa)	Temperature (°C)	Net Liquid (kgmol/h)	Net Vapour (kgmol/h)	Net Feed Kgmol/h	Net Draw Kgmol/h
0	9190	37.96	203.235	487.800	193.3	487.669
1	9191	38.09	204.367	497.572		
2	9193	38.08	204.361	498.704		
3	9194	37.92	205.106	499.198		
4	9196	37.46	205.238	499.443		
5	9197	36.29	205.325	499.573		
6	9199	33.45	205.426	499.662		
7	9200	26.65	205.536	499.763	500.29	205.95

The graphical representations of the column profile are shown in figures 12 and 13:
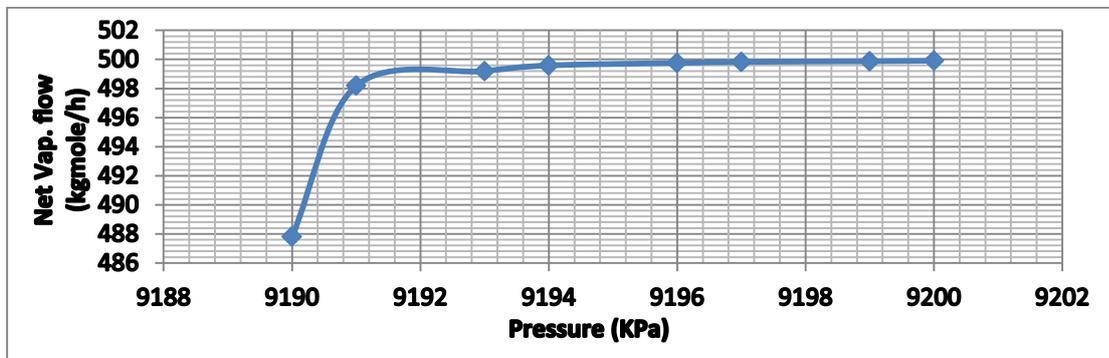
Figure 12 Plot of Net vapour vs Pressure.
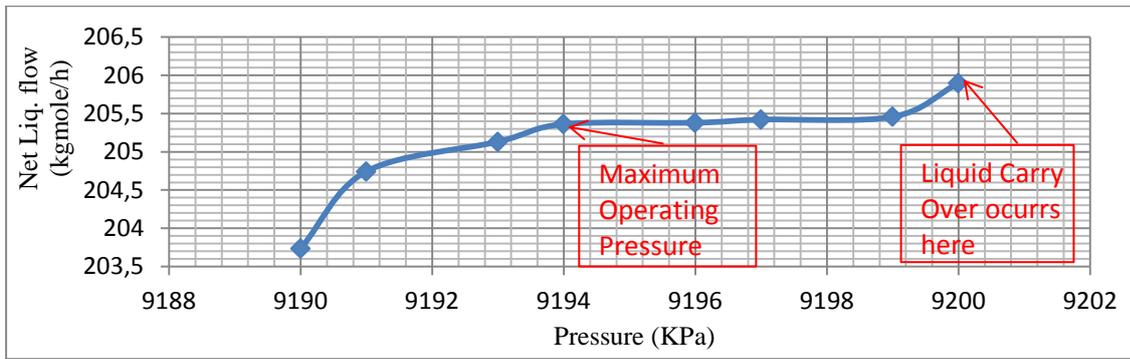
Figure 13 Plot of Net Liquid vs Pressure.

Figure 7 shows an interesting result, because we are interested in how much of the vapour phase can be recovered from the feed to the contactor, it is important to know the pressure at which recovery will be maximum. The plot shows that net vapour recovery increase sharply up to a pressure of 9196KPa (91.945bar). The same can be seen in the net liquid flow, but maximum liquid is obtained at pressure of 9200KPa. Operating close to this pressure may cause liquid "Carry Over", a phenomenon in which liquid enters the gas stream, causing the dew point temperature and also the hydrate formation temperature of the processed gas to increase. Contactors are designed such that the operating temperature is well above hydrate formation temperature, to avoid clogs in pipelines and process vessels. Similarly, column profile and curves for TEG flow rate of $3.5m^3/h$ are shown in table 6 and figures 14 and 15 respectively.

Table 6 Contactor Column Profile (TEG rate of $3.5m^3/h$)

Stages	Pressure (Kpa)	Temperature (°C)	Net Liq. (kgmol/h)	Net Vap. (kgmol/h)	Net Feed Kgmol/h	Net Draw Kgmol/h
0	9190	32.00	28.629	497.86	26.565	497.860
1	9191	28.00	28.687	499.928		
2	9193	26.82	28.694	499.986		
3	9194	26.50	28.695	499.993		
4	9196	26.41	28.696	499.994		
5	9197	26.40	28.697	499.995		
6	9199	26.40	28.698	499.995		
7	9200	26.40	28.700	499.997	500.29	28.990
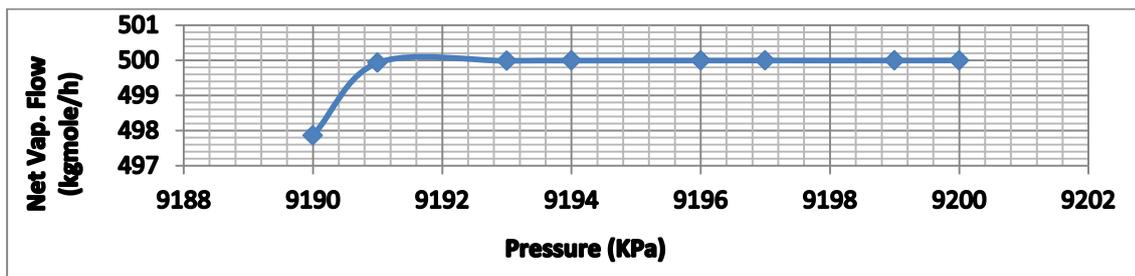
Figure 14 Plot of Net vapour vs Pressure.
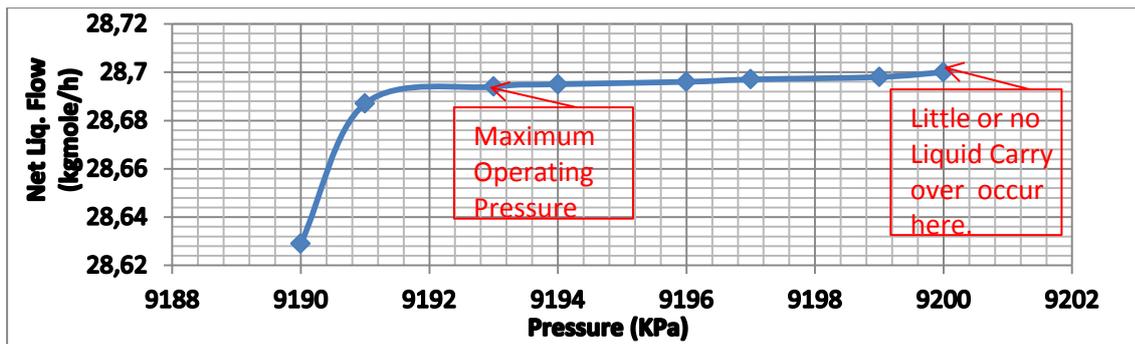
Figure 15 Plot of Net liquid vs Pressure.

Figure 3, 8 and 10, reveal interesting results. In figure 3, for a TEG flow rate of 3.5m^3/h, the water content is within the tolerated limit and for a TEG flow rate of 25.47m^3/h, the water content is below 6lb/MMSCFD. These results are acceptable, since they are not above 7lb/MMSCFD. In Figure 8, using a TEG flow rate of 25.47m^3/h, there was a reduction in water content below 6lb/MMSCFD, this may result in liquid carryover at pressure of 9200KPa. But in Figure 10, for a TEG flow rate of 3.5m^3/h, there will be little or no liquid carryover at a pressure of 9200KPa. Thus, it will be more economical to use TEG rate of 3.5-14m^3/h and contactor pressure of 9200KPa. In natural gas dehydration plant, where a drop in temperature is noticed, heat is usually supplied to the line to heat up the stream to avoid the stream losing more heat, which will cause the temperature to drop towards the hydrate formation temperature. When this drop in temperature is not noticed, the economic consequence is great.

In this work, the amount of heat removed from the dry gas stream is -4.208x10^{7}KJ/hr, at the stream temperature of 37.96^{o}C. A drop in temperature below this value will cause the amount of heat removed to be less than the -4.208x10^{7}KJ/hr, and it will necessitate the supply of heat from an external source to heat up the stream so as to raise the temperature. Supplying heat from an external source will increase operating cost and thereby reducing the revenue that may accrue from producing 1.0MMSCFD of natural gas. Economically, this is not healthy to the business. Therefore, it is important that natural gas plants are designed and optimized based on process conditions, to keep the plant running.

5. Conclusion

Natural gas is usually saturated with water from the reservoir, removing this water is a major task for the process engineers. Natural gas facilities are designed to handle water removal from the gas stream to meet pipeline specification of water content in the processed gas stream. With the use of HYSYS software, natural gas dehydration plant was designed; process conditions and compositions were inputted and simulated. Results obtained show that water content in natural gas stream from reservoirs can be reduced to the pipeline specification limit. However, different water contents in the processed gas stream were obtained for different flow rates of TEG. For the purpose of running the plant economically, the minimum flow rate of TEG which will reduce the water content to within the limit of pipeline specification, is very important and the result obtained showed that a minimum of 3.5m^3/h of TEG is required to reduce the water content of a gas stream of 10MMSCFD to 6.8lb/MMSCFD, which is within the limit of 6-7lb/MMSCFD, this value when compare to OVP gas plant which uses 15m^3/h for the gas stream of 10MMSCFD to achieve the same water content specification is far lower. Values below this flow rate (3.5m^3/h) may not reduce the water content to the specified limit. This will pose threat to process facilities because of hydrate formation and cannot be tolerated when transporting the gas to a region of low temperature. From the result, the company can run OVP gas plant more economically with a TEG flow rate of 3.5m^3/h or slightly above that.

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