International Journal of Academic Engineering Research (IJAER)
ISSN: 2643-9085
Vol. 10 Issue 1 January - 2026, Pages: 35-43

Design Of An Absorption Column For Removal Of Carbon Iv Oxide From Natural Gas

[1]Yelebe Blessing Zekieni, Owei L. Youpele

[1,2] Department of chemical engineering
Niger Delta University, Amassoma, Bayelsa state, Nigeria.

ABSTRACT: *This study designs and simulates an absorption column for removing acid gases, primarily CO_2, from natural gas using the physical solvent Selexol (polyethylene glycol dimethyl ether). The system was modeled in Aspen HYSYS Version 10 using the Acid Gas–Physical Solvent fluid package, with a high-acid gas feed composition sourced from literature. The objective of this work is to reduce the CO_2 content of natural gas while enhancing the methane (CH_4) concentration to meet pipeline quality specifications. Key process parameters, including temperature, pressure, stream composition, and the flow rates of both liquid and gas phases, were systematically monitored and adjusted to achieve optimal separation performance. Simulation results indicate that the CO_2 concentration was reduced to 1.05%, which falls within acceptable limits for pipeline-quality natural gas.*

Keywords: *Carbon dioxide, Purification, Natural Gas, Simulation, Absorption,*

1. BACKGROUND OF STUDY

Natural gas is a flammable mixture of hydrocarbon gases found deep underground within porous rock formations. It is a fossil fuel made up mainly of hydrocarbons such as methane, ethane, propane, butane, and pentane, along with other gases including carbon dioxide, hydrogen sulfide, nitrogen, and small amounts of trace components. Among these, methane is by far the most abundant, typically making up about 75–90% of natural gas (Richard & Kaaeid, 2005).

Natural gas, a type of petroleum, is found in nature as a complex mixture of hydrocarbons with trace amounts of inorganic elements. Petroleum may come from the remains of plants and animals that once lived on ancient seabeds, according to geological and chemical research. These elements were buried beneath sedimentary layers for millions of years, during which time they progressively changed into sedimentary rocks. Bacterial activity, increased pressure, rising temperatures, natural distillation at depth, potential hydrogen contributions from deep sources, catalytic reactions, and extended geological time periods are some of the elements that drive this process (Guo & Ghalambor, 2005).

Geological traps like reservoirs, fields, or pools are frequent places to find natural gas. A naturally occurring subterranean storage system, a gas reservoir is composed of porous and permeable rocks—typically sandstone—sealed by impermeable rock layers that keep the gas from escaping. Natural gas is trapped in these reservoirs after migrating through fractures and fissures after developing beneath the surface of the Earth. A pool is one or more reservoirs inside a field, whereas a field may have one or more reservoirs connected to the same geological structure. Depending on the kind of hydrocarbons produced, wells drilled into these structures are categorized as gas, condensate, or oil wells (Guo & Ghalambor, 2005).

The composition of natural gas varies from one reservoir to another due to differences in location, depth, geological conditions, and reservoir characteristics. As a result, natural gas does not have a fixed composition and can differ significantly between sources (Faramawy et al., 2016; Shimekit & Mukhtar, 2012). Although methane remains the primary component in most cases, other inorganic gases such as nitrogen, carbon dioxide, and hydrogen sulfide are considered undesirable. These components are non-combustible and can cause corrosion and operational problems during gas production and processing.

Table I Composition of Typical Natural Gas (Guo and Ghalambor, 2005)

Compound	Mole Fraction
Methane	0.8407
Ethane	0.0586
Propane	0.0220
i-Butane	0.0035
n-Butane	0.0058
i-Pentane	0.0027
n-Pentane	0.0025
Hexane	0.0028
Heptane and Heavier	0.0076
Carbon Dioxide	0.0130
Hydrogen Sulphide	0.0345

Nitrogen	0.0345
Total	1.000

Think of natural gas as the quiet, clean-burning member of the fossil fuel family. In its raw form, it's invisible and odorless, but when ignited, it packs a serious energetic punch. It burns much cleaner than coal or oil, releasing fewer greenhouse gases for every bit of energy we get from it. While it's less dense in energy per volume than liquid fuels, it makes up for that by being rich in hydrogen, allowing it to convert fuel into usable energy more efficiently than many of its hydrocarbon cousins.

Because it is highly energy-efficient and burns more cleanly than coal and liquid fuels, natural gas is often considered a better fuel choice. As global energy needs continue to grow, the use of natural gas has also increased. By 2013, it had become the second most consumed energy source in the world, coming only after oil (Lilleng, 2016). Its ability to burn cleanly and efficiently has strengthened its role as one of the most widely used energy resources today. For these reasons, natural gas is commonly viewed as one of the safest and most flexible energy sources for everyday use (Al-Aswed, 2017).

When properly transported, stored, and used, natural gas is generally very safe. It is widely applied for heating in homes, commercial buildings, and industrial facilities, and it is also an important source of electricity and heat generation. Beyond energy production, natural gas plays a key role in the petrochemical industry, where it is used as a raw material for manufacturing products such as ethylene. In the fertilizer industry, it serves as a major input for ammonia production. Additionally, natural gas is used in the production of hydrogen, sulfur, and carbon black (Faramawy et al., 2016).

Before natural gas can reach our homes and businesses through pipelines, it needs to be cleaned up. Just like filtering water, the gas goes through a treatment process that removes water and heavier compounds, leaving behind a clean, dry fuel that's ready for safe and efficient delivery.

1.1 Statement of the problem

Natural gas extracted from both onshore and offshore sites often contains impurities and non-hydrocarbon gases that must be removed before it can be safely transported through pipelines. These non-hydrocarbon components do not burn in air and can cause serious problems if left untreated. One common impurity is hydrogen sulfide (H_2S), a highly toxic gas that is detectable even in very small concentrations by its characteristic rotten-egg smell. Natural gas that contains H_2S is referred to as "sour," while gas free of H_2S is called "sweet." When present, hydrogen sulfide can corrode pipelines and other equipment, making its removal essential before natural gas enters the distribution system.

Another common non-hydrocarbon is carbon dioxide (CO_2), a colorless and odorless gas. High concentrations of CO_2 reduce the flammability and energy value of natural gas (Hyne, 2001). Removing CO_2 is also critical because it contributes to corrosion in pipelines and has negative environmental impacts. In process engineering, the separation of CO_2 from natural gas remains a significant challenge, making purification essential to improving gas quality (Shimekit & Mukhtar, 2012).

The goal of this study is to design an absorption column to remove CO_2 from natural gas using Polyethylene Glycol Dimethyl Ether (Selexol) as the solvent. The process simulation is performed using Aspen HYSYS software, with the aim of reducing CO_2 content to meet standard pipeline specifications.

Hydrogen sulfide and carbon dioxide are often referred to as "acid gases" because they form acidic solutions when in contact with water. They have no heating value, are highly corrosive, and can cause serious environmental and operational issues. In pipelines, valves, and other equipment, the presence of these gases can lead to corrosion, failures, and even safety hazards. With the growing demand for high-quality, pipeline-grade natural gas, upgrading low-quality gas has become increasingly important (Hao et al., 2008). This study highlights the necessity of removing impurities from natural gas to protect equipment, enhance its calorific value, and ensure that it meets pipeline quality standards.

1.2 Process description

Think of the Selexol unit like a tall, busy tower where natural gas gets a deep clean. The gas, still sour and full of impurities, enters from the bottom and flows upward. At the same time, the Selexol solvent is chilled down a bit and dripped in from the very top. As they pass each other moving in opposite directions, the solvent soaks up unwanted gases like CO_2 and H_2S.

By the time the solvent reaches the bottom, it's rich with absorbed impurities, while the cleaned gas exits from the top. SELEXOL® is a specially designed physical solvent, great at pulling out CO_2 and selectively capturing smelly sulfur compounds. Unlike chemical processes (like amine treatment), this physical method really depends on pressure and temperature—it works best when the pressure is high and the temperature is low.

2. DEVELOPMENT OF MODEL EQUATIONS

2.1. Calculation for number of trays

The Kremser equation can be used for basic research, but computer models based on a tray-by-tray heat and material balance are the ideal way for final designs. Three factors are correlated by the Kremser equation:

a. The fraction ofa given gas component that is absorbed,
b. The number of theoretical plates in the column, N, and

c. The absorption factor, a (Kohl andNielsen, 1997).

The following equations for determining the number of trays are taken from Treybal (1980).

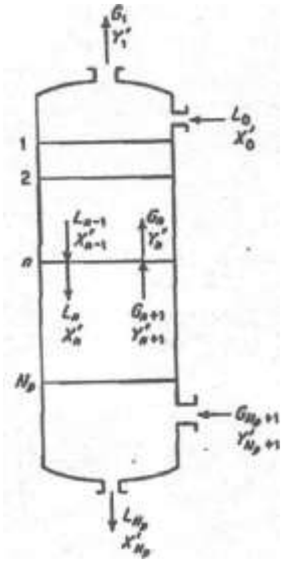

Fig 1 Schematic diagram of an absorption column (Treybal, 1980)

Consider the tower in Fig l above. A material balance for any component about equilibrium tray n is:

$$L_0(X'_n\ 'X'_{n-1}) = G_{Np+1}(Y'_{n+1}\ 'Y'_n) \quad (1)$$

Where,
L_0 $GN_p + 1$ = inlet liquid and gas flow rates (moles/time), respectively
X', Y' = mole ratio of inlet liquid and gas steams, respectively
Subscripts n, n-1, n+l, N_P, 1, 2 refer to tray numbers.
The equilibrium relation for the equilibrium tray is:

$$y_n = M_n x_n \quad (2)$$

y_n x_n = mole fraction of component in gas or liquid phase on tray n, respectively
m = equilibrium constant
The ratio y/x at equilibrium is usually written as K, but here we use m to distinguish it from mass transfer coefficients.
In terms of new concentrations,

$$Y'_{n-1}\frac{GN-1}{Gn} = m_n X'_n \frac{L0}{Ln} \quad (3)$$

Similarly for tray n – 1,

$$Y'_{n-1}\frac{GNp+1}{Gn-1} = m_{n-1} X'_{n-1} \frac{L0}{Ln-1} \quad (4)$$

Solving equation (3) and (4) for the X's substituting into eqn. (1), and rearranging, we have:

$$Y'_n\frac{Y'2+A}{Gn} = m_n X'_n \frac{L_0}{L_n} \quad (5)$$

Similarly, for tray n – 1,

$$Y'_{n-1}\frac{GNp+1}{G_n-1} = m_{n-1} X'_{n-1} \frac{L_0}{L_n-1} \qquad {}_1\frac{Y'2+A}{Gn} = m_n X'_n \frac{L_0}{L_n}$$

Where $A_n = \frac{L_n}{m_n - G_n}$ and $A_{n-1} = \frac{L_{n-1}}{m_{n-1} - G_{n-1}}$ are the component absorption factors on two trays.
If the absorbed contained only on one tray (n=1), equation. (6) would read

$$Y'_1 = \frac{Y'_2 + A_0 Y'_0}{1+An} \quad (6)$$

From eqn. (3.4)

$$Y'_0 = m_n X'_{0-1} \frac{L_0 \quad G_0}{L_o - GNp+1} = \frac{m_0 X'0G0}{GNp+1} \quad (7)$$

$$\text{And, } A_0 Y'_0 = \frac{L_0 \quad G_0}{m_{oG0} \quad GNp+1} = \frac{L_0 X'0}{GNp-1} \quad (8)$$

Substituting this into eqn. (6) gives

$$Y'_1 = \frac{Y'_2 L_0 X'/GNp-}{1+A1} \qquad (9)$$

If the absorbed contained two trays, eqn. (6) with n = 2 would become

$$Y'_2 = \frac{Y'_3 + A_1 Y'1}{1+A2} \qquad (10)$$

Substituting Y'_1 from eqn. (9) and rearranging gives

$$Y'_2 = \frac{(A_1 + 1)\, Y'_3 + \frac{A_1 L_0 X'_0}{G_{Np+1}}}{A_1 A_2 + A_2 + 1} \qquad (11)$$

Similarly, for three stage absorber,

$$Y'_3 = \frac{(A_1 A_2 + A_2 + 1)\, Y'_4 + \frac{A_1 A_2 L_0 X'_0}{G_{Np+1}}}{A_1 A_2 A_3 + A_2 A_3 + A_3 + 1} \qquad (12)$$

For Np trays,

$$Y'_{Np} = \frac{(A_1 A_2 A_3 \ldots A_{Np-1} + A_2 A_3 \ldots A_{Np-1} + \cdots + A_{Np-1} + 1)\, XY'_{Np+1} + \frac{A_1 A_2 \ldots A_{NP-1} L_0 X'_0}{G_{Np+1}}}{A_1 A_2 A_3 \ldots A_{Np} + A_2 A_3 \ldots A_{Np} + \cdots A_{Np-1} + 1} \qquad (13)$$

To eliminate Y'_{Np}, which is inside the absorber, a component material balance of the entire column is taken:

$$L_0 (X'_{Np} - X'_0) = G_{Np+1} (Y'_{Np+1} - Y'_1) \qquad (14)$$

And eqn. (3) for n $=N_p$,

$$Y'_{Np} = m_{Np} X'_{Np} \frac{L_0}{L_{Np}} \frac{G_{Np}}{G_{Np+1}} = \frac{L_0 X'_{Np}}{A_{Np} G_{Np+1}} \qquad (15)$$

Are solve to eliminate X'_{Np}, thus;

$$\frac{Y'_{Np+1} - Y'_1}{Y'_{Np+1}} = \frac{\frac{A_1 A_2 A_3 \ldots A_{Np} + A_2 A_3 \ldots A_{Np} + \cdots A_{Np}}{A_1 A_2 A_3 \ldots A_{Np} + A_2 A_3 \ldots A_{Np} + \cdots A_{Np+1}}}{\frac{L_0 X'_0 \;\; A_2 A_3 A_4 \ldots A_{Np} + A_3 A_4 \ldots A_{Np} + \cdots A_{Np+1}}{G_{Np+1} Y'_{Np+1} A_1 A_2 A_3 \ldots A_{Np} + A_2 A_3 \ldots A_{Np} + \cdots A_{Np+1}}} \qquad (16)$$

Equation (16) represents the fractional absorption of a component, derived from material balance and equilibrium relationships, which define the behavior of an ideal tray. To apply Equation (16), the liquid-to-gas (L/G) ratio and the temperature of each tray are needed to calculate the absorption factor,

A. It is important to note that these equations are applicable only to ideal solutions. The gas flow rate, $G\,n$ for tray n in an absorber can be estimated under the assumption that the fractional absorption is the same across all trays:

$$\frac{G_n}{G_{n+1}} \approx \left(\frac{G_1}{G_{Np+1}}\right)^{1/\mathrm{Np}} \qquad (17)$$

The temperature rise upon absorption is approximately proportional to the amount of absorption if all components have similar molar latent heats and heat capacities and no heat of solution is evolved.

$$G_n \approx G_{n+1} \left(\frac{G_1}{G_{Np+1}}\right)^{(\mathrm{Np}+1-\mathrm{n})/\mathrm{Np}} \qquad (18)$$

$$\frac{G_{Np+1} - G_{Np+1}}{G_{Np+1} - G_1} \approx \frac{t_{Np} - t_n}{t_{Np} - t_0}$$

Edmister has simplified computations in terms of effective absorption factors (AE) for each tray. Therefore, eqn. (16)

$$\frac{Y'_{Np+1} - Y'_1}{Y'_{Np+1}} = \left(1 - \frac{L_0 X'_0}{A' G_{Np+1} Y'_{Np+1}}\right) \frac{A_E^{Np+1} - AE}{A_E^{Np+1} - 1} \qquad (19)$$

If $X'_0 = 0$, eqn. (20) is the Kremser equation.

$$A' = \frac{A'_{Np}(A_{1-1})}{A_{Np+1}}$$

$$A_E = [A'_{Np}(A'_1 + 1) + 0.25]^{0.5} - 0.5$$

Equations (17) to (22) apply for any number of trays provided unusual temperatures do not develop.

According to Treybal (1980), the above procedures are very tedious, and the use of highspeed computers will help ease the tediousness.

2.2 Design procedure

Today, computer-aided process simulation is widely recognized as an essential tool in the process industries. Simulation software plays a critical role in various aspects of process engineering, including process development—where it is used to evaluate alternatives, assess feasibility, estimate preliminary economics, and interpret pilot-plant data; process design—where it helps optimize flow sheets and equipment, estimate costs, and assess feedstock flexibility; and plant operation—where it supports efforts to reduce energy consumption, increase yield, and improve pollution control.

In this work, the simulation of a SELEXOL solvent-based CO_2 removal absorber is carried out using the HYSYS process simulator to determine the optimum operating conditions that will enhance the process's environmental performance. The absorber design is therefore performed in Aspen HYSYS, which is among the most widely used process simulation programs worldwide (Ebenezer, 2005).

Within Aspen HYSYS, the gas-liquid equilibrium for a given component is typically calculated using K-values, which are defined by the following equation:

$K_i = Y_i/X_i$

where Yi and Xi are the mole fractions of (i) in the gas and liquid phase. (Oi L. E. 2007).

Aspen HYSYS is a simulation program that uses equations. Simulation programs based on equations can compute out-streams based on in-streams. We calculate the height, column diameter, and other parameters needed for the necessary separation using the process simulation (Munro et al., 2003).

2.3 Gas Composition Data

To model our process, we used a representative gas composition sourced from published data on a standard Nigerian gas field.

Table 2: Gas composition data (Enyi and Appah, 2005

Component	**Composition**
Methane	88.1
Ethane	6.3
Propane	2.1
Butanes	0.3
Pentanes	1.1
Carbon dioxide	2.1
Total	**100.0**

2.4 Parameters for Column Simulation (Sinnott, 2005)

Feed gas:

Temperature:	100C
Pressure:	40 atm
Molar flow rate:	2000kgmole/hr

Selexol (Absorbent):

Temperature:	25 oc
Pressure:	40 atm
Molar flow rate:	1000kgmole/hr
Fluid package:	Acid gas -Physical Solvent package
Tray type:	Valve tray

3 RESULT AND DISCUSSIONS

The results obtained from the simulation of an Absorption column using Aspen HYSYS V10 is presented.

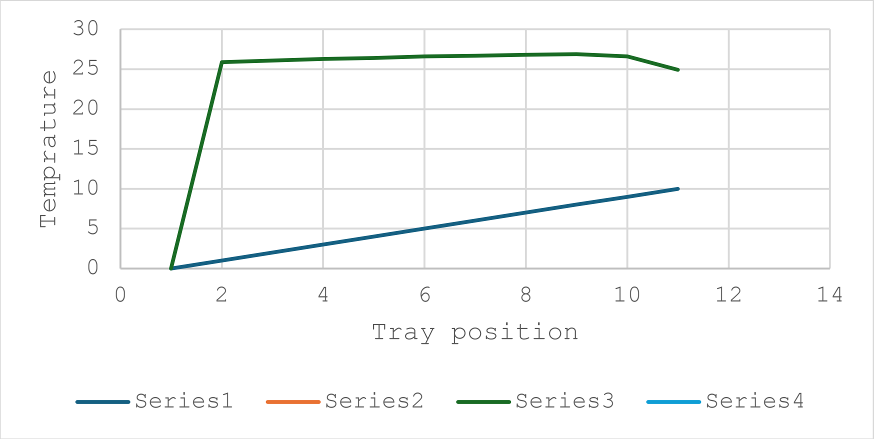

Fig. 2 Temperature Vs Tray Position

Figure 2 presents the relationship between temperature and tray position in the absorption column. Absorption columns generally perform most efficiently at low temperatures and high pressures (Ebenezer, 2005). Introducing the feed at a lower temperature is important to ensure effective separation. In this study, the column operates within a temperature range of 24–27 °C.

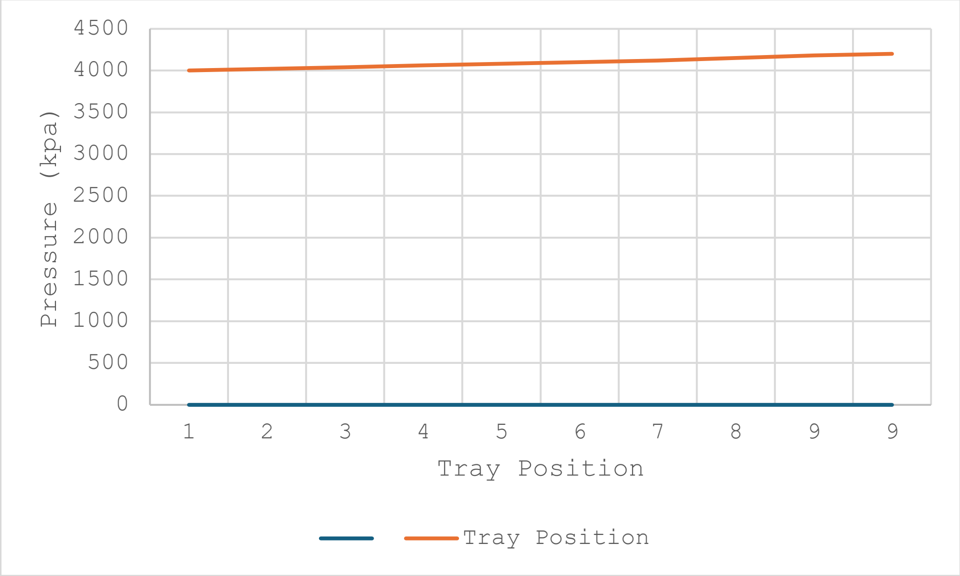

Fig. 3: Pressure Vs Tray Position

Figure 3 shows how pressure changes with each tray in the column. To keep the process steady, we maintained a constant pressure throughout. This is crucial for the design because pressure has a major impact on performance. That's why we chose a high operating pressure of 4053 kPa, it's the key to effectively purifying the natural gas in this setup.

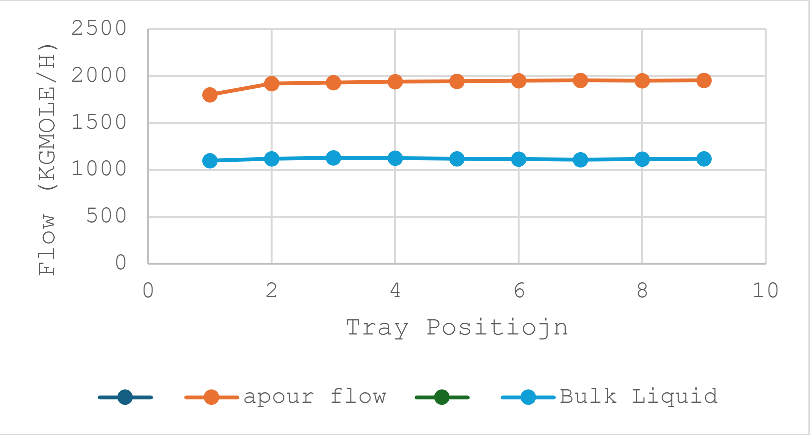

Fig. 4: Flow Vs Tray Position

Figure 4 illustrates the relationship between flow rate and liquid in the column. The figure shows the flow rates of both gas and liquid, which remain relatively constant throughout the column. This consistency promotes laminar flow conditions, contributing to the efficient operation of the absorber.

Table 4: Inlet and Outlet compositions Feed as and Selexol

Compositions mole fraction				
	Inlet ʒas (Feed	Inlet liquid Selexol	Outlet gas n as	Outlet liquid •ch selexol
Methane	0.8810	0.0000	0.9292	0.0777
Ethane	0.0630	0.0000	0.0502	0.0298
Pro ane	0.0210	0.0000	0.0100	0.0199
n-Butane	0.0030	0.0000	0.0002	0.0047
n-Pentane	0.0110	0.0000	0.0000	0.0183
C02	0.0210	0.0000	0.0105	0.0193
DEPG	0.0000	1.0000	0.0000	0.8303
	0.0000	0.0000	0.0000	0.0000
H20	0.0000	0.0000	0.0000	0.0000

As you can see from the results, the CO_2 was successfully reduced to just 1.05%, which lands well within the standard pipeline specification of 2% or less.
Now, about the setup: we actually added some water and H_2S to the inlet gas on purpose. Why? Because the specific simulation tool we're using, the Acid Gas–Physical Solvent Package is designed to remove both of those at the same time.
Also, you'll notice hydrocarbons getting absorbed into the Selexol solvent on its way out — that's the "rich" liquid stream. And as you might expect, when we increase the solvent flow rate, we also pick up more hydrocarbons along the way.

Table 5: Conditions of liquid and gas streams

Name	**Selexol**	**Feed gas**	**Lean gas**	**Rich selexol**
Vapour	0.0000	1.0000	1.0000	0.0000
Temperature CC)	25.00	10.00	25.93	24.89
Pressure (kPa)	4053	4053	4053	4053
Molar flow (kgmole/h)	1000	2000	1796	1204

Mass flow (kg/h)	2.800+005	3.769+004	3.111+004	2.866+005
Std Ideal liq vol flow (m3/h)	266.5	114.1	99.60	281.0
Molar enthalpy (kJ/kgmole)	-9.671+004	-8.495+004	-7.937+004	-1.030+005
Molar entropy (kJ/kgmole-C)	-211.6	-124.6	-116.1	-208.1
Heat flow (kJ/h)	-9.671+007	-1.699+008	-1.425+008	-1.241+008

Once the composition, temperature, pressure, and flow rates of the liquid and gas streams are specified, Aspen HYSYS, equipped with a wide range of equations and solution methods, calculates the remaining parameters, including mass flow, standard ideal liquid flow, molar enthalpy, molar entropy, and heat flow.

Table 6: Column Desi Results

Number of stages	10
Total Height [m]	9.000
Total Head Loss [mm]	2449
Total Pressure Drop [mbar]	247.3
Number of Sections	1
Number of Diameters	1

The column contains 10 trays (Valve trays) and a total height of 9meters

4 CONCLUSIONS

Absorption plays a central role in natural gas treatment, especially for removing acid gases in the gas sweetening process. During absorption, impurities such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), and other acid gases are separated from the natural gas stream, ensuring higher gas quality.

Gas absorption has been used for decades to separate valuable components from unwanted ones. Since its introduction in the early 1920s, the methods for modeling and calculating absorption processes have continuously improved, allowing engineers to better describe, optimize, and predict system performance. Today, absorption is a vital part of natural gas processing plants, helping to remove impurities and ensure that gas streams meet pipeline and industrial standards.

Simulation results show that the solvent flow rate has a strong influence on purification efficiency. Choosing the right solvent is critical to achieve the desired level of contaminant removal. Increasing the liquid flow rate generally improves purification, but it can also lead to excessive weeping in the column. To prevent this, the gas flow rate must be carefully controlled. Furthermore, the composition, temperature, and pressure of both the gas and liquid streams significantly affect the rate and efficiency of the absorption process.

5. REFERENCES

Al-Aswed» A, A. (2017). Natural Gas Dehydration Process by Mono and Tri-EthyleneGlycol.

Al-Juaied, M. A. (2004). Carbon dioxide removal from natural gas by membranes in the presence of heavy hydrocarbons and by Aqueous Diglycolamine/Morpholine, PhD thesis, pp. 1-424, The University of Texas at Austin, Texas.

Baker R. W. (2004). Membrane Technology and Applications (2nd edition), John Wiley & sons, ISBN 0-470-85445-6, West Sussex.

Ebenezer S. A. (2005): Removal of carbon dioxide from natural gas for LNG production

Economides M. J. and Wood D. A. (2009). The state of natural gas. Joumal of Natural Gas Science and Engineering, Vol. l, No. 1-2.

Enyi C., and Appah D, (2005): Economics of conditioning Nigerian Natural gas for Market", SPE Paper 08799, 2005.

Faramawy Zaki, T., Sakr A. E. (2016). Natural gas origin, composition, and processing: A review.

Guo B.,and Ghalambor A. (2005). Natural Gas Engineering Hand book.

Hyne N. J. (2001). Non-technical guide to petroleum geology, exploration, drilling and production.

Hao J., Rice P. A. and Stern S. A. (2008). "Membrane processes for the removal of acid gases from natural gas. Il. Effects of operating conditions, economic parameters, . and membrane properties".

Lilleng, M. I. (2016): Simulation of combined Hydrate Control and H_2S Removal Using Aspen Plus.

Oi L. E. (2007): Aspen HYSYS Simulation of CO2 Removal by Amine Absorption from a Gas Based Power Plant.

Pascoli, S. D., Femia A., et al. (2001). Natural gas, cars and the environment. A (relatively) 'clean' and cheap fuel looking for users. Ecological Economics, Vol. 38, No. 2, pp. 179-189.

Sinnott R. K. (2005). Coulson & Richardson's Chemical Engineering: Chemical Engineering Design (vol. Butterworth-Heinemann, edition.

Richard W. Baker and KaaeidLokhandwala (2005). "Natural gas processing with membranes: an overview," Industrial Engineering Chemistry Research, Vol. 4, Nov 2008, pp. 2109-2021..

Shimekit, B., and Mukhtar, 1--1. (2012). Natural Gas Purification Technologies-Major Advances forC02 Separation and Future Directions.

Treybal, R. E. (1980): Mass-Transfer Operations, 3rd ed., McGraw-Hill, New York,