Synergy between two natural gas sweetening processes

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ABSTRACT

Merox process is a developed process for natural gas sweetening. However this process has one main disadvantage, which is the fact that carbon dioxide in the feed gas consumes the sorbent solution. High efficiency of carbonate based solutions for removal of bulk of CO_2 from natural gas is a well-known fact. The alkalinity is important in removal of acid gases by potassium carbonate solution. The main idea behind this work was to investigate the possibility of inhibition of Merox solution consumption by a synergy between Merox and carbonate based sweetening processes. In this study, a carbonate based sweetening process is simulated using Aspen Plus simulator for sweetening the natural gas produced in one of gas fields located in Iran. The effects of addition of sodium hydroxide to the solution on the gas sweetening performance and efficiency are investigated. It is revealed that modifying the solution of this process using sodium hydroxide increases the capacity of the solution in removing acid gases.
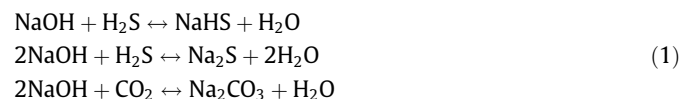
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Introduction

Presence of acid gases in natural gas results in corrosion in facilities and reduction of the natural gas heating value. Removal of the acid gases from natural gas before transmission through pipeline is inevitable (Iliuta et al., 2004; Amoore and Hautala, 1983; Kohl, 1997; Processors, 2004). The maximum allowable concentrations of hydrogen sulfide and carbon dioxide for natural gas transmission are 4 ppm and 2 mol%, respectively (Kidnay and Parrish, 2006; Kohl, 1997). Gas sweetening processes of industrial gas treating plants must provide (a) complete removal of H_2S, (b) handling large flow rates of gas, (c) high pressure operation, and (d) solution regeneration (Katz and Donald La Verne, 1959; Kohl, 1997; Processors, 2004). For the removal of these two gases from natural gas, several processes such as amine based, Sulfinol, and carbonate based processes have been developed (Cousins et al., 2011; Ghanbarabadi and Khoshandam, 2015; Kazemi et al., 2014; Kim et al., 2013; Polasek and Bullin, 1984). The possibility of a synergy between different solutions used for the purpose of natural gas sweetening is arisen by usage of different Sulfinol solutions and mixed amine solutions. In various Sulfinol processes a mixture of either diisopropanol amine–sulfolane or MDEA–sulfolane and in

the mixed amine processes a mixture of tertiary amines and secondary (or primary) amines are used for natural gas sweetening (Anufrikov et al., 2007; Erga et al., 1995; Fouad and Berrouk, 2013; Idem et al., 2005; Kazemi et al., 2014; Kohl, 1997; Nuchitprasittichai and Cremaschi, 2011; Processors, 2004; Rajani, 2004). In Sulfinol-M, Sulfinol-X and Sulfinol-D processes a synergy between chemical and physical absorption of acid gases, while, in mixed amine processes synergy between methods of chemical absorption are exploited. Each of the mentioned processes combines advantages of the two solutions while the advantage of each solution covers for the disadvantage of the other one.

Solution of 20 wt% potassium carbonate can be used for natural gas sweetening. This solution has a large capacity for chemical absorption of CO_2 and also in presence of SO_2 it is a cost effective process (Wappel et al., 2009). A large number of the natural gas sweetening plants around the world (over 700 sweetening plants) implement the potassium carbonate process (Rufford et al., 2012). Sodium hydroxide (NaOH) can react with the acid gases H_2S and CO_2 according to the reaction set (1), which are occurring in namely Merox natural gas sweetening process (Jensen et al., 1966; Kohl, 1997)

$$NaOH + H_2S \leftrightarrow NaHS + H_2O$$
$$2NaOH + H_2S \leftrightarrow Na_2S + 2H_2O \tag{1}$$
$$2NaOH + CO_2 \leftrightarrow Na_2CO_3 + H_2O$$

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Merox process is used for the removal of small quantities of CO_2 and H_2S from natural gas and refinery gases (Kohl, 1997; Raab, 1976; Manieh and Ghorayeb, 1981). One of the main problems of this process is consumption of the solution upon contact of carbon dioxide. On the other hand, high efficiency of potassium carbonate process in removal of CO_2 according to reaction (2) is an important and well-known fact:

$$K_2CO_3 + CO_2 + H_2O \leftrightarrow 2KHCO_3 \qquad (2)$$

Considering these facts, this study investigate a possible synergy in acid gas removal with the use of a combination of these two solutions, each of which taking a part in chemical absorption of each of the main two acid gases.

The sour gas composition

The composition of the sour gas entering the unit, is supposed to be the same as feed gas of a sweetening unit at northern east of Iran. The composition of sour natural gas of this gas field is according to Table 1.

Steady state, rate based simulation

Simulation

The gas sweetening unit that is located in Iran was simulated by Aspen Plus process simulator. Because of the ionic nature of the reactions, the property model for the simulation must utilize a true component approach in order to model short range forces between molecule–molecule, ion–molecule and ion–ion and also long range forces between ion–ion species. Thus, ELECNRTL model is used for simulation of this process (ASPEN, 2012; Chen et al., 1979).

In previous studies, the rate-based distillation model in Aspen Plus was used for the modeling of the absorber in natural gas sweetening plants (Zhang et al., 2009; Tönnies et al., 2011; Jayarathna et al., 2011; Qi et al., 2013). Equilibrium distillation model is not suggested for the modeling of the chemical absorption processes (e.g. carbonate based processes) because of its inability in prediction of the effect of reactions on the heat and mass transfer phenomena (Mudhasakul et al., 2013). The rate-based model solves mass and heat transfer correlations along with liquid holdup correlations (Mudhasakul et al., 2013; Zhang et al., 2009). Nevertheless, for the modeling of stripper column, as suggested by Mudhasakul et al., due to higher temperatures and higher reaction rates, equilibrium approach will result in the same results as the rate-based approach (Mudhasakul et al., 2013). Thus, rate-based and equilibrium approaches were used in modeling the absorber and stripper columns, respectively.

Table 1
The sour gas composition.

Component	Mole%
CH_4	74.2
C_2H_6	10.9
H_2O	0.1
H_2S	5.7
CO_2	5.6
C_3H_8	2.3
i-butane	0.3
N-butane	0.2
i-pentane	0.2
N-pentane	0.15
N-hexane	0.15
C_7+	0.2
Total	100

In accordance to Table 1, there is 0.2 mol% of C_7+ in the feed gas. As this hydrocarbon cut contains hydrocarbon molecules with 7 or more carbons, in the simulation environment normal octane was used instead.

Process description

The simulation was performed based on a flow sheet as presented in Fig. 1, however an industrial unit might have different unit operations based on the sour gas conditions and the specifications required for the sweet gas (Chowdhury, 2013). According to Fig. 1, the sour gas at 40 °C and 22 atm enters the bottom of absorber unit. The carbonate solution at 116 °C and 26 atm enters the absorber at the top stage. In the absorber based on reaction (2) CO_2 and H_2S of the natural gas are absorbed by the solution. The sweet gas leaves the absorber with low H_2S and CO_2 mole fractions. The rich solution containing absorbed the acid gases and a little amount of other components present in the natural gas leaves the contactor at the bottom stage. The rich solution is transferred to a solution regenerator, but prior to regenerator it passes through an expansion valve and then a two phase separator. The valve reduces the pressure and temperature of the solution to 2 atm and 101 °C. The two phase separator operates under these operational conditions. In this separator some part of the solution might vaporize and leave the system. In the solution regenerator, the absorbed acid gases in the solution leave the system from the top of the column. The regenerated solution from the bottom of the column are transferred back to the contactor by passing through a centrifugal pump for rising the pressure to 26 atm and a heater for setting its temperature to 116 °C. A makeup solution is added to the recycle solution in order to adjust the solution loss in the operational units.

Results and discussion

The synergy

A set of simulation was designed by application of a change in composition of the solution and the process efficiency was calculated. If the applied changes do not affect the H_2S and CO_2 removal efficiencies, then the proposed synergy fails. But upon variation of removal efficiencies of the acid gases, a comprehensive interpretation of the results is needed to evaluate the synergy. Having this procedure in mind, 10 MMSCFD of the introduced natural gas in Table 1 was processed with lean solution modified with sodium hydroxide at various concentrations. The process removal efficiencies are reported in Table 2 and Fig. 2.

As indicated in Table 2 and Figs. 2 and 3, upon addition of sodium hydroxide to the lean solution, the H_2S and CO_2 mole fractions in the sweet gas decreased. The fraction of H_2S in the sweet gas reduced to a minimum (less than 1 ppm) at sodium hydroxide weight percent of 5.5%, the mole fraction of CO_2 in the sweet gas reached a minimum (less than 0.1%) for sodium hydroxide concentration of 12 wt%. Based on the presented results, when the weight percent of sodium hydroxide in the lean solution is between 0% and 5.5%, the fraction of H_2S and CO_2 in the sweet gas are decreased. But by increasing concentration of the added sodium hydroxide to a value in the range of 5.5–12 wt%, the fraction of CO_2 in the sweet gas decreases further, while the fraction of H_2S in the sweet gas does not change. Upon increasing concentration of sodium hydroxide concentration in the solution to a value higher than 12%, the CO_2 and H_2S are almost completely removed from the natural gas.

Another important aspect of applying this change is the fact that sodium hydroxide increases the pH of the solution and at a