



Optimization of Energy Efficiency in Amine Regeneration Using a Novel Side Draw Flow Modification Method

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تحسين كفاءة الطاقة في عملية تجديد الأمين باستخدام طريقة تعديل التدفق الجانبي الجديدة

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Abstract:

Optimizing energy efficiency in gas-sweetening processes is crucial for reducing operational costs and improving environmental sustainability. This study introduces a novel approach to optimize the amine regeneration process, a critical component of gas sweetening operations, at the Mellitah gas plant. Using Aspen HYSYS software, a simulation model was developed and validated against actual plant data, achieving an absolute error of less than 1%, thereby confirming its accuracy. The optimization strategy is based on an innovative modification of the process flowsheet by incorporating a side draw stream on Tray 12, with flow rates ranging from 1000 to 6000 kgmol/h. New equipment, a heat exchanger (HX-101), and a flash separator (V-102) were integrated into the gas-sweetening process to enhance efficiency. HX-101 effectively reduced carbon dioxide (CO₂) concentration in the liquid side draw, while V-102 facilitated efficient phase separation. Analysis of side draw flow rates demonstrated significant energy savings. At a side draw flow rate of 6000 kgmol/h, the reboiler duty was reduced by 18% and the condenser duty by 5%. Additionally, increasing the side draw flow rate showed further potential for energy savings. These findings highlight the feasibility and effectiveness of this novel process modification, which is recommended for implementation at the Mellitah gas plant. This innovative optimization reduces energy consumption and operational costs and enhances the overall efficiency and sustainability of the amine regeneration process in gas sweetening operations.

Keywords: Energy efficiency, Amine regeneration, Gas sweetening, Optimization, Side draw flow rate.

المخلص

تحسين كفاءة الطاقة في عمليات تحلية الغاز أمر بالغ الأهمية لتقليل تكاليف التشغيل وتعزيز الاستدامة البيئية. تقدم هذه الدراسة نهجاً جديداً لتحسين عملية تجديد الأمينات، وهي عنصر أساسي في عمليات تحسين الغاز، في مصنع مليتة للغاز. باستخدام برنامج Aspen HYSYS، تم تطوير نموذج محاكاة والتحقق من صحته مقارنة ببيانات المصنع الفعلية، حيث حقق خطأ مطلق أقل من 1%، مما يؤكد دقته. تعتمد استراتيجية التحسين على تعديل مبتكر لمخطط العملية من خلال إدراج تدفق جانبي عند الصينية رقم 12، مع معدلات تدفق تتراوح بين 1000 و6000 كجم/مول/ساعة. تم دمج معدات جديدة، ممتثلة في مبادل حراري (HX-101) وفاصل تفريغ (V-102) في وحدة تحلية الغاز الطبيعي لتحسين الكفاءة. قلل HX-101 بشكل فعال تركيز ثاني أكسيد الكربون (CO₂) في التدفق الجانبي السائل، بينما سهل V-102 فصل المراحل بكفاءة.

أظهرت تحليلات معدلات التدفق الجانبي توفيرًا كبيرًا في الطاقة. عند معدل تدفق جانبي قدره 6000 كجم مول/ساعة، انخفضت قدرة إعادة الغليان بنسبة 18% وقدرة المكثف بنسبة 5%. علاوة على ذلك، أظهرت زيادة معدل التدفق الجانبي إمكانية أكبر لتوفير الطاقة. تؤكد هذه النتائج جدوى وفعالية هذا التعديل الجديد للعملية، والذي يُوصى بتنفيذها في مصنع مليئة للغاز. يساهم هذا التحسين المبتكر في تقليل استهلاك الطاقة وتكاليف التشغيل، كما يعزز الكفاءة والاستدامة العامة لعملية تجديد الأمينات في عمليات تحلية الغاز.

الكلمات المفتاحية: كفاءة الطاقة، تجديد الأمينات، تحلية الغاز، التحسين، معدل التدفق الجانبي.

1. Introduction

The treatment of natural gas is a crucial element within the global energy sector, facilitating the transformation of raw natural gas into a clean, efficient, and environmentally compliant energy resource that is ready for distribution and use [1, 2]. Central to this process is the removal of impurities such as sulfur compounds, water vapor, nitrogen, and carbon dioxide (CO₂). This not only helps meet strict industry standards but also minimizes environmental impacts by reducing pollutant emissions during combustion [3, 4]. Among the various treatment processes, gas sweetening plays a vital role. It selectively removes acidic gases, primarily hydrogen sulfide (H₂S) and CO₂. These gases, which are often found in raw natural gas, present significant operational, safety, and environmental challenges [5]. H₂S and CO₂ in natural gas can substantially complicate its safe use and commercial distribution; H₂S, being a highly toxic and corrosive gas, threatens the safety of personnel and operations. Furthermore, it causes deterioration of pipelines and equipment, thereby increasing maintenance costs and operational risks [6]. Similarly, CO₂ (although non-toxic) diminishes the heating value of natural gas and worsens corrosion, especially when water is present. This situation poses a considerable threat to pipeline integrity and fuel efficiency [7]. To address these challenges, it is crucial to remove such acidic gases through effective gas-sweetening technologies; this is essential for producing pipeline-quality gas that adheres to rigorous environmental standards, market demands and safety regulations [6, 8].

Throughout the years, numerous methodologies for removing H₂S and CO₂ have been conceptualised and executed, each presenting distinct advantages and inherent limitations contingent upon various factors, including gas composition, operational conditions, and economic viability. Standard techniques encompass the amine gas-sweetening process, physical solvents, such as Selexol and Rectisol, adsorption strategies utilising solid absorbents like activated carbon and molecular sieves, and sophisticated membrane-based separation technologies [8, 9]. The amine gas-sweetening process has become the most widely adopted and commercially feasible technology, primarily because of its remarkable efficiency, scalability, and adaptability to diverse gas compositions and processing conditions [10]. This sweetening process capitalises on the chemical absorption properties of certain amine compounds to selectively eliminate acidic gas constituents from the natural gas stream [11]. Among the amines frequently employed in this context are monoethanolamine (MEA), diethanolamine (DEA), and methyl-diethanolamine (MDEA), all of which possess distinctive performance attributes tailored for specific applications [12]. However, while these compounds are effective, selecting a particular amine often depends on the specific operational requirements and economic considerations. MEA, recognized as a primary amine, exhibits a notable degree of reactivity and is, in fact, particularly adept at eliminating both H₂S and CO₂ under conditions of low partial pressure. However, it is susceptible to elevated corrosion rates and increased energy demands for its regeneration [13]. On the other hand, DEA, classified as a secondary amine, demonstrates enhanced selectivity and diminished degradation, rendering it more suitable for demanding applications [14]. MDEA, a tertiary amine, is widely esteemed because of its low energy requirements for regeneration, substantial resistance to thermal degradation, and mitigation of corrosion issues. This makes it especially beneficial when partial CO₂ removal is permissible [15, 16].

Advanced amine preparations containing mixtures of traditional amines with additives or activators can enhance performance and significantly expand the applicability and effectiveness of chemical absorption technologies [12]. Studies have indicated that adding activators such as piperazine (PZ) in MDEA systems can improve the kinetics of CO₂ absorption. The enhancement increases the rate of processing and thus reduces the energy demand during regeneration [17]. Moreover, those new solvent systems can be combined with optimized process designs, such as split-flow configurations or heat-integrated regeneration systems, to decrease energy consumption and increase operational efficiency [18]. However, despite their widespread application, amine-based sweetening systems still have numerous inherent challenges. These challenges include high energy demands for solvent regeneration, solvent losses due to degradation or foaming, and problems related to the environmental impacts of the waste streams from the process [19]. Although good progress has been made, the complexity of these issues calls for continued research and innovation to solve these and other pressing matters. These have been the theme of constant study, particularly in the development of sustainable and energy-efficient methods of gas processing. However, the complexity of such issues demands a multifaceted approach. This becomes a necessity since the consequences of such are more than mere technical innovations. While much knowledge has already been gained in this area, further research is needed to ensure practices are aligned with current needs and anticipate future needs [20].

MDEA has become more prominent in gas-sweetening operations because of its greater stability, lower regeneration energy use, and lesser tendency to corrode [21]. It is especially suited for applications where complete CO₂ removal is unnecessary, making it an ideal choice for gas plants like Mellitah, where partial acid gas removal suffices [4]. Nevertheless, despite these advantages, MDEA gas-sweetening systems are characterized by high energy consumption, particularly during the amine regeneration process [22]. The regeneration column, responsible for recovering the amine solution, is a highly energy-intensive component of the gas-sweetening process, requiring significant heat input for solvent regeneration and cooling. This results in elevated operational costs and increased environmental impacts, underscoring the critical need for process optimization [22, 23]. The research showed that optimizing MDEA concentration and using activators could lead to significant savings in energy consumption, up to 76.8% for reboiler energy requirement with some activator-promoted mixtures [22, 23]. While progress has been made in the process, intrinsic energy intensities of MDEA systems remain a great challenge, thus highlighting the continued need for further research in the direction of more efficient solvent formulations and novel operating approaches that will minimize energy requirements and alleviate environmental burdens.

Although incremental measures, such as fine-tuning operating parameters and optimizing temperatures and flow rates can yield minor improvements in energy efficiency, researchers are increasingly highlighting that significant energy savings are more closely associated with structural and technological upgrades [24]. These strategies include adopting advanced process flow sheet configurations (e.g., heat integration and low-pressure steam use) and modifying column internals to enhance mass and heat transfer efficiency [25]. For instance, deploying high-performance packing materials or advanced trays notably enhances stripping efficiency, thus enabling lower energy input for solvent regeneration [26]. Additionally, exploring next-generation amine solvents has emerged as a viable avenue for achieving meaningful energy reductions. Alternative solvents, including blends of amines with higher selectivity or lower regeneration energy demands, are currently being tested in pilot-scale operations with promising results [27]. These developed solvents often exhibit lower heat duty requirements for CO₂ desorption, making them attractive candidates for large-scale adoption. However, implementing such innovations requires careful consideration of their economic and operational implications [28]. Moreover, the integration of comprehensive process control methodologies, coupled with the utilization of simulation instruments to forecast energy trajectories, can assist in uncovering latent inefficiencies; thus, it can yield actionable insights for sustained optimization [28]. However, one must consider the variability inherent in such systems. Although the potential for improvement is significant, executing these strategies can be complex because it requires a nuanced understanding of both the technology and the underlying processes. This multifaceted approach enhances efficiency and promotes a more resilient operational framework.

The Mellitah gas plant, an essential facility dedicated to gas-sweetening processes, employs MDEA as its principal solvent for extracting acid gases, including H₂S and CO₂ [4]. One of the prominent challenges confronting the Mellitah gas plant resides in the considerable energy consumption linked to the amine regeneration process, which is a notably energy-intensive phase necessary for the recycling and reuse of the amine solvent. This high energy demand not only escalates the plant's overall energy consumption but also markedly inflates operational costs, presenting a dual challenge to economic viability and environmental sustainability. Consequently, addressing these challenges through energy optimization within the amine regeneration process has emerged as a critical priority, given that research indicates such enhancements can significantly diminish energy usage and costs while preserving consistent system performance. However, although incremental strategies, such as meticulous modifications to operating parameters, might yield some modest benefits, their impact is ultimately inadequate to tackle the enormous energy expenses associated with the regeneration process. Instead, realizing substantial energy savings necessitates more transformative procedures. Advancements in chemical engineering, particularly the adoption of innovative process flow sheet configurations (heat integration systems) and upgrading column internals with high-efficiency trays, can significantly enhance heat and mass transfer. Consequently, this reduces the energy intensity of regeneration operations. However, it is essential to consider the implications of these changes on overall system efficiency and sustainability. Although improvements are evident, the complexities involved in implementation must not be overlooked because they can influence operational stability and cost-effectiveness.

This study aims to investigate a targeted, innovative process modification and examine the feasibility of diminishing energy consumption within the amine regeneration process at the Mellitah gas plant. The proposed optimization process which is crucial prioritizes energy conservation while maintaining the effectiveness of gas-sweetening operations; this creates a pathway toward enhanced efficiency and sustainability. Specifically, this research pursues two primary objectives. First, the Aspen HYSYS simulation software models and validates the current amine sweetening and regeneration processes at the Mellitah gas plant. Second, the study aims to propose and subsequently evaluate modifications to the process flow sheet configuration of the amine regeneration system to forecast potential reductions in energy consumption and, consequently, associated operating costs. Furthermore, this study supports the broader goals of achieving sustainable and cost-effective natural gas production, addressing the energy demands of the amine regeneration process. However, it is essential to note that the challenges inherent

in implementing these modifications may arise because the balance between operational efficiency and energy conservation is delicate. Although the proposed changes may yield significant benefits, their practical application must be examined closely to ensure effectiveness. The optimization process derived from this research significantly enhances operational efficiency in gas treatment plants and aligns with the global imperative, minimizing the environmental impacts of energy production. This work represents a crucial step toward integrating energy-efficient solutions into natural gas processing. Although the benefits are tangible for industry stakeholders, they also extend to the environment because the implications of such advancements are profound.

2. Evaluation of raw gas properties and processing conditions

The gas stream emanating from the Mellitah gas plant embodies a multifaceted amalgamation of hydrocarbons and impurities, significantly shaping the facility's design and operational paradigms. Methane, constituting approximately 70% of the overall composition, is the principal energy carrier and the most economically valuable component. Its elevated concentration renders the gas stream particularly amenable to various applications, including liquefaction for liquefied natural gas (LNG) production and pipeline transportation, thereby solidifying its status as a vital product within both domestic and international markets. However, this gas stream also harbours approximately 15.7% carbon dioxide (CO₂), an unwelcome impurity that diminishes the heating value and has the potential to instigate corrosion [29]. To counteract this issue, implementing CO₂ removal technologies, such as amine-based absorption, becomes imperative to satisfy quality benchmarks and sustain operational efficiency. Similarly, nitrogen (N₂), which is present at an estimated 4.6%, serves to dilute the calorific value of the gas. This inert component necessitates separation processes, such as cryogenic distillation, to ensure the gas remains suitable for energy applications or liquefaction endeavours. Furthermore, the detection of 1.3% hydrogen sulfide (H₂S) categorises the gas as sour, thereby necessitating immediate remediation. H₂S is both toxic and corrosive, posing significant risks to environmental integrity and infrastructural stability.

Sour gas sweetening processes exemplified by the Claus process are indispensable for effectively eliminating this impurity and safeguarding plant equipment while complying with environmental regulations. Furthermore, trace quantities of heavier hydrocarbons (including ethane, propane, butanes and pentanes) augment the energy content of the gas. These components possess considerable value as natural gas liquids (NGLs); they can be extracted through cryogenic distillation, thus enhancing the economic viability of the plant's operations. However, although the presence of water vapour is minimal, its removal is paramount because it mitigates the risk of hydrate formation, which can obstruct pipelines and disrupt operations. Dehydration systems such as glycol dehydration are therefore implemented to ensure a consistent and stable gas flow. Furthermore, the operational conditions governing the gas stream, especially temperature and pressure are crucial in the processing phase. The gas is subjected to a temperature of 30°C, which not only aids in maintaining stability but also prevents any potential phase transitions. The pressure, calibrated at 3950 kPa, significantly improves impurity removal efficiency and facilitates the effective separation of hydrocarbons. However, the elevated molar flow rate of 14,388 kgmol/h accentuates the necessity for a resilient processing infrastructure. This is because the Mellitah gas plant requirement implements large-scale compression, separation and purification systems to manage this considerable volume adeptly, ensuring that the gas conforms to industry specifications. Although challenges abound, the meticulous design of these systems is essential for operational success.

3. Description of amine sweetening and regeneration process

The amine gas treatment process designed for the Mellitah gas plant is a sophisticated system that meets stringent pipeline gas requirements, especially regarding the contents of H₂S and CO₂. Specifically, it is required that the gas have a CO₂ content of less than 2% by volume and an H₂S content of less than 5 ppm [30]. Continuous absorption with a 50% wt achieves such a high purity requirement. MDEA (Methyl Diethanolamine) solution. A significant characteristic of the MDEA solution is its swift interaction with H₂S, coupled with a comparatively slower interaction with CO₂, which facilitates the efficient elimination of these contaminants [31].

The process begins by preheating the raw natural gas in the sweet/raw heat exchanger (S/F HE-100) and then sending it to the separator (S-101). The separated gas is then sent to the absorber (V-100), where a 50% weight MDEA solution is introduced. In the absorber column, which contains 34 trays and operates under high pressure, H₂S and CO₂ are eliminated through chemical reactions, leaving a sweet gas free of these contaminants. The sweet gas is then cooled in the sweet gas cooler (C-102) and the raw/sweet gas heat exchanger (S/F HE-100) before it goes to the gas dehydration unit to remove entrained water. At the same time, the byproduct formed from the absorption column, which has a high content of H₂S and CO₂, is known as the rich amine solution. This stream undergoes a pressure drop through the throttling valve before it flows into the flash separator (S-102), separating and removing free gases, mainly hydrocarbons. This amine solution is heated in the rich/lean amine heat exchanger (A/A HE-100) due to heat exchange from regenerated lean amine. The preheated, concentrated amine is then fed into the central tray of the amine regeneration column (V-101), where the MDEA is stripped from the acid gases and dissolved hydrocarbons. The lean amine solution, taken from the bottom part of the regenerator, is

first cooled in the rich/lean amine heat exchanger (A/A HE-100) and further cooled in the lean amine cooler (C-100) until it reaches the temperature of the amine solution entering the absorber column. The lean amine, now cooled, is then re-circulated back into the absorption column.

Figure 1 depicts the detailed gas sweetening procedure employed at the Mellitah gas facility, highlighting the complex stages involved. This meticulously engineered process guarantees that the resultant sweet gas product complies with the stringent pipeline gas standards necessary for both distribution and utilisation.

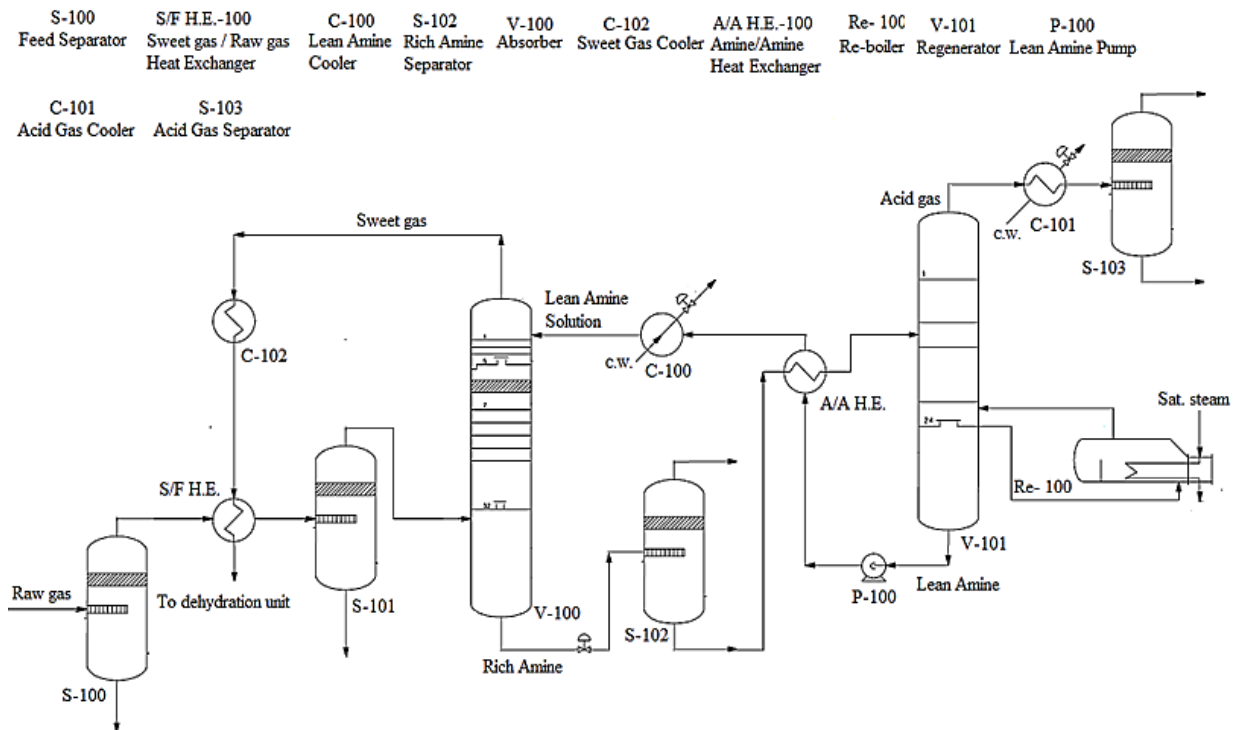


Figure 1. Amine sweetening process at Mellitah gas plant [32]

4. Simulation of the amine sweetening process at Mellitah gas plant

The amine sweetening and regeneration system at the Mellitah gas plant was simulated using Aspen HYSYS software, as shown in Figure 2. The model was developed based on the actual flow diagram of the plant to represent its operating realities closely. The principal components of the system include an absorption column, a regeneration column, a heat exchanger, a flash separator, pumps, mixers, and additional cooling and water make-up units. This configuration allows for the efficient removal of acid gases from sour gas and simultaneously enables the regeneration of amine solvents with high reusability. A 50 wt.% MDEA solvent was used where the acid gas-chemical solvent mixture was applied to predict thermodynamic properties accurately.

The process initiates when sour gas enters the system via the absorption column Absorption Column-100 where it comes in contact with lean MDEA. The column operates at a pressure of 3950 kPa and a temperature of 30 °C, optimized conditions for efficient acid gas removal. The lean MDEA solvent is fed into the system using a lean amine pump, which is preheated to 50 °C to enhance the interaction between the gaseous and liquid phases. To ensure sufficient contact for the effective absorption of acid gases, the lean MDEA 's flow rate is 2.5 times that of the sour gas flow rate. This design allows the lean solvent to absorb acidic components, such as H₂S and CO₂, while the treated sweet gas is released through the top of the absorption column for further processing. The rich amine solution, now loaded with absorbed acid gases, is let down from the bottom of the absorption column and flows to further treatment in the flash separator (V-100). This unit removes dissolved hydrocarbons and lighter components through vapour disengagement and then directs the resulting vapour stream to recovery or downstream processing. The liquid-rich amine solution is then preheated in the amine-amine heat exchanger (Amine HX-101), where it transfers heat with the lean amine coming from the regeneration system. This stage improves energy consumption, with a recorded temperature difference of 37 °C on the rich side and -50 °C on the lean side, significantly influencing the entire system's total energy efficiency. The preheated, concentrated amine solution is fed to the regeneration column (Amine Regen Column-101) designed and engineered with 18 trays for efficient thermal desorption and enhanced mass transfer between the liquid and vapor phases. The column is operated at carefully controlled conditions: feed temperature at 103 °C and pressure at 637 kPa, while the bottom pressure is maintained at 210 kPa with a minimal pressure drop of 2 kPa [30]. These conditions are optimized for releasing acid gases, mainly H₂S and carbon CO₂ absorbed during sweetening. The concentrated amine solution is heated in the regeneration column to strip the absorbed acid gases effectively. The released H₂S and CO₂ are

removed from the top of the column and then sent for further processing or disposal methods that may involve flaring, sulfur recovery, or reinjection, depending on specific processing requirements. This step is necessary to maintain environmental regulations and ensure the proper functioning of downstream equipment. The lean amine regenerated leaves the bottom of the column and is then cooled with the lean amine cooler to the optimum temperature for reuse.

Cooling the lean amine reduces the thermal degradation of the solvent while allowing the lean amine to absorb acid gases effectively in the next cycle. A portion of the cooled lean amine is mixed with water in the mixer (MIX-101) to compensate for small solvent losses during the regeneration process, thus maintaining the desired concentration of MDEA (methyl diethanolamine). The regenerated and conditioned lean amine is then returned to the absorption column through the lean amine pump. The recirculation mechanism enables continuous extraction of acid gas, improving process effectiveness and reducing operational costs. Solvent recycling promotes sustainable and economically feasible operations that underpin gas sweetening in the Mellitah gas plant. The Aspen HYSYS model of the amine sweetening and regeneration processes at the Mellitah gas plant highlights the importance of energy integration and using recycled solvents to improve overall efficiency and reduce operating costs. Simulation results confirm the effectiveness of the chosen configurations and operating conditions, showing a high removal of acid gases from the sour gas feed. Furthermore, accurate modeling of energy recovery through the amine-amine heat exchanger adds to sustainability by lowering energy needs. Future research could further focus on testing improved solvents with better absorption characteristics or hybrid setups to improve the process's cost-effectiveness and environmental impact.

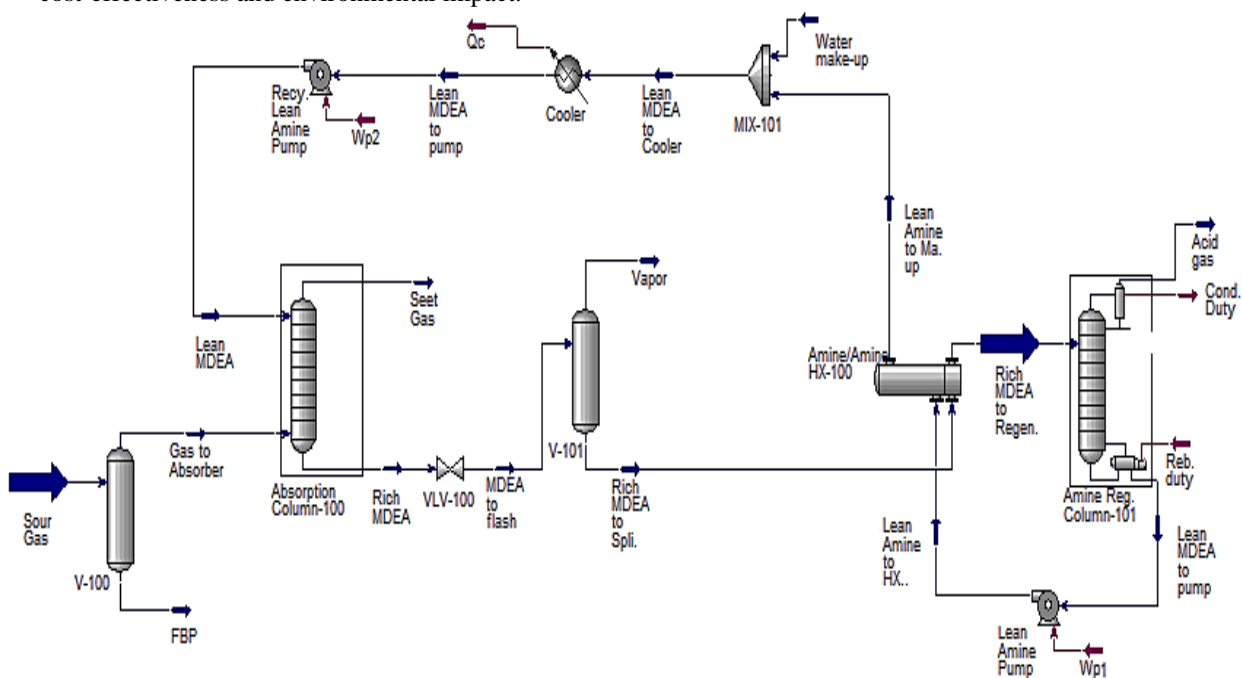


Figure 2. Simulation of the amine sweetening and regeneration process

5. Results and discussion

5.1. Comparative evaluation of the amine sweetening process using actual Mellitah gas plant data and simulation model

The analysis of the molar flow data from the Mellitah gas plant, together with the simulation results summarised in Table 1, gives important information on the accuracy of the simulation model. The model works very well for most compounds, with some deviations occurring; these differences are worth discussing in detail below, underlining their implications for plant operations and the overall performance of the simulation. For nitrogen, the measured molar flow at the Mellitah gas plant is 660.59 kgmol/h, and the simulation assumes a prediction of 660.00 kgmol/h, which results in an error of 0.09%. This small difference means that the simulation model is good at predicting the nitrogen flow because nitrogen is an inert gas, so it behaves in a very predictable manner. The model has seemingly encapsulated this characteristic quite effectively. Accordingly, the negligible error infers that the simulation is well-calibrated and apt at foreseeing nitrogen flow under standard operating conditions. Correspondingly, the molar flow recorded for methane is 10088.20 kgmol/h, and the simulation estimates 10076.00 kgmol/h, which amounts to an error of 0.12%. The minor discrepancy noted here indicates that the simulation is, in fact, tremendously trustworthy for methane flow prediction. The dominant constituent of natural gas is methane, so accurate prediction of methane flow is a part of optimising any operation in gas

processing. On the other hand, a slight change in environmental or system parameters, which wasn't ideally captured by simulation, may cause the small error realised at this site. However, this error is still within the acceptable range, thus proving that the simulation gives a good estimate of methane flow. The molar flow of ethane, which is measured as 641.34 kgmol/h in the Mellitah gas plant, is very close to the result obtained from the simulation, which is 641.22 kgmol/h, with an error of almost zero of 0.02%. This finding confirms that the simulation model is accurate, especially for lighter hydrocarbons. Although methane is a fairly simple compound (exhibiting very well-defined behaviour under standard conditions), the small deviation suggests that the simulation effectively accounts for its properties. Nonetheless, there are only slight deviations between the actual and predicted values.

In contrast, the error in the case of propane increases to 0.30%. The facility registers a molar flow rate of 259.12 kgmol/h. The simulation, on the other hand, predicts a value of 259.90 kgmol/h. This inconsistency is marginally greater than that observed for lighter hydrocarbons. It may be ascribed to propane's intricate phase behaviour (because it exhibits heightened sensitivity to fluctuations in both temperature and pressure). The simulation might not comprehensively consider all the variables impacting propane's behaviour in the gaseous state. However, this oversight results in a somewhat elevated error. This error is relatively small, which means that the model manages to make predictions for propane that are very precise for all intents and purposes. The error on i-butane is almost nil, with a flow rate of 56.89 kgmol/h from plant data and 56.90 kgmol/h from the simulation; this makes an error of only 0.02%. Once again, this very minor difference points out how well the simulation predicts butane flow. Similar to methane and ethane, i-butane exhibits relatively straightforward behaviour in the gaseous state, thereby facilitating more accurate modelling. Consequently, the negligible error would tend to indicate that the simulation model accurately represents the behaviour of i-butane, producing a very good prediction.

In addition, n-Butane has a slight difference of 0.05%, wherein the plant's actual data has a flow rate of 95.44 kgmol/h, and the simulation predicts 95.39 kgmol/h. This slight deviation between the two figures shows that the simulation model works well for n-butane. Since n-butane and i-butane are very similar in structure and behaviour, it is unsurprising that the simulation model can predict the flow rates of these compounds with such small errors. However, considering i-pentane, the deviation is somewhat larger at 0.17%, where the simulation shows a flow of 41.79 kgmol/h compared to the plant's 41.86 kgmol/h. While still quite small, this discrepancy may reflect the more complex behaviour of heavier hydrocarbons like pentanes. The heavier hydrocarbon molecules show larger deviations from ideal gas behaviour and, hence, are harder to predict. Despite this complexity, the error is still small, meaning the simulation model still holds a good accuracy for i-pentane. However, minor improvements may be applied to account for its more subtle properties. In the case of n-pentane, the data elucidates a reported flow of 40.77 kgmol/h, which dramatically contrasts with a simulation prediction of 40.72 kgmol/h, resulting in an error margin of 0.12% which is close to that of i-pentane.

On the other hand, significant differences arise regarding the trace components H₂S and CO₂. For H₂S, the plant data shows a value of 3.29×10^{-6} kgmol/h, whereas the simulation predicts a value of 5.44×10^{-7} kgmol/h. The difference in magnitude is large, making it difficult to calculate an error percentage of any relevance. This large difference could result from the challenges in correctly modelling trace gases, especially at low concentrations. Such species commonly exhibit non-ideal behaviour, and complex interactions between these and other gases are difficult to include fully within the simulation model. So, although the error is large, it is justifiable given the inherent issues involved in modelling trace species within gas mixtures. Accordingly, the large difference observed in the case of CO₂, where the plant shows 0.0139 kgmol/h and simulation predicts only 0.0014 kgmol/h, can be attributed to several reasons, particularly due to the limitations of HYSYS software. Since CO₂ is a critical impurity found in natural gas, an accurate prediction is necessary for effective gas treatment and separation. The difference between actual and simulated values may come from the inability of the software to precisely model CO₂ behaviour at the plant operating conditions when it comes to the changes in pressure and temperature. HYSYS software might also not consider some non-ideal interactions between CO₂ and other components in the gas stream, producing results far from simulations. The significant deviation suggests that improvement is needed in the simulation model, particularly in the models of trace components and non-ideal gases like CO₂. Further improvement in this respect, at both the phase behaviour and chemical interaction levels, will increase the accuracy of the simulation and, by extension, the reliability of its predictions; this means more realistic modelling of conditions found in actual plants. By improving these components, the model can better align with the true behaviour of CO₂ in the gas stream, producing more accurate results and an improved paradigm for gas processing operations.

Table 1. Comparison of molar flow data between Mellitah gas plant and simulation model.

Compound	Actual plant molar flow data (kgmol/h)	Simulated molar flow data (kgmol/h)	Error (%)
Nitrogen	660.59	660.0	0.09
Methane	10088.20	10076	0.12
Ethane	641.34	641.22	0.02
Propane	259.12	259.9	0.30
i-Butane	56.89	56.90	0.02
n-Butane	95.44	95.39	0.05
i-Pentane	41.86	41.79	0.17
n-Pentane	40.77	40.72	0.12
H ₂ S	3.29×10^{-6}	5.44×10^{-7}	-
CO ₂	0.0139	0.0014	-

5.2. Comparative evaluation of the Amine regeneration column using actual Mellitah gas plant data and simulation model

Verifying simulation data is very important to establish the accuracy and reliability of process models, as it ensures that simulations represent real operating conditions. In this work, validation focused on examining simulation data related to the amine regeneration column using actual data from the Mellitah gas plant for comparison. The validation procedure prominently featured the responsibilities of the re-boiler and condenser concerning the parameters of the amine regeneration column, which are vital for ensuring the process's efficacy and comprehensive performance. The precise simulation and validation of these responsibilities are crucial to ascertaining the model's capacity to depict the real dynamics of the plant accurately. The objective was to evaluate whether the simulation model accurately predicted the reboiler and condenser duties. These are necessary to ensure the thermodynamic and operational stability of the amine regeneration process. A valid model must give correct predictions for these parameters to be considered for monitoring, controlling, or optimising the plant. The juxtaposition of simulation findings with empirical operational data presented in Table 2 invariably indicated an extraordinarily minimal absolute error, with discrepancies for the duties of the re-boiler and condenser maintaining levels under 1%. This result underscores the dependability of the simulation model and its ability to emulate the complex dynamics of the real system accurately.

The data presented in Table 2 presents a critical evaluation of the simulation results for the amine regeneration column against real-world data from the Mellitah gas plant. Specifically, the comparison focuses on key operational parameters, including H₂S and CO₂ concentrations in the feed and bottom streams and the re-boiler and condenser duties. These parameters are critical factors in determining the efficiency of the amine regeneration process. The overall results show good agreement between the empirical and simulation-based outcomes, with deviations in all parameters within 1%. Such a fact leads to the conclusion that the simulation model captures the real operation characteristics of the plant well. Nevertheless, a more in-depth analysis must be performed to find plausible causes for the small deviations observed. Initially, the simulated value for the concentration of H₂S in the feed stream directed toward the regeneration column is about 185.5 kgmol/h, which is very close to the recorded value of 187.2 kgmol/h, resulting in a minor difference of 0.90%. This agreement shows that the simulation model effectively replicates the dynamics of H₂S. However, the small deviation might be due to plant feed composition fluctuations, which are not entirely accounted for in static simulation models, or due to measurement uncertainties in the plant setup. Similarly, the CO₂ concentration in the feed stream shows a deviation of only 0.24%, where the simulated value of 2112.7 kgmol/h is almost equal to the plant data of 2117.9 kgmol/h. This level of precision not only confirms the accuracy of the model but raises questions regarding assumptions made regarding the uniformity of flow and thermodynamic consistency during the simulation process. Moreover, the concentration of CO₂ observed at the base of the regeneration column, an essential metric for assessing the stripping efficiency of the column, demonstrates a negligible difference between the empirical data obtained from the plant (0.0100 vol. %) and the findings generated by the simulation (0.0101 vol. %), resulting in an error margin of 0.99%. This outcome suggests that the model accurately reflects the CO₂ extraction process. Nevertheless, the observed discrepancy may arise from the simplifications employed in the simulation, including approximations related to mass transfer coefficients or equilibrium relationships at certain locations within the column.

Moving on to energy dynamics, the re-boiler and condenser duties can be compared further to bring out the accuracy of the model. The simulated re-boiler duty (35,710 kW) is only 0.39% different from the actual plant data (35,852.2 kW), which shows that the model can predict the heat requirements for solvent regeneration with high accuracy. Notably, limitations may affect this slight deviation in the correlations of the thermal properties utilised in the simulation or minor inefficiencies in heat transfer in the real system, which were absent in the model. Equally, concerning the condenser performance, the value obtained from the simulation of 23,700 kW

compares very well with the measured one at the plant site of 23,628.1 kW, with a difference of only 0.30%. The close agreement in the performance of the condenser further confirms the adequacy of the model in correctly representing the heat rejection mechanism. However, practical considerations, such as fluctuations in cooling water temperatures or the possibility of fouling within heat exchangers, may lead to slight discrepancies.

Results generally show an excellent agreement of the simulation results with actual plant data, proving the accuracy of the model. The existence of small discrepancies shows a robust and reliable simulation model that can represent the complexities involved in the amine regeneration column. At the same time, the small deviations obtained, although negligible, unveil the intrinsic limitations of simulations. These models are often based on simplified assumptions, ideal conditions, and generalised operating parameters. However, realistic environmental condition fluctuations, fluid properties, and equipment performance translate into differences that make simulation models of full integration difficult to accomplish. The strong correlation obtained between the simulated data and the empirical measurements increases the credibility of the model for analysis and optimization of plant operations. The simulation results validate the model as an effective tool for understanding plant performance in order to improve operational efficiency and develop process improvements. Further work in the area of finer tuning of input parameters and advanced modelling techniques can reduce minor discrepancies resulting in even greater predictive accuracy for industrial applications of gas processing.

Table 2. Validation of Mellitah gas plant data against Aspen HYSYS simulation results.

Parameters	Mellitah gas plant data	Simulation results	Error (%)
H ₂ S conc. in the feed stream to the amine regeneration column (kgmol/h)	187.2	185.5	0.90
CO ₂ conc. feed stream to the amine regeneration column (kgmol/h)	2117.9	2112.7	0.24
CO ₂ conc. at the bottom of the amine regeneration column (vol. %)	0.0100	0.0101	0.99
Re-boiler duty (KW) in the amine regeneration column	35852.2	35710	0.39
Condenser duty (KW) in the amine regeneration column	23628.1	23700	0.30

5.3. Modification of gas sweetening process

The modification of the amine regeneration process at the Mellitah gas plant represents a strategic effort aimed at improving efficiency while consistently achieving the specified gas purity conditions for the bottom outlet stream: 0.01 vol.% H₂S and 0.01 vol.% CO₂. Minimising the energy requirements for the amine regeneration column is essential for enhancing the process's economic and operational feasibility. However, this approach demands a critical evaluation to assess the merits and constraints of the methods employed and the efficacy of the outcomes.

The first stage of the modification process involved incorporating side draw streams at various tray levels (10 to 16) in the amine regeneration column, with flow rates varying from 1000 to 6000 kgmol/h. A detailed analysis identified Tray 12 as the optimal location for the side draw stream due to the relatively stable CO₂ concentration difference between this tray and those below it. Tray 12's selection reflects a calculated effort to ensure efficiency while maintaining process stability. However, the logic behind this selection prompts further critical examination. The choice appears to be rooted in the uniformity of CO₂ concentration rather than other crucial factors such as operational limits, tray design, or hydraulic constraints, which could influence the column's overall efficiency. Furthermore, while the approach is explained, this optimization method raises questions about whether the tray levels above 16 or below 10 were considered or whether the selection rationale comprehensively accounted for other key parameters alongside CO₂ concentration. The second stage of the process modification incorporated significant reconfigurations into the process flowsheet by introducing a heat exchanger (HX-101) and a flash separator (V-102). Both components were strategically positioned to reduce the CO₂ concentration in the side collaboratively draw stream to meet Mellitah gas plant specifications. HX-101's placement after the flash separator (V-101) demonstrates an intentional design to ensure efficient thermal energy utilization for evaporating CO₂ from the rich MDEA solution. Similarly, V-102 complements this function by effectively separating dissolved CO₂ gas from free CO₂ in the solution. Applying these elements appears technically sound, aiming to improve gas separation efficiency and reduce re-boiler duty, resulting in energy savings.

However, certain aspects of the configuration warrant a more critical discussion. For instance, the effectiveness of HX-101 in reducing the CO₂ concentration relies heavily on the heat exchange interaction between the lean amine stream (from the regeneration column) and the rich MDEA stream. While the design leverages this interaction efficiently, the thermal integration process could introduce new challenges, such as limited heat transfer efficiency due to varying fluid properties or fouling in the heat exchanger over time.

Additionally, the heat efficiency gain by using 50% of the flow rate of the rich MDEA stream for heat exchange appears promising. Still, it may introduce operational complexity in maintaining consistent flow and avoiding excessive pressure drops. The placement of V-102 directly after HX-101 highlights another critical design consideration. The separation of free CO₂ gas from the CO₂-saturated MDEA solution occurs after thermal modification, ensuring the flash separator functions under optimized conditions. However, achieving stable operation in the flash separator depends on maintaining precise control over temperature and pressure conditions, which could be sensitive to upstream changes in HX-101. Any deviations in the heat exchange process may adversely affect the separation efficiency in the flash separator and compromise the downstream mixer and regeneration column operations.

In addition to technical feasibility, the economic and practical implications of these modifications merit further evaluation. Introducing new components such as HX-101 and V-102 likely incurs capital and operational costs, which the energy savings and process optimization benefits must justify. Furthermore, the long-term reliability of these components is crucial for ensuring the sustainability of the modifications. Maintenance of the heat exchanger and flash separator must be factored in, as fouling, scaling, or mechanical wear could diminish performance over time, leading to deviations from the intended outcomes. Lastly, while the modifications highlight a detailed technical process for improving the amine regeneration system, the explanation lacks clarity on how these changes balance other critical process variables. For instance, how are the reconfiguration impact the pressure profile, stripping efficiency, or solvent loading conditions? Additionally, while HX-101 uses the lean amine stream's thermal energy, it is unclear whether the temperature adjustments affect the downstream operations of the amine tower or other units beyond the immediate modification scope.

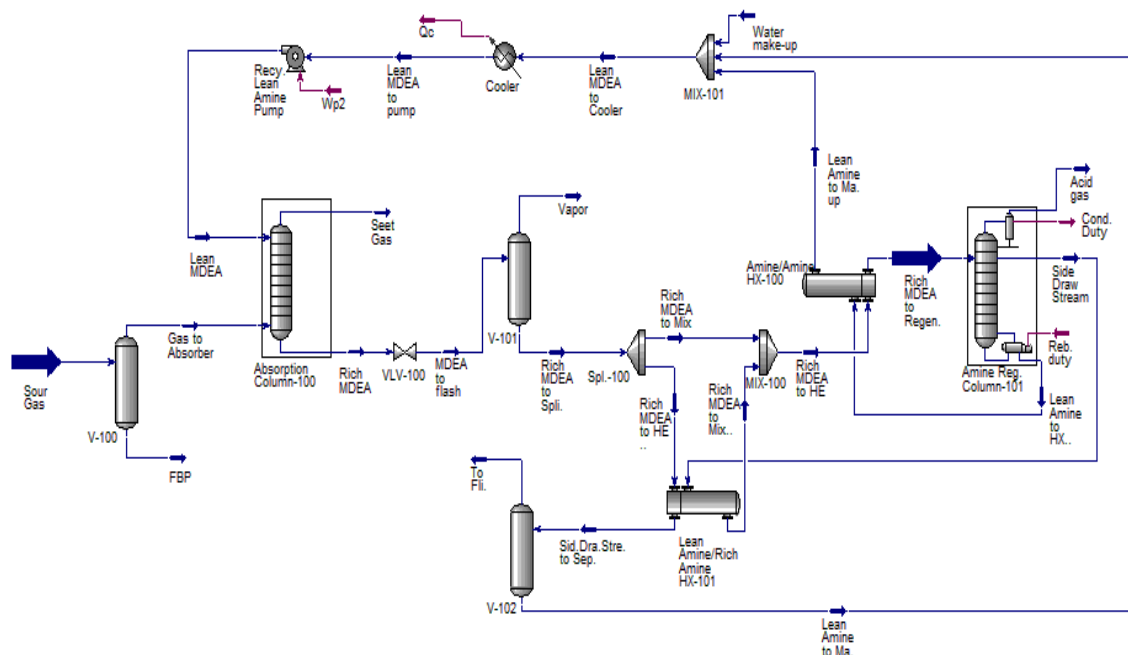


Figure 3. Modification of the process flow sheet of the gas sweetening process

5.4. Optimization of energy efficiency through side draw flow rate adjustments in the regeneration column

The modification process began with a detailed analysis of the relationship between side draw flow rates, CO₂ concentration in the side draw stream, and reboiler duty. This phase established how these variables were interconnected and how changes in one affected the others. The study revealed that the relationship between side draw flow rates and reboiler duty was bidirectional, with flow rate variations requiring adjustments in both reboiler and condenser duties. This insight was crucial for optimizing system efficiency by fine-tuning energy use and heat exchange. Additionally, the investigation examined the broader impact of changing side draw flow rates on energy balance and operating costs, helping to assess the economic feasibility and sustainability of the modifications.

5.4.1. Effect of side draw flow rates on reboiler duty and CO₂ concentration

Figure 4 illustrates the trade-off between side draw flow rate, reboiler duty, and CO₂ concentration. At 0 kgmol/h side draw flow rate, reboiler duty is highest (34,400 kW) and CO₂ concentration is also at its peak (4.28 vol.%) due to full liquid hold-up. As the flow rate increases to 1,000 kgmol/h, reboiler duty drops to 33,600 kW,

and CO₂ concentration slightly decreases to 4.27 vol.%, reflecting reduced thermal load but a small loss in separation efficiency. Further increases in flow rate to 2,000 kgmol/h reduce reboiler duty to 32,800 kW and CO₂ concentration to 4.26 vol.%, signaling a larger impact on separation. At 3,000 kgmol/h, reboiler duty reaches 32,000 kW, and CO₂ concentration falls to 4.25 vol.%, showing the growing trade-off between energy efficiency and CO₂ purity. At 4,000 kgmol/h, reboiler duty drops to 31,200 kW, and CO₂ concentration to 4.24 vol.%, while at 5,000 kgmol/h, reboiler duty decreases to 30,400 kW and CO₂ concentration to 4.23 vol.%, indicating significant energy savings but reduced CO₂ enrichment. Finally, at 6,000 kgmol/h, reboiler duty hits its lowest (29,600 kW), and CO₂ concentration drops to 4.22 vol.%, demonstrating the trade-off between maximizing energy efficiency and maintaining product purity.

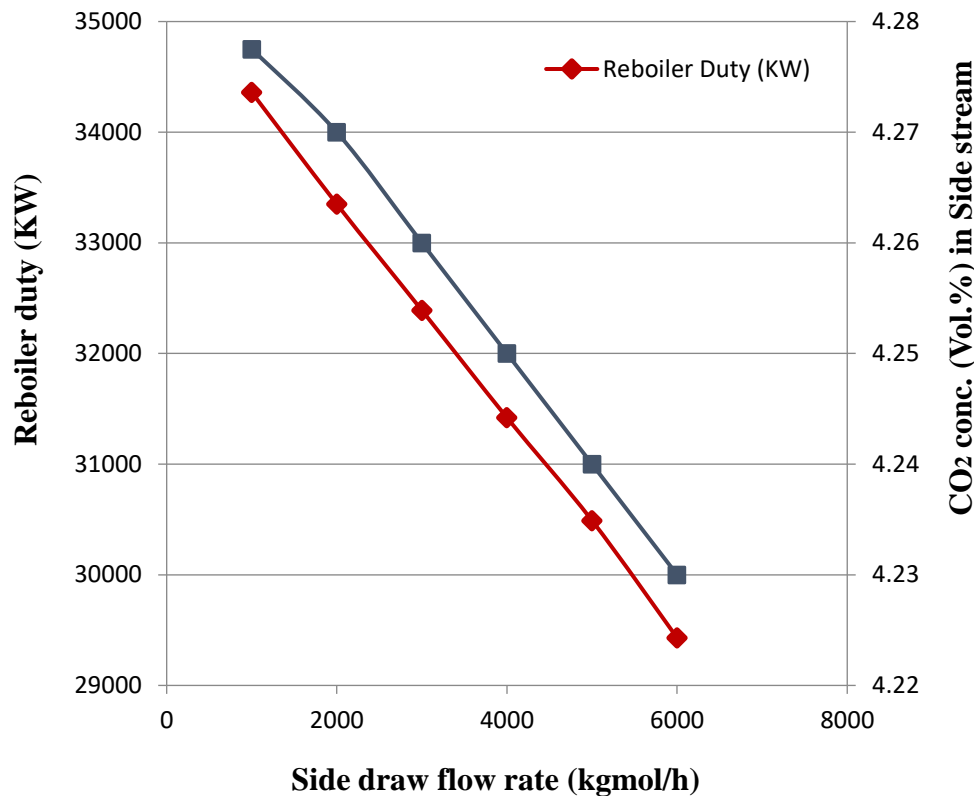


Figure 4. Effect side draw flow rates on re-boiler duty and CO₂ concentration.

5.4.2. Effect side draw flow rates on re-boiler and condenser duties

Figure 5 illustrates the effect of side draw flow rate on reboiler and condenser duties, showing a near-linear decrease in both as the flow rate increases. Initially, at 1,000 kgmol/h, the reboiler and condenser duties are 34,400 KW and 23,500 KW, respectively, reflecting significant energy requirements for vaporization and condensation. As the flow rate increases to 2,000 kgmol/h, the reboiler duty drops to 33,500 KW, and the condenser duty decreases to 23,300 KW, due to the reduced vapor generation and condensation needs. Furthermore, the trend continues as the flow rate rises to 3,000 kgmol/h, where the reboiler and condenser duties fall further to 32,500 KW and 23,100 KW. This consistent decline highlights the improved energy efficiency as more liquid is withdrawn, reducing the load on both components. At 4,000 kgmol/h, the reboiler and condenser duties decrease to 31,500 KW and 22,900 KW, reinforcing the thermodynamic advantage of higher side draw flow rates. As the flow rate reaches 5,000 kgmol/h, the reboiler duty reduces to 30,500 KW, and the condenser duty decreases to 22,700 KW. Finally, at the maximum flow rate of 6,000 kgmol/h, the reboiler duty reaches 29,500 KW, and the condenser duty drops to 22,500 KW. These reductions confirm that increasing the side draw flow rate optimizes energy use, reducing the heat load on both the reboiler and condenser, leading to a more efficient distillation process overall.

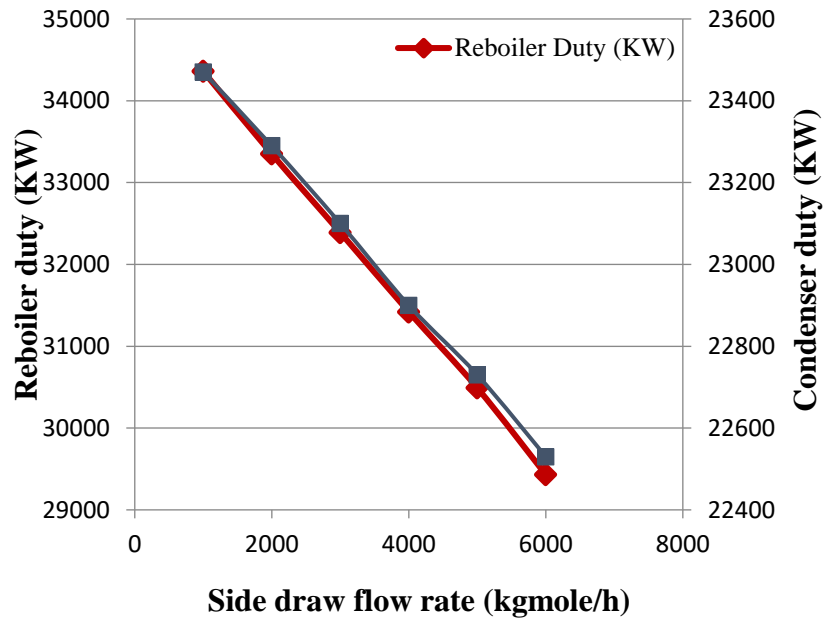


Figure 5. Effect side draw flow rates on re-boiler and condenser duties

5.4.3. Effect of side draw flow rates on energy savings in reboiler and condenser duties

The side draw flow rate significantly affects energy efficiency, as demonstrated in Figure 6. To begin with, increasing the flow rate from 0 to 6,000 kgmol/h leads to a near-linear rise in saved reboiler and condenser duties. For instance, at 1,000 kgmol/h, the savings are 1,200 kW and 1,000 kW, respectively. Subsequently, these savings increase to 2,400 kW and 2,000 kW at 2,000 kgmol/h. Moreover, by 3,000 kgmol/h, the reboiler and condenser savings reach 3,600 kW and 3,000 kW, highlighting a proportional relationship that reflects efficient heat redistribution and operational synergy. Continuing this trend, at 4,000 kgmol/h, the savings climb to 4,400 kW for the reboiler and 4,200 kW for the condenser, further reducing thermal loads and energy consumption. By the time the flow rate reaches 5,000 kgmol/h, savings achieve 5,400 kW and 5,000 kW, demonstrating the effectiveness of the side draw in maintaining system balance and enhancing energy savings. Importantly, the parallel trends observed in saved reboiler and condenser duties throughout the range of side draw flow rates reflect the system's efficient heat load management. In particular, both duties exhibit similar rates of increase, which indicates that energy savings achieved in the reboiler are closely mirrored in the condenser. This alignment can be attributed to the thermodynamic balance within the distillation process, where reductions in reboiler heat duty directly translate into reduced condensation requirements.

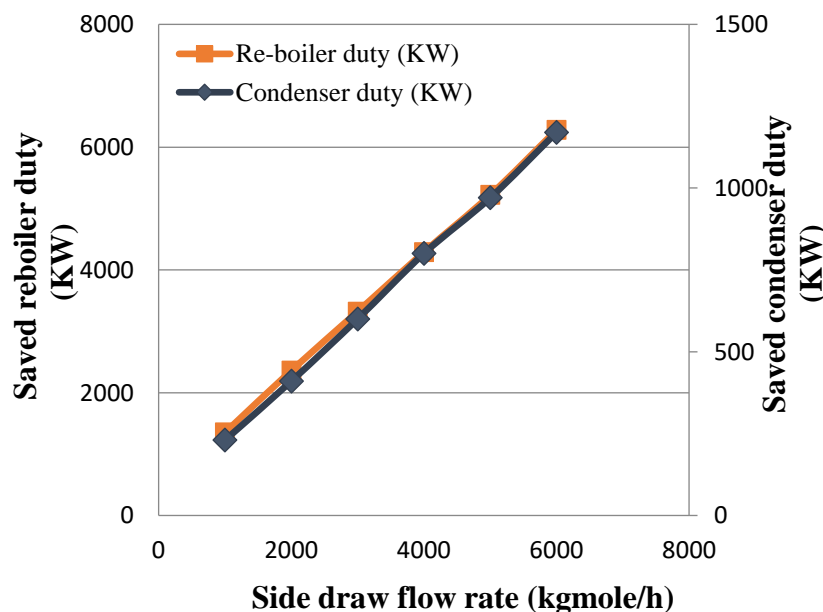


Figure 6. Effect of side draw flow rates on energy savings in reboiler and condenser duties.

5.4.4. Effect of side draw flow rates on total saved duty

Figure 7 explores the relationship between side draw flow rate, total saved duty, and CO₂ concentration. Initially, at a flow rate of 0 kgmol/h, the system records 8,000 kW of saved duty and a CO₂ concentration of 4.265 vol.%. As the flow rate increases to 1,000 kgmol/h, the saved duty rises to 9,000 kW. However, the CO₂ concentration remains unchanged, suggesting that early flow rate adjustments focus primarily on energy savings without affecting emissions. Subsequently, at 3,000 kgmol/h, the saved duty reaches 11,000 kW, while the CO₂ concentration slightly decreases to 4.250 vol.%, indicating simultaneous improvements in energy efficiency and CO₂ removal. Moreover, with a further increase to 5,000 kgmol/h, the saved duty climbs to 13,000 kW, and the CO₂ concentration drops to 4.230 vol.%, demonstrating notable progress in both metrics. Finally, at 7,000 kgmol/h, the saved duty peaks at 14,000 kW, but the CO₂ concentration stabilizes at 4.215 vol.%. This plateau suggests that while energy savings continue to improve, the benefits for emissions reduction diminish. Consequently, this highlights the intricate balance required to optimize energy efficiency and emissions control.

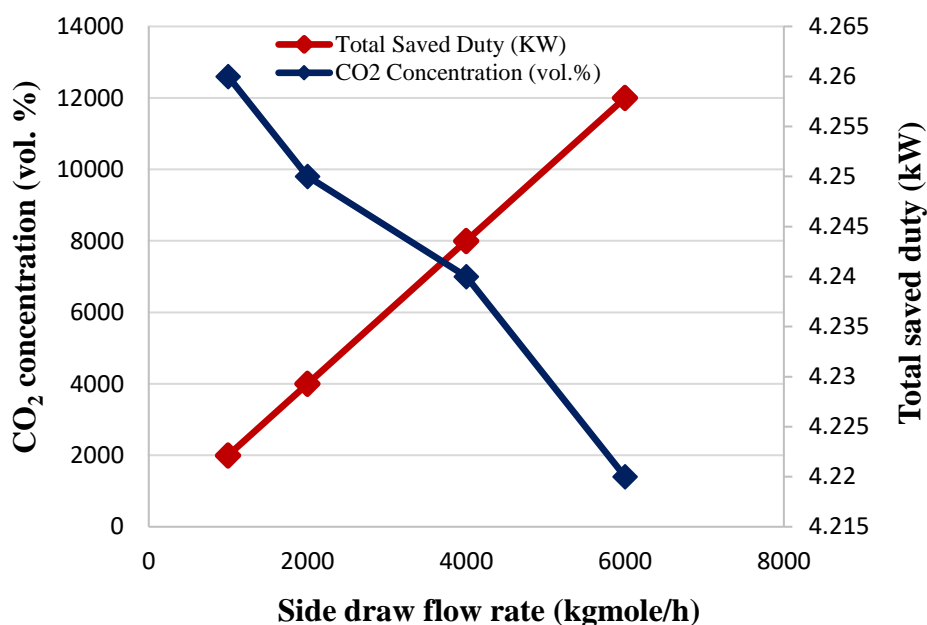


Figure 7. Effect of side draw flow rates on CO₂ concentration and total saved duty.

6. Environmental Effects of CO₂ and H₂S Emissions from sweetening units at Mellitah gas plant

The emissions of CO₂ and H₂S from gas-sweetening processes pose notable environmental concerns, especially in the context of their impact on climate change and air quality [33]. CO₂ is a significant greenhouse gas, contributing considerably to global warming by trapping atmospheric heat [34]. Excessive CO₂ emissions exacerbate climate change, leading to rising global temperatures, ice caps melting, sea-level rise, and more frequent natural disasters [33]. H₂S, though emitted in smaller quantities than CO₂, is a highly toxic and odorous gas that can lead to acid rain, degrading ecosystems, infrastructure, and water quality [35]. Moreover, long-term H₂S exposure causes severe respiratory and neurological health issues, with high concentrations posing fatal risks to both humans and wildlife [36]. This study demonstrates actionable strategies to mitigate these environmental effects through energy-efficient solutions. The Mellitah gas plant integrates simulation-based optimizations and targeted process modifications to reduce emissions and energy consumption. As summarized in the provided figures, increasing the side draw flow rate of sweetening columns improves the energy efficiency of the reboiler while simultaneously reducing CO₂ concentrations in the treated gas stream. This highlights a critical opportunity to align process improvements with environmental objectives. By optimizing energy usage, such as lowering reboiler duty (Figure 4) while maintaining consistent reductions in CO₂ concentrations (Figure 5), the Mellitah gas plant achieves enhanced operational efficiency while reducing its carbon footprint. Furthermore, properly managing H₂S content through robust amine solvent cycles and advanced separation techniques minimizes the release of these pollutants into the atmosphere. Process optimization reflected in energy savings (Figure 6) shows the potential for cost-effective solutions that align with sustainability goals. Finally, the findings from Mellitah underscore the importance of combining emission control measures with energy-efficient modifications to minimize environmental risks and reduce the oil and gas sector's overall ecological impact. This approach meets tightening environmental regulations and paves the way for cleaner energy practices.

7. Conclusion and Recommendation

In conclusion, this study employed Aspen HYSYS software with an acid gas-chemical solvents package and 50% MDEA as the solvent to simulate operations at the Mellitah gas plant. The simulation results, validated against plant data, showed an absolute error of less than 1%. Notably, process improvements in the amine regeneration column were achieved by introducing a side draw stream at plate 12. A side draw flow rate of 1,000 kgmol/h (3% of feed) resulted in maximum reboiler and condenser duties of 34,400 kW and 23,500 kW, with a CO₂ concentration of 4.28 vol.%. This configuration saved 1,350 kW (4%) in reboiler duty and 230 kW (1%) in condenser duty. Conversely, at 6,000 kgmol/h (15% of feed), the minimum duties were 29,400 kW and 22,500 kW, with CO₂ at 4.23 vol.%. This achieved savings of 18% and 5% for reboiler and condenser duties, respectively. Moreover, further savings can be achieved by adjusting the side draw flow rate based on specific requirements. Therefore, we recommend adopting this flowsheet configuration to optimize the Mellitah gas plant's amine regeneration process. This approach reduces reboiler and condenser duties, lowers operating costs, enhances efficiency, and improves environmental sustainability.

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