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Process Simulation and Optimization of CO_2 Removal from Niger Delta Natural Gas Using DEA in Aspen HYSYS

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Abstract*: The progressive decline in reservoir pressure and increasing water cut in mature Niger Delta oil wells have made the implementation of artificial lift systems essential to sustaining economic production. This study presents a comprehensive modelling and optimisation of well performance through nodal analysis and gas lift design, applied to a representative Niger Delta well using the PROSPER simulation environment. The methodology combines inflow performance relationship (IPR) modelling with vertical lift performance (VLP) analysis to characterise production system behaviour under both natural flow and gas-lifted conditions. Field data, including reservoir pressure, production rates, fluid properties, and completion parameters, were calibrated to establish a reliable base case model. Sensitivity analyses were conducted to investigate the impacts of gas injection rate, water cut, and reservoir pressure depletion on oil production efficiency. Under natural flow conditions, the well exhibited a maximum production of 1,150 STB/day at an average reservoir pressure of 2,800 psia, with deliverability declining sharply below 2,200 psia, resulting in unstable inflow–outflow matching. At a 40% water cut, oil production decreased by over 35%, highlighting the critical need for artificial lift support. Implementation of gas lift significantly improved production, with an optimised injection rate of 3 MMscf/day increasing oil output to 1,950 STB/day—a 69% improvement over natural flow. The optimised system maintained stable IPR–VLP intersections across a wide range of bottomhole pressures, ensuring sustainable drawdown and operational efficiency. Economic evaluation indicated that gas lift extended the productive life of the well by more than five years and increased the net present value (NPV) by approximately 30% relative to continued natural flow. These results demonstrate that gas lift is a technically robust and economically advantageous artificial lift strategy for pressure-depleted Niger Delta reservoirs. Furthermore, the integration of nodal analysis within PROSPER provides a reliable framework for production forecasting, optimisation, and informed decision-making in mature field development.*

Keywords—Gas lift; Nodal analysis; Vertical lift performance (VLP); Inflow performance relationship (IPR); Niger Delta; Oil production optimization; PROSPER simulation; Well performance modelling.

1. INTRODUCTION (*Heading 1*)

Raw natural gas produced at the wellhead consists predominantly of methane, with smaller quantities of higher-molecular-weight hydrocarbons such as ethane, propane, butanes, and pentane-plus. In addition to hydrocarbons, natural gas contains various impurities including carbon dioxide (CO_2), hydrogen sulfide (H_2S), nitrogen, mercaptans, water vapour, and other sulphur compounds. The presence of CO_2 and H_2S classifies the gas as sour. These "acid gases" lower the heating value of natural gas and significantly increase the likelihood of operational problems such as corrosion, hydrate formation, and sulphide stress cracking during pipeline transportation [3]. The concentration of acid gases and other impurities varies depending on the reservoir source; therefore, they must be reduced to acceptable limits as defined by pipeline gas specifications before transportation [2].

The removal of CO_2 and H_2S commonly known as natural gas sweetening is essential to meet product quality, environmental, and transportation requirements. Several sweetening technologies exist, including absorption, adsorption, membrane separation, chemical conversion, and cryogenic distillation. Among these, absorption processes remain the most established due to their high acid-gas removal efficiency [12], [4]. Absorption processes are categorized into physical and chemical absorption methods, which employ physical and chemical solvents respectively. Physical solvents typically inorganic compounds absorb acid gases through physical affinity without chemical reaction. Sulfolane is a widely used physical solvent because of its high absorption capacity, low vapour pressure, and low energy requirements [6]. However, physical solvents are less effective at low pressures, making them unsuitable for many field applications.

For this reason, chemical absorption using amine-based solvents remains the industry standard. Alkanolamines such as monoethanolamine (MEA), diethanolamine (DEA), and methyl diethanolamine (MDEA) are the most common chemical solvents [4]. DEA and MDEA are particularly popular: MDEA is less corrosive and requires lower circulation rates, while DEA offers higher acid-gas removal capacity.

Process simulation plays a vital role in designing and optimizing natural gas sweetening systems. Commercial simulators such as Aspen HYSYS, Aspen Plus, and ChemCAD enable detailed modelling of mass transfer, chemical reactions, and thermodynamic behaviour. These tools support the determination of optimal operating conditions for efficient and cost-effective removal of acid gases. Simulation is particularly advantageous because it reduces cost and operational risks relative to full-scale experimentation, while providing reliable pathways for operational optimization during field development.

Natural gas composition varies significantly across fields, reservoirs, and even between wells producing from the same reservoir [9]. Methane typically constitutes more than 70 mol%, while the natural gas liquids (ethane through pentane-plus) appear in varying proportions. The non-hydrocarbon impurities including CO_2, H_2S, nitrogen, oxygen, water vapour, and sulfur compounds also vary widely. Despite these compositional differences, natural gas remains one of the most important global energy sources. It is widely used for domestic heating and cooking, industrial processes, electricity generation, and as fuel for transportation. It also serves as a key chemical feedstock in the production of numerous petrochemical derivatives such as plastics, tyres, ammonia-based fertilizers, and synthesis gas [7].

Given its lower carbon intensity relative to other fossil fuels such as coal and oil, natural gas is expected to maintain a dominant role in the global energy transition. Beyond energy use, methane remains a critical feedstock for producing methanol, syngas, and other platform chemicals essential to modern industrial value chains [11], [10]. Thus, the efficient and economical removal of impurities through advanced sweetening processes supported by rigorous simulation is fundamental to maximizing natural gas utilisation, safety, and value.

Several types of amines are commonly employed in natural gas sweetening processes to remove acid gases, particularly hydrogen sulfide (H_2S) and carbon dioxide (CO_2). The primary amines used include **monoethanolamine (MEA)**, **diglycolamine (DGA)**, and **methyldiethanolamine (MDEA)**. Additionally, **mixed amine solutions**, which combine different amines, are sometimes utilized to enhance acid gas removal efficiency [3].

Monoethanolamine (MEA), also referred to as 2-aminoethanol or ethanolamine, is a primary amine and alcohol compound produced by the reaction of ethylene oxide with aqueous ammonia. MEA was among the earliest amines applied in sour gas sweetening and remains widely used due to its well-understood operational characteristics [13]. It reacts with CO_2, COS, and CS_2 to form non-regenerative compounds that must be periodically removed to limit corrosion. Despite its effectiveness, MEA has higher vapor losses and is more corrosive due to degradation products formed during the sweetening process [3].

Diglycolamine (DGA) is a secondary amine developed in the 1950s. Compared to MEA, DGA requires a lower circulation rate of solution to achieve equivalent acid gas removal, allowing for smaller and less costly regeneration equipment. However, DGA is susceptible to degradation by CO_2 and exhibits higher solubility for heavier hydrocarbons, which can be disadvantageous in some applications. It is typically employed in aqueous solutions with concentrations ranging from 50% to 70% by weight [1].

Methyldiethanolamine (MDEA) is a tertiary amine widely used in the oil and gas industry. It reacts more slowly with CO_2 than MEA or DEA, forming different salt compounds. MDEA exhibits a higher selectivity for H_2S over CO_2, making it suitable for applications requiring partial CO_2 removal. Additional advantages include lower vapor pressure, lower heat of reaction, and reduced corrosivity compared to primary and secondary amines. MDEA is generally used in aqueous solutions with concentrations of 30% to 50% by weight [5], [8].

Mixed amine systems combine different amines commonly MDEA as the base amine with smaller proportions of DEA or MEA, typically less than 25% on a molar basis. These mixtures improve CO_2 removal efficiency in cases where MDEA alone may allow CO_2 to slip through. Mixed amines are particularly beneficial in low-pressure operations or when the CO_2 content in the feed gas increases over time [4].

The selection of an appropriate amine-based sweetening process depends on several factors, including the concentrations of H_2S and CO_2 in the raw gas, maximum design flow rate, inlet gas pressure, sulfur recovery requirements, and waste management strategies. The chosen process must balance cost-effectiveness with performance. For gases with low H_2S concentrations, scavenger chemicals may suffice, while higher concentrations generally necessitate full regenerative chemical plants [4].

2. MATERIALS AND METHODS

The natural gas **sweetening** process was modeled and simulated using Aspen HYSYS V11**.** For this study, the Amine Property Package was employed to accurately represent the behavior of amine-based absorption systems. Diethanolamine (DEA**)** was selected as the chemical solvent to remove acid gases from the natural gas stream. The feed gas used in the simulation is the wellhead gas from the Assa field in the Niger Delta, Nigeria**,** which contains appreciable concentrations of CO_2. The simulation aims to reduce the acid gas content to levels compliant with pipeline-quality sales gas specifications.

2.1 **Simulation Process**

The simulation workflow involves setting up and implementing the natural gas sweetening process in HYSYS through the following steps:

1. Inputting the feed gas composition and defining the stream conditions.

2. Selecting and configuring the amine-based absorption process for acid gas removal.
3. Specifying DEA solvent parameters, including concentration, flow rate, and operating temperature.
4. Configuring the absorption and regeneration columns to model acid gas stripping and solvent recovery.
5. Integrating all process units to establish a steady-state simulation.
6. Evaluating process performance, including acid gas removal efficiency and compliance of the treated gas with pipeline specifications.

The overall process is summarized in the block diagram below, which depicts the sequential stages of modeling and simulation of natural gas sweetening in Aspen HYSYS.

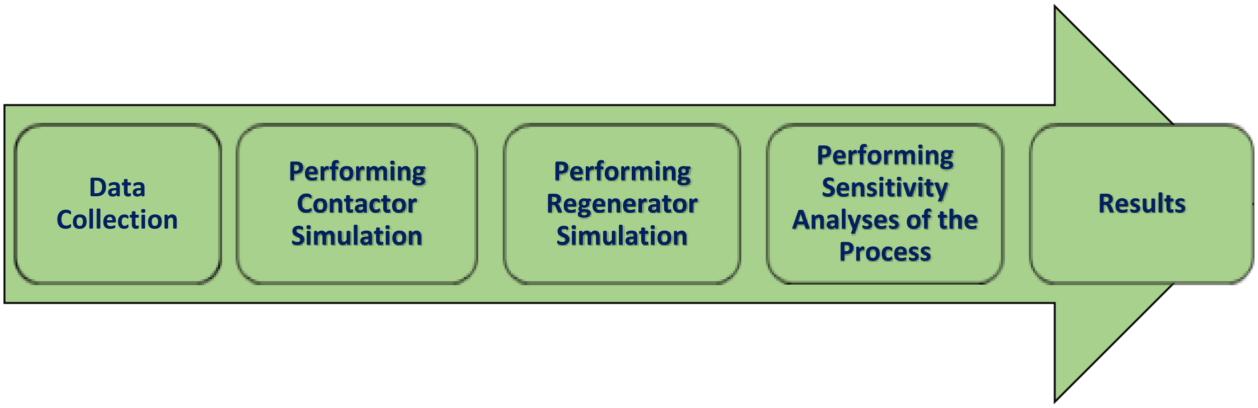

Figure 1: Simulation process steps

From Figure 1, it is evident that data collection plays a critical role in the simulation process. The collected data must be carefully verified for accuracy to ensure realistic and reliable modeling outcomes. Key data include the natural gas composition, feedstock inlet conditions, and operational parameters for the contactor and regenerator units.

The simulation begins with the contactor column, where sour natural gas is introduced from the bottom while the DEA solution is fed from the top. A mass transfer process occurs between the two streams, enabling the removal of acid gases from the natural gas. The resulting DEA, now rich in absorbed acid gases, is sent to the regenerator unit for stripping and subsequent reuse. Additionally, a sensitivity analysis is conducted to investigate the effects of temperature and pressure variations on the acid gas removal efficiency.

2.2 Simulation

The natural gas sweetening process was modeled in Aspen HYSYS V11 using the acid gas chemical property package. The simulation represents a conventional gas-liquid treating process, where DEA is employed as the amine solvent at high pressure to remove CO2 from the feed gas. For this study, CO_2 is the primary acid gas, as the typical Niger Delta gas contains negligible H_2S. A feed rate of 5.1 MMscfd of sour natural gas was introduced into a high-pressure absorber operating at 510 psig. A 26 wt% DEA solution in water was fed into the top of the absorber, flowing counter-current to the sour gas entering from the bottom. Mass transfer between the DEA and sour gas resulted in the absorption of CO2, effectively stripping it from the natural gas stream. The DEA, now rich in CO2, collected at the bottom of the absorber for regeneration, while the treated gas exited at the top as sweet natural gas, ready for storage or further processing.

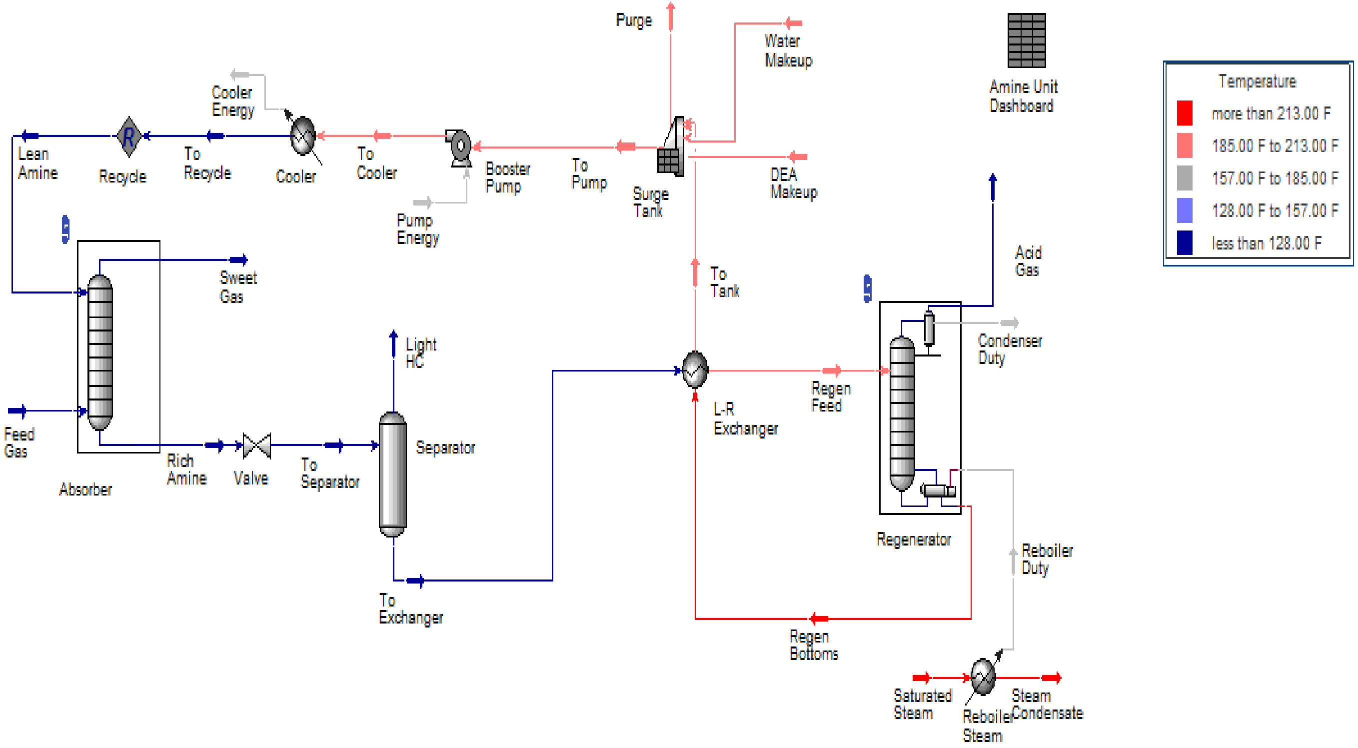

Figure 2: Process flow diagram (PFD) of the process simulation in Hysys

The rich amine exiting the bottom of the absorber was first flashed from 514.7 psia to 70 psia in a two-way separator to release most of the absorbed light hydrocarbons. The partially treated amine was then directed to the lean/rich amine heat exchanger, where heat transfer adjusted the rich DEA to a suitable temperature for entry into the regenerator. In this heat exchanger, thermal energy was exchanged between the rich DEA and the regenerated amine stream. Within the regenerator, acid gases were removed from the rich amine. The stripping process occurred at low pressure (35 psia) and elevated temperature (109.8°F), allowing the DEA solvent to release the absorbed acid gases. The regenerated lean DEA was then recycled back to the absorber column, with makeup amine added as needed to maintain solvent balance.

3. RESULTS AND DISCUSSIONS

3.1 Base Case Results

This section presents the results of the base case simulation for natural gas sweetening carried out in Aspen Hysys. The results indicate the proportion of acid gas (CO2) removed from the natural gas stream under the base operating conditions. At the base case conditions of 85°C and 950 psig, the simulation shows that 98.28% of the CO2 is effectively removed from the natural gas stream.

3.2 Effect of Temperature Vs Tray Position

The temperature profile along the tray positions in the absorber and regenerator illustrates how temperature varies within the equipment. The temperature distribution across the trays in the absorber is shown in Figure 4.

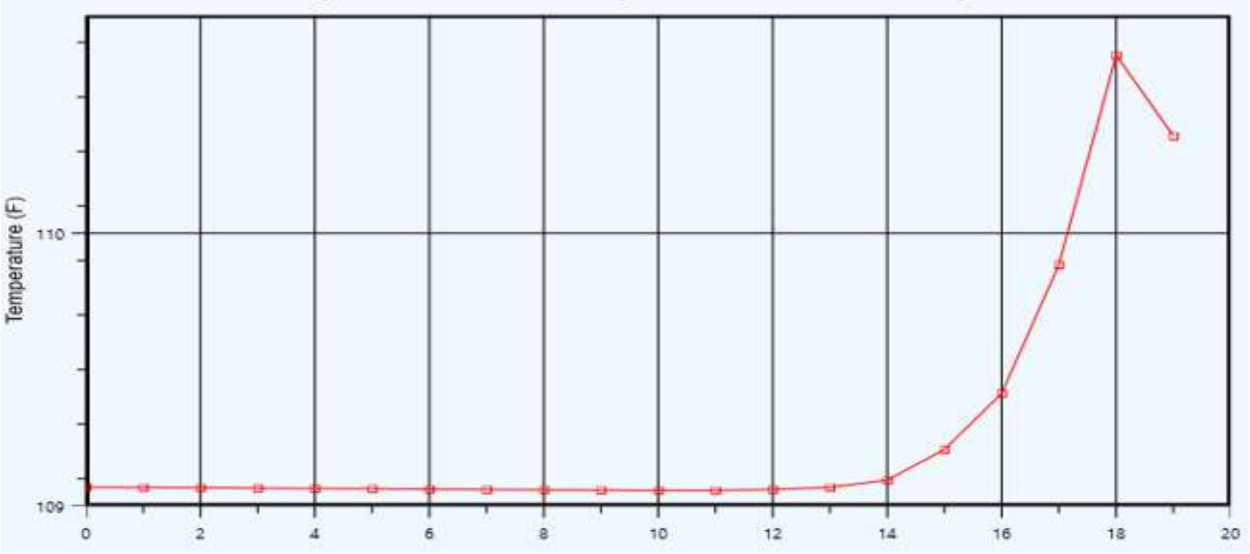

Figure 3: Temperature vs tray position in the absorber

From Figure 3, the temperature profile in the absorber shows that the temperature remains fairly constant at 109.1°F from the absorber inlet up to tray 15 (15_TS-1). Beyond this point, from tray 16 (16_TS-1), the temperature begins to rise gradually, reaching 110.7°F at tray 19 (19_TS-1). After tray 19, the temperature decreases slightly to 110.4°F at the absorber outlet on tray 20 (20_TS-1). This trend indicates that the heat of absorption is gradually affecting the temperature along the absorber. The initial constant temperature suggests that the incoming rich amine and sour gas are at thermal equilibrium, with minimal net heat generation or absorption. The gradual rise in temperature from tray 16 to 19 is likely due to the exothermic nature of CO2 absorption by DEA, as the amine reacts with the acid gas, releasing heat. The slight drop at the final tray may result from heat losses to the surrounding equipment or the decreasing concentration of CO2 in the gas stream as it approaches full sweetening. Overall, the temperature variation along the trays provides insight into the efficiency of mass transfer and the thermal behavior within the absorber. Maintaining optimal temperature is crucial, as excessive temperature rise could reduce CO2 absorption efficiency or lead to amine degradation, while too low a temperature may slow down the reaction kinetics.The temperature vs tray position in the regenerator is given in figure 4 below.

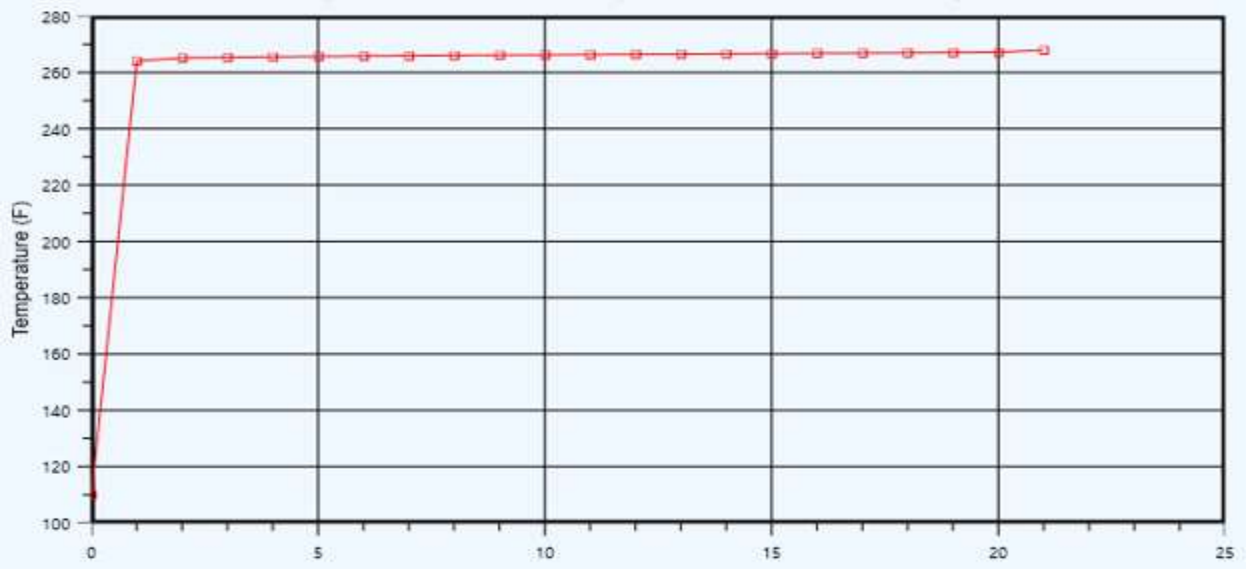

Figure 4: Temperature vs tray position in the regenerator

Figure 4 illustrates the temperature profile along the trays in the regenerator. In this unit, the rich DEA is stripped of its absorbed acid gases and subsequently recycled back to the absorber. The temperature at the condenser is maintained at 110°F. From the condenser, the temperature rises sharply to 264.1°F at tray 1, reflecting the initial heating of the DEA solution as it enters the regenerator. Between tray 1 and tray 20, the temperature increases gradually to 267.1°F, indicating steady heat transfer along the regenerator column. Finally, the temperature reaches 267.9°F at the reboiler, where the remaining acid gases are fully stripped from the amine solution.

This temperature profile demonstrates the typical thermal behavior in a regenerator column. The sharp initial rise from the condenser to tray 1 shows the effect of the applied heat needed to initiate acid gas desorption. The gradual temperature increase along the trays suggests efficient counter-current contact between the rising acid gas and the descending amine solution, promoting mass transfer and gas stripping. The further rise at the reboiler highlights the role of concentrated heating in completing the regeneration process, ensuring the DEA is sufficiently lean before recycling. Maintaining this temperature gradient is crucial for effective acid gas removal while avoiding excessive thermal degradation of the amine.

3.3 Effect of Pressure on Tray Position

The pressure profile along the tray positions in both the absorber and regenerator indicates how pressure varies within the equipment. Figure 5 presents the variation of pressure with tray position in the absorber.

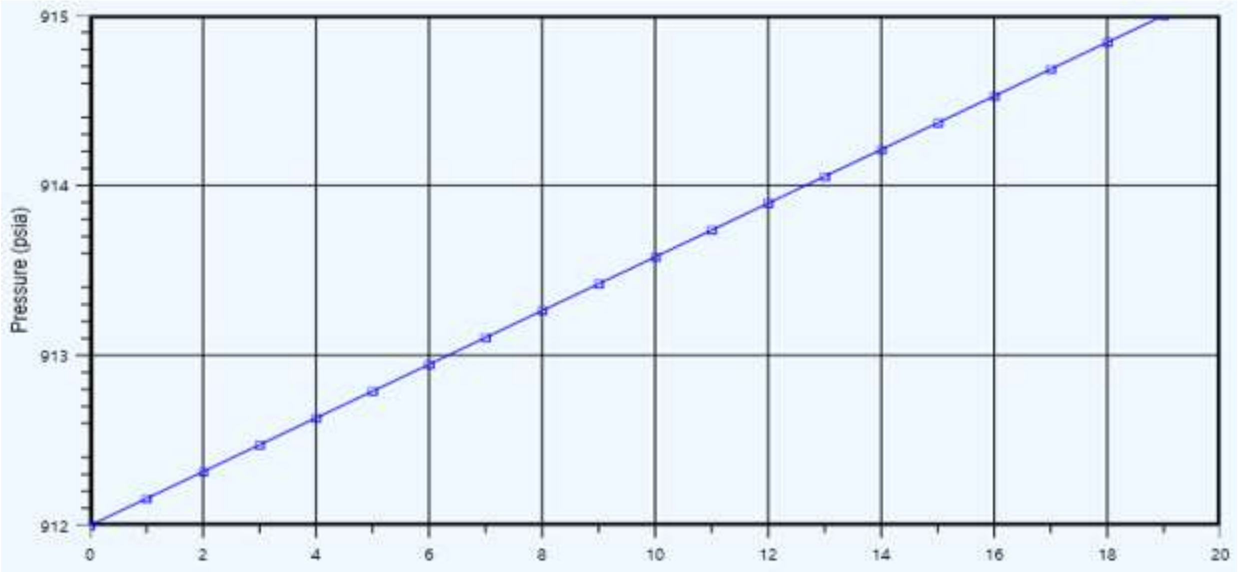

Figure 5: Pressure vs tray position in the absorber

The pressure within the absorber exhibits a nearly linear variation along the tray positions. It begins at 912 psi at the absorber inlet and gradually increases to 915 psi at the outlet, resulting in a total pressure drop of 3 psi across the column. This small pressure drop indicates minimal resistance to flow and efficient design of the absorber.

The corresponding pressure profile in the regenerator is shown in Figure 7. In the regenerator, pressure distribution is crucial as it affects the stripping efficiency of the acid gases from the rich DEA. Maintaining appropriate pressure gradients ensures effective mass transfer and proper regeneration of the amine for recycling back to the absorber.

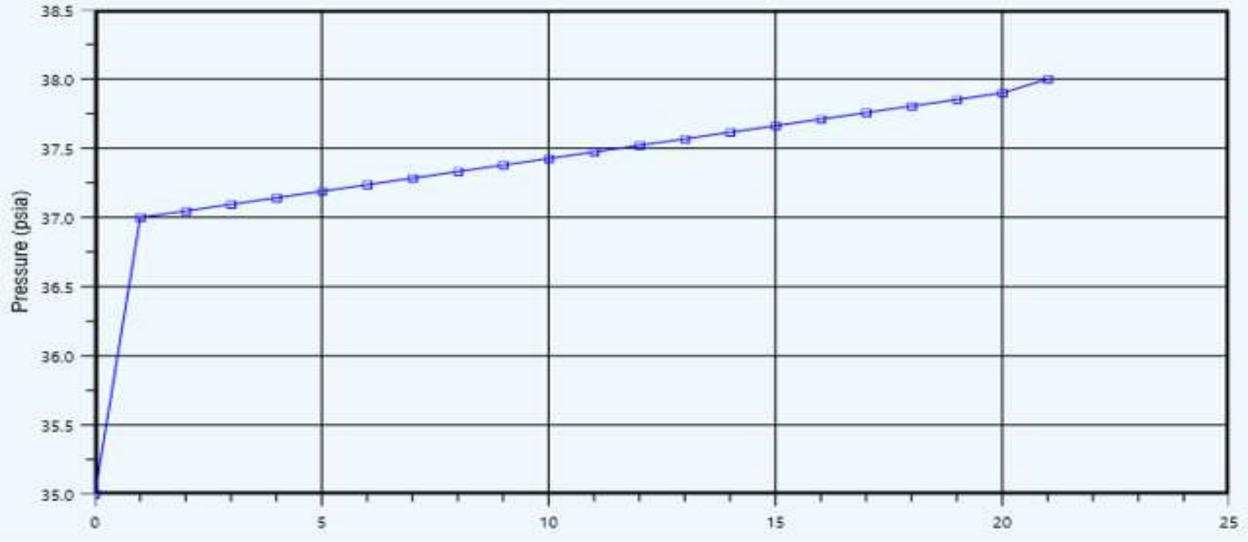

Figure 6: Pressure vs tray position in the regenerator

Figure 6 illustrates the pressure variation along the tray positions in the regenerator. The pressure at the condenser was 35 psi, which increased to 37 psi at tray position 1. From this point, the pressure rose linearly along the column, reaching 37.43 psi at the reboiler. The linear increase in pressure with tray position indicates a uniform pressure gradient throughout the regenerator, with a total pressure drop of only 0.43 psi. This minimal pressure drop suggests that the regenerator operates efficiently, with negligible flow resistance along the trays. The uniform pressure profile is beneficial for consistent stripping of acid gases from the rich DEA, ensuring effective regeneration and reliable performance when the lean amine is recycled back to the absorber.

3.4 Effect of Molar Composition of CO_2

The effect of the molar composition of CO2 in the stream flowing in the absorber and regenerator are given and discussed in this section.

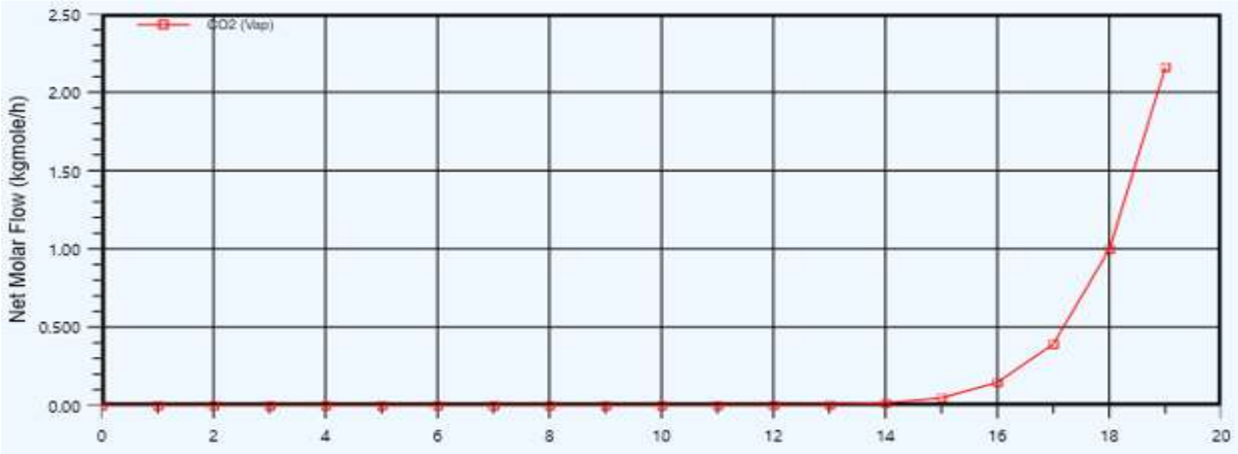

Figure 7: Composition vs tray position in the absorber

Figure 7 presents the CO2 composition along the tray positions in the absorber. The net molar flow of CO2 remains effectively zero from the inlet of the absorber up to tray position 15, indicating near-complete absorption of CO2 in the lower section of the column. Beyond tray 15, the CO2 molar flow increases sharply, reaching 2.161 kgmol/hr at tray position 20, which corresponds to the outlet of the absorber. This trend suggests that the bulk of CO2 removal occurs in the lower and middle sections of the absorber, where the contact between the sour gas and DEA is most effective. The increase in CO2 toward the top trays indicates the approach to equilibrium conditions, where the solvent's capacity to absorb CO2 diminishes. This highlights the importance of sufficient tray design and solvent circulation to maximize acid gas removal and ensure the sweetened gas meets pipeline specifications.

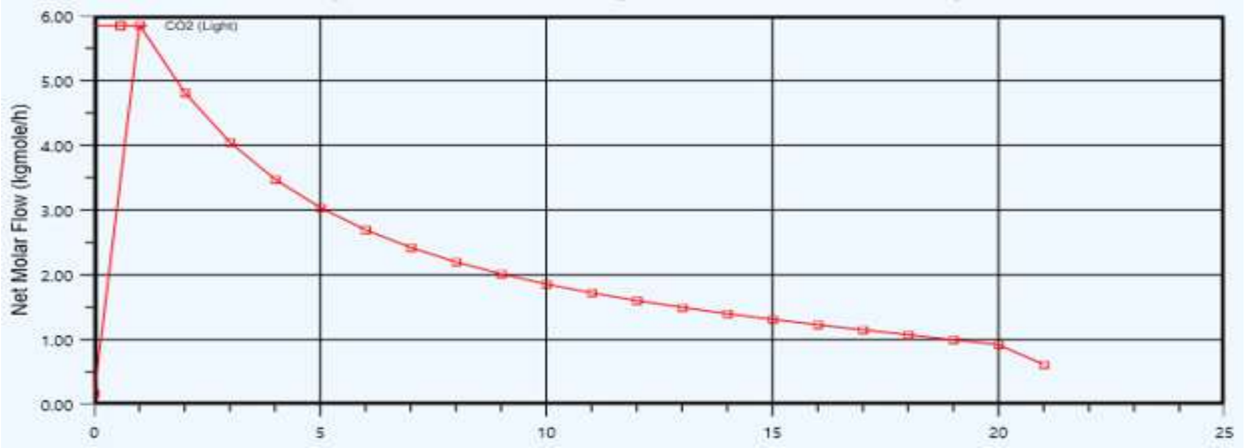

Figure 8: Composition vs tray position in the regenerator

Figure 8 illustrates the variation of CO2 molar flow along the tray positions in the regenerator. At the condenser, the CO2 molar flow is relatively low at 0.175 kgmol/hr. However, upon entering tray position 1, the CO2 molar flow rises sharply to 5.86 kgmol/hr, indicating the rapid release of absorbed CO2 from the rich DEA solvent at the bottom of the regenerator. Beyond tray 1, the CO_2 molar flow gradually decreases along the tray positions, reaching 0.614 kgmol/hr at the reboiler. This pattern reflects the effective stripping of CO2 from the amine solution as it ascends the regenerator. The initial sharp rise demonstrates the high driving force for desorption at the lower trays where the rich amine first enters. The gradual decrease toward the reboiler shows that most of the CO2 has been removed, and only residual amounts remain in the upper trays. This highlights the regenerator's efficiency in reclaiming the amine solvent for recycling while ensuring acid gas is adequately separated for disposal or processing.

3.5 Sensitivity Analyses

The sensitivity analysis examined how variations in temperature and pressure influence the percentage of CO2 removed from the natural gas stream. Figure 10 illustrates the impact of temperature on the CO2 removal efficiency from the natural gas.

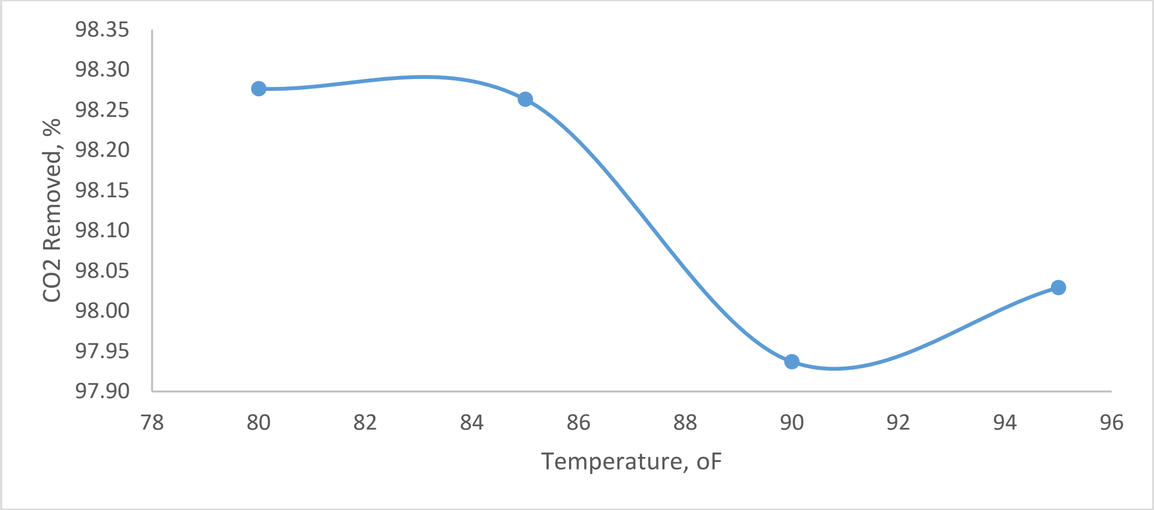

Figure 9: Effect of temperature on the percentage CO2 removed from the natural gas

Figure 9 illustrates the effect of varying the inlet temperature on the percentage of CO2 removed from the natural gas stream. The inlet temperature was varied from 80°F to 95°F in increments of 5°F. The CO2 removal efficiency exhibited a non-linear trend with temperature variation. Initially, as the temperature increased from 80°F to 90°F, the percentage of CO2 removed decreased slightly from 98.28% to 97.94%, indicating a reduction of 0.34%. Interestingly, further increasing the temperature to 95°F led to a slight recovery in CO2 removal efficiency, rising to 98.03%, corresponding to an increase of 0.09% compared to 90°F.

This behavior can be interpreted in terms of the thermodynamics and kinetics of the absorption process. At lower temperatures, the chemical reaction between DEA and CO2 is favored, leading to higher absorption. As temperature rises, the solubility of CO2 in the amine solution decreases, slightly reducing removal efficiency. However, beyond a certain point (in this case, 90°F), the higher temperature may enhance mass transfer rates and reduce viscosity, allowing the solvent to more effectively contact the gas and slightly improve CO2 capture.

The overall variation is relatively small, indicating that the process is moderately robust to small fluctuations in inlet temperature. In practical terms, maintaining the absorber within the 80–95°F range ensures that CO2 removal remains above 97.9%, demonstrating operational flexibility and resilience of the DEA-based sweetening system.

The effect of pressure on the percentage of CO2 removed is shown in figure 11 below.

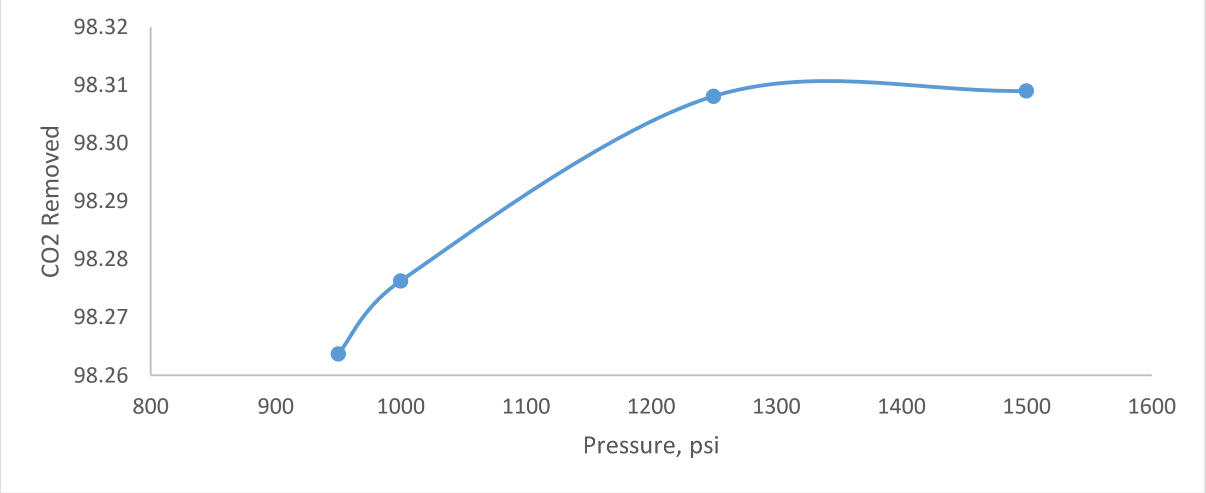

Figure 10: Effect of pressure on the percentage CO2 removed from the natural gas

Figure 10 illustrates the effect of operating pressure on the percentage of CO2 removed from the natural gas stream. The results show that CO2 removal efficiency generally increases with increasing pressure. At 950 psi, the percentage of CO2 removed was 98.26%, which rose to 99.31% when the pressure was increased to 1250 psi. However, further increasing the pressure to 1500 psi resulted in a slight decrease, with the CO2 removal stabilizing at 98.31%.

From the principles of gas solubility and mass transfer, higher pressures enhance the solubility of CO2 in the DEA solution, thereby improving absorption efficiency. Beyond the optimal pressure (around 1250 psi in this case), additional pressure offers diminishing returns, and slight decreases may occur due to reduced gas-liquid contact efficiency or operational limitations such as flooding in the absorber.

The results highlight the importance of carefully selecting operating pressure in the design of CO2 sweetening systems. Operating near the optimal pressure maximizes acid gas removal while avoiding unnecessary energy consumption or mechanical stress. This underscores that process parameters such as pressure play a critical role in achieving efficient and cost-effective natural gas sweetening.

4. CONCLUSION

This study investigated the process simulation of natural gas sweetening for the removal of CO2 from a natural gas stream. The feed gas used in the simulation was the wellhead stream from the Assa field in the Niger Delta region of Nigeria. Being a typical Nigerian natural gas, the stream contains no H2S but has a significant concentration of CO2, which poses challenges for pipeline transportation. To comply with pipeline sales gas specifications, the CO2 content must be reduced to below 4% mole fraction, as shown in Appendix 1. The process simulation was carried out using Aspen HYSYS V11 with the acid gas chemical property package.

The key conclusions from the simulation are as follows:

1. The percentage of CO2 removed increased with increasing operating pressure. However, beyond 1250 psi, the CO2 removal efficiency plateaued, showing negligible improvement with further pressure increase.
2. The percentage of CO2 removed decreased with rising inlet temperature from 80°F to 90°F. Beyond 90°F, CO2 removal efficiency began to increase slightly with further temperature rise.
3. In the absorber, the molar flow of CO2 remained zero up to tray position 15, after which it increased steadily, reaching 2.161 kgmol/hr at the outlet (tray 20).

4. In the regenerator, the molar flow of CO2 decreased consistently along the tray positions, starting from 5.86 kgmol/hr at tray 1 and reaching 0.614 kgmol/hr at the reboiler.
5. Proper process design and simulation are critical to optimizing CO2 removal from sour natural gas streams, ensuring maximum efficiency while minimizing energy consumption and operational costs.

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