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Integrated process development for an optimum gas processing plant



Abd El-Rahman Sayed^{a,b,*}, Ibrahim Ashour^{b,c}, Mamdouh Gadalla^d

^a Egyptian Natural Gas Company (GASCO), New Cairo, Egypt

^b Department of Chemical Engineering, Faculty of Engineering, Minia University, Egypt

^c Environmental Engineering, Zewail City of Science and Technology, 6th October, Egypt

^d Department of Chemical Engineering, The British University in Egypt (BUE), Egypt

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ABSTRACT

The aim of this work is to develop and optimize an integrated process for natural gas plant in Egypt instead of flaring these gases and losing their revenues. The natural gas is sour wet feed gas containing mercury and some of volatile organic compounds with a capacity of around 21 million cubic feet per day. These impurities require sophisticated gas treatment processes that can handle and control the pollutants to acceptable limits.

The design of new gas plant will be performed through firstly, the design methodology and cascade configuration of gas plant units based on feed gas composition. Secondly, integrated development and optimization of gas treatment process model is achieved using Aspen HYSYS simulation program. Thirdly, modeling of natural gas liquids extraction unit and fractionation train is conducted based on the required marketable products specifications. Finally, Aspen process economic analyzer program is used to calculate the expected capital expenditures of the plant. Optimizing the plant configuration accounts for best selection of treatment units and processing equipment, including mercury removal unit, sulfur recovery unit, BTEX recovery unit, etc. The preliminary capital expenditures of the gas conditioning and processing plant will be around 48 MUSD.

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1. Introduction

Natural gas is a gas obtained from a natural underground reservoir, containing a large quantity of methane along with heavier hydrocarbons such as ethane, propane, etc. In addition, it contains a considerable amount of non-hydrocarbons, for instant nitrogen, carbon dioxide and hydrogen sulfide (Younger, 2004). The sold natural gas specifications should meet the standard specifications of sales gas (ES: 1606, 2008). Therefore, the raw gas from the reservoir, which is at certain pressures and is generally saturated with water vapor, will need considerable treatment and processing.

The current study presents an optimum and integrated process design for gas plant to treat a sour wet feed gas that contains mercury and some of volatile organic compounds (VOCs) with around capacity 21 MMSCFD. The developed process design contains all mandate

gas treatment units, natural gas liquids recovery unit and marketable products' fractionation train.

Currently these gases are flaring which in a way this poses a negative impact on the environment protection and thus leads to the loss of the revenues of these gases and the products which can be recovered from these gases.

2. Design methodology

2.1. Optimizing and integrating the design of gas processing plant

For gas processing plant, the optimal design will be achieved with focusing around (Paradowski et al., 2005);

* Corresponding author at: Egyptian Natural Gas Company (GASCO), New Cairo, Egypt.

E-mail address: arahmans110@gmail.com (A.E.-R. Sayed).

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- Configuration of gas treatment processes cascade, which will be more economic and has high operability.
- Selection of the proper acid gas removal process; type of solvent, H₂S vs. CO₂ selectivity, requirement to remove other sulfur compounds...etc.
- Selection of the proper gas dehydration process; liquid desiccant, solid desiccant or both.
- Economic handling of separated impurities in the treatment units.
- Selection of NGLs recovery technology; absorption or cryogenic process.
- Environment pollutants control; all effluents streams contain pollutants within permissible limits as per Egyptian Environmental Law.

In addition to the above list, the desired integration inside each unit in new plant means achieving the combination between needs and tasks of “opposite” kinds so that savings can be obtained (Gundersen, 2013). For example, the cooling & condensation are integrated with heating & evaporation as a kind of heat integration. Also, expansion integrated with compression is made as a kind of power integration.

Moreover, the desired integration between different units in new plant can be achieved by using byproducts from unit as raw materials in other unit as a kind of chemical integration.

2.2. Natural gas treatment units design methodology

Natural gas treatment units are designed based on the impurities present in the process feed gas and permissible limits of these impurities in the sales gas. All acid gases like H₂S and CO₂, shall be removed to prevent corrosive damage to equipment and piping. Hydrogen sulfide is also toxic and total sulfur content is normally regulated. The conversion of H₂S to elemental sulfur is done in the event if it is economical, or required for environmental reasons. Also, all free liquids, both hydrocarbon and water, will be removed.

Based on the composition of natural gas, the required gas treatment units are designed. Also, the impurities in natural gas control the sequences of gas treatment processes.

In the event that the gas contains mercury, installing mercury removal unit upstream gas sweetening unit is undoubtedly considered the preferred location for sour gas and upstream dehydration package for sweet gas, which avoid emissions of mercury to the atmosphere and contamination of plant equipment. Such a location within the whole treatment plant shall minimize the environmental impact and hence is considered an optimization exercise. This location will ensure any NGLs produced are free from mercury. However, this location is more of a challenge for the mercury removal absorbent (Johnson Matthey, 2014).

In the event of sour feed gas, sweetening unit is required to be installed downstream of mercury removal unit to remove H₂S from feed gas and avoid expensive material of construction for downstream units.

H₂S removal technology and sulfur recovery process are selected based on flow rate of sour feed gas and the concentration of H₂S in it. The feed gas compositions and conditions, desired purity of the treated gas and the selectivity of H₂S over CO₂ act as the evaluation criteria of acid gas removal technologies (NREL, 2009). Amine based solvent processes consider a simplified process flow scheme, representing a typical chemical solvent process. Acid gas to be treated is introduced into the bottom of tray or packed tower and is contacted counter-

currently with lean regenerated solvent. Sweet gas exits at the top of the tower (Okimoto and Gadeholt, 1998). Methyl Di Ethanol Amine (MDEA) is a tertiary amine that offers many advantages over other alkanol-amines. The difference in the rates of reaction with H₂S and CO₂ gives MDEA a desirable feature over other amines, namely selectivity of H₂S over CO₂. This selectivity is advantageous when the acid gas stream is sent to a sulfur recovery unit (SRU), since CO₂ is undesirable in SRU (BRE V.1401, 2013).

For rich H₂S acid gas stream, the Claus process is the most widely used process technology for conversion of H₂S to elemental sulfur (Linde Process Plants, Inc.—Sulfur Process Technology, 2013). The conversion of H₂S to elemental sulfur in Claus process is achieved through two types of reactions; thermal and catalytic reactions. A typical Claus-plant can recover 95–98% of the sulfur of rich H₂S stream then incinerator may be required to burn residual H₂S to SO₂ which is less toxic than H₂S (Okimoto and Gadeholt, 1998). After gas sweetening, the gas will be saturated with water. Therefore, it is required to dehydrate sweet feed gas.

The selection of a proper dehydration method depends on the initial water content and required water dew point downstream of it (Kocken, 2016). Also, process character and economic factor are considered in choosing the proper dehydration method (Netusil and Ditl, 2011).

Absorption by tri-ethylene glycol (TEG) is used widely for gas dehydration in the petroleum industry to dehydrate the natural gas, while adsorption dehydration can achieve very low water content and is best applied where very low dew point are required (<−50°C) (Netusil and Ditl, 2011). In the event of saturated gas with water vapor, it is economically using TEG. However, if water dew point is required for cryogenic temperatures of propane recovery, mole sieve dehydration package will be installed in downstream of TEG unit.

In the event that the plant feed gas contains benzene, toluene, ethyl benzene and xylene (BTEX), the BTEX treatment will be in two locations; for acid gas stream released from amine stripper in sweetening unit and gases from TEG re-boiler.

Removal of BTEX from acid gas is necessary to protect SRU catalysts from cracking and producing coke that blocks active sites (Petrofac Services Ltd., 2010). Deactivation of catalyst results in low sulfur recovery and subsequently frequent plant shutdowns to replace catalyst and very short catalyst life (Crevier et al., 2001). Axens CSM 31 is an advanced promoted alumina beads used as protective layer to avoid poisoning due to BTEX. Axens materials recommend CSM 31 for BTEX content <100 ppm. Also, Axens recommend BTEX removal facilities upstream to sulfur recovery unit for BTEX content >100 ppm (Roisin, 2015).

Re-generable activated carbon beds used for BTEX removal depends on the fundamental principles of adsorption which takes place with acid gas in an upward flow (Morrow and Lunsford, 1997), where activated carbon beds with a low pressure drop of 0.2 bar are installed on the acid gas feed to adsorb the majority of BTEX (98%).

Activated carbon has a bulk density of about 350 kg/m³ and surface area of 500 m²/g (Burton et al., 2015). Regeneration is performed with downward flow of low pressure steam which eliminates the possibility of steam condensing and fluidization of the bed if the opposite flow regime were used. With the majority of the BTEX removed the acid gas flows to SRU. The steam strips the BTEX from the carbon. The resulting regeneration gas (steam and desorbed BTEX) is vaporized and sent

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