Investigation of Alkanol-Amine Solvents and their Blends for CO\textsubscript{2} Removal from Natural Gas using Aspen-Hysys

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**ABSTRACT:** The removal of carbon dioxide (CO\textsubscript{2}) from natural gas is vital towards meeting pipeline sales gas specifications and evading operational complications during the liquefaction of natural gas. Therefore, the removal of CO\textsubscript{2} from natural gas is necessary for the effective utilization of natural gas and for the reduction of global CO\textsubscript{2} emission. It is also vital for the effective liquefaction process in the liquefied natural gas project A common and widespread technique used at natural gas plants in Nigeria is the removal of carbon dioxide (CO\textsubscript{2}) from natural gas through chemical absorption using alkanolamine solutions. In this research, an amine sweetening process is simulated using Aspen HYSYS V10 with a typical Nigerian natural gas composition. The simulation is used to investigate four different kinds of amines and their blends (mixed amines). The investigated amines are Monoethanolamine (MEA), Diethanolamine (DEA), Diglycolamine (DGA) and Methyldiethanolamine (MDEA) while the blends are MDEA + MEA, MDEA + DEA and MDEA + DGA. Results obtained from the simulation show that the mixed amine “MDEA + MEA” with lean amine strength of 11% MEA and 39% MDEA, absorbs 99.97% of CO\textsubscript{2} present in the gas and hence, amine blends absorb carbon dioxide from natural gas better than the individual amines. It was also concluded that increasing the composition of the primary or secondary amine while decreasing the composition of the tertiary amine in the lean amine solution (amine blend) led to an increase in the amount of CO\textsubscript{2} being absorbed. The study provides useful information on the absorption of CO\textsubscript{2} using alkanolamine solvents and their blends in a standard amine sweetening plant.

**KEYWORDS:** Aspen Hysys, amines, CO\textsubscript{2} emission, liquefaction, natural gas

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**I. INTRODUCTION**

Nigeria is one of the most populous countries in Africa that has amply various energy resources and its gas reserves are ranked globally as the ninth largest with about 182 trillion cubic feet of gas (Nwoha & Wood, 2014). The discovery of natural gas in Nigeria was secondary as the exploration was aimed at the discovery of crude oil, therefore, prior to 1999, natural gas produced alongside crude oil were flared and not utilized (Ubani & Goodness, 2016). From a global perspective, gas flaring is a major cause of significant environmental problems and also a waste of valuable energy source that could serve as a source of employment to many and, revenue to the country (Hassan & Kouhy, 2013).

The sustainability of the environment and utilization of natural gas for socioeconomic benefit is on course in Nigeria through the successful utilization of natural gas that could have been flared in the form of Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), and Liquefied Petroleum Gas (LPG) (Otene et al., 2016). Nigeria is rapidly growing as the second fastest LNG producer in the world with a capacity of 22 million tons per annum (Agbonifo, 2016). Presently, about two-third of thermal power for electricity generation in Nigeria is derived from natural gas (Kamil et al., 2021).

Natural gas must be treated to certain quality specifications in order to meet up with market specification (Grande et al., 2017), ensure the reduction of potential greenhouse gas (GHG) emissions (Dong et al., 2017) and reduce the possible operational problems that may occur in the plants or during the gas transmission (Zahid et al., 2017). Carbon dioxide (CO\textsubscript{2}) and hydrogen sulphide (H\textsubscript{2}S) are the two major contaminants in natural gas due to their corrosiveness, toxicity and lack of heating value (Taemeh et al., 2018). Natural gas reserves in Nigeria contain little or no sulphur content, (Ubani & Goodness, 2016) and therefore the major focus is on the removal of CO\textsubscript{2} to negligible concentration levels which must be performed before the gas can be sold or utilized (Nwoha et al., 2017). The specification of CO\textsubscript{2} in natural gas for pipeline and the production of LNG is less than 3 mol % and 50 ppm respectively (Quek et al., 2021).

The most effective, efficient and commercially established separation technique widely used in the energy industries for the recovery of CO\textsubscript{2} from natural gas is the chemical absorption process with the use of alkanolamine solvents (Abdulsalam et

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al., 2019). Due to the selectivity of tertiary amines towards H₂S and the degradation products of the primary and secondary amines, mixed amines or amine blends are created to combine the advantages of the solvents and enhance the removal of CO₂ from natural gas (Ghanbarabadi & Khoshandam, 2015).

This study considers the efficiency of four different alkanol-amines and their blends in the removal of CO₂ from natural gas obtained from a gas reserve in Nigeria. The aim of this study is to simulate amine sweetening process using Aspen HYSYS V10 with a typical Nigerian natural gas composition.

II. METHODOLOGY

A. Process Configuration

A gas sample from a gas refinery located in Nigeria with composition as shown in Table 1 is sent into a separator to separate the gas from any liquid entrained in it. The gas contains some components that are not defined on HYSYS therefore information from the plant as regarding these components is used to define these components on HYSYS; Table 2. The gas is further sent into an absorber where the amine solvent or blend is used to absorb CO₂ from the gas with the possibility of attaining gas purity greater than 90%. The four amine solvents (MDEA, MEA, DEA, & DGA) and their blends (MDEA+MEA, MDEA+DEA and MDEA+DGA) were investigated using their respective lean amine strength range as shown in Table 3. The amine and acid gas mixture from the absorber was pumped into a regenerator so the solvent can be recirculated after it is cooled.

B. Process Simulation

1) Component selection

The component list was created by selecting the components in Table 3 on Aspen HYSYS. The pseudo components (C₆* - C₂₀*) were defined on HYSYS using the properties given from the gas refinery in Table 4.

2) Fluid package basis selection

The “Acid Gas – Chemical Solvents” fluid package was selected as the appropriate property. The package supports all the amines and components needed for this research study and handles all the chemical reactions and thermodynamic calculations involved in the plant.

3) Process flow diagram (PFD)

In this study, a typical natural gas treatment facility was simulated using design data and parameter for a typical acid gas sweetening model. A model from AspenTech was used as a guideline for simulating the plant for using the component and compositions of natural gas from a refinery located in Nigeria. The following steps were used to carry out the simulation.

The process simulation began with the definition of the ‘Gas’ stream by specifying the conditions (temperature, pressure, and molar flow rate) and composition (Table 3) on the worksheet. The ‘lean amine solution’ stream was defined on HYSYS using the properties given from the gas refinery in Table 4.

Table 1: Reservoir gas composition.

| Component | Mole % | Component | Mole % |
|-----------|-------|-----------|-------|
| H₂S       | 0.19  | C₂₀⁺      | 0.19  |
| CO₂       | 0.56  | C₂⁺       | 0.89  |
| N₂        | 0.05  | C₃⁺       | 0.05  |
| C₁        | 0.05  | C₄⁺       | 0.04  |
| C₂        | 0.04  | C₅⁺       | 0.04  |
| C₃        | 0.05  | C₆⁺       | 0.03  |
| i-C₄      | 0.03  | C₇⁺       | 0.02  |
| n-C₄      | 0.03  | C₈⁺       | 0.02  |
| C₆⁺       | 0.02  | C₉⁺       | 0.02  |
| C₇⁺       | 0.02  | C₁₀⁺      | 0.02  |

Table 2: Reservoir gas composition – Characterization properties of pseudo components.

| Component | Molecular weight (g/mol) | Density (kg/m³) | Critical temperature (°C) | Critical pressure (bara) | Acentric factor | Normal boiling point (°C) | Critical volume (m³/kmol) |
|-----------|--------------------------|-----------------|---------------------------|--------------------------|------------------|--------------------------|--------------------------|
| C₆⁺       | 86.17                    | 664             | 262.66                    | 28.81                    | 0.29             | 68.75                    | 0.37                     |
| C₇⁺       | 96                       | 738             | 320.42                    | 28.58                    | 0.33             | 91.95                    | 0.48                     |
| C₈⁺       | 107                      | 765             | 198.28                    | 26.6                     | 0.37             | 116.75                   | 0.49                     |
| C₉⁺       | 121                      | 781             | 218.59                    | 24.32                    | 0.41             | 142.25                   | 0.53                     |
| C₁₀⁺      | 134                      | 792             | 289.98                    | 22.6                     | 0.45             | 165.85                   | 0.57                     |
| C₁₁⁺      | 147                      | 796             | 514.06                    | 21.13                    | 0.49             | 187.25                   | 0.63                     |
| C₁₂⁺      | 161                      | 810             | 539.11                    | 19.96                    | 0.53             | 208.35                   | 0.68                     |
| C₁₃⁺      | 175                      | 825             | 563.06                    | 19.03                    | 0.57             | 227.25                   | 0.72                     |
| C₁₄⁺      | 190                      | 836             | 587.17                    | 18.15                    | 0.61             | 246.45                   | 0.78                     |
| C₁₅⁺      | 206                      | 842             | 611.31                    | 17.33                    | 0.65             | 265.85                   | 0.85                     |
| C₁₆⁺      | 222                      | 849             | 634.65                    | 16.65                    | 0.7              | 282.85                   | 0.92                     |
| C₁₇⁺      | 237                      | 845             | 654.85                    | 16.01                    | 0.73             | 299.85                   | 0.99                     |
| C₁₈⁺      | 251                      | 848             | 673.8                     | 15.56                    | 0.77             | 312.85                   | 1.06                     |
| C₁₉⁺      | 263                      | 858             | 690.38                    | 15.28                    | 0.79             | 324.85                   | 1.11                     |
| C₂₀⁺      | 368.21                   | 863             | 603.22                    | 16.11                    | 1.215            | 422.09                   | 1.732                    |
A valve and separator were modelled to reduce the pressure of the ‘Rich amine solution’ stream to a pressure close to the operating pressure of the regenerator column and flash off the residue gas from the rich amine solution respectively.

A heat exchanger is modelled to heat the amine solution stream coming from the separator before it is introduced into the regenerator. The regenerator was modelled as a distillation column in the simulation environment and the process conditions (number of stages, condenser pressure, reboiler pressure, reboiler temperature, condenser temperature, tray 1 temperature, inlet stage, overhead rate, reflux ratio, reboiler duty and the pressure drop in the condenser) were specified. The distillation column has 18 stages excluding the condenser and reboiler. The component efficiency for CO2 for the 18 stages and the condenser are in Table 5 (obtained from the GPSSA engineering data book, 14th edition). Each amine was compared with their respective lean amine strength range. A separator operator was introduced into the simulation environment to separate any liquid or free water entrained in the gas before it is sent to the absorber.

The amine contactor column was modelled as an absorber operation column where the feed at the top stage and bottom stage were the ‘Lean amine solution’ stream and the ‘Raw gas’ stream (coming from the separator column) respectively. The process conditions of the column (top pressure, bottom pressure, number of stages, top temperature estimate and bottom temperature estimate) were also specified. The property package used in this study requires the trays in the bottom temperature estimate) were also specified. The weir height, weir length and diameter were done by modelling the specific efficiency of CO2 on a tray-by-tray basis and the tray dimensions were supplied to enable this feature. The weir height, weir length and diameter were specified according to the AspenTech model to enable the calculation of the efficiency by estimating the height of the liquid on the tray and the residence time of vapour in the liquid. The internals of the absorber were also automatically specified using HYSYS.

The ‘Sweet Gas’ comes out of the absorber through the top of the column and the ‘Rich amine solution’ stream through the bottom of the absorber. The rich amine solution stream is further sent to a distillation column where the amine and CO2 are separated with the application of heat so that the amine solvent can be recycled for absorption.

### Table 3: Recommended lean amine strength in water.

| Amine     | Weight% |
|-----------|---------|
| MEA       | 10 – 20 |
| DEA       | 25 – 35 |
| DGA       | 50 – 60 |
| MDEA + MEA| MDEA (39 – 49); MEA (1 – 11) |
| MDEA + DEA| MDEA (39 – 49); DEA (1 – 11) |
| MDEA + DGA| MDEA (39 – 49); DGA (1 – 11) |

### Table 4: Plant simulation parameters.

| Gas                      |                     |
|--------------------------|---------------------|
| Temperature              | 25 °C               |
| Pressure                 | 6900 kPa            |
| Molar Flow               | 1250 kmol /hr       |
| Lean Amine               |                     |
| Temperature              | 35 °C               |
| Pressure                 | 6850 kPa            |
| Std Ideal Liq Vol Flow   | 43 m³/hr            |
| Absorber Column          |                     |
| Number of stages         | 20                  |
| Top Pressure             | 6850 kPa            |
| Bottom Pressure          | 6900 kPa            |
| Top Temperature          | 40 °C               |
| Bottom Temperature       | 70 °C               |
| Weir Height              | 0.025 m             |
| Weir Length              | 1 m                 |
| Tray Volume              | 0.5655 m³           |
| Tray Diameter            | 1.2 m               |
| Valve                    |                     |
| Outlet stream Pressure   | 620 kPa             |
| Heat Exchanger           |                     |
| Tube Side ∆P             | 70 kPa              |
| Shell Side ∆P            | 70 kPa              |
| Heat Exchanger mode      | Exchanger Design (Weighted) |
| Tube Side Outlet Temp.   | 95 °C               |
| Distillation Column      |                     |
| Number of stages         | 18                  |
| Type of Condenser        | Overhead            |
| Feed Stage               | 4                   |
| Damping Factor           | 0.4                 |
| Solving Method           | Modified HYSIM Inside-Out |
| Condenser Pressure       | 190 kPa             |
| Condenser ∆P             | 15 kPa              |
| Reboiler Pressure        | 220 kPa             |
| Reboiler Temperature     | 125 °C              |
| Tray 1 Temperature       | 100 °C              |
| Efficiency (CO2)         | 0.15                |
| Efficiency (H2S)         | 0.8                 |
| Overhead rate Estimate   | 75 kmol/hr          |
| Reflux Ratio estimate    | 1.5                 |
| Condenser column Temp.   | 50 °C               |
| Reboiler Column duty     | 1.3e1 kJ/hr         |
| Mixer                    |                     |
| Pressure Assignment      | Equalize All        |
| Outlet’s Std Ideal Liq Vol Flow | 43 m³/hr |
| Cooler                   |                     |
| Pressure Drop            | 35 kPa              |
| Pump                     |                     |
| Outlet Temperature       | 35 °C               |

The ‘Sweet Gas’ comes out of the absorber through the top of the column and the ‘Rich amine solution’ stream through the bottom of the absorber. The rich amine solution stream is further sent to a distillation column where the amine and CO2 are separated with the application of heat so that the amine solvent can be recycled for absorption.
Reboiler were specified along with the damping factor which is also a requirement for the column. Usually, the damping factor required for amine regenerators has a value between 0.25 and 0.5 but 0.40 was specified in this simulation because it provided a faster and more stable convergence. The ‘CO₂’ goes out through the overhead stream of the distillation column while, the separated lean amine solution known as the ‘Regen bottoms’ stream comes out at the bottom of the column. The ‘Regen bottoms’ stream was introduced into the heat exchanger to cool the stream down.

Water is lost in the absorber and regenerator’s overhead streams and a mixer is modelled to combine the ‘Lean amine from HX’ stream (the cooled down stream coming from the heat exchanger) with a fresh stream that contains only water (‘Water’ stream) at the same pressure.

This is to make up for the water that is lost by adjusting the flowrate of the water to achieve the lean amine circulation rate. The ‘Amine to cooler’ stream was further cooled down by modelling a cooler and the cooled stream was pumped back to the absorber (contacting column) by modelling a pump.

A set operation was modelled to set the pressure value of the “Sour Gas” stream in relation with the recycled lean amine solution (‘Amine to recycle’ stream). A recycle operation was also modelled to replace the lean amine solution stream with the recycle amine solution stream. The contactor and regenerator ran until the recycle loop converged. After the convergence, the results were analysed. The alkanolamines were investigated by replacing them in the properties section on HYSYS and their compositions were also varied in the simulation environment.

The Process Flow Diagram (PFD) built in the simulation environment is shown in Figure 1.

The relationship between the lean amine strength of MEA and the amount of carbon dioxide being absorbed is shown in Figure 2. The plot shows that as the concentration of the MEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also reduced.

B. Absorption of Carbon dioxide with Diethanolamine (DEA)

The results for the sensitivity analysis performed on the composition of DEA is recorded in Table 6. The composition of DEA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14th edition). From the results recorded, DEA is capable of treating the gas to the required specification of 50 ppm. The amine solvent (MEA) approximately absorbed all of the carbon dioxide present in the natural gas.

The Process Flow Diagram (PFD) built in the simulation environment is shown in Figure 1.

The relationship between the lean amine strength of MEA and the amount of carbon dioxide being absorbed is shown in Figure 2. The plot shows that as the concentration of the MEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also reduced.
Table 6: Results from sensitivity analysis on DEA.

| Lean amine strength | Amount of CO₂ in the raw gas | Amount of CO₂ in the sweet gas | Amount of CO₂ absorbed |
|---------------------|------------------------------|-------------------------------|------------------------|
| 25%                 | 8.5543E-05                   | 0.005514456                  | 0.0055                  |
| 26%                 | 8.3390E-05                   | 0.00551661                   | 0.0055                  |
| 27%                 | 8.2585E-05                   | 0.005517415                  | 0.0055                  |
| 28%                 | 8.0938E-05                   | 0.005519061                  | 0.0055                  |
| 29%                 | 8.0343E-05                   | 0.005519657                  | 0.0055                  |
| 30%                 | 8.0343E-05                   | 0.005521175                  | 0.0055                  |
| 31%                 | 7.8088E-05                   | 0.005521912                  | 0.0055                  |
| 32%                 | 7.6917E-05                   | 0.005523082                  | 0.0055                  |
| 33%                 | 7.5681E-05                   | 0.005524318                  | 0.0055                  |

Table 7: Results from sensitivity analysis on DGA.

| Lean amine strength | Amount of CO₂ in the raw gas | Amount of CO₂ in the sweet gas | Amount of CO₂ absorbed |
|---------------------|------------------------------|-------------------------------|------------------------|
| 50%                 | 3.8516E-07                   | 0.005599615                  | 0.0055                  |
| 51%                 | 3.4740E-07                   | 0.005599653                  | 0.0055                  |
| 52%                 | 3.1319E-07                   | 0.005599687                  | 0.0055                  |
| 53%                 | 2.7971E-07                   | 0.00559972                   | 0.0055                  |
| 54%                 | 2.5805E-07                   | 0.005599742                  | 0.0055                  |
| 55%                 | 2.3023E-07                   | 0.00559977                   | 0.0055                  |
| 56%                 | 2.0462E-07                   | 0.005599795                  | 0.0055                  |
| 57%                 | 1.8128E-07                   | 0.005599819                  | 0.0055                  |
| 58%                 | 1.5985E-07                   | 0.00559984                   | 0.0055                  |
| 59%                 | 1.4085E-07                   | 0.005599859                  | 0.0055                  |
| 60%                 | 1.2371E-07                   | 0.005599876                  | 0.0055                  |

C. Absorption of carbon dioxide with diglycolamine (DGA)

The results for the sensitivity analysis performed on the composition of DGA is recorded in Table 7. The composition of DGA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14th edition). From the results recorded, DGA is capable of treating...
the gas to the required specification of 50 ppm. The relationship between the lean amine strength of DGA and the amount of carbon dioxide being absorbed is shown in Figure 4. The plot shows that as the concentration of the DGA in the lean amine increases, the amount of carbon dioxide left in the sweet gas also reduces.

D. Absorption of Carbon dioxide with Methyl diethanolamine (MDEA)

The results for the sensitivity analysis performed on the composition of MDEA is recorded in Table 8. The composition of MDEA in the lean amine was varied according to the lean amine strength recommended by the GPSA handbook (14th edition). From the results recorded, MDEA is not capable of treating the gas to the required specification of 50 ppm.

The relationship between the lean amine strength of DEA and the amount of carbon dioxide being absorbed is shown in Figure 4. The plot shows that as the concentration of the MDEA in the lean amine increased, the amount of carbon dioxide left in the sweet gas also increased.

E. Absorption of carbon dioxide with methyl diethanolamine (MDEA) and monoethanolamine (MEA)

The mixed amine (MDEA based amine with a primary or secondary amine) solution was created by making a 50:50 percent amine-water solution.

The sensitivity analysis was performed by varying the concentration of MEA from 1% to 11% while the remaining amount was balanced with MDEA. This is because the second amine in the mixture generally comprises less than 20%. The results for the sensitivity analysis performed on the composition of MDEA and MEA is recorded in Table 9. From the results, it is observed that the (MDEA and MEA) solution is capable of treating the gas to the required specification of 50 ppm. It was also observed that when the concentration of MEA was increased in the mixed amine, the mixed amine was able to absorb more carbon dioxide.
Table 8: Results from sensitivity analysis on MDEA.

| Lean amine strength | Amount of CO$_2$ in the raw gas | Amount of CO$_2$ in the sweet gas | Amount of CO$_2$ absorbed |
|---------------------|---------------------------------|----------------------------------|--------------------------|
| 40%                 | 0.0056                          | 0.0273455                        | 0.00286545               |
| 41%                 | 0.0056                          | 0.02740452                       | 0.00285954               |
| 42%                 | 0.0056                          | 0.02746279                       | 0.002853721              |
| 43%                 | 0.0056                          | 0.02752078                       | 0.002847922              |
| 44%                 | 0.0056                          | 0.02757872                       | 0.002842128              |
| 45%                 | 0.0056                          | 0.02763678                       | 0.002836322              |
| 46%                 | 0.0056                          | 0.02769497                       | 0.002830503              |
| 47%                 | 0.0056                          | 0.02769497                       | 0.002830503              |
| 48%                 | 0.0056                          | 0.02781381                       | 0.002818619              |
| 49%                 | 0.0056                          | 0.02787495                       | 0.002812505              |
| 50%                 | 0.0056                          | 0.02793785                       | 0.002806215              |

The relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 6(a) while the relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 6(b). The plots show that as there is an increase in concentration of MEA in the lean amine, there is also a reduction in the amount of CO$_2$ left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is also an increase in the amount of CO$_2$ left in the sweet gas.

F. Absorption of Carbon dioxide with Methyldiethanolamine (MDEA) and Diethanolamine (DEA)

The results for the sensitivity analysis performed on the composition of MDEA and DEA is recorded in Table 10. From the results recorded, the (MDEA and DEA) solution will treat the gas to the required specification of 50 ppm when there is a further increase in the concentration of DEA as it was observed that when the concentration of DEA was increased in the mixed amine, the mixed amine was able to absorb more carbon dioxide.

The relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is as shown in Figure 7(a) while the relationship between the lean amine strength of MDEA and the amount of carbon dioxide being absorbed is shown in Figure 7(b). The plots show that, as there is an increase in concentration of DEA in the lean amine, there is a reduction in the amount of CO$_2$ left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is an increase in the amount of CO$_2$ left in the sweet gas.

![Figure 6(a)](image-url)
Figure 6(b): Plot of the lean amine strength of MEA in MDEA + MEA against the amount of carbon dioxide left in the sweet gas.

Table 10: Results from sensitivity analysis on MDEA and DEA.

| Lean amine strength | Amount of CO2 in the raw gas | Amount of CO2 in the sweet gas | Amount of CO2 absorbed |
|---------------------|-------------------------------|-------------------------------|------------------------|
| MDEA 49.00% 1.00% | 0.0056 | 0.001969029 | 0.003630971 |
| MDEA 48.00% 2.00% | 0.0056 | 0.001406932 | 0.004193068 |
| MDEA 47.00% 3.00% | 0.0056 | 0.000923208 | 0.004676792 |
| MDEA 46.00% 4.00% | 0.0056 | 0.000616179 | 0.004938281 |
| MDEA 45.00% 5.00% | 0.0056 | 0.000565069 | 0.005034931 |
| MDEA 44.00% 6.00% | 0.0056 | 0.000584578 | 0.005215422 |
| MDEA 43.00% 7.00% | 0.0056 | 0.000550027 | 0.005249973 |
| MDEA 42.00% 8.00% | 0.0056 | 0.000265925 | 0.005334075 |
| MDEA 41.00% 10.00% | 0.0056 | 0.000209922 | 0.005399078 |

G. Absorption of carbon dioxide with methyl-diethanolamine (MDEA) and diglycolamine (DGA)

The results for the sensitivity analysis performed on the composition of MDEA and DGA is recorded in Table 11. From the results recorded, the (MDEA and DGA) solution can treat the gas to the required specification of 50 ppm. It was observed from the obtained results that the (MDEA and DGA) solution absorbed almost all the carbon dioxide. The relationship between the lean amine strength of MDEA and DGA and the amount of carbon dioxide being absorbed is shown in Figure 8(a) and 8(b) respectively. Figure 8(b) show that as there is an increase in concentration of DGA in the lean amine, there is a reduction in the amount of CO2 left in the sweet gas and for MDEA, as there is an increase in the concentration of MDEA, there is an increase in the amount of CO2 left in the sweet gas (Figure 8(a)).

Figure 7(a): Plot of the lean amine strength of MDEA in MDEA + DEA against the amount of carbon dioxide left in the sweet gas.
Table 11: Results from sensitivity analysis on MDEA and DGA.

| Lean amine strength | Amount of CO₂ in the raw gas | Amount of CO₂ in the sweet gas | Amount of CO₂ absorbed |
|---------------------|------------------------------|--------------------------------|-------------------------|
| MDEA 49.00% 1.00%  | 0.0056                       | 0.001369111                    | 0.004230889             |
| MDEA 48.00% 2.00%  | 0.0056                       | 0.000527355                    | 0.005072645             |
| MDEA 47.00% 3.00%  | 0.0056                       | 8.0777E-05                     | 0.005519223             |
| MDEA 46.00% 4.00%  | 0.0056                       | 4.12581E-05                    | 0.005558742             |
| MDEA 45.00% 5.00%  | 0.0056                       | 2.40065E-05                    | 0.005575994             |
| MDEA 44.00% 6.00%  | 0.0056                       | 1.69278E-05                    | 0.005583072             |
| MDEA 43.00% 7.00%  | 0.0056                       | 1.21671E-05                    | 0.005587833             |
| MDEA 42.00% 8.00%  | 0.0056                       | 9.37398E-06                    | 0.005590626             |
| MDEA 41.00% 9.00%  | 0.0056                       | 6.3238E-06                     | 0.005593676             |
| MDEA 40.00% 10.00% | 0.0056                       | 4.12581E-05                    | 0.005575994             |
| MDEA 39.00% 11.00% | 0.0056                       | 2.40065E-05                    | 0.005575994             |

H. Percentage of carbon dioxide absorbed by each of the solvents

The effect of each of the investigated alkanolamine solvent or amine blend on the gas being treated is evaluated by comparing the percentage of CO₂ absorbed by each of the solvents at the various composition investigated. The result is recorded in Table 12 and 13 respectively.

Figure 8(a): Plot of the lean amine strength of DEA in MDEA + DGA against the amount of carbon dioxide left in the sweet gas.
Table 13: Percentage of CO₂ absorbed by the amine blends.

| Lean amine strength | MDEA + MEA | MDEA + DEA | MDEA + DGA |
|---------------------|------------|------------|------------|
| %CO₂ absorbed       |            |            |            |
| 49.00%              | 1.00%      | 1.00%      | 1.00%      |
| 48.00%              | 2.00%      | 2.00%      | 2.00%      |
| 47.00%              | 3.00%      | 3.00%      | 3.00%      |
| 46.00%              | 4.00%      | 4.00%      | 4.00%      |
| 45.00%              | 5.00%      | 5.00%      | 5.00%      |
| 44.00%              | 6.00%      | 6.00%      | 6.00%      |
| 43.00%              | 7.00%      | 7.00%      | 7.00%      |
| 42.00%              | 8.00%      | 8.00%      | 8.00%      |
| 41.00%              | 9.00%      | 9.00%      | 9.00%      |
| 40.00%              | 10.00%     | 10.00%     | 10.00%     |
| 39.00%              | 11.00%     | 11.00%     | 11.00%     |
IV CONCLUSION

The study simulated the design of a standard CO₂ capture plant using Aspen HYSYS V10. The thermodynamic package “Acid Gas – Chemical Solvents” available in Aspen HYSYS reasonably predicted the CO₂ capture process using amine solvents and its blends. A detailed sensitivity analysis has been performed to analyse the effect of various amines on the absorption of CO₂ from the absorber. The amines were analysed at different concentrations within their respective lean amine strength range to find out the concentration at which it absorbs the most CO₂.

Absorption with mixed amines was used to enhance the absorption of CO₂ from the gas because tertiary amines (MDEA) are selective towards the acid gas “H₂S” and the degradation products of the primary and secondary amines. The mixed amine utilized less of the primary and secondary amines (MEA, DEA and DGA) and more of the tertiary amine (MDEA) to achieve desired sweet gas specification.

The results showed that the mixed amine “MDEA + MEA” absorbs 99.97% of CO₂ present in the gas with lean amine strength of 11% MEA and 39% MDEA. In this study, the “MDEA + MEA” blend is most suitable for the adsorption of CO₂. The future prospects of this study are expected to focus on finding the preferred mixed amine solvent with consideration for the cost, energy requirement and environmental impact in terms of degradation products and corrosion.

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