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Simulation of Acid Gas Removal Unit using different amines

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Abstract

The removal of acid gases such as hydrogen sulphide (H2s) and carbon dioxide (CO2) from process gas streams is often required in natural gas plants and in oil refineries. Acid Gas cleaning process used in gas processing plants deploys gas sweetening process. Due to the inexpensive cost of amine solvent, more than 95 % of Gas processing plants use an acid gas removal unit that utilizes an aqueous amine solvent to remove sour gas components such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S). The gas needs to be treated for safety considerations and environmental regulations for H_2S toxicity (H_2S present in sales gas). The acid gas dissolved in water to form acids which causes corrosion, and the equipment needs to be protected. The acid gas needs to be treated to meet the the environmental regulations to reduce SO_2 emissions also called acid rain. The present investigation addresses the performance of using different amines to determine the absorption capacity of CO_2 & H_2S using Aspen HYSYS software

Keywords**—**Aspen Hysys V12, Amine, Acid Gas (CO_2& H_2S) Removal, Absorption

Introduction

Acid gas removal processes using absorption technology and chemical solvents are popular, particularly those using aqueous

solutions of alkanolamines. The Amines Property Package is a special property package designed to aid in the modeling of Acid gas treating units in which H_2S and CO2 are removed from gas streams. The Property Package contains data to model the absorption/desorption process where aqueous solutions of single amines - monoethanolamine (MEA) which is a primary amine, diethanolamine(DEA) which is a secondary amine, methyldiethanolamine (MDEA) which is a tertiary amine.

Amines are compounds and functional groups that contain a basic nitrogen atom with a lone pair. Basically amines are derivative of ammonia wherein one hydrogen atom is replaced by a substituent such as an alkyl or aryl group. The substituent −NH2 is called an amino group. Amines are categorized in three categories. Primary amines: Primary amines arise when one of three hydrogen atoms in ammonia is replaced by an alkyl or aromatic group. Examples include monoethanolamine (MEA), Secondary amines: Secondary amines have two organic substituents (alkyl, aryl or both) bound to the nitrogen together with one hydrogen. Important representatives include diethanolamine(DEA) and Tertiary amines: In tertiary amines, nitrogen has three organic substituents. Examples include methyldiethanolamine (MDEA)

This study aims to investigate the capture of both CO2 and H2S using three different amines i.e. monoethanolamine (MEA), diethanolamine (DEA), triethanolamine (TEA) to find out the solubility of CO2 and H2S. MDEA,MEA,TEA are selected as the main amines in this study. The concentration of H2S and CO2 in sweet gas using MDEA,TEA & MEA at 25 ^{o}C to 50 ^{o}C and at pressure of 57 bar was investigated by using the Aspen HYSYS V12 simulator.

Methodolgy

The present work was completed by using Aspen HYSYS V12.1, a commonly used software for acid gas removal unit (AGRU) in different oil and gas fields. The Acid Gas (chemical solvent) built-in thermodynamic package was used for this simulation because both solvents are chemical solvents, and the Acid Gas package produces output with lesser deviation.

In this example, a typical acid gas treating facility is simulated. A water-saturated natural gas stream is fed to an amine contactor. Three different amines are used as absorbing medium Recommended amine strength ranges:For MEA 15-20 wt% is used,For DEA 25-35 wt% is used, For MDEA 35-50 wt% is used . The contactor consists of 20 real stages. The rich amine is flashed from the contactor to release most of the absorbed hydrocarbon gas before it enters the lean/rich amine exchanger. In the lean/rich exchanger, the rich amine is heated to a regenerator feed temperature of 147 °C. The regenerator also consists of 20 real stages. Acid gas is rejected from the regenerator at 46°C, while the lean amine is produced at approximately 119°C. The lean amine is cooled and recycled back to the contactor.

Process Description

In the first experimental study using Primary Amine (MEA), A feed stream of natural gas with bulk spec concentration of CO_2 and H_2S containing above specification levels of acid gases (both CO_2 and H_2S) and Lean amine solution of 20wt% MEA and 80 wt% Water.

In the second experimental study using Secondary Amine (DEA), A feed stream of natural gas with bulk spec concentration of CO_2 and H_2S containing above specification levels of acid gases (both CO_2 and H_2S) and Lean amine solution of 35wt% MDEA and 65 wt% Water.

In the third experimental study using Tertiary Amine (MDEA), A feed stream of natural gas with bulk spec concentration of CO_2 and H_2S containing above specification levels of acid gases (both CO_2 and H_2S) and Lean amine solution of 45wt% MDEA and 55 wt% Water. The remaining process parameters are kept at same values to compare the experimental results obtained.

The absorber is critical unit in acid gas cleaning. It contains 20 trays and operates at high pressure. Th sour feed gas and lean amine enters the column while sweet gas and rich amine exits the column. The temperature in the absorber can range from 15-65^oC.

Higher temperature helps prevent condensation and foaming. Other factors that affect performance can include strength of amine, flowrate and impurity loading in amine.

Most of the mass transport occurs in bottom half of the column. A phenomenon called ‘temperature bulge’ can occur due to high heat of absorption generated by mass transfer. Heat is quickly carried by the column by liquid flow so heat travels upwards with the vapor flow. Increase in vapor flow rate will increase temperature bulge.

The separator flashes rich amine to low pressure. It is used to separate dissolved sweet gas. Dissolved hydrocarbons can cause foaming Residence time can be over 20 minutes. Light hydrocarbon liquids are skimmed within the flash tank.

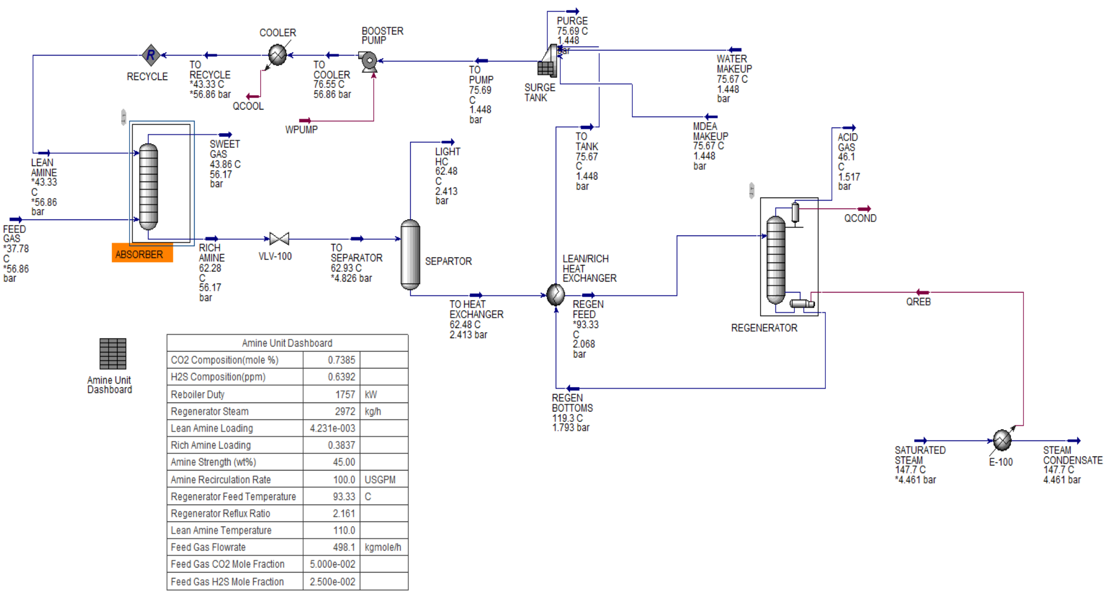
Regenerator allows for reclamation of amine by separation. It is energy intensive process. The heat exchanger preheats the regenerator feed stream with bottoms product stream from absorber. This heat integration controls the temperature profiles in the system and reduces the amount of cooling and heating energy that needs to be used in the process. Passing as much heat as possible from the lean amine to rich amine provides the most favorable heat integration. The regenerator heats the amine solution unbinding the contaminants from amine solution. This takes place at elevated temperatures and low pressures to facilitate the separation. The condenser will not condense CO_2 and H_2S instead only returning water, amine and hydrocarbons. Common reflux ratio range from 1 to 3. The reboilers are major cost center to the Column. A typical Reboiler duty is 6 MMBtu/hr. The lean amine solution from the column leaves through bottom of column and sent to lean/rich heat exchanger.

The Concentrated contaminants stream leaves through top of column for further process. To keep the process at steady state a storage tank is used to provide makeup water and lean amine. This restores the amine solution to its original strength. Replenishing losses due to separation operation or formation of heat stable salts. In addition, a portion of lean amine called the slip stream is diverted to remove contaminants such as iron sulfides. Subsequent pumping and cooling will bring the recycled amine for conditions to required to be used in absorber. This closes the recycle loop for lean amine. Process limits for the sweet gas stream is 4 ppmv H_2S and 2% CO_2 by volume.

Simulation Basis

Process Simulation

This study consists of a liquid-liquid acid gas treating process using MDEA as a chemical solvent at high pressure to remove H_2S and CO_2 from acid feed gas. 9610 kg/hr of acid gas feed (2.5 mol% H_2S and 5 mol% CO_2) is fed to Absorber (57 bar), where the H_2S is removed to < 1 ppm H_2S in the overhead hydrocarbon product (mostly C3). Acid gases are stripped from amine by a regenerator column at low pressure (1.5 bar) and high temperature (119 ^oC) from the MDEA solvent, which is recycled with makeup back to the extractor column. The Feed Gas enters the absorber at 56.86 bar and temperature 38 ^oC where acid gases are absorbed with lean amine and the sweet gas (sales gas) from the top of absorber is achieved with desired spec. The bottom rich amine from absorber at temperature of 63 ^oC is fed to separator where light hydrocarbons are flashed and the outlet is preheated with the bottoms form regenerator at temperature of 93 ^oC fed to Regenerator. In Regenerator the rich amine is stripped of acid gases (H_2S and CO_2) at a reboiling temperature of 147 ^oC and heat duty of 1757 KW. The stripped rich amine from bottom of Regenerator at temperature of 119 ^oC is cooled to 76 ^oC in lean/rich heat exchanger and fed to surge tank for makeup lean amine going to absorber. The desired sakes gas specification of less than 10 ppm H_2S gas and 0.74 mol% (<2 mol%) CO_2 in sweet gas is achieved with MDEA as amine solvent.



Amine Unit Dashboard		
CO2 Composition(mole %)	0.7385	
H2S Composition(ppm)	0.6392	
Reboiler Duty	1757	kW
Regenerator Steam	2972	kg/h
Lean Amine Loading	4.231e-003	
Rich Amine Loading	0.3837	
Amine Strength (wt%)	45.00	
Amine Recirculation Rate	100.0	USGPM
Regenerator Feed Temperature	93.33	C
Regenerator Reflux Ratio	2.161	
Lean Amine Temperature	110.0	
Feed Gas Flowrate	498.1	kgmole/h
Feed Gas CO2 Mole Fraction	5.000e-002	
Feed Gas H2S Mole Fraction	2.500e-002	

Input specification for Aspen Hysys Simulation

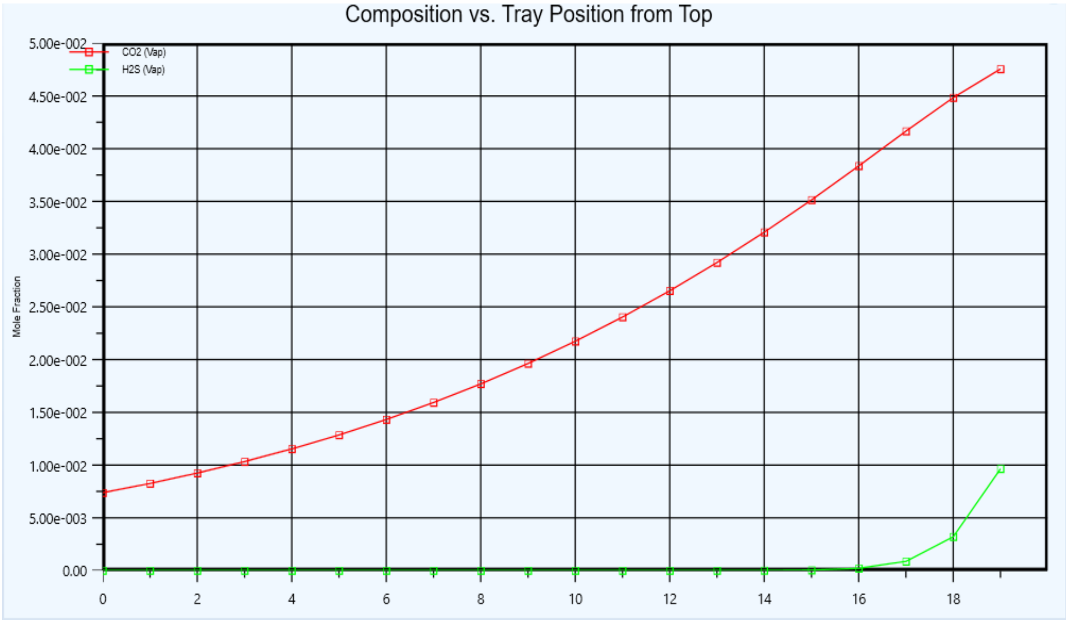
Parameters	
Gas flowrate (kgmole/hr)	498.1
Gas temperature (ºC)	38
Gas pressure (bar)	57
Composition of CO_2 in feed gas (mole fraction)	0.05
Composition of H_2S in feed gas (mole fraction)	0.025
Solvent flowrate (m^3/h)	24
Solvent temperature ºC	43
solvent pressure (bar)	57
Absorber trays	20
Regenerator trays	10
Condenser temperature ºC	46
Reboiler temperature ºC	148

Results And Discussion

For Mdea Solution

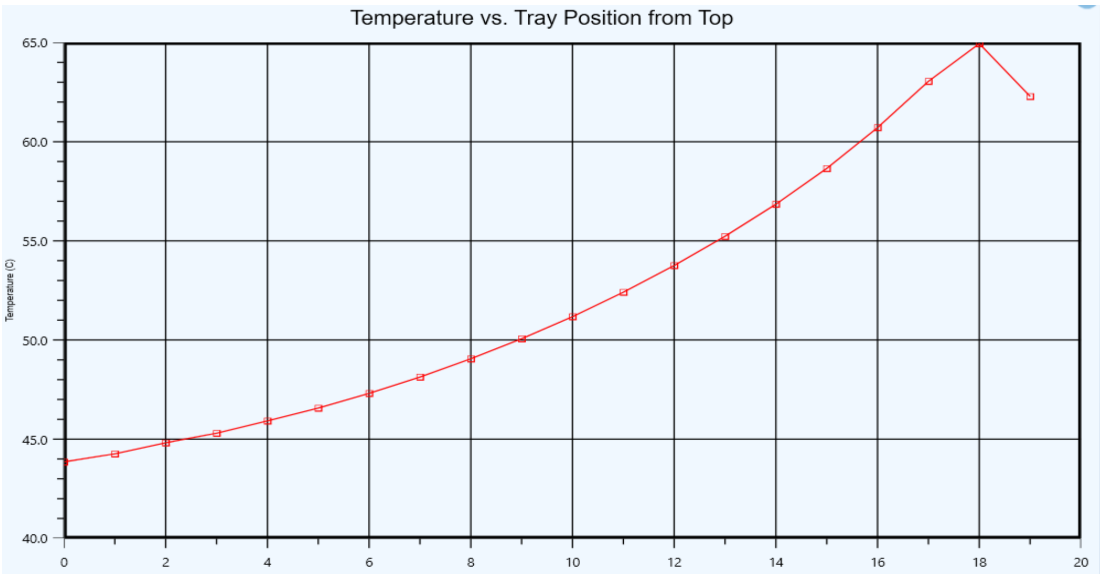
- **Effect of Composition vs Tray Position from Top**

It can be seen from the composition vs the tray position from top curve that as the acid gas rises in the absorber with countercurrent flow of lean MDEA Solution, the H_2S concentration gradually decrease from 0.96 mole % (Vapor phase) at 20th tray to 0.06 mole % (Vapor phase) at first tray. H_2S concentration is 2.5 mol% in feed gas inlet. Remaining 1.48 mol% (Aqueous phase) is carried away in rich amine solution. Similarly, the CO_2 concentration gradually decrease from 5 mole % (Vapor phase) at 20th tray to less than 1 mole % (0.74 mol%) (Vapor phase) at first tray. This shows that the most of mass transfer from acid gas to lean MDEA solution takes place at the bottom of the Absorber.



- **Effect of Temperature vs Tray Position from Top**

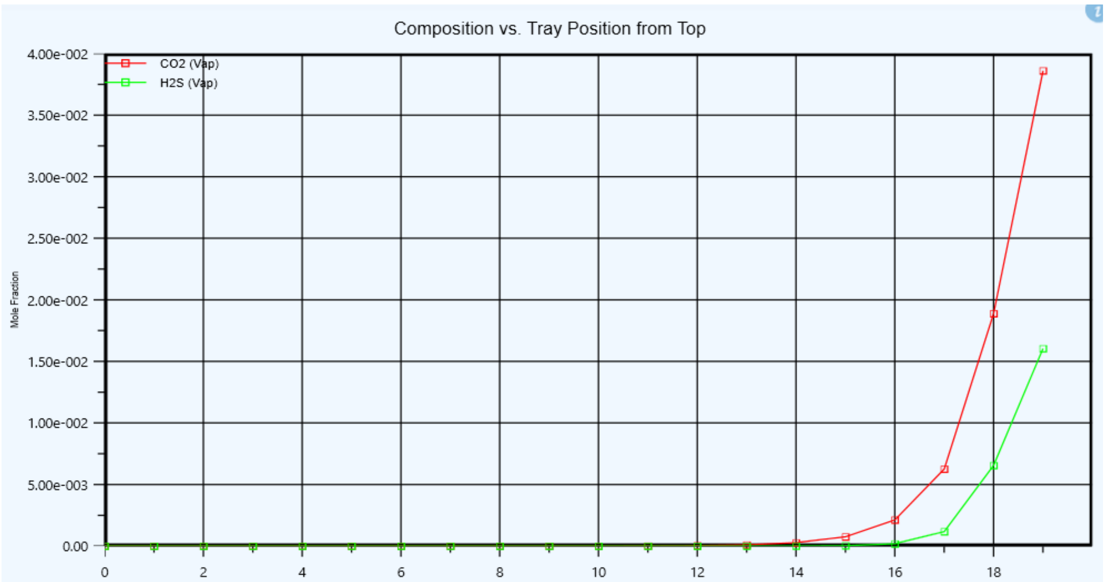
Also, it can be seen that as the acid gas rises to top in the Absorber, Temperature bulge occurs in the column with temperature rising highest at tray eighteen in the bottom of the absorber. This temperature rise is due to high heat of absorption taking place at the maximum mass transfer towards the bottom of the absorber.



For MEA Solution

- **Effect of Composition vs Tray Position from Top**

It can be seen from the composition vs the tray position from top curve that as the acid gas rises in the absorber with countercurrent flow of lean MEA Solution, the H_2S concentration gradually decrease from 1.6 mole % (Vapor phase) at 20th tray to zero mole % (Vapor phase) at first tray. H_2S concentration is 2.5 mol% in feed gas inlet. Remaining 1.16 mol% (Aqueous phase) is carried away in rich amine solution. Similarly, the CO_2 concentration gradually decrease from 5 mole % (Vapor phase) at 20th tray to 0 mol% (Vapor phase) at first tray. This shows that the most of mass transfer from acid gas to lean MEA solution takes place at the bottom of the Absorber.



- **Effect of Temperature vs Tray Position from Top**

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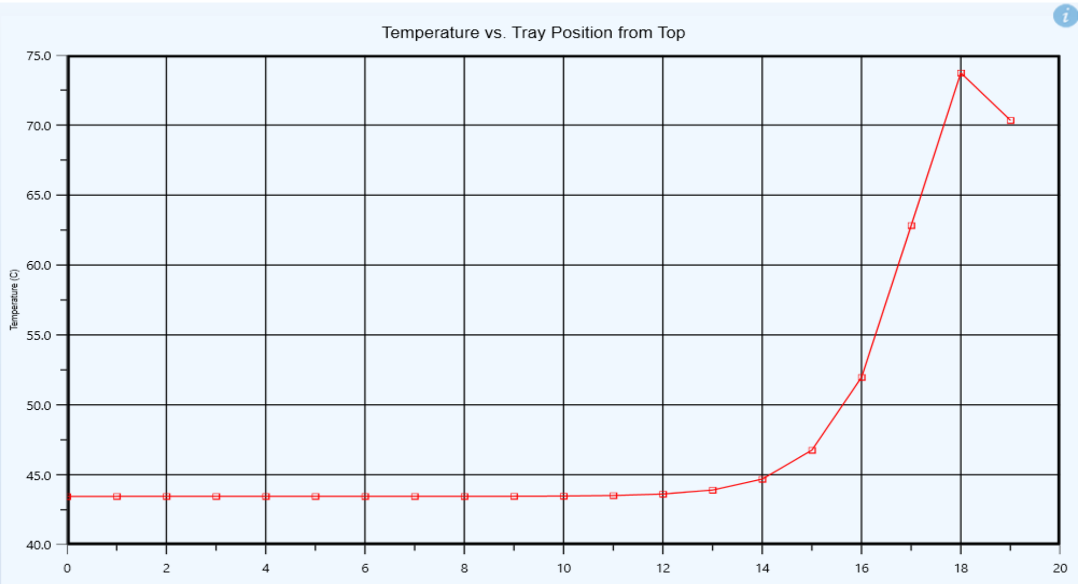
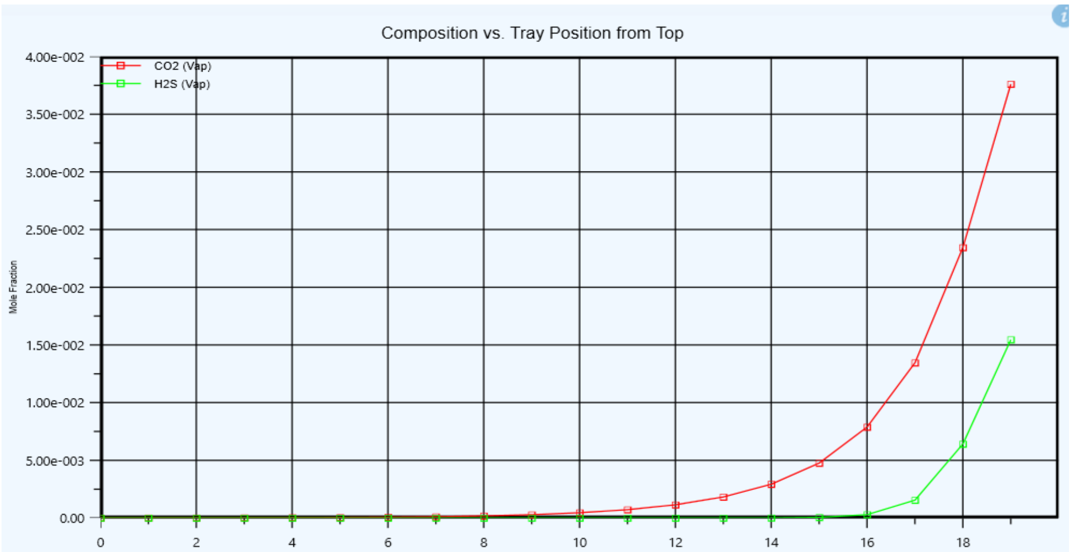


For DEA Solution

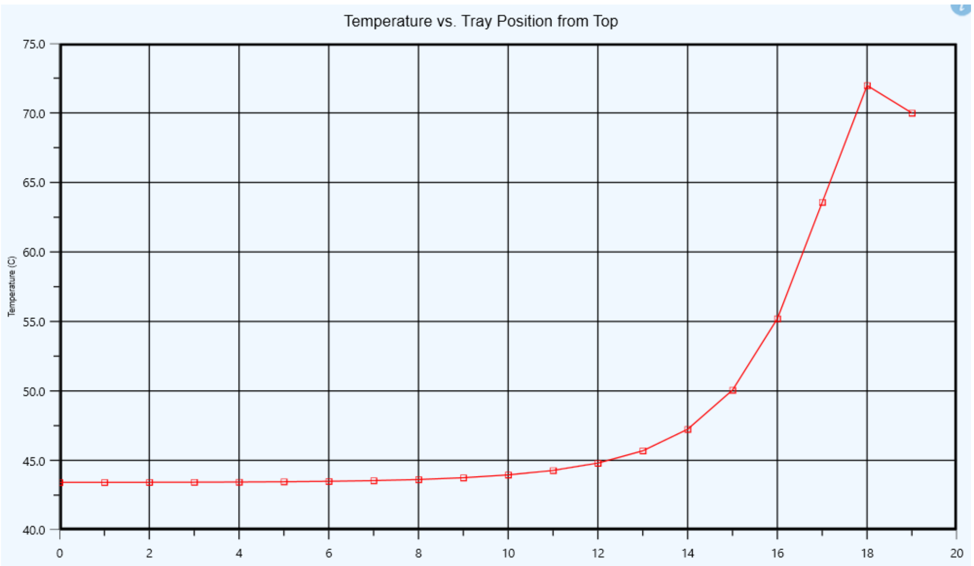
- **Effect of Composition vs Tray Position from Top**

It can be seen from the composition vs the tray position from top curve that as the acid gas rises in the absorber with countercurrent flow of lean DEA Solution, the H_2S concentration gradually decrease from 1.55 mole % (Vapor phase) at 20th tray to zero mole % (Vapor phase) at first tray. H_2S concentration is 2.5 mol% (Vapor phase) in feed gas inlet. Remaining 1.3 mol% (Aqueous phase) is carried away in rich amine solution. Similarly, the CO_2 concentration gradually decrease from 5 mole % (Vapor phase) at 20th tray to 0 mol% (Vapor phase) at first tray. This shows that the most of mass transfer from acid gas to lean DEA solution takes place at the bottom of the Absorber.



- **Effect of Temperature vs Tray Position from Top**

Also, it can be seen that as the acid gas rises to top in the Absorber, Temperature bulge occurs in the column with temperature rising highest at tray eighteen in the bottom of the absorber. This temperature rise is due to high heat of absorption taking place at the maximum mass transfer towards the bottom of the absorber.



Conclusion

The overall CO_2 and H_2S absorption in a MDEA, MEA and DEA solution was investigated using Aspen HYSYS simulation software. It is investigated that the tertiary amines MDEA have recently become very important amines because it is selective and more ideal for H_2S and having the high capacity to remove H_2S and CO_2 using the Acid Gas Cleaning -Chemical Solvent Property Package in Aspen Hysys V12. Out of 2.5 mol% (Vapor phase) H_2S, 1.48 mol% (Aqueous phase) H_2S is carried away in rich amine solution. This concentration is highest among 3 types of amines and makes MDEA the most suitable for H_2S absorption. The effect of Composition and Temperature on tray position from top was studied and it is observed that the bulk of mass transfer takes place at the bottom of the Absorber with high temperature in the Rich Amine outlet in the Absorber due to high heat of Absorption.

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