

Improving the performance of a natural gas dehydration plant using a combination of solvents

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ABSTRACT

Natural gas dehydration using solvents like triethylene glycol (TEG) can reduce water dew point to sales gas quality, thereby avoiding corrosion, hydrate formation and plugging of flowlines. A study of the water dew point adjustment unit of a real plant within an Associated Gas Gathering (AGG) Facility in Nigeria's B field revealed that the limited performance of the TEG solvent currently in use decreases the quality of the marketed gas by raising the hydrate formation potential of the gas exported from this facility, with the number of complaints from gas buyers also increasing. In this work, we investigate the performance of the dehydration unit within the AGG Facility using a proprietary process simulator in which the performance of the glycol currently in use (TEG) and a proposed glycol with adjusted properties (TEG plus fifteen percent (15%) diethylene glycol (DEG) additive) are compared. This study uses different sets of sensitivity parameters: TEG circulation rate, inlet gas pressure, inlet gas temperature, and inlet gas flow rate, for its parametric analysis. Results, guided by key performance indicators including rich solvent-water mole fraction, amount of water removed from dehydrated gas, and water content in dehydrated gas, show that the dehydration process improved upon the application of the reformulated glycol (TEG+DEG), with the quality of the marketed gas increasing by about 25%. Overall, results yield criteria for design and improved operating conditions for the natural gas dehydration plant.

KEYWORDS; -Natural gas dehydration, triethylene glycol (TEG), diethylene glycol (DEG).

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I. INTRODUCTION

There has been remarkable growth in the global demand for natural gas [5, 14] which is attributable to the varied primary uses of this fuel including its use as petrochemical feedstock[15], fuel for power generation, and a host of other uses. This growth in demand can also be linked to its clean burning characteristics, as it is easier for gas processors to meet stringent environmental requirements worldwide [11].

Found in much of the world's offshore fields [6] the principal market for natural gas is achieved via transmission lines, which distribute it to different consuming centers, such as industrial, commercial and domestic sectors. Before selling to customers, field processing operations are enforced in order to treat and condition the natural gas towards meeting the requirements and specifications set by the gas transmission companies, by ultimately freeing the gas of its impurities [3, 4, 8, 9]. One of the 'impurities' to free from the gas is water vapour, and dehydration processes are employed for this, with several techniques that could be deployed [7, 10, 15, 16] including absorption and adsorption processes [18].

Absorption processes involve the use of solvents like glycols, with triethylene glycols (TEG) considered the most common glycol used by industry for natural gas dehydration. This water removal process almost always takes place within a gas processing plant of several staged processes including a condensate removal unit, acid gas removal unit, dehydration unit, and mercury removal unit. The processing of the gas is motivated by impurity issues and sales gas specification issues relating to heating value and Wobbe Index (also called Wobbe Number).

In this work, we investigate an associated gas gathering (AGG) facility of Field B located in the Niger Delta region of Nigeria with a primary objective of studying performance issues associated with the TEG solvent currently in use and proffering a realistic solution to the problem.

II. PROCESS DESCRIPTION

The Process of Glycol Dehydration

Figure 1 shows a block flow diagram of a typical processing plant for natural gas. A gas dehydration unit within such a plant, which usually comes after the acid gas removal unit, if the latter is present, can be easily identified from Figure 1. The sweetened gas upstream of the dehydration unit is water saturated and can be

removed depending on the size and nature of the facility. In natural gas liquid (NGL) extraction and liquefied natural gas (LNG) operations, dehydration by adsorption is often the best solution [6, 18], however, for an outlet dew point requirement above -40°C , absorption using glycol solvents is generally preferred [9, 13]. Water removal processes would prevent condensation of water under high pressure and/or low temperature that would have resulted in problems associated with the presence of free water in natural gas pipelines [12, 17], including hydrate formation (with tendency to plug pipes or downstream process equipment), corrosion (in the presence of acid gases such as carbon dioxide and water), and slugging problems (which reduces the flow efficiency and causes damage to downstream equipment).

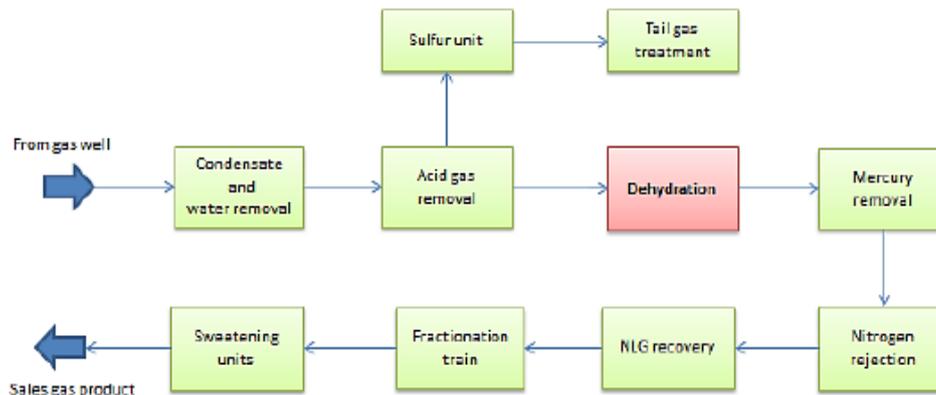


Figure 1: A typical processing plant for natural gas [6].

The Associated Gas Gathering (AGG) Facility

The Associated Gas Gathering (AGG) project of Field B in the Niger Delta has a primary function of monetizing associated gas as a means of reducing flaring, with a design capacity of 250 MMSCF/D [1, 6]. Currently, a total of about 68MMSCF/D is compressed and a maximum of 53MMSCF/D is supplied for sales to customers and approximately 9MMSCF/D to gas lift facilities and 6MMSCF/D for utilities[6]. There are inlet facilities (including pig receiver and slug catcher), compression facilities (including a three-stage centrifugal compressor driven by a solar mars T-100 gas turbine), dehydration facilities (key catcher) and export facilities (including flow and quality monitoring equipment). The compressor has two inlet streams going into both the first and second stages, with the low pressure (LP) gas from the local flow station (II) feeding into the first stage. The high pressure (HP) gas from the local flow station (II) is fed into the second stage, while the compressor third stage discharge pressure is fed into TEG contactor. The TEG contactor outlet is controlled at a water dew point of -100°C to prevent any dehydration or corrosion problems in the downstream systems. The liquid generated in the AGG plant are metered and disposed of directly into the crude oil export pipelines downstream of flowstation (II). The flow process of the AGG facility is schematically indicated in Figure 2.

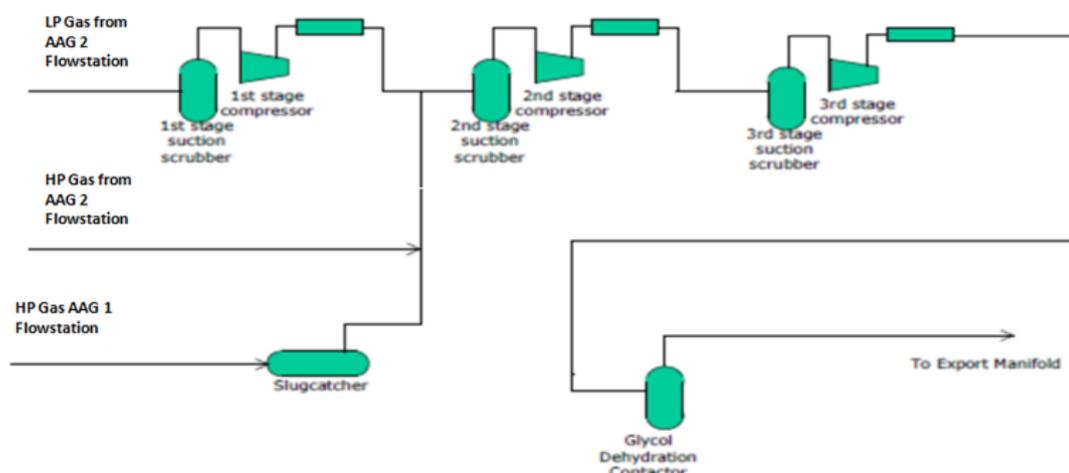


Figure 2: The AGG process flow scheme[6]

Triethylene Glycol Dehydration Process

The dehydration of the gas currently employs the “traditional” triethylene glycol (TEG) based dehydration process and represents a unit with gas absorption and solvent regeneration, with the overall

objective being to reduce the amount of water in the natural gas. Ultimately, an improvement of the process using a hybrid solvent approach of combining the TEG and DEG solvents is investigated. Figure 3 shows a typical gas dehydration unit used in the facility where the wet gas feeds the contactor for the absorption process to resume using either TEG or TEG+DEG, as solvents. From the end of the regenerator column, figure 3 shows that a lean solvent, say TEG, feeds the top part of the contactor and absorbs water, then leaves the bottom level control as rich solvent, while dry or dehydrated gas leaves the top of the first contactor. The regenerated column on the right recovers the solvent while stripping of the absorbed gas.

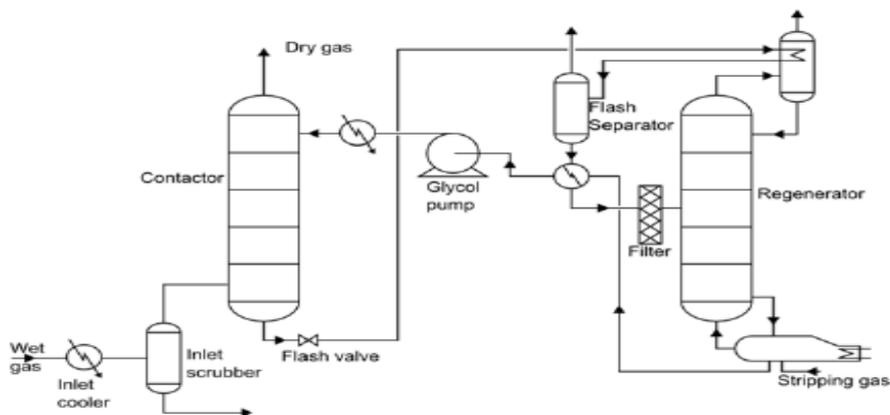
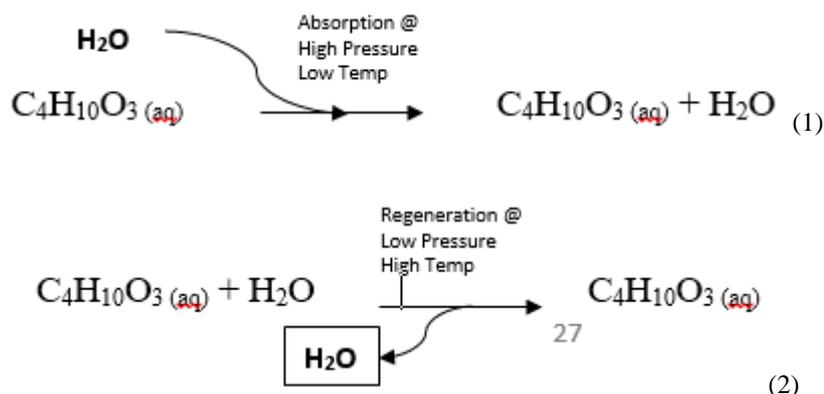


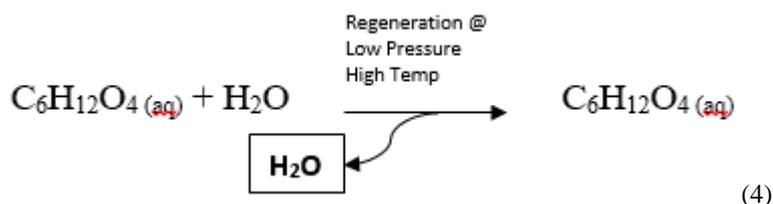
Figure 3: Typical gas dehydration process[2, 6]

Some Chemistry of the Solvents

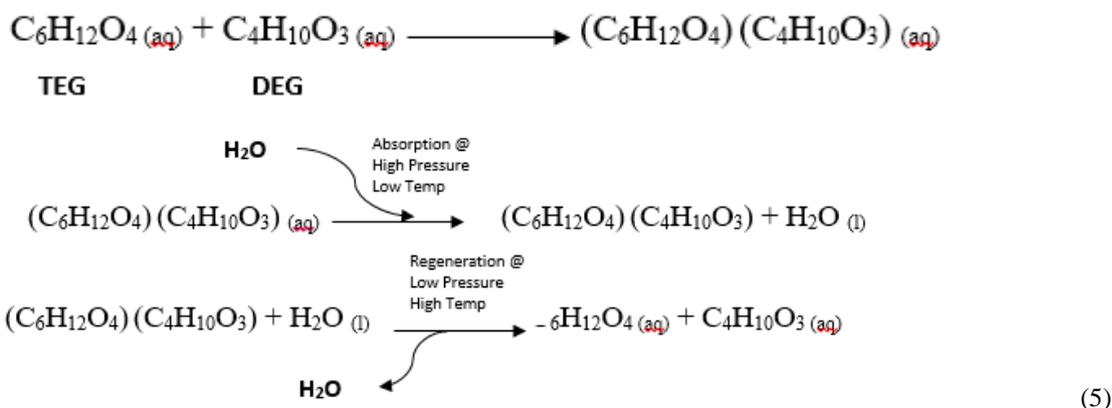
Diethylene glycol (DEG), as one of the solvents considered, is an organic compound with a colorless, practically odorless, poisonous, hygroscopic liquid with a sweetish taste [15]. It is miscible in water, and hence its use as a solvent for water removal. DEG is produced by the partial hydrolysis of ethylene oxide and is derived as a co-product with ethylene glycol and triethylene glycol [15]. The reaction between triethylene and diethylene glycols is expected to form new compound(s) and this reaction can only take place if there are free radicals that will go into reaction or the presence of suitable catalyst to generate the radicals. Hydrogen bonds exist between the two compounds and hence, can undergo combination reaction with no new compound forming without a catalyst trigger [6, 15]. The formation of glycol rich solution and its regeneration are governed by reactions 1 and 2 below. In the forward, dehydration reaction, water is removed (by absorption) from the gas using glycol at high pressure and low temperature while in the backward regeneration stage, the glycol is recovered by removing water at low pressure and high temperature from it for reuse in dehydration [6].



The triethylene glycol reaction with water is similar to that of diethylene glycol with water. It simply absorbs water, for instance, from natural gas and the TEG can be recovered through regeneration at low pressure and high temperature. The forward and backward reactions are also shown in reaction 3 and 4. Both monoethylene, diethylene and triethylene glycols show similar behaviour with water as shown in reactions 1, 2, 3 and 4. Combining one solvent with another do not necessarily lead to formation of a new compound(s) with distinct chemical properties since they are soluble in one another.



The combination and regeneration reaction for the glycol rich solution of TEG and DEG is presented in reaction 5. Here, the combined solution of TEG and DEG will absorb water just as the process stated in the reactions of equations 1 and 2. In the regeneration process, the temperature is high enough to make all the water in the rich glycol go into vapour but not high enough to reach the boiling point of DEG which is about 245°C. In this work, TEG and DEG are combined and its efficiency as an absorbent tested and compared with the lone TEG [6].



Natural Gas Composition and Operating Conditions

The raw gas components for simulation and the operating conditions at the inlet are as presented in Table 1. Also, considering the temperatures and pressures of the contactor, an equation of state approach will be chosen, allowing the accurate calculation of the thermodynamics functions [6]. As polar components are also present (water and TEG in particular), a complex mixing rule will be used in order to use an equation of state approach with this type of components and deploying a steady state simulator [6, 19].

Table 1: Raw natural gas composition [6]

Case Study 1 (TEG only)		Case Study 2 (TEG + DEG)	
Components	Mole %	Components	Mole %
Methane	0.7164	Methane	0.7164
Ethane	0.1565	Ethane	0.1565
Propane	0.0606	Propane	0.0606
Iso butane	0.0153	Iso butane	0.0153
N-Butane	0.0276	N-Butane	0.0276
Iso Pentane	0.0114	Iso Pentane	0.0114
N-Pentane	0.0083	N-Pentane	0.0083
Water	0.0029	Water	0.0029
Nitrogen	0.0010	Nitrogen	0.0010
Carbon Dioxide	0.0000	Carbon Dioxide	0.0000
Hydrogen sulphide	0.0000	Hydrogen sulphide	0.0000
Gas Rate	250 MMSCFD	Gas Rate	250 MMSCFD
Pressure	60 - 70 bar	Pressure	60 - 70 bar
Temperature	40 - 45 °C	Temperature	40 - 45 °C
Glycol		Glycol	
Type	TEG	Type	TEG + DEG
Temperature	45 - 50 °C	Temperature	45 - 50 °C

III. RESULTS AND COMPARATIVE ANALYSIS

The performance of natural gas dehydration processes using two different solvents was investigated. The results from use of TEG dehydration solvent (Case 1) was compared against the process using TEG+DEG dehydration solvent (Case 2), in terms of the water content remaining in the gas after it passed through the gas dehydration unit, rich glycol concentration, and water removed from dehydrated gas. The manipulated parameters used in this study are solvent circulation rate, inlet gas temperature, inlet gas pressure, and inlet gas flow rate. The main approach was to increase the lean solvent rate from 0.5 m³/h through 1.0 m³/h, and the corresponding rates and amounts were recorded and plotted using excel spreadsheet.

Figure 4 is a flowsheet of the dehydration process where it can be observed that the lean solvent inlet to the absorber and gas outlet from the absorber are at the top, with rich solvent exiting the bottom of the absorber. In order to minimize the condensation of heavier hydrocarbons in the absorber, solvent maintains a temperature at 5°C above the inlet gas temperature. Sensitivity analysis was performed with respect to temperature within a range from 40 – 55 °C and a pressure of 35 – 70 bars. Essentially, the process consists of an absorption column, where the natural gas and solvent come into contact, and a regeneration column where the absorbed water and hydrocarbons are removed from the solvent stream, so that it can be recycled back to the absorber. As the natural gas rich in water contacts counter currently with the hygroscopic solvent, the water vapour in natural gas is absorbed by the solvent stream. In the “solvent Regenerator”, the regenerated solvent passes through a heat exchanger to lower the heat content of the solvent before been recycle to the feed stream. A similar process is repeated for case 2 – where about 15% of the whole solvent is DEG.

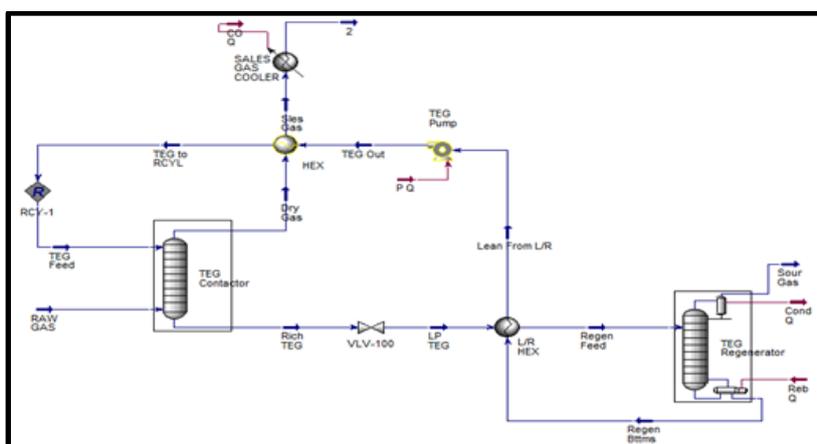


Figure 4: Process flow diagram of gas dehydration using TEG and TEG+DEG solvents[6]

Water Content in Dehydrated Gas

Figure 5 shows that increasing lean solvent circulation rate from 0.5m³/h to 1.0 m³/h decreases the water content in dehydrated gas for both case 1 and case 2. At 40 bar and inlet gas flow rate of 250 MMSCFD, approximately 0.0022 water content in dehydrated gas would be achieved at 0.5 m³/h using TEG solvent, and this

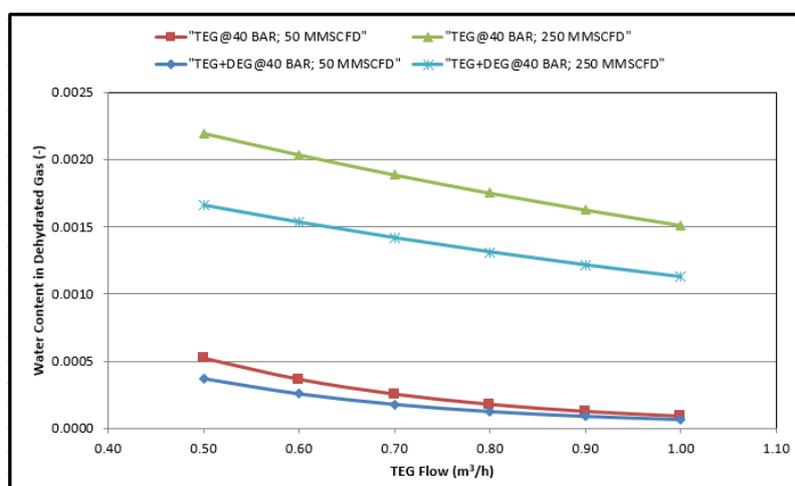


Figure 5: Dry gas water content at 40 bar and inlet gas flow rates of 50 MMSCFD and 250 MMSCFD.

is reduced by 23 per cent when the combined TEG+DEG solvent was used, indicating the better performance of case 2 over case 1 at this range of inlet gas flow rates. Further, when the inlet gas flow rate dropped to 50 MMSCFD at the same pressure of 40 bar, water content in dehydrated gas dropped even further and this was as low as 0.0005 for the TEG solvent as against the even lower value of 0.0004 found for the combine solvent (TEG+DEG). Another instructive observation is the fact that the reduction in water content in dehydrated gas at the relatively lower inlet gas flow rate is by 20 percent, a value, relatively smaller than the value found at the higher inlet gas flow rate. Thus, the performance of the different solvents at different flow rate differ more at higher inlet gas flow rate than at the lower one. Similarly, at increased pressure of 50 bar (see Figure 6) and same inlet gas flow rate conditions, there was further reduction in water content in dehydrated gas for the respective solvents. However, for in inlet gas flow rate of 50 MMSCFD, the TEG+DEG solvents approaches that of TEG

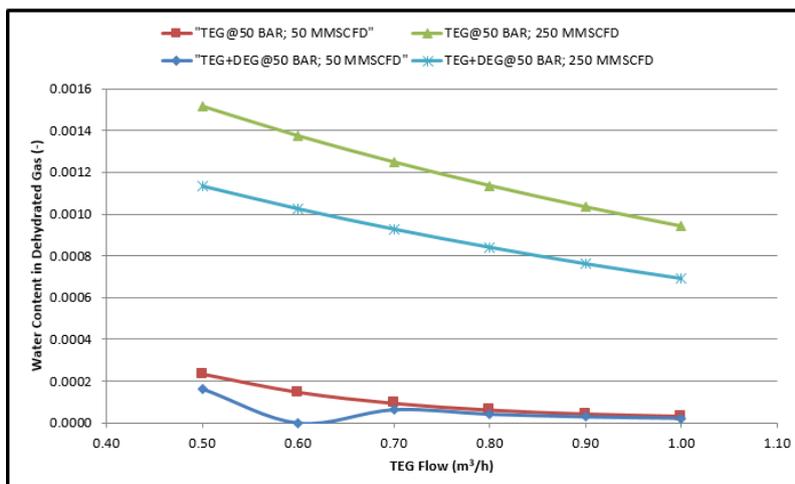


Figure 6: Dry gas water content at 50 bar and inlet gas flow rates of 50 MMSCFD and 250 MMSCFD.

solvent at 0.6 m³/h, suggesting similar performance of both solvents at higher solvent flow rates. This similarity is clearly demonstrated in figure 7 where the water content in dehydrated gas is plotted as a function of flow rates under same pressure and inlet gas flow rate conditions.

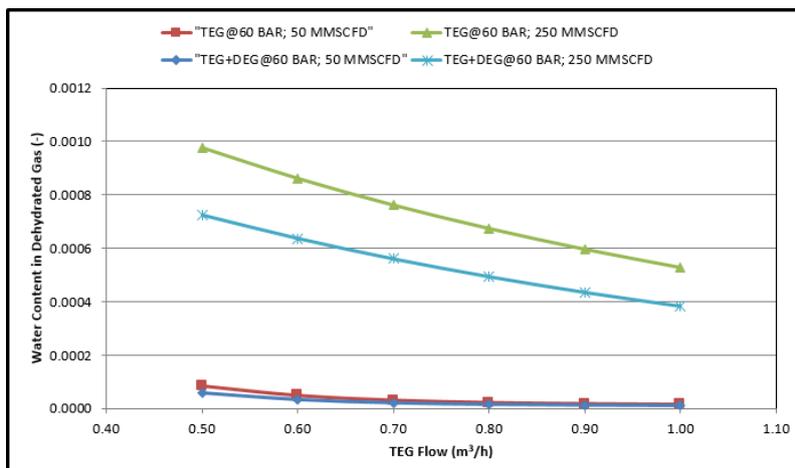


Figure 7: Dry gas water content at 60 bar and inlet gas flow rates of 50 MMSCFD and 250 MMSCFD.

Figure 8 shows that a rapid decrease in water content in dehydrated gas occurs at 65 bar where the TEG+DEG solvent was performing better until reaching a flow rate of over 0.54 m³/h when the TEG solvent started registering better dehydration performance at the higher inlet gas flow rate. The rapid drop in water content for TEG solvent is quite close to the performance of both the TEG and TEG+DEG at the lower inlet gas flow rates, respectively. At this flow rate the TEG and TEG+DEG solvents exhibit similar dehydration performance as a result of the sharp decline in water content in dehydrated gas.

At a pressure of 70 bar, figure 9 indicates the similar performance of either solvent at flow rates of 0.6 m³/h and above, but still, the TEG+DEG solvent at solvent flow of less than 0.6 m³/h performs better than the corresponding TEG solvent. It is observed that, at 70bar, increase in flow rate has no effect on the water content that is, the water content of inlet gas (250MMSCF/D) remained constant at near zero value. So, comparing CASE1 and CASE 2 at 65 bar, TEG has a better performance over TEG +DEG over a certain solvent circulation rate as already indicated above. Whereas, at 70bar TEG + DEG has a considerably higher performance over TEG at a dehydrating flow rate of 0.5m³/h and above this flow rate TEG and TEG + DEG has the same performance at a flow rate of 250MMSCF/D.

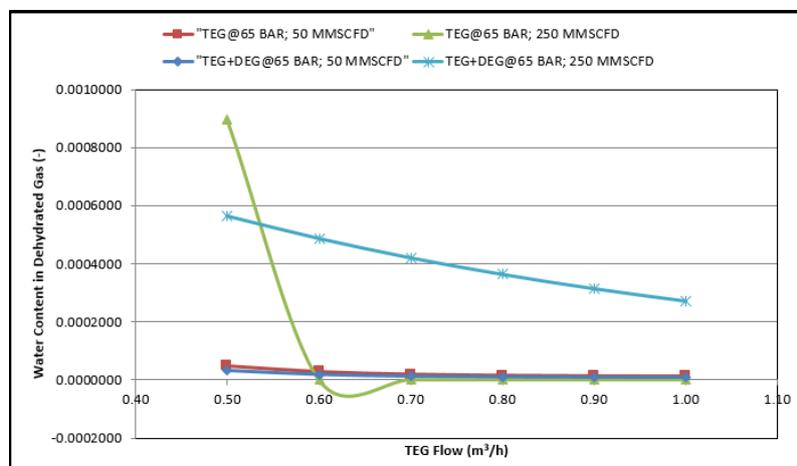


Figure 8: Dry gas water content at 65 bar and inlet gas flow rates of 50 MMSCFD and 250 MMSCFD.

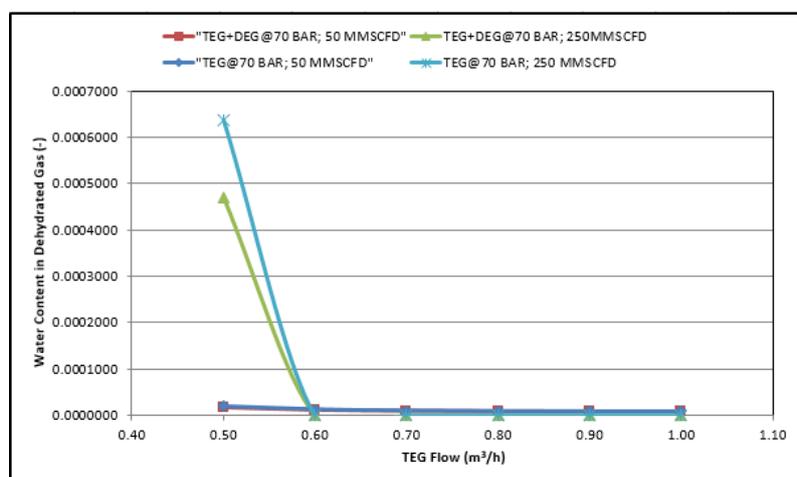


Figure 9: Dry gas water content at 70 bar and inlet gas flow rates of 50 MMSCFD and 250 MMSCFD.

Temperature and Pressure Effects

Figures 10, 11 and 12 show rich solvent results for lean solvent flow rates of between 0.5 m³/h and 1.0 m³/h; feed gas temperatures of 40 °C and 55 °C, pressure = 40 bar (Fig. 10); 40 °C and 55 °C, pressure = 55 bar (Fig. 11); and 40 °C and 55 °C, pressure = 70 bar (Fig. 12). Rich Solvent for case 2 dropped from 0.16 to 0.10 when the inlet gas temperature was increased to 55 °C from 40 °C, suggesting that at lower temperature, water absorption by lean solvent increases. Similar drop was also observed for TEG rich solvent which dropped from 0.6 to 0.45. At higher pressure, 70 bar, the effect of pressure is significant implying that operation at high pressure is recommended. At pressures of 40 and 55 bar, all the temperature ranges considered were able to influence the amount of water in both cases (CASE 1 and CASE 2) although slowly, but at pressures of 70 bar and solvent rate of 0.5m³/h and 0.6 m³/h more of the water molecules are trapped in the rich solvent for both cases.

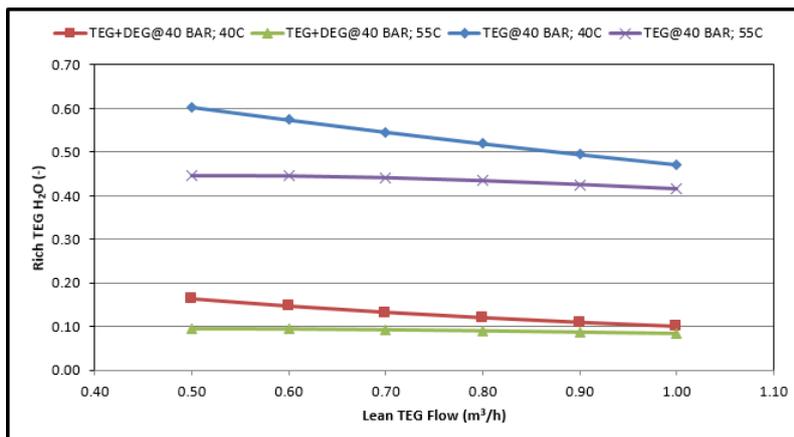


Figure 10: Rich TEG H₂O concentration at 40 bar and inlet gas temperatures of 40 °C and 55 °C.

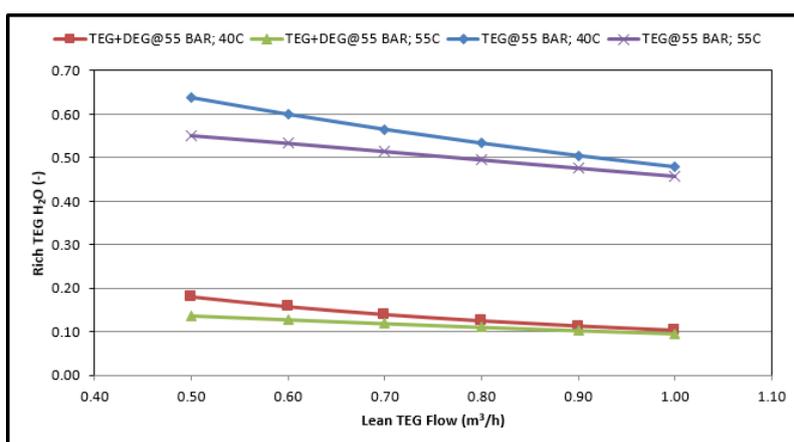


Figure 11: Rich TEG H₂O concentration at 55 bar and inlet gas temperatures of 40 °C and 55 °C.

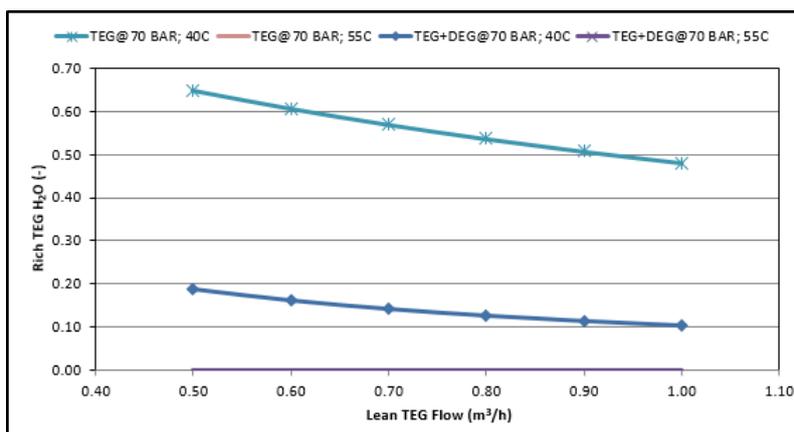


Figure 12: Rich TEG H₂O concentration at 70 bar and inlet gas temperatures of 40 °C and 55 °C.

Water Removal from Natural Gas

Figure 13 shows that increasing solvent flow increases the amount of water removed from the gas. The amount of water removed for TEG+DEG solvent at 40 bar and 40 °C are relatively higher than the amount removed for TEG solvent and this becomes more visible and larger for larger inlet gas temperature of 55 °C. Operating at a low solvent circulation rates for both cases at 0.5 m³/h removes the following amounts of water: water removed = 0.0025 (-) for TEG+DEG Flow = 0.5 m³/h and inlet gas pressure = 40 bar; and water removed = 0.0024 for TEG flow = 0.5 m³/h and inlet gas pressure = 40 bar. Figure 14 also shows the performance for inlet gas temperature of T = 40 °C and 55 °C, and inlet gas pressure P = 55 bar. For a TEG+DEG solvent circulation rate of 0.5 m³/h and at the lower inlet gas temperature, as an example, the amount of water removed is found to be almost similar to TEG solvent circulation rate. Figure 15 shows what happens

at 70 bar pressure when water removal is no longer possible and both solvent results coincide as a single line with a water removal value of 0.0029.

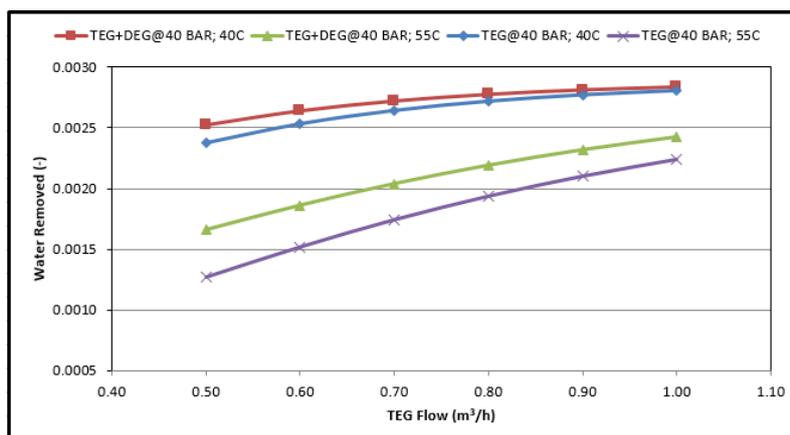


Figure 13: Water removed in dry gas at 40 bar and inlet gas temperatures of 40 °C and 55 °C.

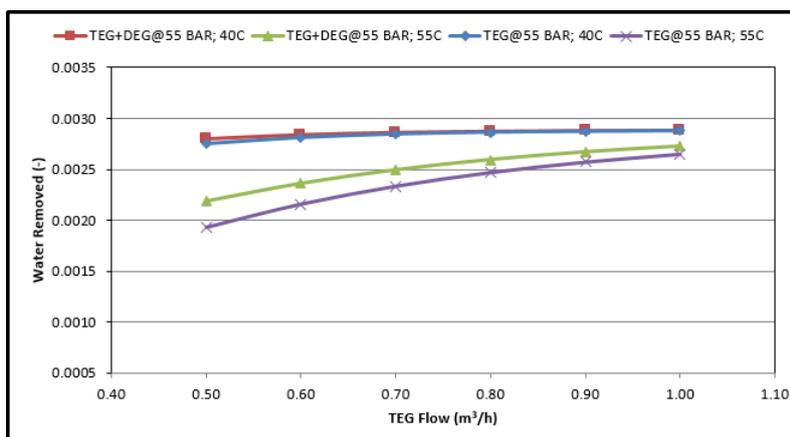


Figure 14: Water removed in dry gas at 55 bar and inlet gas temperatures of 40 °C and 55 °C.

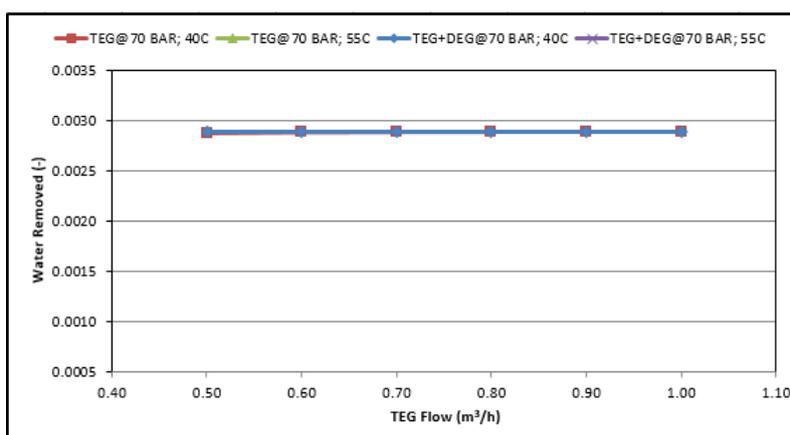


Figure 15: Water removed in dry gas at 70 bar and inlet gas temperatures of 40 °C and 55 °C.

From the plots shown in Figures 13 to 15 for TEG solvent, the amount of water removed from the gas increases steadily as the TEG circulation rate increases. This can be seen at different increasing pressures but at two different temperatures. The best results were obtained at temperature of 40 °C for the TEG+DEG solvent. At a pressure of 70 bar, the maximum water removal was attained at temperatures of 40 °C and 55 °C. Any further increase of solvent flow rate is minimal and uneconomical. At pressure of 70 bar, dehydration only occurs, of which almost all the water (approx. 0.0030 mole) present in the gas has been removed irrespective of the lean solvent flow rate. Similar trend occurs for case 2. Fig. 16 shows the plot between water content of dry gas and flow rate for both solvents with values of TEG circulation rate varying between 0.5 m³/h and 1.0 m³/h.

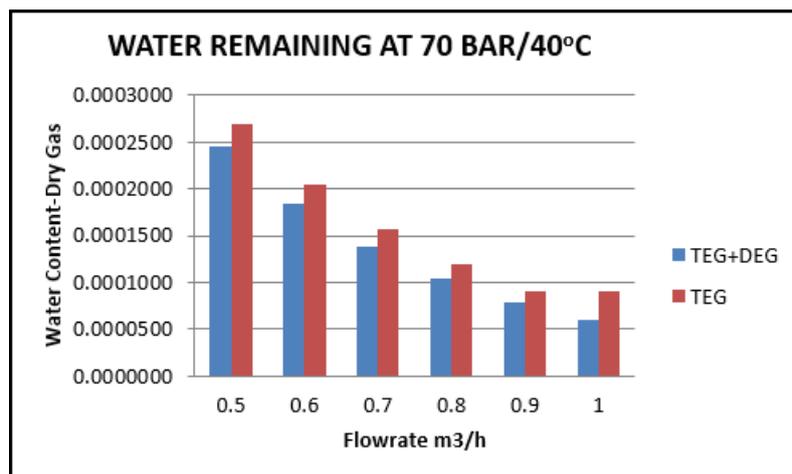


Fig. 16: Comparative performance between TEG and TEG+DEG solvents.

IV. CONCLUSION

The present investigation provides recommendations for the use of a combination of solvents in the dehydration of natural gas for improved performance of a dehydration plant. In this work, a TEG solvent was first used for gas dehydration with limited performance. The increased dehydration performance recorded is due to the use of the combined solvent (TEG+DEG). The combined solvent provides increased dehydration performance as evidenced from a solvent enrichment analysis. The analysis yields the following main conclusions based on the parametric trends: (i) Lower dehydration using TEG solvent at pressures of between 65-70 bar renders it less effective when compared to the higher performing TEG+DEG solvent; (ii) Consistently higher dehydration performance at increasing lean solvent circulation rates rendering the TEG+DEG solvent more effective in the dehydrating the gas (iii) Lower rich solvent-water content at higher temperatures rendering the TEG+DEG solvent more effective in the dehydration process and establishing positive temperature effects on dehydration performance for both processes; and (iv) significantly reduced dehydration at higher inlet gas flow rate, and (v) Slightly increased water removal using TEG+DEG solvent than using the TEG solvent. Overall, the TEG+DEG solvent has comparative advantages over its less performing alternative (TEG solvent). The combined solvent can condition the gas to comfortably achieve the desired water dew point at appropriate temperature and pressure values.

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