Optimization of Amine-Based Sweetening Processes for Enhanced Natural Gas Purification

Kate Odafe Idolor[1], Oluwafemi Awodoyin[2]
[1]Department of Petroleum Engineering, University of Benin, Nigeria
[2]Department of Science Laboratory Technology (SLT), Gateway ICT Polytechnic, Saapade, Ogun State, Nigeria

Abstract- *The world we live in today is a global village involving rapid industrialization and increase in demand for energy, which has led to tireless research for alternative source of primary energy. The use of natural gas as an industrial and domestic fuel has become a prime source of energy generation. Natural gas (from reservoir or associate crude production) can contain acid gases such as H2S and/or CO2, mercaptans and other impurities which hinders natural gas production processes and constitute great environmental hazards when it gets to the atmosphere. These impurities must be removed in other to meet the pipe-line quality standard specifications as a consumer fuel, enhance the calorific value of the natural gas, avoid pipelines and equipment corrosion and further overcome related process bottle necks. This research focuses on optimizing the amine-based sweetening process, a critical step in purifying natural gas by removing acidic contaminants such as hydrogen sulfide (H2S) and carbon dioxide (CO2). Utilizing the advanced simulation capabilities of Aspen HYSYS, this study evaluates the performance and economic feasibility of employing Monoethanolamine (MEA) and Methyldiethanolamine (MDEA) in the gas sweetening process. Our research presents a simulation-based evaluation of amine treatment methods for purifying natural gas. The core findings indicate that Methyldiethanolamine (MDEA) surpasses Monoethanolamine (MEA) in removing acidic impurities such as hydrogen sulfide and carbon dioxide, offering a more effective and cost-efficient solution. These results suggest a preference for MDEA in natural gas sweetening applications, with potential implications for improved industry practices and environmental outcomes.*

I. INTRODUCTION

As the demand for cleaner energy sources intensifies globally, natural gas emerges as a pivotal resource in the United States' energy strategy. Recognized as the cleanest burning fossil fuel, natural gas not only plays a significant role in reducing the country's carbon emissions but also serves as a critical bridge in the transition towards renewable energy. However, the efficient and environmentally safe processing of natural gas remains a technical challenge due to the presence of acid gases such as hydrogen sulfide (H2S) and carbon dioxide (CO2)[1]. These contaminants, if not properly managed, can lead to environmental degradation, operational inefficiencies, and increased maintenance costs due to equipment corrosion.

In the evolving landscape of energy production, the efficient and environmentally responsible treatment of natural gas stands as a pivotal challenge for the global energy sector. As the cleanest burning fossil fuel, natural gas plays a critical role in the transition towards more sustainable energy systems. However, its extraction and purification often result in the presence of acid gases like hydrogen sulfide (H2S) and carbon dioxide (CO2), which pose significant environmental risks and technical challenges [2-3]. The removal of these contaminants is not only crucial for meeting stringent environmental regulations but also for ensuring the safety and efficiency of energy production processes.

The conventional amine treatment process, which utilizes aqueous alkanolamine solutions, has emerged as a predominant method for acid gas removal. This process is favored due to its efficiency in selectively removing H2S and CO2, thus enhancing the calorific value of natural gas and preventing corrosion in transport and processing infrastructure [4-6]. Despite its widespread application, amine treatment processes' operational and economic aspects require continual optimization to adapt to varying gas compositions and operational settings.

This research explored the efficacy of different amine solutions, particularly focusing on Monoethanolamine (MEA) and Methyldiethanolamine (MDEA), in removing H2S and CO2 from natural gas. Using Aspen HYSYS, a leading process simulation software, this study conducts a comparative analysis to determine the most effective amine treatment under varied operational conditions. By optimizing the parameters such as amine concentration and contactor pressure, this work endeavors to enhance the overall efficiency and cost-effectiveness of the gas treatment process, thereby contributing to more sustainable and economically viable natural gas production.

In simpler term, the objectives of this research are;

1. To develop a flow sheet of conventional amine system using HYSYS simulation software
2. To evaluate the efficacy of conventional gas treatment in removing acidic gas using amine solution
3. To determine the efficacy of sweetening natural gas before it reaches its end users.
4. To analyze on the best parameter and specifications in both plant operation and amine solutions for maximum efficiency of CO2 and H2S removal.

Through achieving these objectives, this paper aims to contribute significantly to the field of chemical engineering by providing a deeper insight into the operational optimization of amine gas sweetening processes, thereby supporting the U.S. energy sector's move towards more sustainable and economically viable natural gas production.

II. METHODOLOGY

2.1 Software

Aspen HYSYS software version 8.8 [7] was employed for the simulation design of this project. Aspen HYSYS is a comprehensive project modeling system designed to optimize process operations and designs; users input the process by describing the equipment and interconnecting process streams, and the software resolves all relevant mass, energy, and equilibrium equations based on specific design parameters for each unit. In this study, acid gases such as CO2 and H2S are separated, recycled, and treated for industrial use. The selection of the appropriate fluid package is crucial as it fundamentally influences the simulation results; thus, the amine fluid package was chosen over the commonly used Peng Robinson fluid package due to its superior performance with lower chain hydrocarbons. Additionally, an extensive economic analysis was conducted using the Aspen HYSYS Economic Analyzer (Aspen-EA) software, which facilitates the evaluation of capital investments during the design process. This software also provides estimates of equipment costs, utility costs, and operating expenses when utilizing both MEA and MDEA solvents.

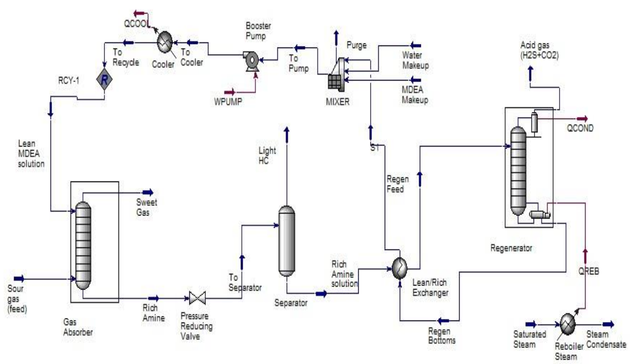

Fig. 1a: A simulated Process Flow Diagram (PFD) of Acid Gas removal plant using Amine (MDEA) solvent.

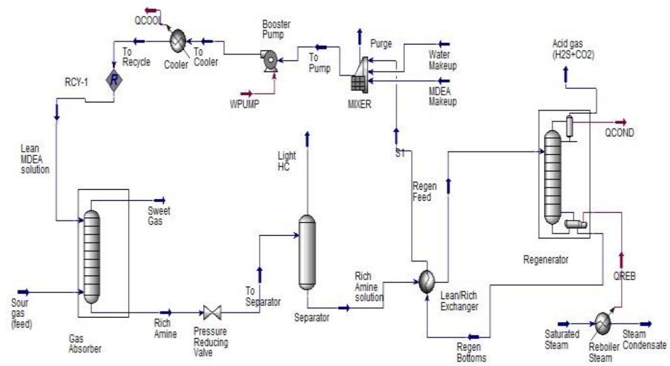

Fig. 1b: A simulated Process Flow Diagram (PFD) of Acid Gas removal plant using Amine (MDEA) solvent.

2.2 Sour Gas Introduction and Absorption

Sour gas, primarily methane (85%), enters the system at a molar flow rate of 498 kgmol/hr, temperature of 37.78°C, and pressure of 56.86 bar (824.7 psi). It is introduced at the bottom of the absorber column. This gas then travels upward, moving counter-currently to the lean MDEA solvent which is introduced in stages at the top of the absorber. The treated gas, now sweetened and meeting pipeline specifications, exits from the top of the column and is channeled into the distribution system. The solvent laden with absorbed acid gases, termed "rich amine," is transferred from the absorber to a flash drum known as the SEPARATOR [9-11]. Here, lighter hydrocarbons are flashed out. Following this, the rich amine proceeds to the REGENERATOR, a stripper column where it is regenerated using a reboiler that applies saturated steam at a temperature of 147.70°C and a pressure of 4.461 psi with a molar flow rate of 165.1 kgmol/hr.

Table 1: Feed composition of sour natural gas used for the process simulation.

Compositions	Mole fraction
Methane	0.850
Ethane	0.040
Propane	0.030
Nitrogen	0.030
H_2S	0.020
CO_2	0.030
Amine	0.000
i-butane	0.000
n-butane	0.000
H_2O	0.000
Total	1.00

2.3 Gas Absorber Design, Acid Gas Stripping and Solvent Regeneration

The gas absorber was configured as either a tray or a packed tower, with packing generally preferred due to its higher capacity and better material construction options. The solvent laden with absorbed acid gases, termed "rich amine," is transferred from the absorber to a flash drum known as the SEPARATOR. Here, lighter hydrocarbons are flashed out. Following this, the rich amine proceeds to the REGENERATOR, a stripper column where it is regenerated using a reboiler that applies saturated steam at a temperature of 147.70°C and a pressure of 4.461 psi with a molar flow rate of 165.1 kgmol/hr [9-11].

2.4 Pressure and Temperature Management

Post-absorption, the stream from the bottom of the gas absorber is directed through a Pressure Reducing Valve (PRV) to decrease the pressure from 57.17 bar to 4.81 bar before it reaches the separator. In the Lean-Rich (L-R) exchanger, the rich amine at 53.91°C and 2.4 bar exchanges heat with the heated lean amine from the bottom of the regenerator, warming up to 79.65°C.

2.5 Amine Recycling and Cooling

The amine mixture is prepared for reuse by mixing with make-up water and additional MDEA solvent in a MIXER to achieve optimal composition for further gas sweetening. A booster pump then raises the pressure of this stream from 1.448 bar to the operational pressure of the gas absorber at 56.86 bar, matching the inlet pressure of the make-up streams in the MIXER. A cooler further reduces the temperature of the stream from 81.17°C to 43.33°C.

2.6 Acid Gas Liberation and Condensation

As steam rises through the regenerator column, it liberates the absorbed acid gases (H2S + CO2) along with water. These liberated gases and steam are then condensed in the reflux condenser. The condensed steam is separated in the reflux accumulator and returned to the still, completing the cycle.

III. RESULTS AND DISCUSSION

The simulation results are deemed reliable as the thermodynamic model accounts for temperature, pressure, and composition in determining the reaction equilibrium. A comparative analysis of the simulation outcomes for MEA and MDEA solutions reveals that MDEA is both a more cost-effective and efficient option for removing acid gases. Both MEA and MDEA prove effective as sweetening agents for acid digestion; however, MDEA stands out as the more economical choice, achieving a hydrogen sulfide (H2S) removal efficiency of 99.5% and a combined H2S and carbon dioxide (CO2) removal efficiency of 99.07%.

3.1 Methyldiethanolamine (MDEA) Solvent Acid Gases Removal

The concentration of hydrogen sulfide (H2S) and carbon dioxide (CO2) in the acid gas decreases uniformly from Tray No. 21 to Tray No. 1, where both concentrations reach zero, achieving a combined removal efficiency of 99.07% (Fig 2). Additionally, data from Table 2 indicated that while CO2 removal is complete at 100% at Tray No. 1, the overall removal of both H2S and CO2 stands at 99.07% using a 45.0 wt% MDEA solution (Aspen Hysys).

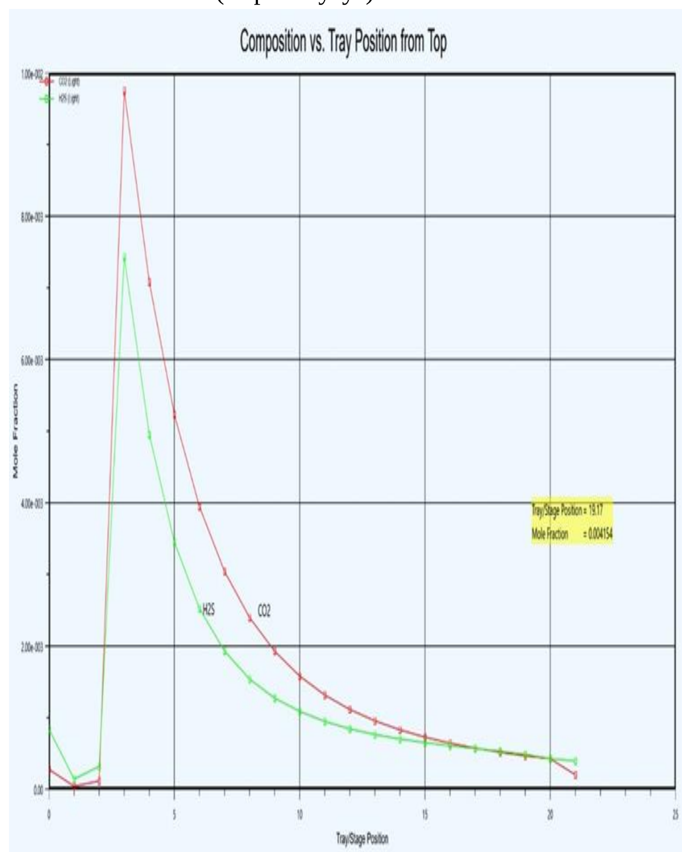

Fig. 2: Graph of mole fractions against tray/space positions in removing H2S and CO2 in the regenerator using MDEA solvent.

In terms of cost-effectiveness and efficiency, the results demonstrate that MDEA is highly effective for sweet gas treatment, achieving an H2S removal efficiency of 99.5% and a combined H2S and CO2 removal efficiency of 99.07%. The average cost of MDEA is approximately 98 USD per kilogram, indicating not only high performance but also economic viability. The total mass flow required for MDEA in this process is 23,620 kg/hr, underscoring its substantial role in acid gas removal operations.

Table 2: Composition profile table of acid gases removal at different trays in a regenerator using MDEA as a solvent.

	CO_2 light liquid	**H_2S light liquid**
Condenser	0.0003	0.0008
Main Tray 1	0.0000	0.0001
Main Tray 2	0.0001	0.0003
Main Tray 3	0.0098	0.0074
Main Tray 4	0.0071	0.0050
Main Tray 5	0.0052	0.0035
Main Tray 6	0.0039	0.0025
Main Tray 7	0.0030	0.0019
Main Tray 8	0.0024	0.0015
Main Tray 10	0.0019	0.0013
Main Tray 11	0.0016	0.0011
Main Tray 12	0.0013	0.0009
Main Tray 13	0.0011	0.0008
Main Tray 14	0.0010	0.0008
Main Tray 15	0.0008	0.0007
Main Tray 16	0.0007	0.0006
Main Tray 17	0.0006	0.0006
Main Tray 18	0.0006	0.0005
Main Tray 19	0.0005	0.0005
Main Tray 20	0.0004	0.0004
Reboiler	0.0002	0.0004

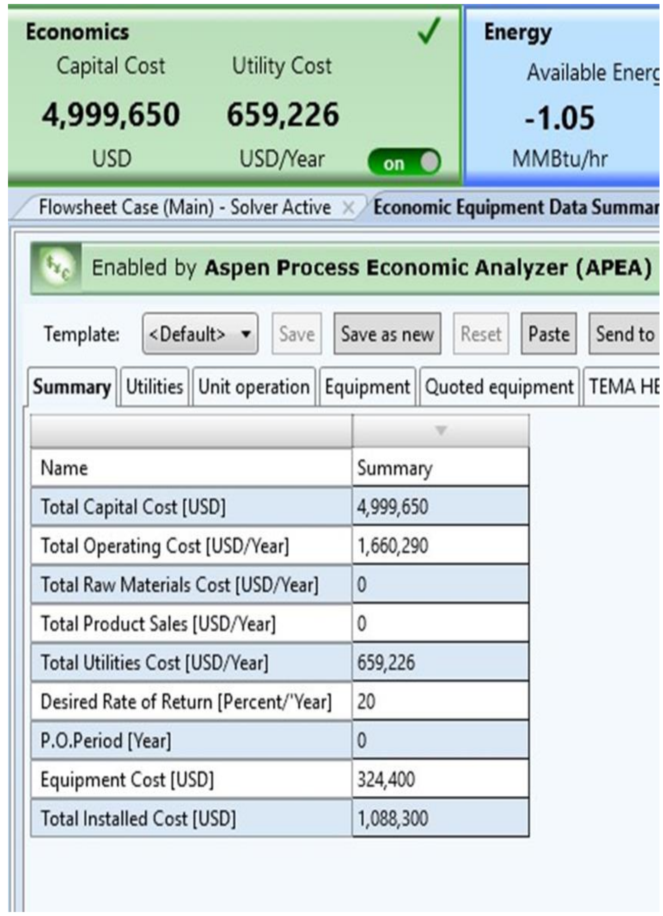

Fig. 3: Overall summary of the economic analysis result using MDEA as a solvent in an acid gas treatment plant from the Aspen Process Economic Analyzer (APEA) software.

3.1.2 Energy Analysis using MDEA as solvent for acid gas treatment plant

When MDEA is used as a solvent for acid gas treatment in our setup, the total utility consumption was estimated at 5.934 MMBtu/hr, which favorably falls below the target of 6.987 MMBtu/hr by 17.74% (Fig 4). This discrepancy underscores a noteworthy opportunity for energy savings. In parallel, cooling utilities mimic this trend, suggesting a systemic overperformance in energy conservation, with identical percentages in potential savings. Carbon emissions, a critical environmental metric, stood at 1,543 lb/hr, significantly under the target of 1,817 lb/hr. This denotes a potential emission reduction of 273.6 lb/hr, equating to a 17.73% positive variance from the established target.

These results underscore not only the current plant's operational efficiency but also sheds light on the tangible benefits of employing MDEA as a solvent. Our findings corroborate MDEA's role in bolstering the plant's energy efficiency, leading to economic benefits while concurrently diminishing the environmental impact through lowered carbon emissions [12]. These outcomes present a compelling case for the broader adoption of MDEA in similar applications within the industry, aligning operational objectives with environmental stewardship as noted by several other literature [12-14].

Fig. 4: ASPEN software output indicating Energy saved on major utilities duty flow mainly between target and actual values for MDEA treatment plant.

3.2 Monoethanolamine (MEA) Solvent Acid Gases Removal

The concentrations of hydrogen sulfide (H2S) and carbon dioxide (CO2) in the acid gas treatment process decrease progressively from Tray No. 20 to Tray No. 1. Despite this decline, the concentrations of both gases do not fully reach zero by Tray No. 1, resulting in a final removal efficiency of 95.0% for both H2S and CO2 (Fig. 5).

The economic analysis results for both MEA and MDEA acid gas treatment plants (Fig. 3 and Fig. 6), suggested that designing and constructing MDEA acid removal plant is way cheaper as its Total Capital Cost (TCC) is 4,999,650 USD and operating cost per year is 1,660,290 USD while that of MEA acid gas removal plant is 12,072,500 and its operating cost per year is 11,879,600 USD. Hence, MDEA acid gas treatment plant is highly viable.

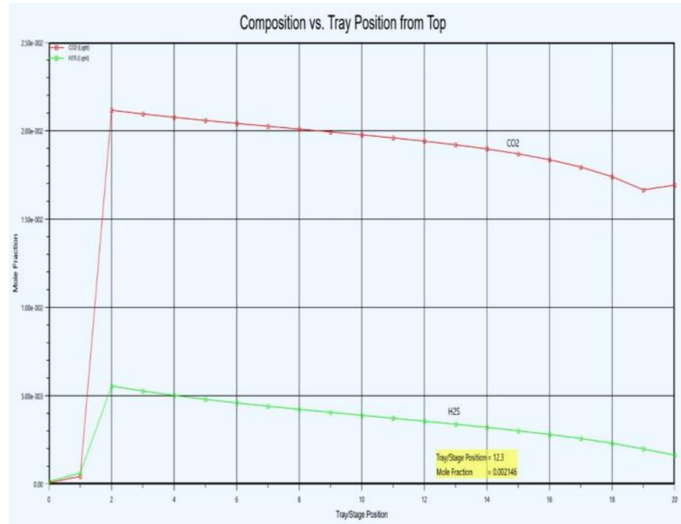

Fig. 5: Graph of mole fractions against tray/space positions in removing H2S and CO2 in the regenerator using MEA solvent.

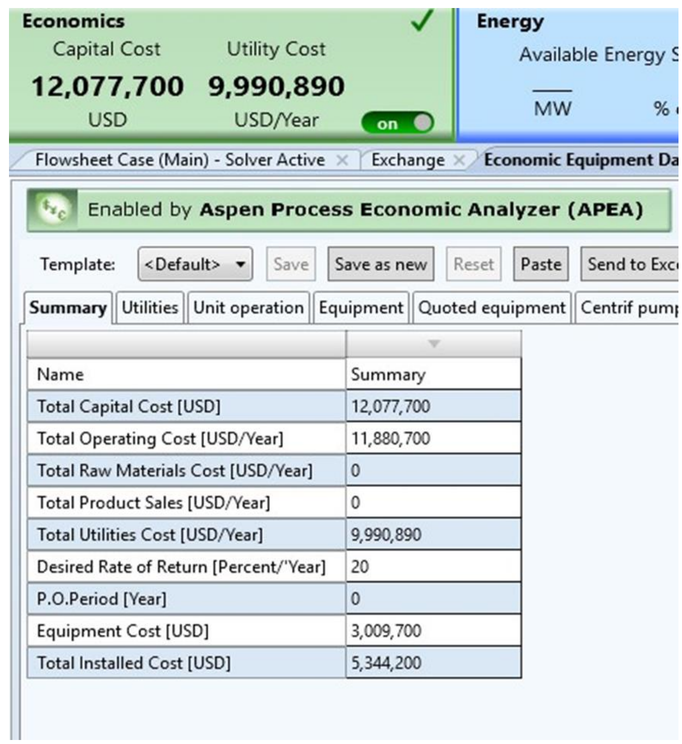

Fig. 6: Overall summary of the economic analysis result using MEA as a solvent in an acid gas treatment plant from the Aspen Process Economic Analyzer (APEA) software.

Data presented in Table 3 supported these observations, indicating that the CO2 removal efficiency stands at 94% at Tray No. 1. For the combined gases, using a 29.97 wt.% Monoethanolamine (MEA) solution, the removal efficiency reaches 95%. This table also presents detailed simulations of H2S and CO2 mole fractions across various tray positions in the top section of the absorber.

Table 3: Composition profile table of acid gases removal at different trays in a regenerator using MEA as a solvent.

	CO_2 light liquid	H_2S light liquid
Condenser	0.0001	0.0001
Main Tray 1	0.0004	0.0006
Main Tray 2	0.0212	0.0055
Main Tray 3	0.0209	0.0053
Main Tray 4	0.0208	0.0050
Main Tray 5	0.0206	0.0048
Main Tray 6	0.0204	0.0046
Main Tray 7	0.0203	0.0044
Main Tray 8	0.0201	0.0042
Main Tray 9	0.0199	0.0041
Main Tray 10	0.0198	0.0039
Main Tray 11	0.0196	0.0037
Main Tray 12	0.0194	0.0036
Main Tray 13	0.0192	0.0034
Main Tray 14	0.0190	0.0032
Main Tray 15	0.0187	0.0030
Main Tray 16	0.0184	0.0028
Main Tray 17	0.0179	0.0026
Main Tray 18	0.0174	0.0023
Main Tray 19	0.0167	0.0020
Reboiler	0.0169	0.0016

In terms of economic considerations (Fig. 6), the cost of MEA is approximately 108 USD per kilogram, and the process requires a total mass flow of 367,000 kg/hr to achieve these levels of gas sweetening. This configuration highlights the effectiveness and cost implications of using MEA in industrial applications for acid gas removal.

3.2.2 Energy Analysis using MEA as solvent for acid gas treatment plant

Our data indicates that the actual total utility consumption for the MEA-based process is 25,660 kW, which is lower than the targeted 28,920 kW, reflecting a reduction in energy usage by 3,260 kW, or 12.70%. This trend of surpassing energy-saving targets is consistent across the utility spectrum, with cooling utilities also reporting the same level of savings (Fig. 7). Carbon emissions for the MEA process stand at 2.868 kg/s, which is notably lower than the target of 3.234 kg/s. This represents a reduction of 0.366 kg/s in carbon emissions, equating to a 12.76% improvement compared to the target.

In comparison to the MDEA solvent analysis, where the actual energy and carbon emission figures also fell below their respective targets, the MEA process shows a similar trajectory of energy conservation and reduced emissions. Both solvents demonstrate considerable potential for operational savings and environmental benefits. However, the MEA process reveals a slightly higher percentage in actual savings compared to the target, which could be attributed to the distinct chemical interactions and efficiencies intrinsic to MEA as a solvent. These insights are pivotal for the ongoing quest to optimize acid gas treatment processes. They offer a compelling narrative not only on the operational prudence of using MEA but also on its capacity to deliver an environmentally and economically preferable outcome. This juxtaposition of MEA with MDEA underscores the necessity for a case-by-case evaluation of solvent performance, as the choice between MEA and MDEA can be influenced by specific operational contexts and environmental goals as also noted by Erayamen [15].

Fig. 7: ASPEN software output indicating Energy saved on major utilities duty flow mainly between target and actual values for MEA treatment plant.

IV. CONCLUSION

In the field of natural gas processing, the paramount objective is the production of a high-quality product that not only aligns with stringent product specifications but also adheres to economic imperatives. Utilizing the HYSYS process simulator for an in-depth analysis of conventional amine treating units, particularly in relation to amine concentration, we have garnered valuable insights into the performance and economic aspects of acid gas removal.

The process we have evaluated successfully removes acid gases, specifically hydrogen sulfide (H2S) and carbon dioxide (CO2), from natural gas streams. This facilitates the production of 'sweetened' gas, ready for transportation to meet consumer demands. The efficacy of this treatment reinforces the practical utility of conventional amine treatment units, especially when dealing with natural gas streams containing minimal acid gas content.

Our investigation has revealed that Methyldiethanolamine (MDEA), when employed as a solvent in acid gas removal plants, stands out for its efficiency and economic viability. The unique physical properties of MDEA, including its low vapor pressure, result in lower solvent losses, reduced corrosiveness, and increased resistance to degradation. Moreover, MDEA's energy-efficient utilization underscores its suitability for industrial applications where CO2 and H2S need to be segregated for use in enhanced oil recovery and as feedstock in petrochemical processes, such as sulfur production, respectively. Given the promising results obtained with MDEA, it remains a solvent of choice for acid gas treatment. However, there is potential to achieve even greater acid gas removal efficiencies. Through the strategic adjustment of amine concentrations, contactor pressures, and the exploration of amine mixtures tailored to specific operational needs, the efficiency of gas sweetening processes may be further enhanced.

V. RECOMMENDATIONS

Our study recommends a continued examination of amine mixture performance across different concentration ratios to optimize acid gas removal. Moreover, while the conventional amine treatment units demonstrate practicality and economic efficiency within certain acid gas concentrations, alternative methods and technologies should be explored to surpass current operational benchmarks.

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