Proceedings of the 3rd International Conference on Chemical Engineering (ICCE2021), Mehran University of Engineering and Technology, Jamshoro, September 22-23, 2021, 40-50

Sweetening of Natural Gas by Optimizing Feed Parameters (Feed Flow Rate, Feed Temperature and Feed Pressure) through Simulation

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ABSTRACT

A large part of the world's natural gas resources has a high content of CO_2 and H_2S. CO_2 has to be removed from natural gas because of transport requirements and sale gas specifications. Natural gas is usually considered acidic if CO_2 content is more than 3 PPM of natural gas (Quality standard limit). To overcome the problem, most industries use aqueous alkanolamine solutions to get rid of acid gases from natural gas. There have been sincere efforts taken to minimize acid gas emissions by controlling parameters optimally to control acid gas percentage in sour gas as per standard requirement. The same sort of problem persisted over the years for the uncontrolled amount of acid gases at the KPD plant (OGDCL PLANT); resulting in lower feed flow, causing economic regressions in the company. In this research, MDEA as a solvent is used to absorb CO_2 from the natural gas of OGDCL KPD Plant by carrying out modeling and simulation of the Acid Gas Removal process to limit the acidity of gas through ASPEN HYSYS. Different parameters including feed flow, feed pressure, and feed temperature is adjusted to find the optimized conditions. Optimized conditions such as feed temperature 29 ºC, feed pressure 1200 psia can bring CO_2 value below the standard amount and can allow feed flow to be increased to the full capacity of the plant that is 250 MMSCFD limit within the prescribed limit of SSGCL. Finally, economic evaluation and energetically efficient operating conditions of the entire model were carried out via in-built features of Aspen HYSYS.

Keywords:

Gas sweeting
MDEA Solvent
Economic Analysis
Process Simulation
Aspen HYSYS

1. Introduction

A large part of the world's natural gas resources has high content of CO_2 and H_2S. Natural gas is usually considered sour if the hydrogen sulfide content is more 4 ppm by volume and CO_2 by 3 ppm by volume. Aqueous alkanolamine solutions are the most widely used solvent in industry to absorb acid gases from natural gas. The share of natural gas in the world energy panorama has been appreciably growing for the last years. The trend is expected to be increased in the next few decades with the replacement of fuel oil and coal by the comparatively environment-friendly source of energy. However, this development will depend on the progress of gas processing technologies to give access to reserves now not exploitable. Processes that remove hydrogen sulfide and/or mercaptans (generally acid gases) are commonly referred as sweetening processes because they result in products that no longer have acid gases [1].

Although all sour gas sweetening intake the amine absorption process, it is also possible to use solid desiccants like iron sponge to remove hydrogen sulphide and carbon dioxide [2]. Acid gas removal processes are fundamentally of two types which are adsorption and absorption. Absorption varies from adsorption in that it is not a physical-chemical surface phenomenon. Absorption is achieved by dissolution (a physical phenomenon) or by reaction (a chemical phenomenon) [3]. Process for acid gas removal is selected on the basis of well head composition and parameters. Today, computer-assisted process simulation is almost universally recognized as an essential tool in the process industries. Simulation software plays a key role in studying the alternatives to the process development process. It helps in process design to optimize hardware and flow sheets, estimate equipment, operating cost, investigate feedstock flexibility, and plant operation to reduce energy use, increase yield and improve pollution control [4].

1.1. Why is it mandatory to remove acid gases?

Acid gas causes significant damage to the gas pipeline from which it operates and the equipment it operates. Not only can it cause extensive corrosion and rust, it can significantly reduce the lifespan of both pipelines and equipment. It costs the companies in question millions of pounds in repairs and replacements In addition to their corrosive nature, acid gases can cause serious health complications in humans. Prolonged exposure to acid gases can bring about severe illness or exacerbate existing conditions, even causing death in the most extreme situations. Finally, the presence of acid gases in the atmosphere can cause irreparable damage to the environment, manifesting itself in phenomena such as acid rain and global warming. (Envirotech.com).

1.2. Acid gas Removal Techniques

There are two widely used techniques for acid gas removal known as Amine method and Membrane technology. Amine method Amine-based solvents are an effective method for processing acid gas. It refers to a group of processes that use aqueous solutions of various alkylamines (commonly referred to simply as amines) to remove hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from gases. It is a common unit process used in refineries, and is also used in petrochemical plants, natural gas processing plants and other industries [5].

While membrane technology is preferred in case of carbon dioxide rich gas, meeting product specifications requests a particularly efficient method of removing carbon dioxide. In collaboration with Air Liquid Advanced Separations/Porogen, Air Liquide Engineering & Construction offers hollow fiber membrane technology for selective permeation of carbon dioxide while minimizing hydrocarbon losses. This technology combines high permeability with high hydrocarbon resistance, making it an attractive option for bulk carbon dioxide removal [6].

In present proposed research, modeling and simulation of bubble cap absorption column for the removal of Acid Gas from raw stream using MDEA absorbent is conducted theoretically using ASPEN VERSION10 software. Industrial data was collected from OGDCL field. The data was then processed and run on the simulation model initializing steady state simulation. Parameters were adjusted to get the reduced acid gas percentage from gas stream and eventually an optimized process.

2. Methodology

A simulation of a system is the operation of a model, which is a representation of that system. The model is amenable to manipulation which would be impossible, too expensive, or too impractical to perform on the system which it portrays. Modeling and simulation are the modern tools to conduct the several scientific and engineering. The present study was conducted through the simulation of acid gas removal process on Aspen HYSYS®10.

2.1. Data collection

Acid gas removal process simulation requires following input data:

- Natural gas flow rate and its composition
- Feed Gas Pressure
- Inlet temperature of natural gas

Industrial data was collected from OGDCL's plant KPD Tandojam.

2.2. Process Modelling

In Aspen HYSYS software, components are first selected as per the feed composition. The fig. 01 shows the component selection tab where components of the choice are incorporated before moving towards simulation environment for process modelling. The details of components are and base conditions of feed streams given in table 01 and table 02.

Moreover, when components are selected, the next step is to enter the simulation environment where simulation bar and items are mentioned for difference process purposes. Also, simulation environment is a screen portion where process modelling is carried out that is shown in fig. 02.

Table 01: Feed compositions from OGDCL KPD-Plant (8)

Components	**Composition**
C1	0.8539
C2	0.0136
C3	0.0055
i-C4	0.0016
n-C4	0.0013
i-C5	0.0005
n-C5	0.0003
Nitrogen	0.0749
H_2S	0.000
CO_2	0.046

Table 02: Base conditions for feed stream

PARAMETER	**VALUE**
Molar Flow Rate (MMSCFD)	120
Temperature (ºF)	95
Pressure (Psig)	1014
Gas Composition	Kunar Pasaki Deep Gas Field OGDCL

2.3. Development of Model in Aspen HYSYS®10

Aspen HYSYS, a powerful engineering simulation tool, has been uniquely created with respect to the program architecture, interface design, engineering capabilities and interactive operations. The integrated steady state and dynamic modeling capabilities, where the same model can be evaluated from either perspective with full sharing of process information, represent a significant advancement in the engineering software industry. Aspen HYSYS serves as the engineering platform for modeling processes from Upstream, through Gas Processing and Cryogenic facilities, to Refining and Chemicals processes [7].

In present work an acid gas removal process model was developed using Aspen HYSSYS®10 for Kunnar Pasaki Deep (KPD), OGDCL, Tandojam (Capacity 250 MMSCFD). Also investigation of effects of different operating parameters (Feed Flow rate, Feed Temperature and Feed Pressure) for process optimization was carried out. The Peng-Robinson equation of state was used, as it is the recommended thermodynamic property package for hydrocarbon systems [1].

$$p = \frac{RT}{v-b} - \frac{a}{v(v+b)+b(v-b)} \tag{1}$$

Whereas, P= Pressure, T=Temperature, R=General Gas Constant, v' specific volume, a and b are constants.

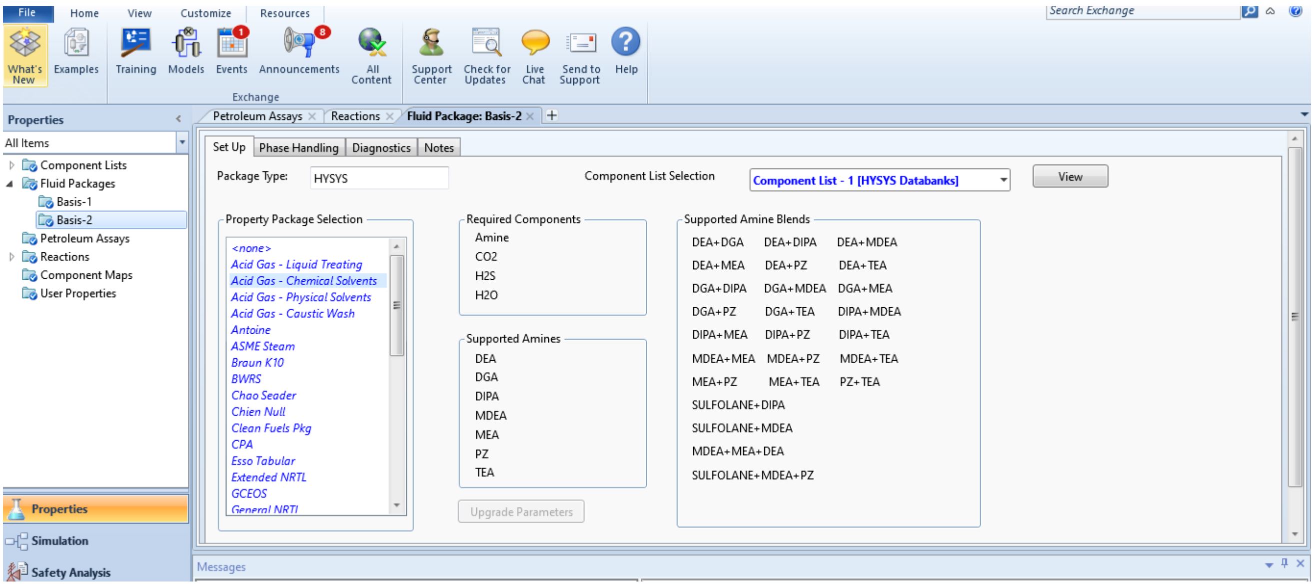

Fig. 01: Selection of components in Aspen HYSYS

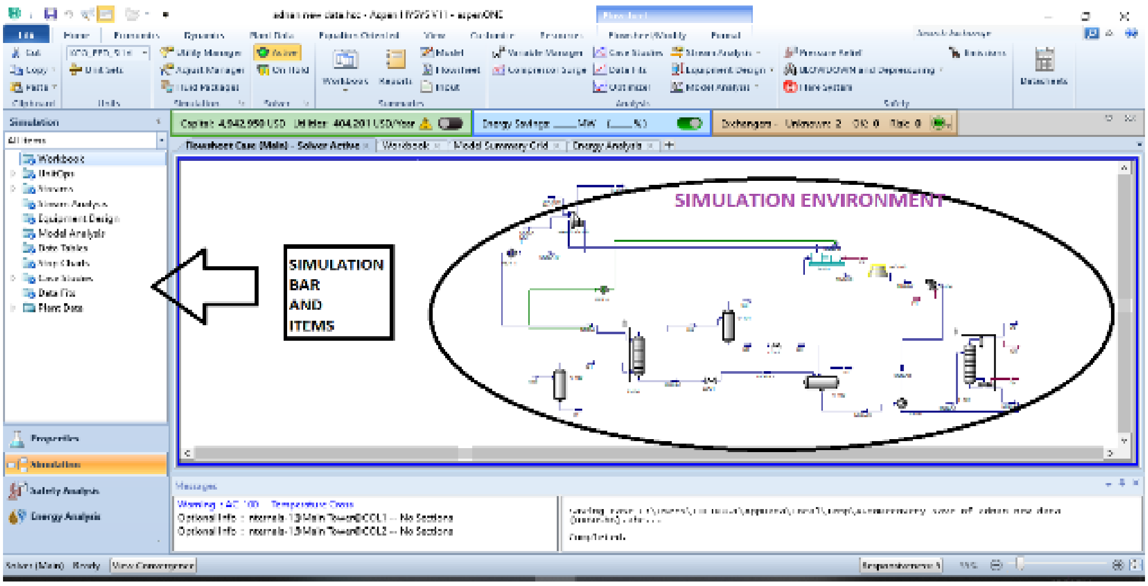

Fig. 02: Simulation environment in Aspen HYSYS

PFD (Process Flow Diagram) of the model developed in the software is shown in Fig. 03.

3. Results and discussions

Natural gas contains various components as per the well composition. The prominent one is methane that largely contribute towards efficient fuel product. However, natural gas also has unwanted components that endanger ecosystem. Acid gas (CO_2) is one of those dangerous gasses. Acid gas emissions are hurting the very essence of environment and the biodiversity. Acid gas in environment is one of the reasons for multifarious menace humans and animals are facing; it weakens internal power of humans especially living near the plant area. But more importantly it lowers the natural gas calorific value, corrodes pipelines, brings instability in process and so on and so forth.

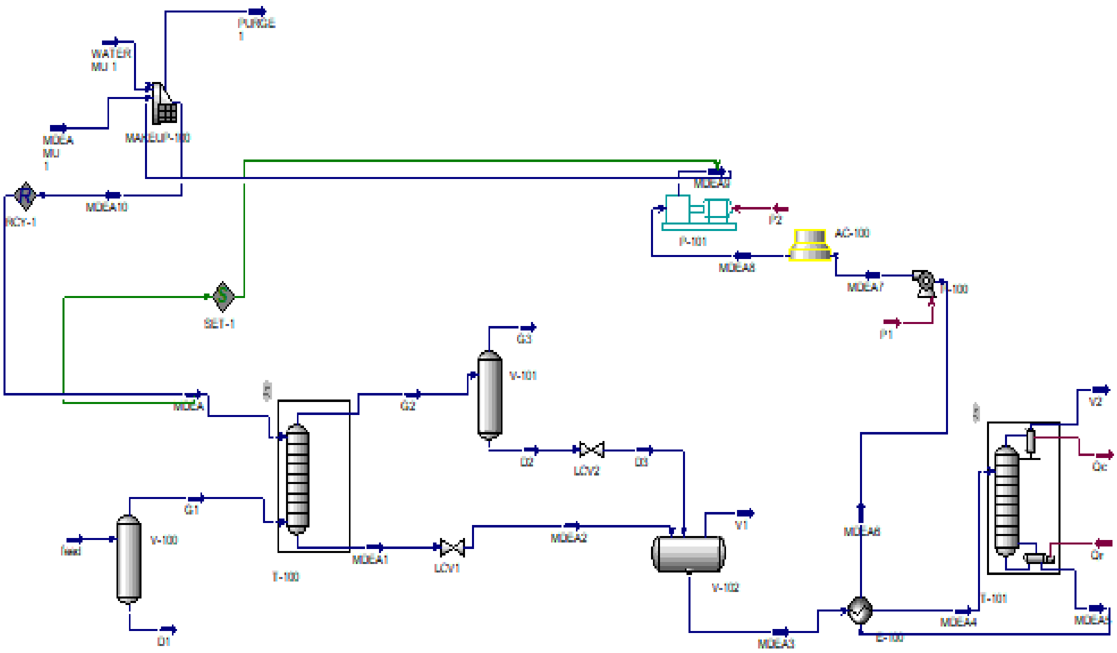

Fig. 03: Simulated acid gas removal process

It then enforces to reduce feed flow in order to keep the operation in order. The problem persisted over the years for uncontrolled amount of acid gases at KPD plant (OGDCL PLANT); resulting in lower feed flow, causing economic regressions in company.

Therefore, operating parameters including feed flow, feed temperature and feed pressure are adjusted against acid gas (CO_2) removal in order to achieve optimized conditions so that feed flow can be raised with better sweetening capacity. As per SSGC, the sale gas composition should not have CO_2 mole per cent more than 3.

Fig. 04 indicates that at constant conditions of Temperature 35°C, feed pressure 1015 Psia and solvent flow rate at 3550 Bar/day, feed flow rate has direct relation with CO_2 mole percent in sweet gas so increasing feed flow rate will eventually result in increased CO_2 mole percent in product stream (sweet gas).

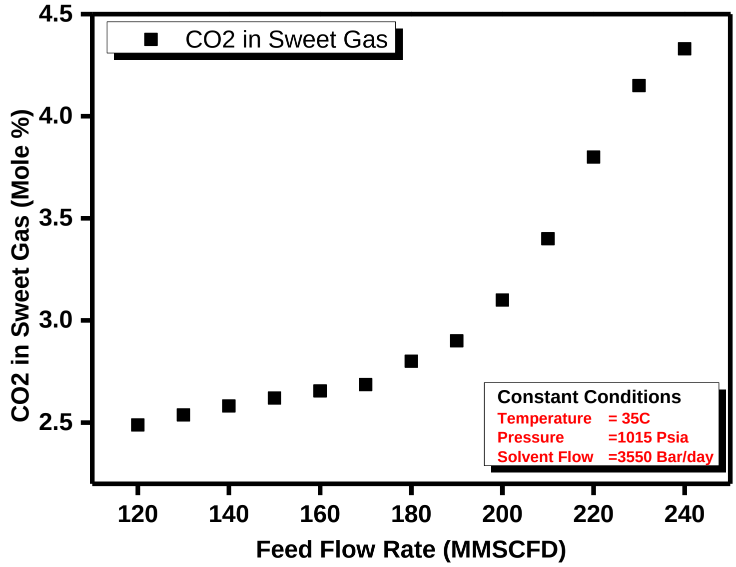

Fig. 04: Effect of feed flow on CO_2 removal

At 200 MMSCFD sweet gas exceeds the limit of CO_2 mole % in sweet gas which is proposed by SSGC. Ergo, on such pattern, 200 MMSCFD flow can be enhanced against the limit set by SSGC.

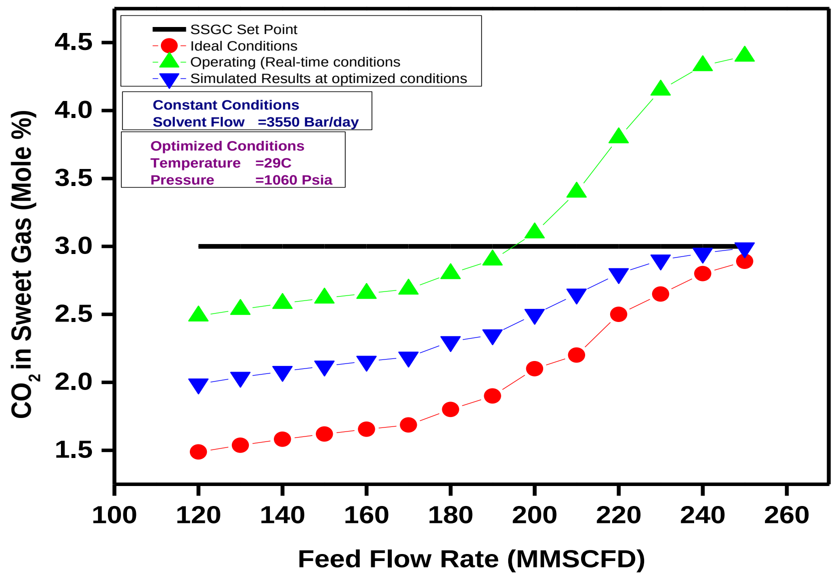

Fig. 05: Effect of feed flow on CO_2 mole % in sweet gas under ideal, operating and simulated conditions

The fig. 05 shows a comparison of three different scenarios: ideal conditions, operating conditions (plant side at operating parameters) and simulated conditions (Feed Temperature 29'c and Feed Pressure 1060 Psia) through Aspen HYSYS. The profile indicates that CO_2 amount (Mole %) exceeds the SSGC set limit (3 Mole Percent) in Sweet Natural Gas in plant real time conditions (35°C and 1014 Psia) when feed flow touches 190 MMSCFD. But simulated data as per optimized conditions (Feed Temperature 29°C and Feed Pressure 1060 Psia) gives room to enhance feed flow rate till 245 MMSCFD under CO_2 limit (2.98) which satisfies the designed feed flow for KPD Plant.

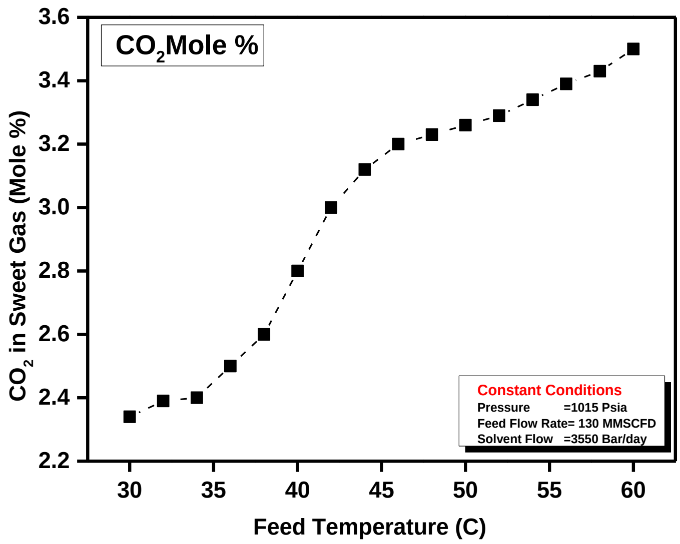

Fig. 06: Effect of feed temperature on CO_2 removal

The fig. 06 depicts that increasing feed temperature will result in increased CO_2 mole percent in sweet gas at constant feed pressure of 1015 psia and feed flow rate at 130 MMSCFD. It is all because of inefficient absorption of CO_2 by solvent due to high temperature which eventually results increasing amount of CO_2 in product gas (Sweet Gas). As absorption works best under low temperature.

The profile in fig. 07 shows simultaneous effect of feed pressure and feed temperature on CO_2 mole per cent in sweet gas. Increasing feed pressure has direct relation with CO_2 removal from sweet gas and increasing temperature has indirect relation. At constant feed flow and solvent flow, optimum conditions are achieved at 42 °C and 1130 psia. At these conditions CO_2 will be removed from natural gas as required by SSGC.

This can be deduced from the fig. 08 that feed pressure is inversely proportional to the CO_2 mole percent in product gas. Thus increasing feed pressure will result in decreasing CO_2 amount in sweet gas because higher will be the pressure lower will be the absorption at constant feed temperature, feed flow rate and solvent flow rate.

The profile in fig. 09 shows feed pressure impact on CO_2 in sweet gas w.r.t ideal conditions, real time conditions, and two other optimized conditions.

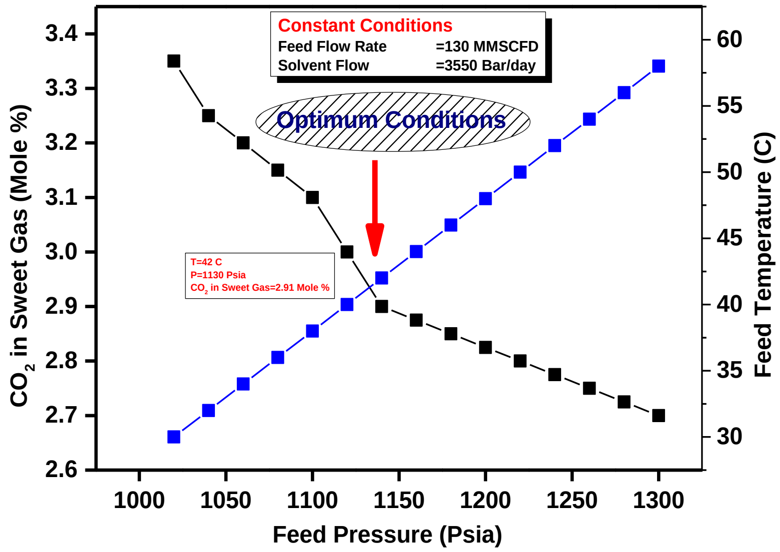

Fig. 07: Simultaneous effect of feed temperature and pressure on CO_2 removal

Real time conditions can be improved by decreasing temperature from 35°C to 27°C at 230 MMSCFD with increase in feed pressure.

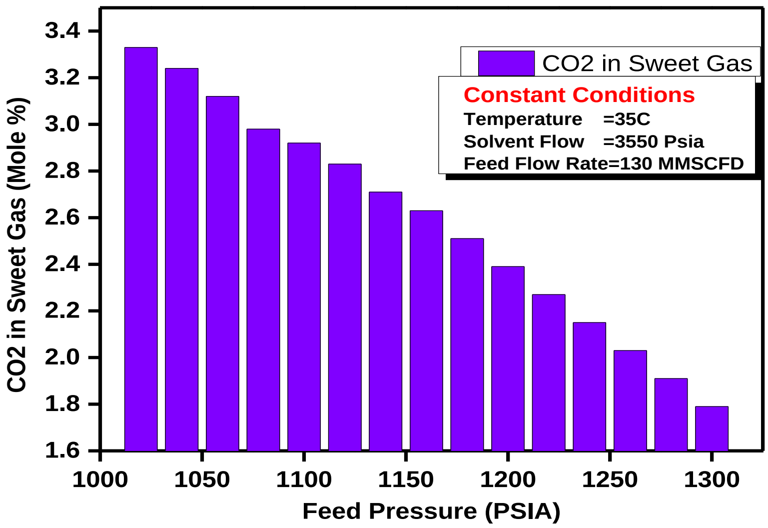

Fig. 08: Effect of feed pressure on CO_2 removal

This can further be interrupted that raising the feed pressure and lower the temperature to 27 °C, as compare to 35 °C of plant side data, will allow feed flow to be raised to 230 MMSCFD.

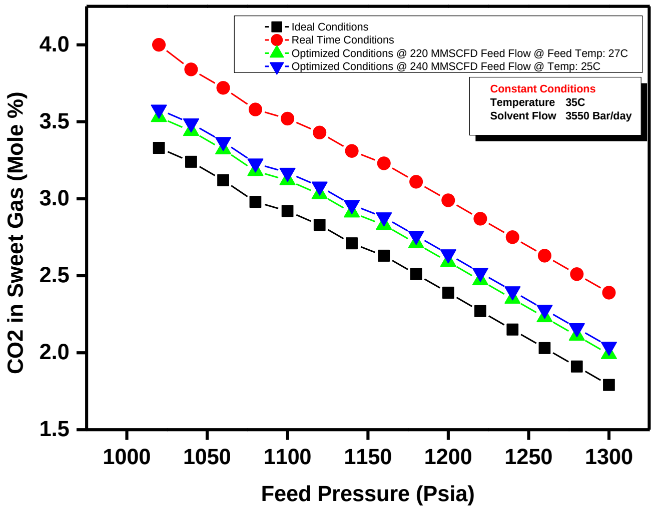

Fig. 09: Comparison of different conditions for CO_2 mole % vs feed pressure

4. Conclusion

Natural gas facilities are designed to handle acid gas removal from the gas stream to meet gas and pipeline specification of CO_2 contained in the sweet gas. With the use of ASPEN HYSYSV10 software and industrial data from OGDCL KPD Plant, natural gas sweetening plant was designed; process conditions and compositions were inputted and simulated.

Results obtained shows that CO_2 content in natural gas stream from reservoirs can be reduced to the required gas and pipeline specification limits as set by SSGC by optimizing operating parameters. It is observed that at feed temperature 35°C, feed pressure 1015 Psia and solvent flow 3550 Bar/day, feed flow rate of 190 MMSCFD is controlled for on-spec sweet gas product. Further, it is concluded that at 29°C feed temperature, 1060 Psia feed pressure, feed flow can be enhanced to 240 MMSCFD (plant's full capacity) while keeping solvent flow constant at 3550 Bar/day.

It is further concluded that feed temperature cannot be exceeded to 43°C at constant conditions otherwise gas will go off-spec but at 42°C and 1130 Psia CO_2 can be controlled in sweet gas. The simulation model developed can also be used as a guide for understanding the process and the economics, and also a starting point for more sophisticated models for plant designing and process equipment specifying.

The simulation work has achieved high acid removal which meets the gas pipelines specifications for almost all amine types and blends.

Acknowledgement

Authors would like to extent his gratitude and please to thank CHEMICAL Engineering Department and faculty of Engineering in MEHRAN UET JAMSHORO for support, guidance

in the work and engagements.

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