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An Investigation of Dehydration Inefficiencies and Associated Design Challenges in a Gas Dehydration Unit: A Case Study of X Gas Plant

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Abstract
The value and contribution of natural gas in both domestic and economic terrains are extensive. However, its contaminant limits direct application and hence must be treated. Water vapour existing in equilibrium with dry gas is the principal among contaminants. Most corrosion both with acid gases and carbonate salts are traceable to the presence of water. Also the formation of solid icy structures called hydrates constitutes a threat to flow assurance. Removal of water by TEG dehydration trains is not uncommon.

Dehydration inefficiencies such as high water content of the outlet gas and glycol losses could impair operations and considerably reduce profit. Inefficiency in GDU was identified to be due to design factors and operational conditions/scenarios. In the case studied, laboratory analysis of TEG was combined with process simulation results to resolve inconsistencies in design and operational phases. Recommendations for further improvements were also presented.

Key words: Optimization; Dehydration; Design; TEG; savings; Water vapour

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INTRODUCTION

Natural gas is the cleanest and safest burning fuel.[2] However, it is produced from natural gas wells with impurities which must be removed to ensure economic and safe transfer to gas sales terminals. Water is the most common undesirable impurity in natural gas[1, 3] and must be removed in other:

- √ To prevent the formation of hydrates which plug flow conduits and obstruct flow.
- √ To minimize corrosion and frequent uneconomic pipeline interventions.
- √ To meet up with sales gas contract specifications.

Water content in natural gas ranges from 400-500 lbm/MMscf while gas contracts specify a maximum of 6-8 lbm/MMscf.[1] To justify economic investments and meet the stringent sales gas contract requires improvement in the design, optimization and surveillance of the gas dehydration unit.

This paper presents a study of the dehydration system with emphasis on the regeneration unit—its optimization that ensures minimized TEG make-up requirements.

1. DEHYDRATION PROCESS

Dehydration is the removal of water vapour from natural gas streams.[3, 6] Several processes such as refrigeration, Compression, Absorption and Adsorption exist but Absorption which involves the use of liquid desiccants with high affinity for moisture has gained wide acceptance.[5] The likely liquid to be used includes MEG, DEG, TEG and TREG. As shown in Table 1, low vapourization losses, higher boiling point and lower operating and maintenance cost fuels the choice of TEG among alternatives.

Table 1
Properties of Glycols Used for Natural Gas Dehydration[7]

	MEG	DEG	TEG	TREG	Water
Formula	C2H6O2	C4H10O3	C6H14O4,	C8H18O5,	H2O
Molar mass(kg/kmol]	62.07	106.12	150.17	194.23	18.015
Normal boiling point[℃]	197.1	245.3	288.0	329.7	100.0
Vapor pressure@25℃[Pa]	12.24	0.27	0.05	0.007	3170
Density@25℃[kg/ms]	1110	1115	1122	1122	55.56
Viscosity@25℃[cP]	17.71	30.21	36.73	42.71	0.894
Viscosity@60℃[cP]	5.22	7.879.89	10.63	0.469	
Maximum recommended regeneration temperature[℃]	163	177	204	224	-
Onset of decomposition[℃]	-	240	240	240	-

The TEG dehydration system (Figure 1) consists of the Absorber unit and the regeneration unit. The removal of water from wet gas takes place in the absorber whiles the water saturated TEG is pumped to the regenerator which aims to recover optimum TEG which can be re-circulated for reuse. Wet gas enters the absorber through the bottom inlet stream, flows upward across trayed sections while the lean TEG enters the absorber through the top inlet stream, flows downwards and contacting counter-currently with the wet gas. The wet gas losses some of its moisture content to the TEG at high pressure and low temperature. The dried gas exits the tower across mist extractors through the top outlet stream. The mist extractor coalesces tiny water particles into larger liquid droplets which fall back into the column thereby reducing liquid carryovers. The rich TEG exits through the lower outlet stream to the regeneration unit.

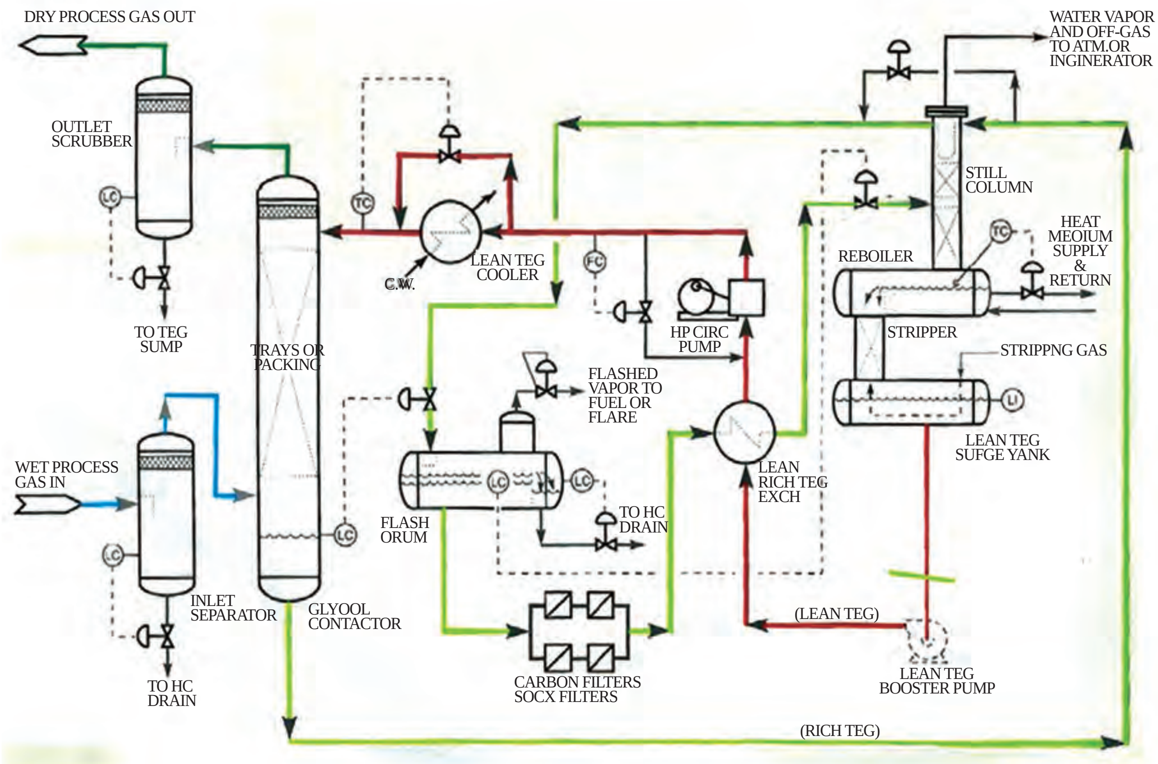

Figure 1
Typical PFD for TEG Dehydration [13]

The rich TEG enters the regeneration unit. The heat supplied by the reboiler vapourizes water and other volatile contaminants towards the upper exit stream across reflux condenser while the liquid TEG flows towards the lower outlet stream across the reboiler. A major concern with TEG dehydration is the release of unwanted BTEX and VOCs into the environment. Authors[10-11] have given ways of controlling such.

2. WATER CONTENT OF NATURAL GAS

The water content of natural gas is a function of pressure, temperature, composition and amount of salts dissolved in the free water.[1, 4] As shown in Figure 2, for a given temperature (dew point), the water content increases with decrease in pressure and increases with increase in temperature for a given pressure.[6, 3].

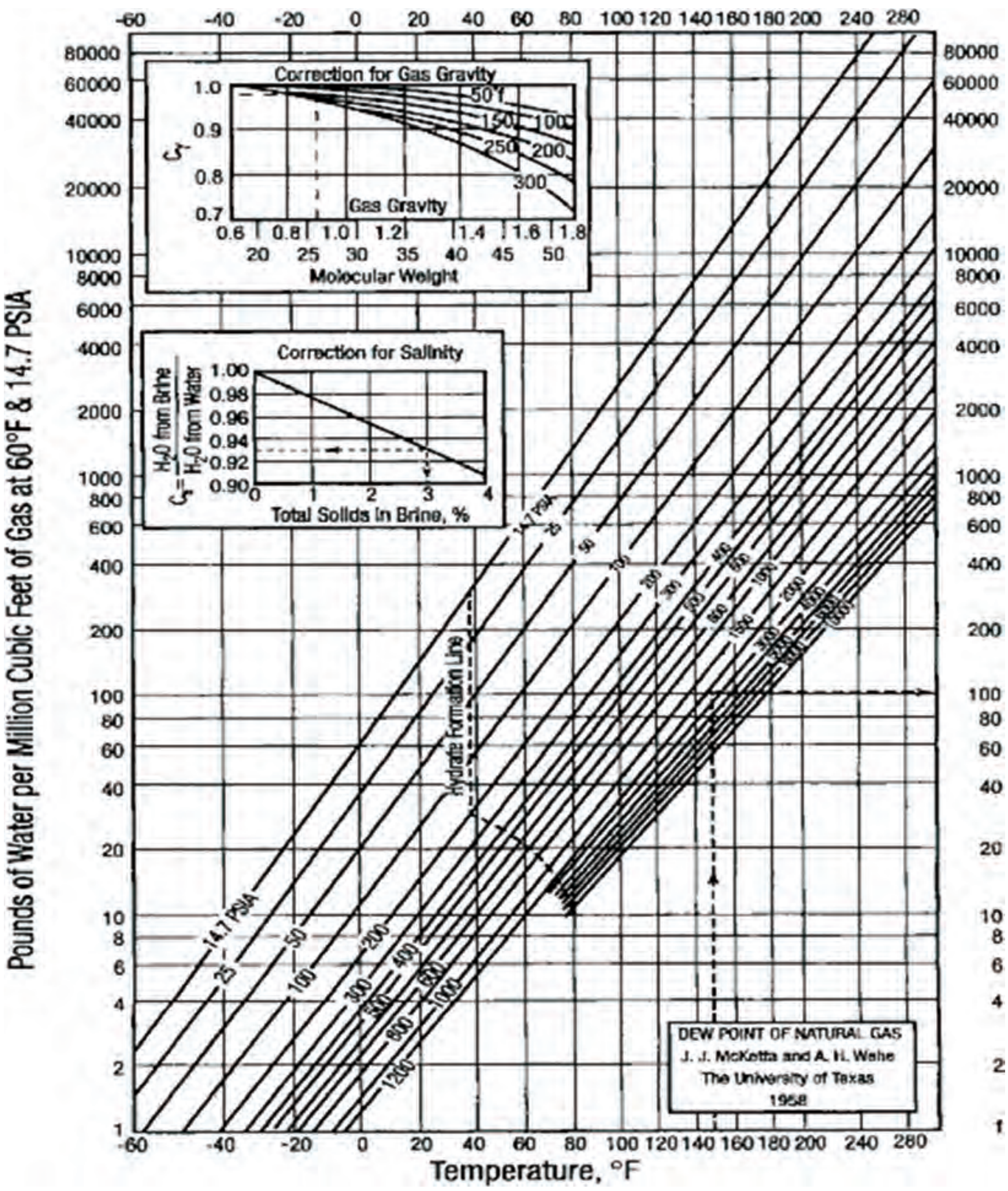

Figure 2
Water Content of Natural Gas[12]

Correlations of experimental data such as the McKetta and Wehe chart (Figure 2) and Campbell chart (Figure 3) can be used to estimate water content of natural gas. However, the McKetta and Wehe chart is not explicit and continuous below the hydrate formation line, hence the Campbell chart is preferred.

For pressure and temperature ranges of 1-690bar and -40℃ to -110℃, respectively, the following analytical expression may be used.[1]

$$W=\frac{A}{P}+B \text{ if } S.G=0.6 \tag{1}$$

$$W=\left(\frac{A}{P}+B\right)*Cg*Cs \text{ if } S,G > 0.6 \tag{2}$$

A and B are constants determined from Table 2

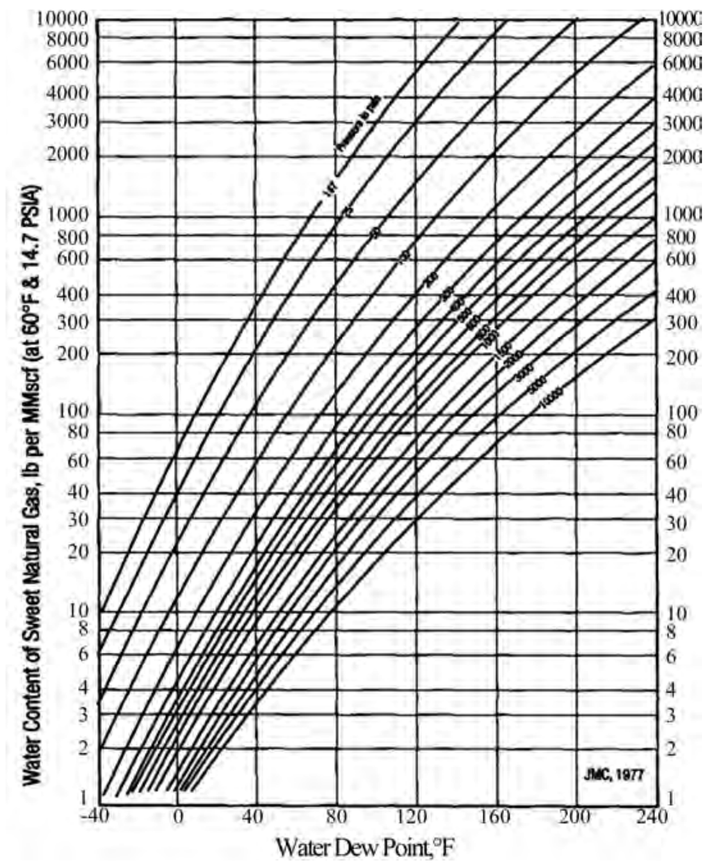

Figure 3
Campbell Correlation for Water Content of Sweet Natural Gas

Table 2
Coefficient A and B for Equation 1 and 2

Temp°C	A	B	Temp°C	A	B
-40	0.1451	0.00347	+32	36.10	0.1895
-38	0.1780	0.00402	+34	40.50	0.207
-36	0.2189	0.00465	+36	45.20	0.224
-34	0.2670	0.00538	+38	50.80	0.242
-32	0.3235	0.00623	+40	56.25	0.263
-30	0.3930	0.00710	+42	62.70	0.285
-28	0.4715	0.00806	+44	69.25	0.310
-26	0.5660	0.00921	+46	76.70	0.335
-24	0.6775	0.01043	+48	85.29	0.363
-22	0.8090	0.01168	+50	94.00	0.391
-20	0.9600	0.01340	+52	103.00	0.422
-18	1.1440	0.01510	+54	114.00	0.454
-16	1.350	0.01705	+56	126.00	0.487
-14	1.590	0.01927	+58	138.00	0.521
-12	1.868	0.021155	+60	152.00	0.562
-10	2.188	0.02290	+62	166.50	0.599
-8	2.550	0.0271	+64	183.30	0.645
-6	2.990	0.3035	+66	200.50	0.691
-4	3.480	0.03380	+68	219.00	0.741
-2	4.030	0.03770	+70	238.50	0.793
0	4.670	0.04180	+72	260.00	0.841
+2	5.400	0.04640	+74	283.00	0.902
+4	6.225	0.0515	+6	306.00	0.965
+6	7.150	0.0571	+78	335.00	1.023
+8	8.200	0.0630	+80	363.00	1.083

To be continued

Continued

Temp˚C	A	B	Temp˚C	A	B
+10	9.390	0.0696	+82	394.00	1.148
+12	10.720	0.767	+84	427.00	1.205
+14	12.390	0.0855	+86	462.00	1.250
+16	13.940	0.0930	+88	501.00	1.290
+18	15.750	0.1020	+90	537.50	1.327
+20	17.870	0.1120	+92	582.50	1.327
+22	20.150	0.1227	+94	624.00	1.405
+24	22.80	0.1343	+96	672.0	1.445
+26	25.50	0.1453	+98	725.0	1.487
+28	28.70	0.1595	+100	776.0	1.530
+30	32.30	0.1740	+110	1093.0	2.620

Determination of plant parameters to achieve a specified water dew point requires a Vapor-Liquid phase equilibria of TEG-water system. However, dew point from such charts (Equilibrium dew point) is about (10-15℃) less the actual dew point. Also equilibrium is unrealistic because the TEG and wet gas do not stay in contact for long to allow equilibrium to be reached.

With a reboiler temperature of 204℃, TEG cannot be regenerated upto 98.8%-98.9%,[2] hence a stripping gas is required to enhance regeneration.

3. INTEGRATING LABORATORY DATA

Glycol Laboratory report usually contains information on:

- √ Glycol weight percentage/concentration
- √ Water content
- √ Hydrocarbon content
- √ Salt content
- √ pH of Glycol
- √ Iron content and
- √ Foaming tendencies

From gas dehydration process manual (from Gas Dehydration Process Manual, 2007), the concentration window for both lean and rich TEG under normal operating condition is [98.5%-99.9%] and [93%-96%] respectively. In the still/condenser, temperatures should not go below 212^{o}F [100℃]. Lower temperatures will ultimately overload the reboiler and result in higher energy/fuel consumption/demand. Excessive high temperature will result in the volatilization of TEG into the exiting streams which are undesirable. The reboiler temperature should lie between 380-400^{o}F [193-204℃]. This is because we want a temperature higher than water boiling point but lower than TEG degradation temperature of 404^{o}F [240℃]. If the hydrocarbon content exceeds 0.1%, associated problems of plugging, foaming and fouling combines to yield glycol losses and poor dehydration. The iron content exceeds 10-15ppm, then corrosion prevention strategies should be considered/sought after. Laboratory results showed high pH of 10.48. A pH of 7.3 could be a safe operating level. pH values up to 8-8.5 and above will likely result in foaming tendencies. Salt content should be maintained below 0.01% or 100ppm. Solid content should be within 0.1% at most.

Water content spread which is the difference between the water content of the rich and lean TEG should also be checked. A narrow water spread [0.5%-2%] indicates excessively high glycol circulation rate and wide spreads [4%-6%] will usually necessitate an increase in TEG circulation rate.

4. IDENTIFICATION OF THE PROBLEM AND SOLUTION METHOD

Under the constraints of cost, reboiler temperature, maximum water content specification and stripping gas rate [though not for all application]. A measure of dehydration efficiency is expressed as:

- √ Low dewpoint/higher dewpoint depression
- √ Low water content, lbm/MMscf
- √ High TEG concentration

The performance of the GDU (absorber and regenerator) is affected by pressure, temperature and flow scenarios. By establishing an upper and lower limits for these variables, and optimizing each will certainly result in an overall optimization of the system. The method used HYSYS process simulation program and laboratory data to understand and troubleshoot TEG dehydration system in a Niger Delta gas plant.

Of the four dehydration trains, one was selected for this study. The current operating scenario which formed the base case was modelled in HYSYS. The program PFD set up/interface is shown in Figure 4. Attempts were made to reproduce the system very closely using the PR EOS/thermodynamic model. This is shown by the close prediction of the exit/dry gas composition which showed good agreement with field data. The program showed excessively high water content in the outlet gas [66 lbm/MMSCF] indicating that operations were far from specifications. Attempts made to curtail this resulted in excessive use in the amount of make-up TEG which added considerably to operational cost and significant reduction in profit. Yet, operations were no close to the acceptable range for sales gas specification. Laboratory analysis of TEG was requested and insight gained from it was integrated with simulation results to arrest the situation.

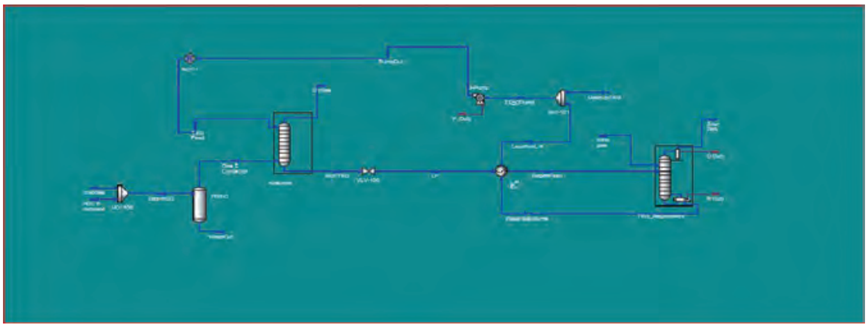

Figure 4
PFD From HYSYS Simulation

5. GDU OPERATIONAL CONSIDERATIONS

The temperature of the inlet gas exerts considerable influence in residual water content of the exiting dry gas. High inlet gas temperature (increased stream water content) results in TEG vapourization losses in the absorber while low temperature promotes liquid (HC and water) condensation. The upper limit of the inlet gas temperature being fixed at 6-10°F less than the lean TEG temperature and lower limit at ambient conditions. Sensitivity on the effect of inlet gas temperature on water content of outlet gas was carried out. The result showed a linear relationship (Figure 5) which was extrapolated to determine the temperature that produces the desired water content. This showed that a lower temperature of 95°F but when this value was set, water content was still high about 38lbm/MMscf which drew attention to the contribution by other variables such as the strip gas rate which was reduced to 0.71MMscfd and the inlet temperature further to 86°F brought the situation to 8.5lbm/MMscf. This is only marginal and calls for improvements.

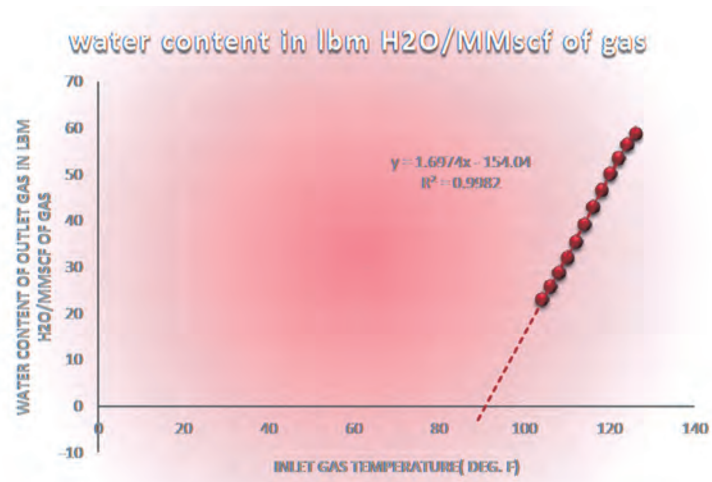

Figure 5
Correcting the Inlet Gas Temperature

An inlet scrubber installed before the absorber helps to recover maximum condensable components from the feed stream. Inefficient separation resulting in liquid carryovers will cause glycol to foam in the absorber. In reality, this scrubber should be located close to the absorber to ensure that the gas enters the contactor as single phase (fluid phase integrity). A pre-heat exchanger may be necessary to increase the feed temperature if applicable.

Pressure and flow effects are associated with cost concerns. Low pressure increases the gas volumes and water content thus the absorber appears too small for the application-larger sizing and trays will be required. Also, additional cost of recompression of the exit gas stream needs to be considered. High pressures encourage foaming tendencies, fouling effects and consequent glycol loss in addition to increased column cost.

The lower limits of the lean TEG will be fixed at temperature (122°F) below which it generates pumpability issues/challenges due to high viscosity and formation of stable emulsion with hydrocarbon.[8] The inlet lean TEG flow depends on the water content of the feed gas and the required dew point depression according to Equation (3) and (4) respectively:[1, 3]

$$W_r = \frac{(W_i - W_o)q}{24} \tag{3}$$

$$\Delta T = T_{\text{in}} - T_{\text{out}}. \tag{4}$$

On the other hand, the regenerator unit, operated at high temperature and low pressure reconcentrates the rich TEG through the removal of dissolved gases, hydrocarbon solids and water. The heat supplied by the reboiler vapourizes impurities laden in the rich TEG. Due to the high boiling temperature difference between water (100℃) and TEG (204℃), water and other volatile components are volatized and TEG reconcentrated to about 98.7 wt%.[9] Where higher concentration is required, stripping gas will be employed to lower the effective partial pressure of the water in the reboiler and enhance separation.

6. DESIGN CHALLENGES

Inefficiency in dehydration as indicated by marginal water content value in the outlet gas is due to design and operational conditions. While that due to operational conditions can be managed by the variation in pressure, temperature and flow rate of process equipment, design challenges will require a modification in the configuration, nature and/number of equipment used. In our case study, high inlet gas temperature influences water content considerably. This will necessitates an installation and circulation of the wet gas through heat exchangers. The same heat exchanger that cools the inlet gas is used to heat it up prior to entering the absorber so that the absorber feed is single phase.

Laboratory results showed high pH value of 10.58. Although TEG is alkaline in nature, operating conditions demand that pH should not exceed 8.[7] Thus there is likelihood of foaming in the contactor. Filters and scrubbers should be installed close to the absorber to remove solid particles and condensable liquids respectively.

Dehydration could be highly improved (about 6 lbm/MMscf as water content of outlet gas) if the number of trays is increased as indicated from simulation.

Name	InletGas	H20 to Saturate	Gas+H20	Gas 2 Contacto	WaterOut	TEG Feed	DryGas	RichTEG	LP	RegenFeed	LeanFmL/R	Strip gas	RegenBottoms
Vapour Fraction	0.9990	0.0000	0.9990	1.0000	0.0000	0.0000	1.0000	0.0000	0.0046	0.0567	0.0000	1.0000	0.0000
Temperature [F]	86.00	80.00	86.00	86.00	86.00	258.6	87.17	103.2	109.0	212.0	264.5	200.0	399.2
Pressure [psia]	1175	1175	1175	1175	1175	1189	1175	1500	835.7	16.00	16.53	20.00	16.53
Molar Flow [MMSCFD]	169.8	1.002e-002	169.8	169.7	0.1734	6.866e-002	169.6	0.1743	0.1743	0.1743	6.774e-002	0.7500	6.774e-002
Mass Flow [lb/hr]	3.811e+005	19.82	3.811e+005	3.807e+005	343.2	1130	3.805e+005	1342	1342	1342	1115	2307	1115
Std Ideal Liq Vol Flow [ft3/hr]	1.767e+004	0.3181	1.767e+004	1.766e+004	5.510	16.04	1.766e+004	19.65	19.65	19.65	15.83	45.83	15.83
Heat Flow [Btu/hr]	-7.056e+008	-1.352e+005	-7.057e+008	-7.034e+008	-2.339e+006	-2.463e+006	-7.019e+008	-3.973e+006	-3.973e+006	-3.872e+006	-2.434e+006	7.070e+004	-2.332e+006
Molar Enthalpy [Btu/lbmole]	-3.784e+004	-1.229e+005	-3.784e+004	-3.775e+004	-1.229e+005	-3.267e+005	-3.770e+004	-2.076e+005	-2.076e+005	-2.023e+005	-3.272e+005	858.5	-3.135e+005
Name	Sour Gas	MakeUpTEG	TEg2Pump	PumpOut	C-Duty	R-Duty	P_Duty	TEG Feed @C(	Gas 2 Contacto	DryGas @COL1	RichTEG @CO	Reflux @COL2	To Condenser (
Vapour Fraction	1.0000	0.0000	0.0000	0.0000	<empty>	<empty>	<empty>	0.0000	1.0000	1.0000	0.0000	0.0000	1.0000
Temperature [F]	212.0	60.01	262.0	258.6	<empty>	<empty>	<empty>	258.6	86.00	87.17	103.2	212.0	238.4
Pressure [psia]	15.00	16.53	16.53	1189	<empty>	<empty>	<empty>	1189	1175	1175	1500	15.00	15.00
Molar Flow [MMSCFD]	0.0566	9.229e-004	6.866e-002	6.866e-002	<empty>	<empty>	<empty>	6.866e-002	169.7	169.6	0.1743	1.479e-003	0.0581
Mass Flow [lb/hr]	2534	15.22	1130	1130	<empty>	<empty>	<empty>	1130	3.807e+005	3.805e+005	1342	21.37	2556
Std Ideal Liq Vol Flow [ft3/hr]	49.65	0.2160	16.04	16.04	<empty>	<empty>	<empty>	16.04	1.766e+004	1.766e+004	19.65	0.3042	49.96
Heat Flow [Btu/hr]	-1.135e+006	-3.457e+004	-2.469e+006	-2.463e+006	2.204e+004	3.571e+005	5059	-2.463e+006	-7.034e+008	-7.019e+008	-3.973e+006	-4.917e+004	-1.161e+006
Molar Enthalpy [Btu/lbmole]	-1.206e+004	-3.451e+005	-3.274e+005	-3.267e+005	<empty>	<empty>	<empty>	-3.267e+005	-3.775e+004	-3.770e+004	-2.076e+005	-3.027e+005	-1.232e+004
Name	Boilup @COL2	To Reboiler @C	T-Vap @COL2	B-Liq @COL2	RegenFeed @C	Strip gas @COL1	C-Duty @COL2	R-Duty @COL2	**New**				
Vapour Fraction	1.0000	0.0000	1.0000	0.0000	0.0567	1.0000	<empty>	<empty>					
Temperature [F]	399.2	398.8	212.0	399.2	212.0	200.0	<empty>	<empty>					
Pressure [psia]	16.53	16.53	15.00	16.53	16.00	20.00	<empty>	<empty>					
Molar Flow [MMSCFD]	0.8354	0.1531	0.8566	6.774e-002	0.1743	0.7500	<empty>	<empty>					
Mass Flow [lb/hr]	3712	2520	2534	1115	1342	2307	<empty>	<empty>					
Std Ideal Liq Vol Flow [ft3/hr]	65.78	35.78	49.65	15.83	19.65	45.83	<empty>	<empty>					
Heat Flow [Btu/hr]	-2.513e+006	-5.273e+006	-1.135e+006	-2.332e+006	-3.872e+006	7.070e+004	2.284e+004	3.571e+005					
Molar Enthalpy [Btu/lbmole]	-2.740e+004	-3.136e+005	-1.206e+004	-3.135e+005	-2.023e+005	858.5	<empty>	<empty>					

Figure 6
HYSYS Simulation Worksheet

CONCLUSION

The water content of natural gases must be reduced to an acceptable limit. Current designs and operational conditions of GDU prove to be inefficient. Optimum conditions and results determined from sensitivity analysis in most cases cannot be directly applied to real plant operations. A modification in design and operating conditions is key to efficient gas dehydration. Laboratory data and results from computer simulation program have shown this to be vital.

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APPENDIX

Nomenclature

BTEX Benzene, Toluene, Ethybenzene and Xylene
VOCs Volatile Oil Compounds
MEG Monoethylene Glycol
DEG Diethylene Glycol
TEG Triethylene Glycol
TREG Tetra ethylene Glycol
℃ Degree Celsius
Fig. Figure
Cg Correction factor for gas gravity
Cs Correction factor for salinity
W Water content of natural gas
P Pressure
S.G Specific gravity
TEG Triethylene Glycol
Wr Amount of water removed from the wet gas
Wi Water content of inlet gas
Wo Water content of outlet gas
*T*in Inlet gas temperature
*T*out Outlet gas temperature
ΔT Dewpoint depression
Q Gas flow rate
GDU Gas Dehydration Unit
Lbm/MMscf Pound mass per million cubic feet
HC Hydrocarbon
PTQ Pressure,Temperature, Flow rate
VOCs Volatile Oil Compounds
Lbm/MMscf Pounds mass per million standard cubic feet
W Water content of natural gas
P Pressure13
S.G Specific gravity
GDU Gas Dehydration Unit

