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Modeling and Optimization of the Natural Gas Decarbonization Unit at the CPF (QH) Rhourde Nouss Field

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Dedication

I dedicate this work to:

*My beloved **mother**, the symbol of love, tenderness, and sacrifice, who has always supported me and prayed for my success.*

*My dear **father**, my role model and lifelong guide, who has continuously encouraged and supported me throughout my academic journey.*

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To the one who stayed awake many nights for my comfort,

to the one whose prayers accompanied me in every step…

to the source of tenderness and the safety of my life, my beloved ***mother****.*

To the one who taught me that determination can make the impossible possible,

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ملخص

يحتوي الغاز الطبيعي المنتج في مركز المعالجة (CPF) بحقل غرد النص إليزي على ثاني أكسيد الكربون، والذي يجب إزالته من أجل مطابقة مواصفات التصدير وتجنب مشاكل عملية مثل التآكل وتشكل هيدرات الغاز. تركز هذه الدراسة على محاكاة وتحسين وحدة إزالة الغازات الحمضية (AGRU) باستخدام عملية الامتصاص بالأمينات.

تمت محاكاة العملية باستخدام برنامج Aspen HYSYS اعتماداً على بيانات مقياسية. وقد تم التحقق من صحة النموذج من خلال مقارنة نتائج المحاكاة مع بيانات الوحدة التطبيقية، حيث أظهرت النتائج توافقاً جيداً بارتياب نسبي مقبول.

بعد ذلك، تم إجراء دراسة لتقييم تأثير بعض العوامل التي يتم تغييرها أثناء تشغيل الوحدة الصناعية، خاصة تركيز مادة ميثيل ثنائي إيثانول أمين (MDEA) ونسبة CO_2 عند المدخل، على أداء العملية واستهلاك الطاقة. أظهرت النتائج أن نسبة تركيز الأمين تحسن كفاءة إزالة ثاني اكسيد الكربون، لكنها تؤدي في المقابل إلى زيادة استهلاك الطاقة في مرجل اعادة الغليان.

تؤكد هذه الدراسة أن محاكاة العمليات اثبتت نظريا فعالية تخفيض نسبة الكربون وتقليل استهلاك الطاقة في معالجة الغاز الطبيعي.

الكلمات المفتاحية: الغاز الطبيعي، ثاني أكسيد الكربون، وحدة إزالة الغازات الحمضية (AGRU)، ميثيل ثنائي إيثانول أمين، برنامج Aspen HYSYS.

Résumé

Le gaz naturel produit au niveau du Centre de Traitement (CPF) du champ de Rhourde Nouss à Illizi contient du CO_2, qui doit être éliminé afin de respecter les spécifications d'exportation et d'éviter des problèmes opérationnels tels que la corrosion et la formation d'hydrates. Cette étude porte sur la simulation et l'optimisation de l'unité d'élimination des gaz acides (AGRU) utilisant un procédé d'absorption aux amines.

Le procédé a été simulé à l'aide du logiciel Aspen HYSYS sur les bases de données industrielles réelles. La validation du modèle a été réalisée par comparaison des résultats de simulation avec les données de l'unité industrielle, montrant une bonne concordance avec une marge d'erreur acceptable.

Par la suite, une étude a été menée afin d'évaluer l'influence de certains paramètres opératoires, notamment la concentration de méthyldiéthanolamine (MDEA) et la teneur en CO_2 à l'entrée, sur les performances du procédé et la consommation énergétique. Les résultats ont montré qu'une augmentation de la concentration en amine améliore l'efficacité

d'élimination du CO_2, mais entraîne également une augmentation de la consommation d'énergie au niveau du rebouilleur.

Cette étude confirme que la simulation des procédés a démontré théoriquement l'efficacité de la réduction du CO_2 tout en minimisant la consommation énergétique dans le traitement du gaz naturel.

Mots-clés: gaz naturel, CO_2, unité d'élimination des gaz acides (AGRU), méthyldiéthanolamine (MDEA), Aspen HYSYS.

Abstract

Natural gas produced at the Treatment Center (CPF) of the Rhourde Nouss field in Illizi contains CO_2, which must be removed to meet export specifications and avoid operational problems such as corrosion and hydrate formation. This study focuses on the simulation and optimization of the Acid Gas Removal Unit (AGRU) using an amine absorption process.

The process was simulated using Aspen HYSYS based on real industrial operating data. The model was validated by comparing simulation results with industrial unit data, showing good agreement with an acceptable margin of error.

A parametric study was then conducted to evaluate the effect of certain operating parameters, particularly methyldiethanolamine (MDEA) concentration and inlet CO_2 content, on process performance and energy consumption. The results showed that increasing amine concentration improves CO_2 removal efficiency, but also leads to higher energy consumption in the reboiler unit.

This study confirms that process simulation theoretically demonstrated the effectiveness of reducing CO_2 while minimizing energy consumption in natural gas treatment.

Keywords: Natural gas, CO_2, Acid Gas Removal Unit (AGRU), methyldiethanolamine (MDEA), Aspen HYSYS.

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CPF	Central Processing Facility
QH	Hamra Quartzite
Hg	Mercury
CO_2	Carbone Dioxide
H_2S	Hydrogen Sulfide
LPG	Liquefied Petroleum Gas
mg/Nm^3	Milligrams per Normal Cubic Meter
H_2O	Water
COS	Carbon oxysulfide
IUPAC	International Union of Pure and Applied Chemistry
CAS	Chemical Abstracts Service
°C	Degree Celsius
KPa	Kilopascal
MPa	Megapascal
Kg	Kilogram
KJ	Kilojoule
CS_2	Carbon disulfide
AMP	2-Amino-2-Methyl-1-Propanol
RNS	Rhourde Nouss
RN	Rhourde Nouss Well Designation
CSC	Compression and Separation Center
U-70	Unit 70
MSm^3/day	Million Standard Cubic Meters per Day
$\mu g/Nm^3$	Micrograms per Normal Cubic Meter
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
Mol%	Mole Percent
GR4	Gas Pipeline Network 4
TRC	Transport and Compression
AGRU	Acid Gas Removal Unit
ppmv	Parts Per Million by Volume
KW	Kilowatt

P&ID	Piping and Instrumentation Diagram
TEG	Triethylene Glycol
RCY	Recycle
MMKcal/h	Million kilocalories per hour

GENERAL INTRODUCTION

General Introduction

Faced with global economic challenges, fluctuating oil prices, and new international recommendations aimed at reducing greenhouse gas emissions responsible for climate change, natural gas is emerging as a strategic alternative energy source. It stands out for its low environmental impact compared to other fossil fuels, while offering abundant availability and reliable operation [1]. These advantages give it a major role in global economic development in the medium and long term [2], [3]. Currently, natural gas represents approximately 24.7 % of global energy consumption, and its reserves continue to grow steadily [1], [3].

In this context, Algeria occupies a strategic position in the international energy market, ranking among the leading exporters of natural gas [1]. The commissioning of the CPF at Rhourde Nouss – QH is fully aligned with SONATRACH's exploitation policy, particularly within the framework of developing and utilizing unconventional deposits [4], [5]. This policy primarily aims to maximize natural gas production while respecting technical, economic, and environmental constraints [4], [6].

However, raw natural gas from unconventional gas fields cannot be used or exported directly. It contains, in varying proportions, several undesirable compounds such as Hg, CO_2, H_2S, various impurities, and Water from reservoir formation, [7], [8]. The gas supplying the Rhourde Nouss QH CPF is characterized in particular by a high CO_2 content, which is one of the most frequently encountered problems in the gas industry [7], [4]. In the presence of water, CO_2 promotes equipment corrosion, while mercury causes major problems in cryogenic units, especially during LPG recovery and natural gas liquefaction operations, [7], [5].

To address these constraints, a decarbonization unit using a mixture of amines was installed at the CPF (Central Processing Facility), with the primary objective of reducing the CO_2 concentration to the specifications required for gas transport and marketing [7], [4]. To date, CO_2 capture using chemical solvents, particularly those based on alkanolamines, remains the most mature and widely deployed technology in the natural gas processing industry.

However, these processes have the major drawback of high energy consumption, coupled with operational challenges related to solvent composition and flow rate optimization, which directly impacts operating costs. Therefore, optimizing decarbonization units is crucial to

ensuring reliable, economically viable operation that meets environmental requirements. This work falls within this context.

This dissertation is structured into three main parts:

- **Chapter I**: Bibliographic study on natural gas and decarbonization processes.
- **Chapter II**: Geographic presentation and process description of the Rhourd Nouss CPF unit.
- **Chapter III**: Modeling, simulation, validation, and optimization of the decarbonization unit using Aspen HYSYS.

Finally, a general conclusion summarizes the main findings and perspectives of this work.

BIBLIOGRAPHIC SYNTHESIS

Chapter I: Natural Gas & Decarbonization

I.1 Introduction:

Natural gas is a fossil fuel found in underground porous rock formations and widely used as a major energy source [8]. Natural gas is composed primarily of methane (CH_4), which generally represents 75–95% of its composition, along with smaller amounts of other hydrocarbons and impurities [7], [8]. Its high hydrogen-to-carbon ratio explains its classification as a hydrocarbon and contributes to its relatively cleaner combustion compared to other fossil fuels [8]. The exploitation of natural gas requires expertise across the entire gas value chain, from extraction through processing, storage, and transportation to final consumption [7], [9].

Natural gas is used for the production of heat and electricity, as well as in various industrial processes, including petrochemicals and power generation [8]. Its use has increased in the context of the growing environmental awareness of recent decades [1].

I.2 Origin and formation of natural gas:

There are three possible modes for the formation of natural gaseous hydrocarbons [7]:

Table I.1. Origin and Formation of Natural Gas.

Formation Type	Process	Conditions	Main Components	Importance
Bacterial Gas	Bacterial decomposition of organic matter	Low temperature & shallow depth	Methane (CH_4)	Secondary
Inorganic Gas	Geological processes (volcanic, hydrothermal, igneous rocks)	Deep geological environments	Methane & light hydrocarbons	Rare
Thermal gas	Thermal degradation of buried organic matter	High temperature & pressure	Methane + heavier hydrocarbons + CO_2	Primary source

I.3 Composition of Natural Gas:

Natural gas is primarily composed of Methane(CH_4), the amount of which can vary considerably from one deposit to another [8]:

Table I.2. Chemical Composition and Constituents of Natural Gas

Category	Constituent Name
Primary Component	Methane(CH_4)
Other Hydrocarbons	Heavy Hydrocarbons
Acid Gases	Sulfur dioxide(SO_2), Hydrogen sulfide(H_2S), Carbon dioxide(CO_2)
Inert/Trace Elements	Helium(He), Mercury(Hg), Nitrogen(N_2)

I.4 Characteristics of natural gas:

At the final stage of its exploitation, natural gas can be characterized by the following properties:

I.4.1 Density:

For a gas, density is defined as the ratio of its mass per unit volume to that of air under specific temperature and pressure conditions [10].

I.4.2 Calorific Value:

This is the amount of heat released by the combustion of a unit volume of gas, measured under reference conditions. The calorific value for natural gas is expressed in J/m³ [10]. There are two calorific values:

- **Higher Heating Value (HHV):** This is the amount of heat released when all combustion products are cooled to ambient temperature, with the water formed remaining liquid [11].
- **Lower Heating Value (LHV):** This is the amount of heat released when all combustion products are cooled to ambient temperature, with the water remaining in a vapor state [11].

I.5 Properties of Natural Gas:

Natural gas is a gaseous mixture of saturated hydrocarbons, exhibiting the typical physical characteristics of a gas [12].

I.5.1 Physical properties:

- Colorless, odorless: An odorant is added to detect leaks.
- Lighter than air, dispersed in the atmosphere.
- Non-explosive
- Flammable if exposed to any ignition source (Its concentration must be 5% to 15% in air for combustion) [12].

I.5.2 Chemical properties:

Natural gas is the least polluting fossil fuel; it is composed primarily of methane (95%) and ethane (2%), with some inert gases: CO_2 (<2%) and N_2 (<3%). The gaseous form of natural gas, when burned, releases a significant amount of heat. The maximum inert gas content is regulated, but not the hydrocarbon composition; it is the calorific value that is regulated [12].

I.6 Types of Natural Gas:

The appearance of a liquid phase depends on the temperature and pressure conditions in the reservoir and at the surface [11]. This leads to distinguishing the following cases:

- **Dry gas:** Not forming a liquid phase under production conditions.
- **Wet gas:** Forming a liquid phase during production under surface conditions.
- **Condensate gas:** Forming a liquid phase in the reservoir during production.
- **Associated gas:** Coexisting in the reservoir with an "oil" phase (oil field). Associated gas includes cap gas (gaseous phase present in the reservoir) and dissolved gas [13].

I.7 Impurities Present in Natural Gas:

The treatment of natural gas aims to partially or completely separate the various components present at the wellhead, such as water, acid gases, and heavy hydrocarbons [9]. The main objective of this operation is to make the gas compliant with commercial specifications or transportation requirements. Some components must absolutely be removed, either to facilitate the subsequent stages of processing and transportation, or to comply with commercial or regulatory standards. Among the elements to be at least partially removed are [14]:

Table I.3. Natural Gas Impurities and Their Operational Impact

Impurity	Primary Reason for Removal
H_2S	Toxic and corrosive gas.
CO_2	Corrosive compound, without energy value.
Hg	Corrosive under certain conditions.
H_2O	Responsible for the formation of hydrates.
Heavy Hydrocarbons	Likely to condense in transport networks.
N_2	Gas without calorific power.

I.8 Specifications and quality standards:

Natural gas must meet specific quality standards before it can be transported or sold. Typical specifications for sales gas are summarized in the table below.

Table I.4. Typical Specifications of Sales Gas

Parameter	Specification
CO_2	$< 2.5\ \%$
H_2S + COS	$< 5\ mg/Nm^3$
Mercaptans	$< 6\ mg/Nm^3$
Total sulfur	$< 30\ mg/Nm^3$
H_2O	Dew point $\leq -8\ ℃$ at 70 bar

These specifications ensure that the gas is safe for transportation, prevents corrosion in pipelines, and meets commercial requirements [15].

I.9 Natural Gas Decarbonization:

The CO_2 is an acidic gas present in natural gas that can cause corrosion of equipment and pipelines, particularly in the presence of free water, and may lead to freezing due to the formation of CO_2 crystals in liquefaction zones operating at very low temperatures. In addition, CO_2 dilutes natural gas, reducing its calorific value and increasing transportation costs [16].

To address these issues, decarbonization, which is a process aimed at reducing the CO_2 content is applied. Through decarbonization, natural gas treatment achieves three main objectives: minimizing pipeline corrosion, preventing solidification during cryogenic operations, and preserving a higher calorific value [15].

I.10 Carbon Dioxide:

The presented at the figure I.1 referred to a carbonic gas molecular structure 3D, is a colorless gas classified among acidic gases. It occurs naturally in natural gas and is also recognized as a greenhouse gas [7], [8]. Chemically, CO_2 is a compound made up of one carbon atom bonded to two oxygen atoms, giving it the molecular formula CO_2 [17].

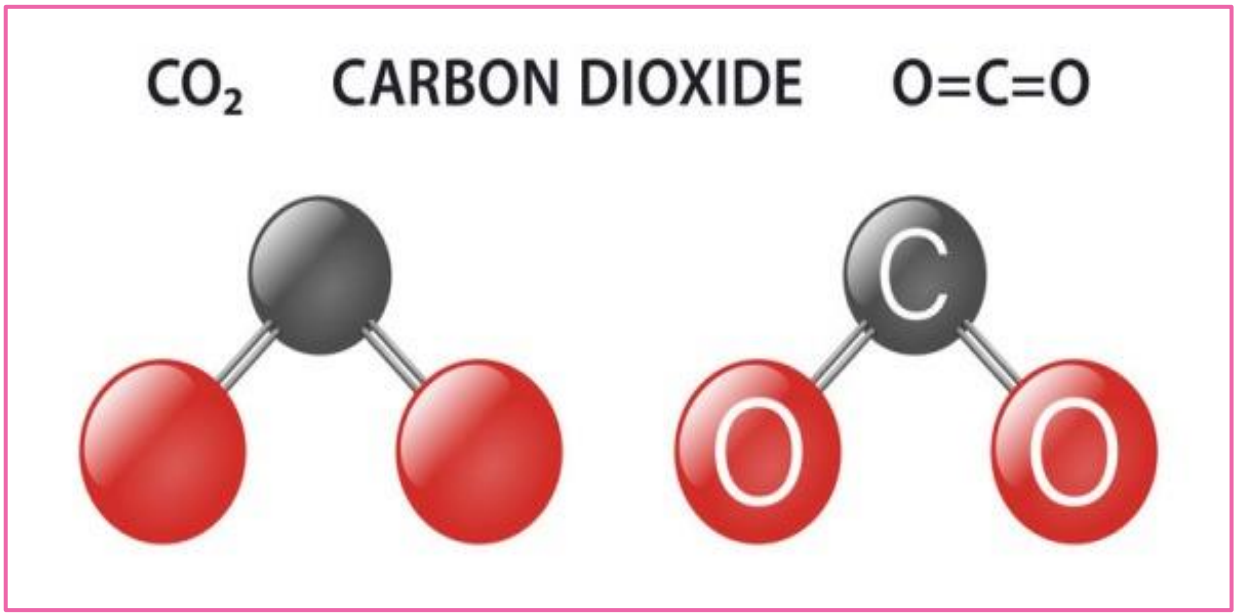


Figure I.1. *Molecular structure 3D of* ($\boldsymbol{CO_2}$) **[48]**

I.10.1 Physicochemical characteristics of CO_2:

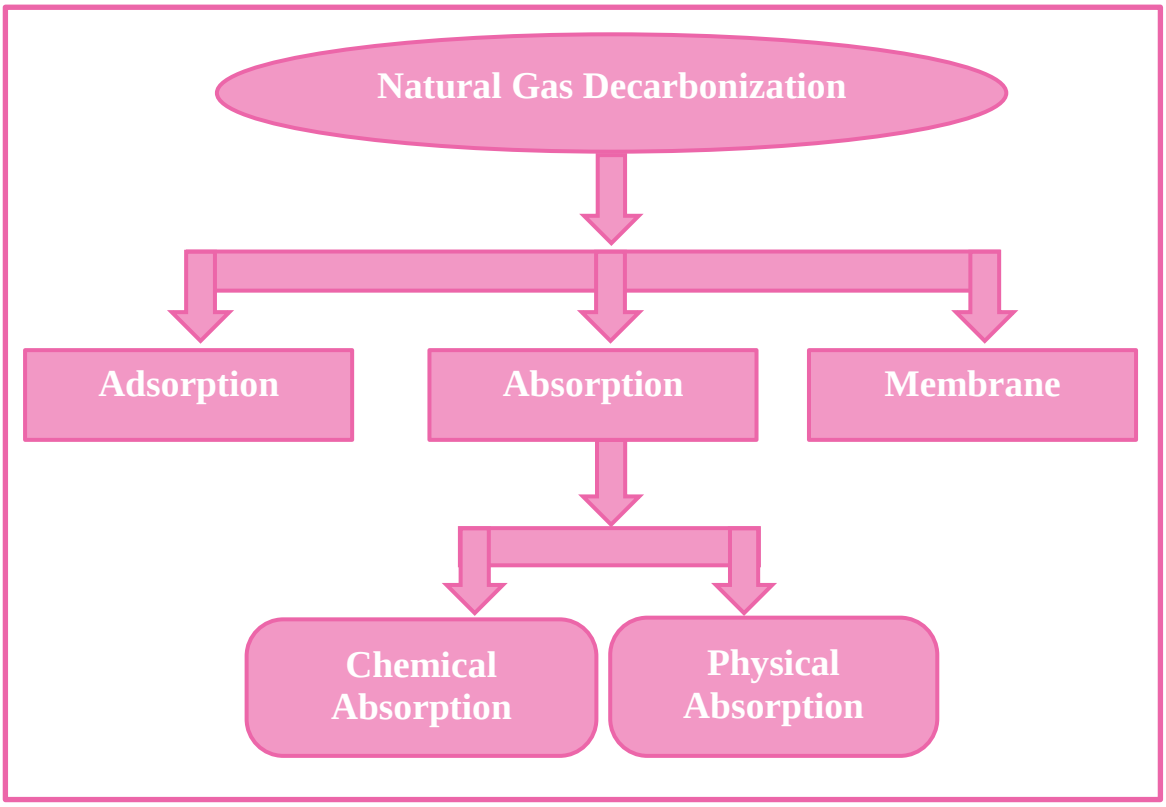
The physical and thermodynamic properties of CO_2 are presented at the following table I.5.

Table I.5. The physical and thermodynamic properties of (CO_2) **[17]**

Category	Property	Details and Values
Identity	IUPAC Name	Carbon dioxide (Carbonic anhydride)
	CAS Number	124-38-9
	Appearance	Colorless gas
Physical	Chemical formula	CO_2
	Molecular weight	44.01 g/mol
	Density	1.87 kg/m^3 (298 K, 1.013 bar), denser than air
	Solubility	1.45 kg/m^3
	Dynamic viscosity	0.07 cP at −78 °C
	Critical pressure	7.4 MPa
	Melting temperature	−78.5 °C (195 K)
	Boiling temperature	−57 °C (216 K)
	Critical temperature	31.1 °C
	Triple point	−56.6 °C at 519 kPa
	Latent heat of vaporization (0 °C)	234.5 kJ/kg
	Latent heat of vaporization (−16.7 °C)	276.8 kJ/kg
	Latent heat of vaporization (−28.9 °C)	301.7 kJ/kg
	Latent heat of fusion (at −56.6 °C)	199 kJ/kg
Thermochemical	Standard enthalpy of formation (ΔfH° gas)	−393.5 kJ/mol

I.11 Methods used for natural gas decarbonization:

Several technologies are used for natural gas decarbonization, mainly absorption, adsorption, and membrane separation is presented at the scheme I.1. Among these, absorption processes are the most widely used in industry due to their technological maturity and high efficiency in acid gas removal [16].



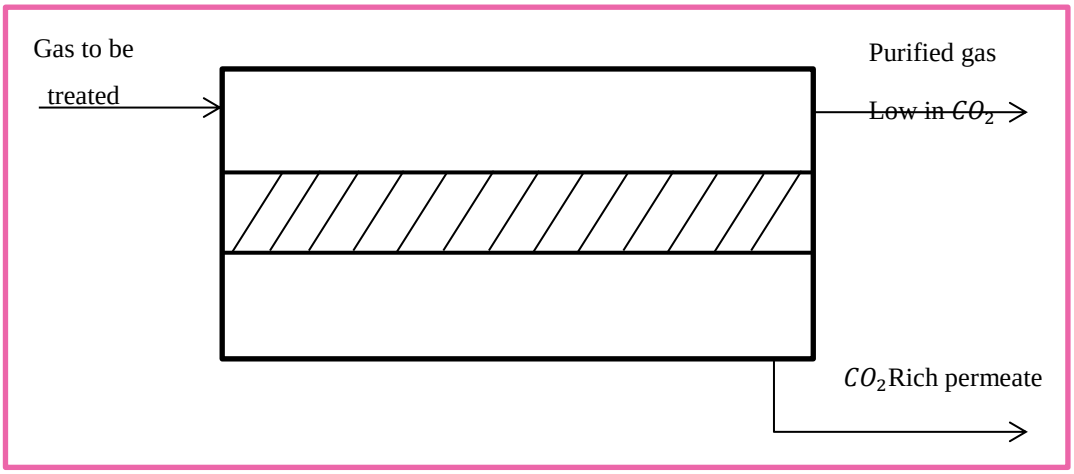
Scheme I.1. *Methods used for natural gas decarbonization*

The main techniques for separating CO_2 from production gases are based on absorption processes (chemical or physical), adsorption processes, and membrane processes [7], [18]. Chemical absorption, particularly using amine solutions, remains the most established technology for industrial gas sweetening applications [19]. In addition to these conventional processes, which will be described below, other "breakthrough" separation techniques are under investigation. These include low-temperature separation processes, the use of ionic liquids, and gas hydrate crystallization techniques [16], [18].

I.11.1 **Membranes:**

Membrane separation is used for natural gas decarbonization, mainly for small processing capacities [7]. It enables the removal of CO_2 and H_2O vapor from the gas stream. A scheme I.2 is shown below.

Effective separation requires membranes with high CO_2 permeability, allowing it to pass through under pressure and high selectivity to retain methane [18].



Scheme I.2. *Membrane Separation, Schematic Diagram*

I.11.2 **Adsorption:**

The adsorption process removes acidic gases by trapping them on the surface of a solid adsorbent, presented at the figure I.2. This removal occurs through physical or chemical interactions between the gas and the solid material [18]. Common adsorption methods use materials such as iron oxide, zinc oxide, and molecular sieves (zeolites) [20]. These adsorbents typically have a microporous structure that selectively retains the target components [7]. Once the adsorption column becomes saturated with acidic gases, the bed must be regenerated or replaced [21].

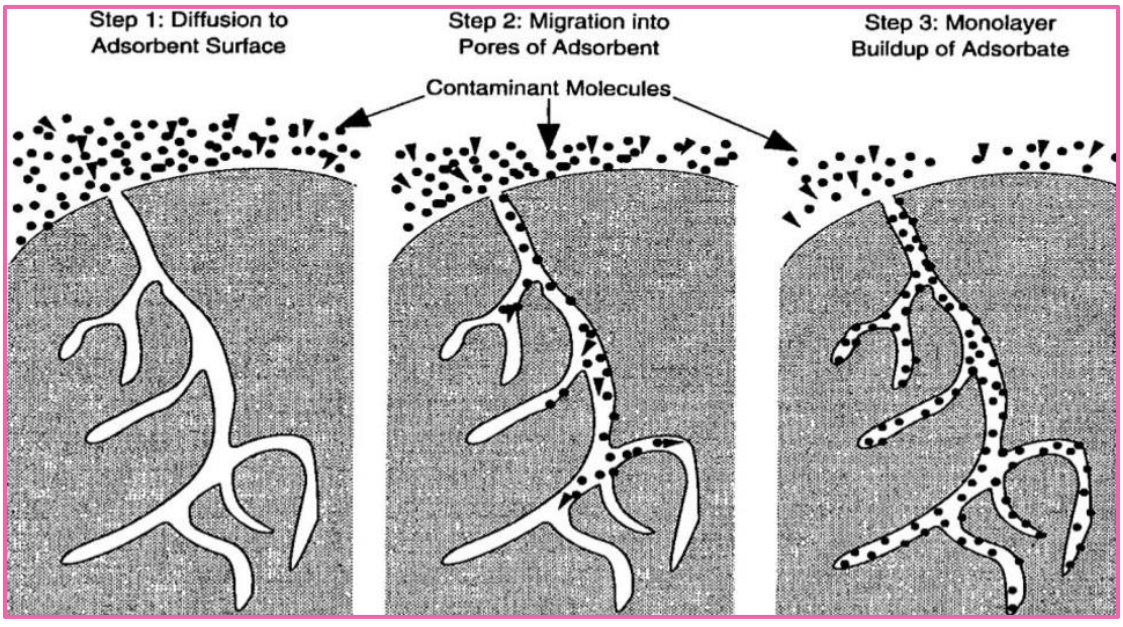


Figure I.2. *Adsorption Mechanism* **[49]**

I.11.3 **Absorption:**

Absorption involves the transfer of matter between a gaseous phase and a liquid phase, the latter consisting of a pure substance or a mixture of several substances (solvent) [20]. Furthermore, the gaseous phase is generally considered to consist of only two components: the substance being transferred (solute) and the inert gas or diluent. The often necessary recovery of the substance that has dissolved in the liquid is called desorption [22], [18].

The main families of processes can be identified: physical and chemical absorption [7].

a) Physical Absorption:

Physical absorption is based on the preferential solubility of acid gases in organic solvents without chemical reaction. This process is generally used when the partial pressure of acid gases is high, the concentration of heavy hydrocarbons in the gas is low and large quantities must be removed [23].

b) Chemical Absorption:

Chemical absorption involves a chemical reaction between acid gases and a solvent, typically aqueous amine solution [24]. Alkanolamines are the most commonly used solvents for CO_2 removal in natural gas treatment [19].

I.12 Process selection criteria:

Chemical absorption is widely used in industrial applications for several reasons:

- High efficiency in removing CO_2 to very low concentrations
- Suitable for large gas flow rates
- Effective in the presence of impurities and heavy hydrocarbons
- Moderate investment and operating costs compared to alternative technologies [7].

I.13 Chemical Solvents:

Among the chemical solvents used for acid gas removal, aqueous amine solutions are the most widely employed in industry [7]. These solvents are formulated with amines, which are organic compounds containing one or more amine functional groups. In particular, alkanolamines have a molecular structure that includes at least one hydroxyl group (–OH) and one amine group (–N).

The hydroxyl group improves solubility in water and reduces the vapor pressure of the aqueous solution, while the amine group imparts the basicity required for reaction with acidic gases such as CO_2 and H_2S [19], [25].

Amines are classified into primary, secondary, and tertiary types, depending on the substitution of the nitrogen atom, which affects their reactivity and absorption performance as illustrated in Figure I.3.

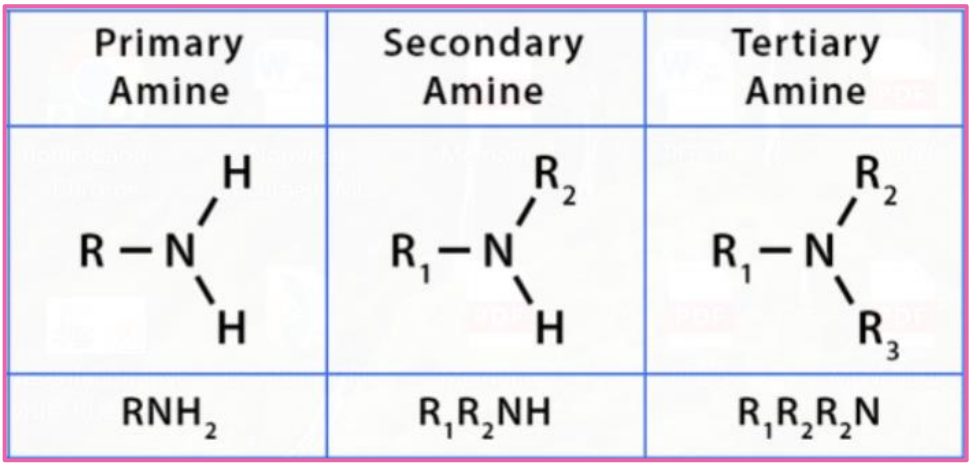


Figure I.3. *The Classification of Amines: Primary, Secondary, and Tertiary* **[47]**

Where R, R′and R″ are carbon chains

The following table I.6 presents the most commonly used amines in acid gas treatment processes, these solvents are widely applied in gas sweetening due to their effectiveness in removing CO_2 and H_2S.

Table I.6. Common Amines Used for Acid Gas Removal

Amine	Full name	Amine type	Simplified chemical formula
MEA	Monoethanolamine	Primary amine	HO–CH_2–CH_2–NH_2
DEA	Diethanolamine	Secondary amine	HO–CH_2–CH_2–NH–CH_2–CH_2–OH
DIPA	Diisopropanolamine	Secondary amine	(CH_3–CHOH–CH_2)$_2$NH
MDEA	Methyldiethanolamine	Tertiary amine	[HO–CH_2–CH_2]$_2$N–CH_3

For CO_2 absorption, the selection of amines depends on process requirements such as selectivity, energy consumption, and gas composition [26].

a) Primary Amines:

The most commonly used primary amines in acid gas treatment are monoethanolamine (MEA) and diglycolamine (DGA). They react strongly with acid gases, enabling high removal efficiency. However, their CO_2 absorption capacity is limited because carbamate formation requires two moles of amine per mole of CO_2, with partial hydrolysis into bicarbonate [27].

- **Chemical Reaction:**

$$RNH_2 + CO_2 \overset{k_2,k_{-2},k_2}{\longleftrightarrow} RNH_2^+COO^-$$

$$RNH_2^+COO^- + B \overset{k_b,k_{-b},k_b}{\longleftrightarrow} RNHCOO^- + BH^+$$

With B as a base: H_2O, amine, OH^-, $HCO^{-3}$and CO^{2-}

Primary amines react rapidly with CO_2, which ensures high absorption efficiency. However, this strong reactivity increases corrosion risks and solvent degradation. MEA can also react irreversibly with COS and CS_2, reducing its performance. Although corrosion inhibitors allow higher concentrations, operational limitations remain. DGA offers similar performance but lower volatility, reducing solvent losses [7], [28].

b) Secondary Amines:

The most commonly used secondary amines are Diethanolamine (DEA) and Diisopropanolamine (DIPA). They are less reactive than primary amines but more stable, making them suitable when ultra-high gas purity is not required. They also tend to be more stable and show lower degradation in the presence of COS and CS_2.

- **Chemical Reaction:**

$$RR'NH + CO_2 \overset{k_2,k_{-2},k_2}{\longleftrightarrow} RR'NH^+COO^-$$

$$RR'NH^+COO^- + B' \overset{k_{b'},k_{-b'},k_{b'}}{\longleftrightarrow} RR'NCOO^- + B'H^+$$

With B' as a base: H_2O, amine, OH^-, $HCO^{-3}$and CO^{2-}

Secondary amines form carbamates more slowly than primary amines and show partial hydrolysis to bicarbonate. DEA is widely used due to its lower volatility and reduced solvent losses, making it suitable for industrial operation [7].

c) Tertiary Amines:

The most widely used tertiary amine is Methyldiethanolamine (MDEA). Unlike primary and secondary amines, tertiary amines do not react directly with CO_2 but enhance its hydration into bicarbonate. One mole of MDEA can absorb one mole of CO_2.

- **Chemical Reaction:**

$$RR'R''N + H_2O + CO_2 \overset{k_2, k_{-2}, k_2}{\longleftrightarrow} RR'R''NH^+ + HCO_3^-$$

MDEA is highly resistant to thermal and chemical degradation and can be used at high concentrations with low solvent losses [25]. However, its reaction rate is slow and is often improved by adding activator amines. Sterically hindered amines (e.g., AMP) are also used to reduce regeneration energy consumption [7], [19].

I.14 Main Features and Limitations:

Primary amines provide fast reaction kinetics but suffer from corrosion and degradation issues. Secondary amines offer a balance between stability and reactivity. Tertiary amines provide high absorption capacity and excellent stability but slower kinetics. Therefore, amine selection significantly affects absorber design, operating conditions, and regeneration energy requirements [29].

GEOGRAPHIC PRESENTATION & UNIT DESCRIPTION

Chapter II: Gas Treatment at Rhourde Nouss Field

II.1 Geographical Location:

The Rhourde Nouss region, located in Illizi Province in southeastern Algeria, lies approximately 350 km south-southeast of Ouargla, 270 km from Hassi Messaoud, and about 1200 km from Algiers. It is connected to National Road No. 03 (Ouargla–Illizi) by a secondary road of approximately 30 km, as presented at the figure II.1.

Situated on the edge of the Great Eastern Erg, the area features alternating rocky plateaus (hamada) and sand dunes. Its average elevation is about 275 m above sea level. The climate is desertic, characterized by extremely low rainfall (2–4 mm/year), very low humidity, frequent sandstorms, and significant temperature variations ranging from −5 °C in winter to above 50°C in summer [30].

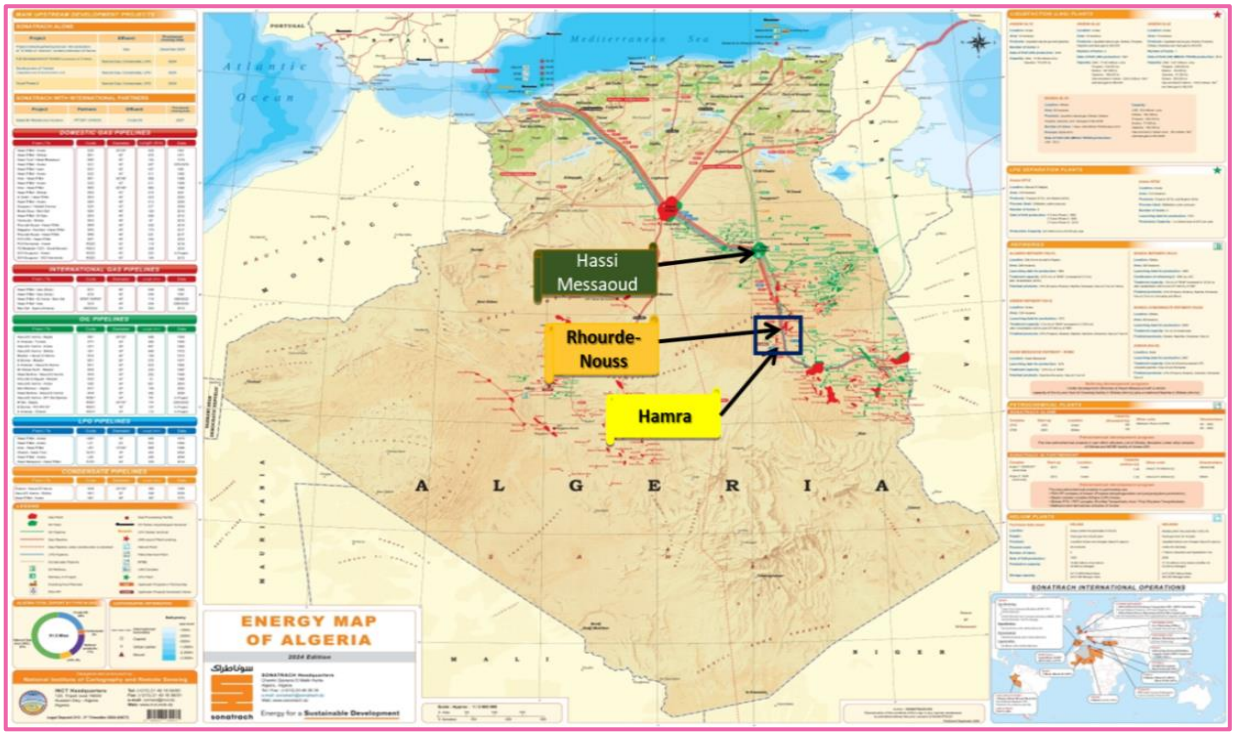


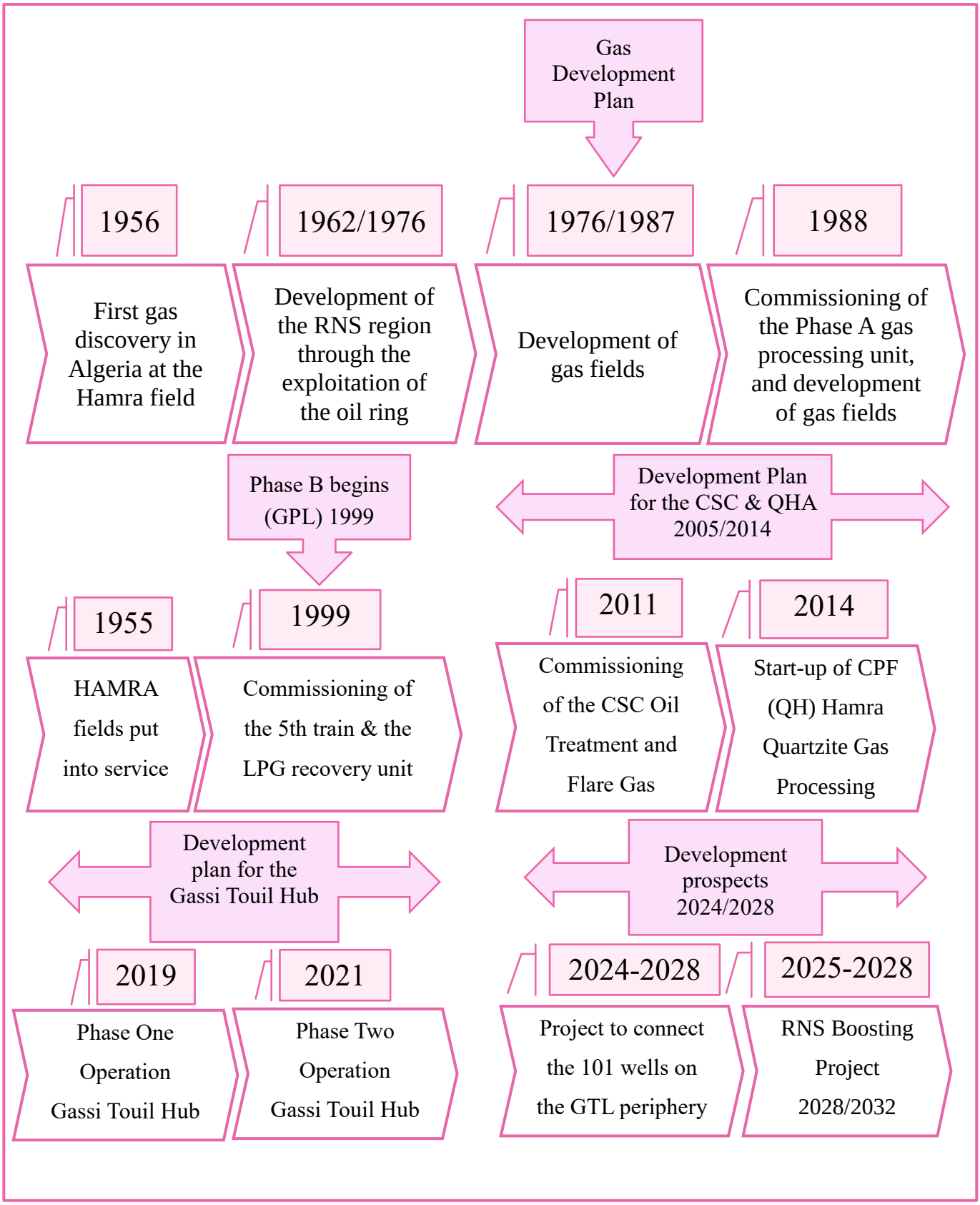
Figure II.1. *Geographical Location of the RHOURDE NOUSS Region* **[30]**

II.2 Historical Development of Rhourde Nouss (RNS):

The first gas discovery in the Rhourde Nouss region dates back to 1956. The drilling of the first well, RN-1, in 1962, revealed the presence of condensate-rich gas in several reservoirs. Subsequently, the discovery of oil in the RN-4 well led to the construction of an oil processing plant, which became operational in 1966, A scheme II.1 is shown below.

The evolution of oil and gas activity in the Rhourde Nouss region can be divided into several major periods, illustrating the gradual ramp-up of production and processing facilities. This

allowed the field to become the second largest gas field in Algeria after Hassi R'Mel, and its continuous adaptation to the new technical and economic requirements of the energy sector [30].



Scheme II.1. *History and Major Milestones of the Rhourde Nouss Region* **[30]**

II.3 The Various Complexes in the Region:

The Rhourde Nouss region comprises four major facilities:

- Phase A: designed to process approximately 51 Mm^3/d of raw gas, with the primary objective of condensate recovery.
- Phase B: capable of processing 48.3 Mm^3/d, dedicated to the recovery of LPG and residual traces of condensate.
- CSC: for oil production.
- CPF: dedicated to the treatment of acid gases [30].

II.4 Overview of the Region's Various Complexes:

The Rhourde Nouss region is primarily dedicated to the production and processing of natural gas, while also ensuring the valorization of liquid hydrocarbons. It includes several complementary industrial facilities enabling the recovery of condensate and LPG, and the production of gas that meets commercial specifications [30].

II.4.1 **Phase A:**

Phase A processes raw gas using four identical trains, supplemented by a fifth train (U-70) dedicated to processing the high-pressure portion. This unit allows for efficient separation to maximize condensate recovery (C5+), compress the gas for delivery to Phase B, and recycle the treated dry gas for reinjection or export. It processes approximately 46 to 51 MSm^3/D of raw gas and produces nearly 2,690 t/day of condensate.

II.4.2 **Phase B:**

Phase B facilities are designed to recover the LPG contained in the sales gas from Phase A. The produced LPG is transported by pipeline to Haoudh El Hamra (HEH). The condensate from the fractionation is returned to Phase A for storage, while the residual gas is also sent back to Phase A for sale and reinjection to preserve the reservoir.

II.4.3 **Compression and Separation Center (CSC):**

The CSC separates the oil, water, and gas from 33 wells. The effluents are treated according to their pressure level in several separators, and then the gases are compressed to approximately 92 bar before being sent to the processing facilities. The recovered condensates are desalinated, stabilized, and then stored. The primary objective of this unit is oil production.

II.4.4 **CPF (Hamra Quartzite):**

The new Hamra Quartzite (QH) CPF is designed to process up to 10 million Sm³/day of gas (dry basis) from 24 production wells across four perimeters. Current production is approximately 7 million Sm³/day, with dry residual gas meeting the following specifications:

- CO_2 content less than 2.0 mol%.
- Mercury (Hg) content less than 10 $\mu g/Nm^3$.

The treated gas is then transported to the Phase B plant for the recovery of LPG and condensate, while the unstabilized condensate is sent to the Phase A plant for stabilization. The extracted CO_2 is released into the atmosphere after the incineration of the BTEX aromatic compounds (benzene, toluene, and xylenes) [31].

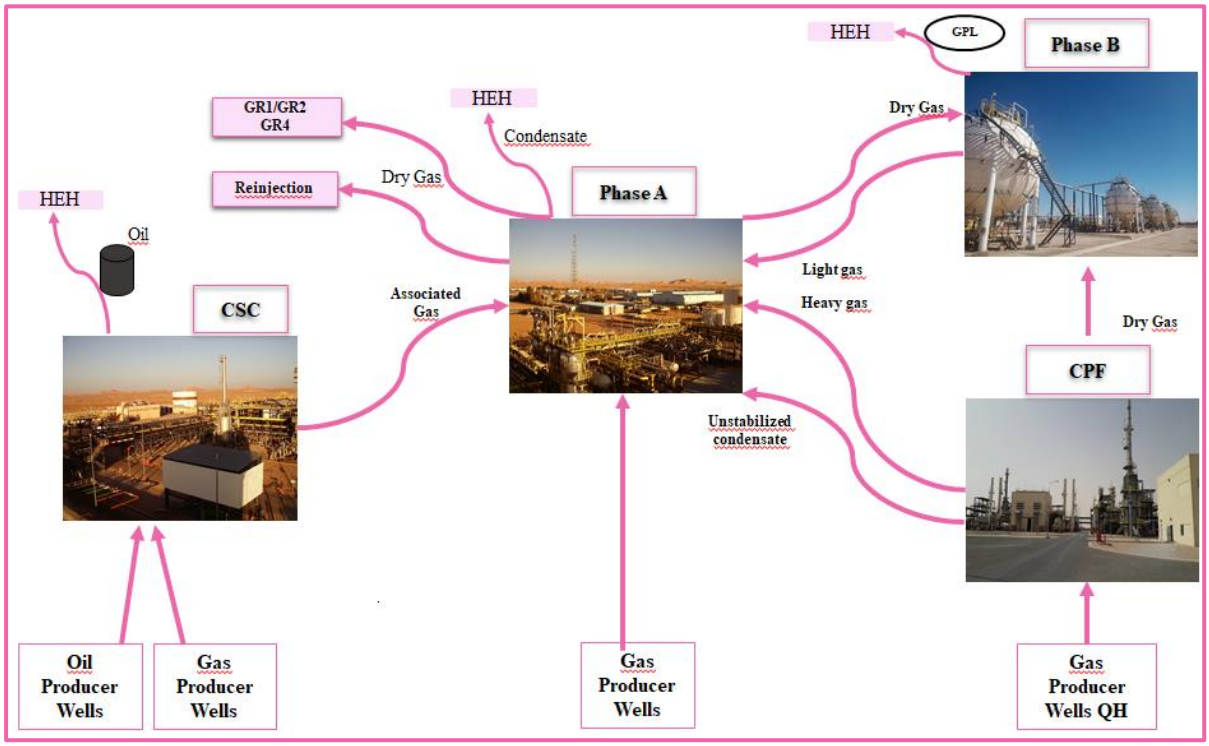


Figure II.2. *Simplified Diagram of Phase A, Phase B, CSC and CPF Installations* **[31]**

II.5 General Description of CPF (QH):

The new Hamra Quartzite (QH) processing plant is designed to process 10 million Sm³/day of gas (dry basis) from 33 production wells in four (4) fields in the Rhourde Nouss region. The plant has a nominal production capacity of 10 million Sm³/day and produces dry residual gas with a Higher Heating Value (HHV) between 9,800 and 9,900 kcal/Sm³ and a CO_2 content of less than 2.0 mol%. The exported gas is sent to the GR4 gas pipeline of the TRC transmission network [31], [32].

The multiphase mixture of gas, condensate, and water enters the plant's slug catcher at a normal operating pressure of approximately 40 bar, at a temperature of approximately 50°C, and containing up to 8.6 mol% CO_2. In the slug catcher, the gas is separated from the condensate and free water.

Inside the processing plant, the gas is compressed by booster compressors (2x50%) to 85 bar and passes through a decarbonization unit (Acid Gas Removal Unit or AGRU) to reduce the CO_2 content to less than 2.0 mol%.

The gas exiting the AGRU, which is saturated with water, passes through a molecular sieve dehydration unit to reduce its moisture content to less than 1.0 ppmv.

The dry gas then passes through an expansion unit where the condensate is separated by the cooling effect of isentropic expansion. This process allows the gas's calorific value to be adjusted as needed. After this, the dry decarbonized gas is compressed to 96 bar and cooled to 60°C before being blended with return gas from the LPG plant. The gas leaving the new processing facility, 8.6 million Sm³/day, is blended with export gas produced at the existing Rhourde Nouss facilities, amounting to 49 million Sm³/day under design conditions. A portion of the blend, 34 million Sm³/day, is sent to the GR4 gas pipeline of the national network via a new dispatch pipeline. This new 28 pipeline includes a tax metering station.

The CO_2 extracted from the gas by the decarbonization unit is compressed in five compression stages to 207 bar. Between the third and fourth compression stages, the acid gas, at a pressure of 55 bar, passes through a glycol dehydrator to reduce the water content to less than 100 ppmv before reinjection into a well.

The unstable condensate, at a design flow rate of 145 m³/h (110 m³/h nominal under operating conditions), is recovered from the wet gas entering the plant and dewatered to less than 0.1% by volume before being sent to the existing Phase A plant facilities for stabilization.

The oily water produced is sent to a treatment unit for processing in accordance with SONATRACH's quality requirements, i.e., less than 10 mg/L of free oil and oil suspended in water, before being sent to an evaporation pond. The treatment capacity is 500 m³/day.

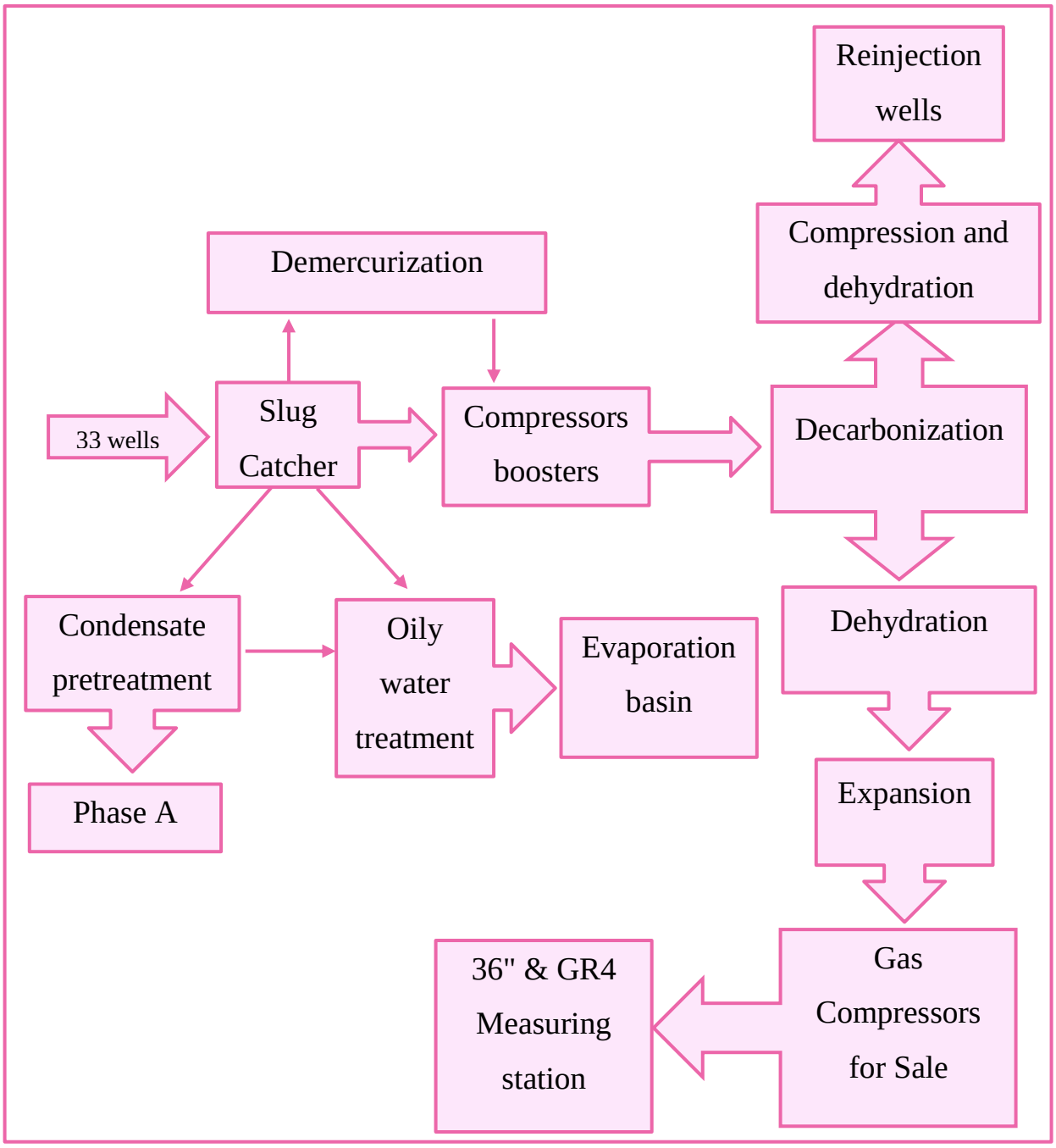
The new Rhourde Nouss QH treatment facility comprises the following two (2) systems:

- The gas collection system and manifolds
- The Rhourde Nouss gas treatment unit, designated by CPF.

The CPF is subdivided into six (6) sections:

- The separation of the multiphase mixture (Slug Catcher)
- The gas treatment
- The compression and dehydration of CO_2
- The pretreatment of unstable condensate
- The treatment of the produced water (oil removal)
- The utilities [33].

A scheme II.2 and figure II.3 is shown below.



Scheme II.2. *CPF Block Diagram* **[31]**

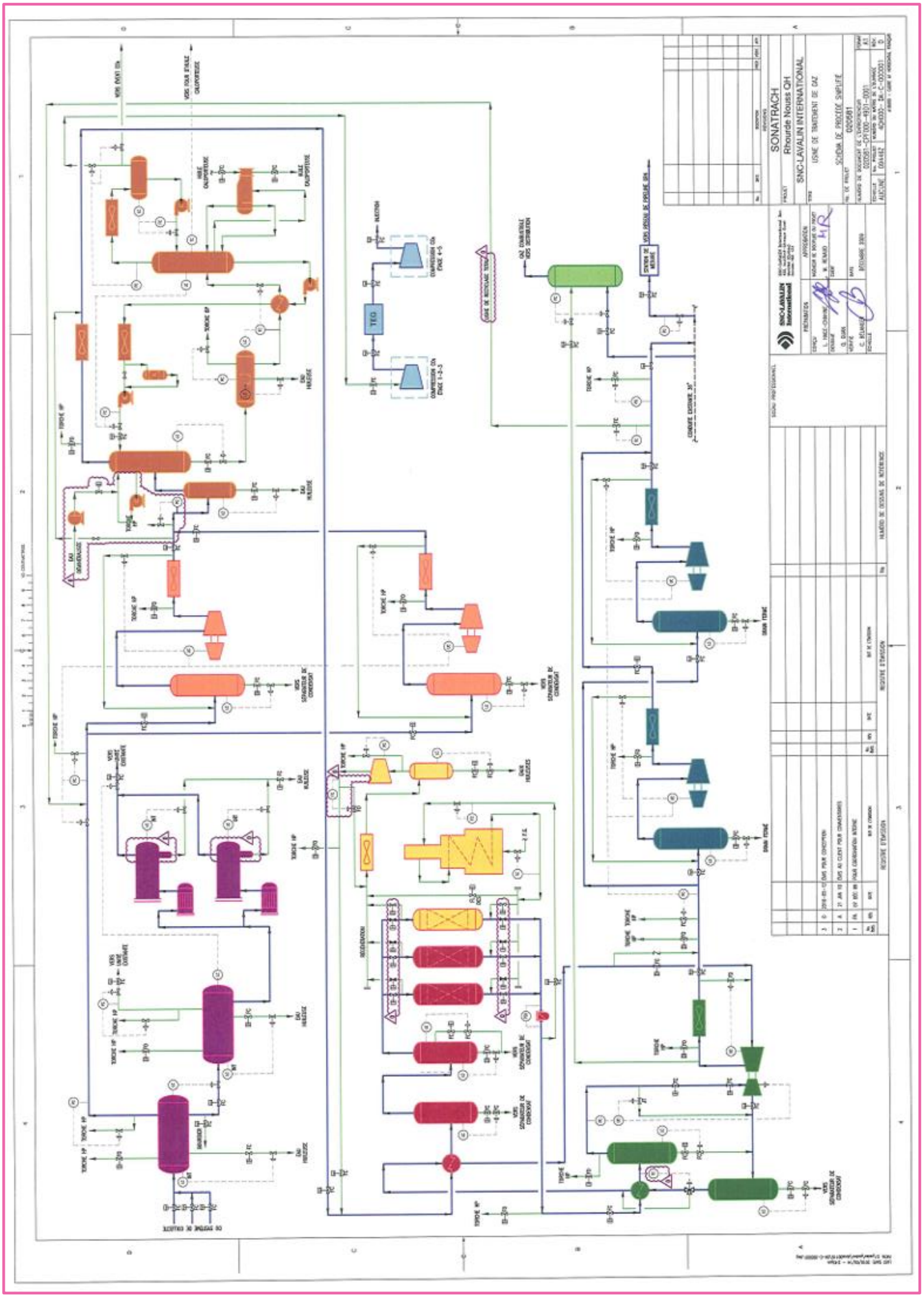


Figure II.3. *Overview of the CPF* **[31]**

II.6 Process Data Description:

II.6.1 Feed Description:

The dry crude composition of the deposit is presented at the following table II.1. The data presented are for the four production fields.

Table II.1. Dry Gas Composition of the Feed

Component	Dry base composition (mole fraction)			
	Nominal (N)	**10% CO_2 (N2)**	**Lean (L)**	**Rich (R)**
N_2	0.0051	0.0050	0.0051	0.0052
CO_2	0.0842	0.1000	0.0848	0.0792
Methane	0.7927	0.7790	0.7982	0.7455
Ethane	0.0501	0.0492	0.0504	0.0751
Propane	0.0193	0.0190	0.0175	0.0290
i-Butane	0.0064	0.0063	0.0058	0.0086
n-Butane	0.0065	0.0064	0.0059	0.0084
i-Pentane	0.0041	0.0040	0.0037	0.0045
n-Pentane	0.0021	0.0021	0.0019	0.0025
n-Hexane	0.0044	0.0043	0.0040	0.0045
n-Heptane	0.0045	0.0044	0.0041	0.0055
n-Octane	0.0030	0.0029	0.0027	0.0076
n-Nonane	0.0034	0.0033	0.0031	0.0060
n-Decane	0.0027	0.0027	0.0024	0.0046
n-C_{11}	0.0019	0.0019	0.0017	0.0030
C_{12}+	0.0096	0.0094	0.0087	0.0108
TOTAL	**1.0000**	**1.0000**	**1.0000**	**1.0000**

The chloride concentration is estimated at 658 mg/L. No sulfur compounds, ammonia compounds, or other contaminants have been identified. However, the gas is assumed to be saturated with water.

- Design flow rate at CPF inlet: 11 million Sm^3/day of gas (dry basis)
- Nominal operating flow rate at CPF inlet: 10 million Sm^3/day of gas (dry basis)
- Pressure: 40 bar
- Temperature: 55°C [34]

II.7 Description of the Decarbonization Unit (AGRU):

The decarbonization unit (AGRU) presented at figure II.4 is designed to reduce the (CO_2) content of the feed gas from 8.6 mol% to below 2 mol%, in order to meet export gas specifications [33]. The process is based on a conventional amine absorption–regeneration cycle, where CO_2 is selectively absorbed in a countercurrent contactor and subsequently stripped from the solvent in a regeneration section [24].

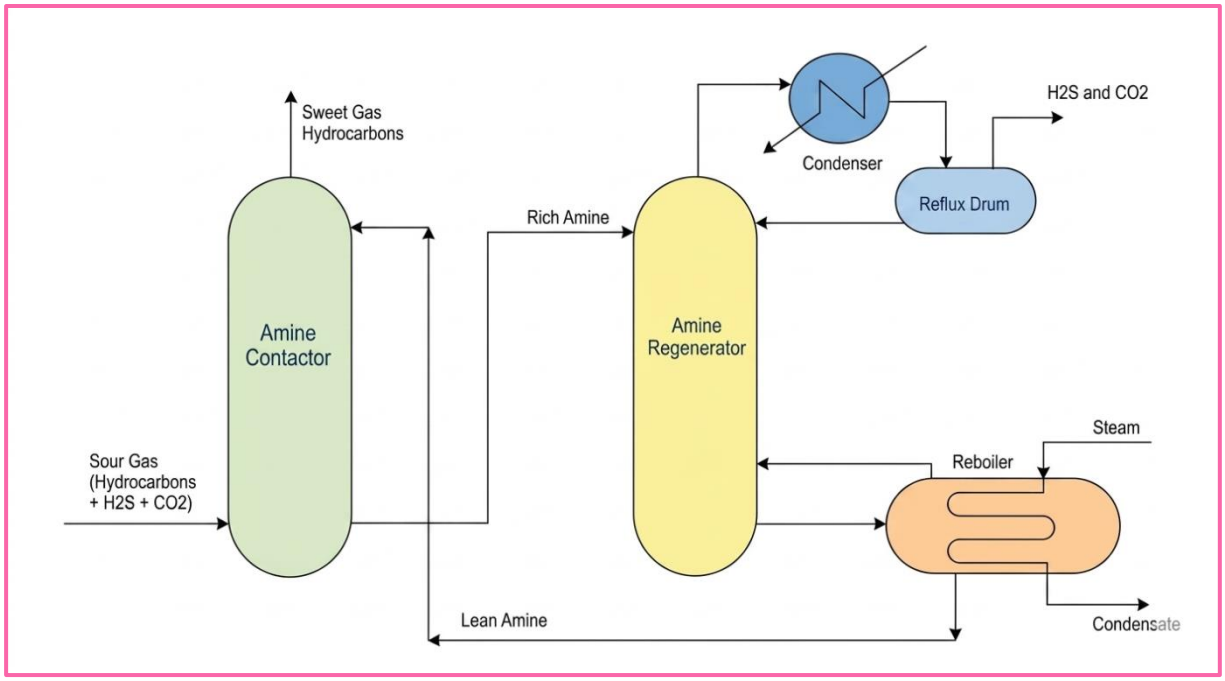


Figure II.4. *Acid gas removal from the natural gas process flow diagram* **[24]**

II.8 Acid Gas Inlet (DC-C-28OO01):

The acid gas stream coming from the booster compressors enters the inlet separator (G64-VD-28-01) at approximately 82 bar and 55 °C. In the separator, the liquids present are separated from the gas phase and routed to the oily water treatment system to avoid contamination of downstream equipment [34].

II.9 CO_2 Absorber (DC-C-28OO02):

The separated gas flows to the bottom of the absorption column (G64-CA-28-01), where it contacts a lean amine solution in countercurrent flow across 18 trays. CO_2 is absorbed due to its high solubility and chemical reactivity with amines.

The treated gas exits the top of the absorber with a CO_2 content below 2 mol% and is saturated with water. It is then cooled from 73 °C to 60 °C using air coolers before being sent to the dehydration unit. Since CO_2 absorption is an exothermic reaction, the treated gas temperature is higher than the inlet gas temperature.

To prevent amine losses, a water wash section is installed at the first two trays at the top of the column. This section uses demineralized water circulated continuously to capture entrained amine droplets. the water circulating counter-currently with the gases accumulates on a stack tray between trays 2 and 3 [34].

II.10 Amine Flash Tank (DC-C-28OO03):

The rich amine leaving the absorber at approximately 80 °C is sent to the flash tank (G64-VD-28-02), where the pressure is reduced from 82 bar to 4.8 bar. This pressure reduction allows the release of dissolved CO_2 and light hydrocarbons, thereby decreasing the load on the downstream amine regenerator (G64-CE-28-01).

Pressure control in the flash tank is ensured by controller 28-PIC-015, which regulates the venting of gases to the low-pressure flare through valve 28-PV-015. The controller operates continuously due to the relatively constant gas production rate. During start-up, the flash tank is pressurized with nitrogen via a dedicated nitrogen connection.

The flash tank is also equipped with a skimmer system that removes any hydrocarbon layer formed during normal operation. These hydrocarbons are directed to the oily water system for further treatment [34].

II.11 Rich/Lean Amine Heat Exchanger (Pet ID C-28OO04):

The rich amine, at 80°C and coming from the Flash Tank, passes through the tubes of the Lean/Rich Amine Heat Exchangers (G64-GA-28-01A/B/C/D/E/F/G/H) to be preheated to 103°C by heat exchange with the hot lean amine from the Regenerator.

The preheated rich amine is then directed to the amine regenerator in a 20-inch pipe. This flow is two-phase, as a small amount of gas vaporizes during the heating process.

The lean amine, cooled to approximately 89°C, is directed through an 18-inch pipe to the recycled amine air coolers before being pumped and circulated to the absorber. A minimum flow line, which includes valve 28-FV-078, protects the amine booster pumps by returning the amine to the bottom of the regenerator.

A 3-inch branch line allows the amine to be diverted to the G64-MB-28-05 amine drain filter and the G64-RA-28-01 amine buffer tank during shutdowns [33].

II.12 Amine Regeneration (DC-C-28OO11):

The regenerator column is the tallest unit in the CPF and contains 17 trays. CO_2 is removed from the rich amine by thermal stripping using reboilers heated by thermal oil.

The regenerated CO_2 leaves the top of the column as a water-saturated gas and is cooled before entering a reflux drum, where condensed water is separated and recycled. Makeup water is continuously added to compensate for losses.

The lean amine collected at the bottom is pumped back to the absorption section after heat recovery and cooling. Operating conditions are carefully controlled to avoid thermal degradation of the solvent, with reboiler temperatures maintained below 130 °C [34].

II.13 Amine booster pumps (Pet ID C-28OO12):

The hot lean amine solution collected at the bottom of the regenerator is pumped at 10 barg by the amine booster pumps (G64-PA-28-05A/B) to the shells of the rich/lean amine heat exchangers. These 2x100% pumps have a power rating of 300 kW. Only one pump operates at a time except during switchovers.

Each suction branch of the pumps has a manual isolation valve and a strainer with a local differential pressure indicator.

The pump bodies are connected to the amine drainage system and open drains [35].

II.14 Amine Filters (P&ID C-28OO09):

Amine is drawn from a 6-inch pipe, representing approximately 10% of the total flow, downstream of the recycled amine air cooler. This amine flows through the filters before re-joining the main stream upstream of the recirculation pumps.

The primary purpose of this withdrawal is to continuously remove contaminants such as degradation products and organic acids (precursors to Heat Stable Salts, HSS) to reduce the risk of amine foaming and gradual fouling of the system. The filtration system consists of a G64-MB-28-03 activated carbon filter installed between a pre-filter and a post-filter with cartridges (G64-MB-28-02 and G64-MB-28-04).

The pre-filter protects the activated carbon bed from clogging, while the post-filter removes any dislodged carbon particles.

The cartridge filters are equipped with a local differential pressure indicator. The carbon filter has a differential pressure transmitter with a high alarm on the DCS.

Each filter is protected by a safety valve with a spare. The valves are set at 13.0 barg and are connected to the amine drainage system. The filter bottoms are also connected to the amine drainage systems in addition to the open drain system.

The amine circulates from top to bottom in the activated carbon bed. Before use, the bed must be washed to remove carbon dust. This is done by backwashing with water using the 10-inch connections. The bed must be changed when it is breached, when the pressure differential reaches 1.0 bar, or as deemed necessary by the monitoring program established with the amine supplier.

In the pre-filter and post-filter, the amine flows from inside the cartridges to the outside.

There are three cartridges per filter, and they must be changed when the pressure differential reaches 1.0 bar. Three-inch manual vents and local pressure gauges are provided on each filter for production shutdowns [35].

II.15 Amine Drainage System (DC-C-28OO17):

The decarbonization Unit is equipped with a dedicated amine drainage system. The Amine Drainage Tank (G64-VD-28-03) collects all amine drains by gravity. The drained liquids are then sent to the Amine Buffer Tank by the Drainage Tank Pumps (G64-PN-28-04A/B). Before entering the tank, the amine solution passes through a mechanical cartridge filter (G64-MB-28-05). The amine level in the drainage tank is maintained by a level controller (28-LIC-106) which automatically starts or stops the Drainage Tank Pumps from the DCS. The level is measured by the 28-LIT-106, which sends a signal to the 28-LIC-106 controller, which operates intermittently. When the level reaches the low level, the controller stops the pump. Conversely, when the level reaches the high level, the controller starts the pump. If the level in the drainage tank is very low, alarm 28-LAL L-107 triggers the emergency stop system, shutting down the drainage tank pumps and the electric heater.

The electric heater is used only to pump amine from the tank during the winter, if the amine temperature is below 30°C. The temperature in the tank is measured by transmitter 28-TIT-105, which sends a signal to controller 28-TIC-105 to start the heater. Selector switch 28-HS-118 allows the operator to set the heater to manual or automatic mode. Automatic mode starts the heater automatically when the controller sends its signal. The operator uses automatic mode only when pumping amine is required. Under normal conditions, the selector is in manual mode to avoid unnecessarily heating the amine.

In automatic mode, temperature control is performed by the 28-TIC-105 controller, which operates intermittently. When the temperature is below 30°C, the heater is activated. When the temperature reaches 30°C, the controller shuts off the heater.

At very high temperatures (28-TAHH-118), the heater is automatically shut off by the emergency stop system. Nitrogen is used as a buffer gas in the amine drainage flask to prevent contact between the amine and oxygen. The flask's operating pressure is measured by the 28-PIT-145, located in the buffer gas line. The pressure transmitter signal is sent to the 28-PIC-145A and 28-PIC-145B controllers.

The 28-PIC-145A/B controllers have continuous modulation and act on the control valves 28-PV-145A and 28-PIC-145B, respectively [34].

II.16 Amine Storage (DC-C-28OO10):

The decarbonization Unit is equipped with an amine storage tank with a holding capacity equal to the volume of the entire unit. The amine buffer tank (G64-RA-28-01) is equipped with a buffer gas to prevent the amine from coming into contact with oxygen. The operating pressure of the tank is measured by the 28-PIT-048, located in the buffer gas line. The signal from the pressure transmitter is sent to the 28-PIC-048 controller. The pressure in the tank must be maintained at 15 mm H_2O. When the pressure drops below 14.5 mm H_2O, the 28-PIC-048 controller opens the 28-PV-048 control valve to admit nitrogen into the tank until the pressure reaches 14.5 mm H_2O. However, if the pressure in the tank is higher than 15.5 mm H_2O, valve 28-PCV-044 opens to vent the nitrogen and reduce the pressure to the set point. The CO_2 from the AGRU is compressed and dehydrated in the CCDU located downstream. If these CO_2 treatment units (CO_2 compressor and TEG unit) are out of service, the CO_2 from the regenerator column is sent to the CO_2 stack via control valve 28-PV-067B located downstream of the Amine Header [34].

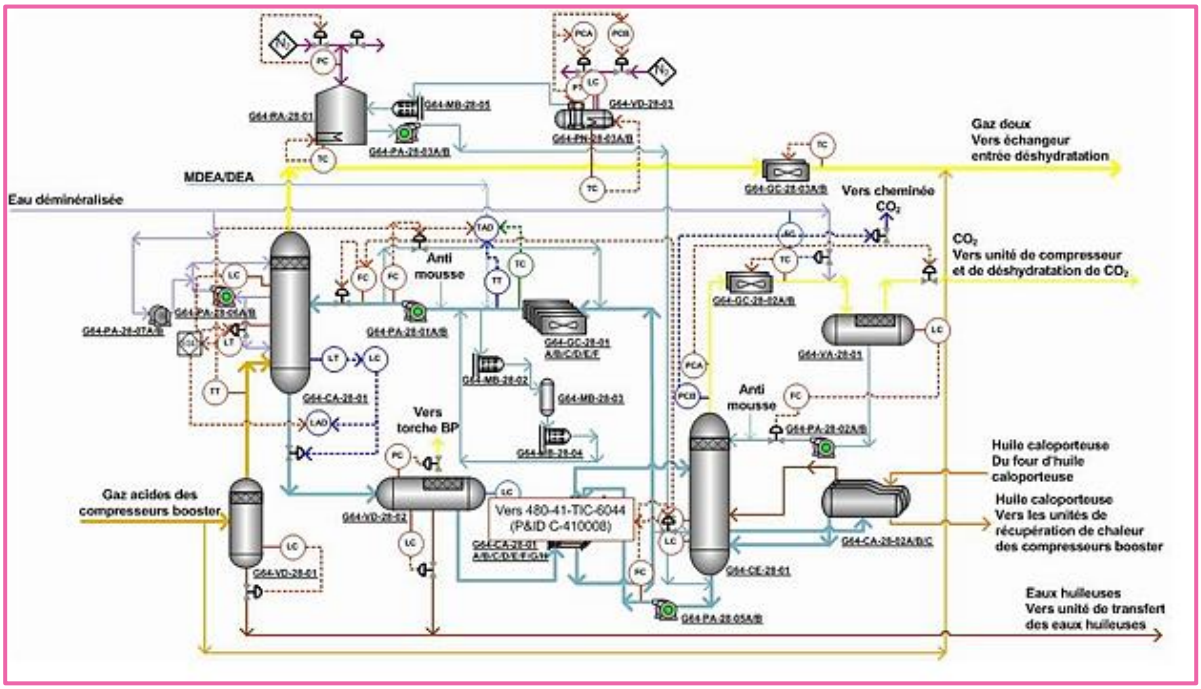


Figure II.5. *Process Flow Diagram of The AGRU Unit* **[35]**

II.17 Safety:

Every industrial activity, regardless of its size or location, is subject to a wide variety of incidents or serious situations that can seriously disrupt its operation damage it and destroy it [33].

II.17.1 **Organizational Element:**

The Safety Function (Intervention, Prevention, and Environment) is responsible for providing management with a control mechanism and the resources to support operational and management activities in a climate of stability.

Its three levels of command are functional (department head), sub-functional (service head), and section levels. Its purpose is the protection of personnel, equipment, and the environment; it assists occupational health and safety professionals and the organization in monitoring workstations and hazards.

It is subdivided into three specialized departments, each headed by a department head:

- **Prevention Department:**

The safety inspectors and engineers, each with proven experience, are responsible for inspecting facilities, issuing work permits, and monitoring work to identify and mitigate risks, depending on their assigned role.

They may also act as trainers, risk analysts, and accident cause analysts.

- This department is responsible for analysing incidents, accidents, and nuisances.
- It determines the causes and proposes solutions for elimination or reduction.
- It proposes alternatives when a risk is perceived.
- It selects individual and collective protective equipment.
- It must be responsive to everyone and everything.
- She is responsible, in conjunction with her superiors and the training department (HR), for research, including the selection of trainers, and the choice of teaching methods and resources to ensure the implementation of her training plan.

- **Intervention Service:**

Its task is to ensure continuous availability for responding to incidents or accidents.

It is composed of qualified personnel, and its mission is to:

- Intervene in the event of an accident.

- Maintain constant vigilance against fire and explosion.
- Assist hazardous work by providing the necessary safety cover.
- Ensure the preventive maintenance of protection systems and fire-fighting equipment and materials.
- Provide staff training for intervention drills.
- Establish, update, and implement intervention plans for the complex and other facilities.
- Enforce general and specific safety instructions.

- **Environmental Department:**

This specialized function, headed by an Environmental Department Manager, is typically composed of specialists in the fields of Gases, Solids, and Liquids. These three areas form the core of its organization.

The department's activities will encompass all aspects of the industrial unit, and its collaboration with government agencies may extend to Non-Governmental Organizations (NGOs).

The work of this department will primarily involve observations and analyses.

Opinions and conclusions will be communicated only to management and will be handled with the utmost discretion, in accordance with professional confidentiality [33].

II.18 Fire and Gas Safety System:

II.18.1 Fire Water System (DC-C-71OO01 to DC-C-71OO13):

Diesel fuel is required for the diesel generator (6PO-EG-84-01) and the diesel-powered fire water pumps (700-PA-71-02A/B). Diesel fuel is supplied to the storage tanks in each system by tanker trucks.

The emergency power system includes a daily diesel tank and a 400V AC, three-phase, 3W generator. The diesel storage tank capacity is sufficient for 12 hours of full operational load.

Each diesel-powered fire water pump is equipped with a daily tank (700 RX-71-01A/B) with a minimum capacity of eight (8) hours. The fire water system includes a fire water storage tank (700-RA-71-01) with a nominal capacity of 11,356 m^3 (approximately 12-hour capacity), two electric-driven main fire water pumps (700-PA-71-01A/B), two 100% diesel-powered emergency fire water pumps (700-PA-71-02A/B), and two electric-driven booster pumps

(700-PA-71-03A/B). The pumps discharge into a main fire water distribution line conforming to NFPA standards.

During normal operation, the fire water tank must be kept full under level control (71-LT-040) and connected to the utility water supply system.

The pressure in the main fire water supply line is maintained by the booster pump at a pressure of 8.6 bar or more, and the pump is started and stopped automatically by the fire and gas system, based on signals from the 71-PIT-044 A/B/C discharge manifold pressure transmitters. The main fire water pumps (electric or diesel) are automatically started by the fire and gas system. A fire water demand exceeding the capacity of the booster pump ($45.4m^3/h$) will therefore cause a pressure reduction in the main loop to the set point to start the (electric) fire water pump. Failure of the electric fire water pump start signal will automatically cause the emergency diesel fire water pump to start. The electric and diesel fire water pumps have a nominal flow rate of 908.5 m³/h at a hydraulic head of 97.6 m. The regulating pump must stop when the main fire water pump starts and when the flow rate has stabilized. All pumps are equipped with local and remote manual selectors and on/off switches for testing and maintenance. Pump tests must be performed periodically as required with the pump in "manual" mode and the discharge to the main distribution line closed. A bypass fitting upstream of the main discharge isolation valve connects to the test manifold, which recirculates to the fire water storage tank. The flow restriction and indication (71-FE-090) are provided on the test line.

The fire system is integrated with the existing system. However, the systems are normally separate, and the valve is closed. This system is not designed to operate with the valve open. SNC-Lavalin does not recommend opening the integration valve.

II.18.2 **Fire and Gas Detection:**

Note that process equipment activation is always triggered by the ESD system upon signal transmitted from F and G.

- **Decarbonization Zone G64**

A pre-alarm alerts the operator upon detection of a high gas level.

Detection of a very high gas level triggers a general alarm in the area.

No system shutdown occurs [35].

II.19 Hazard Identification of Amine Solutions:

1) Effects on the eyes:

The liquid and vapors cause severe conjunctival irritation and corneal damage.

Serious effects may occur if treatment is not initiated promptly.

2) Effects on the skin:

The liquid and aqueous solutions containing more than approximately 50% of the amine cause irritation and chemical burns, which will be severe upon prolonged contact.

3) Effects of Ingestion:

Upon ingestion, the following effects may occur: severe irritation of the mouth, throat, and digestive tract.

A large quantity may cause the following effects: severe gastrointestinal irritation. A large dose may cause the following effects: central nervous system depression, fainting, convulsions.

Based on animal studies, the following effects may be predicted: liver damage, kidney damage.

4) Effects of Inhalation:

Exposure to vapors may cause the following effects: severe irritation of the nose, throat, and respiratory tract.

Prolonged or repeated exposure will cause the following effects: breathing difficulties, bronchitis, and liver damage.

Exposure to high concentrations of vapors may cause the following effects:

- Lung swelling.
- Serious effects may appear sometime after exposure [33].

II.20 First aid:

- **Eye contact:**

Immediately and thoroughly rinse the eye with water for at least 15 minutes, keeping the eye open. Seek immediate medical attention.

- **Skin contact:**

Immediately and thoroughly wash the skin with soap and water. Remove contaminated clothing as you wash. Seek medical attention if blisters appear or if redness persists.

- **Ingestion:**

Rinse the mouth with water. Give small sips of water or milk to soothe the affected areas. Do not induce vomiting. If the victim is in shock, appropriate treatment may be necessary. If breathing is difficult, administer oxygen. If breathing stops or shows signs of failure, provide artificial respiration. If the heart has stopped beating, perform external cardiac massage. Seek immediate medical attention.

- **Inhalation:**

Remove from exposure. Keep the person warm and at rest. If breathing is difficult, administer oxygen. If breathing stops or shows signs of failure, perform artificial respiration. If the heart has stopped beating, perform external cardiac massage. Seek immediate medical attention [33].

MODELING & SIMULATION

Chapter III: Modeling and Simulation using Aspen HYSYS

III.1 Problematic:

The Rhourde-Nouss Gas Treatment Plant (GTP) was designed to process a nominal load of 10 $MMsm^3/day$ of quartzite gas, with a CO_2 content of approximately 9% molar. To this end, the plant incorporates an absorption decarbonization process that reduces the CO_2 content to 2% molar, a value that meets the specifications required for gas transport [36]. The solvent used is a mixture of MDEA/DEA amines, with a mass composition of 50% water, 48% MDEA, and 2% DEA.

The reservoir on which the plant is located is of an unconventional type, classified as tight gas [37]. After 12 years of operation, the reservoir experienced a natural decline in production, accompanied by a reduction in CO_2 content to approximately 4% molar, following connection to conventional reservoirs. The current production rate is approximately 8 $MMsm^3/day$.

Furthermore, following the COVID-19 pandemic, the decarbonization unit has been shut down since January 2020. Consequently, senior management has decided to restart this unit for both technical reasons (corrosion problems and hydrate formation at the Phase B plant) and contractual reasons, in accordance with commitments made to international partners [6].

In this context, the objective of this work is to study and optimize the operating parameters of the decarbonization unit under current operating conditions, as well as to identify potential optimization levers that can assist the operational teams and CPF management in making optimal technical decisions. The optimization efforts focused primarily on the influence of potential dilution of the amine solvent on the various components of the unit, including:

- The solvent flow rate required to achieve a CO_2 content of 2%,
- The associated energy demand,
- And the ability of the two absorption and regeneration columns to operate under optimal conditions.

To achieve these objectives, the decarbonization unit was simulated using Aspen HYSYS software. The choice of this simulation tool will be discussed in more detail in the following sections [38], [39]. The validity of the developed model was confirmed by a parallel simulation performed with Pro Max software, provided by the contractor, as well as by comparison with actual DCS data and the most recent process analyses.

Finally, a parametric study was conducted to evaluate the impact of amine dilution on the overall performance of the unit, with the aim of identifying the optimal solvent composition.

III.2 Description of the decarbonization unit:

Raw natural gas, containing approximately 8% CO_2, is supplied from the compression unit at a pressure of about 81 bar and a temperature of 55°C. Before entering the absorption column, it passes through a guard vessel to remove traces of liquids, including water, to protect downstream equipment from corrosion and operational disturbances [34], [33].

The gas is then introduced into the absorption column, where it comes into countercurrent contact with a low CO_2 amine solution injected at the top of the column. This contact allows for the absorption of the CO_2 contained in the natural gas. At the outlet of the column head, a treated gas is obtained, with its CO_2 content reduced to less than 2% (approximately 1.89%). At the bottom of the column, the CO_2 rich amine solution is recovered at a temperature of approximately 82–84°C and a pressure of approximately 82.5 bar [34], [7].

The rich amine solution, charged with acidic gases, then passes through a flash tank where the pressure is reduced to approximately 5 bar, allowing the dissolved gases to separate. It then passes through a heat exchanger to increase its temperature before being introduced at the top of the regeneration column [34].

In this column, the rich amine solution is counter-currently contacted with steam produced by the reboiler at reduced pressure. The input of thermal energy then promotes desorption reactions, releasing the acidic gases (mainly CO_2) from the amine solution. The acidic gases recovered at the condenser are then directed to the incinerator for treatment. [34]

After regeneration, the lean amine solution is cooled and then recycled to the top of the absorption column for reuse in the process.

Thus, the process relies on two main steps:

- Absorption, carried out in the absorber, which operates at high pressure and low temperature.
- Regeneration (desorption) takes place in the regenerator, which operates at low pressure and high temperature [40].

This system effectively removes CO_2 from natural gas to meet gas treatment specifications [41], A figure III.1 is shown below.

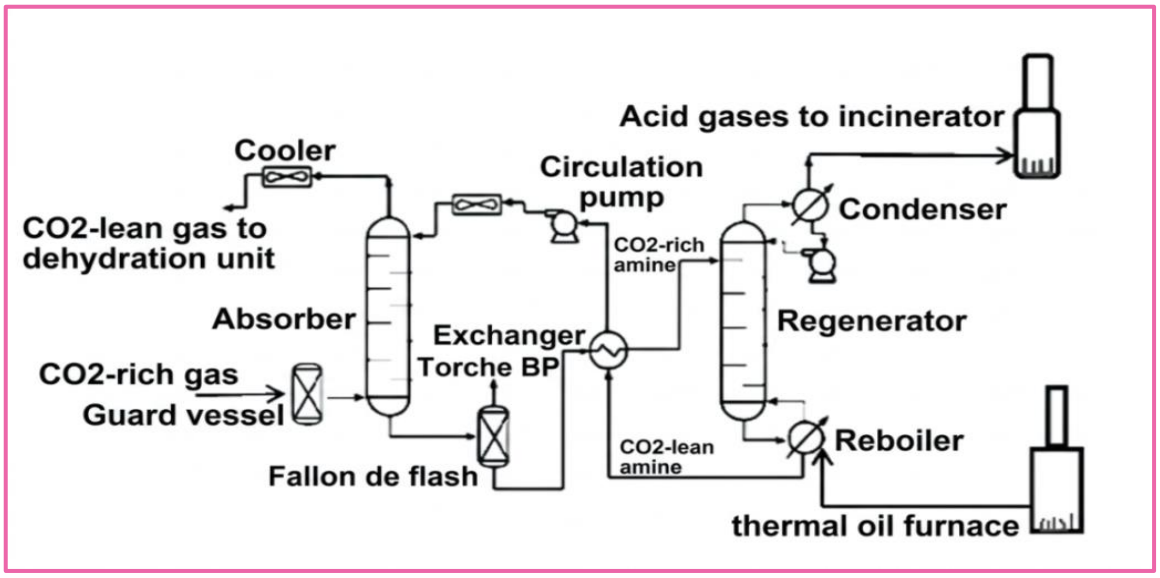


Figure III.1. *Diagram of the decarbonization unit* **[33]**

III.3 General information about simulation:

III.3.1 Definition of simulation:

Simulation can be described as the use of mathematical models to represent and predict the behavior of a physical or chemical system. It offers the possibility of analyzing the operation of a process without directly resorting to actual experimentation. One of the main advantages of simulation is that it provides a comprehensive and realistic view of the behavior of the system under study, while also facilitating process analysis and optimization [42], [43].

III.3.2 Simulation Steps:

Performing a simulation generally involves several essential steps:

- Establish a list of process components (CO_2, H_2O, amine, CH_4, C_2H_6, etc.).
- Choose the appropriate thermodynamic model (e.g., Amine Package).
- Develop the process flow diagram (PFD).
- Define the operating conditions and parameters for each flow or piece of equipment (pressure, temperature, flow rate, etc.).
- Analyze and interpret the results obtained.
- Formulate conclusions regarding the process operation [42], [43].

III.3.3 Definition of HYSYS software:

HYSYS software is a process simulator based on a set of mathematical models and correlations that allow for the representation of various unit operations such as distillation, absorption, separation, and other chemical engineering operations. It is a computer program

widely used for process simulation in the gas, refining, and petrochemical industries [44], [45].

III.3.4 **Uses of HYSYS software:**

HYSYS software is used in several areas of process engineering, including:

- Engineering studies
- Establishing mass and energy balances for industrial processes
- Equipment sizing
- Adjusting operating parameters in case of changes in feed composition
- Evaluating equipment performance
- Optimizing processing units. [45], [43].

III.4 Simulation of the decarbonization Unit:

III.4.1 **List of Components:**

The table III.1 below shows the composition of the raw gas at the inlet of the decarbonization unit. (Case design) refers to [31]:

Table III.1. Mol% Composition of the Feed Gas **[31]**

Component	Composition (% mol)
$\boldsymbol{Nitrogen\ (N_2)}$	0.5255
$\boldsymbol{Carbon\ Dioxide\ (CO_2)}$	8.5798
$\boldsymbol{Methane\ (CH_4)}$	81.3801
$\boldsymbol{Ethane\ (C_2H_6)}$	5.0603
$\boldsymbol{Propane\ (C_3H_8)}$	1.8813
$\boldsymbol{i-Butane}$	0.5896
$\boldsymbol{n-Butane}$	0.5804
$\boldsymbol{i-Pentane}$	0.3212

$n-Pentane$	0.1557
$n-Hexane$	0.2323
$n-Heptane$	0.1429
$n-Octane$	0.0493
$n-Nonane$	0.0270
$n-Decane$	0.1010
$n-C_{11}$	0.0031
$Water\ (H_2O)$	0.4360
Total	**100**

III.4.2 **Thermodynamic Model Selection:**

Thermodynamic models are necessary for calculating the physical, chemical, and energetic properties of fluids [46].

The thermodynamic model is used to calculate mixing properties (density, compressibility factor, enthalpy, etc.), as well as to calculate phase equilibrium in streams and in separation units [46].

For acid gas treatment processes using amine solutions, the "Amine pkg" model is recommended because it contains the thermodynamic formulas and correlations developed for the system properties (amine-acid gas-water) [39], [45].

III.4.3 **The Process Flow Diagram of the AGRU simulation unit:**

Figure III.2 presents the Aspen HYSYS simulation flowsheet developed for the Acid Gas Removal Unit (AGRU) using a mixed MDEA/DEA solvent system. The model represents the main process sections involved in natural gas sweetening, including gas absorption, solvent regeneration, heat recovery, pumping, and solvent recycle operations.

Acid gases are separated from natural gas in the absorption column. As with all absorption processes, this mechanism is preferred at low temperatures and high pressures. The pure gas

exits from the top of the column, while carbon dioxide, which has reacted with the amines, exits from the bottom, trapped in the amine-rich solution. The top of the absorption unit may contain a gas filtration system to prevent the entry of amines.

The regenerator operates at low pressure (near atmospheric pressure) and high temperature. A heater generates distillate vapor at the bottom of the regenerator. The quality of the diluted solvent is controlled by the flow of distillate vapor through the temperature at the top of the regenerator. The acid gas condenser produces reflux to reduce the amount of water required (the amines in aqueous solution).

The main challenges we face are corrosion, foaming, and amine degradation due to oxidation. Therefore, various preventative measures must be taken, such as the use of corrosion inhibitors, antifoaming agents, and filters to remove foreign particles.

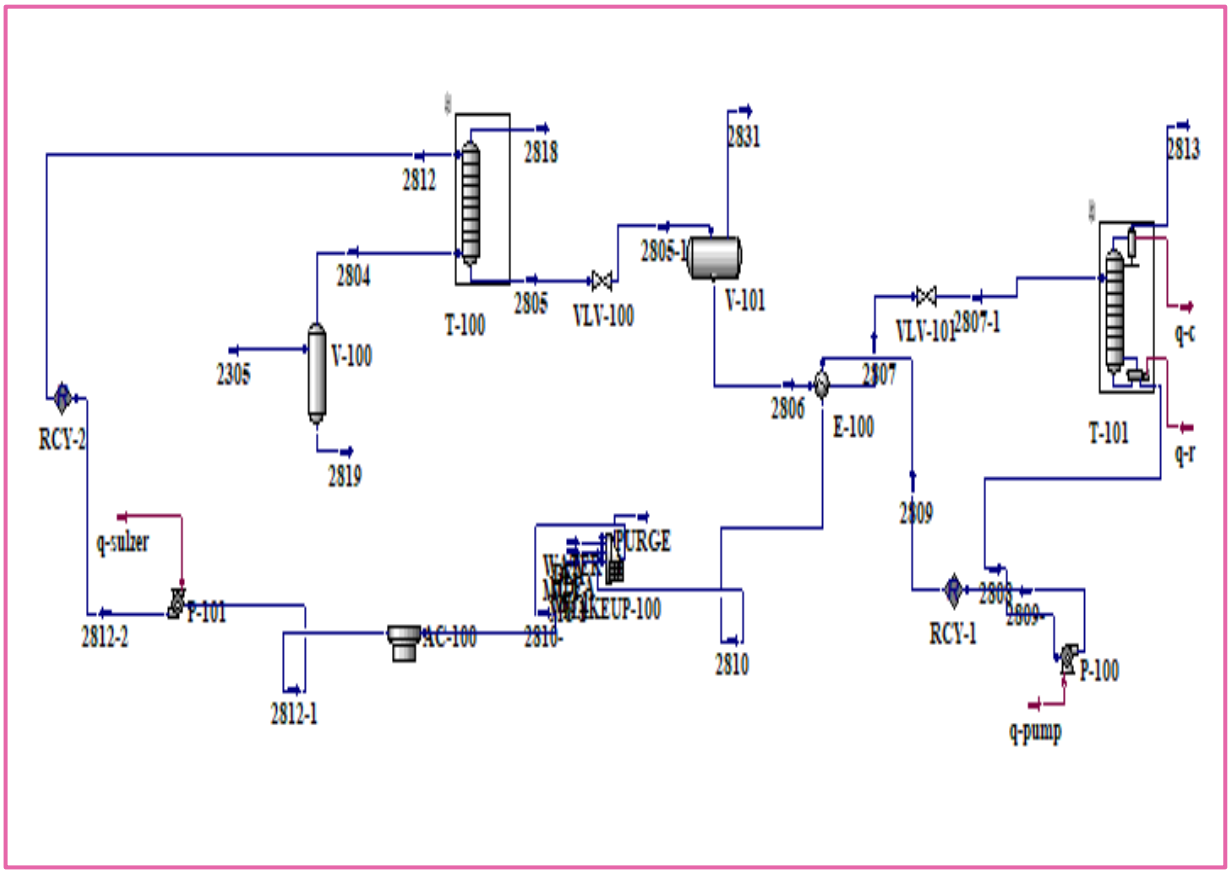


Figure III.2. *Process Flow Diagram of the AGRU Simulation Model (Screenshot)*

The sour natural gas feed enters the process via stream 2305 and is first directed to the inlet separator V-100, where entrained liquids and impurities are removed prior to treatment. The pretreated gas is then sent to the absorber column T-100, where (CO_2) is removed through contact with the lean amine solvent.

Inside absorber T-100, the lean amine enters from the top while the sour gas enters from the bottom, ensuring efficient counter-current gas–liquid contact. During this operation, CO_2 is absorbed into the amine solution, producing two outlet streams:

- **Stream 2818**: Sweet gas leaving the top of the absorber, with significantly reduced CO_2 content, representing the treated natural gas product.
- **Stream 2805**: Rich amine leaving the bottom of the absorber, loaded with absorbed acid gases.

The rich amine stream 2805 is expanded through pressure reduction valve LV-100, producing stream 2805-1, which is then sent to the flash separator V-101. In this vessel, dissolved hydrocarbons and flashed gases are removed before the solvent proceeds to the regeneration section.

The liquid rich amine then flows via stream 2806 to the heat exchanger E-100, where it is preheated through heat integration with the hot regenerated lean amine stream. This heat recovery system improves the overall thermal efficiency of the process and reduces reboiler energy requirements.

After preheating, the rich amine enters the regenerator column T-101 via stream 2807-1. In the regenerator, absorbed CO_2 is stripped from the solvent under elevated temperature conditions provided by the reboiler duty.

Two outlet streams are obtained from the regenerator:

- **Stream 2813**: Acid gas stream exiting the top of the column, mainly composed of CO_2 and water vapor.
- **Stream 2808**: Regenerated lean amine stream leaving the bottom of the column.

The regenerated lean amine stream 2808 is first pressurized by pump P-100 to restore the required circulation pressure and then recycled through RCY-1. It is subsequently routed to heat exchanger E-100, where it transfers heat to the incoming rich amine stream, resulting in cooling of the lean solvent prior to recycle to the absorber.

Before returning to absorber T-100, the lean amine passes through conditioning and makeup addition points, where water, MDEA, and DEA are added to compensate for solvent and water losses during operation (RCY-2 loop).

Additional auxiliary equipment included in the simulation model comprises:

- **V-100**: Removes liquid droplets and impurities from the sour gas feed.
- **T-100**: Absorber column for CO_2 removal via amine absorption.
- **V-101**: Separates flashed gases and entrained hydrocarbons from the rich amine stream.
- **E-100**: Recovers heat between rich and lean amine streams.
- **T-101**: Regenerator column for stripping absorbed acid gases from the solvent.
- **P-100**: Raises the pressure of the regenerated lean amine for recycle.
- **AC-100**: Provides additional cooling/conditioning of the recycle solvent stream.

Overall, the developed Aspen HYSYS model successfully represents the complete AGRU process, from sour gas treatment and CO_2 absorption to solvent regeneration and recycles. The simulation provides a reliable basis for process analysis, operational validation, and optimization of CO_2 removal efficiency, solvent circulation rate, and energy consumption.

The design and operation of absorption columns depend on several parameters such as temperature, pressure, and solvent flow rate [20].

The main challenges we face are corrosion, foaming, and amine degradation due to oxidation. Therefore, various preventative measures must be taken, such as the use of corrosion inhibitors, antifoaming agents, and filters to remove foreign particles.

III.5 Model validation (Case Design):

To validate the model developed using Aspen HYSYS, a comparison was made between the simulated results and the design data. The relative error was calculated for each parameter.

The relative error was calculated for the main operating parameters using the following equation:

$$\text{Relative Error (\%)} = \frac{\text{Simulated Value} - \text{Design Value}}{\text{Design Value}} \times 100$$

III.5.1 Validation of Main Gas Flows:

In order to evaluate the accuracy of the developed Aspen HYSYS model, the simulated results were compared with the plant design data for the main gas streams of the AGRU unit presented at the table III.2. The comparison includes the principal operating parameters such as temperature, pressure, flow rate, and gas composition.

Table III.2. Comparison Between Simulated and Plant Operating Data

Parameters	**2818**			**2813**		
	Design	Simulation	Error	Design	Simulation	Error
T (°C)	73	78,69	7,79%	89,9	91,18	1,42%
P (°Barg)	82,3	82,3	0,00%	2	2	0,00%
Flow (Kmol/h)	15797	15860	0,40%	1654	1649	-0,30%
Composition						
N_2	0,5658	0,56	-1,03%	0	0	0,00%
CO_2	1,8134	1,94	6,98%	64,7895	62,95	-2,84%
C_1	87,382	87,21	-0,20%			
C_2	5,4232	5,42	-0,06%			
C_3	2,0184	2,02	0,08%			
C_4	1,2555	1,25	-0,44%			
C_5	0,5122	0,51	-0,43%			
C_6	0,2489	0,25	0,44%			
MDEA	0	0	0,00%			
DEA	0	0	0,00%			
H_2O	0,5307	0,59	11,17%	35,1063	37,01	5,42%
Average error	1,77%			0,62%		

a) Example of Relative Error Calculation:

For the absorber outlet temperature:

- Design value = 73 °C
- Simulated value = 78.69 °C

The relative error is calculated as follows:

$$Relative\ Error\ (\%) = \frac{78{,}69-73}{73} \times 100$$

⇩

$$Relative\ Error\ (\%) = 7{,}79\ \%$$

This result indicates that the simulated temperature slightly differs from the design value. Such deviations may be attributed to thermodynamic model assumptions, vapor–liquid equilibrium approximations, and normal industrial operating fluctuations.

The table compares the simulation results with the design data for the two main streams: treated gas (2818) and acid gas (2813).

For stream 2818, the simulation results show good agreement with the design data, particularly for pressure and flow rate, with relative errors below 1%. The gas composition is also accurately represented, with methane content around 87% and a low CO_2 concentration of approximately 1.94%. However, some deviations are observed for temperature (7.79%) and water content (11.17%), which may be attributed to limitations of the model in predicting vapor–liquid equilibrium behavior and process fluctuations.

For stream 2813, the simulation results are highly accurate, with an average relative error of approximately 0.62%. The CO_2 concentration (63–65%) and water content are consistent with the expected regeneration section performance.

Overall, the obtained results demonstrate that the developed simulation model is sufficiently reliable for process analysis, performance evaluation, and optimization of the AGRU unit.

III.5.2 **Amine Circuit Validation:**

The same validation methodology was applied to the amine circuit streams to evaluate the accuracy of the developed simulation model, presented at the table III.3.

Table III.3. Validation of the Amine Circuit Simulation Model

Parameters	**2805**			**2802**			**2808**		
	Desgin	Simultation	Error %	Desgin	Simultation	Error %	Desgin	Simultation	Error %
T (°C)	80,1	77,16	-3,67	54,7	54,18	-0,95	127,7	127,7	0,00
P (°Barg)	5,8	5,8	0,00	1,7	1,8	5,88	2,3	2,3	0,00
Flow (Kmol/h)	21825	21830	0,02	1174	1135	-3,32	20554	20530	-0,12
Composition									
N_2				0	0	0,00			
CO_2	5,5516	5,32	-4,17	91,25	91,39	0,15			
MDEA	11,8963	11,89	-0,05				12,6754	12,65	-0,20
DEA	0,5618	0,56	-0,32				0,5986	0,6	0,23
H_2O	81,7389	82,07	0,41	8,6	8,55	-0,58	86,5412	86,72	0,21
Average error	-1,11%			0,20%			0,02%		

The table presents a comparison between the simulated results and the industrial design data for the main amine circuit streams (2805, 2802, and 2808).

For stream 2805, the simulation results show good agreement with the design data. The temperature, pressure, flow rate, and solvent composition are accurately predicted, with a low average relative error of approximately 1.11%. The simulated concentrations of MDEA, DEA, CO_2, and water are also consistent with the industrial operating conditions.

For stream 2802, the obtained results are highly satisfactory, with very small deviations for most operating parameters. The simulation accurately reproduces the CO_2 rich stream characteristics, particularly the CO_2 concentration (≈91%) and water content. The average relative error remains low at approximately 0.20%.

For stream 2808, an excellent agreement is observed between the simulated and design data, with negligible deviations and an average relative error close to zero (0.02%). The temperature, pressure, flow rate, and solvent composition are very well represented by the simulation model.

Overall, the low relative errors obtained for the different streams confirm the reliability and accuracy of the developed simulation model for representing the amine circulation and regeneration system of the AGRU unit.

III.5.3 **Validation of the Reboiler Heat Load:**

The energy performance of the regeneration section was evaluated through validation of the reboiler heat duty. A comparison between simulated and design values was carried out to verify the accuracy of the thermal model, presented at the table III.4.

Table III.4. Validation of Reboiler Duty

Parameters	**Q Reboiler**		
	Desgin	Simultation	Error %
Reboiler Duty (MMkcal/h)	30	27.9	-7
Average error	-7%		

The table presents a comparison between the simulated and design values of the reboiler duty for the regeneration section.

The simulation predicts a reboiler duty of 27.9 MMkcal/h compared to the design value of 30 MMkcal/h, resulting in a relative error of approximately 7%. This deviation remains acceptable considering the complexity of heat transfer phenomena and thermodynamic assumptions involved in the solvent regeneration process.

The obtained result indicates that the developed simulation model provides a satisfactory representation of the energy performance of the AGRU regeneration system and can therefore be used for optimization studies.

III.5.4 **Overall Model Validation:**

In order to evaluate the reliability and accuracy of the developed simulation model, a comparison was carried out between the simulation results obtained using Aspen HYSYS and the industrial design data provided by the CPF operating documents represented at the figure III. 3.

The main operating parameters, including temperature, pressure, flow rate, and stream composition, were analyzed and compared. This validation step is essential to assess the model's ability to accurately reproduce the real operating behavior of the decarbonization unit.

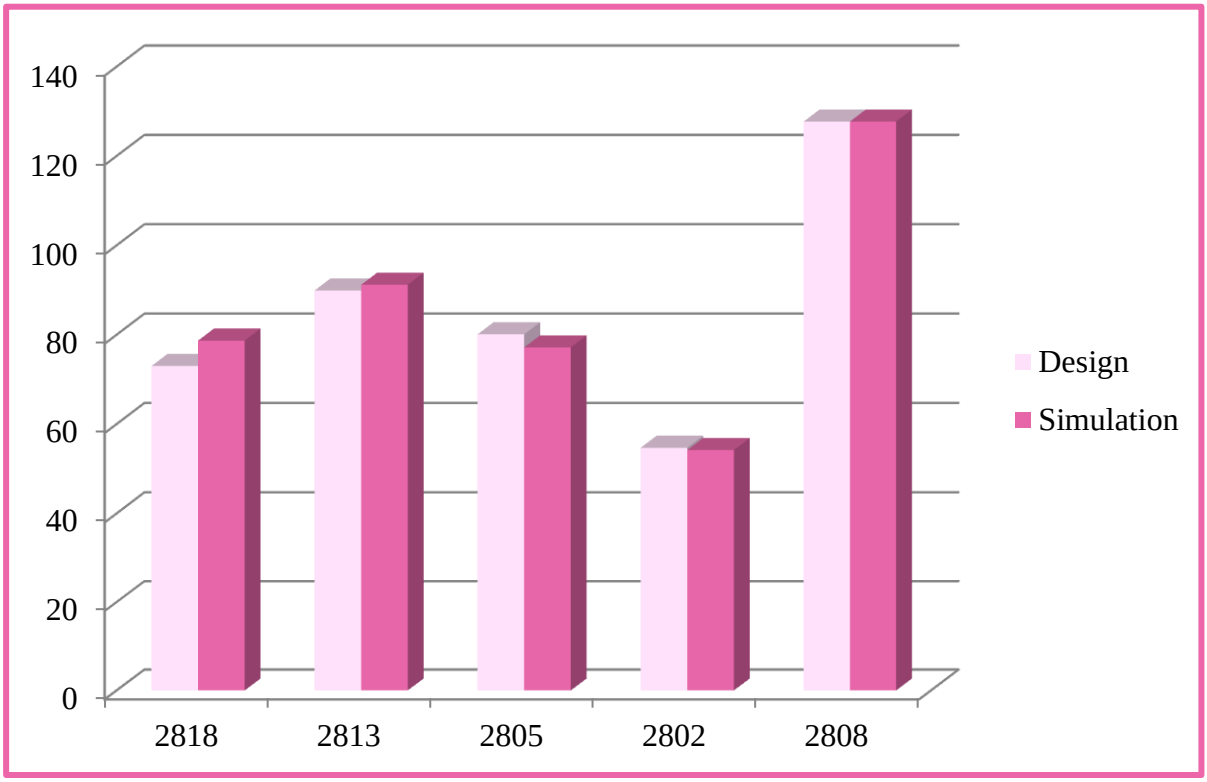


Figure III.3. *Comparison of design and simulated temperatures for selected process streams.*

The comparison shows a good agreement between simulation and design data, with relatively low deviations for most operating parameters. These results confirm the validity of the developed simulation model and its suitability for further optimization studies.

III.6 Optimization Study (Case Studies):

The validated simulation model was used to optimize the decarbonization unit. Due to reservoir depletion, the raw gas flow rate decreased from 10 $MMSm^3/D$ to 6 $MMSm^3/D$, which required redefining the operating parameters to maintain efficient CO_2 removal.

The objective of this study is to evaluate the effect of solvent composition and operating parameters on the CO_2 content and energy consumption in order to determine the optimal conditions for reducing the CO_2 content to less than 2%.

Several simulations were performed using Aspen HYSYS by varying:

- The amine composition (MDEA, DEA, and water)
- Amine flow rate
- Amine temperature.

The results were analyzed based on the outlet CO_2 concentration and reboiler heat duty to identify the optimal operating conditions with minimum energy consumption.

III.6.1 **Influence of Amine composition on CO_2 Removal Efficiency:**

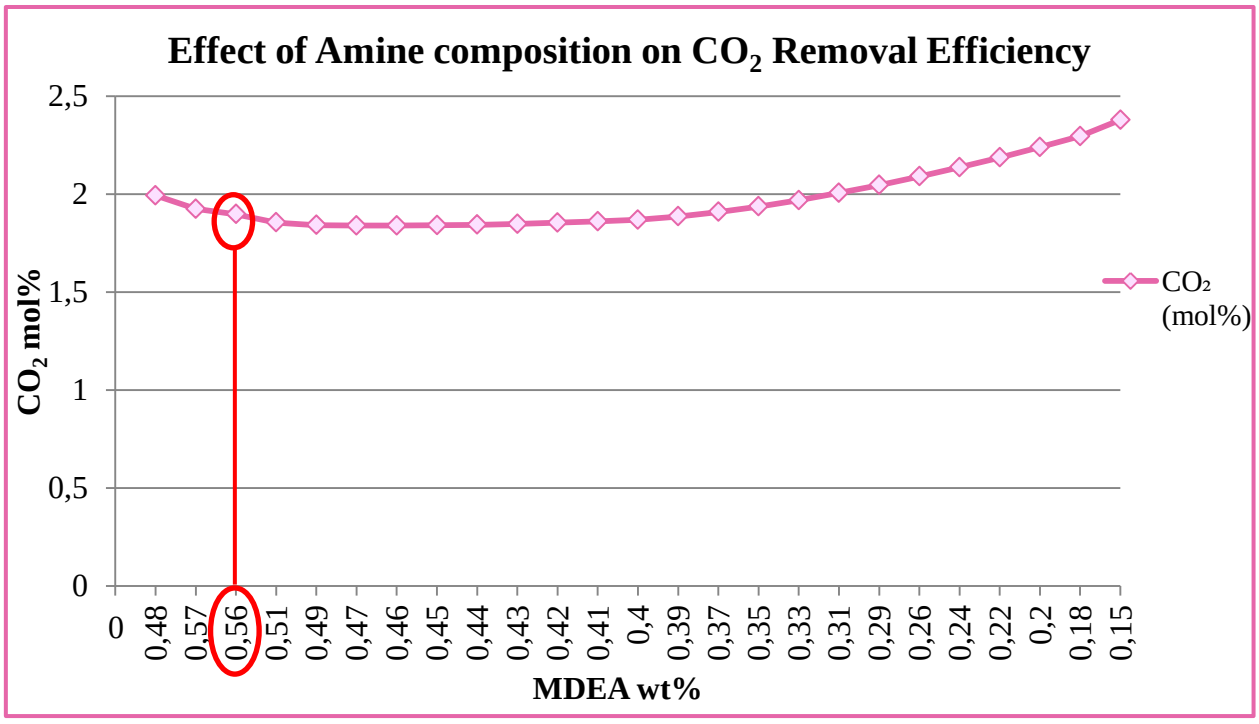


Figure III.4. *Effect of MDEA Concentration on* CO_2 *Removal Efficiency*

The results indicate that increasing MDEA concentration improves CO_2 absorption efficiency by reducing outlet CO_2 concentration. An optimal operating region is observed between 46% and 49% MDEA, where CO_2 removal performance reaches its maximum stability (see appendix page 56).

III.6.2 **Effect of water content on Reboiler Duty:**

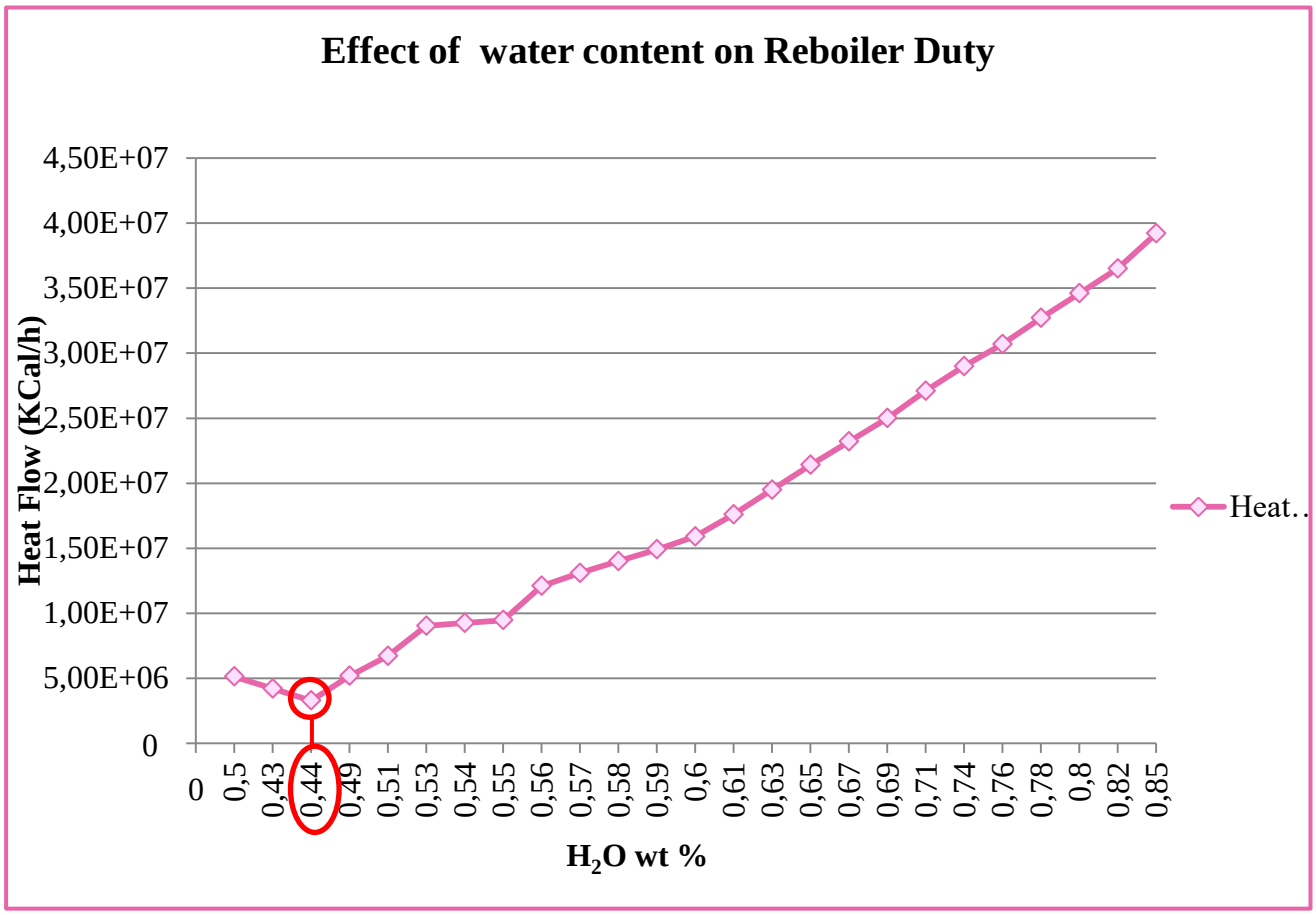


Figure III.5. *Effect of Water Content on Reboiler Duty*

The results show that increasing water concentration in the solvent significantly increases reboiler duty. Higher water content requires more energy for solvent regeneration due to its high heat capacity and vaporization requirements. Therefore, solvent composition must be carefully optimized to balance energy consumption and CO_2 removal performance (see appendix page 56).

III.6.3 **CO_2 Composition vs Reboiler Duty :**

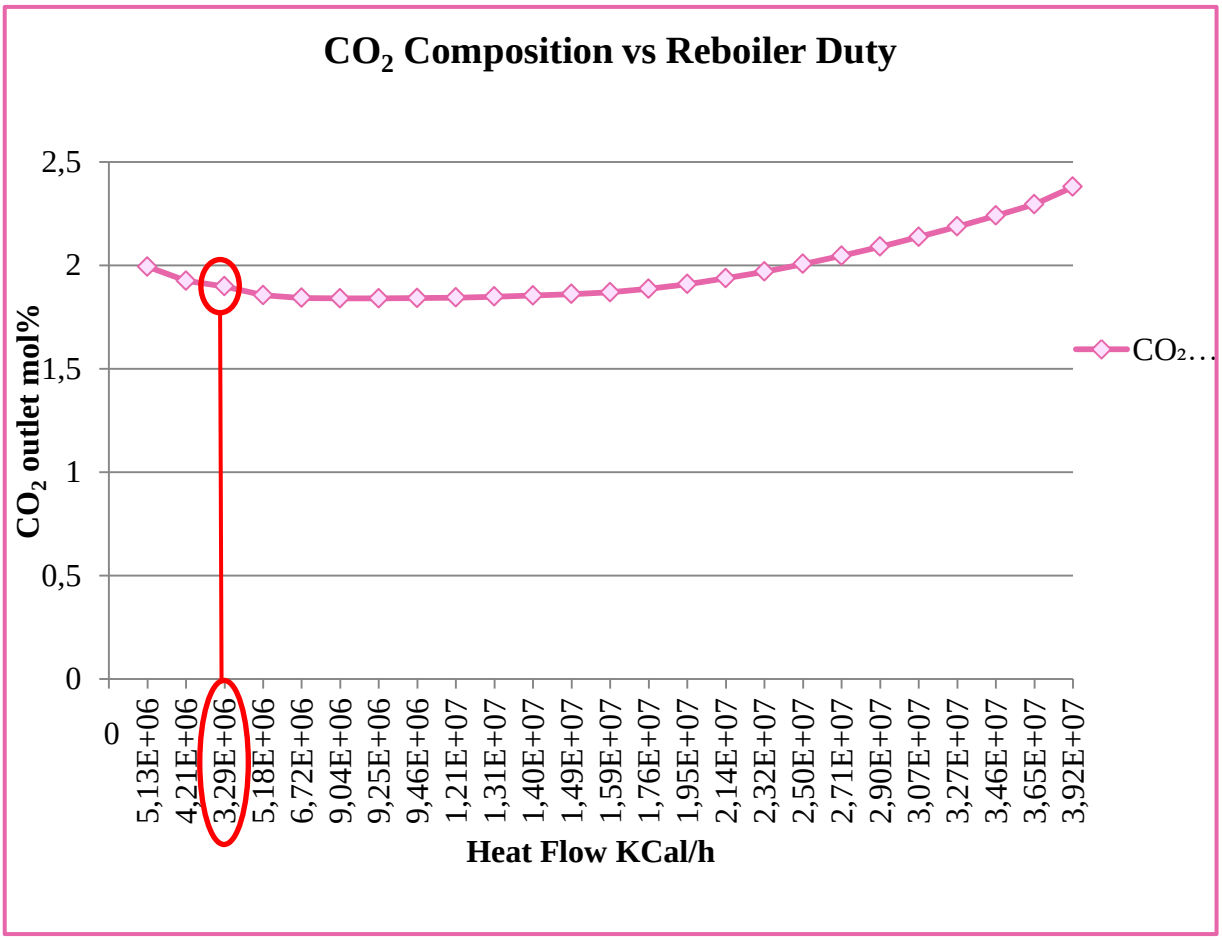


Figure III.6. *Trade-off between Energy Consumption and* CO_2 *Removal Performance*

The optimization results reveal a clear trade-off between energy consumption and separation performance. Lower outlet CO_2 concentrations are achieved within an intermediate reboiler duty range, indicating the existence of an optimal operating region balancing process efficiency and energy demand (see appendix page 56).

III.6.4 **The Hydraulic Performance of the Columns:**

To ensure that these optimal parameters can be effectively implemented in the unit, a hydraulic study of the columns is necessary. Using the “Internals” function in HYSYS, the following results were obtained presented at the table III.5:

Table III.5. Hydraulic Validation of the Absorber and Regenerator Columns

Parameters	Column Absorbor	Amine regenerator column
Flooding %	35.97%	25.74%
Max Pressure Drop	224.2 mbar	101.7 mbar
Weeping	None	None
Maximum % Downcomer Backup (Aerated) (%)	22.60%	24.72%

III.7 Results and interpretations:

After analyzing and evaluating the relative error of the model developed in this study, it was established that a simulation error of less than 1% validates the model's reliability. This level of accuracy allows its use to ensure operational continuity and to apply optimization strategies to the real-world case study.

Under the initial conditions, the optimal operating point was determined for an amine flow rate of 80,000 kg/h, with a composition of 48% MDEA, 2% DEA, and 50% water. This configuration significantly improved energy efficiency at the reboiler of the regeneration column, with an 83% reduction in energy consumption.

However, after consultation with the CPF unit managers, a shortage of DEA was reported at the Sonatrach warehouse (Rhourde Nouss) due to supply constraints related to the international market. This operational situation necessitated the search for new optimal parameters using a DEA-free (0%) amine solution.

For this purpose, the "Case Studies" function of the Aspen HYSYS software, renowned for its effectiveness in process optimization, was used. This approach enabled the determination of new optimal operating parameters, while taking into account the specific constraints of the

Rhourde Nouss site, as well as the energy and hydraulic limitations of the absorption and regeneration columns.

The interpretation of the results led to the identification of a new optimal operating point, corresponding to an amine solution composed of 56% MDEA and 44% water. This configuration allows for a reduction in energy consumption at the regeneration column of up to 89%. However, this energy saving is accompanied by an increase in operating costs, due to the higher concentration of MDEA, a significantly more expensive solvent. No hydraulic issues were observed with this new optimal operating point.

GENERAL CONCLUSION

General Conclusion

In this work, the main objective was to determine the optimal operating parameters of the decarbonization unit after a four-year shutdown caused by maintenance problems and the COVID-19 pandemic crisis.

This study aims to ensure compliance with the specifications of the gas exported from the CPF plant while addressing the problems related to the presence of CO_2 in the LPG extraction unit, particularly hydrate formation, contractual requirements between SONATRACH and its partners, as well as the significant variations in the inlet gas feed rate.

In this context, the CPF-RNS decarbonization unit was simulated using the HYSYS software. A reliable and robust model was developed, presenting a relative error of less than 1% compared with the design case.

The obtained results show that the optimal amine solvent composition consists of 48 wt% MDEA and 2 wt% DEA, with an optimal flow rate of 80,000 kg/h, allowing the desired CO_2 concentration in the treated gas to be achieved. However, due to the unavailability of DEA at the RNS regional division, an alternative case was investigated by considering a binary mixture composed only of MDEA and demineralized water.

Using the *Case Study* functionality integrated into HYSYS, the optimal amine concentrations were determined while taking into account the energy consumption at the reboiler of the amine regeneration column. The results indicate that the optimal operating point corresponds to a solution containing 56 wt% MDEA and 44 wt% water.

Despite the high concentration of MDEA, whose cost is relatively high on the international market, this configuration provides optimal energy efficiency at the reboiler level and prevents problems related to hydraulic phenomena within the absorption and amine regeneration columns.

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Appendices

State	2812-6 - Master Comp Mass Frac (DEAmine)	2812-6 - Master Comp Mass Frac (H_2O)	2812-6 - Master Comp Mass Frac (MDEAmine)	2818-2 - CO_2 Composition (mole %)	q-t02 - Heat Flow (Kcal/h)
Case 1	2%	50%	48%	1,993	5,13E+06
Case 2	0%	43%	57%	1,925	4,21E+06
Case 3	0%	44%	56%	1,898	3,29E+06
Case 4	0%	49%	51%	1,855	5,18E+06
Case 5	0%	51%	49%	1,842	6,72E+06
Case 6	0%	53%	47%	1,84	9,04E+06
Case 7	0%	54%	46%	1,84	9,25E+06
Case 8	0%	55%	45%	1,841	9,46E+06
Case 9	0%	56%	44%	1,844	1,21E+07
Case 10	0%	57%	43%	1,848	1,31E+07
Case 11	0%	58%	42%	1,854	1,40E+07
Case 12	0%	59%	41%	1,861	1,49E+07
Case 13	0%	60%	40%	1,869	1,59E+07
Case 14	0%	61%	39%	1,886	1,76E+07
Case 15	0%	63%	37%	1,909	1,95E+07
Case 16	0%	65%	35%	1,937	2,14E+07
Case 17	0%	67%	33%	1,969	2,32E+07
Case 18	0%	69%	31%	2,006	2,50E+07
Case 19	0%	71%	29%	2,046	2,71E+07
Case 20	0%	74%	26%	2,09	2,90E+07
Case 21	0%	76%	24%	2,137	3,07E+07
Case 22	0%	78%	22%	2,187	3,27E+07
Case 23	0%	80%	20%	2,24	3,46E+07
Case 24	0%	82%	18%	2,295	3,65E+07
Case 25	0%	85%	15%	2,379	3,92E+07
Maximum	2%	85%	57%	2,379	3,92E+07
Minimum	0%	43%	15%	1,84	3,29E+06